Indiana Electricity Projections

The 2001 Forecast

State Utility Forecasting Group
Purdue University
West Lafayette, IN

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EXECUTIVE SUMMARY

Overview

The 2001 forecast predicts Indiana electricity prices to continue to decline in real (inflation adjusted) terms for the next four years. This continues a trend of falling prices that began in 1987. Real prices are projected to level off after 2005 due to the installation of new pollution control devices and increased new generating capacity needed to keep up with continued growth.

The forecast projects electricity usage to grow at an average yearly rate of 1.93 percent. This growth rate is lower than the 3.34 percent growth seen in the 1990s but greater than the 1.80 percent growth projected in SUFG's 1999 forecast. Peak electricity demand is projected to grow at an average rate of 1.49 percent annually from the 1999 level. This corresponds to about 360 megawatts (MW) of increased peak demand per year, which is similar to historical growth in the 1980s and 1990s.

In the 1999 forecast, SUFG identified a concern regarding whether sufficient new capacity would be available to meet expected growth in usage. That concern has been alleviated to some extent by two factors: new generators becoming operational and increased usage of interruptible loads. Since the spring of 2000, a total of 1,792 MW of new generating capacity has been brought on line in Indiana, with additional new generators starting up in neighboring states. While these generators are independent, or merchant plants, and are not dedicated for Indiana loads, Indiana utilities have contracted to use some of the capacity. Additionally, Indiana utilities have made arrangements with their customers to have an additional 500 MW of electric loads available for interruption in times of capacity shortages. The ability to interrupt these loads combined with new generating capacity being available go a long way toward alleviating concerns over shortages. However, it is important to note that Indiana will still need more generating capacity in the future. This forecast projects a need for 1,500 MW of additional capacity by 2004.

Other issues addressed in this forecast include:

- Will sufficient natural gas be available at a reasonable price to meet the increased usage by the new generating facilities?
- What are the advantages and disadvantages of distributed generation, which are very small, local generators located at the source of the load?
- What happened in California and what lessons can be learned from it?
- What are the expected impacts of the recent economic downturn and the events of September 11?

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electricity 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 describes major changes to SUFG's forecasting methodology, specifically the inclusion of wholesale electricity markets in the regulated forecast and the impacts of new air emissions restrictions. A complete description of the SUFG regulated modeling system used to develop this forecast was included in the 1999 forecast and is available at the SUFG website (http://www.fairway.ecn.purdue.edu/IIES/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 other four 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, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2001 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 1.02 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.18 percent. Other key economic projections follow:

- Real personal income (the residential sector model driver) is expected to grow at a 2.62 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average 1.71 percent annual growth rate over the forecast horizon.

- Despite the continued decline of manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 1.43 percent annual rate as gains in productivity offset declines in employment.

To capture some of the uncertainty in energy forecasting, SUFG 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 0.25 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 0.7 percent over the forecast period.

Fossil Fuel Price Projections. All SUFG projections are in terms of real prices, i.e., projections with the effect of inflation removed. SUFG's current assumptions are based on the December 2000 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows:

- *Natural Gas Prices*: Gas price projections for all customers stop increasing after the year 2001 and a slight increase 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

As shown in Figure 1-1, Indiana's total electricity requirements under the base scenario are expected to increase from 100,000 gigawatthours (GWh) (one GWh equals one million kilowatthours (kWh)) to over 145,000 GWh by 2019, the last year of the forecast period. The annual growth rate in electric sales is approximately 1.9 percent, which is slightly higher than the rate projected in 1999.

The SUFG forecast of electricity sales growth varies by sector. Commercial sales are expected to increase most rapidly at 2.6 percent per year. This is followed by residential sales at 2.0 percent and industrial sales at 1.5 percent.

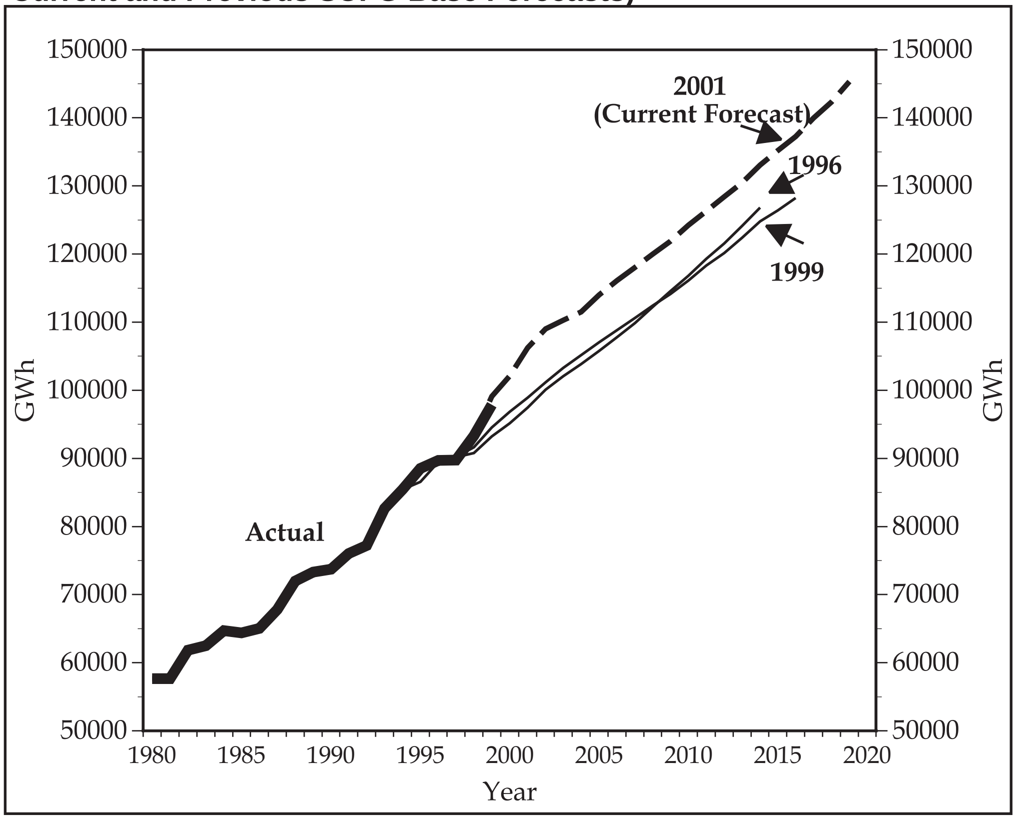
As shown in Figure 1-2, the current forecast of peak demand is slightly lower than the previous 1996 and 1999 forecasts throughout the forecast horizon due to increased interruptible loads.

Demand-Side Resources

This is the fifth time in which SUFG has included the impact of demand-side management (DSM) programs on electricity sales, peak demand requirements and electricity prices. DSM includes traditional utility-sponsored programs designed to influence customers' usage in ways that produce desirable changes in a utility's load shape. DSM typically excludes interruptible loads.

This forecast estimates that existing DSM programs have reduced 1999 Indiana peak demand by about 330 MW, or roughly two percent. In the future, incremental DSM from new programs and expanded participation in existing ones is expected to reduce peak demand by another 26 MW. The relatively low incremental DSM impacts are a result of utilities scaling back both the number of DSM programs and the projected impacts of the remaining programs.

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



Approximately 1,030 MW, or about six percent of the current Indiana peak demand, are classified as interruptible. Projections of interruptible load have roughly doubled from the previous forecast.

Supply-Side Resources

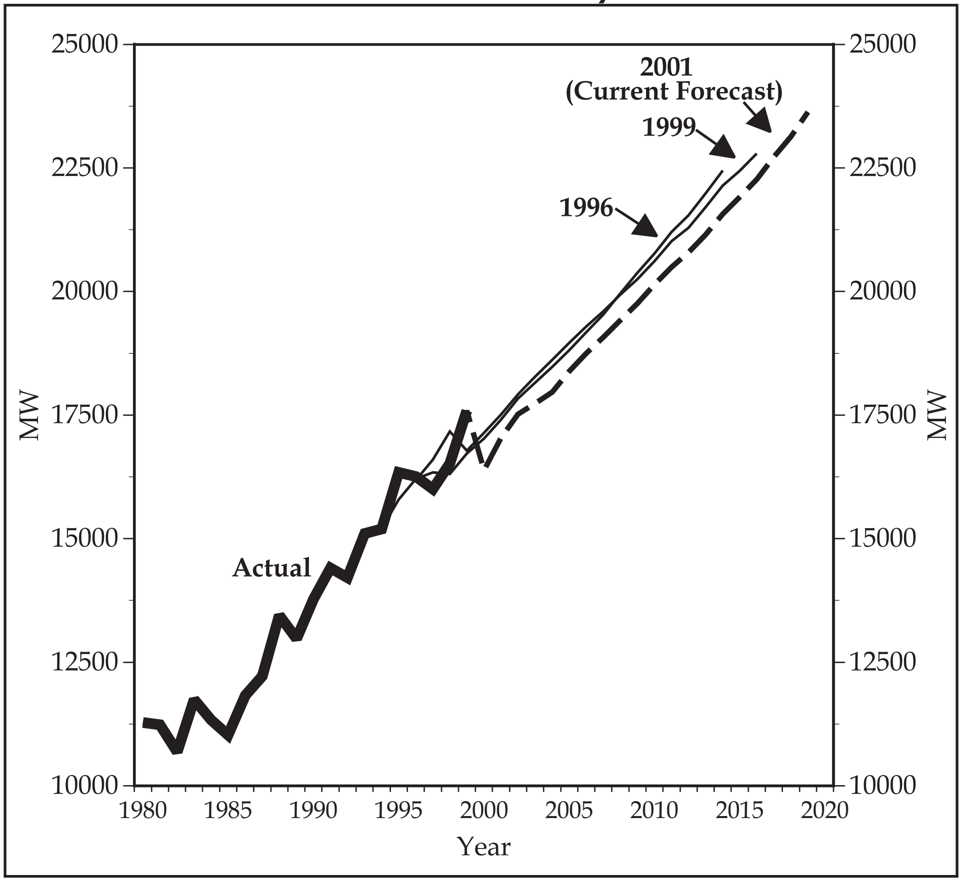
Supply-side resources include purchases from out-of-state utilities, non-utility generation and utility-owned generation facilities. All currently committed capacity changes are included in SUFG's resource plans. Committed capacity changes include: certified generation additions, retirements, deratings due to scrubber retrofits and net changes in firm out-of-state purchases and sales. New capacity is added as necessary in the form of wholesale purchases during the forecast period to maintain a 15 percent statewide reserve margin. SUFG does not attempt to determine whether a utility would be better served by building its own generation, purchasing from others, or expanding its DSM programs. SUFG projects the amount of capacity needed and captures the price impacts of acquiring the resources.

Resource Needs

Figure 1-3 illustrates the electricity supply and demand balance for the state of Indiana. The projected demand includes a 15 percent reserve margin and reductions for interruptible loads. The existing resources include the impacts of current firm purchase/sale contracts between Indiana and non-Indiana utilities. Also included are scheduled future retirements of generating units.

The section labeled "SUFG Required Resources" represents SUFG's projections of additional capacity re-

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



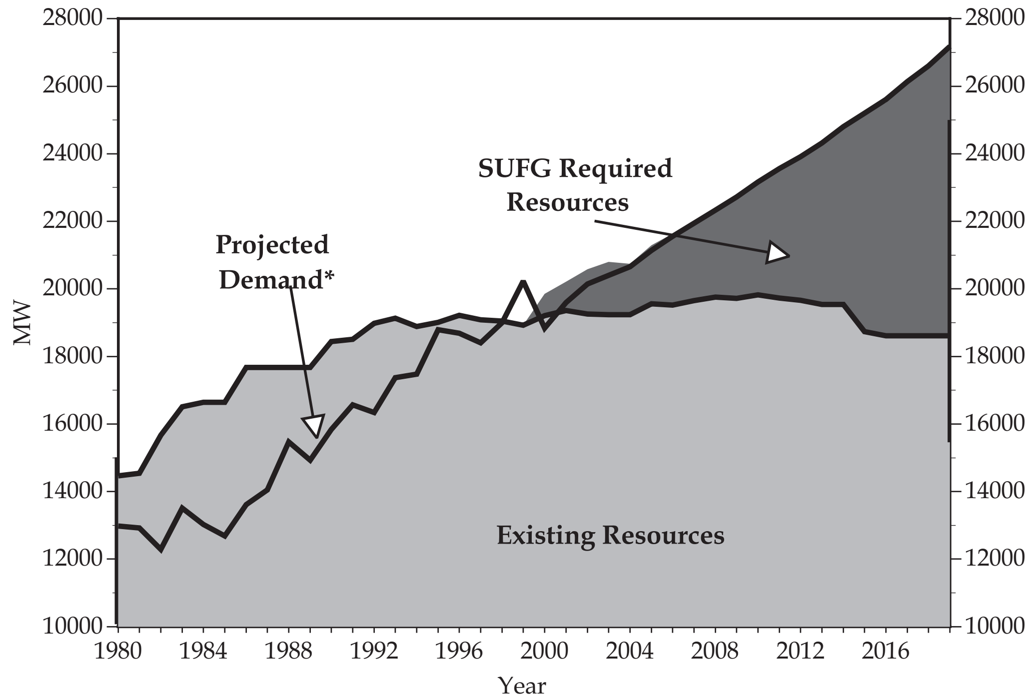
quirements. In general, these requirements are necessary to meet a 15 percent statewide reserve margin. In the early portion of the forecast (through 2003), some new resources are included to keep individual utility reserve margins at six percent, even if the state as a whole does not require it for a 15 percent reserve margin.

As a result of increased interruptible load and increased firm purchases by utilities, new resource requirements have been reduced from those seen in the 1999 forecast. The projected new capacity needs for 2003 in this forecast are 570 MW compared to 1,400 MW in the previous forecast. Resource needs are projected to grow to about 1,700 MW by 2005 and to nearly 3,400 MW by 2010.

The last two years have seen an enormous increase in the number of merchant plants operating in the Midwest. In addition to the combustion turbine (CT) and combined cycle (CC) capacity shown in Table 1-1, 1,100 MW of coal-fired merchant capacity have been proposed in Indiana.

SUFG does not explicitly include this merchant capacity in its forecast. However, any firm purchases by a utility from a merchant plant are included. In addition, Chapter 2 includes the results of an analysis by SUFG that indicates that the wholesale market should be adequate to meet Indiana's needs in the near future.

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



Note: Projected Demand includes 15% Reserve Margin

Electricity Price Projections

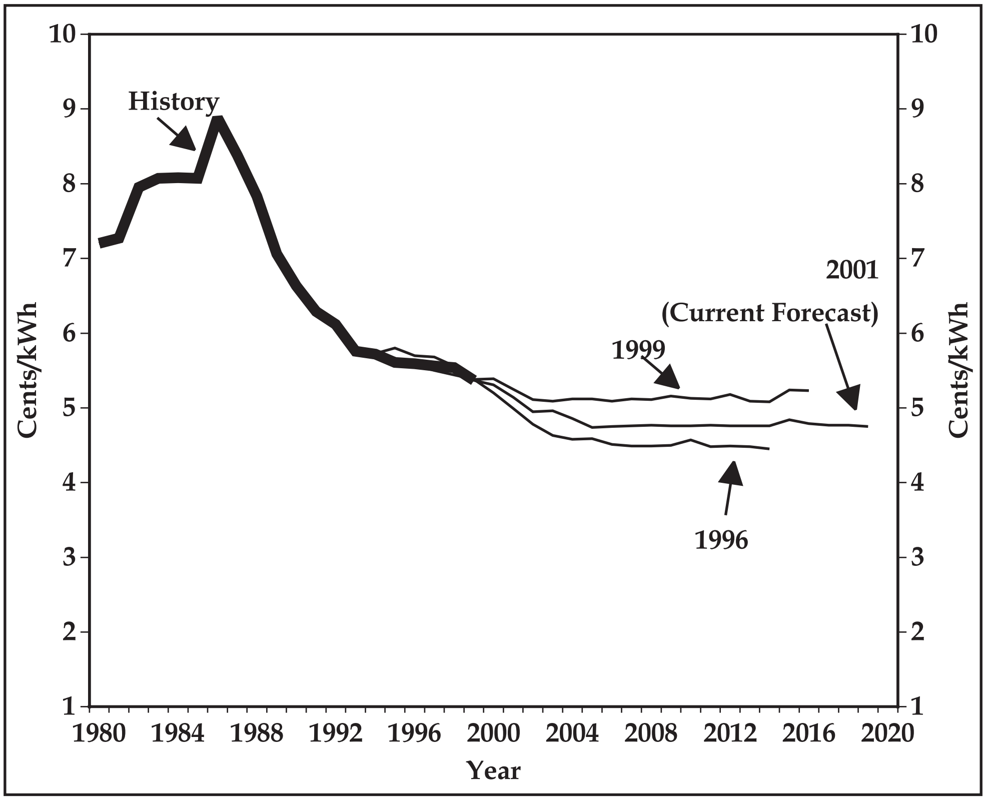
The equilibrium real price[3] projections for the base scenario from SUFG's 2001 forecast , as well as the two previous forecasts, are shown in Figure 1-4. Here, average prices are calculated by taking the electric energy-weighted average of residential, commercial, and industrial rates for Indiana's five investor-owned utilities (IOUs).

The period from 1980 to 1985 was characterized by rising real electricity prices as Indiana ratepayers were required to pay for new facilities that, in retrospect, were not needed at the time (Indiana's reserve margin reached 50 percent in 1985). Since their peak in 1986, real electricity prices in Indiana have fallen by 3.8 percent per year. The base scenario projects a further drop of 2.0 percent per year until the year 2005, after which prices remain fairly level for the rest of the forecast period. The price trajectory is largely a function of two factors: the type of capacity needed during the time period and the installation of new pollution control devices. During the early years of the forecast when prices are declining, a large portion of the new capacity needs are relatively inexpensive peaking purchases. The later years when prices remain steady are characterized by the need for more expensive cycling and base load resources. Also, new

Table 1-1. Status of New Gas-Fired Plants in Indiana, June 2001 (in MW)

	CT	CC
Operating	1,792	0
Approved	1,060	1,858
Proposed	890	4,980
	3,742	6,838

Figure 1-4. Indiana Real Price Projections (1999 Dollars) (Historical, Current and Previous Forecasts)



pollution control regulations impact prices during the later period.

The 2001 forecast is midway between the price forecasts contained in the 1996 and 1999 price forecasts.

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.

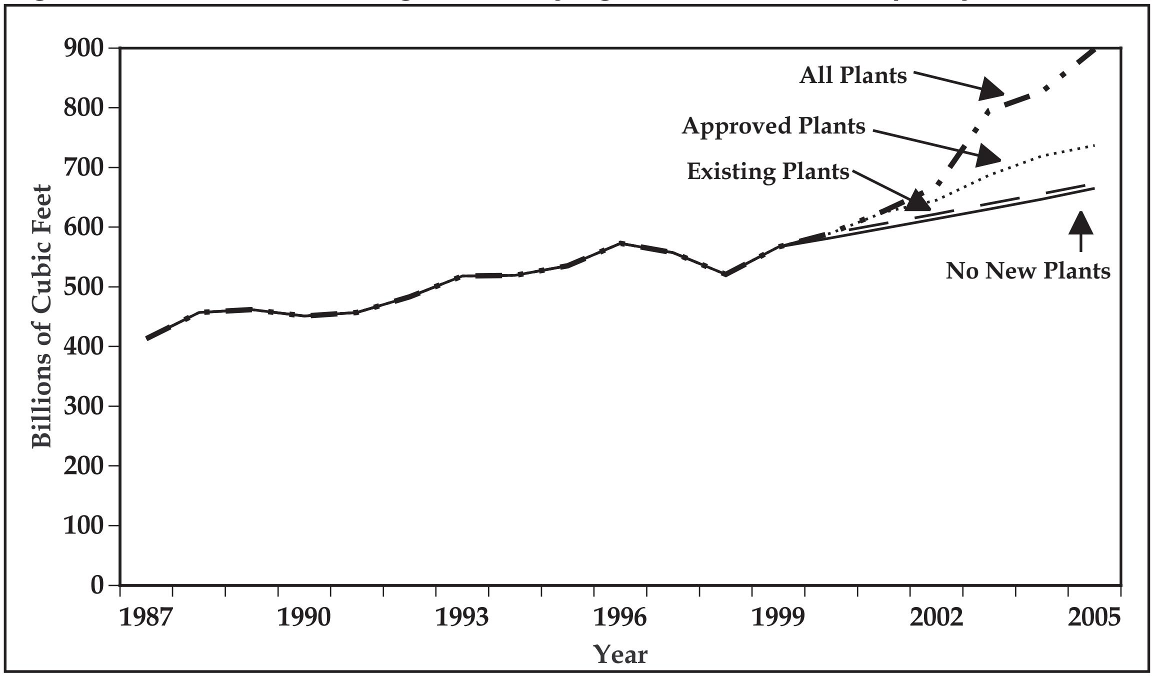
Natural Gas Availability

As seen from Table 1-1, the last two years have seen a large increase in the amount of gas-fired electricity generation capacity. These plants have the capability of having a significant impact on Indiana gas consumption. Figure 1-5 illustrates that impact. The lowest trajectory, "No New Plants," shows consumption growing at historical rates without any use by new generators. The next trajectory, "Existing Plants," adds the expected usage of 1,792 MW of capacity that became operational in 2000 and 2001. The third trajectory, "Approved Plants," also includes those plants that have been approved, but are not yet operational. The uppermost trajectory, "All Plants," includes proposed plants.

Distributed Generation

Distributed generators, small generators located near the load they serve, have the potential for significant economic, reliability and environmental benefits. Due to their proximity to the load, distributed generators avoid transmission costs and losses. Some forms of distributed generation have an added benefit of

Figure 1-5. Natural Gas Usage with Varying New Generation Capacity



greater efficiency than conventional generators. Additionally, some types of distributed generators are attractive from an environmental standpoint.

On the other hand, most types of distributed generators are more expensive to purchase than an equivalent amount of conventional generating capacity. Also, distributed generators face technical, business practice, and regulatory barriers to implementation.

The California Crisis

Over the past year, California has experienced extremely high wholesale electricity prices, rolling blackouts, and a major utility filing for bankruptcy. This has caused several states to reconsider their positions regarding restructuring. This report includes three lessons to be learned from the California experience for those making such decisions.

- Allow flexibility to handle unforeseen circumstances.
- Ensure the proper industry climate is in place for generation, transmission, customer response, and monitoring.
- Expect periods of high prices that provide signals to new market participants.

Short-Term Economic Outlook

While this report represents a set of long-term projections, events of the past few months are likely to impact the short-term use of electricity. These events include a general slowing of the national economy, sharply falling natural gas prices, rising coal prices, and the terrorist attacks of September 11. The result of these factors should be electricity consumption somewhat lower in the short term than would be experienced otherwise, with less effect on long-term projections. SUFG still projects a need for new electricity generation resources, with that need increasing as the economy recovers.

End Notes

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. Exogenous variables are those variables that are determined outside the model system and are then used as inputs to the system.

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).

INDIANA ELECTRICITY PROJECTIONS:
THE 2001 FORECAST

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FOREWORD

This report presents the 2001 projections of future electricity requirements for the state of Indiana for the period 1999-2019. This study is part of an ongoing effort of independent electricity forecasts 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 eighth 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.

While 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 if there has been no significant change. For that level of detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

http://fairway.ecn.purdue.edu/IIES/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:

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CHAPTER 7

INDUSTRIAL ELECTRICITY SALES

Overview

SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 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.

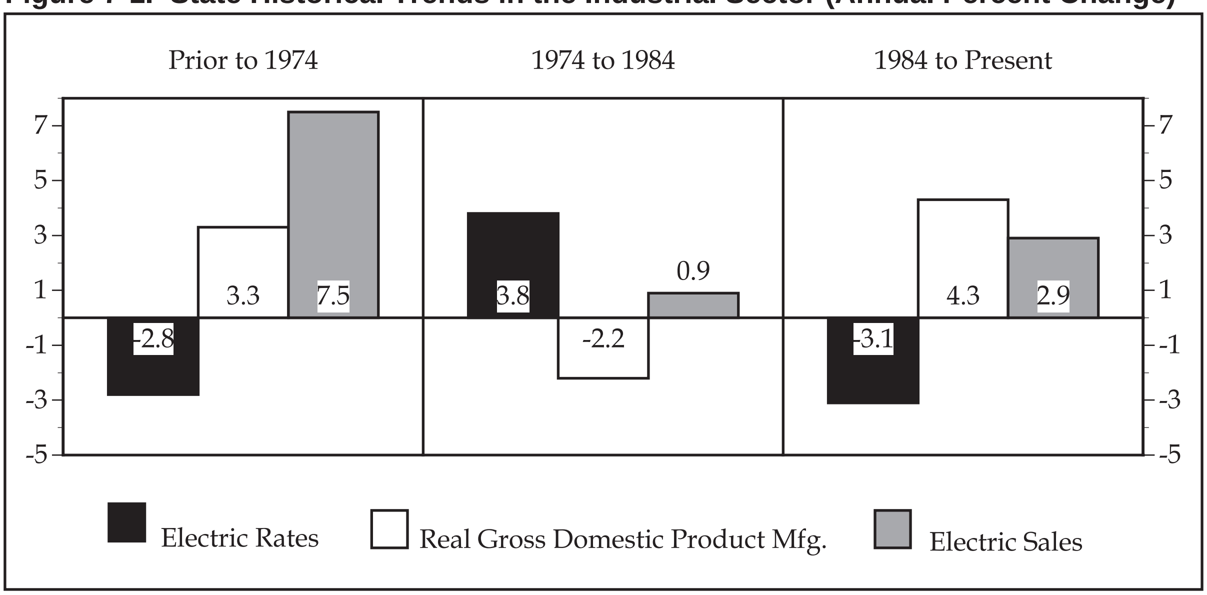
The econometric model is calibrated at the statewide level from data on cost shares obtained from the U.S. Department of Commerce Annual Survey of Manufactures. SUFG has been using INDEED since 1992 to project individual industrial electricity sales for the 16 industries within each of the five IOUs. 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 three recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984 and the more recent period, 1984-1999. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the three 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 electric-

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



ity 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 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.

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 16 manufacturing industries listed in Table 7-1. At this time, only the iron and steel, foundries and aluminum portions of SIC 33 are broken down to Level II models. In addition, a 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 70 percent of GSP is accounted for by the following industries: fabricated metals, 8 percent; transportation, 20 percent; electric machinery, 7 percent; primary metals, 11 percent; nonelectric machinery, 11 percent; and chemicals, 14 percent. The share of total electricity consumed by each industry is shown in column two. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for more than 45 percent 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.

