Indiana Electricity Projections: The 2023 Forecast

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Foreword

This report presents the 2023 projections of future electricity requirements for the state of Indiana for the period 2022-2041. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the nineteenth set of projections.

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

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

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

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. With the exception of the upgrades described in Chapter 2, details on the operation of the modeling system are limited; for more detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

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

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

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

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Chapter 1

Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its nineteenth set of projections of future electricity usage, peak demand, prices and resource requirements. The projections in this forecast are higher than those in the 2021 forecast and lower than those previous to that.

This forecast projects electricity usage to decrease slightly through 2027, then grow through the remainder of the forecast period, with overall growth at a rate of 0.51 percent per year over the 20 years of the forecast. Peak electricity demand is projected to follow a similar pattern with overall growth at an average rate of 0.40 percent annually. This corresponds to about 85 megawatts (MW) of increased peak demand per year.

The 2023 forecast predicts Indiana electricity prices to continue to rise in real (inflation-adjusted) terms through 2027 and then level off. Several factors determine the price projections. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production.

This forecast indicates that the additional resources are needed throughout the forecast period. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. The resources selected in this forecast are a mix of natural gas-fired combined cycle units, wind, solar and battery storage capacity. Natural gas combined cycle and wind resources are added first, while battery storage and solar are not added until 2025 and 2029, respectively. In the long term, the projected required additional resources are higher than in previous forecasts, due to more scheduled retirements of existing units and a higher peak demand projection.

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

Outline of the Report

The current forecast includes projections of electric energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial and industrial. Chapter 2 of the report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts. Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price. Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections for each major consumption sector in the state under three scenarios.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.

- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

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

The Regulated Modeling System

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

To determine future resource requirements, SUFG used individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization (RTO) to determine the reserve requirements in this forecast. Beginning with this forecast, SUFG is modeling seasonal reserve requirements rather than annual reserves. These requirements are based on the installed capacity value of the resources, with a modification for the capacity credit for intermittent resources. Applying the individual reserve requirements and adjusting for seasonal peak load diversity[1] among the utilities provides statewide reserve requirements of approximately 18.0 percent for summer, 25.6 percent for fall, 39.5 percent for winter and 37.8 percent for spring.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables. A summary of these assumptions follows.

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 2023 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 0.68 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 0.57 percent.

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

Other key economic projections from CEMR are:

- Real personal income (a residential sector model driver) is expected to grow at a 1.24 percent annual rate.
- Non-manufacturing employment (the primary commercial sector model driver) is expected to average a 0.77 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 1.14 percent real annual rate.

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

Demographic Projections

The projection for population growth in Indiana is 0.29 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.19 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the March 2023 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: Natural gas prices are projected to decline in the short run and slowly increase from about $2.50/mmBtu to $3/mmBtu over the rest of the forecast horizon.

Utility Price of Coal: Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatt-hours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 0.51 percent, while the growth rate for peak demand is 0.40 percent. The growth rates in the 2021 forecast for electricity requirements and peak demand were 0.21 and 0.02 percent, respectively. The 2023 forecast grows more quickly than the previous ones, primarily due to electrification, including growth in the number of electric vehicles, and lower projected electricity prices. Additionally, projected utility-sponsored energy efficiency is lower in this forecast.

Higher growth is seen in the residential and commercial sectors, while the projection for the industrial sector is lower. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial and industrial sectors.

The growth in peak demand is also higher than in the 2021 forecast. The projections of peak demand are for normal weather patterns. Another measure of peak demand growth can be obtained by considering the year-to-year MW load change. In Figure 1-2, the annual increase is about 85 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2021 and 2019 Projections)

Sector	Current (2022-2041)	2021 (2020-2039)	2019 (2018-2037)
Residential	1.28	0.61	0.45
Commercial	-0.19	-1.02	-0.10
Industrial	0.20	0.53	1.26
Total	0.51	0.20	0.67

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Utility-sponsored energy efficiency is netted from the demand projection and supply-side resources are added as necessary to maintain the seasonal reserve margins. Demand response loads are treated as an existing resource that can be called on to meet the peak load.

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored energy efficiency programs. Incremental energy efficiency programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 160 MW at the beginning of the forecast period and by about 940 MW at the end of the forecast. It should be noted that this represents a lower impact than in the 2021 SUFG forecast. Energy efficiency projections were estimated from utility integrated resource plan filings and from information collected directly from the utilities by SUFG.

These energy efficiency projections do not include the demand response loads, which are projected to remain between 800 MW and 1000 MW over the forecast horizon. See Chapter 4 for additional information about utility-sponsored energy efficiency and demand response.

