Indiana Electricity Projections: The 2005 Forecast

State Utility Forecasting Group
Purdue University
West Lafayette, Indiana

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Prepared by:

Ronald L. Rardin
Douglas J. Gotham
Forrest D. Holland
Zuwei Yu
David G. Nderitu
Angela D. Thomas

State Utility Forecasting Group
Purdue University
West Lafayette, Indiana

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Forward

This report presents the 2005 projections of future electricity requirements for the state of Indiana for the period 2004-2023. 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 tenth 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."*

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:

https://engineering.purdue.edu/IE/Research/PEMRG/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.

Finally, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its 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: 765-494-2351
e-mail: sufg@ecn.purdue.edu

Executive Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its tenth set of projections of future electricity usage, peak demand, prices and resource requirements. In its most recent forecast, released in 2003, SUFG identified a need for new resources in the first few years. This forecast also reports a need in the short term for a significant amount of 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 2.22 percent per year. This growth rate is similar to that seen in the late 1990s and is very similar to the growth in the 2003 SUFG projections. Peak electricity demand is projected to grow at an average rate of 2.24 percent annually. This corresponds to about 500 megawatts (MW) of increased peak demand per year.

The 2005 forecast predicts Indiana electricity prices to increase slightly in real (inflation adjusted) terms through 2008 and then slowly fall through the remainder of the forecast.

Prior to 2003, SUFG forecasts identified early resource needs that could be classified as peaking, which are intended to be operated only during periods of high electricity usage. Peaking resources are characterized by relatively low construction costs, but high operating costs. The 2003 forecast was the first SUFG forecast that identified a substantial need for additional baseload resources in the first few years. Baseload generators, which are intended to be used even during period of low demand, have relatively high constructions costs, but low operating costs. Cycling, or intermediate, resources have construction and operating cost characteristics between those of peaking and baseload resources. This forecast identifies a relatively balanced need for all three types of resources in the short term, with 860 MW of peaking, 1,170 MW of cycling, and 940 MW of baseload resources required by 2010.

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.

Other issues addressed in the forecast include:

- A summary of the Energy Policy Act of 2005.
- The Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) recently issued by the U.S. Environmental Protection Agency (EPA).
- Interactions between electricity and natural gas prices.
- The potential impact on the electricity industry of moving to a hydrogen-based economy.

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, with greater detail provided for changes that have been made to the modeling system. 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:

https://engineering.purdue.edu/IE/Research/PEMRG/SUFG/

Chapter 3 through 7 describe the data inputs and integrated projections of electricity demand, supply and price for each major consumption sector in the state under three scenarios:

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

Chapter 8 discusses the issues of importance to Indiana electricity policymakers described on page 1-1.

Finally, Appendix A 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. Due to diversity in demand among 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,

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[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. 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.

population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by CEMR. SUFG used CEMR's February 2005 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 1.10 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.94 percent. Other key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.22 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average 1.23 percent annual growth rate over the forecast horizon.
- Despite a lack of growth in manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 2.84 percent annual rate due to gains in productivity.

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

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

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

Fossil Fuel Price Projections. SUFG's current assumptions are based on the January 2005 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 slightly through 2010 and increase moderately over the remainder of the forecast horizon.
- *Utility Price of Coal*: Coal prices will decline slightly in real terms throughout the entire forecast horizon.

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 is shown in Figure 1-2. The annual growth rates for electricity requirements and peak demand in this forecast are 2.22 and 2.24 percent, respectively, compared to 2.16 and 2.07 percent in the previous forecast.

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading. Despite the similar growth rate, the trajectory for electricity requirements in this forecast actually lies above the one for the 2003 forecast. This is caused by a slightly higher than previously projected growth in actual sales through 2003. Therefore, despite the similar growth rates, the 2005 forecast is actually higher than the 2003 forecast. The industrial electricity sales projections in the two forecasts exhibit a similar phenomenon, with the current forecast staying above the previous forecast despite having an almost identical growth rate (see Table 1-1). The electricity sales projections

[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 SUFG Base Forecasts)

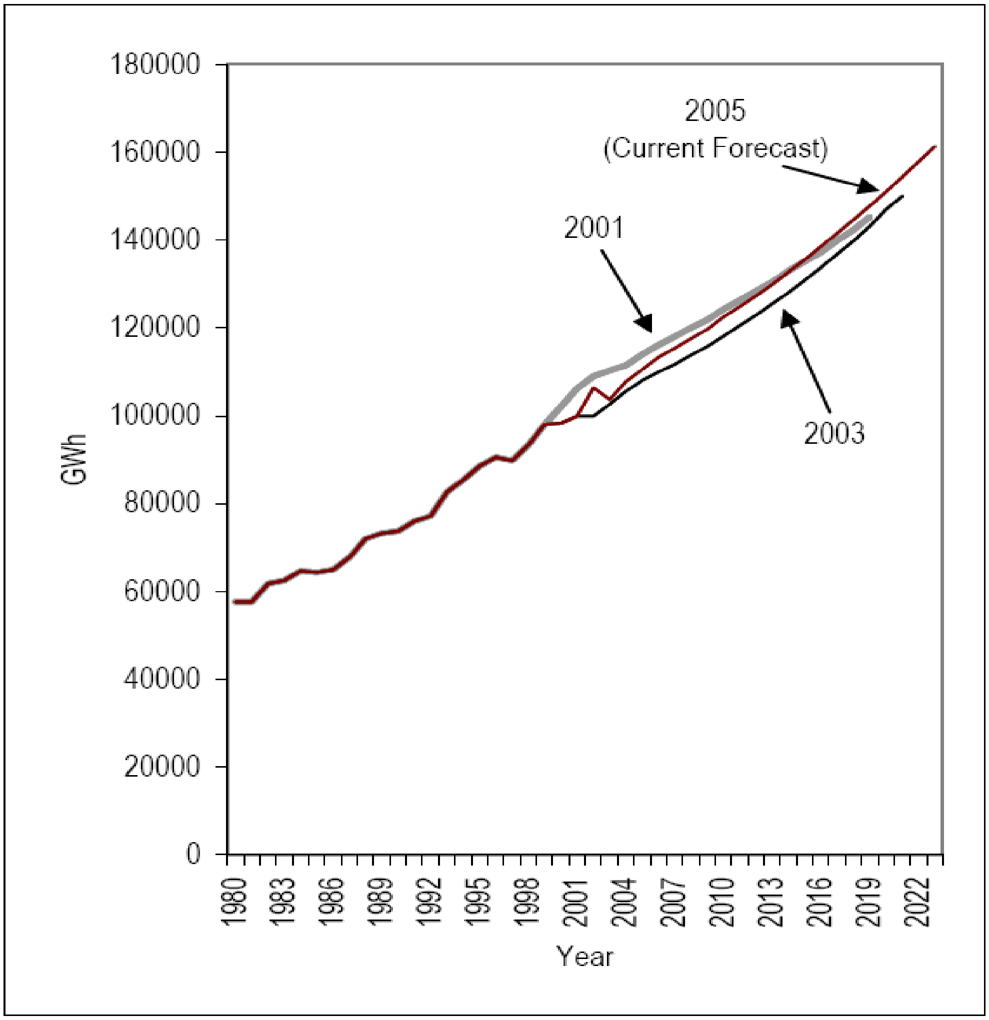


Table 1-1. Annual Electricity Sales Growth (Percent) By Sector (Current vs. 2003 Projections)

Electricity Sales Growth		
Sector	Current (2004-2023)	2003 (2002-2021)
Residential	2.22	1.95
Commercial	2.61	2.71
Industrial	1.99	1.97
Total	2.22	2.16

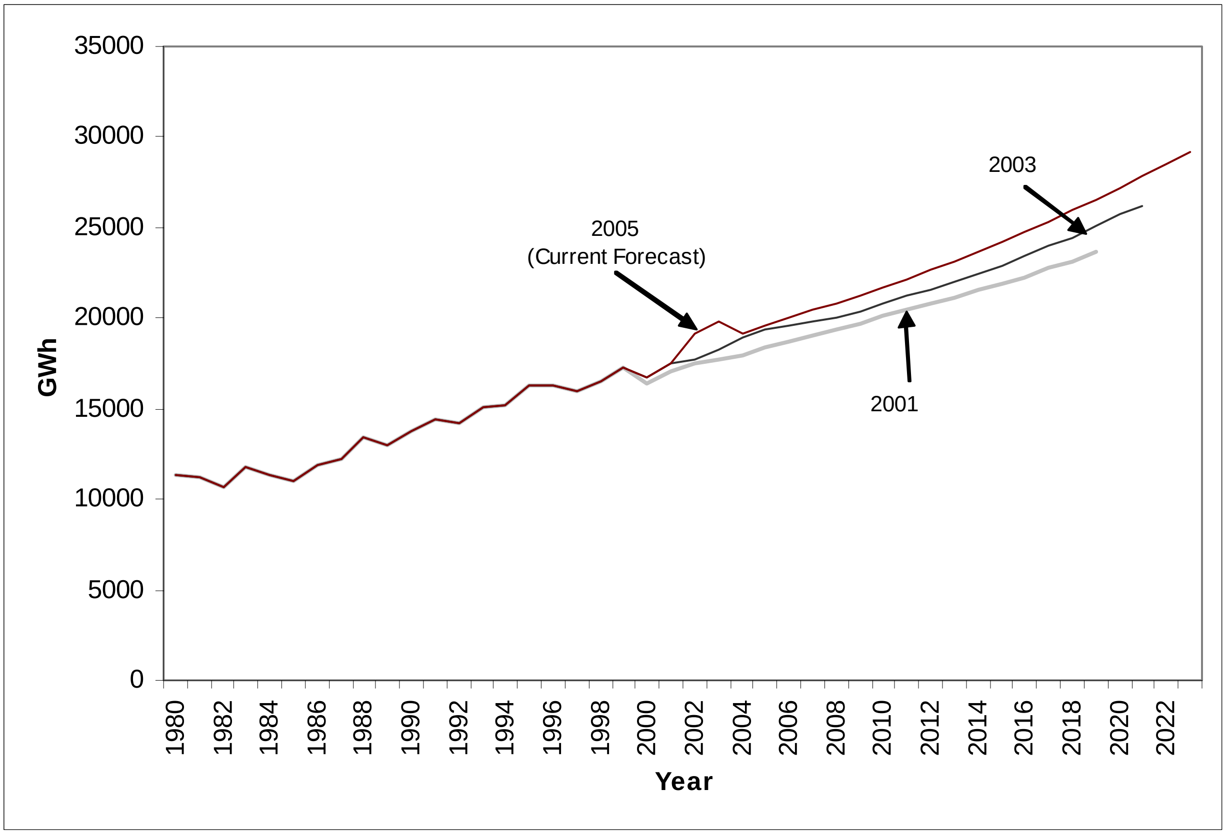
for the commercial sector are slightly below the 2003 projections. The residential electricity sales projections show a stronger growth than those seen in the 2003 forecast.

The growth in peak demand is slightly higher than that projected in 2003. 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 500 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

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



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.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Estimated interruptible loads grow from 750 MW at the beginning of the forecast to about 990 MW at the end. This is similar to the amount of interruptible loads included in the 2003 forecast.

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 210 MW. This represents a substantial increase from the 2003 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, deratings 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.

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.

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 4,800 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2003 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 7,400 MW of resources are required to maintain target reserves.

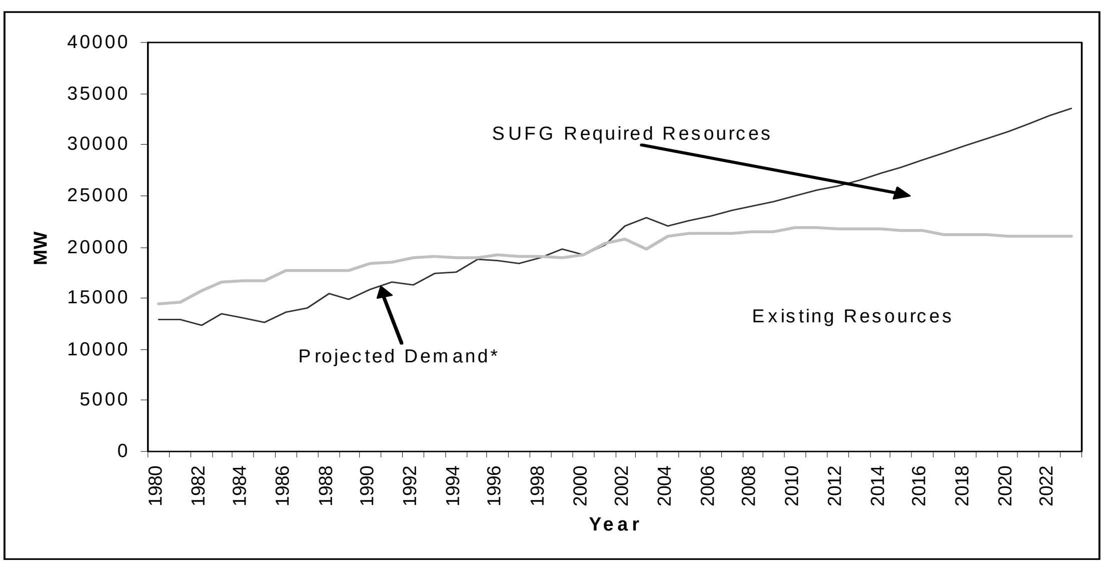
Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2003. Therefore, 2004 and 2005 numbers represent projections. The resource requirements identified in Table 1-2 for 2004 and 2005 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 slightly through 2007 and then remain steady through the remainder of the forecast. Since the change in prices over the forecast horizon is relatively small, price has little impact on the electricity requirements projection for this forecast.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2003" is the base from SUFG's 2003 forecast and the price projections labeled "2001" is the base case projection contained in SUFG's 2001 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2003 dollars (from 1999 dollars for the 2001 projection, and from 2001 dollars for the 2003 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

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



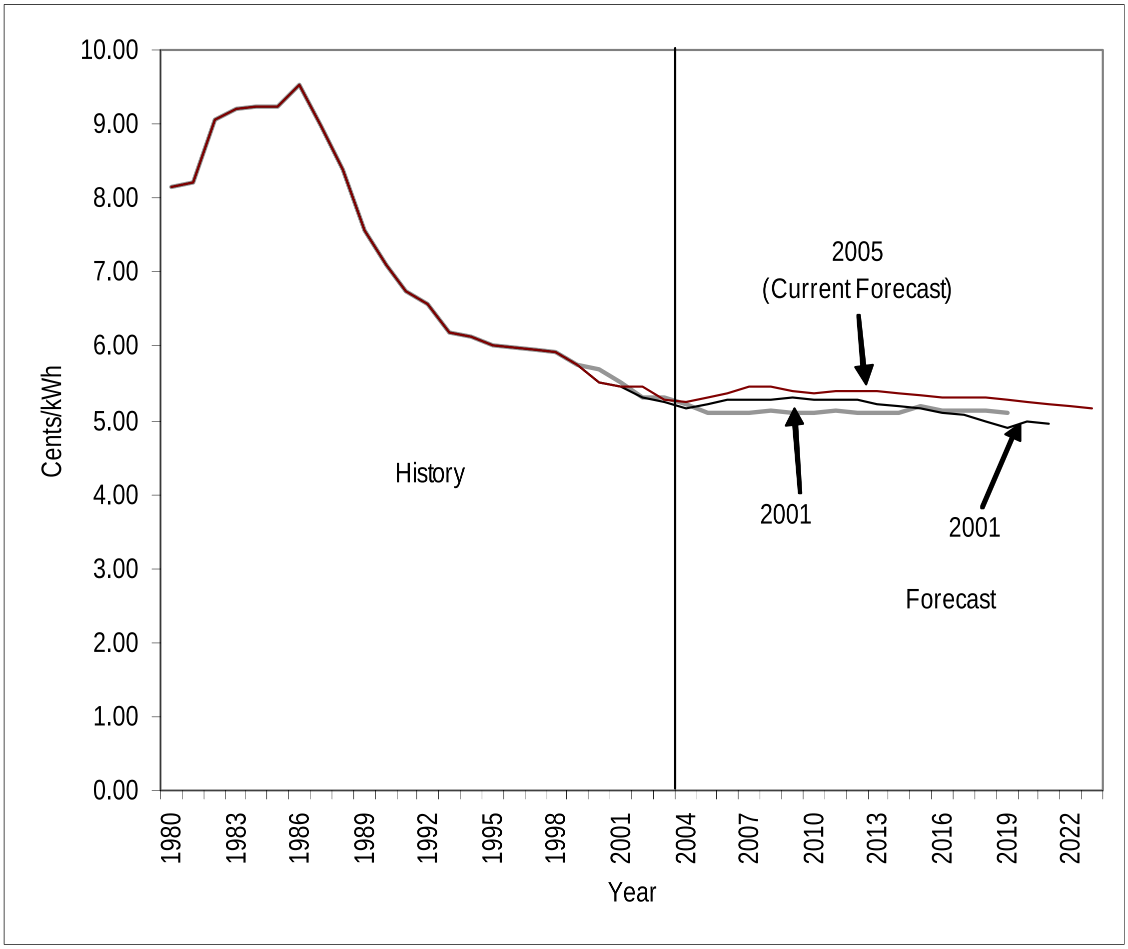
* Projected Demand includes 15% Reserve Margin

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		
2003				19839							
2004	19917	750	19167	21058	1219	240	410	320	970	22028	15
2005	20361	761	19599	21355	296	410	470	450	1330	22685	16
2006	20833	781	20052	21345	-10	490	670	600	1760	23105	15
2007	21278	792	20486	21278	-67	620	860	750	2230	23508	15
2008	21624	804	20820	21493	215	760	930	670	2360	23853	15
2009	22018	817	21201	21493	0	890	1050	880	2820	24313	15
2010	22541	829	21712	21934	441	860	1170	940	2970	24904	15
2011	23006	839	22167	21869	-65	930	1190	1420	3540	25409	15
2012	23474	853	22620	21804	-65	1060	1250	1810	4120	25924	15
2013	23984	863	23121	21704	-100	1300	1340	2140	4780	26484	15
2014	24543	876	23666	21704	0	1460	1430	2490	5380	27084	15
2015	25096	890	24206	21601	-103	1730	1520	2840	6090	27691	15
2016	25694	903	24790	21601	0	1910	1610	3220	6740	28341	15
2017	26276	913	25362	21260	-341	2150	1960	3600	7710	28970	15
2018	26882	928	25954	21260	0	2330	2030	4030	8390	29650	15
2019	27512	938	26574	21260	0	2430	2110	4520	9060	30320	15
2020	28163	952	27211	21097	-163	2730	2180	5030	9940	31037	15
2021	28819	963	27855	21097	0	2860	2250	5540	10650	31747	15
2022	29503	977	28526	21044	-53	3090	2340	6030	11460	32504	15
2023	30185	989	29196	21044	0	3240	2420	6560	12220	33264	15

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

Figure 1-4. Indiana Real Price Projections (2003 Dollars) (Historical, Current and Previous Forecasts)



Two major factors produce the differences among the price projections in Figure 1-4; namely, the capital cost assumptions for new generation equipment and the cost of controlling emissions from coal-fired generation facilities. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices.

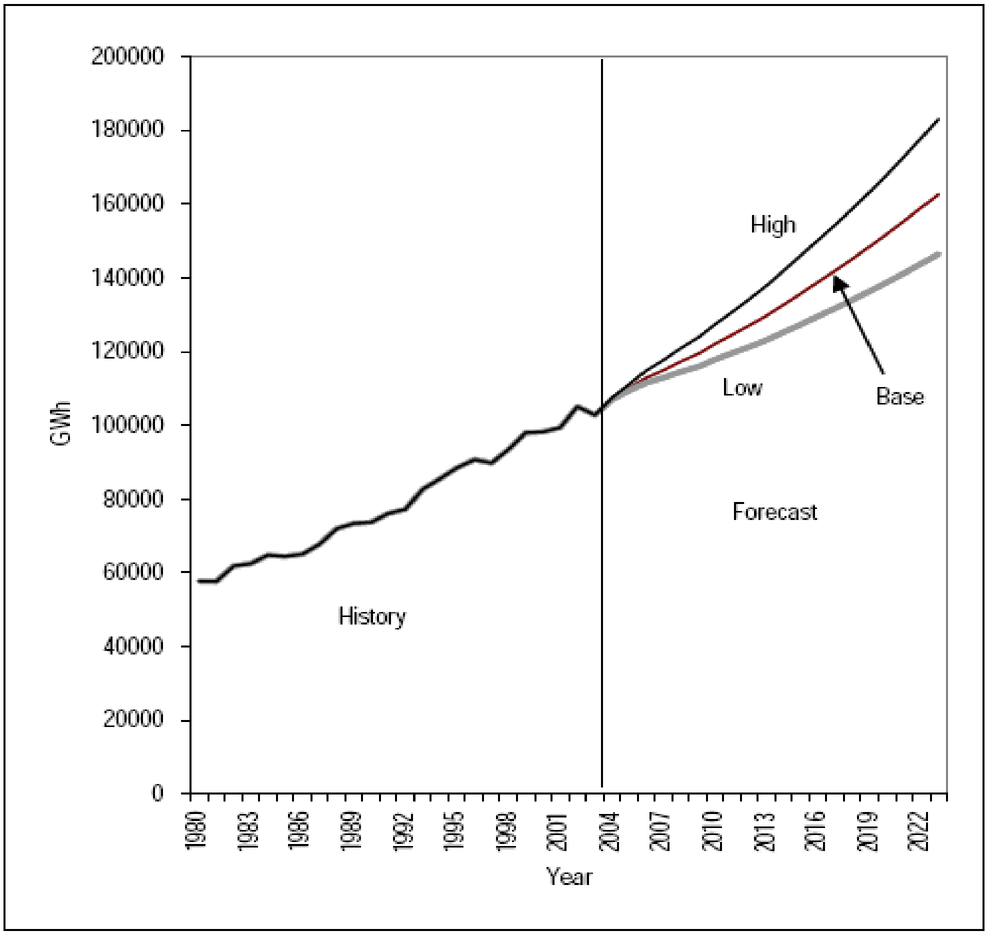
Low and High Scenarios

SUFG has constructed alternative low and high 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 0.56 percent lower and 0.62 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.

Issues of Interest to Policymakers

Four issues of interest to policymakers are briefly addressed here. See Chapter 8 for more detailed discussions of these issues.

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



Summary of the Energy Policy Act of 2005

The Energy Policy Act signed into law on August 8, 2005 has various provisions that affect to varying degrees the electricity industry in Indiana. This section of the report contains a review of these provisions. They include: the repeal of the Public Utility Holding Act of 1935; incentives for clean coal and gasification technologies; incentives targeted at expansion and reliability of the transmission system; the removal of the mandatory purchase requirements in the Public Utility Regulatory Act of 1978; the extension of the renewable energy production tax credit; and the introduction of production tax credit for advanced new nuclear power.

Clean Air Interstate Rule and Clean Air Mercury Rule

In March 2005, EPA issued new rules affecting electric power plant emissions. The Clean Air Interstate Rule (CAIR) lowered allowed emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) from the current levels by roughly 56 percent and 68 percent, respectively. EPA also finalized a rule for mercury emissions called the Clean Air Mercury Rule (CAMR) that is projected to reduce mercury emissions by approximately 70 percent by 2018.

EPA estimates indicate that the installation of SO2 removal equipment on Indiana generators may increase by 70 percent and the number of NOx emission control devices could more than double. While the actual emission control strategies for Indiana's electric utilities will likely differ somewhat from those estimates, they do provide an indication of the level of emission control measures that will be needed.