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

Figure 7-2. Structure of Industrial Energy Modeling System

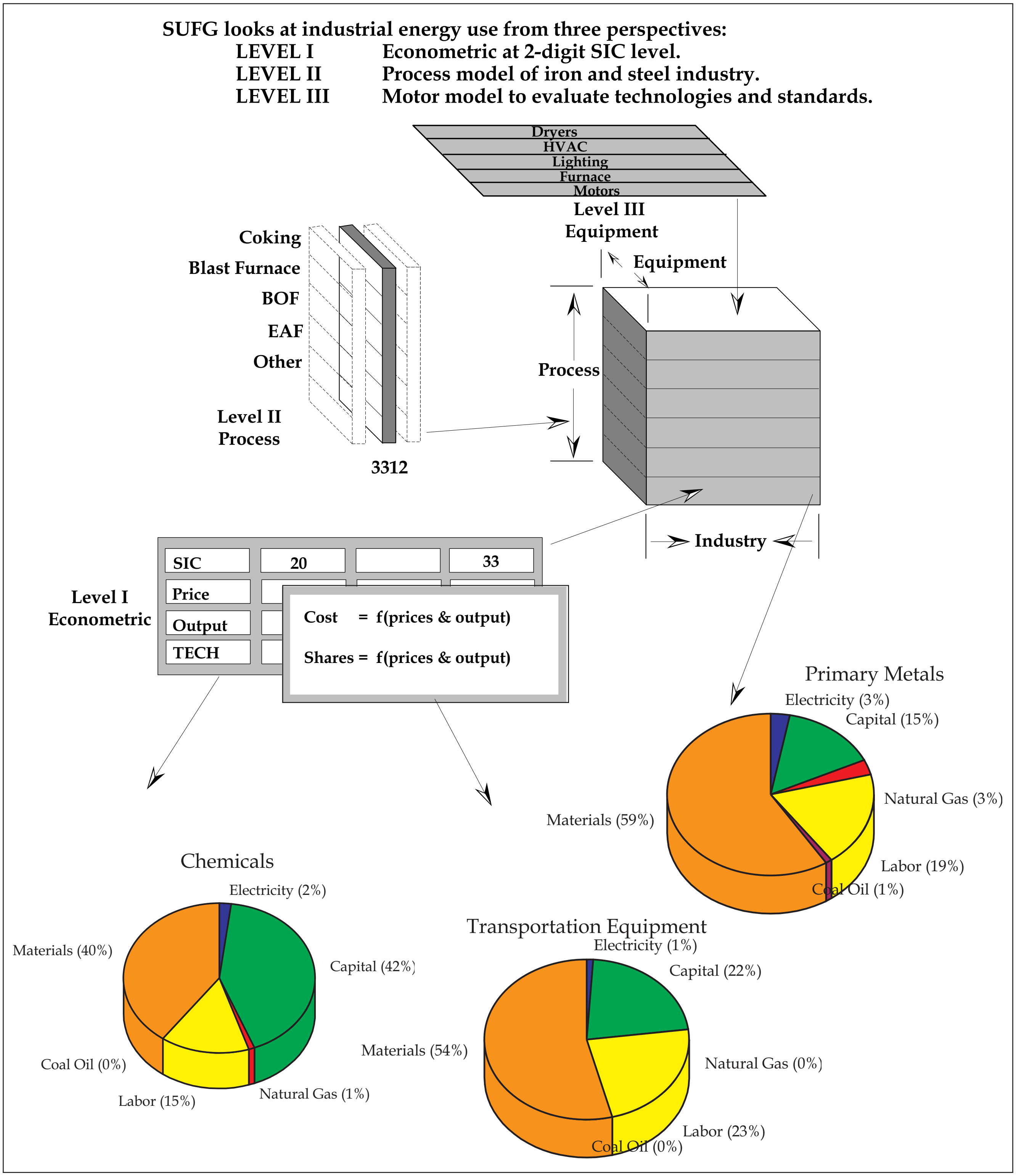


Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (%)

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	4.23	5.68	-0.16	0.17	0.01
24	Lumber & Wood Products	2.37	0.70	0.96	-0.43	0.53
25	Furniture & Fixtures	2.25	0.42	1.82	0.40	2.22
26	Paper & Allied Products	1.71	2.79	0.39	0.87	1.26
27	Printing & Publishing	3.18	3.49	-0.80	0.94	0.14
28	Chemicals & Allied Products	13.85	18.67	1.06	0.52	1.58
30	Rubber & Misc. Plastic Products	5.12	5.50	3.30	0.43	3.73
32	Stone, Clay, & Glass Products	2.32	4.90	0.72	-0.53	0.19
33	Primary Metal Products	11.25	27.37	-0.61	0.51	-0.10
34	Fabricated Metal Products	7.81	5.01	1.23	0.73	1.95
35	Industrial Machinery & Equipment	11.45	5.00	3.03	0.29	3.32
36	Electronic & Electric Equipment	6.86	4.89	3.74	0.34	4.08
37	Transportation Equipment	19.54	10.68	1.01	0.38	1.39
38	Instruments And Related Products	1.97	1.17	-0.92	0.95	0.03
39	Miscellaneous Manufacturing	5.58	0.99	1.43	-1.23	0.20
	Total Manufacturing	**100.00**	**100.00**	**1.43**	**0.08**	**1.51**

by the SUFG modeling system The current SUFG forecast assumes that real natural gas prices in the industrial sector "spike" in 2001 then decline at about 5.6 percent per year until the year 2005 and increase at a rate of about 0.8 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, but are assumed to grow at a faster rate (0.85 percent per year) than gas after the year 2005. 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/dollar of GSP, are shown in column four of Table 7-1. While some intensities are expected to increase and some to decrease, industry-wide electricity intensity is expected to remain nearly constant 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 1.51 percent per year over the forecast horizon (1.47 percent per year after accounting for DSM).

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 Price	1.4
Oil Prices	0.9
Coal Prices	0.2

The Industry-Based Scenarios

In the 1999 forecast, SUFG used scenario-based forecasts for primary metals (steelmaking, aluminum production and foundries), and transportation equipment (motor vehicles and parts) electricity purchases instead of the econometric modeling system and the economic measure of output provided by CEMR. The scenario approach was chosen due to rapid changes and expansion in these large electricity consuming industries. During the mid to late 1990s there was a substantial increasing co-and self-generation of electricity at the integrated steel producing facilities in northwest Indiana, several mini-mills were brought on-line at several different locations in the state and there was a rapid expansion of both motor vehicle assembly and parts production through Indiana. Since these changes have, for the most part, been completed, their affect on purchased electricity is now reflected in observed utility electric sales data. Therefore, for this forecast SUFG has replaced the scenario-based methodology with an econometric approach.

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. Thus, reading across the forecasts for a given year reveals the forecast error present in previous SUFG forecasts. As both the table and graph show, SUFG has tended to slightly underestimate the trajectory of electricity sales to the industrial sector.

The impact of industrial sector DSM programs on growth rates for the 1996 and 1999 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,

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

Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2001 SUFG Base (1999-2019)	1.43	-0.54	0.89	0.62	1.51	0.58	1.47
1999 SUFG Base (1996-2016)	1.61	-0.17	1.44	0.23	1.67	0.20	1.64
1996 SUFG Base (1994-2014)	2.23	-0.20	2.03	0.38	2.41	0.28	2.31

both with and without the impact of industry DSM programs.

The current forecast projects that industrial sector electricity sales will grow from its present level of approximately 39,000 GWh to over 52,000 GWh by 2019. This growth rate of 1.47 percent per year is substantially lower than the 2.60 percent rate projected for the commercial and well below the 1.99 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies above the 1999 forecast throughout the entire forecast horizon and falls below the 1996 forecast near the midpoint of the forecast horizon.

Much of the forecast increase in industrial sector electric energy purchases in the early years of the forecast horizon can be attributed to two factors: the scenario methodology SUFG used in the prior forecasts and the relative costs of natural gas and electricity in the current forecasts. In the 1996 and 1999 forecasts SUFG explicitly included scenarios for primary metals and other manufacturers that accounted for increased self-generation and therefore lowered purchased electricity requirements. SUFG overestimated the impact of self-generation on purchased electricity as manufacturing activity grew more rapidly than anticipated. In the current forecast the relative prices of natural gas and electricity strongly favor electricity use through 2005 and to a lesser extent the remainder of the forecast horizon. After about 2005, most of the difference between the current and prior electricity purchases is due to decreased economic activity.

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 over 60,000 GWh by 2019, more than 14 percent higher than the base projection. In the low scenario, industrial sales grow slowly, which results in only 45,000 GWh sales by 2019, more than 14 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, CEMR expects GSP in the industrial sector to grow 1.43 percent per year during the forecast horizon. That rate is expected to be 2.34 percent in the high scenario and only 0.34 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 other producers.

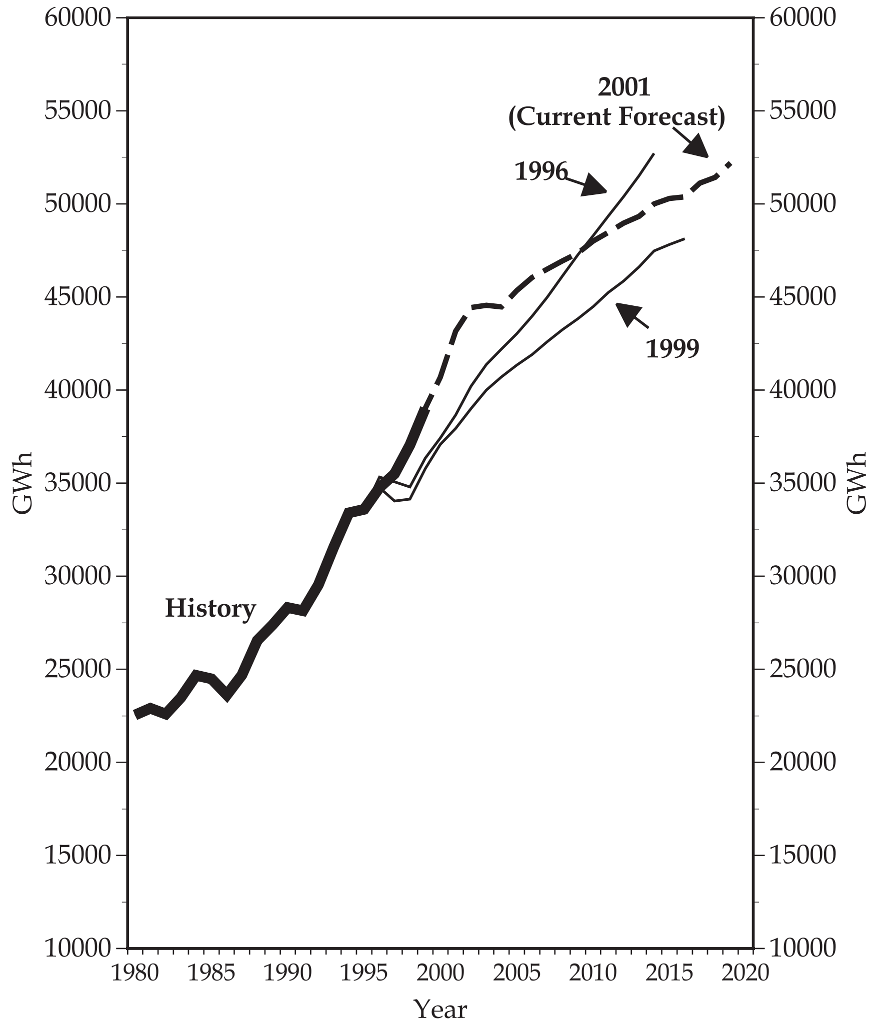
Indiana Industrial Electricity Price Projections

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 this trend to continue until 2005 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead to relatively constant real electricity prices. SUFG's real price projections for the individual IOUs all follow the same patterns in the state as a whole, but there are variations across the utilities.

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

	Year of Forecast		
Year	1996	1999	2001
1990	28311	28311	28311
1991	28141	28141	28141
1992	29540	29540	29540
1993	31562	31562	31562
1994	33395	33395	33395
1995	33580	33590	33590
1996	35324	34755	34755
1997	35072	34031	35499
1998	34802	34148	37052
1999	36336	35776	39020
2000	37427	37079	40680
2001	38666	37940	43156
2002	40214	38998	44425
2003	41370	40004	44550
2004	42201	40703	44461
2005	43022	41332	45344
2006	43965	41914	46045
2007	44979	42587	46486
2008	46132	43241	46948
2009	47260	43827	47345
2010	48291	44490	48014
2011	49348	45248	48467
2012	50400	45864	48969
2013	51508	46620	49324
2014	52709	47479	49994
2015		47824	50291
2016		48127	50383
2017			51111
2018			51430
2019			52197

Average Compound Growth Rates			
Forecast Period	1994-14	1996-16	1999-19
	2.31	1.64	1.47



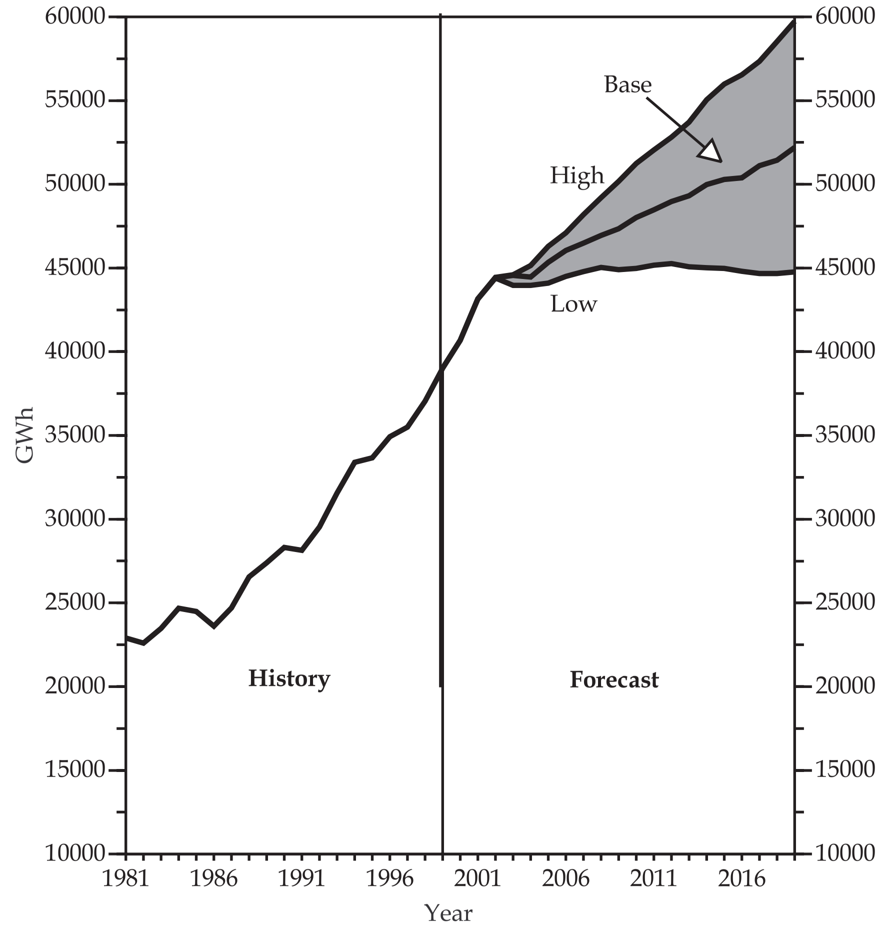
Notes: The shaded numbers in the table are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

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

Year	Base	Low	High
1996	34920	34920	34920
1997	35499	35499	35499
1998	37052	37052	37052
1999	39020	39020	39020
2000	40680	40678	40682
2001	43156	43151	43164
2002	44425	44413	44438
2003	44550	43958	44590
2004	44461	43964	45155
2005	45344	44091	46301
2006	46045	44495	47105
2007	46486	44795	48192
2008	46948	45033	49193
2009	47345	44905	50182
2010	48014	44985	51240
2011	48467	45160	52052
2012	48969	45265	52804
2013	49324	45070	53708
2014	49994	45012	55045
2015	50291	44985	55981
2016	50383	44807	56549
2017	51111	44667	57344
2018	51430	44679	58536
2019	52197	44758	59730

Average Compound Growth Rates

Selected 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
1995-99	3.76	3.76	3.76
1999-05	2.54	2.06	2.89
1999-19	**1.47**	**0.69**	**2.15**



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

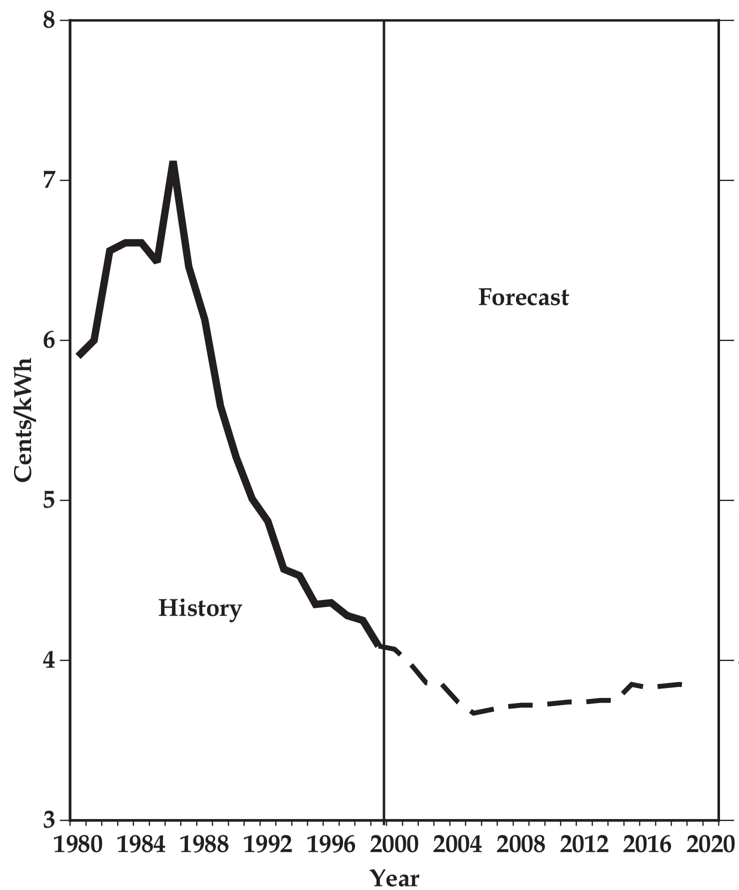
Figure 7-5. Indiana Industrial Base Real Price Projections (in 1999 Dollars)

Year	Real Price
1980	5.90
1981	6.00
1982	6.56
1983	6.61
1984	6.61
1985	6.49
1986	7.12
1987	6.46
1988	6.13
1989	5.59
1990	5.27
1991	5.01
1992	4.87
1993	4.57
1994	4.53
1995	4.35
1996	4.36
1997	4.28
1998	4.25
1999	4.09

Year	Real Price
2000	4.07
2001	3.98
2002	3.86
2003	3.85
2004	3.74
2005	3.67
2006	3.69
2007	3.71
2008	3.72
2009	3.72
2010	3.73
2011	3.74
2012	3.74
2013	3.75
2014	3.75
2015	3.85
2016	3.83
2017	3.84
2018	3.85
2019	3.84

Average Compound Growth Rates

Forecast Period	(%)
1980-85	1.93
1985-90	-4.06
1990-95	-3.79
1995-99	-1.52
1999-05	-1.76
1999-19	**-0.31**



Energy-Weighted Average for Five IOUs

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 currently has econometric and end-use models of commercial electricity sales. These different modeling approaches have specific strengths and therefore, are complementary. 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.

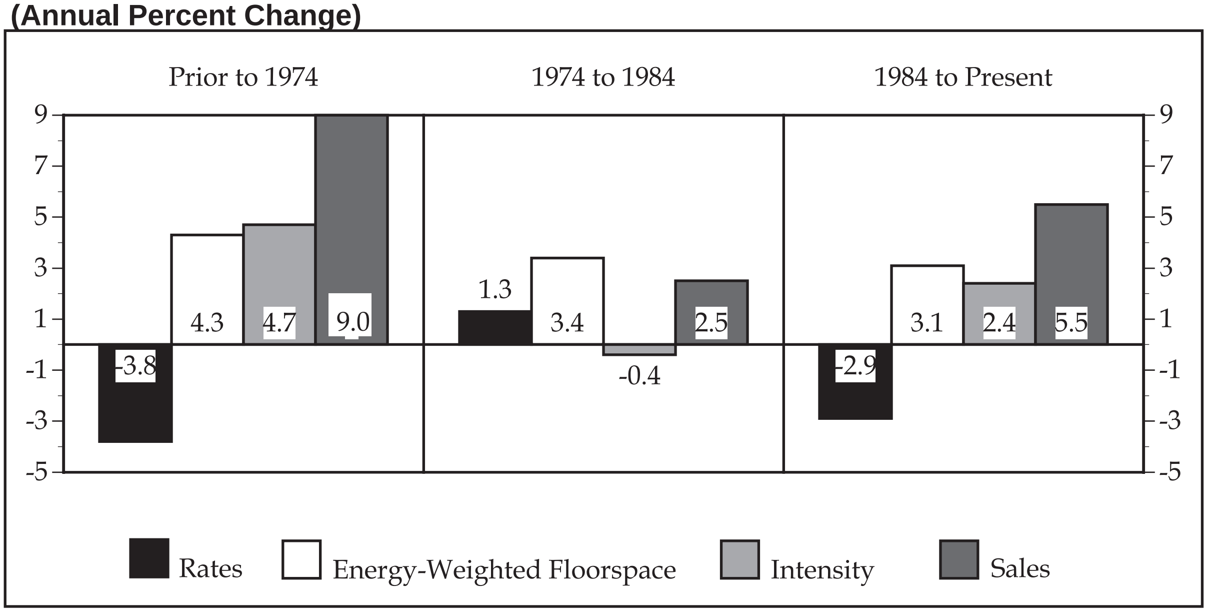
Prior to 1993, SUFG relied on its econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. (CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type.) SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model. In 1993, SUFG made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over the last several years, SUFG is now 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 three recent periods (see Figure 6-1).

Changes in electric intensity, expressed as changes 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, i.e., personal computers in office buildings. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per

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



year) as seen in Figure 6-1 prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during 1974-84, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-99 period, electric intensity rose but at a slower rate (2.4 percent) than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average but these efficiency improvements are offset by an increased demand for energy services.

Model Description

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

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

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

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

where

$*$ = multiplication operator;

T = forecast year;

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

t = building vintage (year);

U = utilization, relative to some base year;

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

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

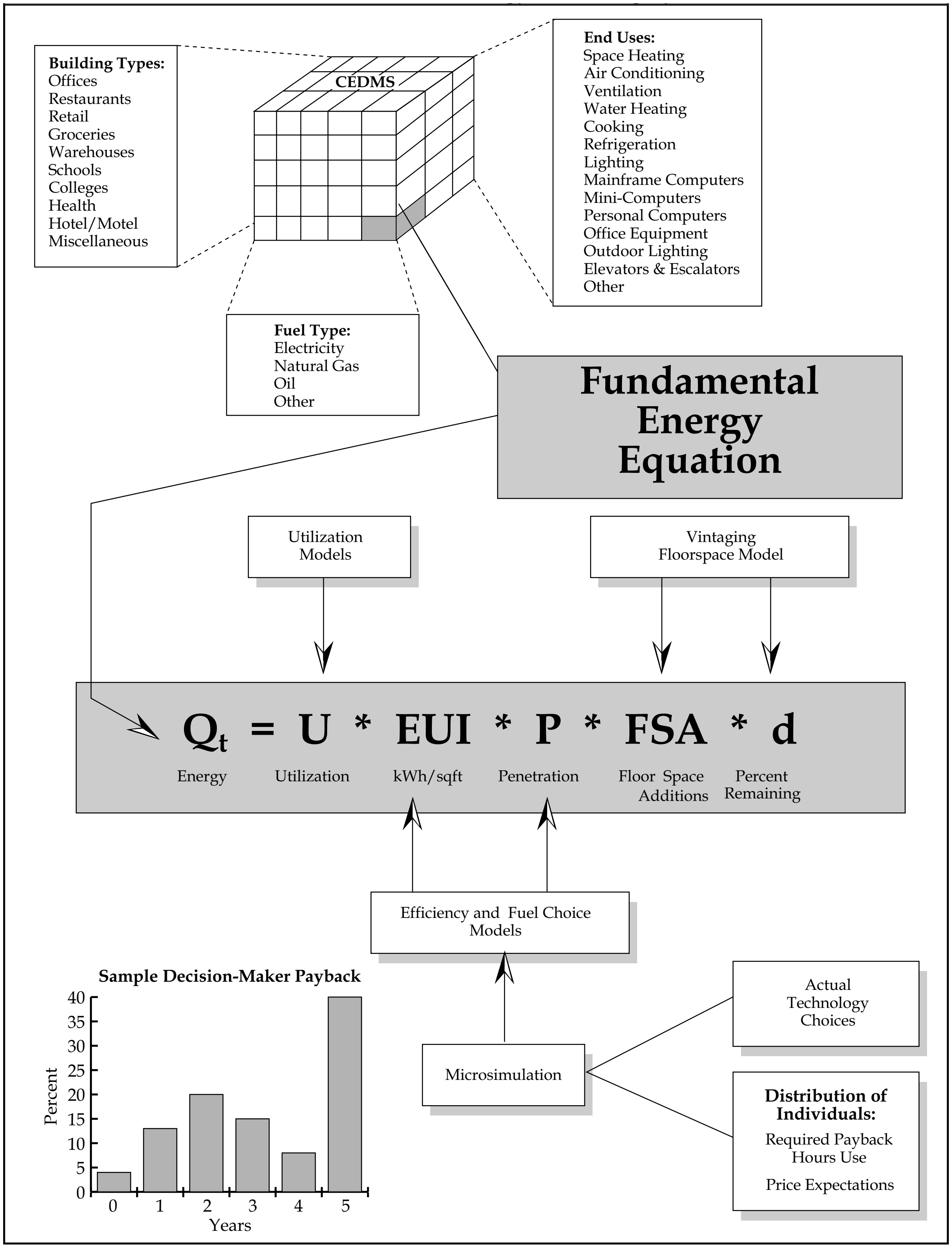
A = floor space additions by vintage t and building type l; and

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

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

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

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



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

Besides efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices. For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary Of Results

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

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population), electricity, natural gas and oil prices. The sensitivity of the electricity projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-1. An interesting result is that changes in commercial floor space lead to more than proportional changes in electricity use. The reason for this is that new buildings tend to have greater saturations of electric end uses, even though they are more efficient. The table also shows that changes in the price of competing forms of energy have little impact on electricity use.

Table 6-1. Commercial Model Long-Run Sensitivities

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

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in 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 2.60 percent. The growth rates for the major explanatory variables are shown in Table 6-2. Note that the change from 1999 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 floor space is to increase electricity use about 0.1 to 0.5 percent per year. The relatively small DSM programs have virtually no effect. Thus, about 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 but somewhat higher to the 1999 forecast. This is due to similar, but higher growth in floorstock and electric intensity in the two forecasts. Finally, Table 6-3 indicates that the impact of utility-sponsored DSM programs is not significant in the current forecast.

As shown in Figure 6-4, the growth rates for the low and high scenarios are about 1.7 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.

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 2005 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead to relatively constant electricity prices. SUFG's real price projections for the individual IOUs all follow the same pattern in the state as a whole, but there are variations across the utilities.