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

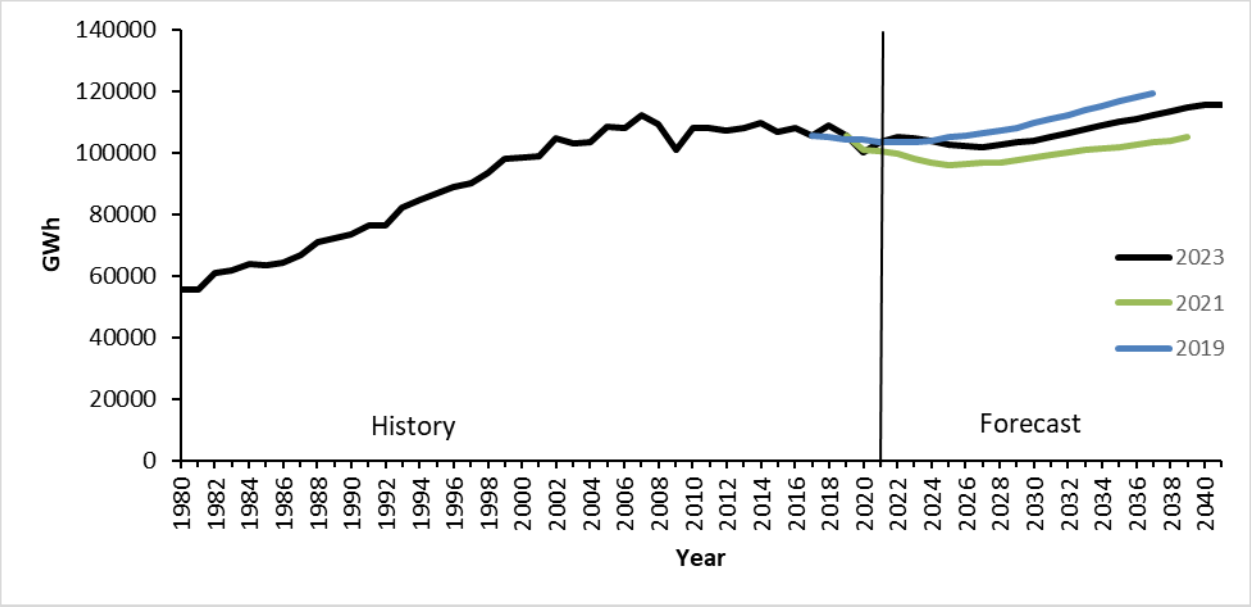
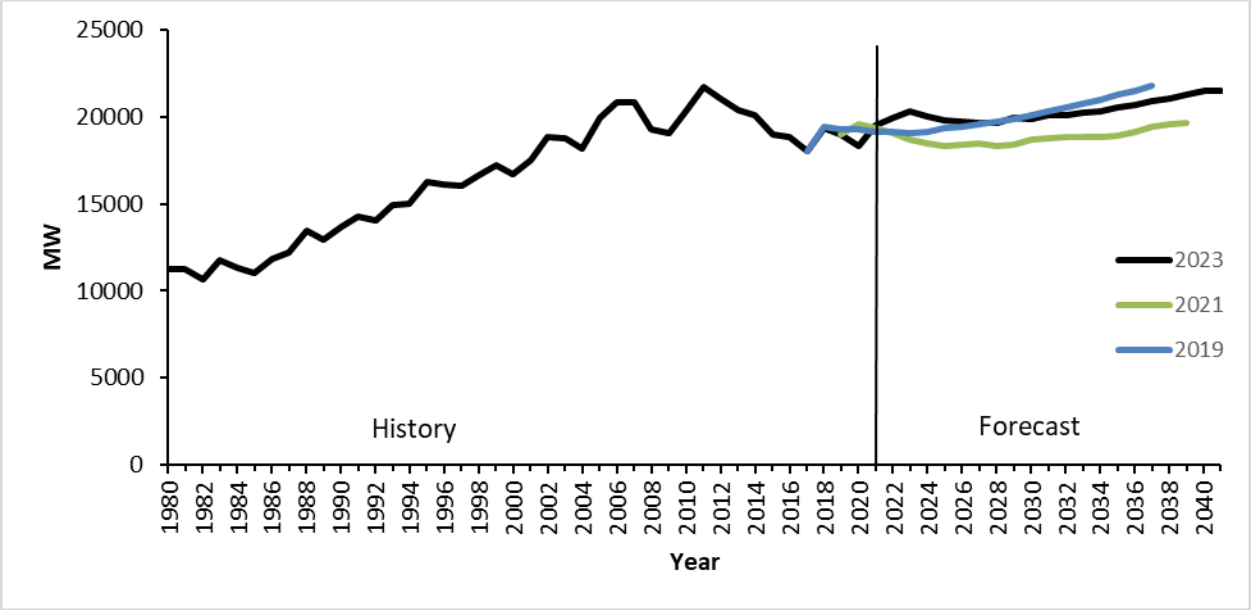