Electricity and Natural Gas Price Interactions

The price of natural gas affects the consumption of electricity in two distinct ways. First, electricity and natural gas are substitutes for each other for several end uses, such as space heating, water heating and industrial processes. Thus, an increase in natural gas price tends to cause an increase in electricity use as consumers switch from natural gas to electricity. Second, natural gas is also used as a fuel for electricity generation, so an increase in natural gas price causes a corresponding increase in electricity price. This tends to reduce electricity usage as consumers tend to conserve more.

Impact of the Hydrogen Economy on the Electricity Industry

In 2004, the National Academy of Engineering released its report, T*he Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs*, which reported that the most promising use of hydrogen was as a transportation fuel and that the likely hydrogen infrastructure would involve local, distributed production rather than using large production facilities and an extensive transportation network. Thus, the likely sources for hydrogen under this scenario would be from either the reformulation of natural gas or from electricity used in the electrolysis of water. Such a development would have a significant impact on the electricity generation and transmission infrastructure.

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.

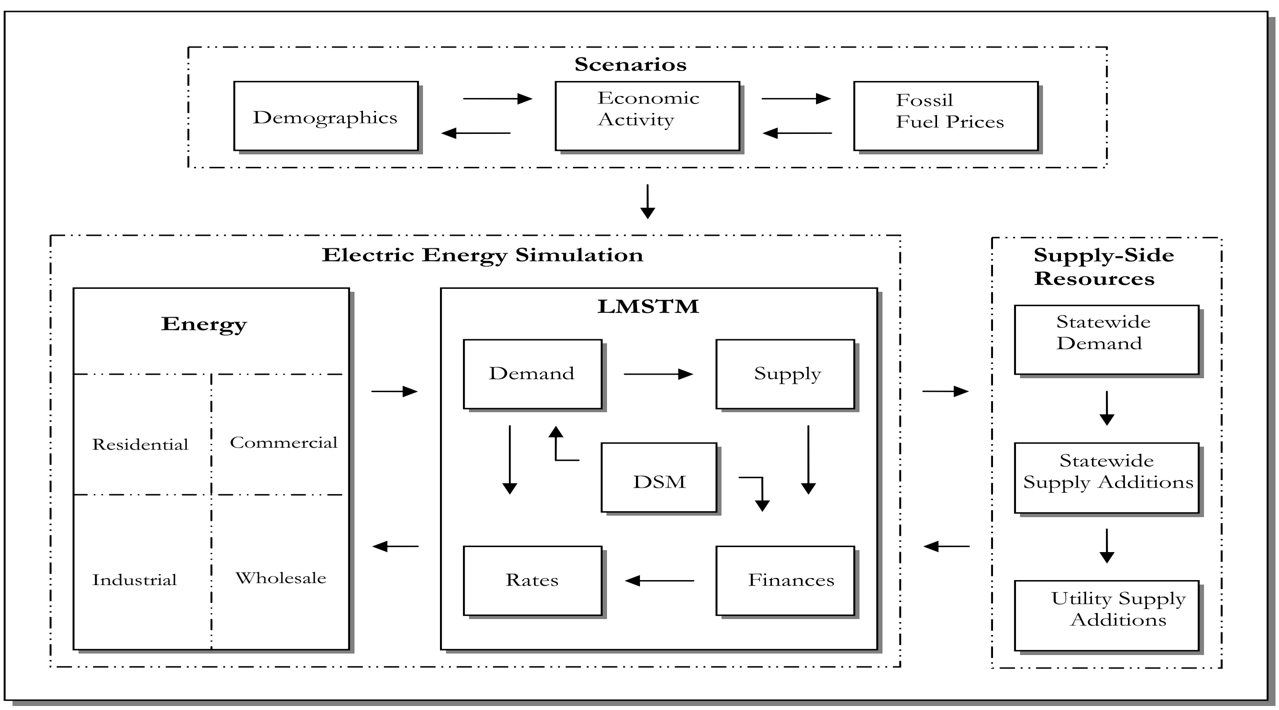
Scenarios

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-

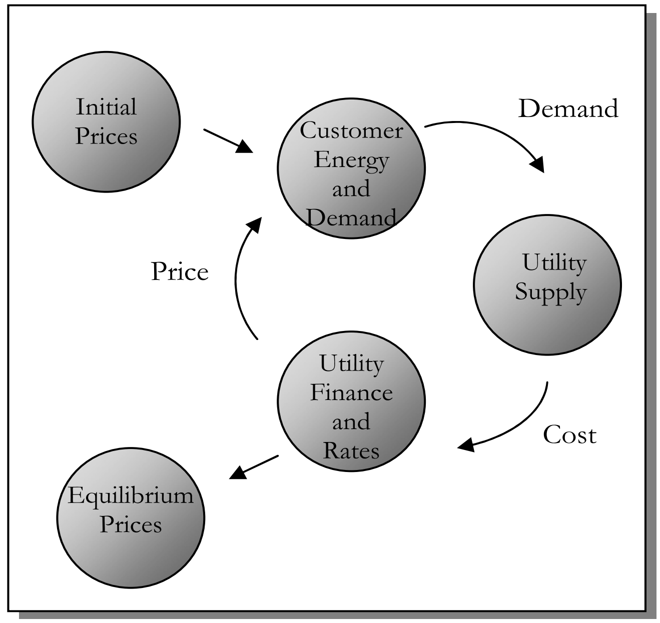
Figure 2-1. SUFG's Regulated Modeling System



owned utilities (IOUs): Indiana Michigan Power Company (I&M); Indianapolis Power & Light Company (IPL); Northern Indiana Public Service Company (NIPSCO); PSI Energy, Inc. (PSI Energy); and Southern Indiana Gas & Electric Company (SIGECO). In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Inc. (HEREC); Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association (WVPA).

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.

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



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.

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. 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 that has been approved by the Indiana Utility Regulatory Commission (IURC).

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

Changes to the Modeling System in this Forecast

In previous SUFG forecasts, additional resource requirements for IMPA and WVPA were assigned to the other utilities as required sales and SUFG did not develop utility-specific projections of resource requirements for these two utilities. The required sales were included in the electricity consumption of the other six utilities under the classification of sales for resale. Thus, required resourcesfor IMPA and WVPA were incorporated in the statewide numbers through the other utilities.

Historically, IMPA and WVPA have purchased a large fraction of their requirements from the other utilities in the state. In recent years, they have begun shifting more toward a combination of self-owned generation and long-term purchases from other entities. Therefore, beginning with this forecast, SUFG has shifted to modeling utility-specific resource requirements for IMPA and WVPA. Existing contracts between them and the other Indiana utilities are included in the modeling system.

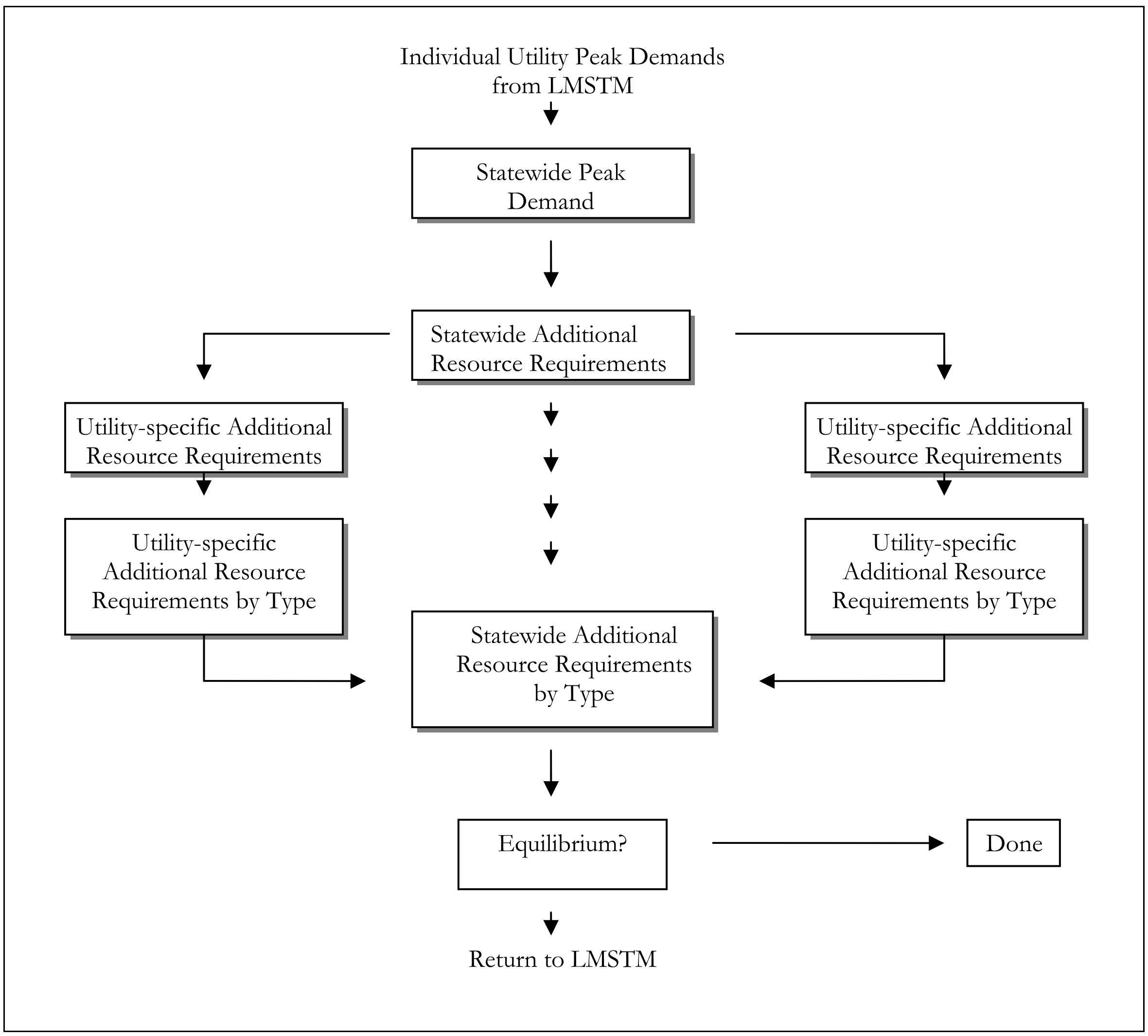
In conjunction with this change, SUFG has recalibrated the load diversity factor that is used to calculate the statewide peak demand. In general, the individual peak demands of the utilities in Indiana are non-coincident; that is, they do not all occur during the same hour of the year. Therefore, the statewide peak demand is generally less than the sum of the individual peak demands. SUFG uses a load diversity factor to calculate the statewide peak demand from the individual peak demands. The impact of the recalibration of the load diversity factor is minimal.

Also, for this forecast SUFG has recalibrated the assignment of each utility's load into base, intermediate, and peak types. Since a utility's annual loadshape can vary considerably from one year to another due to a number of factors (e.g., weather), the assignment of load to type was performed using an average over several years. While the impact of this recalibration varied across utilities, the statewide impact was an increase in the fraction of overall load that is considered to be peak. The base and intermediate load fractions decreased slightly. Absent any other changes, this would result in a slight increase in the need for peaking resources in the future and a decrease in the need for baseload and cycling resources.

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



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 macroeconomics 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 Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of electricity requirements and peak demand of 2.22 and 2.24 percent, respectively. The shaded numbers in the tables and the heavy line in the graphs indicate historical values.

As shown in Table 3-1, the growth rate for electricity sales in this forecast is very similar to the 2003 forecast. Even though overall growth rates are similar, the growth within sectors varies considerably with higher growth in the residential sector offsetting lower growth in the commercial sectors.

In this instance, a comparison of growth rates for electricity requirements between the current and previous forecast can be misleading. Despite the similar growth rate, the trajectory for electricity requirements in this forecast actually lies above the one for the 2003 forecast. This is caused by increased growth in actual sales between 2001 and 2003. Therefore, despite the similar growth rates, the 2005 forecast is actually higher than the 2003 forecast. The industrial electricity sales projections in the two forecast exhibit a similar phenomenon, with the current forecast staying consistently above the previous forecast despite having a similar growth rate. The electricity sales projections for the commercial sector are slightly below the 2003 projections. The residential electricity sales projections show a stronger growth than those seen in the 2003 forecast.

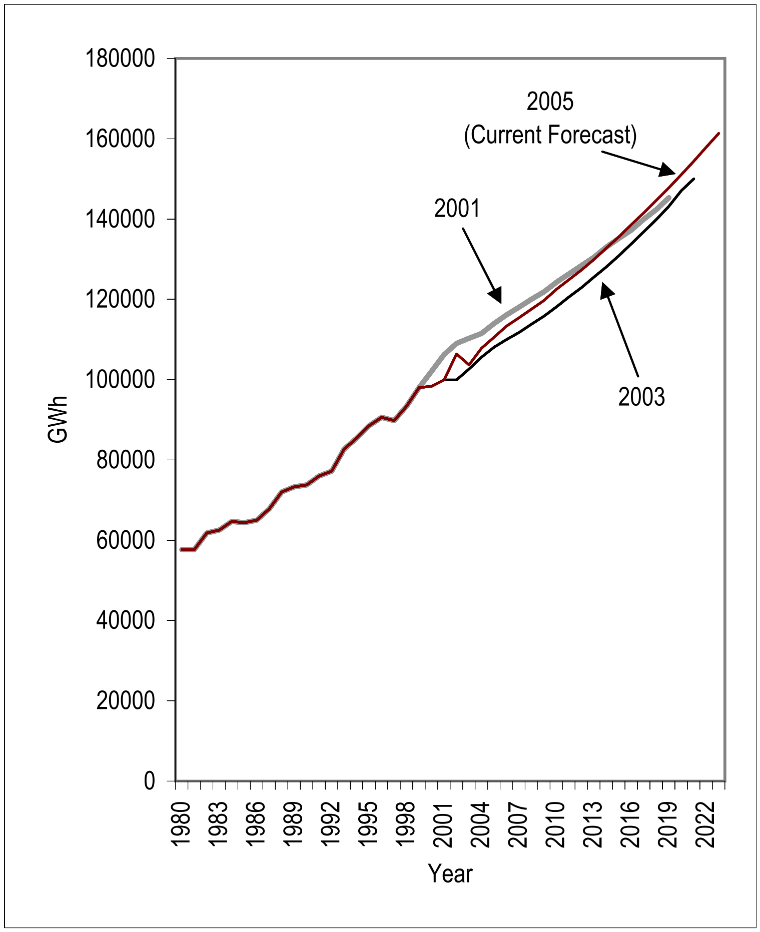
The growth in peak demand is slightly higher than that projected in 2003. Another measure of peak demand growth can be obtained by considering the average year to year MW load change. In Figure 3-2, the annual increase is 500 MW compared to about 420 MW per year in the previous forecast.

Table 3-1. Annual Electricity Sales Growth (Percent) By Sector (Current vs. 2003 Projections)

Electricity Sales Growth		
Sector	Current (2004-2023)	2003 (2002-2021)
Residential	2.22	1.95
Commercial	2.61	2.71
Industrial	1.99	1.97
Total	2.22	2.16

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

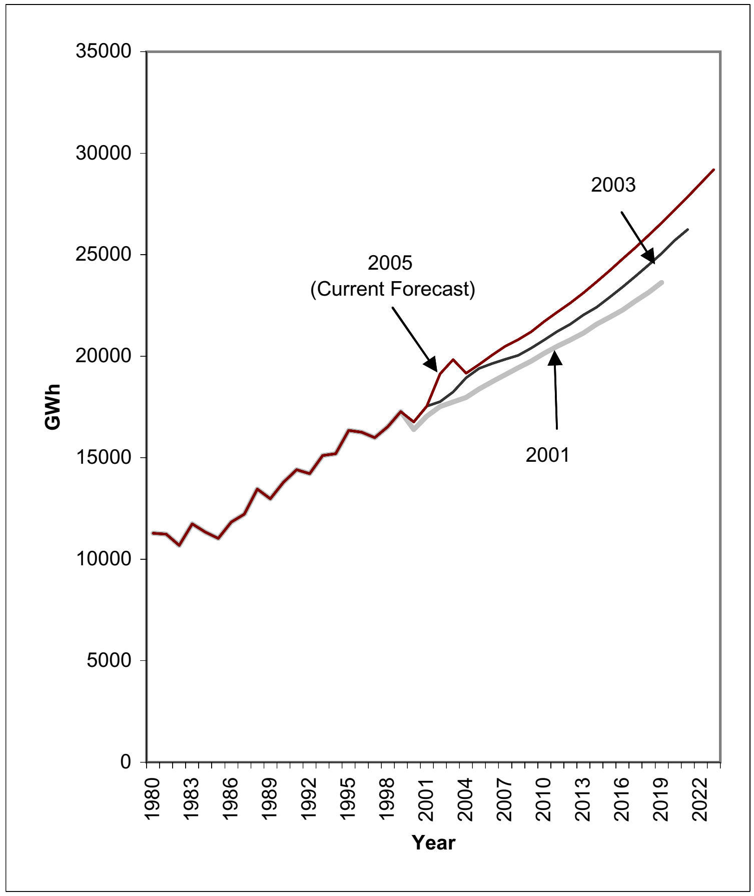
	Year of Forecast		
Year	2001	2003	2005
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	88514	88514	88514
1996	90637	90637	90637
1997	89773	89773	89773
1998	93429	93429	93429
1999	98001	98001	98001
2000	102116	98244	98244
2001	106257	99309	99309
2002	109014	99934	105065
2003	110294	102680	102719
2004	111515	105592	107237
2005	113997	108053	110069
2006	116118	109944	112911
2007	118017	111758	114937
2008	120012	113769	117223
2009	121892	115798	119318
2010	124225	118115	122126
2011	126317	120546	124565
2012	128418	122899	127052
2013	130497	125532	129762
2014	133048	128116	132740
2015	135161	130895	135689
2016	137244	133805	138882
2017	139973	136839	141991
2018	142342	139920	145183
2019	145333	143145	148501
2020		147067	151927
2021		150013	155404
2022			159020
2023			162617



Average Compound Growth Rates			
Forecast Period	2000-19	2002-21	2004-2023
	1.87	2.16	2.22

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

	Year of Forecast		
Year	2001	2003	2005
1990	13775	13775	13775
1991	14403	14403	14403
1992	14209	14209	14209
1993	15103	15103	15103
1994	15198	15198	15198
1995	16342	16342	16342
1996	16254	16254	16254
1997	15993	15993	15993
1998	16527	16527	16527
1999	17266	17266	17266
2000	16383	16757	16757
2001	17038	17531	17531
2002	17519	17762	19137
2003	17739	18231	19839
2004	17964	18934	19167
2005	18385	19398	19599
2006	18748	19633	20052
2007	19080	19845	20486
2008	19422	20047	20820
2009	19756	20400	21201
2010	20143	20794	21712
2011	20493	21224	22167
2012	20795	21581	22620
2013	21146	22044	23121
2014	21568	22410	23666
2015	21912	22900	24206
2016	22269	23413	24790
2017	22729	23945	25362
2018	23133	24489	25954
2019	23633	25057	26574
2020		25709	27211
2021		26231	27855
2022			28526
2023			29196



Average Compound Growth Rates			
Forecast Period	2000-19	2002-21	2004-23
	1.95	2.07	2.24

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 210 MW at the beginning of the forecast period and by about 370 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 750 MW to about 990 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. 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 SO2 and NOx 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.

Table 3-2 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, nearly 4,800 MW of resource additions are required, with over forty percent being of the base load variety. The net change in generation includes the retirement of units as reported in the utilities' 2001 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. Over the second half of the forecast period, an additional 7,400 MW of resources are required to maintain target reserves.

While SUFG identifies resources 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.

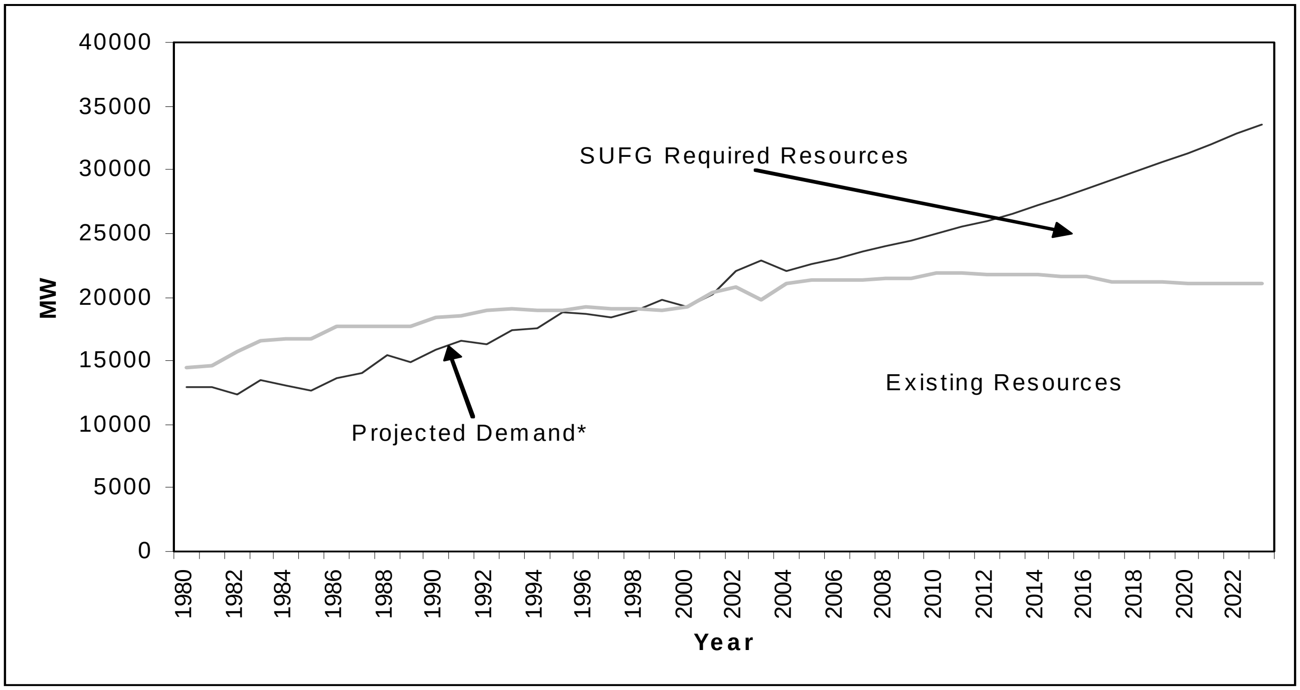
Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2003. Therefore, 2004 and 2005 numbers represent projections. The resource requirements identified in Table 3-2 were 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.

Table 3-2. 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		
2003				19839							
2004	19917	750	19167	21058	1219	240	410	320	970	22028	15
2005	20361	761	19599	21355	296	410	470	450	1330	22685	16
2006	20833	781	20052	21345	-10	490	670	600	1760	23105	15
2007	21278	792	20486	21278	-67	620	860	750	2230	23508	15
2008	21624	804	20820	21493	215	760	930	670	2360	23853	15
2009	22018	817	21201	21493	0	890	1050	880	2820	24313	15
2010	22541	829	21712	21934	441	860	1170	940	2970	24904	15
2011	23006	839	22167	21869	-65	930	1190	1420	3540	25409	15
2012	23474	853	22620	21804	-65	1060	1250	1810	4120	25924	15
2013	23984	863	23121	21704	-100	1300	1340	2140	4780	26484	15
2014	24543	876	23666	21704	0	1460	1430	2490	5380	27084	15
2015	25096	890	24206	21601	-103	1730	1520	2840	6090	27691	15
2016	25694	903	24790	21601	0	1910	1610	3220	6740	28341	15
2017	26276	913	25362	21260	-341	2150	1960	3600	7710	28970	15
2018	26882	928	25954	21260	0	2330	2030	4030	8390	29650	15
2019	27512	938	26574	21260	0	2430	2110	4520	9060	30320	15
2020	28163	952	27211	21097	-163	2730	2180	5030	9940	31037	15
2021	28819	963	27855	21097	0	2860	2250	5540	10650	31747	15
2022	29503	977	28526	21044	-53	3090	2340	6030	11460	32504	15
2023	30185	989	29196	21044	0	3240	2420	6560	12220	33264	15

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

Figure 3-3. Indiana Resource Plan (SUFG Base)



* Projected Demand includes 15% Reserve Margin

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.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 3-4. Real prices are projected to increase slightly through 2007 and then remain steady for the remainder of the forecast period. Since the change in prices over the forecast horizon is small, price has little impact on the electricity requirements projection for this forecast.