Table 6-2. Commercial Model -- Growth Rates (%) for Selected Variables (2001 SUFG Scenarios and 1999 Base Forecast)

Forecast	Current Scenario (1999-2019)			1999 Forecast
	Base	Low	High	Base
Electric Rates	-0.73	-0.69	-0.77	-0.34
Natural Gas Price	0.30	0.30	0.30	-0.65
Oil Prices	1.33	1.33	1.33	0.25
Energy-Weighted Floor Space	2.08	0.50	3.15	1.89

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

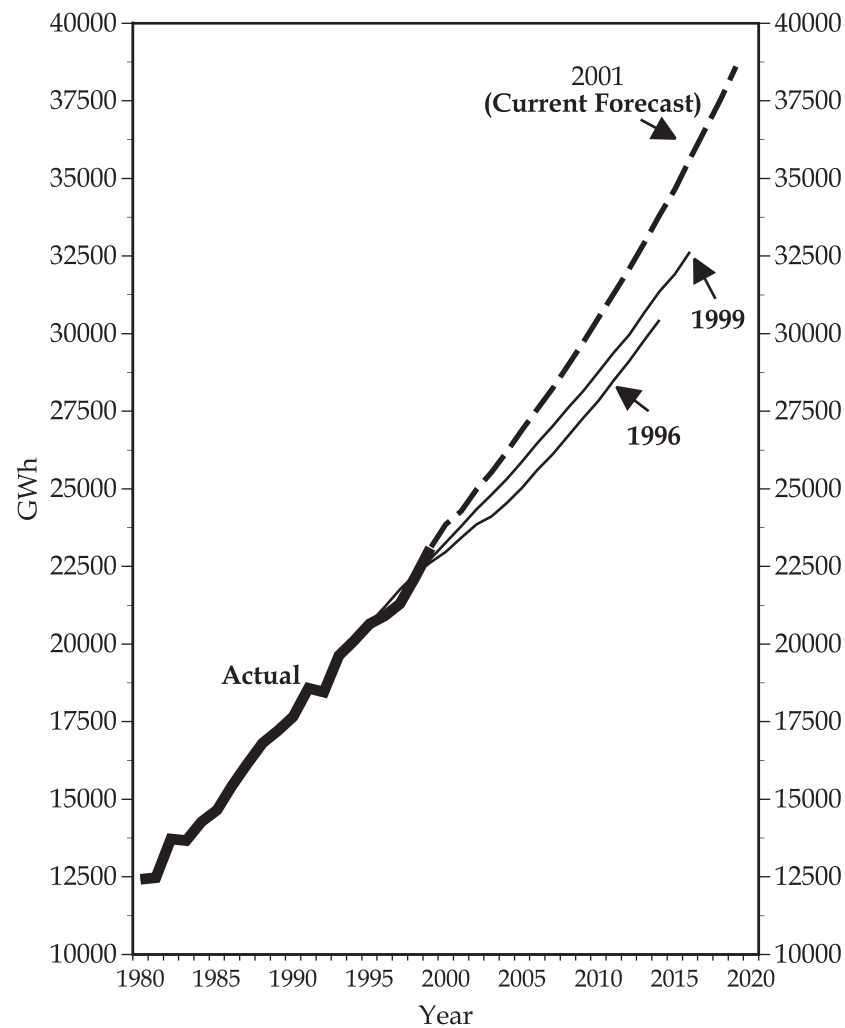
Forecast	Electric Energy-Weighted Floor Space	Prior to DSM		After DSM	
		Intensity	Sales Growth	Intensity	Sales Growth
2001 SUFG Base (1999-2019)	2.08	0.52	2.60	0.52	2.60
1999 SUFG Base (1996-2016)	1.89	0.36	2.25	0.36	2.25
1996 SUFG Base (1994-2014)	1.95	0.31	2.26	0.14	2.09

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

Year	Year of Forecast 1996	1999	2001
1990	17659	17659	17659
1991	18580	18580	18580
1992	18456	18456	18456
1993	19627	19627	19627
1994	20116	20116	20116
1995	20677	20646	20646
1996	21196	20909	20909
1997	21764	21468	21295
1998	22243	22101	22158
1999	22626	22738	23089
2000	22969	23271	23849
2001	23420	23795	24280
2002	23856	24333	24977
2003	24110	24815	25536
2004	24542	25319	26189
2005	25041	25883	26904
2006	25611	26471	27561
2007	26108	27014	28239
2008	26700	27609	28976
2009	27272	28139	29713
2010	27836	28759	30503
2011	28496	29392	31290
2012	29113	29959	32084
2013	29777	30671	32910
2014	30441	31357	33812
2015		31917	34646
2016		32636	35628
2017			36584
2018			37544
2019			38609

Average Compound Growth Rates

Forecast Period	1994-14	1996-16	1999-19
	2.09	2.25	2.60



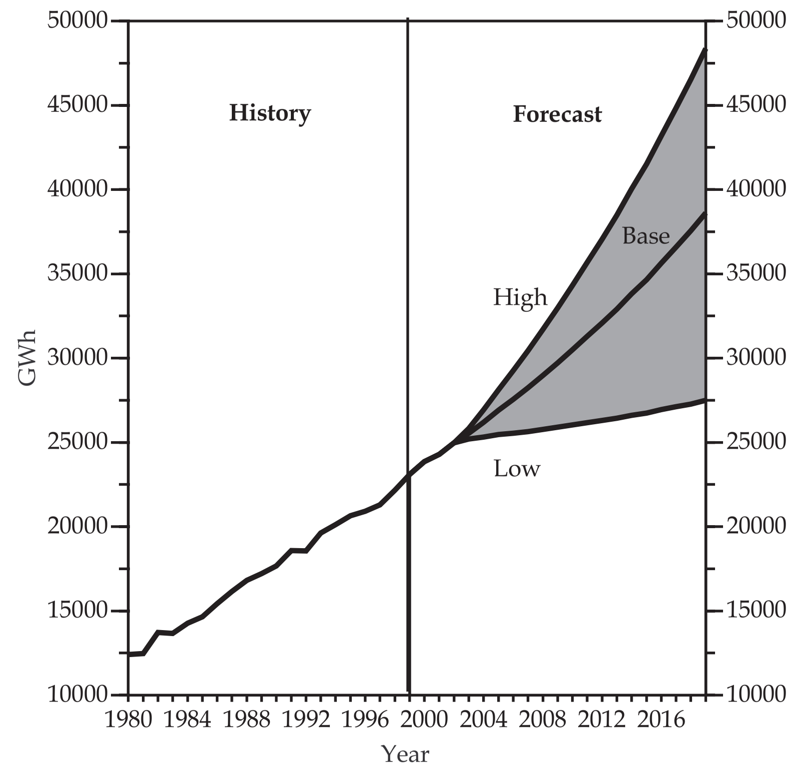
Notes: The shaded numbers in the table and the heavy line in the graph are historical requirements. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

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

Year	Base	Low	High
1996	20909	20909	20909
1997	21295	21295	21295
1998	22158	22158	22158
1999	23089	23089	23089
2000	23849	23848	23849
2001	24280	24280	24282
2002	24977	24975	24978
2003	25536	25191	25825
2004	26189	25310	26928
2005	26904	25458	28115
2006	27561	25544	29257
2007	28239	25637	30438
2008	28976	25778	31701
2009	29713	25899	32972
2010	30503	26036	34314
2011	31290	26170	35678
2012	32084	26301	37062
2013	32910	26430	38485
2014	33812	26608	40033
2015	34646	26733	41512
2016	35628	26938	43192
2017	36584	27116	44842
2018	37544	27274	46535
2019	38609	27495	48361

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
1995-99	2.84	2.84	2.84
1999-05	2.58	1.64	3.34
1999-19	**2.60**	**0.88**	**3.77**



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

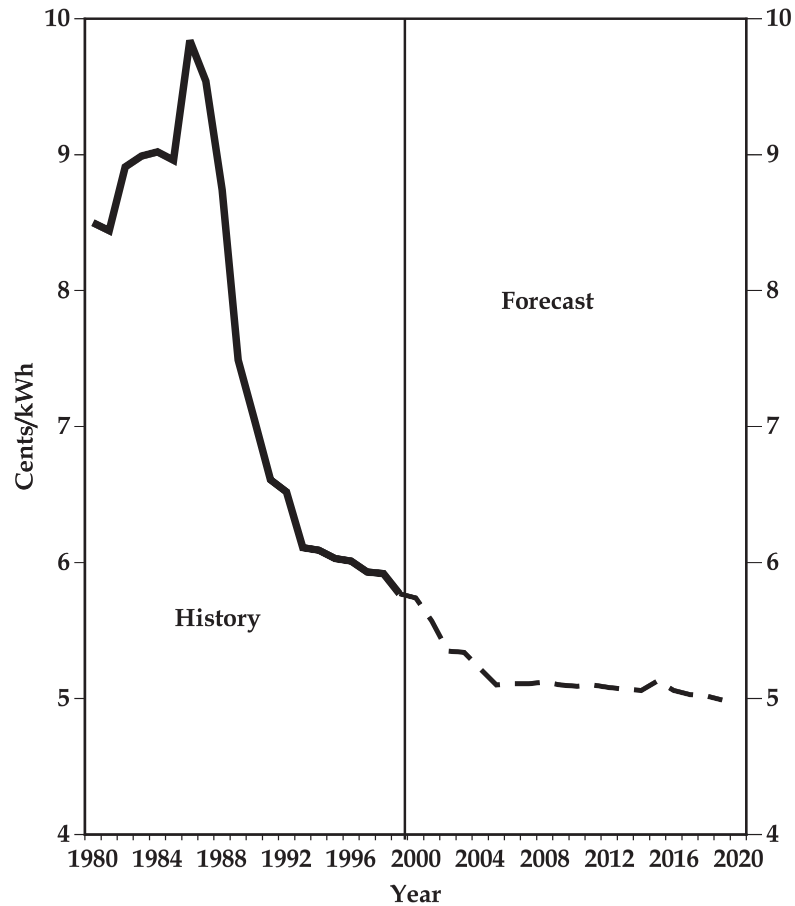
Figure 6-5. Indiana Commercial Base Real Price Projections (in 1999 Dollars)

Year	Real Price
1980	8.50
1981	8.44
1982	8.91
1983	8.99
1984	9.02
1985	8.96
1986	9.84
1987	9.54
1988	8.74
1989	7.49
1990	7.05
1991	6.61
1992	6.52
1993	6.11
1994	6.09
1995	6.03
1996	6.01
1997	5.93
1998	5.92
1999	5.77

Year	Real Price
2000	5.74
2001	5.57
2002	5.35
2003	5.34
2004	5.22
2005	5.10
2006	5.11
2007	5.11
2008	5.12
2009	5.10
2010	5.09
2011	5.10
2012	5.08
2013	5.07
2014	5.06
2015	5.13
2016	5.06
2017	5.03
2018	5.02
2019	4.99

Average Compound Growth Rates

Selected Periods	(%)
1980-85	1.05
1985-90	-4.67
1990-95	-3.09
1995-99	-1.08
1999-05	-2.03
1999-19	**-0.73**



Energy-Weighted Average for Five IOUs

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

CHAPTER 5

RESIDENTIAL ELECTRICITY SALES

Overview

SUFG uses both econometric and end-use models of residential electricity sales. These different modeling approaches have specific strengths and therefore, are complementary. The econometric model is used to separately project the number of customers with and without electric space heating systems as well as average electricity use by each customer group. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been reestimated three times, once in 1988 and again in 1994 and 1996. In addition, SUFG has 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 very 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 three 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 (see Figure 5-1).

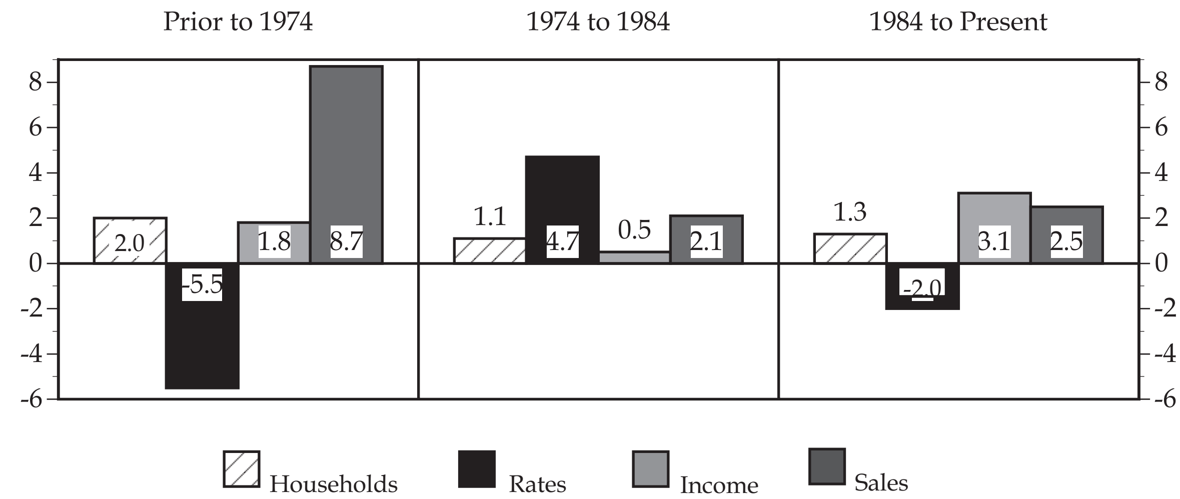
The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (nearly 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. Declining at an annual rate of slightly less than one percent (a swing of 2.5 percent per year), growth in real household income was a miniscule 0.5 percent. 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, not discussed above, contributed to the small difference in sales growth between the post-embargo and most recent period. First, and perhaps most importantly, is the difference in the avail-

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



ability 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.

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 D and E of Figure 5-2, have tended to move in opposite directions as well. Yet another reason for dividing residential customers into electric and non-electric space heating groups is shown in Panel B of Figure 5-2. The growth of electric space heating was quite rapid throughout both the pre- and post-embargo period. Panel A of Figure 5-2 depicts the falling price of electricity relative to natural gas during both periods. Relative electricity and gas prices bottomed out in 1983 and since then, the penetration of electricity in the space heating market has fallen by more than half.

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. 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 stable electricity prices and increasing natural gas prices, the fuel choice model projects the penetration of electric space heating to average about 45 percent over the forecast horizon (for the five IOUs combined). This results in space heating saturation of 25 percent by the end of the forecast horizon (Panel C).

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

Almost 80 percent of all residential customers are non-electric heating customers. Prior to 1974, average electricity consumption by these customers increased about 6 percent per year. Since 1974, average use has increased moderately, averaging about 0.5 percent per year from 1975-85 and about 1.6 percent thereafter.

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. This relationship is capable of picking up emerging nonlinearities or saturation effects not detected by ordinary demand models. This is especially important since the model is used to generate long-range forecasts.

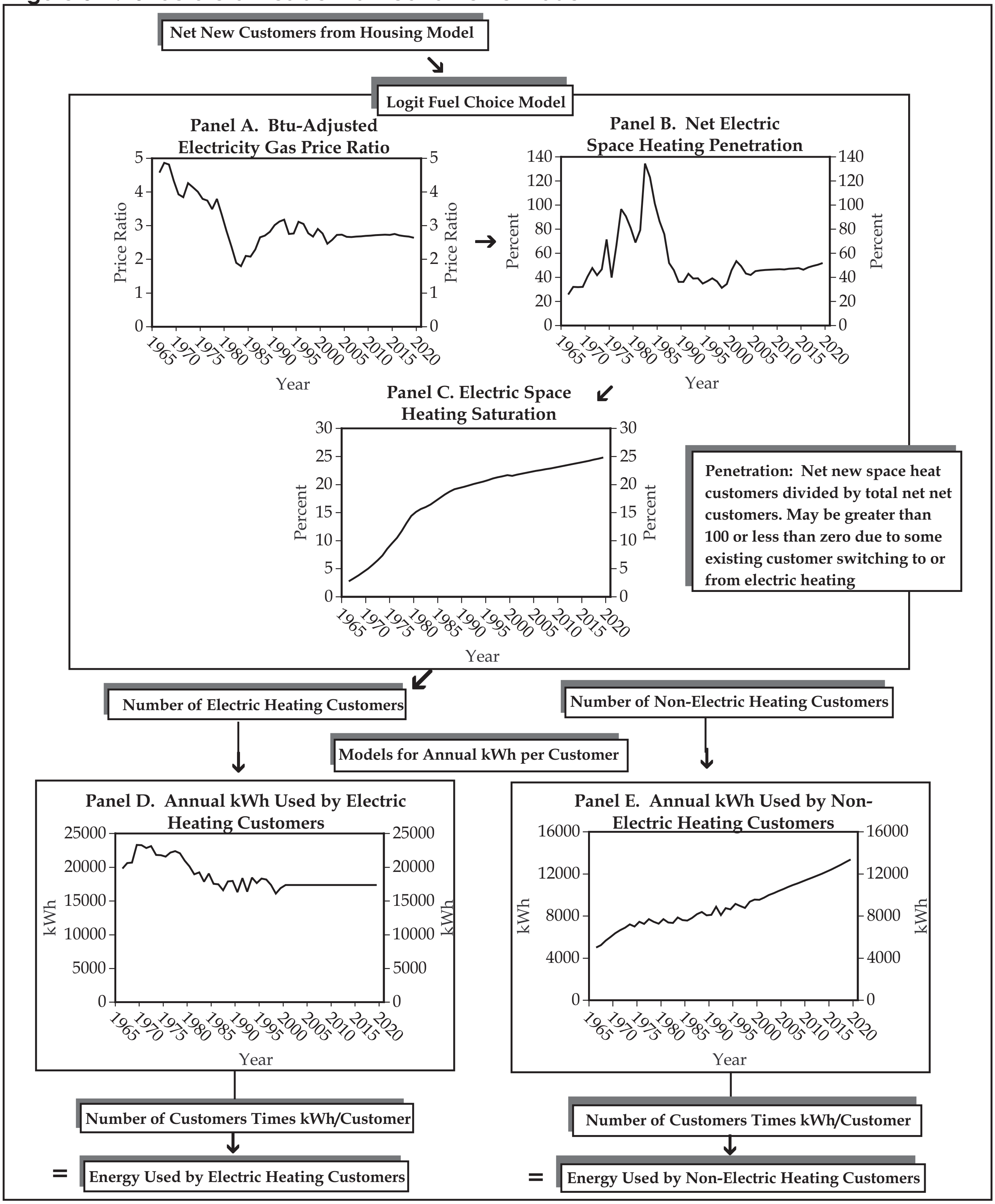
Average kWh Sales: Electric Space Heating Customers

Average sales to electric space heating customers declined significantly throughout the 1970s and 1980s (see Panel D 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 recent years, SUFG assumes that the space heating component of a 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

Figure 5-2. Structure of Residential Econometric Model



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 our first forecast in 1987. They have been reviewed each year as new data have become available.

Summary Of Results

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

Model Sensitivities

The major economic drivers in the residential econometric model include residential customers, household income, and electricity, natural gas and oil prices. The sensitivity of the residential electricity projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in electricity use. The results are shown in Table 5-1.

Electricity consumption increases substantially due to increases in both the number of customers and household income. As expected, electricity rate increases reduce electric consumption. Changes in oil prices do not materially affect electricity consumption.

Indiana Residential Electricity Sales Projections

Actual sales, as well as past and current projections, are shown in Figure 5-3. The boxed 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 1.99 percent, with a projection somewhat higher than SUFG's 1999 projection. Table 5-2 shows the growth rates of the major residential drivers for the current scenarios and the SUFG 1999 base case. In all of the residential sector drivers, the current base exhibits somewhat higher growth resulting in a higher residential electricity use forecast. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 1996. 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, approximately 35 percent of projected sales is attributable to customer growth and 65 percent to changes in electric intensity (price and income effects). The net effect of changes in energy prices is to increase electric intensity about 0.2 percent per year. The small amount of residential DSM, primarily load shifting, 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 0.1 percent higher and 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 until about 2005 when slower declines in utility steam coal prices coupled with the need for additional generation resources lead 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 5-1. 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 Prices	-1.8
Household Income	2.0

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

Forecast	Current Scenario (1999-2019)			1999 Forecast
	Base	Low	High	Base
No. of Customers	0.70	0.69	0.77	0.66
Appliance Prices	-3.00	-3.00	-3.00	-3.00
Electric Rates	-0.96	-0.82	-1.09	-0.26
Natural Gas Price	0.24	0.24	0.24	-0.71
Oil Prices	0.98	0.98	0.98	0.25
Household Income	2.62	1.91	3.83	1.85

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

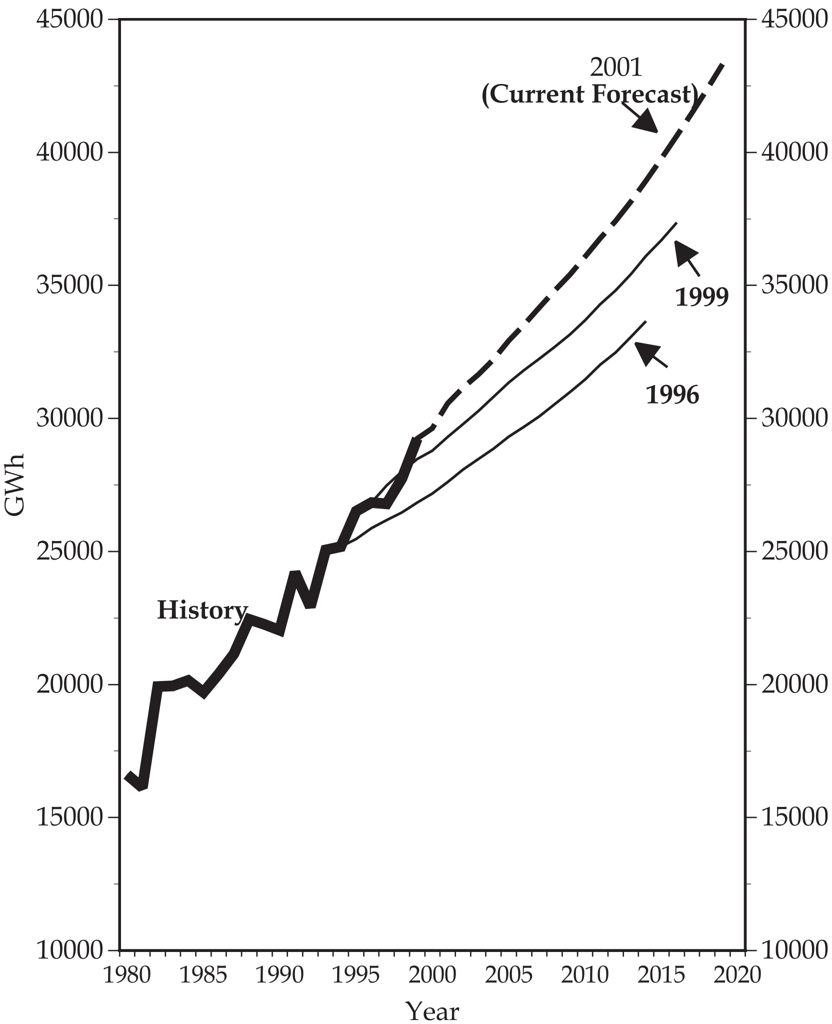
Forecast	No. of Customer	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2001 SUFG Base (1999-2019)	0.70	1.29	1.99	1.29	1.99
1999 SUFG Base (1996-2016)	0.66	1.01	1.67	1.01	1.67
1996 SUFG Base (1994-2014)	0.64	0.95	1.59	0.90	1.46

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

	Year of Forecast		
Year	1996	1999	2001
1990	22037	22037	22037
1991	24215	24215	24215
1992	22916	22916	22916
1993	25060	25060	25060
1994	25176	25176	25176
1995	25463	26513	26513
1996	25880	26833	26833
1997	26183	27476	26792
1998	26471	28011	27745
1999	26833	28468	29238
2000	27179	28783	29625
2001	27604	29300	30569
2002	28080	29791	31161
2003	28470	30280	31651
2004	28863	30811	32213
2005	29315	31353	32918
2006	29688	31823	33525
2007	30068	32242	34159
2008	30525	32686	34797
2009	30988	33154	35396
2010	31472	33693	36090
2011	32020	34299	36778
2012	32480	34813	37420
2013	33070	35430	38158
2014	33662	36109	38939
2015		36696	39766
2016		37366	40625
2017			41471
2018			42382
2019			43319

Average Compound Growth Rates

Forecast Period	1994-14	1996-16	1999-19
	1.47	1.67	1.99



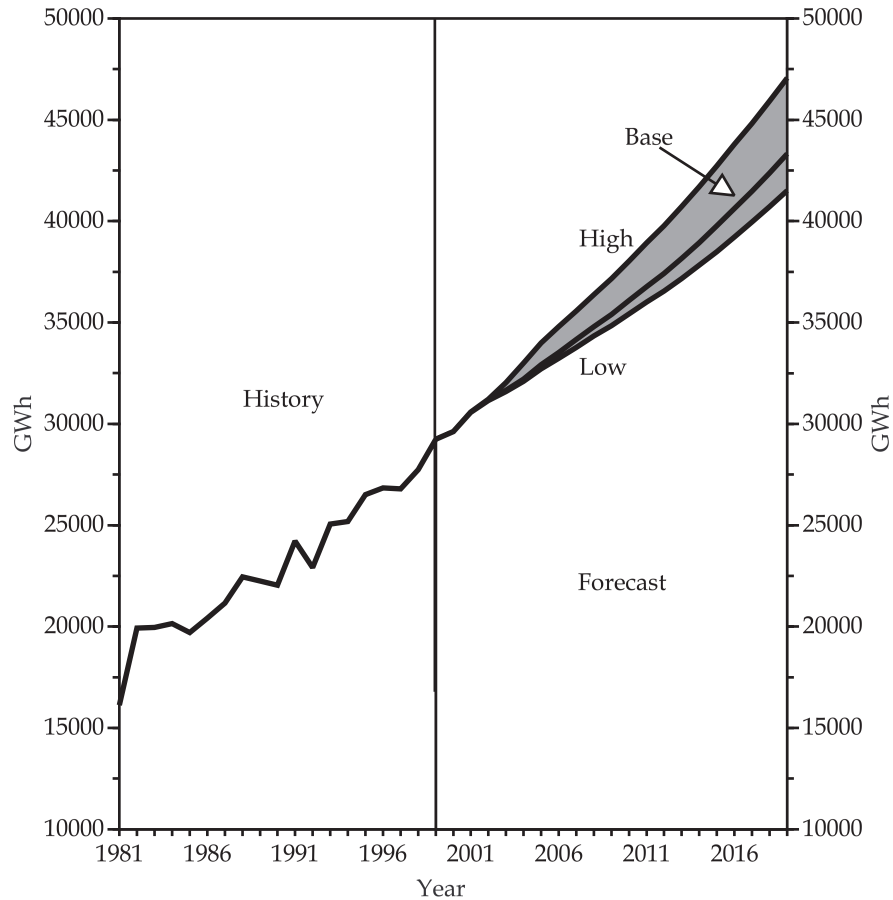
Notes: The shaded numbers in the table and the heavy line in the graph are historical requirements. (For an explanation on how SUFG arrives at these numbers, see Appendix A)