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Supply-Side Resources

SUFG's base resource plan includes all planned capacity changes at the time the model inputs were finalized[2]. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits, changes in the amount of demand response

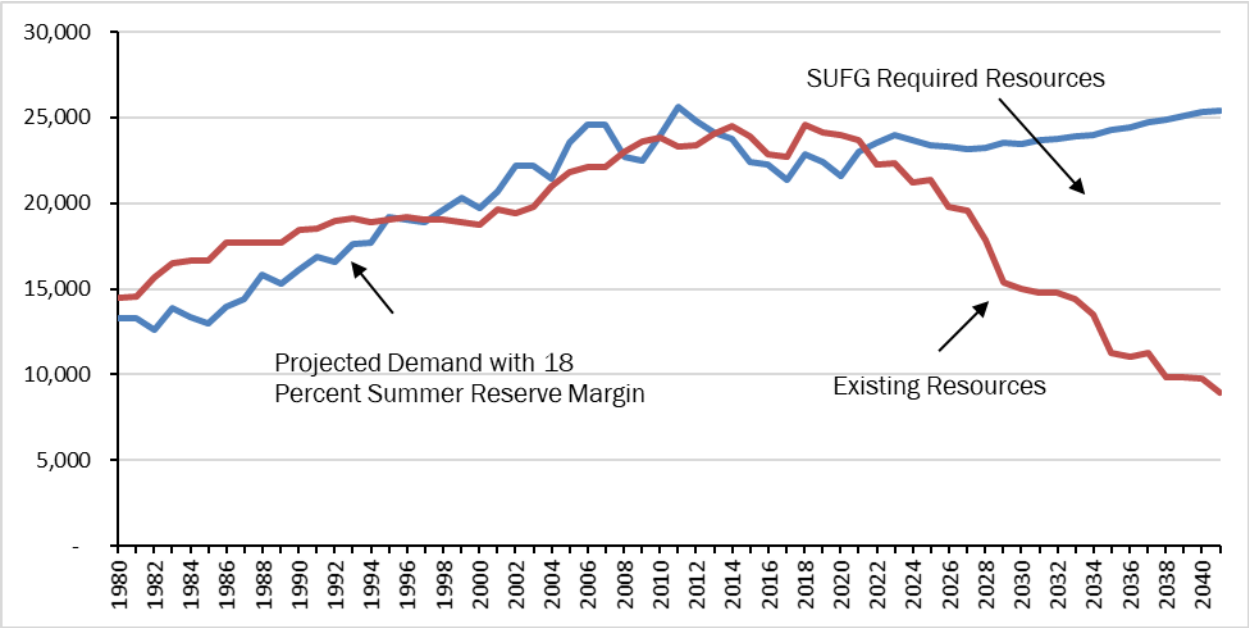
[2] The inputs to the model were finalized in the summer of 2023. As of the time that this report was published, about 1,000 MW of additional wind and solar projects have been approved by the IURC. Also, the retirement of one large coal-fired unit, Gibson 5, has been postponed since the inputs were finalized. The impact of those changes would be to reduce or defer some of the resource additions selected by Aurora.

that is available, 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 new generation resources are then selected by a resource planning optimization model to find the lowest cost of meeting demand while meeting the seasonal reserve margins.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. This forecast indicates that additional resources are needed throughout the forecast period. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. It should be noted that in most years, the Aurora model is adding more new resources than what is strictly necessary to meet the seasonal reserve requirements. This is because the model finds it to be more economical to add additional wind and solar, especially to take advantage of tax credits when they are available. This forecast indicates a need for a mix of natural gas-fired combined cycle units, wind, solar and battery storage capacity. Natural gas combined cycle and wind resources are added first, while battery storage and solar are not added until 2025 and 2029, respectively. While no natural gas-fired combustion turbine resources were selected in the final forecast run, some were selected in earlier iterations and some were selected in the final versions of the low and high scenarios. New coal and nuclear options were never selected. In the long term, the projected required additional resources are higher than in previous forecasts, due to more scheduled retirements of existing units and a higher peak demand projection.

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



Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data was 2021. Therefore, 2022 and 2023 numbers represent projections.