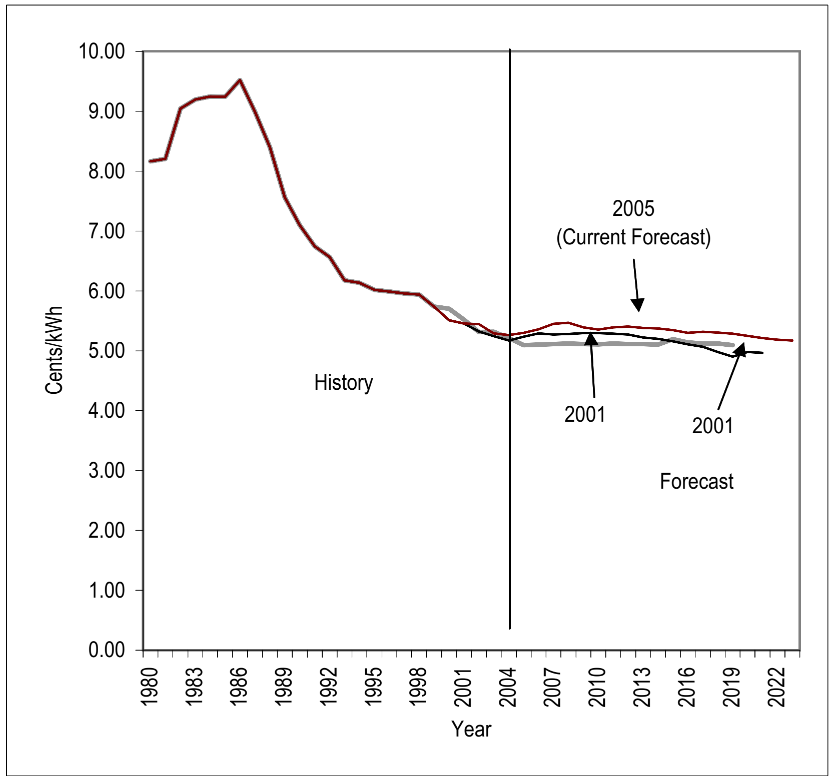
SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 3-4. The price projection labeled "2001" is the base case projection contained in SUFG's 2001 forecast and the one labeled "2003" is the base case projections from SUFG's 2003 report. For the prior price forecasts, SUFG rescaled the original price projections to 2003 dollars (from 1999 dollars for the 2001 projection, and from 2001 dollars for the 2003 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; namely, the capital cost assumptions for new generation equipment and the cost of controlling emissions from coal-fired generation facilities. 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 2001 and 2003 price forecasts may be found in previous SUFG reports.

SUFG's projected generation additions are determined from a statewide as well as individual utility perspective. Thus, SUFG's integrated electricity modeling system develops a base resource plan and electricity price projections for each utility.

Figure 3-4. Indiana Real Price Projections (2003 Dollars) (Historical, Current and Previous Forecasts)

	2001	2003	2005
1980	8.17	8.17	8.17
1981	8.20	8.20	8.20
1982	9.05	9.05	9.05
1983	9.20	9.20	9.20
1984	9.25	9.25	9.25
1985	9.24	9.24	9.24
1986	9.52	9.52	9.52
1987	8.99	8.99	8.99
1988	8.40	8.40	8.40
1989	7.56	7.56	7.56
1990	7.10	7.10	7.10
1991	6.74	6.74	6.74
1992	6.56	6.56	6.56
1993	6.18	6.18	6.18
1994	6.13	6.13	6.13
1995	6.01	6.01	6.01
1996	5.99	5.99	5.99
1997	5.96	5.96	5.96
1998	5.94	5.94	5.94
1999	5.74	5.74	5.74
2000	5.70	5.51	5.51
2001	5.52	5.45	5.45
2002	5.31	5.32	5.45
2003	5.32	5.25	5.29
2004	5.21	5.17	5.26
2005	5.09	5.23	5.30
2006	5.10	5.29	5.36
2007	5.11	5.27	5.45
2008	5.12	5.28	5.47
2009	5.11	5.29	5.39
2010	5.11	5.29	5.35
2011	5.12	5.29	5.39
2012	5.11	5.27	5.40
2013	5.11	5.22	5.38
2014	5.10	5.20	5.37
2015	5.19	5.16	5.35
2016	5.14	5.11	5.30
2017	5.12	5.07	5.32
2018	5.12	4.98	5.31
2019	5.09	4.90	5.28
2020		4.98	5.25
2021		4.96	5.21
2022			5.19
2023			5.17



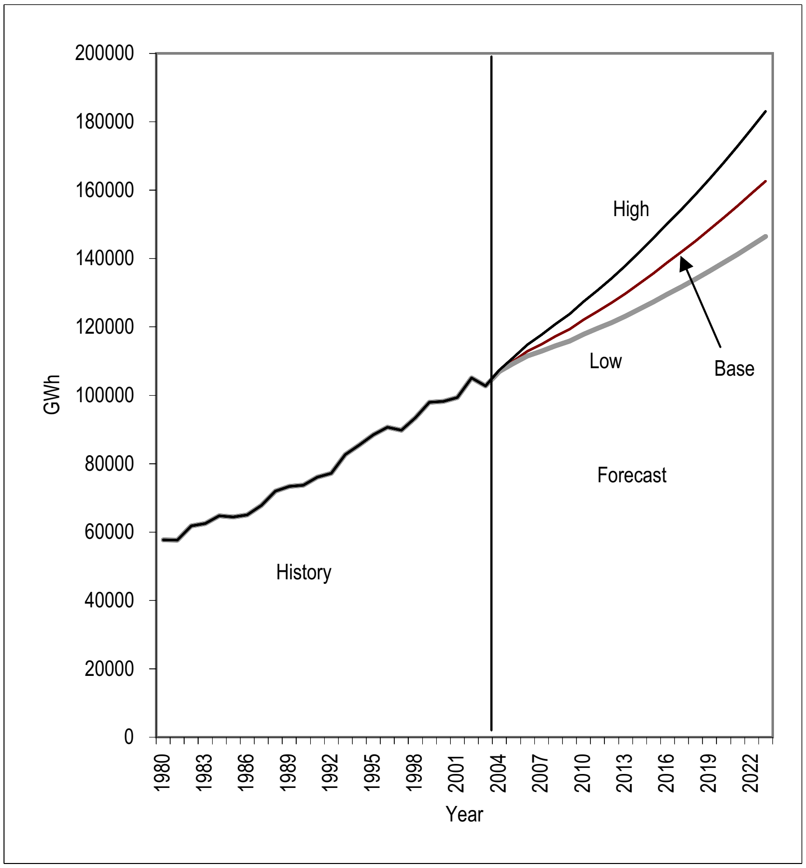
Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

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. 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 0.55 percent lower and 0.60 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.

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

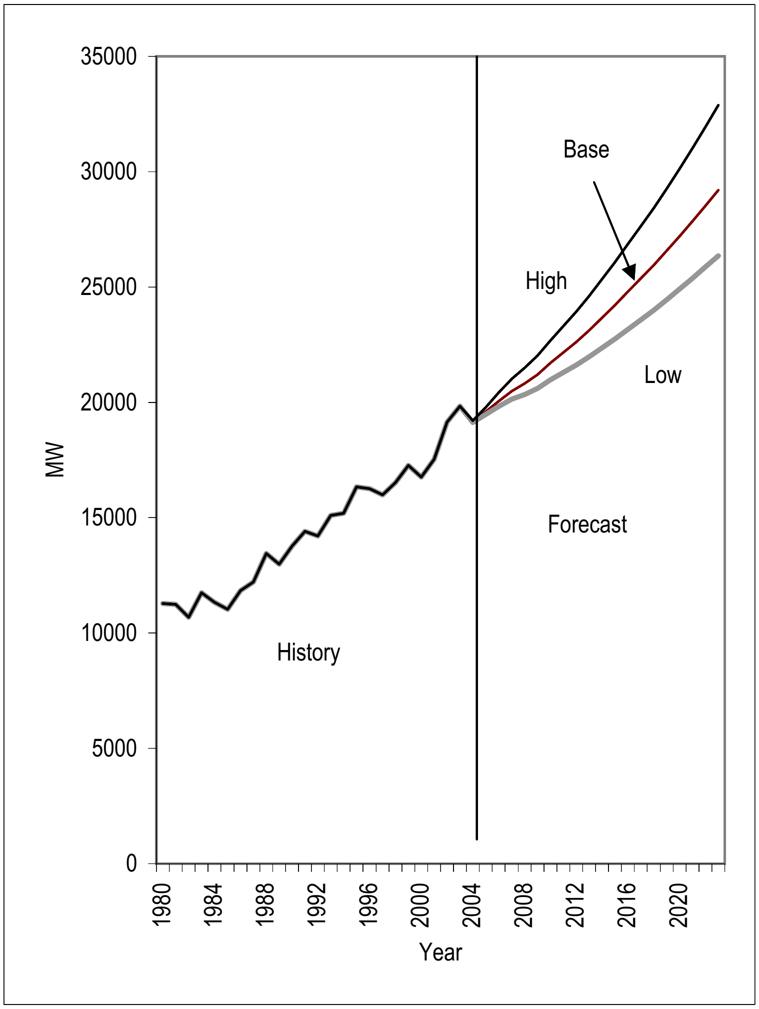
	Base	Low	High
1980	57676	57676	57676
1981	57648	57648	57648
1982	61823	61823	61823
1983	62511	62511	62511
1984	64717	64717	64717
1985	64380	64380	64380
1986	65024	65024	65024
1987	67794	67794	67794
1988	71988	71988	71988
1989	73326	73326	73326
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	88514	88514	88514
1996	90637	90637	90637
1997	89773	89773	89773
1998	93429	93429	93429
1999	98001	98001	98001
2000	98244	98244	98244
2001	99309	99309	99309
2002	105065	105065	105065
2003	102719	102719	102719
2004	107237	107013	107463
2005	110069	109355	111044
2006	112911	111557	114850
2007	114937	112922	117728
2008	117223	114485	120854
2009	119318	115895	123755
2010	122126	117899	127386
2011	124565	119567	130758
2012	127052	121257	134224
2013	129762	123158	137949
2014	132740	125285	141962
2015	135689	127332	145986
2016	138882	129583	150265
2017	141991	131757	154478
2018	145183	133996	158819
2019	148501	136361	163348
2020	151927	138827	168039
2021	155404	141274	172885
2022	159020	143861	177890
2023	162617	146424	183011



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	2.30	2.17	2.48
2004-2023	2.22	1.66	2.84

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

	Base	Low	High
1980	11284	11284	11284
1981	11235	11235	11235
1982	10683	10683	10683
1983	11744	11744	11744
1984	11331	11331	11331
1985	11030	11030	11030
1986	11834	11834	11834
1987	12218	12218	12218
1988	13447	13447	13447
1989	12979	12979	12979
1990	13775	13775	13775
1991	14403	14403	14403
1992	14209	14209	14209
1993	15103	15103	15103
1994	15198	15198	15198
1995	16342	16342	16342
1996	16254	16254	16254
1997	15993	15993	15993
1998	16527	16527	16527
1999	17266	17266	17266
2000	16757	16757	16757
2001	17531	17531	17531
2002	19137	19137	19137
2003	19839	19839	19839
2004	19167	19132	19205
2005	19599	19479	19782
2006	20052	19820	20419
2007	20486	20137	21012
2008	20820	20344	21499
2009	21201	20605	22025
2010	21712	20979	22684
2011	22167	21296	23307
2012	22620	21611	23934
2013	23121	21971	24613
2014	23666	22367	25346
2015	24206	22747	26078
2016	24790	23167	26860
2017	25362	23578	27633
2018	25954	24000	28431
2019	26574	24453	29271
2020	27211	24921	30133
2021	27855	25380	31021
2022	28526	25869	31940
2023	29196	26355	32880



Average Compound Growth Raes			
Period	Base	Low	High
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	3.18	3.06	3.37
2004-23	2.24	1.70	2.87

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. Table 3-3 shows the statewide resource requirements for each scenario. Approximately 16,300 MW over the horizon are required in the high scenario compared to 9,050 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are more than 3 percent higher than in the base case. This is because over 4,000 MW of additional wholesale purchases are acquired relative to the base scenario. Prices in the low scenario are only about 3 percent lower than the base scenario despite significantly fewer resource additions. This is caused by the lack of sales growth, which in addition to delaying the need for resource additions, results in allocation of fixed costs of existing generation resources and firm purchases to fewer kWh.

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

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2004	270	450	320	1040	290	460	340	1090	240	420	320	980
2005	390	460	440	1290	450	490	480	1420	350	430	420	1200
2006	450	660	580	1690	620	760	680	2060	360	580	550	1490
2007	610	830	710	2150	810	970	980	2760	470	740	620	1830
2008	720	920	650	2290	970	1100	1000	3070	530	760	470	1760
2009	870	1040	830	2740	1130	1180	1330	3640	620	840	600	2060
2010	850	1180	800	2830	1110	1310	1530	3950	590	980	470	2040
2011	920	1190	1310	3420	1260	1390	2040	4690	680	1030	770	2480
2012	1040	1270	1680	3990	1450	1490	2510	5450	770	1120	1000	2890
2013	1280	1350	2020	4650	1750	1590	2940	6280	930	1170	1270	3370
2014	1450	1440	2350	5240	1980	1700	3440	7120	1030	1250	1540	3820
2015	1720	1530	2680	5930	2260	1790	3960	8010	1240	1280	1780	4300
2016	1880	1630	3060	6570	2410	1880	4570	8860	1360	1380	2040	4780
2017	2160	1980	3430	7570	2650	2240	5180	10070	1570	1690	2280	5540
2018	2310	2040	3830	8180	2790	2340	5790	10920	1720	1780	2550	6050
2019	2440	2120	4300	8860	2950	2430	6450	11830	1850	1850	2840	6540
2020	2720	2200	4820	9740	3320	2520	7090	12930	2130	1920	3120	7170
2021	2820	2230	5350	10400	3510	2620	7740	13870	2230	1880	3570	7680
2022	3020	2350	5800	11170	3740	2720	8430	14890	2430	1970	3840	8240
2023	3150	2420	6310	11880	3960	2820	9130	15910	2570	2050	4150	8770

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 CEMR.

- 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 2005 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in its 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 are:

- Federal tax rates and grants to state and local governments will increase slightly, but transfer payments show strong growth especially in the first half of the forecast period. As a result, the nominal federal budget rises over the first half of the projection then stabilizes.
- Imports continue to exceed exports, but at a slowing rate (measured in dollars), which leads to a continued, but narrowing negative net trade balance.
- State and local taxes are stable over the projection.

As a result of these assumptions, real Gross Domestic Product (GDP) for the U.S. economy is projected to grow at an average annual rate of 3.25 percent and U.S. employment growth averages 1.10 percent over the 2004 to 2023 period.

In Indiana, total employment is projected to grow at an average annual rate of 0.94 percent. The key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.22 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.23 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 2.84 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 non-manufacturing employment shows an increase in 2003,

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

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Febr. 2001	Aug. 2002	Febr. 2005
	1980-1985	1985-1990	1990-1995	1995-2000	2000-2005*	2000-2019	2002-2021	2004-2023
United States								
Real Personal Income	3.30	2.95	2.04	4.08	1.77	3.22	3.04	3.29
Total Employment	1.50	2.36	1.38	2.37	0.23	0.96	0.98	1.10
Real Gross Domestic Product	3.13	3.25	2.38	4.35	2.64	3.45	3.19	3.25
Personal Consumer Expenditure Deflator	5.14	3.79	2.77	1.87	1.94	2.70	2.28	1.99
Indiana								
Real Personal Income	1.47	2.50	2.48	3.37	1.37	2.62	2.36	2.22
Employment								
Total	0.22	2.84	1.91	1.22	-0.36	1.17	1.24	0.94
Manufacturing	-1.49	0.91	1.40	0.07	-2.40	-0.80	-1.17	-0.02
Non-Manufacturing	1.17	3.82	2.20	1.97	0.37	1.72	1.79	1.23
Real Gross State Product								
Total	6.65	6.17	5.83	4.78	1.84	1.60	2.14	2.82
Manufacturing	5.84	4.76	7.95	4.68	1.29	1.41	1.50	2.84
Non-Manufacturing	7.04	6.81	4.86	4.84	2.05	1.68	2.41	2.81

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Outlooks"
*2004 and 2005 values are projections not actual history

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 personal income is increased by 0.27 percent per year (to 2.49), non-manufacturing employment growth increases almost 0.10 percent (to 1.31) while Indiana real manufacturing GSP growth is raised 0.50 percent to 3.34. In the low growth alternative, the average rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.96, 1.14 and 2.34 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 a 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, 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.

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 January 2005 fossil fuel price projections from EIA for the East North Central Region of the U.S. All SUFG projections are in terms of real prices (2003 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.
- Gas price projections for all customers decrease slightly through 2010 and increase moderately over the remainder of the forecast horizon.
- Distillate prices exhibit a pattern similar to natural gas over the entire forecast horizon, with a more moderate decline early in the horizon and a slower increase in the last three-fourths of this horizon.

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

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.

Figure 4-1. Utility Fossil Fuel Prices

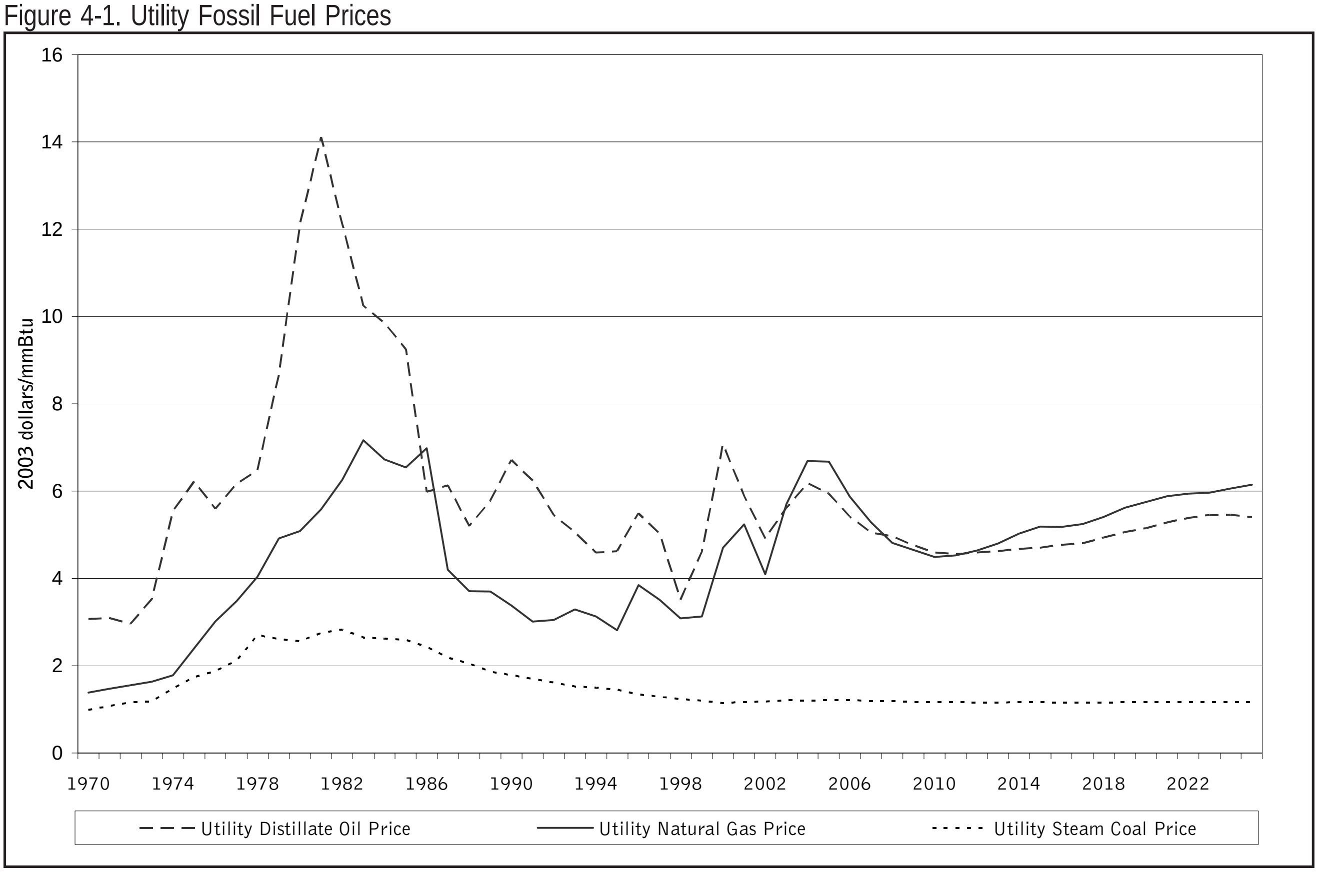


Table 4-2. Peak Demand Reductions

Embedded DSM	Incremental DSM	Interruptible
293 MW	212 MW	750 MW

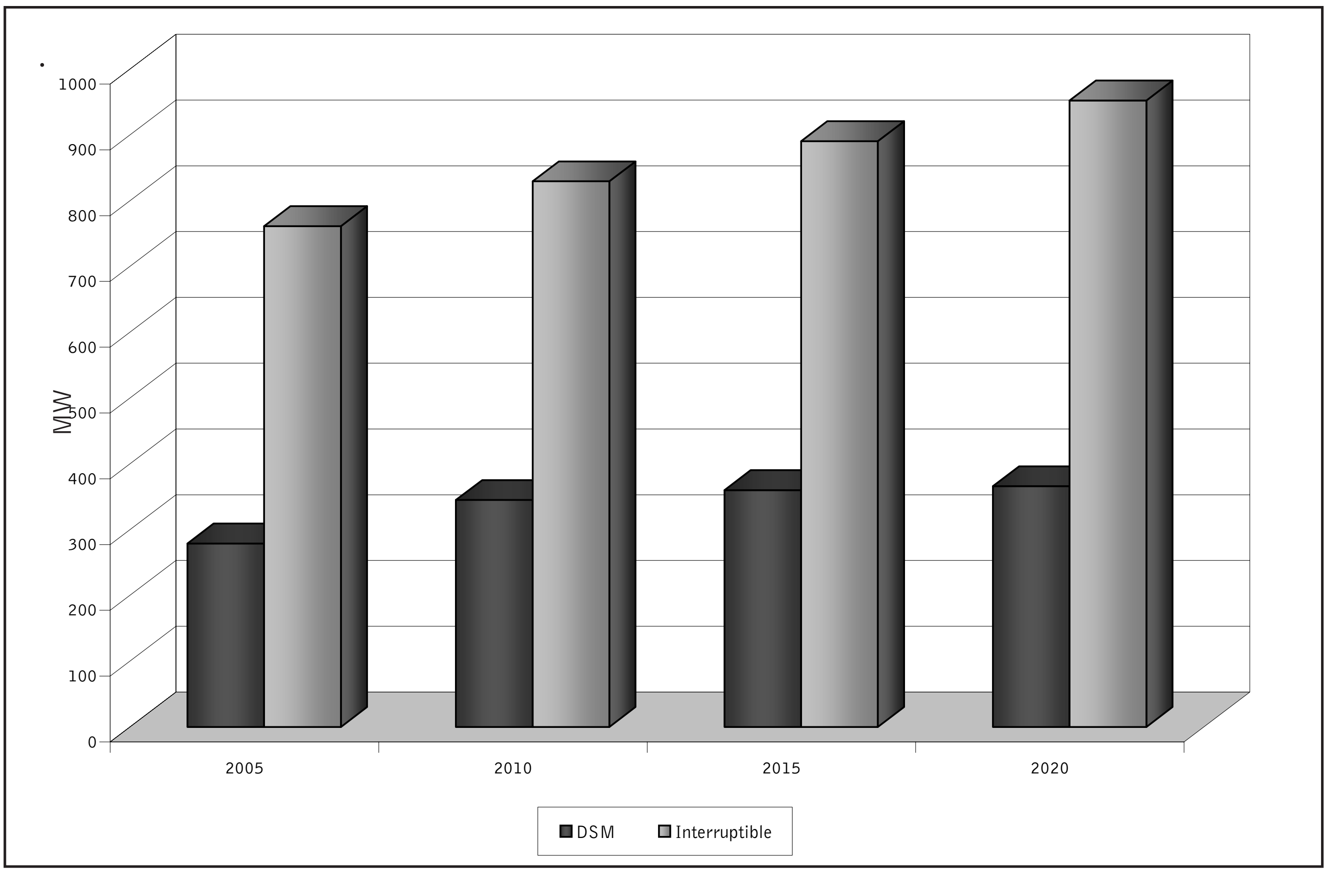
Incremental DSM, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are made by changing the utility's demand by the appropriate level of energy and peak demand for the DSM program. DSM programs that were in place in 2003 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 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 2003 and from incremental DSM and interruptible loads available in 2004 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.