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

Year	Base	Low	High
1996	26833	26833	26833
1997	26792	26792	26792
1998	27745	27745	27745
1999	29238	29238	29238
2000	29625	29625	29625
2001	30569	30564	30589
2002	31161	31150	31212
2003	31651	31597	32036
2004	32213	32096	32994
2005	32918	32716	33986
2006	33525	33233	34790
2007	34159	33776	35576
2008	34797	34335	36379
2009	35396	34842	37161
2010	36090	35425	38038
2011	36778	36018	38932
2012	37420	36546	39777
2013	38158	37170	40710
2014	38939	37827	41700
2015	39766	38498	42729
2016	40625	39224	43791
2017	41471	39955	44818
2018	42382	40710	45925
2019	43319	41511	47068

Average Compound Growth Rates

Selected 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
1995-99	2.48	2.48	2.48
1999-05	2.00	1.89	2.54
1999-19	**1.99**	**1.77**	**2.41**



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

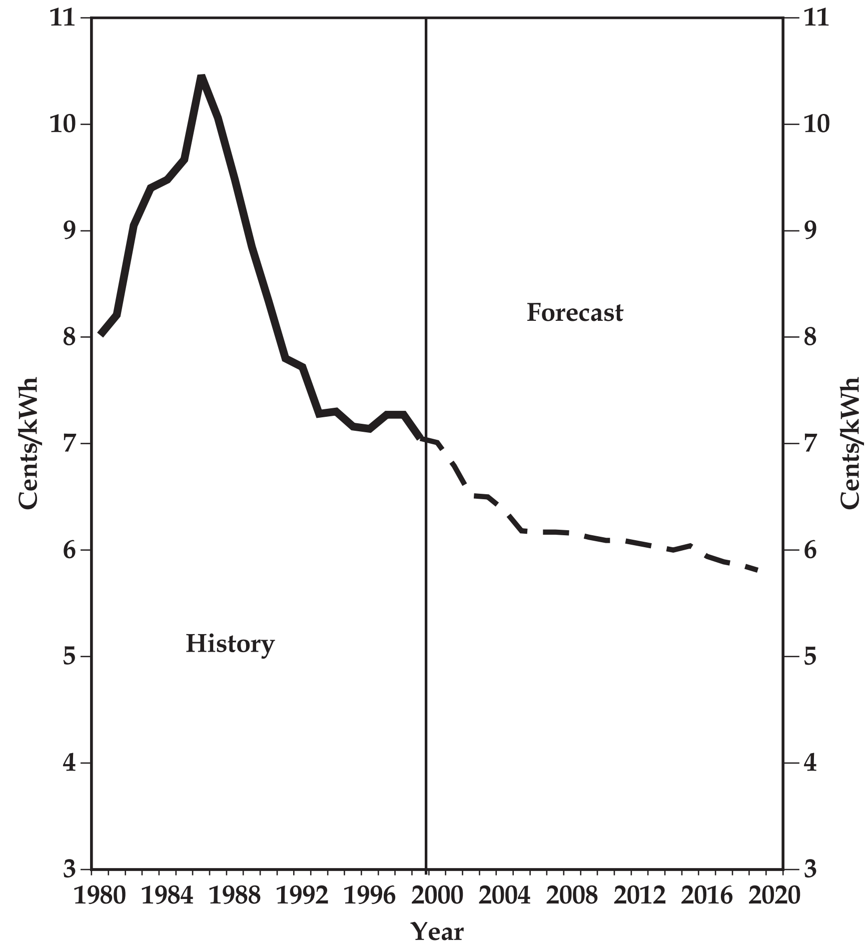
Figure 5-5. Indiana Residential Base Real Price Projections (in 1999 Dollars)

Year	Real Price
1980	8.02
1981	8.21
1982	9.05
1983	9.40
1984	9.48
1985	9.67
1986	10.46
1987	10.06
1988	9.48
1989	8.85
1990	8.34
1991	7.80
1992	7.72
1993	7.28
1994	7.30
1995	7.16
1996	7.14
1997	7.27
1998	7.27
1999	7.05

Year	Real Price
2000	7.01
2001	6.79
2002	6.51
2003	6.50
2004	6.37
2005	6.18
2006	6.17
2007	6.17
2008	6.16
2009	6.12
2010	6.09
2011	6.09
2012	6.06
2013	6.03
2014	6.00
2015	6.04
2016	5.94
2017	5.89
2018	5.86
2019	5.81

Average Compound Growth Rates

Selected Periods	(%)
1980-85	3.81
1985-90	-2.93
1990-95	-2.99
1995-99	-0.40
1999-05	-2.17
1999-19	**-0.96**



Energy-Weighted Average for Five IOUs

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

CHAPTER 4
MAJOR FORECAST INPUTS AND ASSUMPTIONS

Introduction

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

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

Macroeconomic Scenarios

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

- 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.

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 0.25 percent a year. This projection was developed in 1993 and includes projections of county population by age group. SUFG also reviewed a second set of population projections, developed in the early 1990s by the Family Research Center, Department of Sociology at Indiana University-Purdue University, Indianapolis (IUPUI). Both studies project population to grow less rapidly in Indiana than for the nation. Population projection increases are marginally higher in the IBRC forecast.

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. Fertility rates in the state have been below replacement level since the mid-1970s and are projected to decline even further because of the net out migration of young adults during the 1980s. As birthrates drop and the existing population grows older, deaths exceed births and the state's population begins to naturally decrease by about 2020 given that the trend continues.

Indiana population growth has slowed markedly in recent years. The number of people over age 35 (the groups with fewer occupants per household) is projected to grow more rapidly than the total 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 slightly less than 1 percent currently. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 0.70 percent over the forecast period. This is virtually identical to the 0.66 rate projected in SUFG's 1999 forecast. The household projection growth rate decreases slightly to 0.69 percent in the low scenario and increases slightly to 0.77 percent in the high scenario. The growth rates across scenarios are similar because the same population projections are used for each scenario and CEMR's income projections do not vary greatly across scenarios.

SUFG had planned to use an updated set of detailed county level population and age distribution projections from IBRC in the preparation of this electricity forecast. Unfortunately, these detailed projections are not yet available and SUFG used the older projections discussed above. Preliminary projections from IBRC (http://www.ibrc.indiana.edu) indicate that the net out migration observed during the 1980s may have reversed to a net in migration during the 1990s; however, Indiana population growth still lagged behind that of the nation despite an increased rate of growth during the 1990s. Current IBRC state population projections indicate a growth rate of 0.85 percent per year for total Indiana population during the decade of the 1990s. The corresponding population projections for 2000-2020 period yield an annual growth rate of 0.35 percent. This is somewhat larger than the 0.25 percent in the detailed projections SUFG used in preparing this report. This increase in population growth coupled with the relatively strong economic activity in the late 1990s leads SUFG to speculate that the forecast of household or customer growth during the first few years of the forecast horizon may be somewhat low.

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2001 economic projections as its current 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 19 manufacturing and 11 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 February 2001 CEMR forecast are as follows:

- Federal tax rates will decrease slightly and federal purchases and transfer payments will increase slightly. As a result, the federal budget maintains a modest surplus through most of the forecast horizon, but moves into deficit as transfer payments increase at the end of the forecast horizon.
- Imports continue to exceed exports, but at a slowing rate (measured in dollars), which leads to a continued, but narrowing negative net trade balance.

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 3.53 percent and U.S. employment growth averages 1.02 percent over the 1999 to 2019 period.

In Indiana, total employment is projected to grow at an average annual rate of 1.18 percent. The key economic projections are:

- Real personal income (the residential sector model driver) is expected to grow at a 2.62 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.71 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 1.43 percent annual rate as gains in productivity offset declines in employment.

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 about 1.2 percent per year (to 3.83), non-manufacturing employment growth increases more than 0.9 percent (to 2.65), while Indiana real manufacturing GSP growth is raised about 0.9 percent (to 2.34). In the low growth alternative, the average rates of growth of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.91, 0.35 and 0.34 respectively).

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

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

	Short-Run History for Selected Recent Periods				Long-Run Forecast Feb. 1998	Feb. 2001
	1980-1985	1985-1990	1990-1995	1995-1999	1996-2016	1999-2019
United States						
Real Personal Income	3.02	2.59	2.04	4.07	2.61	3.26
Total Employment	1.53	2.00	1.38	2.38	1.21	1.02
Real Gross Domestic Product	2.53	2.73	2.38	4.15	2.66	3.53
Personal Consumer Expenditure Deflator	5.33	4.15	2.71	1.73	2.50	2.69
Indiana						
Real Personal Income	1.13	2.10	2.48	3.48	1.85	2.62
Employment:						
Total	0.21	2.76	1.91	1.19	1.00	1.18
Manufacturing	-1.48	0.91	1.40	0.22	-0.60	-0.75
Non-Manufacturing	1.17	3.70	2.20	2.03	1.47	1.71
Real Gross State Product						
Total	1.61	2.73	3.40	3.85	1.76	1.59
Manufacturing	1.92	2.82	5.85	4.19	1.61	1.43
Non-Manufacturing	1.47	2.69	2.36	3.68	1.83	1.66

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

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.

In this forecast, SUFG has utilized December 2000 fossil fuel price projections from the Energy Information Administration (EIA) for the East North Central Region of the U.S. All SUFG projections are in terms of real prices (1999 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are that:

- Coal prices will decline slightly in real terms throughout the entire forecast horizon.
- Gas price projections for all customers stop increasing after the year 2001 with moderate decreases until 2005 and a slight increase over the remainder of the forecast horizon.
- Distillate prices exhibit a pattern similar to natural gas over the entire forecast horizon.

The pattern of fossil fuel price projections is presented as growth rates in Table 4-2 for selected periods. In the 1999 forecast, SUFG also employed EIA projections. The growth rates for these projections are included for comparison.

Table 4-2. Growth Rates for Real Fossil Fuel Price Projections (%)

	1999-2001 "Spike"	2001-2005 "Decline"	2005-2019 "Trend"	EIA 2001 1999-2019	EIA 1998* 1996-2016
Coal					
Electric Utilities	-1.05	-0.74	-0.83	-0.83	-1.07
Industrial Customers	-1.59	-0.74	-0.82	-0.88	-0.65
Natural Gas					
Electric Utilities	22.14	-6.50	1.69	1.85	2.16
Residential Customers	11.63	-4.27	0.02	0.24	-0.71
Industrial Customers	8.57	-3.97	0.42	0.30	-0.65
Commercial Customers	18.91	-5.57	0.78	1.14	-0.07
Distillate					
Electric Utilities	11.02	-2.36	0.97	1.25	0.37
Residential Customers	8.68	-1.64	0.68	0.98	0.25
Commercial Customers	11.94	-2.26	0.93	1.33	0.25
Industrial Customers	8.27	-2.06	0.85	0.97	1.00

*Used in SUFG's 1999 forecast projections.

Source: EIA Annual Energy Outlook, 2001 DOE/EIA-0383(01), December 2000 Supplement Tables.

Demand-Side Management and Interruptible Loads

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's loadshape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand to a time when overall system demand is lower.

Incremental DSM, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are made by changing the utility's demand by the appropriate level of energy and peak demand for the DSM program. DSM programs that were in place in 1999 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 4-3 shows the amount of embedded and incremental DSM in terms of energy and peak demand reductions, as well as the amount of interruptible load available in Indiana. While incremental DSM has declined in recent years (from 120 MW in 1999 forecast), interruptible loads have increased (from 540 MW in 1999).

Table 4-3. Energy and Peak Demand Reductions

Embedded DSM		Incremental DSM		Interruptible
MW	GWh	MW	GWh	MW
330	920	26	18	1030

These 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 capacity 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.

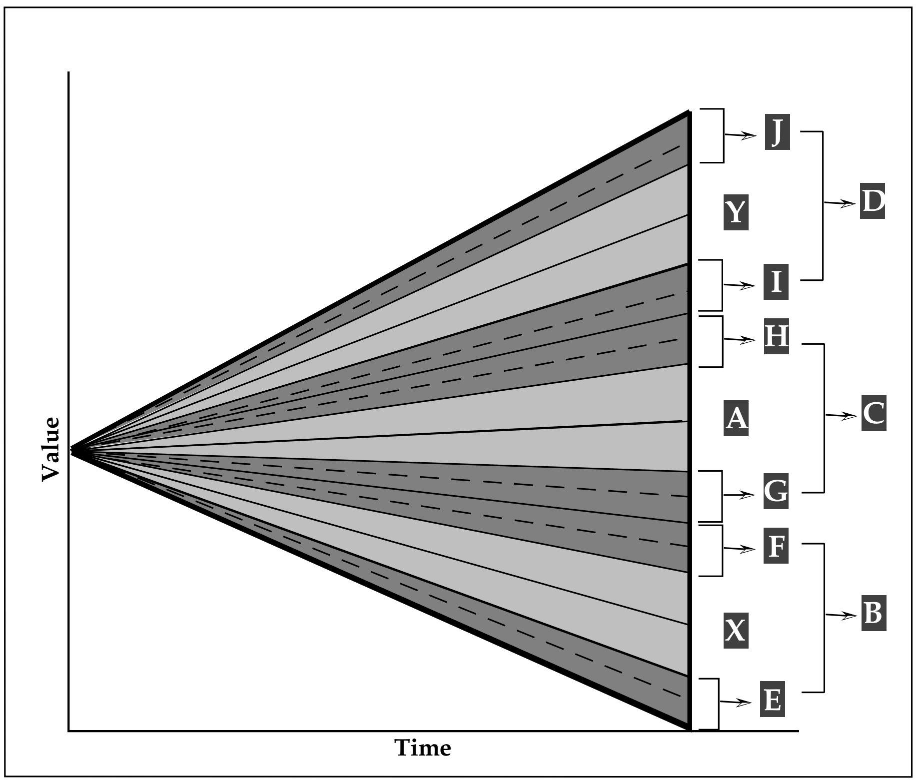
The uncertainty inherent in any energy forecast is illustrated in Figure 4-1. In this figure, *A* denotes the most likely trajectory of any forecast. The trajectories which denote the extreme low and high exogenous assumptions are X and Y, respectively. The range of stochastic model error surrounding the three trajectories are defined by B, C and D. The range of non-stochastic model error are defined by E, F, G, H, I and J.

In Figure 4-1 each set of exogenous assumptions, A, X and Y, defines a scenario and a possible future trajectory with an associated probability of occurrence. Some scenarios are more likely than others. This expected, or "most likely," future trajectory is defined to have an equal probability of being too low or too high. It is the most important point on the forecast distribution curve simply because it is the most probable. In this figure, trajectory A denotes the "most likely" trajectory. This corresponds to SUFG's base scenario. However, trajectory A assumes that the forecasting model and all its inputs are known with perfect certainty. If it is assumed that the exogenous assumptions are known with perfect certainty and the model has stochastic error only, the most likely trajectory lies in the interval denoted by C. If we add non-stochastic error, the most likely forecast lies in the interval that extends from the lower limit of G to the upper limit of H.

By including all sources of uncertainty, the trajectory lies in the interval that extends from the lower limit of E to the upper limit of J. The complete forecast distribution curve includes all possible future trajectories, including all sources of uncertainty, and their associated probabilities.

While the three sources of uncertainty discussed above are important, another major source of uncertainty may be of more importance, and that is the changing structure of the electric utility industry. Over the past several years competitive pressures have begun to change the industry, especially in the marketing of bulk wholesale power. Current pressures appear to be directed toward increasing competition, especially in generation and transmission. The outcome of these pressures on the structure of the industry is extremely uncertain.

Figure 4-1. Forecast Uncertainty



CHAPTER 3

INDIANA PROJECTIONS OF ELECTRICITY REQUIREMENTS, PEAK DEMAND, RESOURCE NEEDS AND PRICES

Introduction

This report includes three scenarios of future electricity demand and supply: base, low and high. The statewide results for these scenarios are presented in this section, along with their associated resource and equilibrium price implications.

The base scenario is developed from a set of exogenous assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG developed low and high growth 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 1.93 and 1.49 percent, respectively. The shaded numbers in the tables and the heavy line in the graphs indicate historical values.

The increase in the projection of electricity requirements, as shown in Table 3-1, can be traced to substantially higher growth in residential and commercial sales, which is offset somewhat by a slight decrease in industrial sales. The increase in residential and commercial sales between this and the previous forecast is primarily due to increased personal income and commercial employment growth in the CEMR projections. The decrease in industrial sales growth compared to the previous forecast is partially due to decreased industrial output growth as well as changes in the mix of industrial output growth for individual 2-digit Standard Industrial Classification (SIC) industries taken from the CEMR macroeconomic projection. For a complete discussion of the sectoral forecasting models and projections, see Chapters 5, 6 and 7.

The growth in peak demand is almost identical to that projected in 1999. The growth rate reported in Figure 3-2 is calculated from the summer peak of 1999, an unusually high load due to extreme weather conditions through 2019, the final year of the forecast horizon. The projections of peak demand are for normal weather patterns, which results in a drop in peak demand for the first year of the forecast. Interruptible load in this forecast is nearly twice that of SUFG's 1999 forecast; therefore, projected peak demand for long-run planning is correspondingly reduced. By adjusting for weather effects in 1999 and assuming that no load interruptions are required, the growth in peak demand is identical to that in energy requirements with the weather adjustment and interruptible load adjustment each accounting for about one-half of the difference in the growth rates reported (1.95 and 1.49) in Figures 3-1 and 3-2. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 3-2, the annual increase is about 360 MW per year.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources (firm purchases) 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.

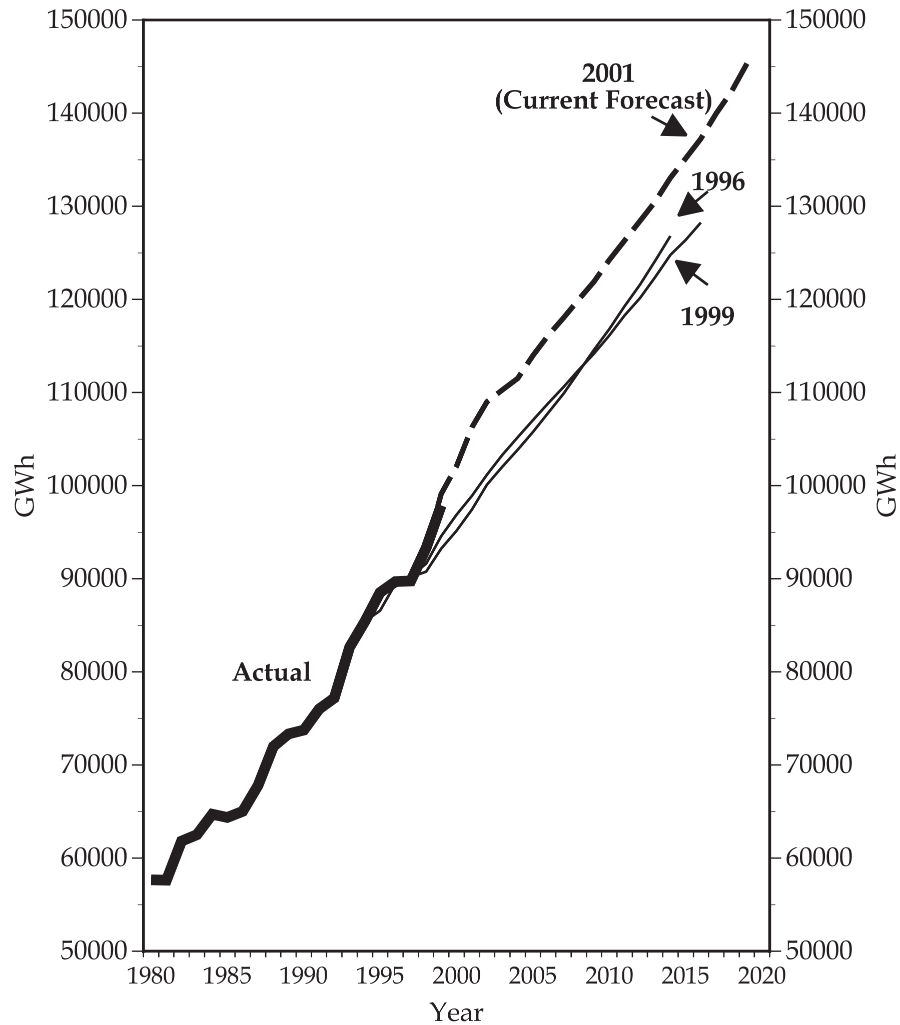
Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs are projected to reduce peak demand by approximately 25 MW.

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

Year	Year of Forecast 1996	1999	2001
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	86572	88514	88514
1996	89468	89398	89698
1997	90183	90237	89773
1998	90765	91634	93319
1999	93233	94561	99099
2000	95154	96867	102116
2001	97441	98922	106257
2002	100101	101170	109014
2003	102047	103298	110294
2004	103845	105179	111515
2005	105769	107058	113997
2006	107810	108833	116118
2007	109852	110601	118017
2008	112234	112433	120012
2009	114573	114148	121892
2010	116825	116124	124225
2011	119279	118291	126317
2012	121578	120130	128418
2013	124137	122389	130497
2014	126802	124797	133048
2015		129406	135161
2016		128237	137244
2017			139973
2018			142342
2019			145333

Average Compound Growth Rates Forecast Period	1994-14	1996-16	1999-19
	1.99	1.80	1.93



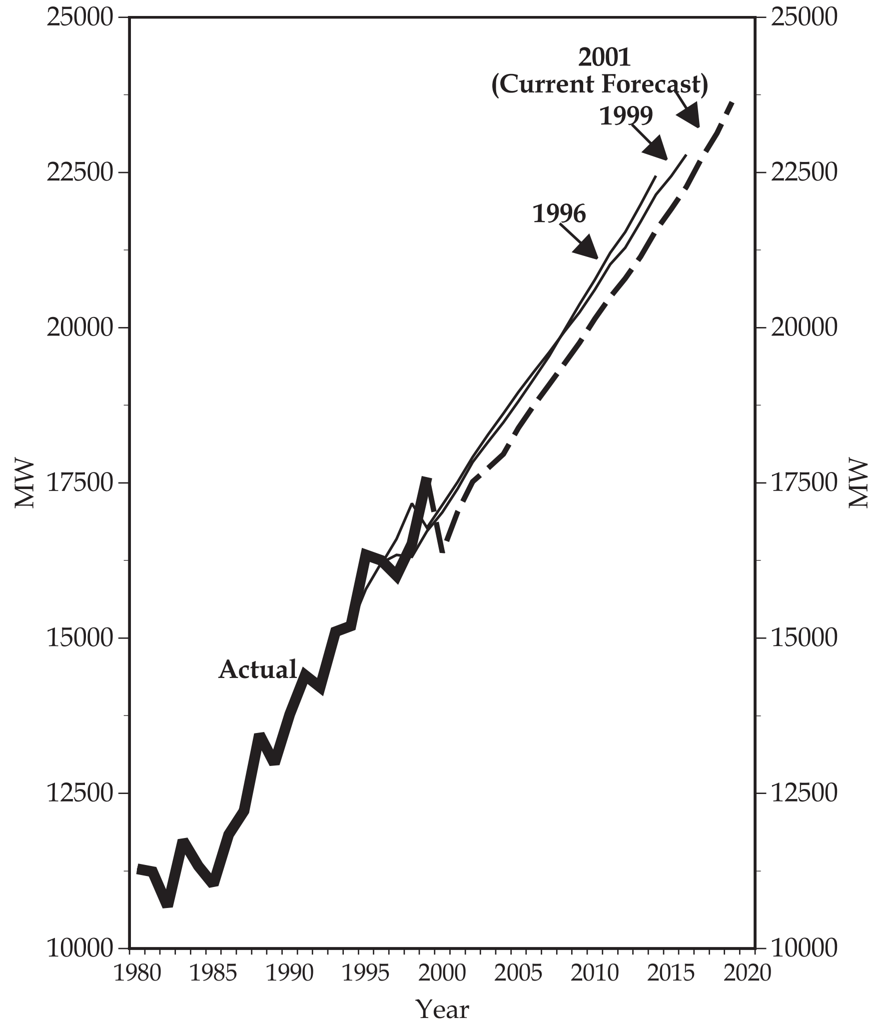
Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

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

Year	Year of Forecast 1996	1999	2001
1990	13775	13775	13775
1991	14403	14403	14403
1992	14209	14209	14209
1993	15103	15103	15103
1994	15199	15198	15198
1995	15789	16342	16342
1996	16212	16184	16253
1997	16342	16596	16004
1998	16311	17168	16521
1999	16720	16779	17591
2000	17026	17145	16383
2001	17407	17514	17038
2002	17837	17917	17519
2003	18158	18279	17739
2004	18473	18620	17964
2005	18812	18962	18385
2006	19177	19288	18748
2007	19539	19604	19080
2008	19965	19936	19422
2009	20377	20248	19756
2010	20773	20614	20143
2011	21204	21019	20493
2012	21541	21290	20795
2013	21985	21703	21146
2014	22447	22142	21568
2015		22443	21912
2016		22789	22269
2017			22729
2018			23133
2019			23633

Average Compound Growth Rates

Forecast Period	1994-14	1996-16	1999-19
	1.97	1.73	1.49



Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see AppendixA.)

Table 3-1. Annual Electricity Sales Growth (%) By Sector (Current vs. 1999 Projections)

	Electricity Sales Growth	
Sector	**Current (1999-2019)**	**1999 (1996-2016)**
Residential	1.99	1.67
Commercial	2.60	2.25
Industrial	1.47	1.53
Total	**1.93**	**1.80**

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Approximately 1,030 MW of large load is classified as interruptible in this forecast, double that in the 1999 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 NOx 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. The anticipated restructuring pressures have led utilities to plan based on lower reserve margins. In some instances, firm purchases have been added to maintain individual utility reserve margins at 6 percent, even if the state as a whole does not need new capacity.

Three types of generic firm wholesale purchases are included:

1. gas-fired combustion turbine peaking units;
2. gas-fired combined cycle (CC) cycling units; and
3. SOx and NOx controlled pulverized coal-fired (PC) base load units.

Figure 3-3 shows the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, about 3,000 MW of wholesale purchases are required. The net change in generation includes the retirement of several units as reported in the utilities' 1999 Integrated Resource Plant (IRP) filings. Over the second half of the forecast period, an additional 5,500 MW of resources are required to maintain target reserves.

Equilibrium Price and Energy Impact

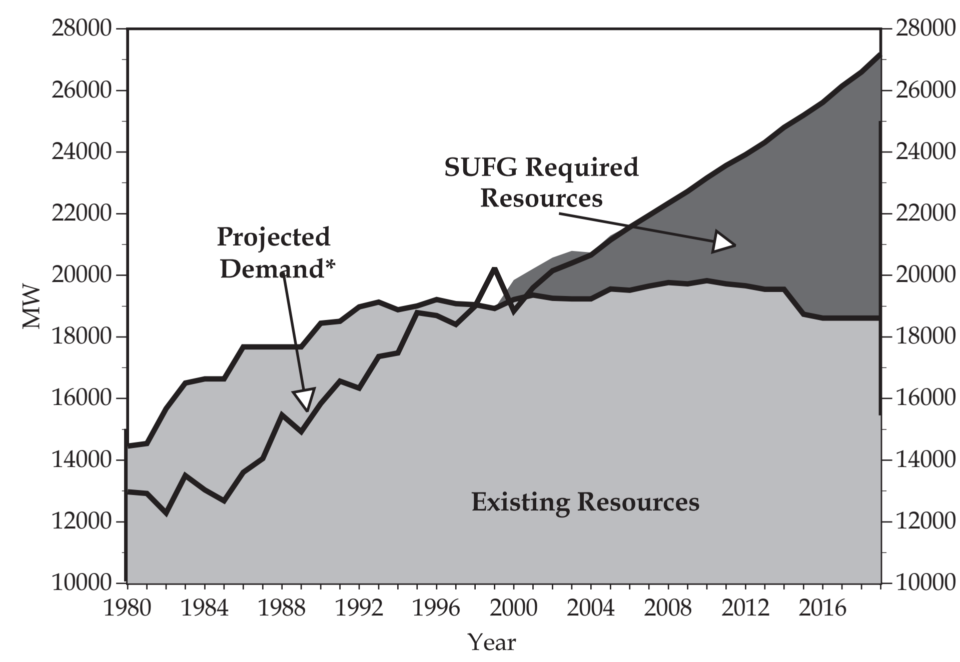
The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop. The impact of this feature on the forecast of electricity requirements can be significant.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 3-4. Declines in the real price of electricity during the first half of the forecast period are largely offset by increases during the second half 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. This price trajectory reflects the schedule of projected firm purchases in the base resource plan. Real prices decline through 2005 when mostly peaking capacity purchases are required to maintain a 15 percent reserve margin. Real prices level after 2005 as capital-intensive NOx retrofits, and cycling and base load purchases are added to maintain adequate system reserves (see Figure 3-4).