The amount of incremental DSM indicates that there is a renewed interest in demand-side options. While the

Figure 4-2. Peak Demand Reductions from Incremental DSM and Interruptible Loads



present level of DSM activity is not close to 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 enter 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 is, the larger the 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 an inappropriate estimation method.

Residential Electricity Sales

Overview

SUFG uses both econometric and end-use models of 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 this 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. Since 1999 economic activity has slowed dramatically with a resultant decline in electric energy sales growth (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.

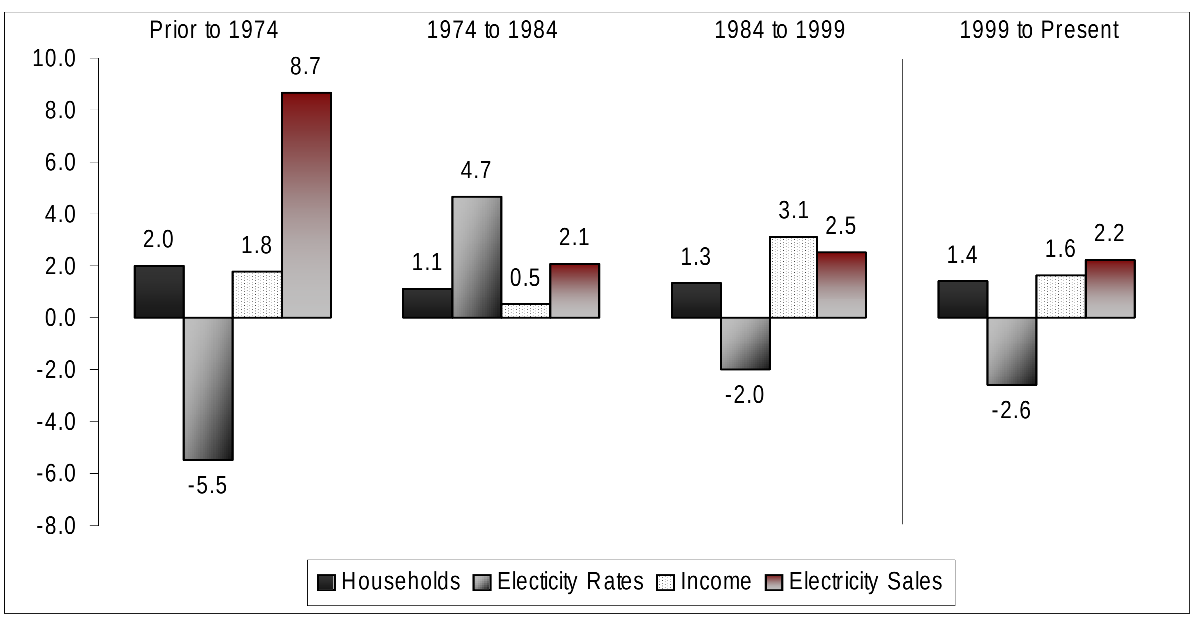
Several market factors contributed to the small difference in sales growth between the post-embargo and more recent period. First and perhaps most importantly, is the difference in the availability and price of natural gas between the two periods. Restrictions on new natural gas hook-ups during the post-embargo 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 have 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 increased slightly to 1.4 percent annual rate similar to the 1984 to 1999 period, real electric rates have continued to decline, but the growth in both personal income, while positive, has slowed markedly. Despite the slow growth in income, electricity sales have continued to grow at a rate only modestly below that 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 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, as well as 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

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



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 assumptions of relatively stable electricity prices and increasing natural gas prices after about 2010, the fuel choice model projects the penetration of electric space heating to average about 30 percent over the forecast horizon (for the five IOUs combined). This results in space heating saturation of nearly 25 percent by the end of 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

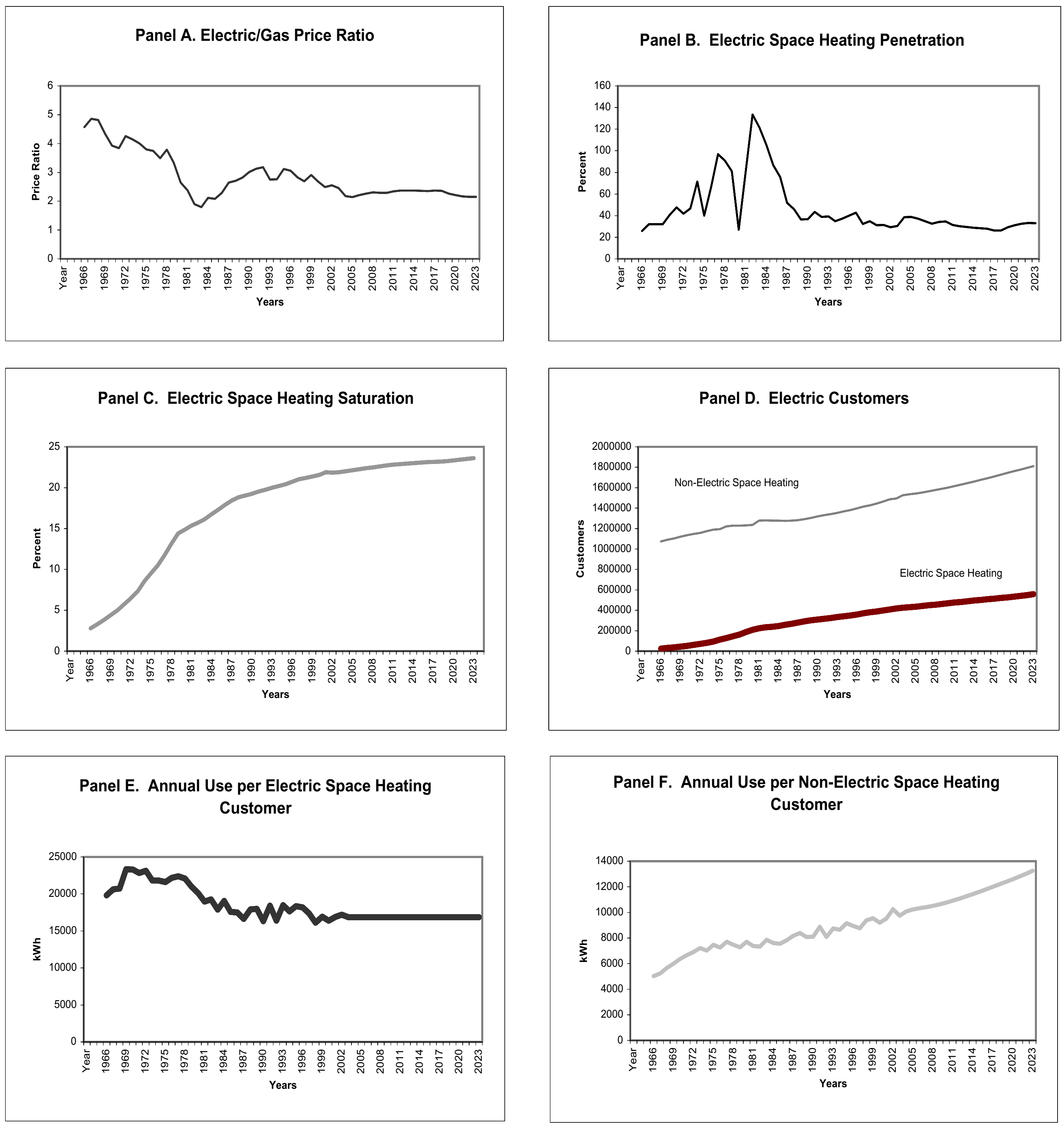
About 80 percent of all residential customers are non-electric heating customers. Prior to 1975, average electricity consumption by these customers increased about 4.5 percent per year. Since 1975, average use has increased moderately, averaging about 1.0 percent per year. A robust econometric demand 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 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 constant or declining real electricity prices during the forecast period and the apparent leveling off of the decline in usage in

Figure 5-2. Structure of Residential Econometric Model



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 resultsare 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 Figure 5-3. The shaded numbers in the table and the heavy line in the graph are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 2.22 percent, moderately higher than SUFG's 2003 projection. Table 5-2 shows the growth rates of the major residential drivers for the current scenarios and the SUFG 2003 base case. In all of the residential sector drivers, the current base exhibits somewhat higher growth resulting in a higher residential 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 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2001. 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 ofprojected sales growth is attributable to customer growth and the remainder to changes in electric intensity (price and income effects). The net effect of changes in energy prices is to increase electric intensity about 0.1 percent per year. 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. The remaining growth in electric intensity is accounted for by income growth and declining real appliance prices.

As shown in Figure 5-4, the growth rates for the high and low residential scenarios are about 0.4 percent higher and 0.1 lower than the base scenario. This difference is due to differences in the growth of total customers and household income.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5. In real terms residential electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue at a slower pace due to the need for additional resources and emissions controls leading to relatively constant electricity prices. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities.

Table 5-2. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

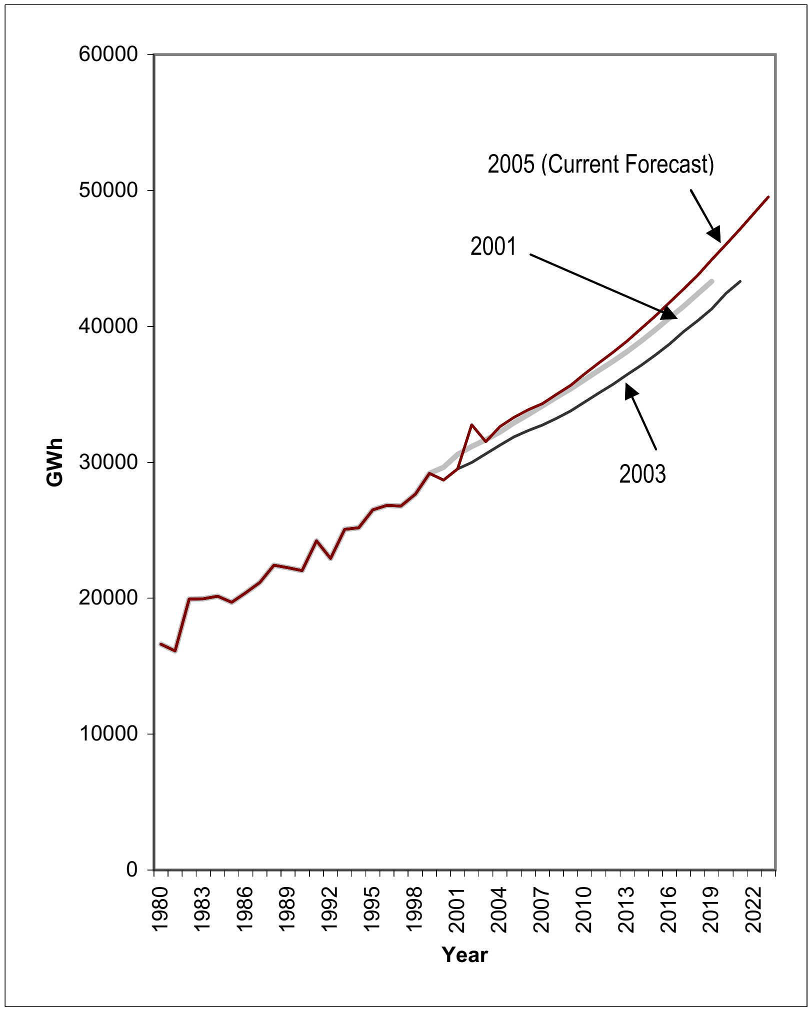
Forecast	Current Scenario (2004-2023)			2003 Forecast (2002-2021)
	Base	Low	High	Base
No. of Customers	1.00	1.00	1.03	0.66
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	-0.52	-0.54	-0.50	-0.38
Natural Gas Price	-0.67	-0.67	-0.67	0.26
Oil Prices	-0.64	-0.64	-0.64	0.43
Household Income	1.43	0.92	2.58	1.69

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

Forecast	No. of Customers	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
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
2001 SUFG Base (2000-2019)	0.71	1.31	2.02	1.31	2.02

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

	2001	2003	2005
1990	22037	22037	22037
1991	24215	24215	24215
1992	22916	22916	22916
1993	25060	25060	25060
1994	25176	25176	25176
1995	26510	26510	26510
1996	26833	26833	26833
1997	26792	26792	26792
1998	27663	27663	27663
1999	29180	29180	29180
2000	29625	28684	28684
2001	30569	29516	29516
2002	31161	29988	32777
2003	31651	30615	31524
2004	32213	31256	32634
2005	32918	31873	33300
2006	33525	32335	33876
2007	34159	32742	34319
2008	34797	33244	35013
2009	35396	33785	35657
2010	36090	34433	36516
2011	36778	35103	37318
2012	37420	35742	38088
2013	38158	36461	38929
2014	38939	37148	39858
2015	39766	37903	40774
2016	40625	38709	41764
2017	41471	39612	42740
2018	42382	40427	43756
2019	43319	41285	44900
2020		42444	46041
2021		43317	47175
2022			48357
2023			49521

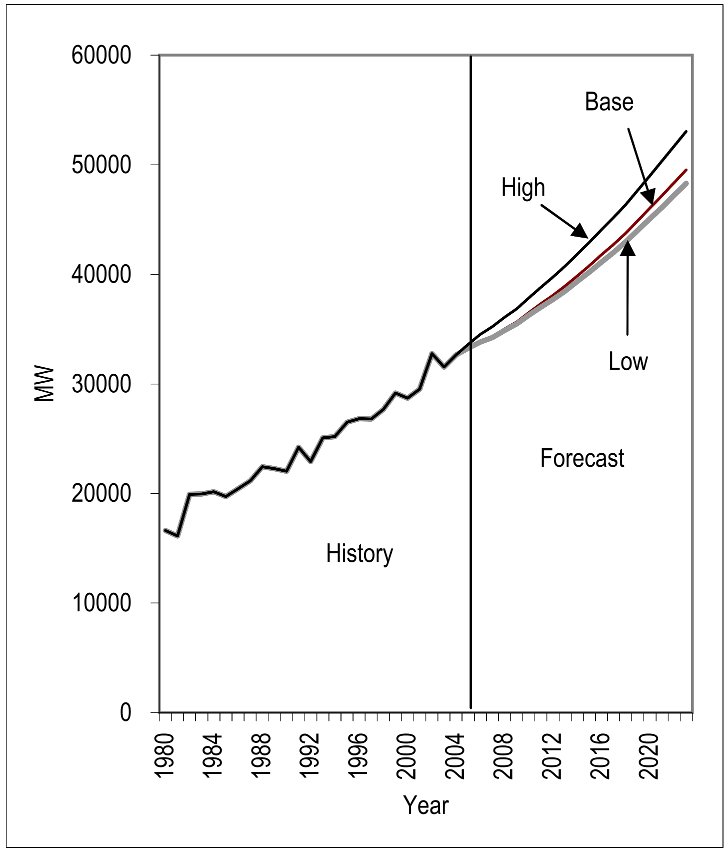


Average Compund Growth Rates			
Forecast Period	2000-19	2002-21	2004-23
	2.02	1.95	2.22

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

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

	Base	Low	High
1980	16612	16612	16612
1981	16118	16118	16118
1982	19927	19927	19927
1983	19950	19950	19950
1984	20153	20153	20153
1985	19707	19707	19707
1986	20410	20410	20410
1987	21154	21154	21154
1988	22444	22444	22444
1989	22251	22251	22251
1990	22037	22037	22037
1991	24215	24215	24215
1992	22916	22916	22916
1993	25060	25060	25060
1994	25176	25176	25176
1995	26510	26510	26510
1996	26833	26833	26833
1997	26792	26792	26792
1998	27663	27663	27663
1999	29180	29180	29180
2000	28684	28684	28684
2001	29516	29516	29516
2002	32777	32777	32777
2003	31524	31524	31524
2004	32634	32634	32640
2005	33300	33274	33599
2006	33876	33814	34534
2007	34319	34221	35221
2008	35013	34869	36079
2009	35657	35491	36857
2010	36516	36269	37842
2011	37318	37002	38810
2012	38088	37699	39745
2013	38929	38479	40753
2014	39858	39341	41840
2015	40774	40186	42915
2016	41764	41101	44062
2017	42740	42008	45193
2018	43756	42960	46381
2019	44900	44022	47693
2020	46041	45086	49010
2021	47175	46118	50334
2022	48357	47212	51685
2023	49521	48302	53044



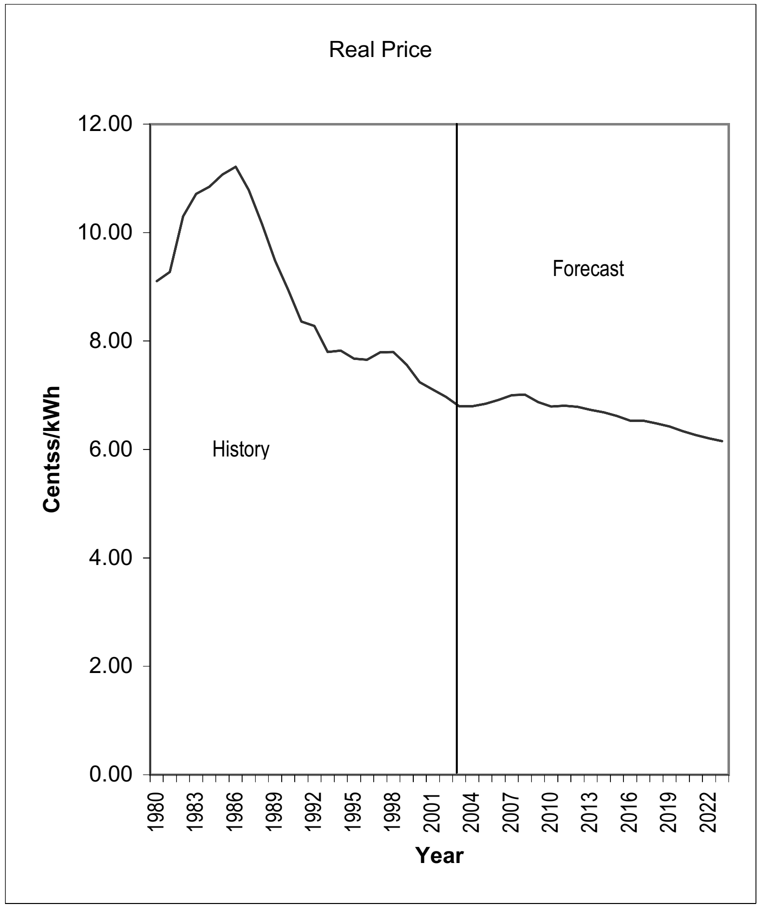
Average Compound Growth Rates			
Periods	Base	Low	High
1980-85	3.48	3.48	3.48
1985-90	2.26	2.26	2.26
1990-95	3.77	3.77	3.77
1995-00	1.59	1.59	1.59
2000-05	3.03	3.01	3.21
2004-23	2.22	2.09	2.59

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

Figure 5-5. Indiana Residential Base Real Price Projections (in 2003 Dollars)

Year	Real Price
1980	9.10
1981	9.27
1982	10.30
1983	10.71
1984	10.85
1985	11.07
1986	11.21
1987	10.78
1988	10.16
1989	9.48
1990	8.93
1991	8.36
1992	8.28
1993	7.80
1994	7.82
1995	7.68
1996	7.65
1997	7.79
1998	7.80
1999	7.56
2000	7.24
2001	7.10

Year	Real Price
2002	6.97
2003	6.80
2004	6.80
2005	6.84
2006	6.91
2007	7.00
2008	7.01
2009	6.88
2010	6.79
2011	6.81
2012	6.79
2013	6.73
2014	6.68
2015	6.62
2016	6.53
2017	6.53
2018	6.48
2019	6.43
2020	6.34
2021	6.26
2022	6.20
2023	6.16



Average Compound Growth Rates Selected Periods	%
1980-85	4.00
1985-90	-4.20
1990-95	-2.99
1995-00	-1.17
2000-05	-1.12
2004-23	-0.52

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

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.

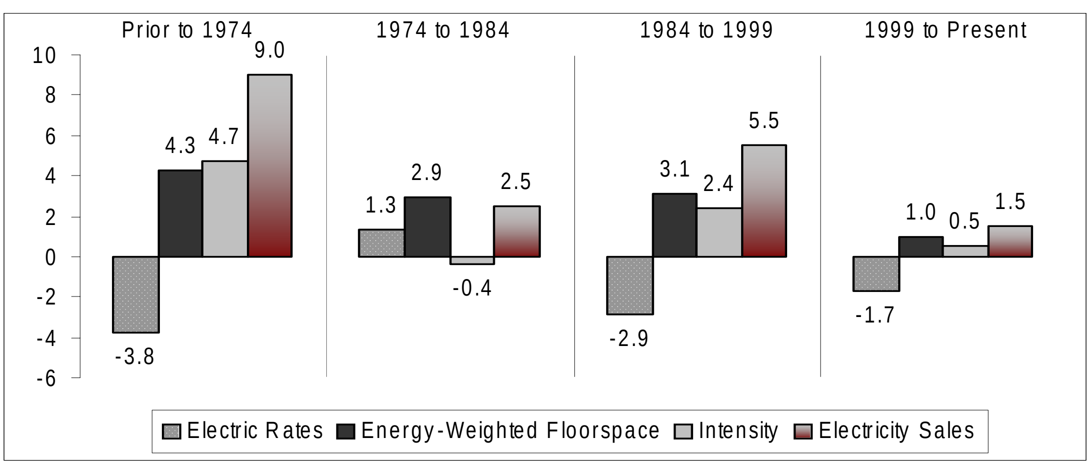
For a few years in the mid 1990s, SUFG relied on its econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. (CEDMS estimates commercial floor space for building types and estimates energy use for end uses within 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. Next, 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).