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

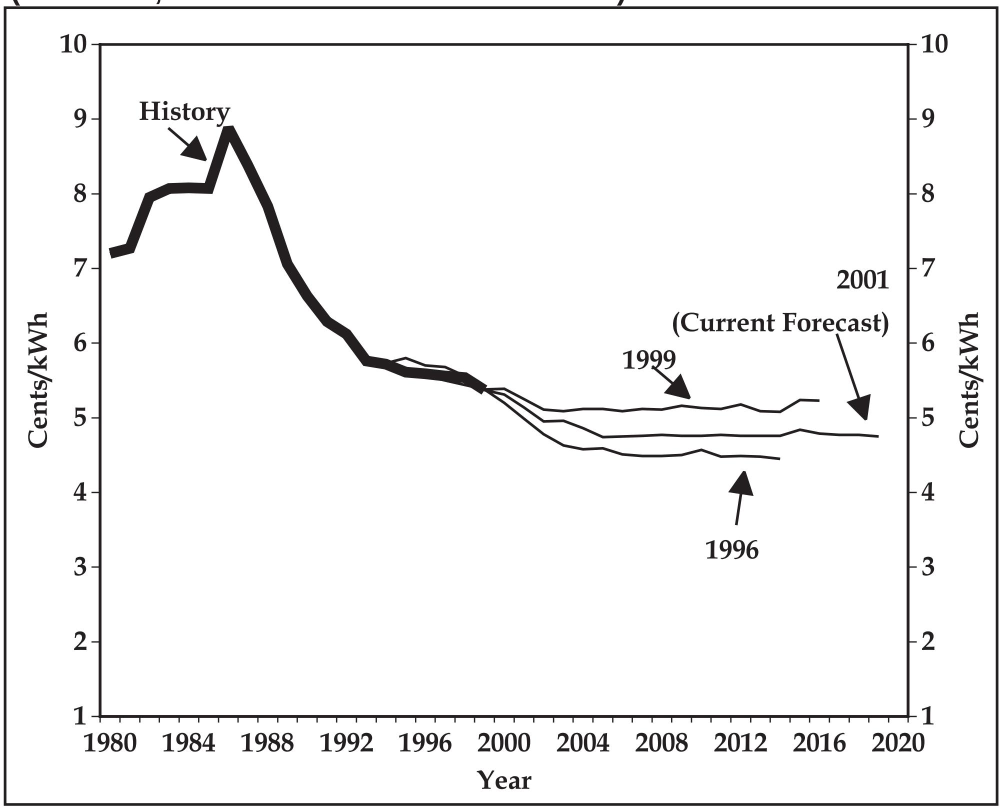
Year	Demand	Available Capacity*	Resource Additions: Peaking	Resource Additions: Cycling	Resource Additions: Base Load	Retired Penalty	Reserve Margin (%)
1999	17591	18920	0	0	0	0	8
2000	16383	19851	70	0	10	0	21
2001	17038	20213	50	30	80	0	19
2002	17519	20577	240	60	270	0	17
2003	17739	20796	340	80	380	0	17
2004	17964	20740	720	300	480	0	15
2005	18385	21290	750	380	600	0	16
2006	18748	21627	820	520	770	43	15
2007	19080	21959	820	590	900	70	15
2008	19422	22351	900	630	1060	88	15
2009	19756	22722	1010	740	1250	39	15
2010	20143	23188	1070	910	1380	99	15
2011	20493	23565	1170	1090	1580	103	15
2012	20795	23910	1290	1160	1800	0	15
2013	21146	24317	1410	1365	2000	118	15
2014	21568	24822	1595	1445	2240	0	15
2015	21912	25189	1970	1950	2530	804	15
2016	22269	25514	2190	1970	2740	125	15
2017	22729	26059	2315	2080	3050	0	15
2018	23133	26574	2415	2155	3390	0	15
2019	23633	27094	2570	2250	3660	0	15

*Includes installed capacity plus firm purchases minus firm sales.
Source: SUFG Modeling System and Utility IRP filings for retirements.



Note: Projected Demand includes 15% Reserve Margin

Figure 3-4. Indiana Real Price Projections (1999 Dollars) (Historical, Current and Previous Forecasts)



SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 3-4. The price projection labeled "1996 LCC" is the Lower Capital Cost (LCC) scenario from SUFG's 1996 report and the price projections labeled "1999" is the base case projection contained in SUFG's 1999 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 1999 dollars (from 1994 dollars for the 1996 projection, and from 1996 dollars for the 1999 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 target reserve margin. The capital cost estimates directly impact projected electricity prices and the reserve margin assumption affects both the timing and magnitude of new generation capacity. The 1996 LCC scenario used capital costs which were one-half of those reported in the 1993 EPRI TAG and assumed a 15 precent statewide reserve margin. The current base case and 1999 forecast capital cost assumptions were developed by SEPRIL and are somewhat higher than those assumed in the 1996 LCC scenario. The current base case also assumes a 15 percent reserve margin consistent with recent electric industry experience. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the tragectory of future prices, but these have been relatively unchanged during SUFG's recent forecasts. More detail regarding the assumptions and procedures used in SUFG's 1996 and 1999 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.

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. 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 0.85 percent lower and 1.55 percent higher than the base scenario for both energy requirements and peak demand. These differences are due to economic growth assumptions in the scenario-based projections.

Resource and Price Implications Of Low and High Scenarios

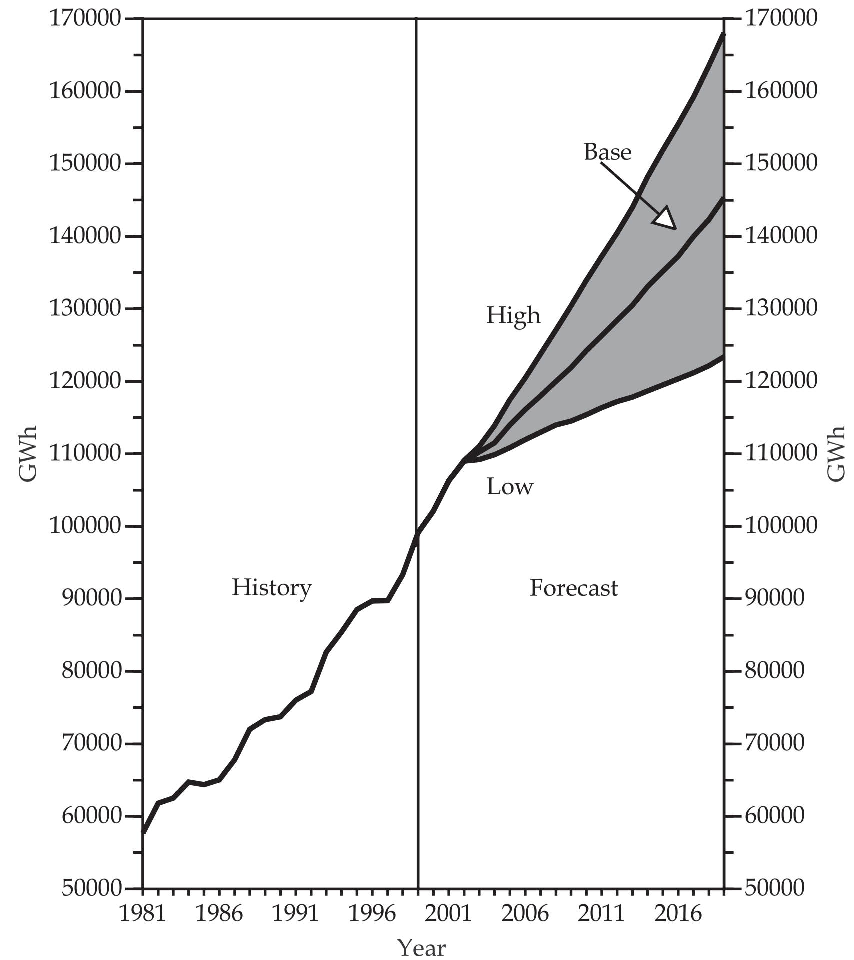
Resource plans are developed for the low and high scenarios in analogous fashion to the base plan. Demand-side resources, including interruptible loads, are the same in all three scenarios, as are retirements. Table 3-2 shows the statewide supply-side additions for each scenario. Approximately 12,675 MW over the horizon are required in the high scenario compared to only 4,420 MW in the low scenario. By the end of the forecast period, electricity prices in the high case are 1 percent higher than in the base case. This is because 4,200 MW of additional wholesale purchases are acquired relative to the base scenario. Prices in the low scenario are only about 1 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.

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

Year	Base	Low	High
1996	89698	89698	89698
1997	89773	89773	89773
1998	93319	93319	93319
1999	99099	99099	99099
2000	102116	102113	102119
2001	106257	106246	106288
2002	109014	108989	109086
2003	110294	109224	111067
2004	111515	109904	113909
2005	113997	110867	117498
2006	116118	111955	120466
2007	118017	112969	123774
2008	120012	113992	127099
2009	121892	114539	130397
2010	124225	115410	133944
2011	126317	116394	137267
2012	128418	117222	140491
2013	130497	117830	144017
2014	133048	118680	148208
2015	135161	119518	151923
2016	137244	120337	155492
2017	139973	121171	159240
2018	142342	122173	163553
2019	145333	123371	168052

Average Compound Growth Rates

Selected 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
1995-99	2.86	2.86	2.86
1999-05	2.36	1.89	2.88
1999-19	**1.93**	**1.10**	**2.68**

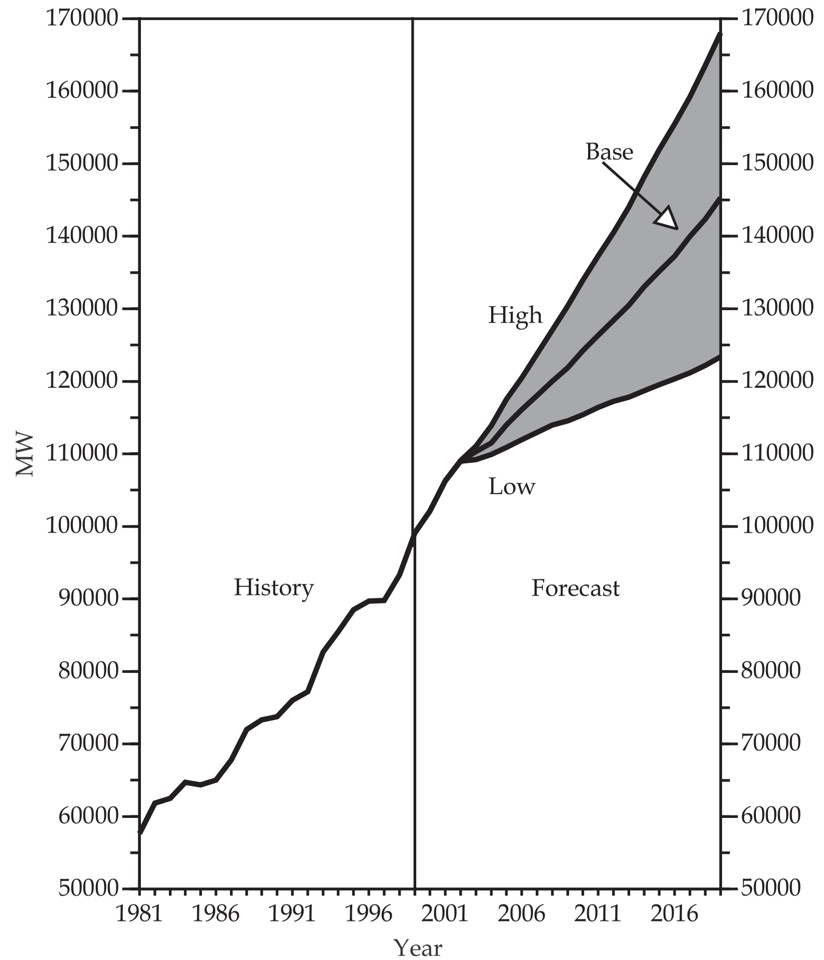


Notes: The shaded numbers in the table and the heavy line in the graph are historical values. (For an explanation on how SUFG arrives at these numbers, see Appendix A.)

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

Year	Base	Low	High
1996	16253	16253	16253
1997	16004	16004	16004
1998	16521	16521	16521
1999	17591	17591	17591
2000	16383	16383	16384
2001	17038	17037	17044
2002	17519	17515	17531
2003	17739	17570	17870
2004	17964	17704	18359
2005	18385	17882	18960
2006	18748	18078	19464
2007	19080	18265	20020
2008	19422	18449	20576
2009	19756	18570	21137
2010	20143	18721	21721
2011	20493	18892	22271
2012	20795	18989	22758
2013	21146	19105	23341
2014	21568	19257	24027
2015	21912	19398	24620
2016	22269	19549	25212
2017	22729	19707	25837
2018	23133	19892	26546
2019	23633	20107	27286

Average Compound Growth Rates			
Selected Periods	Base	Low	High
1980-85	-0.45	-0.45	-0.45
1985-90	4.55	4.55	4.55
1990-95	3.48	3.48	3.48
1995-99	1.86	1.86	1.86
1999-05	0.74	0.27	1.26
1999-19	**1.49**	**0.67**	**2.22**



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

Table 3-2. Indiana Resource Requirements (SUFG Scenarios) in MW

Year	Base				Low				High			
	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total	Peaking	Cycling	Base Load	Total
2000	70	0	10	80	70	0	10	80	70	0	10	80
2001	50	30	80	160	50	30	80	160	50	30	80	160
2002	240	60	270	570	240	60	270	570	250	70	270	590
2003	340	80	380	800	300	50	310	660	380	90	430	900
2004	720	300	480	1500	620	260	350	1230	820	390	700	1910
2005	750	380	600	1730	640	290	380	1310	890	510	910	2310
2006	820	520	770	2100	690	360	460	1510	1020	680	1200	2900
2007	820	590	900	2310	650	360	510	1520	1120	870	1400	3390
2008	900	630	1060	2590	630	350	570	1550	1260	910	1740	3910
2009	1010	740	1250	3000	680	410	620	1710	1477	1077	2030	4584
2010	1070	910	1380	3360	690	500	660	1850	1570	1209	2360	5139
2011	1170	1090	1580	3840	740	620	740	2100	1780	1428	2680	5889
2012	1290	1160	1800	4250	780	670	800	2250	1992	1539	2990	6522
2013	1409	1365	2000	4774	830	810	860	2500	2184	1779	3350	7313
2014	1593	1446	2240	5279	860	860	930	2650	2423	1896	3750	8069
2015	1972	1950	2530	6452	1181	1220	1170	3572	2716	2418	4460	9583
2016	2190	1970	2740	6900	1299	1267	1210	3776	2936	2508	4842	10286
2017	2313	2081	3050	7444	1346	1313	1280	3939	3060	2606	5346	11013
2018	2416	2154	3390	7860	1422	1370	1370	4162	3197	2751	5898	11856
2019	2568	2249	3661	8478	1499	1432	1490	4421	3351	2867	6457	12675

CHAPTER 2
OVERVIEW OF MODELS: WHAT'S NEW?

The Inclusion of Wholesale Markets in the Regulated Forecast

The emergence of Midwest wholesale electricity markets as a significant source of electricity supply for Indiana's utilities has required SUFG to alter the way the SUFG modeling system adds capacity to make up the gap between existing capacity and future peak demand.

In previous reports, a supply deficiency was identified by monitoring the projected reserve margin of Indiana utilities, and whenever the state margin fell below 15 percent, SUFG would then add generic peaking, cycling and base load plants in the service territories, sharing the plants between utilities when it was appropriate, in order to restore state reserve margins to satisfactory levels.

These generic plants were then placed in the rate bases of their home utilities, and the costs were passed on to retail customers, following the traditional "cost plus fair return on investment" regulatory pricing method.

This method reflected the reality of the situation for several years; Midwest utilities did, in fact, request permission of their regulators to add capacity to their rate base, after satisfactorily demonstrating the need for such capacity.

This began to change after 1992, the year the Federal Energy Regulatory Commission (FERC) opened up wholesale electricity markets to independent power producers, allowing utilities far more opportunities to purchase power from the wholesale markets.

Wholesale markets in the Midwest have now grown to the point where the SUFG modeling system needs to revise the way the models treat the need for new capacity. To bring it more in line with what can be expected in the real world, this forecast assumes that all new needs for additional capacity (in excess of any capacity needs planned to be met by IURC approved rate-based additions) will be met by a combination of short- and long-term purchases on the wholesale markets. These purchases are entered into the accounting system through the fuel adjustment charge.

While petitions were pending for plants to be added to the rate base, no plants had been approved by the IURC at the time this forecast was developed. Therefore, the SUFG modeling system assumes that all such capacity needs in the future will be met by purchasing power rather than adding capacity.

This method is not as revolutionary a change as it might appear. For years, SUFG has been keeping track of bilateral sales by, and to, Indiana utilities. These long-term contracts, which included a capacity and an energy charge, were not entered into the rate base, but rather were expensed into customer bills through the fuel adjustment charge.

The change, then, is a matter of degree, not kind. SUFG will now assume that the gap between supply (augmented by rate-based capacity as the IURC receives and approves requests) and demand will all be made up by such purchases. SUFG will continue to use the fuel adjustment charge to allow utilities to recover these costs.

The new process still involves comparing the peak demand with existing generation capacity (net of existing purchase and sales contracts) for each year of the forecast. From this, the amount of capacity needed from the wholesale market to meet a 15 percent statewide reserve margin is determined. This capacity is then assigned to individual utilities according to their needs.

Three types of wholesale purchases are modeled: peaking, cycling and base load. The wholesale capacity assigned to an individual utility is separated into these three categories according to the particular needs of that utility. The wholesale purchases are then dispatched along with the utility-owned generation by the production costing submodel of the overall forecasting model.

The cost of these purchases is determined in the following way. Rather than attempt to predict hour by hour market clearing prices in Midwest wholesale markets, SUFG makes the assumption that the markets will yield an average yearly price equal to the long-run marginal cost (LRMC) of electricity for each of the three types of purchases. The argument is that during hourly periods of shortage/surplus, the market clearing price can be expected to diverge from long-run cost. However, unless the average price over a longer horizon equals the LRMC, firms will enter (if the average price is above LRMC) or leave (if average price is less) the market until the average price equals the LRMC. Hence, each of the three wholesale purchase types has a corresponding pair of capacity and energy charges. The capacity charge is determined using the fixed operation and maintenance (O&M) costs and an appropriate capital recovery charge for the type of generator that might be expected to provide the energy. The capital recovery charge is based on the construction cost and a 15 percent capital recovery factor to provide a return on the investment consistent with the unregulated private sector risk expected in such a market. The capacity charges do not change in real (inflation removed) terms throughout the forecast.

The energy charge is determined from the variable O&M costs and fuel costs for the appropriate generator type. The fuel cost portion of the energy charge is adjusted for each year of the forecast in accordance with the fuel price trajectories described in Chapter 4. Table 2-1 shows the capacity and energy charges for each type of wholesale purchase for 2000.

The purchase cost of gas-fired combustion turbines has risen somewhat during 2001, primarily as a result of a shortage of supply due to the high demand for combustion turbines starting in 1998. Prices for turbines are expected to lower as the supply and demand for them stabilizes. The installation costs used by SUFG in determining the capacity charges for wholesale purchases were developed from a 1998 study performed by SEPRIL Services[1], and do not include these recent higher prices. However, examination of both futures markets and recent wholesale contracts indicates that the wholesale prices used here are reasonable. Furthermore, a survey of new plants recently announced in various trade publications show the SEPRIL prices to be on the low end, but within the range of current costs of new gas-fired plants. It should be noted that such reports should be viewed with some skepticism since they often represent very preliminary estimates and are not always reported on a consistent basis. For instance, one generator may include such costs as transmission and gas pipeline additions, land acquisition costs, and interest accrued during construction in its cost estimate while another may not. Similarly, the reported numbers may be skewed by whether they are based on the rated capacity of the generator or the net summer output, which could be considerably lower.

Table 2-1. Capacity and Energy Charges in 2000

	Peaking	Cycling	Baseload
Capacity ($/MW/Yr)	63,270	109,860	206,500
Energy ($/MWh)	56.74	37.25	11.90

Impact of Increased Reliance on Wholesale Markets

The recent trend toward increased reliance on the wholesale market for new capacity requirements will affect the utility industry. First, the wholesale market exposes the utility to price volatility. This does not necessarily mean higher overall prices. There will likely be periods when wholesale prices are low, even during periods of peak demand, such as were experienced in the Midwest in 2000. Similarly, price spikes such as those seen in 1998 and 1999 in the Midwest will occur. The challenge is to manage the risk of high prices, whether through long-term contracts, load management, or utility-owned capacity, while trying to take advantage of the lower prices.

Another effect of increased reliance on wholesale markets is a shift in risk from overbuilding to underbuilding. In 1986, Indiana utilities relied almost entirely on their own generators to serve their customers and had an overabundance of capacity, as seen by a 48 percent reserve margin. The result was electricity rates that were about 65 percent higher than those seen in 1999, after adjusting for inflation.

In wholesale markets, high prices are associated with too little generating capacity, rather than too much. Examples of this can be seen in the Midwest price spikes of 1998 and 1999 and the California market of the past year. The factors leading to higher prices in both scenarios are shown in Table 2-2.

Table 2-2. Factors Leading to Higher Electricity Prices

Reliance on:	With:	Leads to:
Utility-owned generation	Too much capacity	Higher prices
Wholesale markets	Too little capacity	Higher prices

SUFG does not believe that one method is necessarily better than another; in fact, a diverse capacity portfolio that uses both utility-owned generators and wholesale purchases may be the best option for a given utility.

Availability of Wholesale Market Capacity

Given Indiana's projected dependence on the wholesale market to meet its expanding capacity needs, the amount of merchant capacity built in the region is of vital importance. On the positive side, substantial capacity has been proposed for Indiana and the ECAR/MAIN region. On the other hand, unlike rate-based capacity, the amount of this merchant capacity that actually gets built and commissioned by the announced date is very uncertain.

At the time SUFG's wholesale model was run for the results given in this report, the proposed merchant plant capacity entered into the database was as shown in Table 2-3. Most of the capacity announced at that point was for the year 2000 to 2003, with only about 2,240 MW for the year 2004 and none for the year 2005. In addition, there were several projects, a total of 5,876 MW, which had no announced expected commissioning date. These plants were assigned to the year 2005 for modeling purposes.

Table 2-3. Proposed Merchant Plant Additional Capacity* (in MW)

Year On-Line	ECAR/MAIN	Indiana
2000*	8877	1600
2001*	12228	1375
2002	11313	2775
2003	4170	1380
2004	2240	0
2005	5876	0
Total	**46724**	**7130**

*As of February 2001
Source: SUFG Merchant Plant Database

In recognition of the uncertainty surrounding the commissioning of the merchant plants, SUFG assumed that only one third of the capacity announced each year would be commissioned. For the year 2000, there were several projects in the region, a total of 4,867 MW, whose commissioning could be positively confirmed. These included 1,600 MW for the state of Indiana. These were entered into the model without scaling down. Given these assumptions, the merchant capacity available each year for the purposes of this model is shown in Table 2-4.

Table 2-4. Actual Merchant Plant Capacity Used in SUFG Model (After Adjusting for Uncertainty)

Year On-Line	ECAR/MAIN	Indiana
2000*	6532	1600
2001*	4076	458
2002	4438	925
2003	1390	460
2004	747	0
2005	1965	0
Total	**19147**	**3443**

Source: SUFG Merchant Plant Database

Since the wholesale market is a regional market, the physical location of a merchant plant within a specific geographic area does not ensure that the output of that plant is available to that area. In other words, electricity produced at a facility located in Indiana may be consumed in other areas or conversely electricity produced out-of-state may be consumed in Indiana.

To estimate the wholesale capacity available to Indiana customers, SUFG used a regional model of electricity production, consumption, and trade to simulate the availability in the summer of 2005 when demand is most likely to exceed supply. This model, first used in SUFG's 1999 report on the impact of restructuring, assumes that all Midwest capacity, both rate-based and merchant, compete for the electricity demand at all nodes within the model (Figure 2-1). The nodes in the model correspond to control areas, with demand for electricity at each node and producers of electricity at each node.

The regional model determines the cost minimizing mix of generation and purchases for each node that satisfies demand at that node. Electricity demands are assumed to be fixed rather than price responsive in the model, and the cost minimization objective ensures that all generation is dispatched in competitive, merit order framework. In the model all capacity is derated for expected forced outages and summer capability, and trade between nodes is subject to losses and transmission costs.