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

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



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 unmistakeable.

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

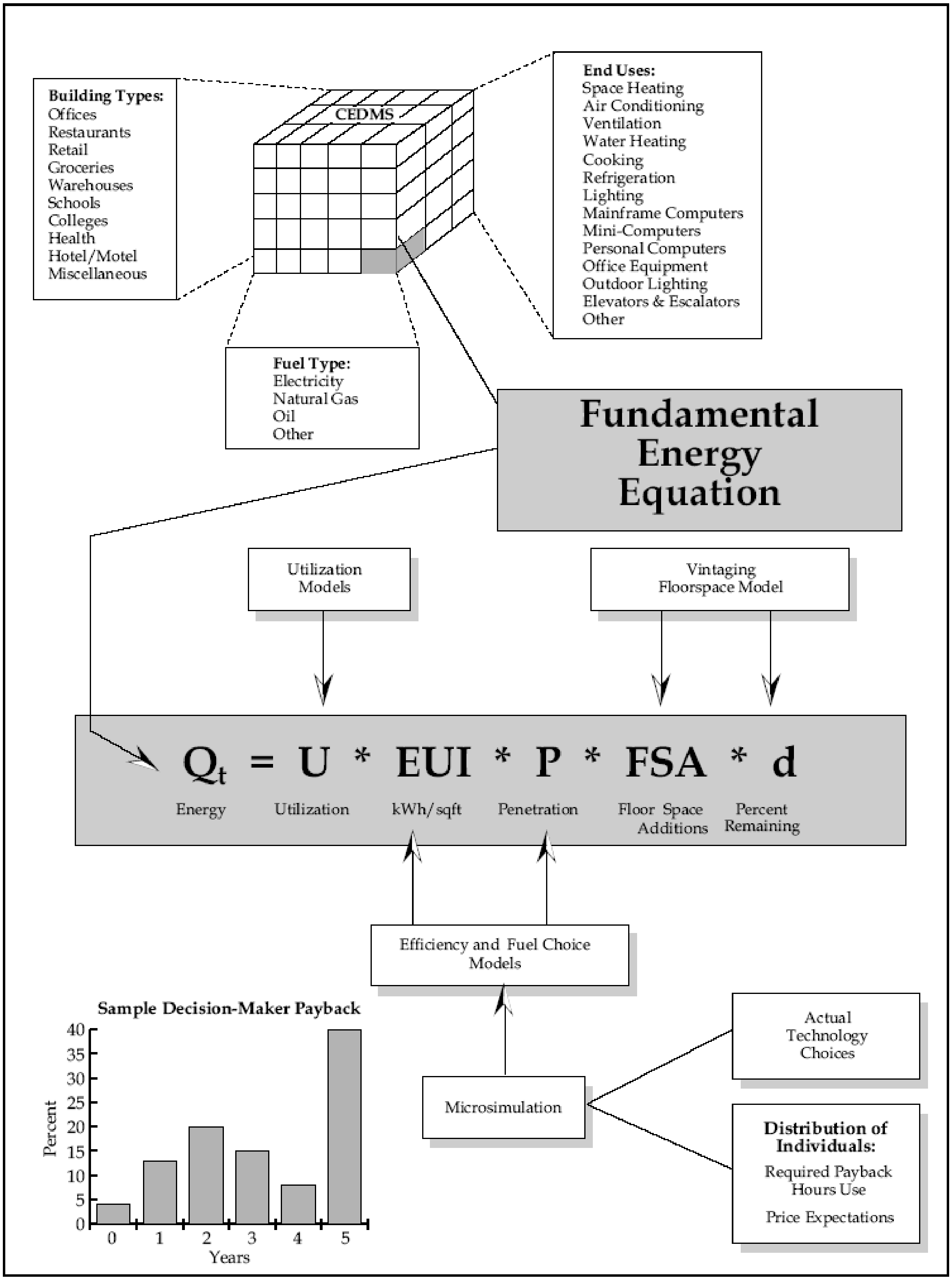
d = fraction of floor space of vintage t still standing in forecast year T.

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.

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

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



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.

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Figure 6-3. The shaded numbers in the table and the heavy line in the graph are historical consumption. As can be seen, the current base projection of Indiana commercial electricity sales growth is 2.61 percent. The growth rates for the major explanatory variables are shown in Table 6-2. Note that the change from 2001 for all of the drivers in Table 6-2 lead to increased commercial sector energy purchases. Table 6-3 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts. Floor space growth accounts for about 2 percent growth annually. The net effect of changes in energy prices and the mix in types of floor space is to increase electricity use about 0.5 percent per year. Incremental DSM programs have virtually no effect on electricity sales. Thus, slightly more than 80 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 2003 forecast. The current projection starts out slightly lower and grows at a slightly lower rate. The lower starting point is due to the continued downturn in the economy and the slower growth rate is due to similar, but lower growth in floorstock and electric intensity in the current forecast.

As shown in Figure 6-4, the growth rates for the low and high scenarios are about 1.1 percent lower and 1.2 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

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

Table 6-2. Commercial Model – Growth Rates (Percent) for Selected Variables (2005 SUFG Scenarios and 2003 Base Forecast)

Forecast	Current Scenario (2004-2023)			2003 Forecast (2002-2021)
	Base	Low	High	Base
Electric Rates	-0.26	-0.35	-0.18	-0.73
Natural Gas Price	0.55	0.55	0.55	-0.11
Oil Prices	0.60	0.60	0.60	-0.75
Energy-Weighted Floor Space	2.12	1.07	3.04	2.11

Table 6-3. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy - Weighted Floor Space	Prior to DSM		After DSM	
		Intensity	Sales Growth	Intensity	Sales Growth
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
2001 SUFG Base (2000-2019)	1.89	0.34	2.23	0.34	2.23

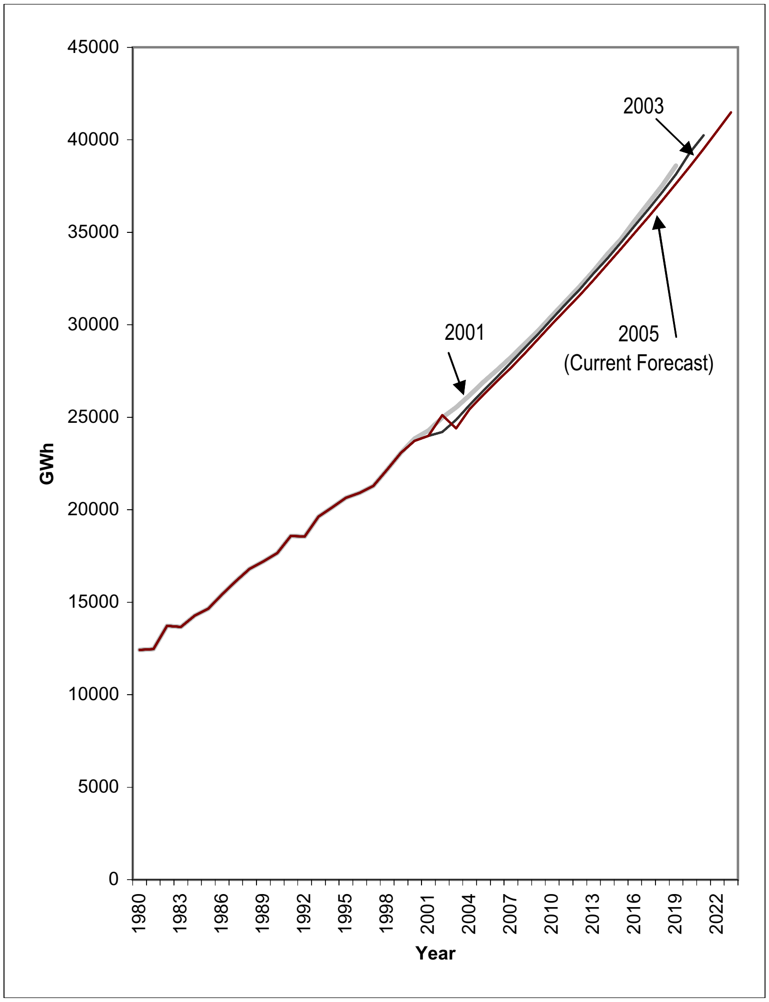
Indiana Commercial Electricity Price Projections

Historical values and current projections for commercial electricity prices are shown in Figure 6-5. In real terms, commercial electricity prices have been declining since the mid-1980s. SUFG projects this trend to continue until about 2004 when slower declines in utility steam coal prices coupled with the need for additional generation resources and emissions controls lead to relatively constant electricity prices through 2012. Real prices are projected to slowly fall through the last half 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.

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

	2001	2003	2005
1990	17659	17659	17659
1991	18580	18580	18580
1992	18556	18556	18556
1993	19627	19627	19627
1994	20116	20116	20116
1995	20646	20646	20646
1996	20909	20909	20909
1997	21295	21295	21295
1998	22166	22166	22166
1999	23078	23078	23078
2000	23849	23721	23721
2001	24280	23991	23991
2002	24977	24206	25119
2003	25536	24855	24404
2004	26189	25663	25444
2005	26904	26451	26219
2006	27561	27195	26972
2007	28239	27960	27677
2008	28976	28751	28451
2009	29713	29524	29252
2010	30503	30327	30053
2011	31290	31145	30823
2012	32084	31923	31601
2013	32910	32765	32416
2014	33812	33582	33265
2015	34646	34462	34110
2016	35628	35355	34975
2017	36584	36247	35842
2018	37544	37184	36733
2019	38609	38133	37626
2020		39309	38557
2021		40240	39510
2022			40488
2023			41491

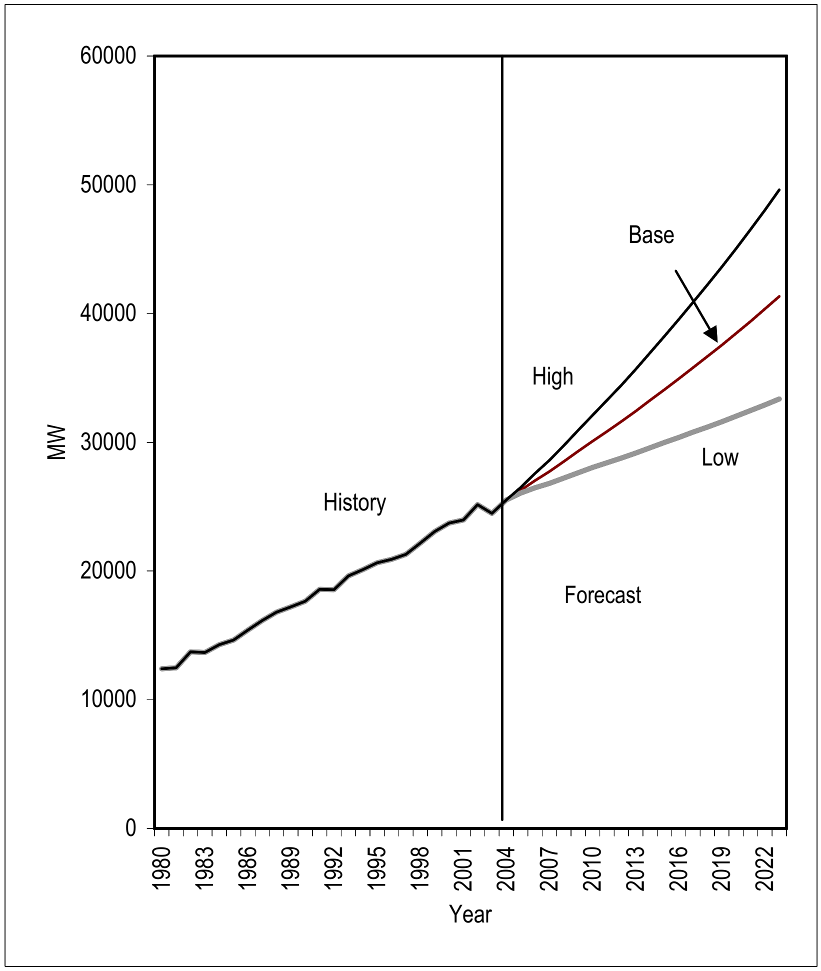
Forecast Period	Average Compund Growth Rate 2000-19	2002-21	2004-23
	2.57	2.71	2.61



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

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

Year	Base	Low	High
1980	12418	12418	12418
1981	12470	12470	12470
1982	13725	13725	13725
1983	13665	13665	13665
1984	14274	14274	14274
1985	14651	14651	14651
1986	15429	15429	15429
1987	16144	16144	16144
1988	16808	16808	16808
1989	17205	17205	17205
1990	17659	17659	17659
1991	18580	18580	18580
1992	18556	18556	18556
1993	19627	19627	19627
1994	20116	20116	20116
1995	20646	20646	20646
1996	20909	20909	20909
1997	21295	21295	21295
1998	22166	22166	22166
1999	23078	23078	23078
2000	23721	23721	23721
2001	23975	23975	23975
2002	25162	25162	25162
2003	24473	24473	24473
2004	25513	25515	25512
2005	26279	26059	26496
2006	27023	26463	27572
2007	27728	26810	28615
2008	28497	27224	29756
2009	29296	27644	30925
2010	30089	28047	32102
2011	30844	28409	33254
2012	31618	28779	34442
2013	32418	29163	35677
2014	33254	29581	36959
2015	34088	29977	38233
2016	34940	30379	39553
2017	35787	30779	40873
2018	36663	31179	42227
2019	37542	31590	43621
2020	38454	32023	45044
2021	39388	32462	46514
2022	40345	32907	48034
2023	41325	33359	49604



Average Compound Growth Rates			
Selected Periods	Base	Low	High
1980-85	3.36	3.36	3.36
1985-90	3.81	3.81	3.81
1990-95	3.17	3.17	3.17
1995-00	2.82	2.82	2.82
2000-05	2.02	1.85	2.19
2004-23	2.61	1.45	3.61

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

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2003 Dollars)

Year	Cents/ kWh
1980	9.65
1981	9.53
1982	10.14
1983	10.25
1984	10.33
1985	10.25
1986	10.55
1987	10.23
1988	9.36
1989	8.03
1990	7.56
1991	7.08
1992	6.98
1993	6.55
1994	6.53
1995	6.46
1996	6.44
1997	6.35
1998	6.35
1999	6.19
2000	5.86
2001	5.90

Year	Cents/ kWh
2002	5.86
2003	5.68
2004	5.71
2005	5.75
2006	5.83
2007	5.93
2008	5.95
2009	5.87
2010	5.83
2011	5.85
2012	5.85
2013	5.82
2014	5.79
2015	5.74
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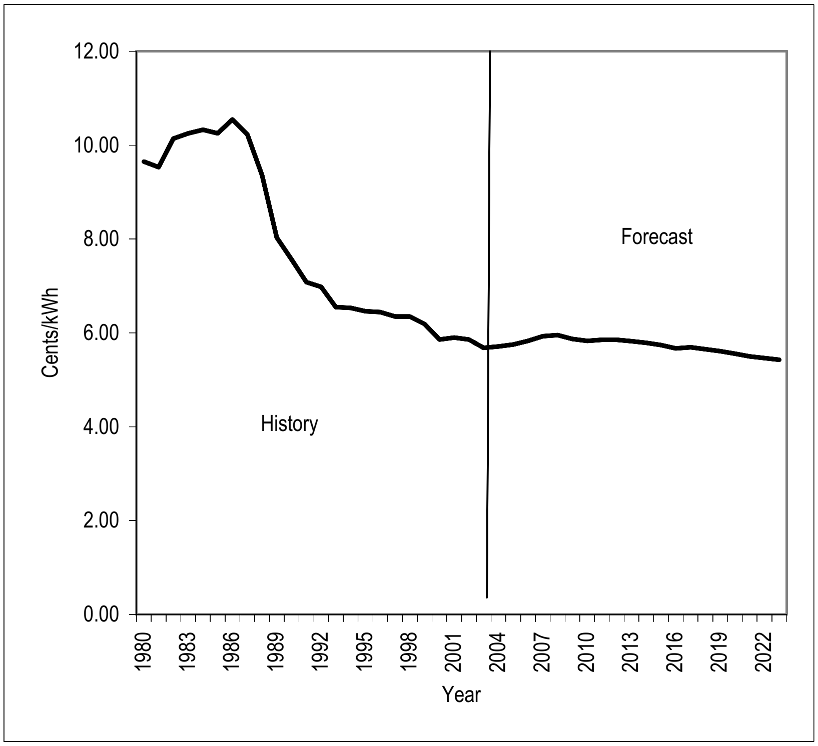
2018	5.65
2019	5.61
2020	5.56
2021	5.50
2022	5.46
2023	5.43



Average Compound Growth Rates Selected Periods	%
1980-85	1.23
1985-90	-5.91
1990-95	-3.09
1995-00	-1.92
2000-05	-0.34
2004-23	-0.09

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

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 16 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 16 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 16 industry groups, INDEED projects the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal and materials.

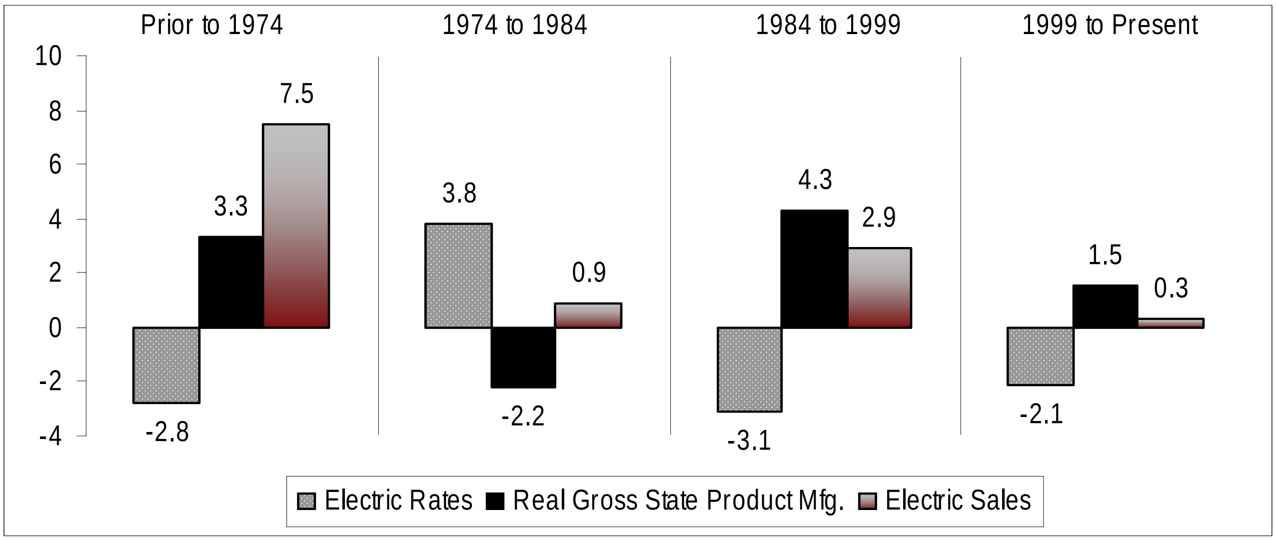
Historical Perspective

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.

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 the last 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 slow 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

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



activity since 1999 has resulted in slower but positive growth in electricity use; however, manufacturing 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. At this time, only the iron and steel, foundries and aluminum portions of SIC (Standard Industrial Classification) 33 are broken down to Level II models. In addition, a 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 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. Over three-fourths of state GSP is accounted for by the following industries: fabricated metals, 7 percent; primary metals, 9 percent; industrial machinery and equipment, 9 percent; chemicals, 14 percent; electronic and electric equipment, 15 percent; and transportation, 21 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.

Figure 7-2. Structure of Industrial Energy Modeling System

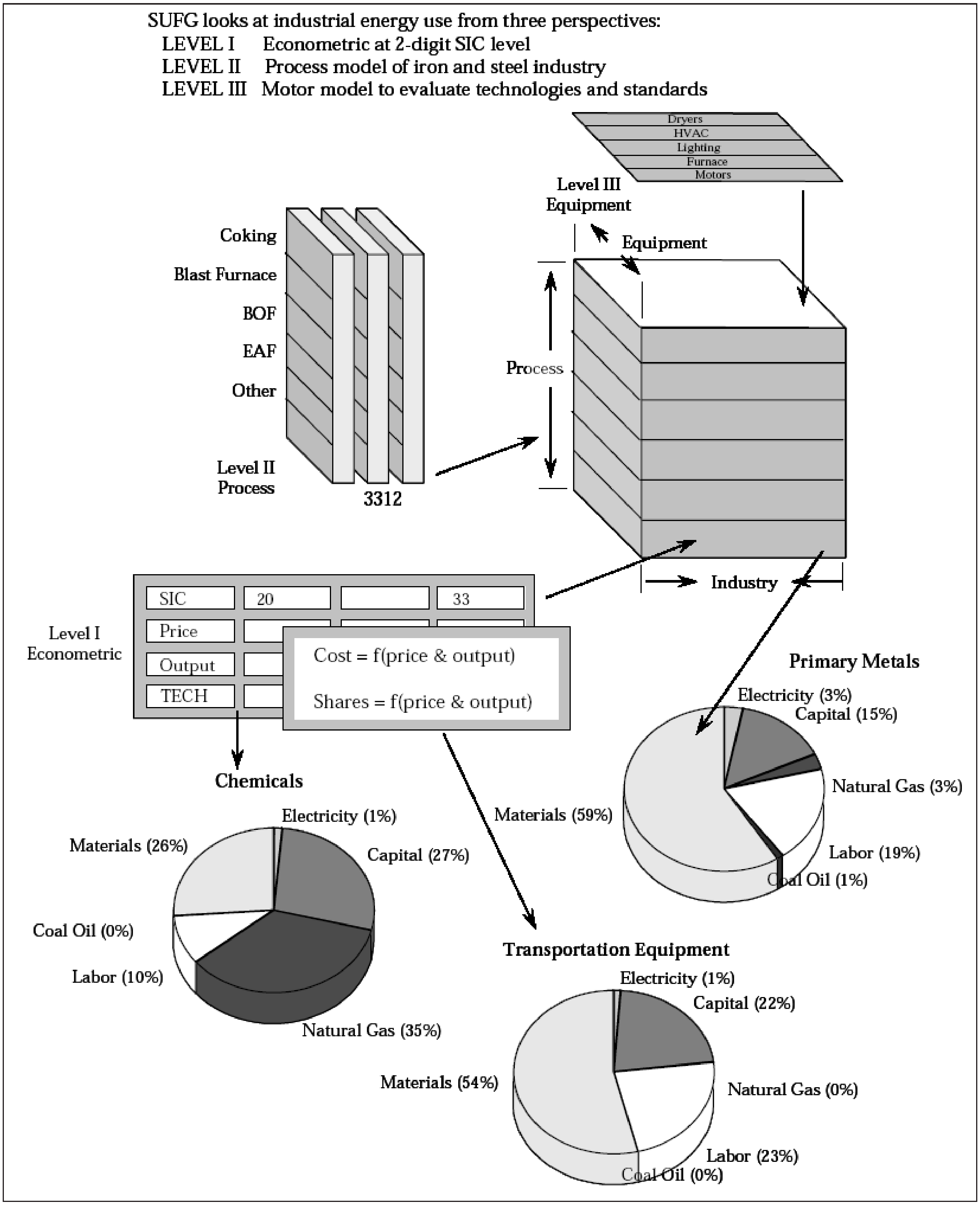


Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (Percent)

SIC	Name	Current Share of GSP	Current Share of Electricity Use	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Use by Sector
20	Food & Kindred Products	3.64	5.73	-1.52	-0.29	-1.81
24	Lumber & Wood Products	2.42	0.71	5.77	-0.12	5.65
25	Furniture & Fixtures	2.15	0.57	4.60	-0.28	4.32
26	Paper & Allied Products	1.40	2.92	-1.52	-0.21	-1.73
27	Printing & Publishing	2.65	1.32	-1.52	-0.17	-1.69
28	Chemicals & Allied Products	14.28	17.46	2.84	-0.31	2.53
30	Rubber & Misc. Plastic Products	4.10	6.21	0.80	-0.24	0.57
32	Stone, Clay, & Glass Products	1.83	5.36	-1.52	-0.24	-1.76
33	Primary Metal Products	8.99	30.05	-0.14	2.54	2.40
34	Fabricated Metal Products	6.64	5.23	1.70	-0.14	1.56
35	Industrial Machinery & Equipment	9.18	4.47	2.22	-0.22	1.99
36	Electronic & Electric Equipment	15.21	5.61	3.94	-0.12	3.82
37	Transportation Equipment	21.36	9.87	2.61	-0.19	2.42
38	Instruments And Related Products	4.26	0.80	3.67	-0.19	3.48
39	Miscellaneous Manufacturing	1.88	1.11	5.02	-5.62	-0.60
Total	Manufacturing	100.00	100.00	2.53	-0.54	1.99

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 projected sector employment projections by a projection of GSP per employee, a measure of labor productivity.