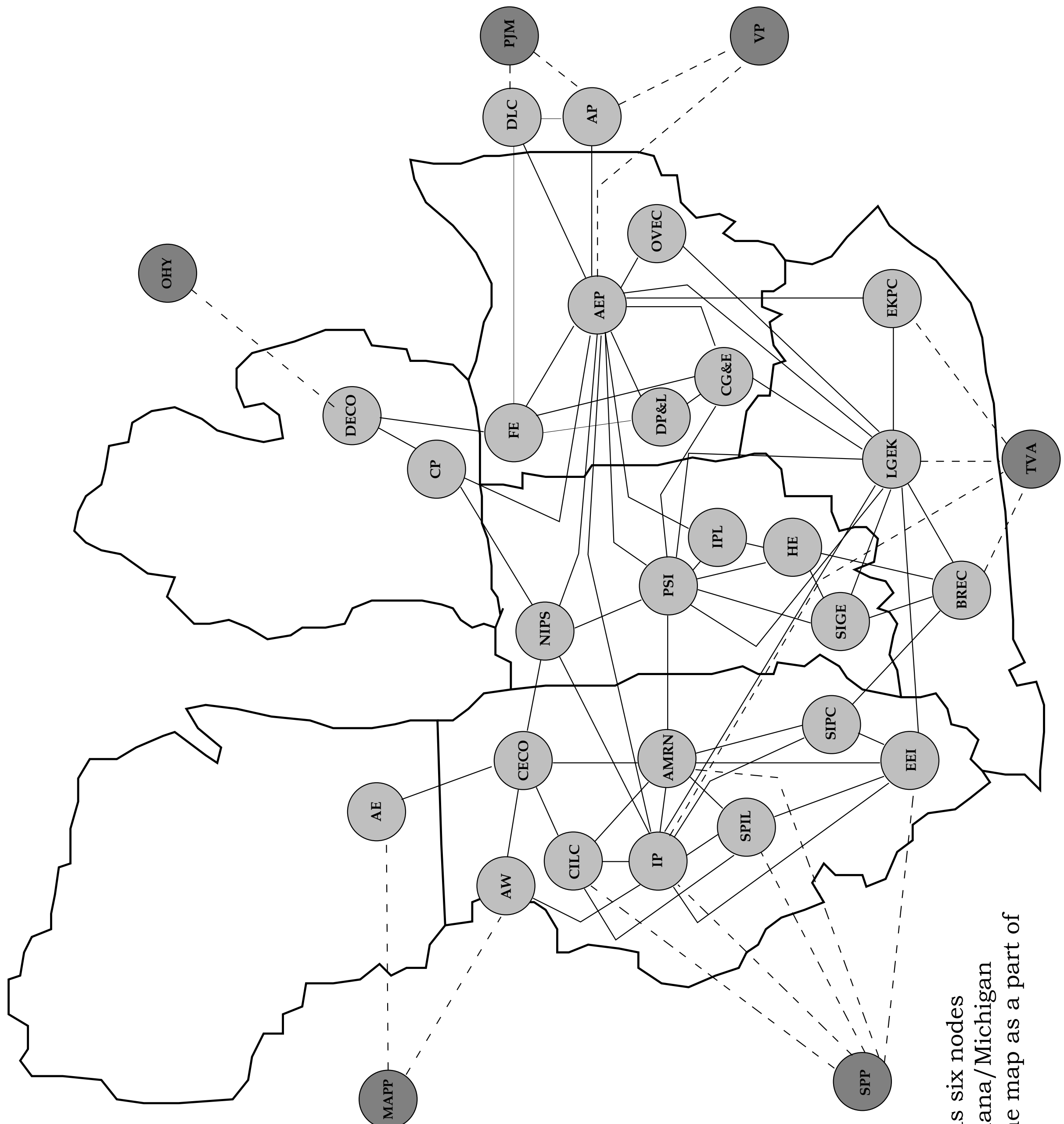
Given these assumptions, simulations performed with the model indicate that for the summer 2005 shortages in Indiana could occur during approximately 20 hours of peak load, with an average shortage of about 0.5 percent of demand and a maximum shortage of about 800 MW. Recall that this model assumes no response to price on the part of any customers so this shortage might be avoided if some customers in the region decreased usage at peak times in response to price signals or voluntary conservation. Furthermore, Indiana utilities have in place about 1,000 MW of interruptible load which is adequate to meet the simulated shortages.

It is likely that some of the interruptible load may not actually be available for interruption at the particular time the interruption is requested, either because the load is not in operation at that time or because of buy through provisions that allow the affected customer to purchase power at the wholesale price in lieu of interruption. On the other hand, other Midwestern utilities have additional interruptible loads that would help alleviate the shortage.

The conclusion of the simulations are that if markets function correctly in the Midwest, Indiana utilities should have access to ample supplies in the wholesale markets in the near future without having to resort to load interruptions, except in very rare situations.

All this, of course, is based on the optimistic assumption that such markets will have enough competition between suppliers to ensure the proper functioning of such markets and that planned additions do in fact come on line between now and then. These issues are addressed in the SUFG report entitled, "Factors Affecting Indiana Prices in Competitive Market," June 2000.[2] Further discussion of the likely role of market forces and expected additions to generation and transmission can be found in that document.

Figure 2-1. Network Topology of Model



Note: Indiana has six nodes counting the Indiana/Michigan node shown in the map as a part of the AEP system.

Impact of Emissions Restrictions

Nitrogen oxides (NOx) is a general term for a group of highly reactive gases which contain nitrogen and oxygen in varying amounts. These gases react with volatile organic compounds in the presence of heat and sunlight to form ozone.

The Clean Air Act Amendments of 1990 called for reductions of NOx emissions in two stages. The first stage, Phase I, went into effect in 1996 and required certain boilers to reduce NOx emissions rates. Phase II took effect in 2000 and further reduced emissions rates for those boilers while also limiting other boiler types. In 1998, the Environmental Protection Agency (EPA) proposed further reductions as of May 2003. This deadline has since been extended by one year.

In 2000, SUFG published a study of the expected impacts of NOx emissions restrictions on Indiana electricity prices.[3] This study used compliance options, a combination of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems, and costs developed by the Indiana Department of Environmental Management (IDEM). These costs include capital costs of NOx removal equipment, reduced generating capacity of generators after the installation of the removal equipment, decreased availability of the generators during the installation procedure, and increased operating costs associated with operating the removal equipment. The net result was an expected increase in electricity prices of six to eight percent. This six to eight percent estimated increase in electricity prices is an average across all Indiana utilities. In some cases utilities will incur higher than average emission control equipment and operation costs due to the difficulty of retrofitting generation facilities and the share of their generation subject to additional control while in other cases utility compliance costs will be below the statewide average.

This forecast includes the compliance costs associated with NOx emissions restrictions. Where available, the IDEM compliance options and costs have been replaced with estimates obtained directly from the utility.

This forecast does not include compliance costs for future emissions restrictions other than those associated with EPA announced restrictions on NOx emissions. Additional emission restrictions may be proposed for trace metals, especially mercury, and for microscopic ("fine") particulates. It is also possible that additional restrictions on sulfur dioxides and nitrogen oxides as well as carbon dioxide could be proposed.

End Notes

1. W.C. Stenzel, SEPRIL LLC., *Plant Design, Performance and Cost Comparison Study*, prepared for the Institute for Interdisciplinary Studies, Purdue University, August 1998.
2. State Utility Forecasting Group, "Factors Affecting Indiana Electricity Prices in Competitive Markets. Prepared for the Indiana Utility Regulatory Commission, November 2001.
3. Gotham, D.J., Holland, F.D., and Nderitu, D.G., "The Projected Impacts of NOx Emissions Reductions on Electricity Prices: A Case Study for the State of Indiana," *Utilities Policy*, v. 9, No. 2, June 2000.

Natural Gas Availability and Prices

The last two years have seen an enormous increase in the number of gas-fired electricity generation units planned, and to a lesser extent, operating in the Midwest. Table 8-1 gives the latest estimate, by type of plant -- combustion turbine (CT) and combined cycle (CC) and by stage of construction -- operating, approved for construction, or simply proposed for Indiana.

Table 8-1. Status of New Gas-Fired Plants in Indiana, June 2001 (in MW)

	CT	CC
Operating	1,792	0
Approved	1,060	1,858
Proposed	890	4,980
	3,742	6,838

While the impact on gas use by CTs will not be as large for the same capacity installed as that of the CCs (CTs are the least-cost supply option if used only to satisfy peak demands, while CCs may supply cycling and base load energy), both technologies taken together have the potential to significantly increase gas use in the Midwest markets.

Table 8-2 gives SUFG estimates of the increase in gas use in billion cubic feet (Bcf) and as a percent of Indiana total 1999 gas demand for various construction scenarios involving CT and CC plants in Indiana list in Table 8-1.

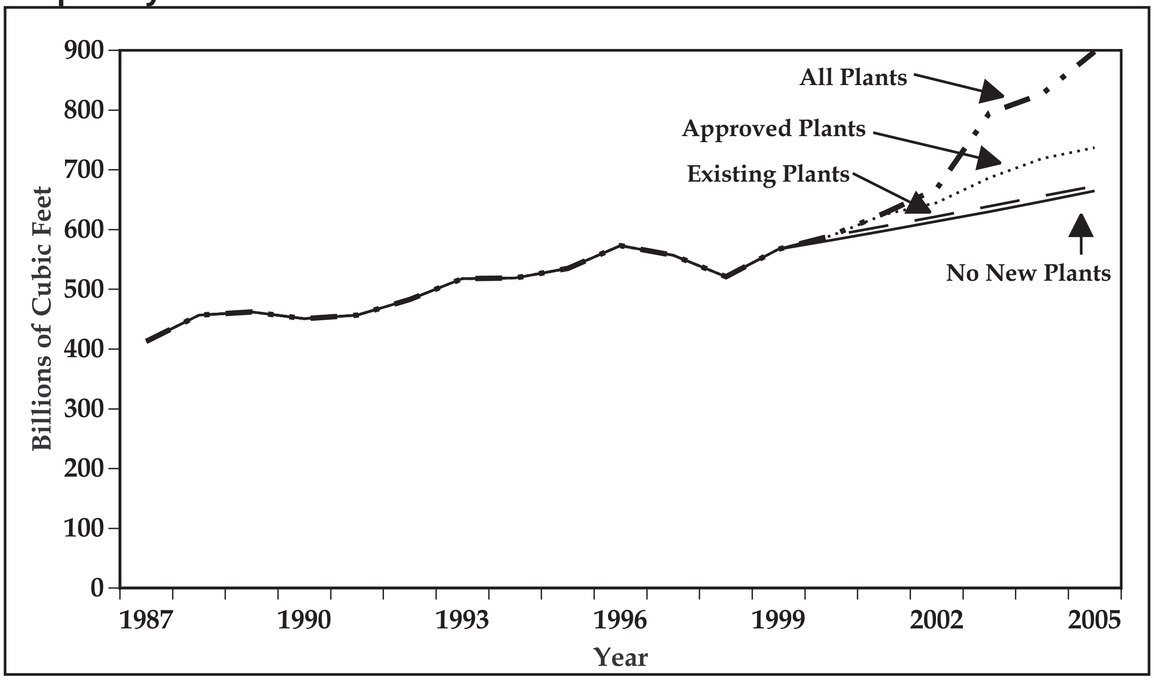
Figure 8-1 illustrates the expected impact of natural gas-fired generation on Indiana consumption. The values through 1999 represent historical statewide natural gas consumption. The lowest trajectory, "No New Plants," shows the consumption level assuming growth at the historical rate seen from 1987 to 1999 (2.7 percent per year) and does not include any new generators. The next trajectory, "Existing Plants," adds the usage of the 1,680 MW that came on line in 2000 and the 112 MW that became operational in June 2001. The third trajectory, "Approved Plants," includes those plants approved for construction. The uppermost trajectory, "All Plants," includes proposed plants. The existing plants are intended for use only during periods of high electricity usage and do not significantly

Table 8-2. Impact on Indiana Gas Use of New Gas-Fired Plants

	CT (Bcf)	CC (Bcf)	Total (Bcf)	Percent of Indiana 1999 Statewide Consumption
Existing	8.46	0	8.46	1.5%
Existing + Approved	13.47	58.56	72.03	12.7%
Existing + Approved + Proposed	17.68	215.52	233.20	41.1%

Assumptions: CT operates at 5% of the time, CC 50%; heat rate 11,000 Btu/kWh for CT, 7,340 Btu/kWh for CC.

Figure 8-1. Natural Gas Usage with Varying New Generation Capacity



impact total gas usage. A large portion of the remaining plants are intended for nearly constant operation. Hence, they have a significant impact on natural gas usage.

While the impact of existing units on gas use is small since there are only 1,792 MW now in operation and all are CTs, the combined impact of CT and CC units running and approved for construction is significant .

It is extremely doubtful that all these units will be constructed, but it is quite possible that a good fraction of those approved in Indiana will eventually be added.

Three questions arise when considering this eventuality:

1. Will there be enough gas produced to satisfy this demand?
2. If so, will the gas transmission system be capable of moving this volume to Indiana generation sites?
3. If so, will the gas be available at a reasonable price?

The answer to the first question can only be addressed nationally, not locally, because of the interconnectedness of the gas pipeline system and the ability of gas to be transported over long distances.

Nationally, electric utilities have accounted for 12-1/2 to 16 percent (in 2000) of total gas consumption, with a slightly increasing percentage trend. (Total utility consumption peaked in 1998 when utilities purchased over 3.2 Bcf of gas.) However, historical time trends of U.S. gas use and prices by customer type are so influenced by the winter weather as to make them of little use for forecasting except to note that gas use by utilities is an important, but not dominant, portion of total use.

The most recent EIA survey of national generation capability indicated that of the total of 785,990 MW installed capacity in 1999, 171,190 or 21 percent, was gas fired. The total MW installed increased by over

10,000 MW from 1998, of which 7,800 MW or 80 percent was gas fired.[1] The SUFG national database indicates that of the 298,208 MW of new capacity that have been proposed by both independent and regulated utility companies, about 87 percent or 259,069 MW are gas fired.

Therefore, if all proposed gas-fired electric plants in the U.S. come on line, there will be a dramatic increase in U.S. gas use for this purpose. It is beyond the scope and resources of SUFG to, at this time, develop an independent assessment of the impact of new U.S. gas-fired electric generation plants on U.S. gas demand given all the uncertainties involving developments outside the state of Indiana, the Midwest, and indeed, the United States (Canadian imports are a major source of gas for U.S. consumers).

Fortunately, there are studies by others available that do address this question. One such study, recently released by the EIA says:

> *Natural gas consumption, which accounted for 23% of domestic energy use in 1999, is expected to grow more rapidly than any other major fuel source from 1999 to 2020, mainly because of projected growth in gas fired electricity generation. ... Gas consumption by electricity generators (excluding co-generation) in 2000 is expected to triple the 1999 level. ... Technically recoverable natural gas resources in North America is believed to be adequate to sustain the production volumes projected. ... Domestic consumption still is expected to increase at a faster rate then domestic production over the period, with Canadian imports making up the difference.*[2]

Another factor is the increasingly tight supply situation for the combustion turbines themselves. Worldwide, gas turbine orders increased 31,000 MW from 1998 to 1999, and 11,570 MW from 1999 to 2000 to a record total order level of 75,850 MW.

Particularly strong North American growth was recorded in two size distributions -- 30 to 60 MW for peaking power (CT) generation, and 180 plus MW for continuous duty (CC) gas turbines. North American peaker orders went from 20 units in 1999 to 88 units in 2000, while continuous duty turbines grew from 4 units ordered in 1999 to an astounding 67 units ordered in 2000.

It is no surprise that a recent article estimated that the waiting time between order and delivery from one major U.S. manufacturer has now grown to 24 months.

Therefore, the distinct possibility exists that at most 60,000 MW of North American capacity -- the total of the last two years orders -- will be installed in the period 2001 to 2003, assuming the order lag is the 24 months reported in the article.

The answer to the second question -- will there be enough gas transmission capacity to move this gas to Midwest markets -- can be found by examining the recent expansions of the pipeline system.

The 2001 Annual Energy Outlook from EIA indicates that over 3000 million cubic feet per day major additions of pipeline capacity in the Midwest were added from 1990 to 2000. The one of most importance to the Midwest is the Alliance line, with a capability of moving over 1,830 million cubic feet a day. From this, the EIA forecast concludes:

> *Given the efficiencies that industry restructuring has brought to the U.S. natural gas market, the abundant technically recoverable domestic resource base, the growing availability of natural gas imports, the role of technology in making additional supplies available and reducing costs, and the continuing expansion of the U.S. pipeline grid, the natural gas industry is expected to be able to respond to the challenge of substantial increases in future demand. As long as the industry is confident that the demand will be there and that natural gas can be produced and delivered at*

> *prices that are competitive with those of other fuels, the needed investments in drilling, manpower, and pipeline infrastructure are expected to be made.*[3]

This conclusion, plus the fact that the largest new pipeline on line in the last 10 years connects the Western Canadian Gas fields with the Chicago gas hub seems to indicate that there will be no serious gas production and distribution problems into Midwest markets. The issue as to the adequacy of the ability of local gas distribution and storage system to handle the increased demand remains an open question to be addressed.

Finally, will this gas supply be available at a reasonable price? The EIA 2001 Annual Energy Outlook gives wellhead gas price projections for their forecast period, 2000-2020. Their forecast shows a decline in real gas prices until 2005 when gas prices are anticipated to start increasing steadily until 2020, when they are expected to return to their current levels of slightly higher than $3.00 per thousand cubic feet. EIA's alternative low resource (and higher priced) projection has real gas prices rising above $4.50 per thousand cubic feet by 2020.

In order to better answer these questions, SUFG, in conjunction with the IURC, the Office of Energy Policy and other interested parties, is developing a regional natural gas pipeline and storage model. This model will be used to measure the impact of the much expanded Midwest gas-fired generation capacity expected to develop during the forecast period, both in terms of the gas production and distribution system's ability to produce and ship the gas to Midwest markets. The likely price impact of such a demand and the implications of all the above on Indiana's coal industry will also be addressed.

Distributed Generation

Introduction

Distributed generators (DG) are small generators located close to the load at the low voltage distribution level. They are distinct from cogeneration "Qualifying Facilities" as defined under the 1978 Public Utilities Regulatory Policy Act (PURPA) and not covered by more recent FERC standards for open access transmission. They can be as small as the few kilowatts needed to supply a residential home to as large as several megawatts. The sizes in a May 2000 National Renewable Energy Laboratory study[4] range from a 0.3 kW photovoltaic system in Pennsylvania to a 26 MW gas turbine in Louisiana. The New York State DG interconnection rules cover generators up to 0.3 MVA while the Texas rules cover generators up to 10 MW.

Distributed generation has the potential to bring significant economic, reliability and environmental benefits. Due to their proximity to the load, distributed generators avoid transmission and distribution costs and losses. Some distributed generation technologies have an efficiency much higher than conventional central station technologies, and because they are close to the load, this efficiency can be further enhanced by combined heat and power (CHP) capability. When connected in parallel to the grid, a distributed generator adds substantially to the reliability associated with the load it supplies. From an environmental viewpoint, distributed generators powered by renewable technologies such as wind and photovoltaics are very attractive. Other technologies such as fuel cells have a much lower environmental impact than conventional central station technologies.

The Technologies

The interest in distributed generation has been sparked by, among other things, technological advancement in micro-generators such as micro turbines, fuel cells, photovoltaics and small wind turbines. Wind turbines and solar-powered photovoltaics are very attractive from an environmental perspective. Fuel cells are a revolutionary technology that uses an electrochemical process (like a battery) to produce electricity from a combination of oxygen and hydrogen. The hydrogen can come from a variety of fuels, but natural gas is the most economical. The fuel cell has a higher energy-conversion efficiency (35 - 60 percent) than combustion related technologies. It is inherently clean and quiet with water and heat as its only byproducts. Most fuel cell generator sets will come attached with CHP capability to make use of its excess heat. However, fuel cells are expensive with capital costs at about 3000 $/kW as compared to about 330 $/kW for a conventional gas turbine. Micro turbines are another of the innovative technologies that have made the concept of distributed generation feasible. They are super small, combustion turbines, in the 30 to 200 kW range with a capital cost of about 1100 $/kW. They are evolved out of the automobile turbocharger, aircraft auxiliary power units and small pilotless jet engines. Finally, internal combustion engines and small combustion turbines, mature technologies that have been used in the past as back-up generators, have found use as distributed generators. The cost characteristics of typical distributed generators and how they compare with conventional central station technologies are given in Table 8-3.

The fuel cost for the distributed generators was calculated assuming a price of 5 $/mmBtu for diesel and price of 3 $/mmBtu for natural gas. The cost for the conventional central station generators are from a study by SEPRIL Services,[5] while the wind turbine data is from the American Wind Energy Association web page.

Barriers to Interconnection

Before customer-side distributed generators can be deployed into the national grid beyond their current minimal levels, there are significant barriers to interconnection to overcome. In the National Renewable Energy's report referred to earlier, the following three groups of barriers to interconnection are identified.

1. Technical barriers consist principally of utility requirements to ensure engineering compatibility of interconnected generators with the grid and its operation. Most significant of them are requirements for protective equipment and safety measures intended to avoid hazards to utility property and personnel, and the quality of the power in the system. Proponents of DG allege that utilities demand much higher protection equipment than necessary since newer generating equipment already incorporates technology designed specifically to address safety, reliability, and power quality concerns.
2. Business-practice barriers arise from the contractual and procedural requirements for interconnection and often, the simple difficulty of finding someone within a utility who is familiar with the issues and authorized to act on the utility's behalf. Other significant business-practice barriers included procedures for approving interconnection, application and interconnection fees, insurance requirements, and operational requirements. Lack of uniform standards, procedures, and designated utility points of contact were reported to lead to prohibitively long and costly approval processes.
3. Regulatory barriers are principally posed by the tariff structures applicable to customers who add distributed generation facilities, but include outright prohibition of parallel operation -- that is, any use other than emergency backup when dis-

connected from the grid. According to this report, backup or standby charges were the most frequently cited rate-related barriers in the study. Unless distributed generators want to disconnect completely from the grid, they will be depending on the utility to augment their onsite power. This is the principle reason for interconnection. For small customers, net metering provides credit at the retail rate. For large distributed generating facilities, however, the typically much lower wholesale rates paid are reportedly seen as unfair. Environmental permitting is also cited as a regulatory barrier. This includes inconsistent requirements from state to state and from site to site.

These barriers are a natural result of the traditional industry structure consisting of large central stations owned by a vertically integrated utility with the sole responsibility of ensuring reliable supply in its franchise territory. Since the price is fixed between rate cases, a utility's revenue and hence, profitability, is directly related to its energy sales. Any customer-side distributed generation has the potential to adversely affect the utility's profitability whenever the customer choses to self generate. The utility therefore does not have an incentive to support the deployment of customer-side distributed generation.

Distributed Generation Regulations in the United States

Several stakeholders are working to resolve the barriers and speed up the deployment of distributed resources in the United States. Among the leaders is the Federal government. In 1998, the U.S. Department of Energy established a Distributed Power Program in the National Renewable Energy Laboratory to address system integration issues and market barriers. In 2000 a distributed energy resources task force was launched to "*enhance the effectiveness of research, development, demonstration, education, and implementation activities*." The task force has a vision to ensure that "*by 2020, the United States will supply the cleanest, most efficient and reliable energy in the world by optimizing the use of distributed energy sources*." At the head of this vision is the Taskforce's goal of "meeting 20% of the nation's generating capacity additions with distributed energy sources by the year 2010."[6]

Uniform national interconnection standards are being developed by the Institute of Electrical and Electronics Engineers (IEEE). The process of designing a standard started in 1999 when the IEEE Standards Association voted to undertake its development (IEEE P1547). The U.S. Department of Energy, through the Distributed Power Program, has been funding the IEEE P1547 in an effort to shorten the development cycle by half to about three years.

At the state level, several states have adopted rules to address barriers to interconnecting distributed generators. Texas and New York led the way when they adopted their rules in 1999. Most of the impetus for enacting these rules came in 1998 when it looked like these states would not have enough capacity to cover their peak demands. Delaware followed suit in 2000 and California is credited with having done the most comprehensive study on issues surrounding DG so far. The California Public Utility Commission and the California Energy Commission have issued several rules addressing the various barriers and still others are in the process. Recently, with the anticipated shortages in the summer 2001 and 2002, New York and California are on record as having made temporary rules to allow diesel fired emergency generators installed at various institutions to generate during imminent system emergencies. Although the rules are envisaged as only temporary to help the states make it through the summer, they illustrate the potential for distributed generators for enhancing system reliability during severe capacity shortages. Fourteen other states

Table 8-3. Cost Characteristics of Distributed Generation Technologies

	Product Rollout	Size Range (kW)	Efficiency	Turnkey Cost No Heat Recovery ($/kW)	Heat Recovery Added Costs (W/kW)	Total Capital Cost - With Heat Recovery ($/kW)	O&M Cost ($/kWh)	Fuel Cost ($/kWh)
Diesel Engine	Commercial	20-10,000+	36-43%	350-500	NA	350-500	0.005-0.010	0.04-0.05
Gas Engine	Commercial	50-5,000+	28-42%	600-1000	75-170	675-1170	0.007-0.015	0.02-0.04
Simply Cycle Turbine	Commercial	1000+	21-40%	650-900	100-200	750-1100	0.003-0.008	0.03-0.05
Microturbine	Under Development	30-200	25-30%	600-1100	75-350	675-1450	0.005-0.010	0.03-0.04
Fuel Cell	Under Development	50-1000+	35-54%	1900-3500	Included	1900-3500	0.005-0.010	0.02-0.03
Photovoltaics	Commercial	1+	NA	5000-10000	NA	5000-10000	0.001-0.004	0
Wind Turbines	Commercial		NA	1000 (Ave.)	NA	1000 (Ave.)	0.0065 (Ave.)	0
Combustion Turbines	Current Central-Station Technology	30,000-150,000	32-37%	320-400	NA	320-400	0.0161	0.0282
Combined Cycle	Current Central-Station Technology	100,000-250,000	29-34%	470-550	NA	470-550	0.0109	0.0184
Pulverized Coal	Current Central-Station Technology	30,000-1,000,000	43-47%	1000-1200	NA	1000-1200	0.0070	0.0098

are listed by the DOE Distributed Power Program[7] as having initiated, but not yet completed, formal proceedings to address these issues. These states are Nevada, Utah, Arizona, New Mexico, Illinois, Wisconsin, Michigan, Ohio, West Virginia, Virginia, Massachusetts, New Jersey, Georgia and Florida.

Regulatory Policies that Encourage Distributed Resources

Some modifications to the current regulatory framework would remove the current disincentive for utilities to interconnect distributed resources. The National Association of Regulatory Utility Commissioners (NARUC) in a February 2000 Regulatory Assistance Project[8] presented such a list. Some of these recommendations that are relevant to the industry structure in Indiana are listed below.

- Revenue-Based Performance-Based Regulation. At the top of the list in terms of impact on customer-side distributed resources deployment is revenue-Based Performance-Based Regulation. Although there are many variations to the Performance-Based Regulation model (PBR), the most important distinction as far as distributed resources are concerned is whether the PBR is price based or revenue based. During a fixed period of several years, the price is fixed for a price-based PBR, while the total revenue, or the revenue per customer, is fixed for a revenue-based PBR. The effect of price-based PBR on the incentive for customer-side distributed sources deployment is the same as that under the more traditional cost-of service regulation. Any self-generated energy represents a loss of revenue to the utility. On the other hand, the revenue in a revenue-based PBR is no longer directly related to the sales volume. The total revenue is fixed irrespective of the amount of energy each customer draws from the grid. The utility therefore can be expected to be indifferent to interconnection of customer-side distributed generation. According to the report, an increase in profits in a revenue-based PBR is best brought about by reducing costs and added other customers as efficiently as possible.
- Marginal Costs. The other recommended regulatory modification recognizes that under the traditional average cost pricing systems, the true cost of distribution to an individual customer is hidden. If the marginal cost of distribution was visible to the customer, it would provide incentive for both the utility and the customer to install distributed generation in high distribution-cost areas. However, sending such a price signal without full retail competitive pricing is impractical. Two alternative methods designed to capture many of the benefits of marginal cost pricing within the traditional regulated framework are presented in the NARUC report. They are distribution credits in high-cost areas and distributed resources development zones.

  Under a program of distribution credits, the utility would establish financial credits for distributed resources located in high distribution cost areas. The credit amount would be a function of the distribution cost savings generated by the distributed resources. Credits would be limited in duration and magnitude in order to match the timing and need for distribution system reinforcements. The dollar amount of the credits should, at most, equal the savings derived from deferring a distribution upgrade.