This is the first SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG is still using the SIC system, SUFG 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 industry- wide GSP growth projections. This was necessary since CEMR's projections did not specifically include chemical manufacturing, a large purchaser of electricity in Indiana.

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 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. The current SUFG forecast assumes that real natural gas prices in the industrial sector "spike" in 2005 then decline at about 6.2 percent per year until the year 2010 and increase at a rate of about 1.5 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, but are assumed to grow at about one-half the rate (0.7 percent per year) than gas after the year 2010. 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 1.99 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 industry 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 Prices	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 Figure 7-3 in both tabular and graphic form. The shaded numbers in the table and the heavy line in the graph are historical sales.

The impact of industrial sector DSM programs on growth rates for the 2001 and 2003 and current forecasts are contained in Table 7-3. 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 affect of conservation activities during the 1900s are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from its 2003 level of approximately 39,000 GWh to nearly 60,000 GWh by 2023. This growth rate of 1.99 percent per year is substantially lower than the 2.61 percent rate projected for the commercial and somewhat lower then the 2.22 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies near the 2003 and 2001 forecasts until the end of the forecast horizon.

The lower forecast of industrial sector electricity energy purchases in the early years can be attributed to reduced economic activity. Industrial electric energy purchases are flat at the beginning of the forecast period. The sales projections increase modestly throughout the remainder of the forecast as economic activity increases and the current projection of purchases is above both the SUFG's 2003 and 2001 projections by 2016.

Indiana Industrial Energy Projections: SUFG Scenarios

Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to almost 67,000 GWh by 2023, more than 11 percent higher than the base projection. In the low scenario, industrial sales grow slowly, which results in only 54,000 GWh sales by 2023, more than 9 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 2.53 percent per year during the forecast period. That rate is 3.52 percent in the high scenario and only 1.80 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

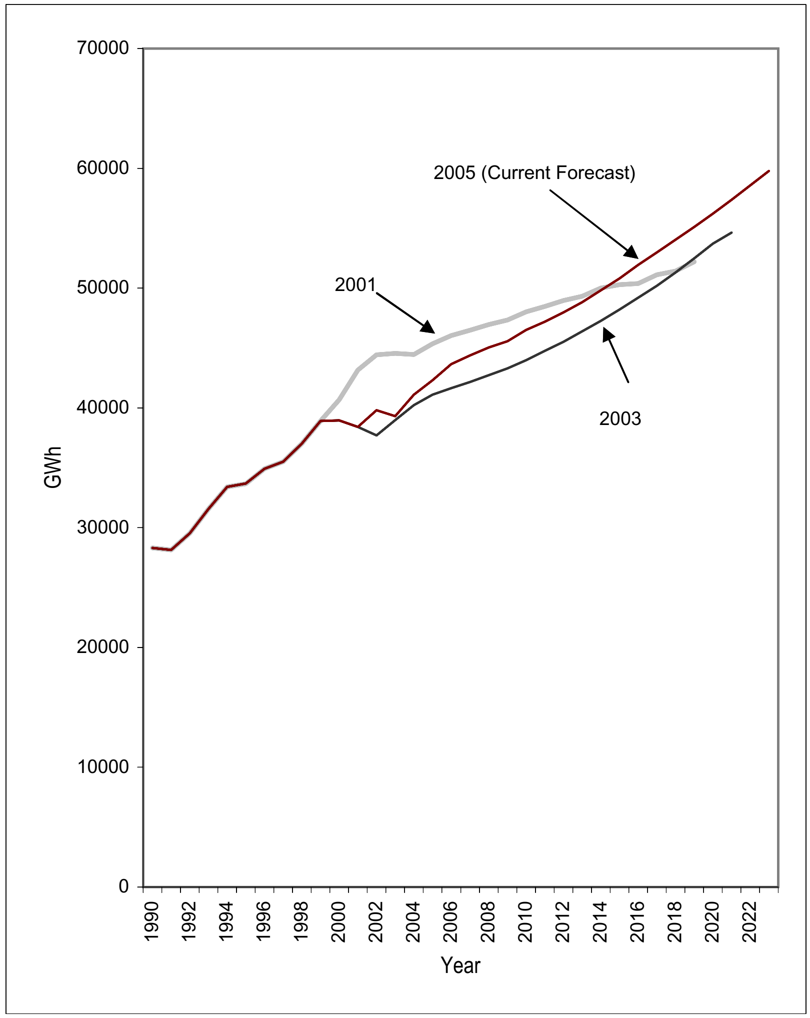
The high and low scenarios reflect an optimistic and pessimistic view regarding the ability of Indiana's industries to compete with producers from other states.

Table 7-3. History of SUFG Industrial Sector Growth Rates (Percent)

				Prior to DSM		After DSM	
Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Intensity	Sales Growth	Intensity	Sales Growth
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
2001 SUFG Base (2000-2019)	1.41	-0.55	0.86	0.46	1.32	0.46	1.32

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

	2001	2003	2005
1990	28311	28311	28311
1991	28141	28141	28141
1992	29540	29540	29540
1993	31562	31562	31562
1994	33395	33395	33395
1995	33659	33695	33695
1996	34920	34920	34920
1997	35499	35499	35499
1998	37012	37012	37012
1999	38916	38916	38916
2000	40680	38957	38957
2001	43156	38409	38409
2002	44425	37697	39802
2003	44550	38973	39317
2004	44461	40224	41096
2005	45344	41101	42310
2006	46045	41650	43647
2007	46486	42166	44391
2008	46948	42736	45048
2009	47345	43304	45554
2010	48014	43994	46507
2011	48467	44751	47200
2012	48969	45512	47966
2013	49324	46386	48832
2014	49994	47272	49826
2015	50291	48207	50811
2016	50383	49196	51930
2017	51111	50200	52982
2018	51430	51296	54048
2019	52197	52471	55102
2020		53713	56223
2021		54623	57371
2022			58579
2023			59766



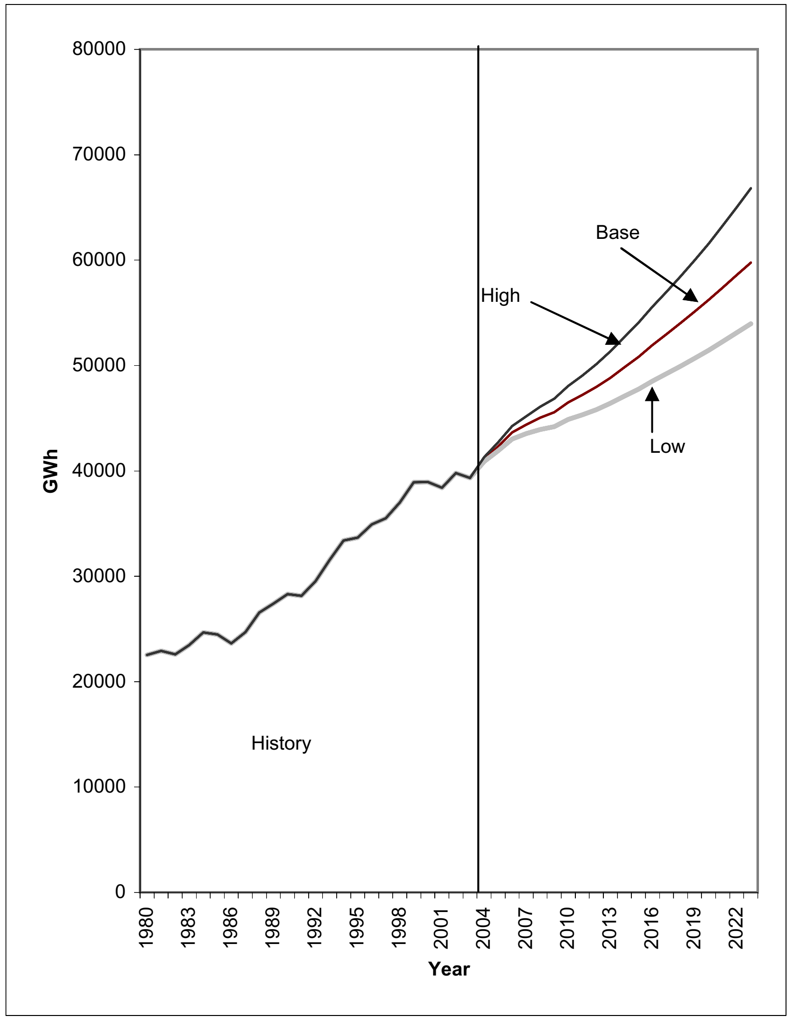
Forecast Period	Average Compund Growth Rate		
	2000-19	2002-21	2004-23
	1.32	1.97	1.99

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Figure 7-5. In real terms, industrial electricity prices have been declining since the mid-1980s. SUFG projects industrial real electricity prices to slowly drift upward as the need for additional generation resources and additional emissions controlled equipment lead to relatively constant real electricity prices. 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.

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

	Base	Low	High
1980	22544	22544	22544
1981	22907	22907	22907
1982	22600	22600	22600
1983	23476	23476	23476
1984	24678	24678	24678
1985	24480	24480	24480
1986	23618	23618	23618
1987	24694	24694	24694
1988	26546	26546	26546
1989	27394	27394	27394
1990	28311	28311	28311
1991	28141	28141	28141
1992	29540	29540	29540
1993	31562	31562	31562
1994	33395	33395	33395
1995	33659	33659	33659
1996	34920	34920	34920
1997	35499	35499	35499
1998	37012	37012	37012
1999	38916	38916	38916
2000	38957	38957	38957
2001	38409	38409	38409
2002	39802	39802	39802
2003	39317	39317	39317
2004	41096	40888	41301
2005	42310	41893	42705
2006	43647	43015	44247
2007	44391	43532	45195
2008	45048	43925	46093
2009	45554	44187	46849
2010	46507	44869	48051
2011	47200	45310	49042
2012	47966	45812	50134
2013	48832	46405	51340
2014	49826	47095	52691
2015	50811	47755	54064
2016	51930	48525	55564
2017	52982	49232	57007
2018	54048	49948	58485
2019	55102	50667	59973
2020	56223	51458	61570
2021	57371	52255	63253
2022	58579	53115	65007
2023	59766	53951	66809

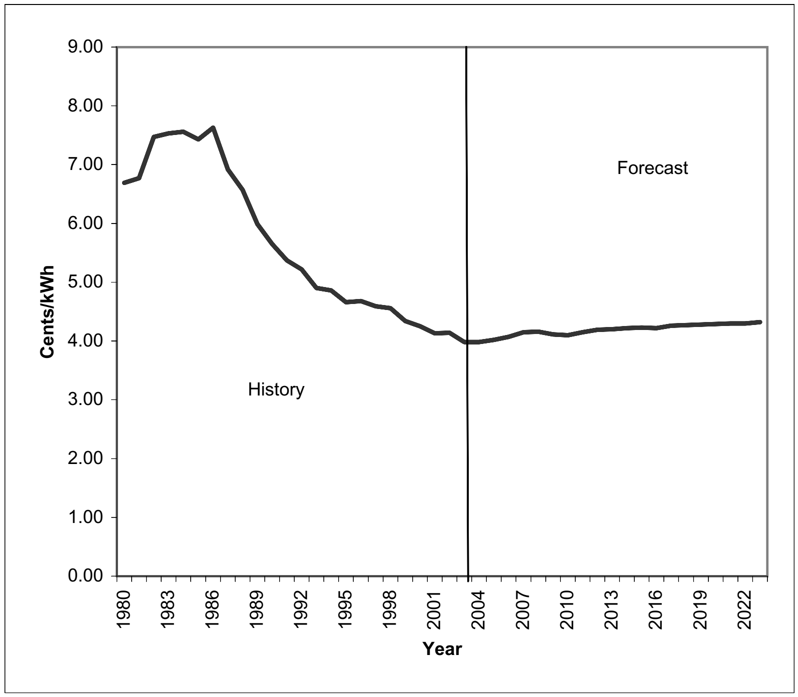


Average Compund Growth Rates			
Periods	Base	Low	High
1980-85	1.66	1.66	1.66
1985-90	2.95	2.95	2.95
1990-95	3.52	3.52	3.52
1995-00	2.97	2.97	2.97
2000-05	1.67	1.46	1.85
2004-23	1.99	1.47	2.56

Figure 7-5. Indiana Industrial Base Real Price Projections (in 2003 Dollars)

Year	Cents/ kWh
1980	6.69
1981	6.77
1982	7.47
1983	7.53
1984	7.56
1985	7.43
1986	7.63
1987	6.92
1988	6.57
1989	5.99
1990	5.65
1991	5.37
1992	5.22
1993	4.90
1994	4.86
1995	4.66
1996	4.68
1997	4.59
1998	4.56
1999	4.34
2000	4.25
2001	4.13

Year	Cents/ kWh
2002	4.14
2003	3.98
2004	3.98
2005	4.02
2006	4.07
2007	4.15
2008	4.16
2009	4.11
2010	4.10
2011	4.15
2012	4.19
2013	4.20
2014	4.22
2015	4.23
2016	4.22
2017	4.26
2018	4.27
2019	4.28
2020	4.29
2021	4.30
2022	4.30
2023	4.32



Average Compund Growth Rates Selected Periods	%
1980-85	2.11
1985-90	-5.32
1990-95	-3.79
1995-00	-1.81
2000-05	-1.13
2004-23	0.44

Issues of Interest to Policymakers

Summary of the Energy Policy Act of 2005

The Energy Policy Act signed into law on August 8, 2005 has various provisions that affect to varying degrees the electricity industry in Indiana. This section of the report contains a review of these provisions. They include: the repeal of the Public Utility Holding Act of 1935; incentives for clean coal and gasification technologies; incentives targeted at expansion and reliability of the transmission system; the removal of the mandatory purchase requirements in the Public Utility Regulatory Act of 1978; the extension of the renewable energy production tax credit; and the introduction of production tax credit for advanced new nuclear power. In writing this section, SUFG used summaries written by ICF Consulting [1], the Edison Electric Institute [2], and the American Public Power Association [3].

Public Utility Holding Company Act of 1935 (PUHCA) Repeal

One of the changes with significant effect on the electricity industry nationwide is the repeal in Subtitle F of the Public Utility Holding Company Act of 1935 (PUHCA). PUHCA had acted as a restriction on merger and acquisition activity in the electricity industry by requiring that utility holding companies could only acquire or merge with other electric utilities that were interconnected and that would operate as a single interconnected system. In exchange for PUHCA repeal the act expanded access by the Federal Energy Rgulatory Commission (FERC) to utility holding company records and books to enable FERC to mitigate the potential for market power and cross-subsidization between utility and non-utility affiliates. The law does not remove a state's existing merger review authority; Section 1265 codifies the requirement for utilities to provide the relevant records, books, etc., to strengthen the states' merger review. The Act transfers the merger review at the Federal level from the Securities and Exchange Commission to the FERC.

Clean Coal Technology Incentives

The incentives for clean coal technologies can be grouped in the following areas:

- Title IV Subtitle A authorizes the expenditure of $200 million per year in the fiscal years 2006 to 2014 for research in coal-based gasification and combustion technologies under a program known as the "Clean Coal Power Initiative." The Act provides that 70 percent of the funds must be used on coal-based gasification projects and other advanced coal-based technologies while 30 percent can be used for other technologies. Also out of the $200 million allocated the Secretary of Energy can establish centers of excellence for energy systems of the future in institutions of higher learning.

- Title IV Subtitle B provides for loan guarantees for various IGCC-based "Clean Power Projects."

- Title IV, Subtitle C authorizes the expenditure of $3 billion over seven years to establish a Clean Air Coal Program (CACP). The program provides loans, cost sharing, and cooperative agreements for a clean coal technology deployment program under two categories: Air Quality Enhancement Program and Generation Projects.

- The energy policy tax incentives title (Title XIII) contains incentives targeted at investment in clean coal facilities. Section 1307 establishes three investment tax credits for clean coal facilities as follows: Integrated Gasification Combined Cycle (IGCC) and industrial gasification projects get a 20% tax credit other advanced coal-based projects that produce electricity get 15% credit. A maximum of $800 million is authorized for IGCC projects, a maximum of $500 million for other advanced coal-based technologies and a maximum of $350 million for industrial gasification projects. Section 1309 extends the special amortization terms to pollution control facilities to include facilities placed in service after 1976 and extends the depreciation period from 60 months to 84 months. This provision is only for pollution control facilities used in electric generating facilities primarily fired with coal. Section 1322 provides incentive for producing fuel from non-conventional sources by modifying the associated tax credit to be part of general credit.

Transmission Siting, Reliability, Open Access and Tax Incentives

Section 1221 of the electricity title of the Act (Title XII) expands the involvement of the Federal government in the siting of transmission lines by providing the authority for the Department of Energy (DOE) to designate "National Interest Transmission Corridors." DOE is required to carry out studies of electric transmission congestion every three years starting 2006 during which they can designate any geographic area experiencing transmission congestion that adversely affect consumers as a national interest transmission corridor.

The section gives the FERC authority to issue construction permits in such designated corridors if the state does not issue the permits within one year or if they state issues attaches conditions to the permit such that the transmission facility will not be economically feasible or not reduce congestion. The Act also provides authority for use of eminent domain to obtain rights-of-way in these national interest transmission corridors if the permit holder is unable to obtain rights-of-way by contract or is unable to agree with the property owner on the compensation.

Section 1211 of the electricity title includes the provision to transform the current voluntary reliability standards in the bulk transmission to mandatory enforceable standards. The FERC is given the authority to form an electric reliability organization (ERO) and to approve and enforce the standards written by the ERO.

Section 1231 gives FERC the authority to require public-owned utilities such as municipalities and rural cooperatives to proved non-discriminatory transmission access. The rule only applies to those public utilities selling over 4,000 GWh per year.

In addition to the above provisions, incentives targeted at transmission facilities are provided for in the tax incentives title (Title XIII).

Removal of the Public Utility Regulatory Policy Act of 1978 (PURPA) "Qualifying Facilities" Mandatory Purchase Requirement

According to Section 1253 of the Act, utilities will no longer be required to sign new purchase agreements with qualifying facilities (QF). In addition FERC has been given the authority to discontinue existing QF contracts, at the request of a utility, if the utility can show that the QF generator has non-discriminatory access to wholesale competitive electricity markets.

This represents a modification of the requirements of the Public Utility Regulatory Policy Act of 1978 (PURPA), which required that utilities buy power from qualified non-utility renewables-based and cogeneration facilities at the utility's avoided cost. This mandatory purchase requirement resulted in significant entry of non-utility generators into the electricity market in the 1980s. However, as the electricity industry has been undergoing restructuring since these avoided-cost based long term contracts have become an issue of significant contention.

Renewable Electricity Production Tax Credits and Clean Renewable Energy Bonds

The Act extends the renewable electricity production tax credit (PTC) for another two years to end of 2007.

The PTC is credited with the rapid growth of wind generators across the country, despite having expired several times in the past prior to being renewed. The PTC provides a ten year production tax credit 1.9 cents per kWh, adjusted for inflation. The Act also extends the full 10 year tax credit to certain renewable energy technologies (such as geothermal, open-loop biomass, solar and landfill gas) that only enjoyed partial credit previously. The PTC is also extended to renewable energy technologies that were not included previously such as hydroelectric power from existing dams.

The Act in Section 1303 also establishes clean renewable energy bonds for public utilities such as municipal utilities and rural electric cooperatives for the construction of renewable energy facilities. This complements the renewable energy tax credits already provided for private entities previously.

Incentives for Advanced New Nuclear Power Plants

The Act contains several provisions and incentives designed to encourage the construction of advanced nuclear facilities. The Energy Policy Tax Incentives Title (Title XIII) contains a 1.8 cents/kWh eight year production tax credit for new advanced nuclear power facilities. The tax credit is limited to a maximum of 6,000 MW of capacity and set to expire at the end of the year 2020. The Nuclear Matters Title (Title VI) contains, among many other provisions, a total of $6 billion standby support for delays of more than six months due to litigation or licensing for six advanced reactors.

Clean Air Interstate Rule and Clean Air Mercury Rule

In March 2005, the U.S. Environmental Protection Agency (EPA) issued new rules affecting electric power plant emissions. The Clean Air Interstate Rule (CAIR) lowers allowed emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) from currently allowed levels by roughly 56 percent and 68 percent , repectively. CAIR is a cap and trade type program for SO2 and NOx emissions with new emissions caps to be fully implemented in two phases. The first phase takes place in 2009 (NOx) and 2010 (SO2), and the second phase in 2015 for both SO2 and NOx. At nearly the same time, EPA also finalized a rule for mercury emissions called the Clean Air Mercury Rule (CAMR). The mercury rule is also a cap and trade, two-phase rule and is projected to reduce mercury emissions from electric power plants by approximately 70 perecent by 2018. The first phase of CAMR depends upon the co-benefits of control measures implemented under CAIR, while the second phase is expected to require additional mercury specific control measures.

EPA used the Integrated Planning Model (IPM) developed and supported by ICF Consulting, Inc., to determine the likely emission control measures necessary to meet the emissions limits required by CAIR. IPM is a regional linear programming optimization model of the U.S. electric power sector which includes electric energy and demand markets, fossil fuel markets, and emission allowance markets. IPM determines the least-cost solution to meeting electric energy and peak demand subject to environmental constraints. The results of the IPM analysis

Table 8-1. Summary of CAIR Control Measures

	FGD		SCR		SNCR		RETIRE	
	Units	MW	Units	MW	Units	MW	Units	MW
Existing	16	5947	20	8266	0	0	-	-
CAIR 2010	3	1850	13	6841	0	0	4	155
CAIR 2015	7	3658	26	10416	5	440	4	155
CAIR 2020	11	4458	26	10416	5	440	4	155

for those Indiana generating units included in SUFG's modeling system are summarized in Table 8-1.

The columns of the table refer to specific emission control measures and show the number of electric generating units and the total megawatt capacity of those generating units subject to the emissions control measure as determined by IPM. FGD is an acronym for flue gas desulfurization ("scrubber") which is used for SO2 emissions control; SCR refers to selective catalytic reduction, a NOx emissions control device; SNCR refers to selective non-catalytic reduction, also used for NOx emissions control; and, RETIRE refers to early retirement of a generating unit. The rows of the table refer to approximate time periods and the rows labeled "CAIR" refer to cumulative emission control measures. Thus the first column shows that three FGD controls are expected to be added by about 2010, another four by about 2015 and a total of 11 by about 2020.

While the Indiana electric utilities' emission control strategies for their electric generating system will differ somewhat from the IPM estimates, the IPM analysis provides an indication of the level of emission control measures necessary to meet the requirements of CAIR.The IPM analysis shows the need to increase the installation of FGDs by about 70 percent and to more than double the number of NOx emissions controls. The costs of these emission control measures is not included in this SUFG forecast and will increase the electricity price estimates presented in previous sections of this report.

Electricity and Natural Gas Price Interactions

The Effect of Natural Gas Price on Electricity Consumption

The price of natural gas affects the consumption of electricity in several ways. Electricity and natural gas are substitutes for each other for several end uses, such as space heating, water heating, cooking and clothes drying in the residential and commercial sectors. In general, electricity and natural gas compete for new loads in these sectors, with retrofits of equipment being rare. Also, since few residential or commercial buildings have the capability to switch quickly from one fuel source to another, short-term natural gas price variations have little impact on electricity usage in those sectors.

In the industrial sector, natural gas and electricity compete primarily for space heating and process loads. In addition to long-term competition for new end uses, some industrial customers have the ability to switch from one source to another in a relatively short period of time. Therefore, electricity usage in the industrial sector tends to be more sensitive to short-term natural gas price variations than the residential and commercial sectors are.

Technological developments can also have a significant impact on the choice between natural gas and electricity at the end-use level. This can take the form of equipment efficiency improvements or of new technologies that at least partially replace existing technologies. An example of the latter from the recent past is the microwave oven. In homes with natural gas ranges, microwave ovens reduced the usage of natural gas and increased the usage of electricity.

Electricity usage in the industrial sector tends to be most sensitive to the price of natural gas in the long term, with a ten percent increase in natural gas price resulting in a 1.4 percent increase in electricity usage. The commercial sector is relatively insensitive to natural gas prices, with a ten percent increase in natural gas price resulting in a 0.2 percent increase in electricity usage. This occurs because the most energy intensive establishments (groceries, retail and heath care) use a lot of air conditioning, lighting and refrigeration. Substitution with natural gas is generally not an option with these end uses.

Sensitivity to natural gas prices in the residential sector falls between that of the other two sectors; a ten percent increase in the price of natural gas causes a 1.0 percent increase in electricity use. Figure 8-1 and 8-2 illustrate the relationship between natural gas price and electricity

Figure 8-1. Btu-Adjusted Electricity to Natural Gas Price Ratio

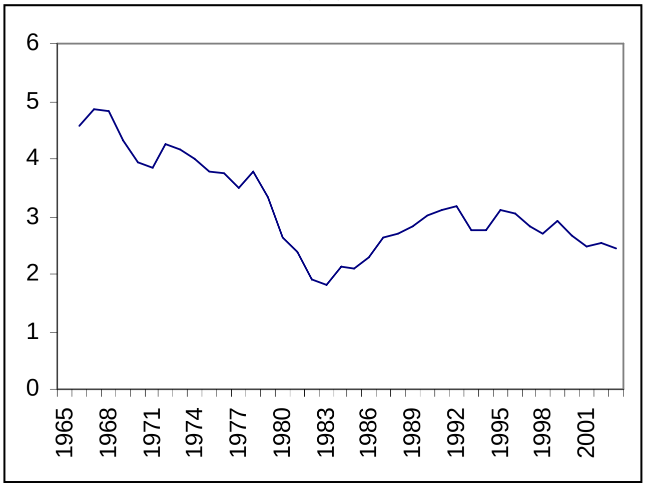


Figure 8-2. Net Electric Space Heating Penetration (Percent)

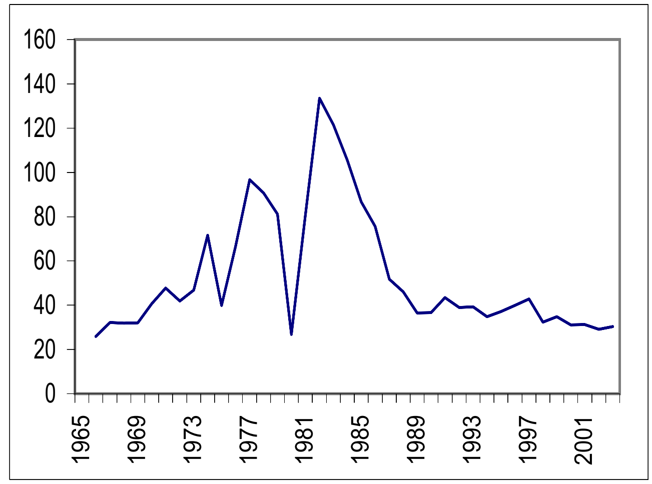


Table 8-2. Indiana and New England Market Characteristics

	Indiana	New England
Generating Capacity	25,252 MW	29,991 MW
Portion of generation that is natural gas-fired	13.3%	19.5%
Portion of electrical energy from natural gas	3.0%	36.0%

consumption for specific residential end use, space heating. Figure 8-1 shows the Btu-adjusted ratio of natural gas prices to electricity prices, which accounts for changes in efficiency over time. Figure 8-2 shows the net electric space heating penetration during the same time period. Note that penetration may be greater than 100 percent or less than zero due to customers switching to or from electric space heating. The two images are nearly mirror images of each other. That is, when the first graph goes down (indicating that natural gas has become relatively more expensive), the second graph goes up (indicating that more customers are choosing electricity for their space heating needs) and vice versa.

The Effect of Natural Gas as a Fuel for Electricity Generation

In addition to being a substitute for electricity at the end use, natural gas is a source of fuel for the generation of electricity. In the 1980s and 1990s, the price of natural gas had little impact on the utilities' cost of supplying electricity in Indiana. During that time period Indiana's electricity industry could be characterized as having relatively high reserve margins. Furthermore, almost all of the generating capacity was coal-fired. In more recent years, there has been a large amount of natural gas-fired capacity constructed. At the same time, reliance on wholesale markets has increased. Since natural gas-fired units are often the marginal cost provider, the cost of natural gas should have a more direct bearing on the price of electricity on the wholesale market.

In order to examine the impact of natural gas prices on wholesale electricity prices, SUFG tracked day ahead and forward market prices as reported by *Megawatt Daily* from August 2004 through March 2005. Prices were tracked for the "into Cinergy" market and for contrast, the "Mass Hub" market. These markets were chosen because they experience relatively high trading volumes, are of similar size, and have different market characteristics in terms of the reliance on natural gas for electricity generation. The characteristics of Indiana and New England, as compiled from EIA's State Electricity Profiles 2002, are provided in Table 8-2.

Figure 8-3 shows the historical relationship between next day natural gas and peak electricity prices for Indiana over the August 2004 to March 2005 period. The figure shows a scatter diagram where each point indicates both the natural gas price (on the horizontal axis) and electricity price (on the vertical axis) for a particular day. The plot shows a mild correlation between the two. That is, as gas prices increase, electricity prices tend to increase, but there is a relatively high amount of variation. Figure 8-4 shows the same plot for New England, which has a very strong correlation. This is to be expected given New England's greater reliance on natural gas-fired generation.

Figure 8-5 shows the historical relationship between next day natural gas and forward electricity prices for Indiana. Forward prices were tracked using the July/ August 2005 prices as reported by *Megawatt Daily* from August 2004 through March 2005. It is interesting to note that the forward price of electricity appears to be more strongly correlated to the next day natural gas price than the next day electricity price is. Figure 8-6 shows the corresponding data for New England. With the exception of a two week period in January 2005 where natural gas prices increased dramatically, forward electricity prices in New England seem to follow short-term gas price changes.

A statistical analysis of the data provides the correlation coefficients that correspond to Figures 8-3 through 8-6. Table 8-3 shows those coefficients for Indiana, along withthose for the relationship between next day peak electricity and the July/August forward electricity prices. Table 8-4 shows the correlation coefficients for NewEngland. The correlation coefficients vary from -1 to +1, with values near -1 indicating a strong inverse relationship (if one goes up, the other goes down). A value near zero indicates little to no relationship between the two (a change in one does not affect the other). A value near +1 indicates a strong correlation between the two (they tend to go up and down together. The values in Tables 8-3 and 8-4 confirm the observed relationships in the scatter diagrams.

The Effect of Fossil Fuel Price Projections

SUFG used fossil fuel price projections based on the East North Central Region projections contained in the Energy Information Agency's January 2005 Annual Energy Outlook in preparing the current SUFG forecast. As shown in Chapter 4, the real natural gas and refined oil product price projections peak around 2005 then decline rapidly until about 2010 and increase slowly thereafter. To investigate the sensitivity of the electric energy, electricity peak demand, and electricity price projections to the fossil fuel price projections SUFG constructed an alternative set of fossil fuel projections by holding all real fossil fuel price projections at their 2005 levels for the entire forecast horizon. This artificially constructed alternative results in real natural gas and oil product prices around 20 to 25 percent higher than the original EIA projections over most of the SUFG forecast horizon. The change in the real coal price projections is much more modest at less than 5 percent due to the coal price trajectory in the original EIA projections.

Incorporating this alternative set of real price projections results in relatively minor year over year changes in the SUFG projections. Total electric energy requirements and peak demand increase by less than 2 percent and real electricity prices increase by slightly over 1 percent during the last three-fourths of the forecast period. Total electric energy requirements and peak demand increase with the alternative fossil price projections due to substitution of electricity for natural gas and to a lesser extent oil products. Electricity prices increase modestly due to the large share of coal-fired electricity generation in Indiana and to the relatively small increase in real coal prices in the alternative fossil fuel price projections.

Obviously, this simple analysis of the effect of higher fossil fuel prices on Indiana electricity use and prices ignores the likely more important impact of higher fossil fuel prices on the macroeconomic activity of the nation, region, and state. Thus, the impact of high fuel prices on the overall economy are not included.

Figure 8-3. Next Day Peak Electricity Price vs. Next Day Natural Gas Price for Indiana

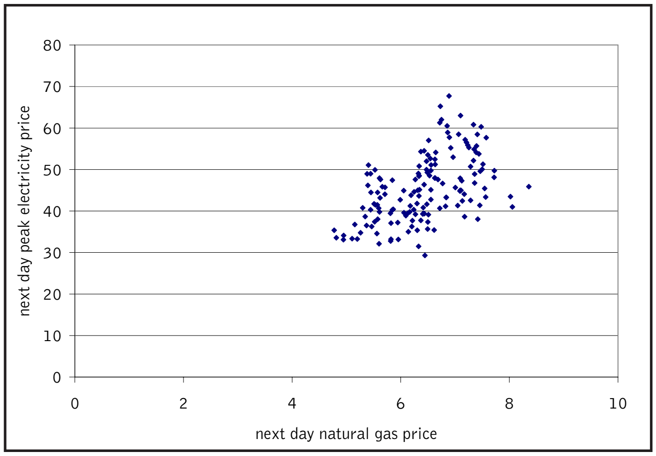


Figure 8-5. Forward Electricity Price vs. Next Day Natural Gas Price for Indiana

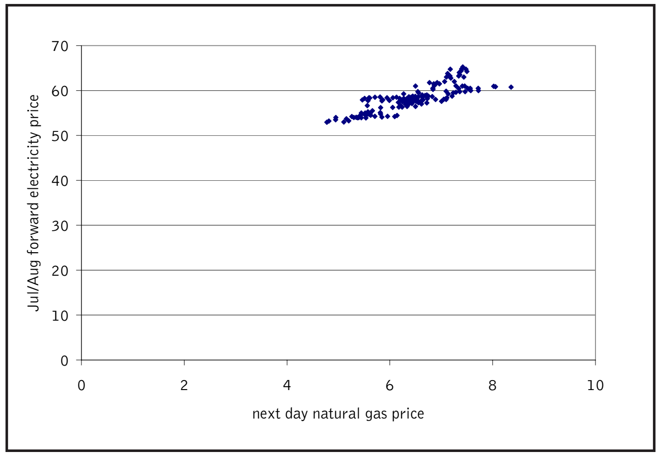


Figure 8-4. Next Day Peak Electricity Price vs. Next Day Natural Gas Price for New England

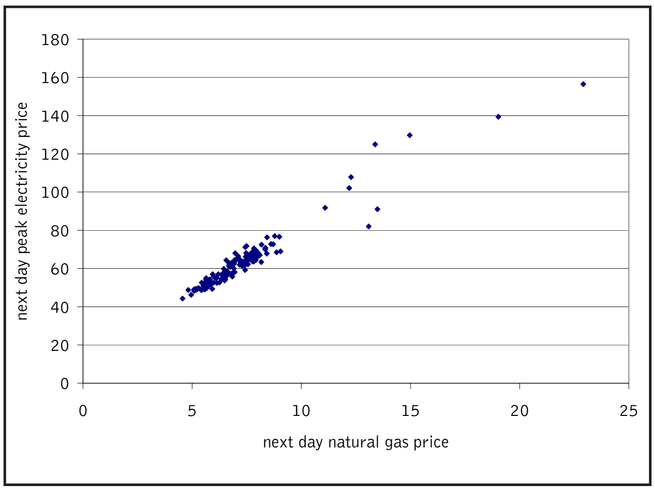


Figure 8-6. Forward Electricity Price vs. Next Day Natural Gas Price for New England

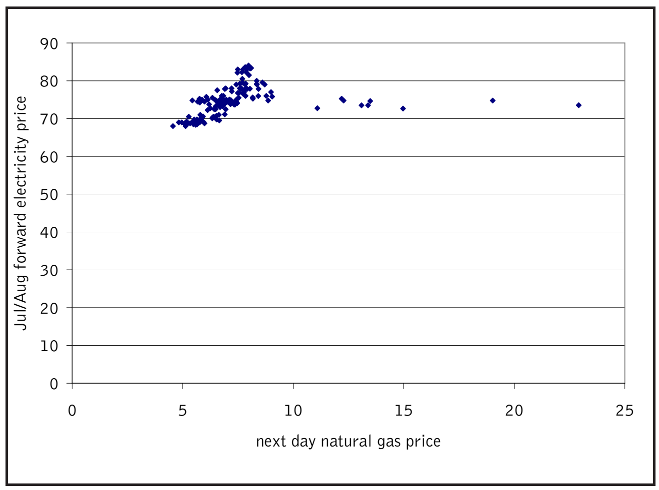


Table 8-3. Correlation Coefficients for Indiana

Change in:	Next day peak elec.	Jul/Aug forward elec.	Next day natural gas
Next day peak elec.	-	0.519	0.512
Jul/Aug forward elec.	0.519	-	0.831
Next day natural gas	0.512	0.831	-

Table 8-4. Correlation Coefficients for New England

Change in:	Next day peak elec.	Jul/Aug forward elec.	Next day natural gas
Next day peak elec.	-	0.325	0.967
Jul/Aug forward elec.	0.325	-	0.314
Next day natural gas	0.967	0.314	-

Impact of the Hydrogen Economy on the Electricity Industry

In 2004, the National Academy of Engineering (NAE) released its report, *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs,* which details the result of its study for the U. S. Department of Energy (DOE) [4]. In the report, NAE reported that the most promising use of hydrogen was as a transportation fuel, helping to reduce the nation's reliance on imported petroleum from unstable regions of the world and to reduce the emission of harmful compounds to the environment.

The report identified the four fundamental technical challenges that must be met for the hydrogen economy to be feasible:

1. *"To develop and introduce cost-effective, durable, safe, and environmentally desirable fuel cell systems and hydrogen storage systems."*
2. *"To develop the infrastructure to provide hydrogen for the light-duty-vehicle user."*
3. *"To reduce sharply the costs of hydrogen production from renewable energy sources, over a time frame of decades."*
4. *"To capture and store ("sequester") the carbon dioxide by-product of hydrogen production from coal."*

The report also recommends that DOE increase R&D expenditures on distributed hydrogen production facilities. It does not support replacing the current petroleum infrastructure (large production facilities with an extensive transportation network) with a similar hydrogen infrastructure, in part due to security and cost concerns. There are currently two methods of producing hydrogen on a small scale distributed method that are even remotely cost effective: reformulation of natural gas and electrolysis of water. The report acknowledges that the nation is already a net importer of natural gas and that a substantial portion of the world's natural gas reserves are located in the same unstable regions that currently export petroleum. Furthermore, increased imports of natural gas from overseas would require a substantial investment in liquified natural gas processing facilities, with the inherent cost and security concerns that come with it.

According to the "optimistic" estimate of hydrogen usage in the report, the nation could be using about 110 million tons of hydrogen by 2050. It takes approximately 33 kWh of electricity to produce 1 kg of hydrogen by electrolysis. If all 110 million tons of hydrogen were produced via electrolysis, it would take 3.3 million GWh of electricity. To put that amount in perspective, the U. S. electric power industry generated 3.9 million GWh of electricity in 2003, according to EIA. This would require a significant investment in not only the nation's generating capability, but also in upgrading a transmission system that is already showing signs of strain from overuse. Also, the environmental impacts would be large unless a dramatic increase in environmentally friendly generation (renewables, nuclear, clean coal) and conservation occurs.

While it is almost certainly true that some of the hydrogen production will come from sources other than electrolysis and that using distributed electricity generation could help alleviate the burden on the transmission system, the transition to a hydrogen economy is sure to have a major impact on the electricity industry.

References

[1] ICF Consulting, Impacts and implications of the 2005 U.S. Energy Policy Act, http://www.icfconsulting.com/Markets/Energy/Energy-Act/default.asp

[2] Edison Electric Institute, Summaries, http://www.eei.org/industry_issues/electricity_policy/federal_legislation/index.htm

[3] American Public Power Association, Legislative/Regulatory page, http://www.appanet.org/legislative/index.cfm?itemnumber=13734

[4] "*The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs,*" National Research Council and National Academy of Engineering of the National Academies, The National Academies Press, Washington, DC, 2004.

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

SUFG relied on public sources where possible, but some generally more detailed data was obtained from Indiana utilities under confidential agreements of non-disclosure. 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 is 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 I&M and 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 WVPA has one member cooperative, which is located in southern Michigan, one member located in eastern Ohio, and four members located in central Illinois. 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 REMCs and unaffiliated municipalities. SUFG obtains aggregate sales data from the FERC Form 1, then allocates the sales to residential, commercial industrial and other sales with an allowance for losses. These allocation factors were developed by examining the mix of energy sales for other Indiana REMCs and municipalities. Thus, the sales estimates for unaffiliated REMCs are weighted heavily toward the residential sector and those for unaffiliated municipalities are more evenly balanced between the residential, commercial and industrial sectors.

SUFG's estimates of sales-for-resale are based on FERC Form 1 data and utility provided data. Traditionally, the five IOUs and HEREC have been sellers and IMPA, WVPA and unaffiliated REMCs and municipalities purchasers of sales-for-resale energy and capacity. Out-of-state sales-for-resale by I&M and purchases-for-resale by WVPA are excluded in SUFG's estimates. Additionally, there are some classification differences similar to those in retail sales. SUFG treats the city of Richmond as part of IMPA and includes the city of Jasper as part of the unaffiliated municipalities while I&M and SIGECO, respectively, have treated them as electric utilities.

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 HEREC, IMPA and WVPA.

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

The historical energy sales and peak demand data presented in this appendix represent SUFG's accounting of actual historical values. However, data availability for the REMCs and municipalities prior to 1982 is limited and the reported values for 1980 and 1981 include SUFG estimates for the not-for-profit utilities for these years. SUFG believes that any errors in statewide energy sales and demand for 1980 and 1981 are relatively small and concentrated in the residential sector.

In developing the current forecast, SUFG was required to estimate some detailed sector specific data for a few utilities. This data was unavailable from some utilities due to changes in data collection and/or reporting requirements. In the industrial sector, SUFG estimates two digit, Standard Industrial Code sales and revenue data for two IOUs. This data was estimated from total industrial sales data by assuming the same allocation of industrial sales to two-digit level as observed during recent years. SUFG was also unable to obtain sales and revenue data for the commercial sector at the same level of detail from some IOUs. The detailed commercial sector data is necessary to calibrate SUFG's commercial sector model, but since the commercial sector model was not recalibrated for this forecast, no estimation was attempted. The not-for-profit utilities have not traditionally been able to supply SUFG with data at this level of data. 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 availability proves to be a problem 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 2003 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales						Energy	Summer
		Res	Com	Ind	Other	Total	Losses	Required	Demand
Hist	1980	16612	12418	22544	556	52131	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
Hist	1983	19950	13665	23476	626	57717	4795	62511	11744
Hist	1984	20153	14274	24678	674	59779	4938	64717	11331
Hist	1985	19707	14651	24480	653	59491	4889	64380	11030
Hist	1986	20410	15429	23618	610	60067	4958	65024	11834
Hist	1987	21154	16144	24694	617	62609	5185	67794	12218
Hist	1988	22444	16808	26546	633	66431	5557	71988	13447
Hist	1989	22251	17205	27394	661	67511	5815	73326	12979
Hist	1990	22037	17659	28311	685	68692	5050	73742	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	28684	23721	38957	571	91932	6312	98244	16757
Hist	2001	29516	23991	38409	564	92481	6828	99309	17531
Hist	2002	32777	25119	39802	634	98332	6733	105065	19137
Hist	2003	31524	24404	39317	609	95855	6864	102719	19839
Frcst	2004	32634	25444	41096	609	99783	7454	107237	19167
Frcst	2005	33300	26219	42310	609	102438	7631	110069	19599
Frcst	2006	33876	26972	43647	609	105104	7807	112911	20052
Frcst	2007	34319	27677	44391	609	106996	7941	114937	20486
Frcst	2008	35013	28451	45048	609	109121	8102	117223	20820
Frcst	2009	35657	29252	45554	609	111072	8246	119318	21201
Frcst	2010	36516	30053	46507	609	113685	8441	122126	21712
Frcst	2011	37318	30823	47200	609	115950	8615	124565	22167
Frcst	2012	38088	31601	47966	609	118264	8788	127052	22620
Frcst	2013	38929	32416	48832	609	120786	8976	129762	23121
Frcst	2014	39858	33265	49826	609	123558	9182	132740	23666
Frcst	2015	40774	34110	50811	609	126304	9385	135689	24206
Frcst	2016	41764	34975	51930	609	129278	9604	138882	24790
Frcst	2017	42740	35842	52982	609	132173	9818	141991	25362
Frcst	2018	43756	36733	54048	609	135146	10037	145183	25954
Frcst	2019	44900	37626	55102	609	138237	10264	148501	26574
Frcst	2020	46041	38557	56223	609	141430	10497	151927	27211
Frcst	2021	47175	39510	57371	609	144665	10739	155404	27855
Frcst	2022	48357	40488	58579	609	148033	10987	159020	28526
Frcst	2023	49521	41491	59766	609	151387	11230	162617	29196

Average Compound Growth Rates (%)								
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	1.59	2.82	3.01	1.12	2.49	-2.66	2.11	0.50
2000-2005	3.03	2.02	1.67	1.30	2.19	3.87	2.30	3.18
2005-2010	1.86	2.77	1.91	0.00	2.11	2.04	2.10	2.07
2010-2015	2.23	2.56	1.79	0.00	2.13	2.14	2.13	2.20
2015-2020	2.46	2.48	2.04	0.00	2.29	2.26	2.29	2.37
2020-2023	2.46	2.47	2.06	0.00	2.29	2.28	2.29	2.38
2004-2023	2.22	2.61	1.99	0.00	2.22	2.18	2.22	2.24