Distributed resources development zones would be high-cost areas within which distributed sources vendors could be encouraged to target customers. Incentives could include direct financial assistance, waiver of standby charges, assistance in contracting with and marketing to customers, and low and or no-cost siting at utility substations and other properties.

- Targeted Incentives for Distributed Resources. Performance-based regulations could be designed with targeted incentives for the deployment of cost-effective distributed resources or distributed resources with particular environmental features. Given that one of the main public benefits of distributed resources is their distribution cost savings, a reasonable incentive would be to allow utilities to keep a share of the savings they bring. If a utility demonstrated that it had reduced its transmission, generation or other distribution costs by installing distributed generation or targeted demand-side investments, they would be allowed to keep some fraction of the savings as a reward. This would be in a similar vein to earlier DSM and energy efficiency programs.

Lessons Learned from the California Crisis

The recent experiences in the California electricity industry have caused many states to reconsider their positions regarding restructuring. It is important for everybody involved in such decision making to examine what happened and determine what lessons can be learned from it. This section includes a brief description of the factors that led to the California crisis and some lessons that can be gained from the experience.

When California restructured its electricity industry in the mid 1990s, steps were taken to ensure that the incumbent utilities could not exercise market power. These steps included forcing the utilities to divest, or sell off, substantial amounts of generation and to limit the amount of generation that they could control through long-term purchases. In exchange for these steps, the utilities were to be allowed to recover the undepreciated portion of their generating assets, which were considered to be stranded costs. This stranded cost recovery was to be accomplished through a fixed rate the utilities would charge their retail customers. The profits resulting from the retail rates less the cost to the utilities of purchasing and delivering the energy were used to pay off the stranded costs. This system worked well for awhile when wholesale power costs were low.

In the period prior to restructuring, growth in electricity usage was low, as California was one of the last states to recover from the slow economy of the early 1990s. In the period after restructuring, growth grew unexpectedly. This caught many people by surprise and contributed to a generation capacity shortage.

During the early period of restructuring, little new generation was proposed. This primarily resulted from a lack of incentive -- the incumbent utilities had been forced to divest some of their generation so they were not looking to build more while the merchant plant generators did not see the high prices that indicate a profit could be made. When high prices were seen in 2000, barriers to new construction were encountered: strong local opposition, environmental restrictions, and heavy regulatory burdens. The effect of these barriers was to increase the time required for new participants to enter the market.

The capacity shortage was further exacerbated by drought conditions that reduced the capability of hydroelectric plants to generate electricity. Additionally, the relatively sparsely connected transmission system made it difficult to bring in large amounts of power from other states.

The capacity shortage, combined with increased natural gas costs and alleged market manipulation by some of the participants caused prices to increase dramatically. The traditional utilities were then forced to buy power at prices much higher than the fixed rates they were allowed to charge their customers. This eventually forced one utility to declare bankruptcy.

Another effect of the capacity shortage has been the frequent institution of rolling blackouts. Rolling blackouts occur when power is cut off to certain regions for a period of time, followed by other regions, until sufficient capacity is available to meet the load.

As more time passes and events continue to unfold in California, a greater understanding of what occurred there will be achieved. However, enough is known at this point to state some general conclusions.

The first lesson is to allow flexibility in the restructuring plan. Circumstances will change over time and a restructuring plan that does not allow for corresponding changes may lead to unintended consequences. Planners and policymakers need to look at both the good and bad scenarios. Often the best strategy is a flexible one that may not be best under any given scenario, but performs quite well over a wide range of scenarios.

The second lesson is to ensure that the proper industry climate exists before restructuring. This climate has at least four clear elements: generation, transmission, customer response, and monitoring. Participants should be allowed to enter or exit the generation market without undue barriers. The operators of the transmission system, be they a regional transmission organization (RTO) or a transmission owner, should have the capability to expand and upgrade the transmission network. A system should be in place that encourages customers to reduce their demand during periods of high prices, either through real-time pricing, DSM, or other means. Finally, a system should be in place that ensures markets are functioning efficiently without excess market power.

The third lesson to be learned is to expect high prices to occur at some point. These prices should be of short duration and are a valuable signal to potential market participants that additional capacity is needed. Persistent low prices do not attract new suppliers to the market. In industries such as electricity where there is a long construction time for new capacity, there can be a longer period of time when high prices are common. The high natural gas prices of last winter are an example of this phenomenon.

Associated with the expectation of high prices is the lesson to allow market participants to reduce their risks. The California utilities were put in a situation where they were forced to purchase power on the short-term spot market at a price much higher than they were allowed to charge their retail customers. This system placed most of the risk burden on the utilities' shoulders. If they had been allowed to hedge their risk, either through owning more of their own generation or by locking in prices on a greater percentage of long-term contracts, they certainly would have been better off.

In response to these issues, the California Public Utilities Commission (CPUC) has suspended retail choice in California. The CPUC estimates that about give person of the state's peak load of 46,000 MW is currently under direct access contracts. Contraces in place will be allowed to continue until their expiration.

Short-Term Economic Outlook

Two of the major inputs to SUFG's electric energy forecasting models are long-term projections of fossil fuel prices and state macroeconomic activity. In preparing this forecast SUFG used a set of fossil fuel prices developed by EIA for their Annual Energy Outlook, which was released in December 2000. The macroeconomic activity projections were developed by CEMR at Indiana University and released in February 2001. Since the fossil fuel price and macroeconomic projections were released there have been significant changes, especially in economic activity. Even though SUFG's projections are focused on the long-term, short-run changes in drivers such as fuel prices and economic activity have some effect on the forecast, especially in the near term.

Fossil fuel prices affect SUFG's energy projections in two ways. First, fossil fuels, especially coal, are a major component in the cost of producing electricity. Second, fossil fuels, especially natural gas, compete with electricity in providing some end-use services such as space and water heating, cooking, and process heat. Thus, fossil fuel prices directly affect electricity consumption through the price of electricity and through fuel competition in end-use services.

EIA's projections for coal prices paid by electric utilities show a gradual decline across the entire forecast horizon of 2000 to 2019, thus missing the increase in coal prices during 200 and 2001. Since SUFG's estimates of electricity prices are directly tied to coal prices, SUFG's electricity price projections may be somewhat optimistic in the near term. EIA's natural gas price projections captured the increase in gas prices during 2000/2001, but gas prices dropped much faster and to a greater degree in 2001 than EIA projected. EIA projected that natural gas prices would decline gradually, leveling out around 2004 in marked contrast to the rapid decline in 2001. Furthermore, the decline in natural gas prices was larger than that projected by EIA. Since one of the determinants of electricity use in SUFG's energy models is the relative price of electricity and natural gas, SUFG's electricity consumption projections are most likely somewhat high since actual natural gas prices dropped more rapidly and father than the projections.

The U.S. economy, which had continued to weaken since the February 2001 CEMR Outlook was released, was shaken further by the September 11 terrorist attacks. All of SUFG's energy forecasting models use various macroeconomic activity measures gas drivers for increases in the size of the consuming base. Specifically, the major drivers are personal income, employment, and gross state product respectively for the residential, commercial, and manufacturing sectors. SUFG expects that the weaker economy coupled with the jolt in September will result in less rapid growth in electricity consumption at least in the near term. Thus, the decline in economic activity could reduce and/or delay the need for Indiana to acquire additional electricity generation resources. However, SUFG still projects a need for additional resources, and that need is likely to increase as the economy recovers from the current weakness and September jolt and returns to a more long-term pattern of sustained growth.

Since SUFG's energy projections are based on the long-term, they do not focus specifically on shorter term economic cycles. Therefore, while this set of projections do not capture all of the effects of the recent economic downturn, the high growth that occurs during the eventual recovery period is not specifically modeling either. In the long run, the cycle tends to even itself out, resulting in electricity use somewhere between the low and high projections shown in Chapter 3.

End Notes

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3. Ibid.

4. National Renewable Energy Laboratory, Department of Energy, *Making Connections; Case studies of Interconnection Barriers and their Impact on Distributed Power Project,* May 2000 http://www.doe.gov/bridge
5. W.C. Stenzel, SEPRIL LLC., *Plant Design, Performance and Cost Comparison Study*, prepared for the Institute for Interdisciplinary Studies, Purdue University, August 1998.
6. U.S. Department of Energy, *Strategic Plan for Distributed Energy Resources*, prepared by the Office of Energy Efficiency and Renewable Energy Office of Fossil Energy, *http://www.eren.doe.gov/der/pdfs/derplanfinal.pdf*.
7. DOE Distributed Power Program, *Status of States Distributed Resource Regulatory Activity*, June 13, 2000, http://www.eren.doe.gov/distributedpower/pages/issue_frame.asp.
8. David Moskovitz, *The Regulatory Assistance Project, Profits and Progress through Distributed Resources*, February 2000.

APPENDIX A
INDIANA ENERGY, SUMMER PEAK DEMAND AND RATES: SOURCES AND PROJECTIONS

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, 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 nondisclosure. All data presented in this report has been aggregated to total Indiana statewide energy, demand and rates to avoid disclosure.

In most instances the source of SUFG's data can be traced to a particular page of a certain publication, e.g., residential energy sales for an IOU 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 in Michigan 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, Fruit Belt Rural Electric Membership Cooperation (REMC), which is located in southern Michigan. 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. Furthermore, for the above four purchasers, SUFG defines IOU requirement sales as well as all other IOU sales as sales-for-resale.

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. For the IOUs and HEREC, the reported summer peak demands are adjusted for non-requirement firm sales to Indiana utilities and for SUFG's classification of the city of Richmond and the city of Jasper as previously discussed.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity and double counting problems. 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. The double counting issue arises due to sales-for-resale by the IOUs and HEREC to IMPA, WVPA and the unaffiliated REMCs and municipalities. To obtain an estimate of statewide peak demand SUFG employs a two-step procedure. First, the summer peak demand estimates for the IOUs and HEREC are added together and adjusted for diversity. Second, an estimate of IMPA and WVPA capacity online at the time of the statewide summer peak demand is added to the diversity adjusted sum of the IOUs and HEREC summer peak demands. This results in a diversity corrected estimate of statewide summer peak demand and avoids double counting.

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 estimate 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, one not-for-profit utility was unable to provide

SUFG with a breakdown of its member's load by sector. SUFG estimated the sectoral load by applying allocation factors derived from recently observed data.

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 2001 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1980	16612	12418	22544	556	52130	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	650	68657	5085	73742	13775
Hist	1991	24215	18580	28141	629	71564	4470	76034	14403
Hist	1992	22916	18556	29540	619	71632	5575	77207	14209
Hist	1993	25060	19627	31562	511	76760	5909	82669	15103
Hist	1994	25176	20116	33395	507	79193	6253	85446	15198
Hist	1995	26510	20646	33659	510	81326	7189	88514	16342
Hist	1996	26833	20909	34920	536	83197	6500	89698	16253
Hist	1997	26792	21295	35499	561	84147	5626	89773	16004
Hist	1998	27745	22158	37052	524	87479	5840	93319	16521
Hist	1999	29238	23089	39020	582	91930	7169	99099	17591
Frcst	2000	29625	23849	40680	582	94736	7380	102116	16383
Frcst	2001	30569	24280	43156	582	98588	7669	106257	17038
Frcst	2002	31161	24977	44425	582	101144	7870	109014	17519
Frcst	2003	31651	25536	44550	582	102319	7975	110294	17739
Frcst	2004	32213	26189	44461	582	103445	8070	111515	17964
Frcst	2005	32918	26904	45344	582	105749	8249	113997	18385
Frcst	2006	33525	27561	46045	582	107713	8405	116118	18748
Frcst	2007	34159	28239	46486	582	109466	8550	118017	19080
Frcst	2008	34797	28976	46948	582	111304	8708	120012	19422
Frcst	2009	35396	29713	47345	582	113035	8857	121892	19756
Frcst	2010	36090	30503	48014	582	115190	9035	124225	20143
Frcst	2011	36778	31290	48467	582	117118	9199	126317	20493
Frcst	2012	37420	32084	48969	582	119056	9362	128418	20795
Frcst	2013	38158	32910	49324	582	120974	9523	130497	21146
Frcst	2014	38939	33812	49994	582	123327	9720	133048	21568
Frcst	2015	39766	34646	50291	582	125285	9876	135161	21912
Frcst	2016	40625	35628	50383	582	127218	10026	137244	22269
Frcst	2017	41471	36584	51111	582	129749	10224	139973	22729
Frcst	2018	42382	37544	51430	582	131939	10403	142342	23133
Frcst	2019	43319	38609	52197	582	134707	10626	145333	23633

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	-0.09	2.91	0.79	2.75	4.55
1990-1995	3.77	3.17	3.52	-4.74	3.44	7.17	3.72	3.48
1995-2000	2.25	2.93	3.86	2.68	3.10	0.53	2.90	0.05
2000-2005	2.13	2.44	2.19	0.00	2.22	2.25	2.23	2.33
2005-2010	1.86	2.54	1.15	0.00	1.73	1.84	1.73	1.84
2010-2015	1.96	2.58	0.93	0.00	1.69	1.79	1.70	1.70
2015-2019	2.16	2.74	0.93	0.00	1.83	1.85	1.83	1.91
1999-2019	1.99	2.60	1.47	0.00	1.93	1.99	1.93	1.49

SUFG 2001 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52130	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	650	68657	5085	73742	13775
Hist	1991	24215	18580	28141	629	71564	4470	76034	14403
Hist	1992	22916	18556	29540	619	71632	5575	77207	14209
Hist	1993	25060	19627	31562	511	76760	5909	82669	15103
Hist	1994	25176	20116	33395	507	79193	6253	85446	15198
Hist	1995	26510	20646	33659	510	81326	7189	88514	16342
Hist	1996	26833	20909	34920	536	83197	6500	89698	16253
Hist	1997	26792	21295	35499	561	84147	5626	89773	16004
Hist	1998	27745	22158	37052	524	87479	5840	93319	16521
Hist	1999	29238	23089	39020	582	91930	7169	99099	17591
Frcst	2000	29625	23848	40678	582	94733	7380	102113	16383
Frcst	2001	30564	24280	43151	582	98577	7669	106246	17037
Frcst	2002	31150	24975	44413	582	101120	7868	108989	17515
Frcst	2003	31597	25191	43958	582	101328	7896	109224	17570
Frcst	2004	32096	25310	43964	582	101952	7951	109904	17704
Frcst	2005	32716	25458	44091	582	102847	8020	110867	17882
Frcst	2006	33233	25544	44495	582	103854	8100	111955	18078
Frcst	2007	33776	25637	44795	582	104790	8178	112969	18265
Frcst	2008	34335	25778	45033	582	105728	8263	113992	18449
Frcst	2009	34842	25899	44905	582	106229	8311	114539	18570
Frcst	2010	35425	26036	44985	582	107029	8381	115410	18721
Frcst	2011	36018	26170	45160	582	107931	8463	116394	18892
Frcst	2012	36546	26301	45265	582	108694	8528	117222	18989
Frcst	2013	37170	26430	45070	582	109253	8577	117830	19105
Frcst	2014	37827	26608	45012	582	110030	8650	118680	19257
Frcst	2015	38498	26733	44985	582	110799	8719	119518	19398
Frcst	2016	39224	26938	44807	582	111551	8786	120337	19549
Frcst	2017	39955	27116	44667	582	112320	8851	121171	19707
Frcst	2018	40710	27274	44679	582	113245	8929	122173	19892
Frcst	2019	41511	27495	44758	582	114346	9025	123371	20107

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	-0.09	2.91	0.79	2.75	4.55
1990-1995	3.77	3.17	3.52	-4.74	3.44	7.17	3.72	3.48
1995-2000	2.25	2.93	3.86	2.68	3.10	0.53	2.90	0.05
2000-2005	2.00	1.32	1.62	0.00	1.66	1.68	1.66	1.77
2005-2010	1.60	0.45	0.40	0.00	0.80	0.89	0.81	0.92
2010-2015	1.68	0.53	0.00	0.00	0.69	0.79	0.70	0.71
2015-2019	1.90	0.70	-0.13	0.00	0.79	0.87	0.80	0.90
1999-2019	1.77	0.88	0.69	0.00	1.10	1.16	1.10	0.67

SUFG 2001 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
Hist	1980	16612	12418	22544	556	52130	5546	57676	11284
Hist	1981	16118	12470	22907	572	52067	5581	57648	11235
Hist	1982	19927	13725	22600	696	56948	4875	61823	10683
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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	650	68657	5085	73742	13775
Hist	1991	24215	18580	28141	629	71564	4470	76034	14403
Hist	1992	22916	18556	29540	619	71632	5575	77207	14209
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Hist	1995	26510	20646	33659	510	81326	7189	88514	16342
Hist	1996	26833	20909	34920	536	83197	6500	89698	16253
Hist	1997	26792	21295	35499	561	84147	5626	89773	16004
Hist	1998	27745	22158	37052	524	87479	5840	93319	16521
Hist	1999	29238	23089	39020	582	91930	7169	99099	17591
Frcst	2000	29625	23849	40682	582	94738	7380	102119	16384
Frcst	2001	30589	24282	43164	582	98617	7671	106288	17044
Frcst	2002	31212	24978	44438	582	101211	7875	109086	17531
Frcst	2003	32036	25825	44590	582	103033	8034	111067	17870
Frcst	2004	32994	26928	45155	582	105660	8249	113909	18359
Frcst	2005	33986	28115	46301	582	108985	8512	117498	18960
Frcst	2006	34790	29257	47105	582	111734	8732	120466	19464
Frcst	2007	35576	30438	48192	582	114788	8986	123774	20020
Frcst	2008	36379	31701	49193	582	117856	9244	127099	20576
Frcst	2009	37161	32972	50182	582	120898	9499	130397	21137
Frcst	2010	38038	34314	51240	582	124174	9770	133944	21721
Frcst	2011	38932	35678	52052	582	127243	10023	137267	22271
Frcst	2012	39777	37062	52804	582	130225	10266	140491	22758
Frcst	2013	40710	38485	53708	582	133485	10532	144017	23341
Frcst	2014	41700	40033	55045	582	137359	10849	148208	24027
Frcst	2015	42729	41512	55981	582	140804	11119	151923	24620
Frcst	2016	43791	43192	56549	582	144114	11378	155492	25212
Frcst	2017	44818	44842	57344	582	147586	11654	159240	25837
Frcst	2018	45925	46535	58536	582	151579	11974	163553	26546
Frcst	2019	47068	48361	59730	582	155742	12310	168052	27286

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	-0.09	2.91	0.79	2.75	4.55
1990-1995	3.77	3.17	3.52	-4.74	3.44	7.17	3.72	3.48
1995-2000	2.25	2.93	3.86	2.68	3.10	0.53	2.90	0.05
2000-2005	2.78	3.35	2.62	0.00	2.84	2.89	2.85	2.96
2005-2010	2.28	4.07	2.05	0.00	2.64	2.80	2.65	2.76
2010-2015	2.35	3.88	1.79	0.00	2.55	2.62	2.55	2.54
2015-2019	2.45	3.89	1.63	0.00	2.55	2.58	2.55	2.60
1999-2019	2.41	3.77	2.15	0.00	2.67	2.74	2.68	2.22

Indiana Base Average Retail Rates (Cents/kWh) (In 1999 Dollars)

Year		Res	Com	Ind	Average
Hist	1980	8.02	8.50	5.90	7.20
Hist	1981	8.21	8.44	6.00	7.27
Hist	1982	9.05	8.91	6.56	7.95
Hist	1983	9.40	8.99	6.61	8.07
Hist	1984	9.48	9.02	6.61	8.08
Hist	1985	9.67	8.96	6.49	8.07
Hist	1986	10.46	9.84	7.12	8.88
Hist	1987	10.06	9.54	6.46	8.38
Hist	1988	9.48	8.74	6.13	7.83
Hist	1989	8.85	7.49	5.59	7.06
Hist	1990	8.34	7.05	5.27	6.63
Hist	1991	7.80	6.61	5.01	6.29
Hist	1992	7.72	6.52	4.87	6.12
Hist	1993	7.28	6.11	4.57	5.76
Hist	1994	7.30	6.09	4.53	5.72
Hist	1995	7.16	6.03	4.35	5.61
Hist	1996	7.14	6.01	4.36	5.59
Hist	1997	7.27	5.93	4.28	5.56
Hist	1998	7.27	5.92	4.25	5.54
Hist	1999	7.05	5.77	4.09	5.37
Frcst	2000	7.01	5.74	4.07	5.31
Frcst	2001	6.79	5.57	3.98	5.14
Frcst	2002	6.51	5.35	3.86	4.95
Frcst	2003	6.50	5.34	3.85	4.96
Frcst	2004	6.37	5.22	3.74	4.86
Frcst	2005	6.18	5.10	3.67	4.74
Frcst	2006	6.17	5.11	3.69	4.75
Frcst	2007	6.17	5.11	3.71	4.76
Frcst	2008	6.16	5.12	3.72	4.77
Frcst	2009	6.12	5.10	3.72	4.76
Frcst	2010	6.09	5.09	3.73	4.76
Frcst	2011	6.09	5.10	3.74	4.77
Frcst	2012	6.06	5.08	3.74	4.76
Frcst	2013	6.03	5.07	3.75	4.76
Frcst	2014	6.00	5.06	3.75	4.76
Frcst	2015	6.04	5.13	3.85	4.84
Frcst	2016	5.94	5.06	3.83	4.79
Frcst	2017	5.89	5.03	3.84	4.77
Frcst	2018	5.86	5.02	3.85	4.77
Frcst	2019	5.81	4.99	3.84	4.75

Average Compound Growth Rates (%)

Year	Res	Com	Ind	Average
1980-1985	3.81	1.05	1.93	2.32
1985-1990	-2.93	-4.67	-4.06	-3.87
1990-1995	-2.99	-3.09	-3.79	-3.27
1995-2000	-0.43	-0.99	-1.31	-1.09
2000-2005	-2.49	-2.31	-2.02	-2.23
2005-2010	-0.28	-0.06	0.28	0.06
2010-2015	-0.16	0.16	0.68	0.33
2015-2019	-0.99	-0.68	-0.08	-0.49
1999-2019	-0.96	-0.73	-0.31	-0.61

Notes:
--Energy-weighted average rates for Indiana IOUs
--Results for the 2001 SUFG low and high scenarios are very similar and not reported

SUFG 2001 Base Total Demand and Supply (MW) for Indiana

Year	Demand	Available Capacity	Additions: Peaking	Additions: Cycling	Additions: Base Load	Retired Penalty	Reserve Margin (%)	
1980	11284	14462	0	0	0	0	28	
1981	11235	14537	75	0	0	0	29	SIGECO adds Broadway CT
1982	10683	15669	0	0	1135	0	47	IMPA, PSI and WVPA add Gibson Unit 5; HEREC adds Merom Unit 2
1983	11744	16506	0	0	993	0	41	HEREC adds Merom Unit 1; NIPSCO adds Schahfer Unit 17
1984	11331	16639	0	0	533	0	47	I&M adds Rockport Unit 1
1985	11030	16639	0	0	0	0	51	
1986	11834	17678	0	0	1109	70	49	IPL adds Petersburg Unit 4; IPL retires Stout Units 1-2; NIPSCO adds Schahfer Unit 18; SIGECO adds Brown Unit 2
1987	12218	17678	0	0	0	0	45	
1988	13447	17678	0	0	0	0	31	
1989	12979	17678	0	0	0	0	36	I&M adds Rockport Unit 2; IMPA adds Trimble County Unit 1
1990	13775	18442	0	0	596	0	34	
1991	14403	18507	0	0	0	0	28	IMPA adds Anderson and Richmond CTs; SIGECO adds Brown CT
1992	14209	18977	220	0	0	0	34	PSI adds Cayuga CT
1993	15103	19128	100	0	0	0	27	IPL adds Stout CT; I&M retires Breed
1994	15198	18885	80	0	0	328	24	IPL adds Stout CT
1995	16342	19010	80	0	0	11	16	PSI adds Wabash River Repowering Project; SIGECO upgrades Culley Unit 3
1996	16253	19216	0	143	27	0	18	
1997	16004	19084	0	0	0	0	19	I&M upgrades Cook Unit 2
1998	16521	19050	0	0	45	0	15	
1999	17591	18920	0	0	0	0	8	I&M long-term firm sale expires
2000	16383	19851	70	0	10	0	21	
2001	17038	20213	50	30	80	0	19	
2002	17519	20577	240	60	270	0	17	
2003	17739	20796	340	80	380	0	17	
2004	17964	20740	720	300	480	0	15	
2005	18385	21290	750	380	600	0	16	I&M long-term firm sale expires
2006	18748	21627	820	520	770	43	15	NIPSCO retires Mitchell gas turbines 9A-9C
2007	19080	21959	820	590	900	70	15	HEREC long-term form sale expires; IPL retires Stout Units 3 and 4
								HEREC long-term firm sale expires; IPL retires Stout gas turbines 1-3;
2008	19422	22351	900	630	1060	88	15	NIPSCO retires Bailly gas turbine 10
2009	19756	22722	1010	740	1250	39	15	IPL retires Pritchard Unit 1
2010	20143	23188	1070	910	1380	99	15	I&M long-term firm sale expires; IPL retires Pritchard Unit 2; NIPSCO retires Michigan City Unit 2
2011	20493	23565	1170	1090	1580	103	15	IPL retires Pritchard Unit 3; NIPSCO retires Michigan City Unit 3
2012	20795	23910	1290	1160	1800	0	15	
2013	21146	24317	1410	1365	2000	118	15	IPL retires Pritchard Units 4 and 5
2014	21568	24822	1595	1445	2240	0	15	
2015	21912	25189	1970	1950	2530	804	15	I&M retires Tanners Creek Units 1-4
2016	22269	25514	2190	1970	2740	125	15	
2017	22729	26059	2315	2080	3050	0	15	
2018	23133	26574	2415	2155	3390	0	15	
2019	23633	27094	2570	2250	3660	0	15	

A

A Priori Beforehand.

Acid Rain Rainfall occurring when atmospheric water vapor combines with oxides of sulfur and nitrogen (from both man-made and natural sources) to form sulfuric or nitric acid. Natural rainfall is slightly acidic due to the presence of carbon dioxide (CO_2) in the atmosphere which forms a mild carbonic acid. If rainfall becomes too acidic, it may cause environmental damage.

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.

Allowance for Funds Used During Construction (AFUDC) Method of capitalizing the cost of money used to build new facilities.

Asset Base Items of value owned by or owed to a business. It represents either a property right or value acquired, or an expenditure made which has created a property right or is properly applicable to the future. Utility assets include: Utility Plant, Other Property and Investments, Current and Accrued Assets and Deferred Debits.

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:

$$\left[\left[\left(\frac{\text{Value of Year 2019}}{\text{Value of Year 2000}}\right)^{\left(\frac{1}{2019-2000}\right)}\right]-1\right] * 100$$

Average Cost The total cost divided by the number of units produced. The average cost method is a method of determining the cost of providing service to the various customer classes. Average cost-of-service figures may be used in setting rates. Average costs are determined with the aid of information gathered in a cost-of-service study. This method of costing, while distinguishing costs between different customer classes, fails to recognize that not all kilowatts and kilowatthours are produced at the same cost within one customer class. For this reason, marginal cost-based rates more accurately reflect the true variable cost of producing the last kilowatthour (See also *Marginal Cost*)

Average Marginal Cost The average, usually weighted by the level of production, of marginal costs incurred at different times or locations.