SUFG 2003 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Rates 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	28684	23721	38957	571	91932	6312	98244	16757
Hist	2001	29516	23991	38409	564	92481	6828	99309	17531
Hist	2002	32777	25119	39802	634	98332	6733	105065	19137
Hist	2003	31524	24404	39317	609	95855	6864	102719	19839
Frcst	2004	32634	25443	40888	609	99574	7439	107013	19132
Frcst	2005	33274	25997	41893	609	101773	7582	109355	19479
Frcst	2006	33814	26404	43015	609	103842	7715	111557	19820
Frcst	2007	34221	26759	43532	609	105121	7801	112922	20137
Frcst	2008	34869	27169	43925	609	106572	7913	114485	20344
Frcst	2009	35491	27599	44187	609	107886	8009	115895	20605
Frcst	2010	36269	28004	44869	609	109751	8148	117899	20979
Frcst	2011	37002	28377	45310	609	111298	8269	119567	21296
Frcst	2012	37699	28751	45812	609	112871	8386	121257	21611
Frcst	2013	38479	29146	46405	609	114639	8519	123158	21971
Frcst	2014	39341	29576	47095	609	116621	8664	125285	22367
Frcst	2015	40186	29976	47755	609	118526	8806	127332	22747
Frcst	2016	41101	30389	48525	609	120624	8959	129583	23167
Frcst	2017	42008	30799	49232	609	122648	9109	131757	23578
Frcst	2018	42960	31217	49948	609	124734	9262	133996	24000
Frcst	2019	44022	31639	50667	609	126937	9424	136361	24453
Frcst	2020	45086	32080	51458	609	129233	9594	138827	24921
Frcst	2021	46118	32529	52255	609	131511	9763	141274	25380
Frcst	2022	47212	32983	53115	609	133919	9942	143861	25869
Frcst	2023	48302	33444	53951	609	136306	10118	146424	26355

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summar 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	1.59	2.82	3.01	1.12	2.49	-2.66	2.11	0.50
2000-2005	3.01	1.85	1.46	1.30	2.05	3.73	2.17	3.06
2005-2010	1.74	1.50	1.38	0.00	1.52	1.45	1.52	1.49
2010-2015	2.07	1.37	1.25	0.00	1.55	1.57	1.55	1.63
2015-2020	2.33	1.37	1.50	0.00	1.74	1.73	1.74	1.84
2020-2023	2.32	1.40	1.59	0.00	1.79	1.79	1.79	1.88
2004-2023	2.09	1.45	1.47	0.00	1.67	1.63	1.66	1.70

SUFG 2003 High 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	28684	23721	38957	571	91932	6312	98244	16757
Hist	2001	29516	23991	38409	564	92481	6828	99309	17531
Hist	2002	32777	25119	39802	634	98332	6733	105065	19137
Hist	2003	31524	24404	39317	609	95855	6864	102719	19839
Frcst	2004	32640	25443	41301	609	99993	7470	107463	19205
Frcst	2005	33599	26432	42705	609	103345	7699	111044	19782
Frcst	2006	34534	27520	44247	609	106910	7940	114850	20419
Frcst	2007	35221	28570	45195	609	109595	8133	117728	21012
Frcst	2008	36079	29719	46093	609	112500	8354	120854	21499
Frcst	2009	36857	30888	46849	609	115203	8552	123755	22025
Frcst	2010	37842	32079	48051	609	118581	8805	127386	22684
Frcst	2011	38810	33253	49042	609	121714	9044	130758	23307
Frcst	2012	39745	34451	50134	609	124939	9285	134224	23934
Frcst	2013	40753	35704	51340	609	128406	9543	137949	24613
Frcst	2014	41840	37002	52691	609	132142	9820	141962	25346
Frcst	2015	42915	38300	54064	609	135888	10098	145986	26078
Frcst	2016	44062	39639	55564	609	139874	10391	150265	26860
Frcst	2017	45193	40991	57007	609	143800	10678	154478	27633
Frcst	2018	46381	42369	58485	609	147844	10975	158819	28431
Frcst	2019	47693	43789	59973	609	152064	11284	163348	29271
Frcst	2020	49010	45245	61570	609	156434	11605	168039	30133
Frcst	2021	50334	46750	63253	609	160946	11939	172885	31021
Frcst	2022	51685	48307	65007	609	165608	12282	177890	31940
Frcst	2023	53044	49917	66809	609	170379	12632	183011	32880

Average Compound Growth Rates (%)								
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	1.59	2.82	3.01	1.12	2.49	-2.66	2.11	0.50
2000-2005	3.21	2.19	1.85	1.30	2.37	4.05	2.48	3.37
2005-2010	2.41	3.95	2.39	0.00	2.79	2.72	2.78	2.78
2010-2015	2.55	3.61	2.39	0.00	2.76	2.78	2.76	2.83
2015-2020	2.69	3.39	2.63	0.00	2.86	2.82	2.85	2.93
2020-2023	2.67	3.33	2.76	0.00	2.89	2.87	2.89	2.95
2004-2023	2.59	3.61	2.56	0.00	2.84	2.80	2.84	2.87

Indiana Base Average Retail Rates (Cents/kWh) (In 2003 Dollars)

Year		Res	Com	Ind	Average
Hist	1980	9.10	9.65	6.69	8.17
Hist	1981	9.27	9.53	6.77	8.20
Hist	1982	10.30	10.14	7.47	9.05
Hist	1983	10.71	10.25	7.53	9.20
Hist	1984	10.85	10.33	7.56	9.25
Hist	1985	11.07	10.25	7.43	9.24
Hist	1986	11.21	10.55	7.63	9.52
Hist	1987	10.78	10.23	6.92	8.99
Hist	1988	10.16	9.36	6.57	8.40
Hist	1989	9.48	8.03	5.99	7.56
Hist	1990	8.93	7.56	5.65	7.10
Hist	1991	8.36	7.08	5.37	6.74
Hist	1992	8.28	6.98	5.21	6.56
Hist	1993	7.80	6.55	4.89	6.18
Hist	1994	7.82	6.53	4.86	6.13
Hist	1995	7.68	6.46	4.66	6.01
Hist	1996	7.65	6.44	4.68	5.99
Hist	1997	7.79	6.35	4.59	5.96
Hist	1998	7.80	6.35	4.56	5.94
Hist	1999	7.56	6.19	4.34	5.74
Hist	2000	7.24	5.86	4.25	5.51
Hist	2001	7.10	5.90	4.13	5.45
Hist	2002	6.97	5.86	4.14	5.45
Hist	2003	6.80	5.68	3.98	5.27
Frcst	2004	6.80	5.71	3.97	5.26
Frcst	2005	6.84	5.75	4.02	5.30
Frcst	2006	6.91	5.83	4.07	5.36
Frcst	2007	7.00	5.93	4.15	5.45
Frcst	2008	7.01	5.95	4.16	5.47
Frcst	2009	6.88	5.87	4.11	5.39
Frcst	2010	6.79	5.83	4.10	5.35
Frcst	2011	6.81	5.85	4.15	5.39
Frcst	2012	6.79	5.85	4.19	5.40
Frcst	2013	6.73	5.82	4.20	5.38
Frcst	2014	6.68	5.79	4.22	5.37
Frcst	2015	6.62	5.74	4.23	5.35
Frcst	2016	6.53	5.67	4.22	5.30
Frcst	2017	6.53	5.69	4.26	5.32
Frcst	2018	6.48	5.65	4.27	5.31
Frcst	2019	6.43	5.61	4.28	5.28
Frcst	2020	6.34	5.56	4.29	5.25
Frcst	2021	6.26	5.50	4.30	5.21
Frcst	2022	6.20	5.46	4.30	5.19
Frcst	2023	6.16	5.43	4.32	5.17

Average Compound Growth Rates (%)				
Year	Res	Com	Ind	Average
1980-1985	4.00	1.23	2.11	2.50
1985-1990	-4.20	-5.91	-5.32	-5.13
1990-1995	-2.99	-3.09	-3.79	-3.27
1995-2000	-1.17	-1.92	-1.81	-1.73
2000-2005	-1.12	-0.39	-1.13	-0.78
2005-2010	-0.14	0.26	0.42	0.20
2010-2015	-0.52	-0.30	0.61	-0.03
2015-2020	-0.86	-0.65	0.31	-0.37
2020-2023	-0.96	-0.76	0.18	-0.48
2004-2023	-0.52	-0.26	0.44	-0.09

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

Additions (To Utility Plant)

Gross —Expenditures for construction (may or may not include interest and other overheads charged to construction) and utility plant purchased and acquired, in a specific period.

Net —Gross additions less retirements and adjustments of a utility plant. It is the net change in a utility plant between two dates.

Average A number that typifies a set of numbers of which it is a function.

Average Compound Growth Rate (ACGR) A commonly used measure to summarize the overall rate of change in percentages of any forecast time series. Only the beginning and ending points plus the number of intervening years are necessary to define an average compound growth rate. For example, in this forecast ACGRs were calculated as follows:

$$\left[\left[\left(\frac{Value\ of\ Year\ 2021}{Value\ of\ Year\ 2001}\right)^{\left(\frac{1}{2021-2002}\right)}\right]-1\right]*100$$

Base Case (Base Scenario) The most likely projection with an equal chance of being high or low.

Base Load Demand The minimum load over a given period of time.

Base Load Plant An electricity generation plant normally operated to meet all or part of the minimum load demand of a power company's system over a given amount of time.

Base Load Unit Generation unit, which is designed for nearly continuous operation at or near full capacity to provide all or part of the base load demand.

Base Year The last year that actual data is available and from which all forecast series emanate.

British Thermal Unit (Btu) The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one Fahrenheit degree. There are 3412 Btu in 1 kWh.

Calibration The process of adjusting model parameters such that when tested for a historical period, the model can produce results that are as close to historical data a possible. This is sometimes referred to as backcasting.

Capacity The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

Base Load Capacity of the generating equipment normally operated to serve continuous loads.

Peaking That portion of the total generation capacity that is used to serve the load under adverse conditions, such as periods of unusually high load or the failure of a base load or intermediate unit. Peaking capacity is not used under normal conditions and may be activated quickly under adverse conditions.

Capacity Factor The ration, as expressed as a percentage, of the average operating load of an electric power generating system for a period of time to the capacity rating of the system during that period, calculated as follows:

$$\frac{Average\ \ Load}{Rated\ \ Capacity}\ X\ \ 100\ \%$$

Capacity Margin The percentage difference between rated capacity and peak load divided by rated capacity. (See also *Reserve Margin*) Capacity margin is calculated as:

$$\frac{Rated\ Capacity - Peak\ Load}{Rated\ Capacity}\ X\ \ 100\%$$

Clean Air Act (CAA) The primary federal law governing the regulation of emissions into the atmosphere. Originally passed in 1963, it has been amended several times with major changes occurring in 1970 and 1990. In 1970, primary responsibility for administering the CAA was given to the newly created Environmental Protection Agency. This act required promulgation and ongoing enforcement of National Ambient Air Quality Standards and National Emission Standards for Hazardous Air Pollutants that limit the maximum local concentrations of various air pollutants. In addition, the act limits the amount of various pollutants that vehicles may emit. The 1990 amendments set stricter provisions for motor vehicle emissions, attainment of the national ambient air quality standards and specific restrictions on use or emissions of chlorofluorocarbons, NO_x and sulfur dioxide (SO_2). The SO_2 restrictions involve a system of tradable emissions allowances.

Combined Cycle A combustion turbine installation using waste heat boilers to capture exhaust energy for steam generation.

Combustion Turbine An electric generating unit in which the prime mover is a gas turbine engine. (See also *Peaking Unit*).

Competition A business environment in which more than one supplier can potentially serve a market and any customer has the ability to choose the supplier that best serves its needs.

Cooperative, Rural Electric Membership (REMC) A consumer-owned utility established to provide electric service in rural portions of the United States. Consumer cooperatives are incorporated under the laws of the 46 states in which they operate. A consumer cooperative is a non-profit enterprise, owned and controlled by the people it serves. These systems obtain most of their financing through insured and guaranteed loans administered by the Rural Utilities Service (formerly the Rural Electrification Administration) and from their own financing institution, the National Rural Utilities Cooperative Financing Corporation.

Deflator An index which is used to adjust for the purchasing power of a dollar.

Demand *(Economic)* The inverse relationship between the price of a good and the quantity demanded.

Demand *(Electric Power)* The instantaneous load on transmission, distribution, substation and generation facilities.

Demand-Side Management (DSM) The planning, implementation and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of DSM include: load management, new uses of electricity, energy conservation, electrification, customer generation adjustments in market share and innovative rates. DSM includes only those activities that involve a deliberate intervention by the utility to alter the load shape. These changes must produce benefits to both the utility and its customers.

Demographics Data on population attributes such as age, income, number of household members, schooling, etc. Demographic data is used to identify and segment customer types.

Discrete Choice Microsimulation A methodology employed by the CEDMS (commercial end-use) model wherein detailed equipment choices by customers are simulated across a variety of distinct technologies for a sample of representative commercial establishments.

Economic Activity A causal factor used in energy models as one of the explanatory variables. In SUFG's energy modeling system, each of the sectoral energy forecasting models is driven by economic activity assumptions, i.e., personal income, population, commercial employment and industrial output.

Econometric Model A single or multi-variant statistical approach to explain the variations in an economic variable by the use of changes in other observed independent variable(s).

Economic Driver(s) Generally used to refer to elements of a small set of primary causal elements in an economic system.

Electric Power Research Institute (EPRI) Founded in 1972 by the nation's electric utilities to develop and manage technology programs for improving electric power production, distribution and utilization.

Electric Energy-Weighted Commercial Floor Space Index This index is a proxy for the physical size of the commercial sector. This index is preferable to other commonly used proxies such as non-manufacturing employment due to the variability of electric intensity among building types. Originally constructed for SUFG's 1987 forecast, the index is annually updated. The weights were reestimated by Jerry Jackson and Associates based in part on data from the 1990 census.

Emissions Air, soil, or water pollutants emitted into a community's atmosphere, soil, or water supply.

End Use Uses of energy including, but not limited to, space heating, water heating, lighting, air conditioning, refrigeration, cooking, electromotive and other processes.

End-Use Model A model focusing on end-use technologies.

End-Use Saturation The percentage of households, building types, etc., that include equipment to provide an end-use service, such as air-conditioning.

Energy As commonly used in the electric utility industry refers to kilowatthours, as opposed to "demand" which refers to kilowatts.

Energy Information Administration (EIA) Since October 1977, the Energy Information Administration (EIA) of the Department of Energy (DOE) has been responsible for collecting and publishing statistical data on energy production, consumption, prices, resources and projections of supply and demand. The EIA serves as an independent statistical and analytical agency within the DOE.

Envelope Retrofits The process of replacing or augmenting the insulation, windows, air exchange, etc. of a building.

Estimate To calculate approximately the extent or amount of.

Exogenous Variable A variable determined outside the system of interest.

Explanatory Variables A variable that is assumed to be determined by forces external to a model and is accepted as given data. These variables are used in an econometric model to explain the changes in the dependent variable.

Firm Purchase A form of contract under which power or power-producing capacity is intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Forecast Horizon The period of time from the start of a forecast until the end of a forecast.

Gas-Fired Combustion Turbine An electric generating unit in which the prime mover is a gas-fired turbine engine.

Generating Unit An electric generator together with its prime mover.

Generation, Electric The act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatthours.

> **Gross** - The total amount of electric energy produced by the generating units in a generating station or stations measured at the generator terminals.
>
> **Net** - Gross generation less kilowatthours used at the generating station(s).

Gigawatt (GW) Tne gigawatt equals one billion watts, 1 million kilowatts or 1 thousand megawatts.

Gigawatthour (GWh) One gigawatthour equals one billion watthours.

Gross Domestic Product (GDP) The best measure of the aggregate value of national output. GDP is equal to Gross National Product net of resident's income from economic activity abroad (i.e., exports, repatriated profits, interest and so on) and property held abroad minus the corresponding income of nonresidents in the country (i.e., imports and profits and interests and dividends taken out of the country).

Gross State Product (GSP) Used to refer to the part of GDP originating within any state.

Heterogeneity Consisting of dissimilar ingredients.

Household Formation The demographic and economic process that describes the creation of a household.

Inflation Rate The rate of change of an economy's price level that is shared by most products.

Integrated Resource Planning A process by which utilities and regulatory commission assess the cost of and choose among various resource options.

Intensity Used in the context of disaggregating observed and forecast changes in electricity use into two components:

> —One related to changes in the level of relevant economic activities generally outside and not sensitive to the cost of electricity. Primary examples are residential households, com-

mercial building floorspace and the level of industrial production.

—One which is directly related to the price of electricity and describes the rate of electricity use per unit level of the relevant economic activity, e.g., kWh per residential customer, kWh per unit of commercial building floorspace, kWh per unit of industrial output.

Interruptible Rate A lower rate offered by a utility to a customer that allows the utility to interrupt electric service.

Investor-Owned Utility Electric utility organized as a taxpaying business usually financed by the sale of securities in the free market and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may be owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

Kilowatt (kW) One kilowatt equals 1,000 watts.

Kilowatthour (kWh) The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatthour equals 1,000 watthours.

Load Diversity The difference between the sum of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

Logit Model A statistical model used to explain the choice between two or more possibilities.

Log-Log Econometric Model A statistical model in which the logarithm of the dependent variable is linearly related to the logarithm(s) of the independent variable(s).

Long Run A period of time long enough to permit the variation of all inputs to production, including capital and technological change. (See **Short Run**)

Loss (Losses) The general term applied to energy (kilowatthours) and power (kilowatts) lost in the operation of an electric system or transmission of power from the generation point of use. Operational losses occur principally as energy transformations from kilowatthours to waste heat in electric conductors and apparatus.

Macroeconomic A study generally having to do with activities observed and measured in terms of aggregates of firms and individuals, e.g., at the national level.

Marginal Cost The change in total costs associated with a unit change in quantity supplied (i.e., demand or energy).

Market Share The percentage of the marketplace captured by a particular producer or provider of services. Also refers to the percentage of homes or building types with installation of end-use services by fuel type.

Mean An average of a series of observations.

Measurement Errors Errors which occur in measuring the data values.

Megawatt (MW) One megawatt equals one million watts.

Megawatthour (MWh) One megawatthour equals one million watthours.

Municipally-Owned Electric System An electric utility system owned and operated by a municipality usually, but not always, providing service within the boundaries of the municipality.

Not-for-Profit (NFP) When used in statistical tables to indicate class of ownership, it includes municipally owned electric systems and federal and state public power projects.

Operating and Maintenance Expense A group of expenses applicable to day-to-day utility operations and maintenance of utility facilities.

Peak Demand The maximum amount of gas, water, or electricity consumed by a utility, its customers or by a group of customers during a specified period of time.

Peak Load The greatest demand which occurred during a specified period of time.

Peaking Unit A generating unit available to assist in meeting that portion of total customer load which is above base and intermediate load.

Penetration This term is used to describe the market share of end-use technologies where electricity competes with other energy.

Process Model A model used to project industry growth and growth in energy use by projecting the growth of the factors used in the production process.

Productivity (Energy) Refers to the productivity of energy as a factor of production and indicates the level of economic value produced per unit of energy input. Energy productivity improvements occur when existing energy uses (e.g., lighting, heating, cooling and motor drive) can be obtained in more efficient ways and when new, energy-using technologies result in providing the same service levels with less energy.

Rate Base The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.

Real An adjective that describes any monetary magnitude measured in constant prices of a single base year. Opposite of nominal. Economic data expressed in real dollars represent the changes in the value of the particular data after taking out the effect of changes in general price levels.

Real Electric Prices A price that has been adjusted to remove the effects of changes in the purchasing power of the dollar. A real price usually reflects change in value relative to a base year.

Reliability The guarantee of system performance at all times and under all reasonable conditions to assure constancy, quality, adequacy and economy of electricity. It is also the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.

Reserve The net accumulated balance reflecting reservations of Income or Retained Earnings to provide for a reduction in the value of an asset, for a contingent liability or loss, or for other special purposes.

Reserve Margin The percentage difference between rated capacity and peak load divided by peak load. (See also *Capacity Margin*)

$$\frac{\text{Rated Capacity} - \text{Peak Load}}{\text{Peak Load}} \; X \; 100\%$$

Sampling Error Error which occurs due to sampling. A sample is a subset of a population. Statistical properties of a sample are used to eliminate parameters pertaining to a population.

Saturation The supplying of a market with all the goods it will absorb. Used in reference to ownership of a particular good/ service in the marketplace.

Space Heating The use of mechanical or electrical equipment to heat all or part of a building to at least 50 degrees Fahrenheit.

Short Run A period of time insufficient to permit any change in the inputs or technology of production. (See *Long Run*)

Standard Industrial Classification (SIC) A systematic methodology for classifying industrial activities. The first two digits define broad classes (i.e., 20 through 39 are manufacturing and 40s are generally commercial sector activities). The third and subsequent digits further define the activity (i.e., 3312 is blast furnace and steel production and 2819 is industrial gases).

Stochastic Random.

Summer Peak Demand The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30 (north of the equator).

Technology Curve A concept employed in REEMS and some other end-use models to capture the tradeoffs between efficiency and life cycle costs for all feasible technologies.

Transmission That portion of a utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of the transmission plant.

Unaffiliated Municipality A municipally-owned electric system that is not affiliated with the Indiana Municipal Power Agency (IMPA). (See also *Municipally-Owned Electric System*)

Unaffiliated Rural Electric Membership Cooperative A rural electric membership cooperative that is not affiliated with Hoosier Energy Rural Electric Cooperative, Inc.

(HEREC) or Wabash Valley Power Association (WVPA). (See also *Cooperative, Rural Electric Membership (REMC)*)

Uncertainty Falling short of complete knowledge about an outcome or result. SUFG uses this term in context with forecast outcome.

Variance A measure of dispersion, spread or variability of a distribution, which will be large if the observations are distant from the mean or average and small if they are close to the mean.

Watt The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower or one joule per second.

Watthour The total amount of energy used in one hour by a device that requires one watt of power for continuous operation.

Btu	British Thermal Unit
CACP	Clean Air Coal Program
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
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FGR	Flue Gas Desulfurization
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatthours
HELM	Hourly Electric Load Model
HEREC	Hoosier Energy Rural Electric
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IGCC	Integrated Gasification Combined Cycle
IMPA	Indiana Municipal Power Agency
IOU	Investor-Owned Utility
IPL	Indianapolis Power & Light Company
IPM	Integrated Planning Model
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
kW	Kilowatt
kWh	Kilowatthours
LMSTM	Load Management Strategy Testing Model
MW	Megawatt
NAE	National Academy of Engineering
NAICS	North American Industry Classification System
NFP	Not-for-Profit
NIPSCO	Northern Indiana Public Service Company
NOx	Nitrogen Oxides
O&M	Operation and Maintenance
OPEC	Organizatio of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PC	Pulverized Coal-Fired
PSI Energy	PSI Energy, Inc.
PTC	Production Tax Credit
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policy Act of 1978
QF	Qualifying Facilities
REEMS	Residential End-Use Energy Modeling System
REMC	Rural Electric Membership Cooperative
SCR	Selective Catalystic Reduction
SIC	Standard Industrial Classification
SIGECO	Southern Indiana Gas & Electric Company
SNCR	Selective non-Catalytic Reduction
SO2	Sulfur Dioxide
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association