Avoided Costs The savings in total production costs achieved as a result of reducing total production.

B

Backup or Standby Charge A fee incurred through a contractual arrangement that provides for backup or standby power to be delivered to a customer in the event that the customer owned generation is unavailable.

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 electric 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 Rate That portion of the total electric rate covering the general costs of doing business unrelated to fuel expenses and other variable operating costs.

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

Building Shell Choice The decisions made in building construction regarding the level and type of insulation, windows, air exchange and so forth.

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.

Building Envelope The level and type of building insulation, windows, air exchange, etc. that determine the thermal integrity of the structure.

C

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 as 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 Additions Additions to generating equipment that increase the ability to produce electric energy.

Capacity Factor The ratio, 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:

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

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

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

Capital Intensive A business condition in which a relatively large dollar investment in plant and equipment is required to produce a unit of revenue. The electric utility industry is one of the most capital intensive of all industries. The ratio of capital investment to annual operating revenues for electric utilities is nearly 3 to 1. That same ratio for an average manufacturing facility is about 0.8 to 1.

Certificate of Convenience and Necessity A special permit (which supplements the franchise), commonly issued by a state commission, which authorizes a utility to engage in business, construct facilities, or perform some other service.

Class of Service A group of customers with similar characteristics (i.e., residential, commercial, industrial, sales for resale, etc.) which is identified for the purpose of setting a rate for its service.

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 which 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 tradeable emissions allowances.

Cogeneration (Cogen) The simultaneous production of electric energy and useful thermal energy for industrial and commercial heating/cooling purposes.

Coincidence The occurrence of two or more demands simultaneously. (See also *Diversity*)

Coincidence Factor The ratio of coincident demand to the sum of the individual demands at a specific time, most commonly at the maximum of coincident peak demand.

Coincident Demand The sum of two or more demands which occurs in the same demand interval.

Collusion Usually this refers to a market strategy by some producers to act cooperatively to increase their joint profit. This can be done explicitly so that they are a cartel. However, if they do not meet to have an agreement on collusion, but act implicitly as a cartel, the strategy is called tacit collusion.

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

Combined Heat and Power (CHP) An electric generation unit installation where there is simultaneous generation of electric power and of usable heat, where the usable heat may provide space or water heating, or be used for some other process.

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.

Competitive Bidding A method of purchasing goods or services through a solicitation of bids from competing suppliers. In the electric industry, this term commonly refers to a competitive procurement process for selecting some portions of future electric generating capacity that may include: the publication of a Request for Proposal (RFP) by an electric utility for the purchase of electric generating capacity, electric energy and/or demand-side management products and services; the submission of bids offering to provide such products and services by multiple would be suppliers; and the selection by an electric utility of one or more winning bids, subject to appropriate oversight by a state regulatory commission.

Consumer Price Index A measure of aggregate prices for commodities and services typically purchased by individuals. This index is generally used to gauge the change in average price levels for all commodities. By comparing the change in the price of any commodity to the change in the Consumer Price Index over a period of time, one can estimate the real price change (i.e., the net price change of general inflation in the economy) for that commodity.

Constraint A physical or artificial (such as government policy) condition/boundary that is not allowed to be violated or that must be respected under a normal environment. A typical example is that a power generator is not allowed to produce more power than its rated capacity.

Cooling Degree-Days (CDD) A measure of how hot a location was over a period of time, relative to a base temperature. The cooling degree-days for a single day is the difference between that day's average temperature and the base temperature if the daily average is greater than the base; and zero if the daily average temperature is less than or equal to the base temperature. (See also *Heating Degree-Days*)

Conjectural Variation Model In some cases, producers would like to use production quantity to influence market outcome. However, if one producer uses its production quantity as a means for gaming, it has to speculate how other producers would respond with their production quantities. This speculation of the relative changes of one producer's production quantity change against the quantity changes of the other producers is called conjectural variation. The model used to quantify this speculation is called conjectural variation model.

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.

Correlation (also used as **Correlation Coefficient**) A measure of the linear association between two variables, calculated as the square root of the R^2 obtained by regressing one variable on the other. Correlation values range from -1 to +1. Correlation values close to +1 or -1 show a strong linear relationship between the two variables (either directly or inversely proportional, respectively) while correlation values close to zero show almost no relationship between the variables.

Cost of Service A pricing concept traditionally used as the primary basis for designing electric rate schedules. This concept attempts to correlate utility costs and revenues with the service provided to each customer class.

Covariance An unscaled measure of how closely two variables move together across time or space.

Curtailable Rate A rate which is designed to reduce a utility's peak load requirements by offering a customer a substantial rate discount when its service is interrupted during the utility's peak demand period. Programs using these rates are usually targeted at large commercial and industrial customers who pledge a minimum interruptible load level to be curtailed as directed by the utility during electrical emergencies.

Customer Class A group of customers with similar characteristics (i.e., residential, commercial, industrial, sales for resale, etc.) which is identified for the purpose of setting a rate for electric service.

D

Deflator An index which is used to adjust for the purchasing power of a dollar. (See also *Consumer Price Index*)

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.

Dependent Variables Variables in a statistical model that are causally influenced by other (explanatory) variable or variables.

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.

Dispatch The operating control of an integrated electric system to: (1) assign generation levels to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls: (2) control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures; (3) operate the interconnection; and (4) schedule energy transactions with other interconnected electric utilities.

Distributed Lag An econometric modeling approach to represent a response that is delayed and spread over time.

Distribution The act or process of delivering electric energy from convenient points on the transmission or bulk power system to consumers. Also a functional classification relating to that portion of a utility plant used for the purpose of delivering electric energy from convenient points on the transmission system to consumers, or to expenses relating to the operation and maintenance of distribution plant.

Distribution Curve A statistical curve that defines the probability of all events. An example of a distribution curve, commonly used, would be a normal, or bell-shaped curve.

Diversity That characteristic of a variety of electric loads whereby individual maximum demands usually occur at different times. Diversity among customers' loads results in diversity among the loads of distribution transformers, feeders and substations, as well as entire systems. (See also *Coincidence and Load Diversity)*

Dollar Weighted Average An average calculated for a variable by using monetary values as a weight (as opposed to using physical quantities).

E

East Central Area Reliability Coordination Agreement (ECAR) One of nine regional power groups that comprise the North American Electric Reliability Council (NERC). Formed in 1967, ECAR is made up of 28 major bulk suppliers in eight east-central states serving some 36 million people.

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 Forecasting An approach used in forecasting that utilizes econometric modeling principles.

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.

Elasticity The ratio of the percentage change in one variable to the percentage change in another variable, where *X* and *Y* represent variables and *t* denotes time.

$$Elasticity = \frac{\left(\left(X_t - X_{t-1}\right) / X_{t-1}\right)}{\left(\left(Y_t - Y_{t-1}\right) / Y_{t-1}\right)}$$

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. The index (WSTK) is constructed as follows:

$$\mathrm{WSTK}_t = \frac{\sum_i \mathrm{W_i STK}_{i,t}}{\sum_i \mathrm{STK}_{i,t}}$$

where :

$\mathrm{W_i}$ = [Electricity Consumption by Building Type/Floorspace Stock by Building Type i for Some Year, Currently 1989]

$\mathrm{STK}_{i,t}$ = [Floorspace Stock for Building Type i and Period t, and is computed/ Estimated in the Commercial End-Use Model (CEDMS)]

Electrotechnologies Technologies which depend in some substantial way on electric power.

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 Load Research Load research conducted for electric end-use equipment-specific load. This is done by metering specific usage for individual appliances and machinery.

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.

Endogenous Variable A variable determined within the system of interest.

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.

Energy Policy Act (EPAct) A comprehensive federal act passed in 1992 generally designed to improve the efficiency of energy use in the United States. Some of the more important Titles in EPAct consisted of the following major provisions:

Title I - Energy Efficiency -- requires more stringent standards for building, lighting, industrial and appliance efficiencies and encourages investments by utilities in energy conservation measures.

Title III - Alternative Fuels (General) -- requires the federal government to purchase a specified number of alternative fuel vehicles each year between 1993 and 1995 and to devote an increasing percentage of its fleet vehicle purchases to alternate fuel vehicles. By 1999 and thereafter, 75 percent of fleet vehicle purchases must use alternate fuels.

Title IV - Alternative Fuels (Non-Federal Programs) -- provides for federally-regulated gas and electric company recovery of costs related to research on alternative fuel vehicles. Also provides incentive payments to various states to encourage development of programs designed to encourage use of alternative fuel vehicles and subsidized loans to small businesses that operate fleets and convert or purchase alternative fuel vehicles.

Title V - Availability and Use of Replacement Fuels, Alternative Fuels and Alternative Fueled Private Vehicles -- requires electric utility and alternative fuel providers devote an increasing percentage of their purchases of light duty motor vehicles to alternative fuel vehicles.

Title VI - Electric Motor Vehicles -- provides subsidies for purchase and demonstration of electric motor vehicles and subsidies for research, development or demonstration of electric vehicle infrastructure and support systems.

Title VII - Electricity -- establishes a new legal category of Exempt Wholesale Generators (EWGs) that are exempt from various restrictions of the Public Utility Holding Company Act. This provision allows public utilities to own and operate separate wholesale generating facilities and cogeneration facilities. In addition, utilities are required to provide power marketing agency, or other person generating electric energy for sale for resale.

In addition, some of the other provisions of EPAct revise the rules for nuclear power plant licensing, establish the United States Enrichment Corporation to take over regulation and marketing of enriched uranium, provide funds for research and development of clean coal technologies, as well as funds for research on the health effects of electromagnetic fields and provide a subsidy for electricity produced from renewable sources.

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

Escalation Rate A factor used to reflect the average increase in price levels in a particular period.

Estimate To calculate approximately the extent or amount of.

Exempt Wholesale Generator (EWG) A wholesale power generator that is exempt from the provisions of the Public Utility Holding Company Act (PUHCA). This legal class of companies was created by the Energy Policy Act of 1992 in order to allow registered public utility holding companies, other corporate entities and individuals to own wholesale generating assets that are leased or sell power to non-affiliates without subjecting the owners to regulation under PUHCA.

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. (See also *Independent Variables)*

Externalities An externality occurs when an entity is engaged in an activity that creates harm or benefits for others as a by-product, but that entity does not pay the costs of, or receive compensation for, the harm or benefits created. It is the absence of payment for the effects on others that distinguishes external impacts from those that are internalized.

F

Federal Energy Regulatory Commission (FERC) An independent agency created within the Department of Energy, FERC is vested with broad regulatory authority. Virtually every facet of electric and natural gas production, transmission and sales conducted by private investor-owned utilities, corporations or public marketing agencies was placed under the commission through either direct or indirect jurisdiction if any aspect of their operations were conducted in interstate commerce. As successor to the former Federal Power Commission (FPC), the FERC inherited practically all of the FPC's interstate regulatory functions over the electric power and natural gas industries.

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.

Fuel Share Model A Logit model used to determine the choice of space heating fuel in SUFG's econometric residential model.

Functional Category Categories in which the investment and cost of utility plant, i.e., production plant, transmission plant, etc. may be assigned for rate making purposes.

G

Gaming Models In this report, gaming is limited to commercial market gaming. Thus, gaming models are mathematical models for simulating different market gaming strategies.

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) One 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 National Product (GNP) The total dollar value of market oriented goods and services produced by the economy. When the proper accounting adjustments are made, this is equivalent to adding up total income and taxes in the economy in a country; or total sales or purchases or the total value of each industry's output.

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

H

Headship Rate The percentage of the population that are heads of households, or equivalent; the inverse of the number of occupants per household.

Heat Rate A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatthour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatthour generation.

Heating Degree-Days (HDD) A measure of how cold a location was over a period of time, relative to a base temperature. The heating degree-days for a single day is the difference between the base temperature and the day's average temperature if the daily average is less than the base and zero if the daily average temperature is greater than or equal to the base temperature. (See also *Cooling Degree-Days)*

Heterogeneity Consisting of dissimilar ingredients.

Holding Company, (Electric Utility) Usually means a Corporation (Parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies. As most states do not permit a foreign utility company (i.e., one which operates in another state) to operate within their own boundaries, the holding company type of organization is used to bring into one family, consistent with state law, companies that can best be operated as part of an integrated utility system.

Homogeneity Of the same or a similar kind of nature.

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

I

Implicit Price Deflator The economy's aggregate price index. Defined as the ratio of nominal GNP to real GNP.

Incentive Rate A rate or rate discount that is designed to induce specific actions by customers. For example, utilities in several states give incentive rates to the customers to have their air conditioners controlled.

Independent Variable A variable that is assumed to be determined by forces external to a model and is accepted as given data.

Inelastic This is related to price elasticity of demand in this report. Price elasticity of demand is defined as the ratio of the relative change of demand divided by the relative change of price. If this ratio is greater than -1.0 but less than zero, the demand is said to be inelastic.

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

Innovative Rate A rate schedule with rates above or below the associated costs of providing service to the customer. A promotional rate establishes a pricing level which permits sales to be made which otherwise would not occur.

Input Information fed into a system.

Integrated Resource Planning A process by which utilities and regulatory commission assess the cost of and choose among various resource options. (See also *Least Cost Plan)*

Intermediate Run A period of time sufficient to allow some change in the input utilization in production, but of insufficient length to allow the variation of all inputs, especially capital. (See also *Short Run* and *Long Run)*

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, commercial 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.

Internally Consistent Used to mean logical coherence among things or parts in a system. Emphasis is placed on consistency in macroeconomic forecasting.

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.

K

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.

L

Least-Cost Plan A plan describing the mix of generating resources and improvements in the efficient production and use of electricity that will meet current and future needs at the lowest cost to the utility and its ratepayers.

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

Load Duration Curve A graph of the amount of time during a period that electric power demand on a system is at a particular level. Demands usually are ordered and plotted from highest to lowest with hours in the year on the horizontal axis and demand in Kilowatts on the vertical axis. The load duration curve is used in planning an electric system because it indicates how many hours in a year the system must be able to supply each of the varying levels of demand.

Load Factor The ratio, expressed as a percentage, of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor also may be derived by dividing the kilowatthours in the period by the product of the maximum demand in kilowatts and the number of hours in the period.

$$Load\ Factor = \frac{Average\ Demand}{Peak\ Demand} X\ 100\% \quad or$$

$$Load\ Factor = \frac{Energy}{Peak\ Demand\ X\ Time} X\ 100\%$$

Load Profiles, Hourly A curve on a chart showing power (kilowatts) supplied plotted against time of occurrence, illustrating the varying magnitude of the load during the period covered.

Load Research Analysis of electric usage data to understand customer usage patterns and responses to electric utility initiatives.

Load Shape The time-of-use pattern of resource use over time, such as a daily 24 hour pattern or an annual 8,760 hour pattern.

Load Shape Forecasting Projections of changes in customer usage patterns during different periods in a time interval such as seasonal or hourly.

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* and *Intermediate 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.

M

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.

Market Clearing The matching of the last unit of product a specific seller is willing to sell with the last unit of product a specific purchaser is willing to buy.

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

Market Gaming An opportunist behavior by either the producers or the consumers or both to artificially influence the production, consumption and prices of a market. Usually, producers can use production quantity or price or both as gaming tools. This term is often used against the term of perfect competition in economics such that market price, quantity and the revenues of the different producers are manipulated and are away from the perfect market outcome.

Market Power refers to the capability of any individual consumer or producer to influence market quantity and price that depart from the optimal quantity and marginal cost. A group of consumers or producers or both can establish market power by a collective effort.

Marginal Revenue The revenue received from the sale of the incremental production of a good or service.

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.

Mill One mill is equal to one-tenth of a cent.

Mix Effect Combined effects of more than one factor.

Money Supply (M2) Currency and demand deposits (checking accounts) and time deposits (savings accounts).

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.

N

Naturally Occurring Conservation The reduction in energy consumption due to increases in fuel prices and equipment efficiency.

Nominal An adjective that describes any monetary magnitude measured in current prices. For example, Nominal Total Personal Income is the current dollar value of Total Personal Income through time not adjusted to reflect the general levels of price increase in the economy through time.

Non-Coincident Demand The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as day, week, month, heating or cooling season and usually for no more than one year.

Non-Firm Purchase Power or power-producing capacity supplied or available under a commitment having limited or not assured availability.

Non-Stochastic Error Systematic errors that arise due to the use of inappropriate statistical techniques, independent or dependent variable measurement errors and the specification of erroneous function forms.

Non-Utility Generation Generation by producers having generating plants for the purpose of supplying electric power required in the conduct of their industrial and commercial operations. Generation by mining, manufacturing and commercial establishments and by stationary plants of railroads and railways.

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.

O

Open Access FERC directive, which requires utilities that own and/or operate bulk electric transmission to offer transmission service to any wholesale seller or purchaser at the same cost and under the same conditions that the owner/operator charges and requires of itself.

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

Optimization Procedure A procedure that generates a most effective and/or efficient solution.

P

Payback Requirement Requirement for the sum of the net savings from a project to equal the initial investment in a specific length of time.

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.

Peak Power Power that is generated or purchased by a utility to satisfy the peak demand.

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.

Performance-Based Regulation (PBR) Regulatory approaches, which provide utilities with a fixed price (price based) or a fixed level of revenues (revenue based), as opposed to a predetermined level of profits allowed under traditional cost-based regulation. Under PBR, utilities are allowed to earn profits that depend on their operating efficiency.

Personal Consumer Expenditure Expenditures by consumers using personal income.

Power Exchange A market institution in which a third party determines electricity market clearing prices by equating the buyers bids with the sellers offers such that the quantity of electricity offered for sale meets the demand for electricity

Power Flow The various paths over which power travels from the generator to the consumer. These paths are determined by laws of nature. Also called load flow.

Power Pool Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Price Elasticity (Elasticity of Demand) The ratio of the percentage change in demand for a good to the percentage change in the price of that good. Demand is elastic when the absolute value of the ratio exceeds 1.0 and inelastic when it is less than 1.0. (See also *Elasticity)*

Price Index A weighted average of prices in the economy at a given time, divided by the prices of the same goods in a base year. An index used to indicate the change in the average price levels during a particular period.

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.

Public Utility Regulatory Polices Act of 1978 (PURPA) Federal legislation designed to encourage conservation and alternative sources of electricity generation.

Q

Qualifying Facility (QFs) An individual (or corporation) who owns and/or operates a generating facility, but is not primarily engaged in the generation or sale of electric power. QFs are either small power production or cogeneration facilities that qualify under Section 201 of PURPA. (See also Cogeneration.)

R

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

Rate Impact Measure (RIM) Measure of the distribution of equity impacts of DSM programs on non-participating utility ratepayers. From this perspective, a program is cost effective if it results in net benefits for non-participating customers.

Rate of Return The ratio of allowed operating income to a specified rate base expressed as a percentage.

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.

Real Gross Domestic Product (RGDP) Real GDP is the figure derived by deflating each component of GDP for the general level of increase in prices in the economy.

Real Gross National Product (RGNP) Real GNP is the figure derived by deflating each component of GNP for the general level of increase in prices in the economy.

Real Gross State Product (RGSP) Real GSP is the figure derived by deflating each component of GSP for the general level of increase in prices in the economy.

Real Personal Income The income received by a person from all sources (interest, wages, transfers) adjusted for the general level of increase in prices in the economy.

Real Wage The monetary value of wages divided by the level of output prices. The real wage measures the payment for a unit of labor in terms of real goods and services.

Rebar Reinforcing rod, commonly used in concrete structures.

Reestimation To estimate the relationship between dependent and independent variables again (possibly using different time intervals and/or more recent data).

Regional Transmission Group (RTG) A voluntary organization of transmission owners, transmission users and other entities interested in coordinating transmission planning, expansion, operation and power usage within a region.

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.

Reliability Council -- North American Electric Reliability Council (NERC) A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all the power regional of the contiguous United States, Canada and Mexico.

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

$$Reserve\,Margin = \frac{Rated\,Capacity - Peak\,Load}{Peak\,Load} X\,100\%$$

Restructuring The process of moving from a regulated business environment to a competitive one. (See also *Competition*)

Retail Wheeling An unbundled transmission or distribution service that delivers electric power sold by a third-party directly to end users. This service would allow a retail customer to buy power from someone other than the franchised local utility, but still receive delivery using the power lines of the franchised local utility.

Revenue Requirement The sum total of the revenues required to pay all operating and capital costs of providing service.

Rural Electrification Administration (REA) A credit agency of the U.S. Department of Agriculture which assisted rural electric and telephone utilities in obtaining financing. REA was established by Executive Order No. 7037 of May 11, 1935 and given statutory authority by the Rural Electricity Act of 1936. Abolished by Secretary of Agriculture memorandum 1010-1 (October 20, 1994). (See also *Rural Utilities Service*.)

Rural Utilities Service (RUS) Established on October 20, 1994, by the Secretary of Agriculture as successor to the REA as mandated by the Department of Agriculture Reorganization Act of 1994 (Pub. L. 103-354, 108 Stat. 3178). RUS assigned responsibility for administering electric and telephone loan programs previously administered by the REA.

S

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.

Scarcity Value The difference between the price a consumer is willing to pay for a commodity and the marginal cost of producing the commodity when the demand for the commodity exceeds the available supply.

Scrubber A device that uses a liquid spray to remove aerosol and gaseous pollutant from an air steam. The gases are removed either by absorption or chemical reaction. Solid and liquid particulates are removed through contact with the spray.

Sectoral Classification of Prices and Quantities For this report, commercial, industrial and residential sector prices are based on tariffs (rates) as specified in the various utilities "FERC Form 1: Annual Report of Major Electric Utilities, Licensees and Others," pages 300-301, lines 2 through 5, page 304. Price projections are performed using LMSTM based on data described in Appendix A. The allocation of energy between commercial and industrial demand is based primarily on SIC codes. The exception is SIGECO which does not provide energy by SIC. SUFG, instead, uses the split based on information provided in SIGECO's FERC Form 1. Indiana Michigan Power Company provides the historical data for its commercial and industrial demand for Indiana only. Residential energy calibration data for all utilities is based on FERC Form 1 data.

Service Area Territory in which a utility system is required or has the right to supply electric service to ultimate customers.

Single-Factor Demand Models A model in which output is projected based on a single factor input.

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 also *Intermediate Run* and *Long Run*)

Specification Error An error which occurs when the wrong relationship is used to estimate a statistical model.

Spinning Reserve Generation capacity committed at some time in excess of the system load projected for that time period, usually expressed as a percentage of the system load.

Standard Deviation A measure of the dispersion or variability of a variable around the arithmetic average. It is defined as:

$$\sqrt{\frac{\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2}{n-1}}$$

where:

x_i denotes observations of variable x,

$\bar{x}$ denotes the mean of the observations of variable x; and

n is greater than 1.

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).

State Plan A resource expansion plan for the state of Indiana that projects required resource allocations and expenditures to reliably meet projected future electricity demand.

Stochastic Random.

Stochastic Error Difference between the estimated and true model.

Stranded Cost/ Benefit The difference between

(1) the revenues that utilities would receive in the future to compensate them for the costs of historical investments and contractual obligations pursuant to regulatory institutions prevailing when the commitments were made, and

(2) the revenues that they will receive in the future when generation services are sold in a competitive market.

When (1) is greater than (2), the amount is called a stranded cost; conversely, when (2) is greater than (1), it is referred to as a stranded benefit.

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).

System Load Impact The effect on a system's annual maximum demand due to items such as DSM.

T

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

Total Resource Cost Test (TRC) Measures the difference between the net present value of the total costs of a DSM program (including costs incurred by the utility and the participant) and the avoided costs (i.e., benefits) of utility supply due to the DSM program. From this perspective, a program is cost effective if the avoided supply costs exceed the total program costs.

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.

U

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.

Undiscounted Sum of Operation & Maintenance (O&M) Summation of future projected amounts for operation and maintenance expenses without using a discount factor for the amount in the future years. A discount factor reflects the time value of money.

Unit Emission Rate Amount of air pollutants emitted into a community's atmosphere in amounts per day.

Utilization Factor The ratio of the maximum demand of a system (or part of a system) to the rated capacity of the system (or part of the system) under consideration.

V

Variable Cost The out-of-pocket costs incurred in producing a good or service.

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.

W

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.

Weather-Normalized Projections Energy use or peak demand projections made under the assumption of normal weather patterns over the projection period.

Wellhead Price of Natural Gas The price of natural gas at the source, excluding transportation cost.

Wheeling An electric utility operation wherein transmission facilities of one system are used to transmit power produced by another system.

Winter Peak Demand The greatest load on an electric system during any prescribed demand interval in the winter (or heating) season, usually between December 1 of a calendar year and March 31 of the next calendar year (north of the equator).

World Oil Price The price of crude oil excluding transportation and refining costs.

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LIST OF ACRONYMS

AEP	American Electric Power
Btu	British Thermal Unit
CEMR	Center for Econometric Model Research
CG&E	Cincinnati Gas & Electric Company
CAAA	Clean Air Act Amendments
CC	Combined Cycle
CT	Combustion Turbine
CEDMS	Commercial Energy Demand Modeling System
CHP	Combined Heat and Power
DG	Distributed Generation
DSM	Demand-Side Management
DOE	Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EMI	Econometric Model of Indiana
EPRI	Electric Power Research Institute
EIA	Energy Information Administration
EPACT	Energy Policy Act of 1992
EUI	Energy Utilization Indices
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
GWh	Gigawatthours
GDP	Gross Domestic Product
GSP	Gross State Product
HVAC	Heating, Ventilation and Air Conditioning
HELM	Hourly Electric Load Model
HEREC	Hoosier Energy Rural Electric Cooperative, Inc.
IBRC	Indiana Business Research Center
INDEPTH	Industrial End-Use Planning Methodology
I&M	Indiana Michigan Power Company
IMPA	Indiana Municipal Power Agency
IUPUI	Indiana University Purdue University, Indianapolis
IURC	Indiana Utility Regulatory Commission
IPL	Indianapolis Power & Light Company
INFORM	Industrial End-Use Forecast Model
IRP	Integrated Resource Plan
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatthours
LMSTM	Load Management Strategy Testing Model
MW	Megawatt
MWh	Megawatthours
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
mmBtu	Million British Thermal Unit
M2	Money Supply
NO_x	Nitrogen Oxides
NERC	North American Electric Reliability Council
NIPSCO	Northern Indiana Public Service Company
NFP	Not-for-Profit
ORNL	Oak Ridge National Labs
OASIS	Open Access Sametime Information System
O&M	Operation and Maintenance
OPEC	Organization of Petroleum Exporting Countries
PBR	Performance-Based Regulation
PJM	Pennsylvania-Jersey-Maryland Power Pool
PURPA	Public Utility Regulatory Policies Act of 1978
PSI Energy	PSI Energy, Inc.
PC	Pulverized Coal-Fired
REEMS	Residential End-Use Energy Modeling System
REMC	Rural Electric Membership Cooperative
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
SIPC	Southern Illinois Power Company
SIGECO	Southern Indiana Gas & Electric Com pany
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
SO_2	Sulfur Dioxide
TAG	Technical Assistance Guide
TEEMS	Technology-Based End-Use Energy Modeling System
T&D	Transmission and Distribution
WVPA	Wabash Valley Power Association