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

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]					
					CT	CC	Wind	Solar	Battery	Total
2022	19,955	22,284		1,261	0	1,415	0	0	0	1,415
2023	20,317	22,302	19	1,670	0	2,345	0	0	0	2,345
2024	20,051	21,198	-1,104	2,458	0	2,345	3,547	0	0	5,893
2025	19,847	21,374	176	2,038	0	2,345	6,076	0	353	8,774
2026	19,742	19,766	-1,608	3,522	0	2,345	6,693	0	824	9,862
2027	19,649	19,559	-207	3,619	0	3,363	6,819	0	824	11,006
2028	19,679	17,876	-1,683	5,336	0	4,811	8,072	0	824	13,707
2029	19,933	15,354	-2,523	8,159	0	5,541	8,928	304	1,397	16,171
2030	19,889	15,034	-320	8,427	0	5,541	8,928	9,805	1,604	25,879
2031	20,086	14,817	-217	8,877	0	5,541	8,942	10,343	1,604	26,430
2032	20,112	14,804	-13	8,920	0	5,952	8,942	10,773	1,630	27,297
2033	20,293	14,389	-416	9,549	0	6,461	8,942	10,773	1,632	27,808
2034	20,356	13,503	-886	10,509	0	7,284	8,942	10,773	1,652	28,651
2035	20,574	11,294	-2,209	12,974	0	9,939	8,942	11,033	1,652	31,566
2036	20,722	11,042	-252	13,401	0	10,255	8,942	11,095	1,652	31,944
2037	20,955	11,299	258	13,419	0	10,490	8,942	11,180	1,652	32,264
2038	21,091	9,845	-1,454	15,033	0	12,220	8,942	11,315	1,652	34,129
2039	21,312	9,838	-7	15,301	0	12,471	8,942	11,455	1,652	34,520
2040	21,489	9,810	-29	15,538	0	12,608	8,942	11,724	1,652	34,926
2041	21,532	8,965	-844	16,434	0	13,356	12,000	11,735	1,864	38,955

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.

Equilibrium and Price Impact

Real prices are projected to increase by 27 percent from 2021 to 2028 and then level off until the end of the forecast period. While prices are affected by a number of different factors, the change in prices early in the forecast results primarily from the significant capital investment in transmission, distribution, and newly approved generation that is modeled in the first few years.

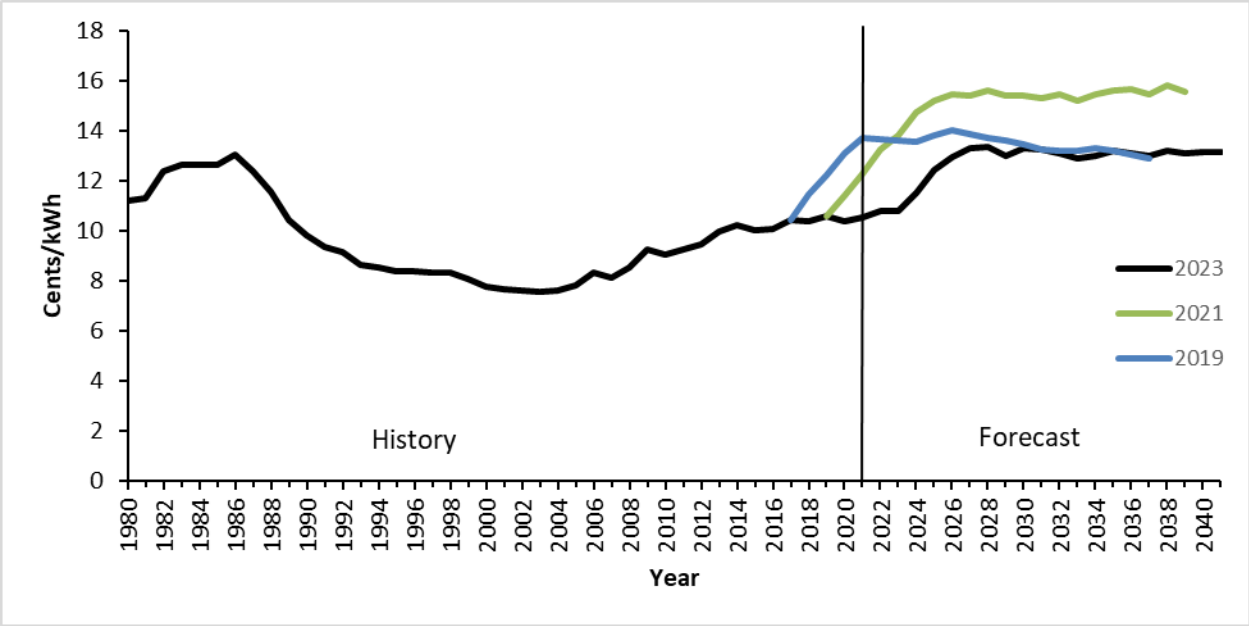
While the price increase is smaller than in the previous forecast, it is still significant. This affects the electricity requirements projection for this portion of the forecast period. Electricity prices are an input to the forecasting models, so the price increases in the early years cause projected sales to decrease. In turn, this can cause further price increases if sales decline more than revenue requirements.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2019" is the base case projection from SUFG's 2019 forecast report and

the one labeled "2021" is the base case projection from SUFG's 2021 report. For the prior price forecasts, SUFG rescaled the original price projections to 2021 dollars (from 2017 dollars for the 2019 projection, and from 2019 dollars for the 2021 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

A number of factors determine the differences among the price projections in Figure 1-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

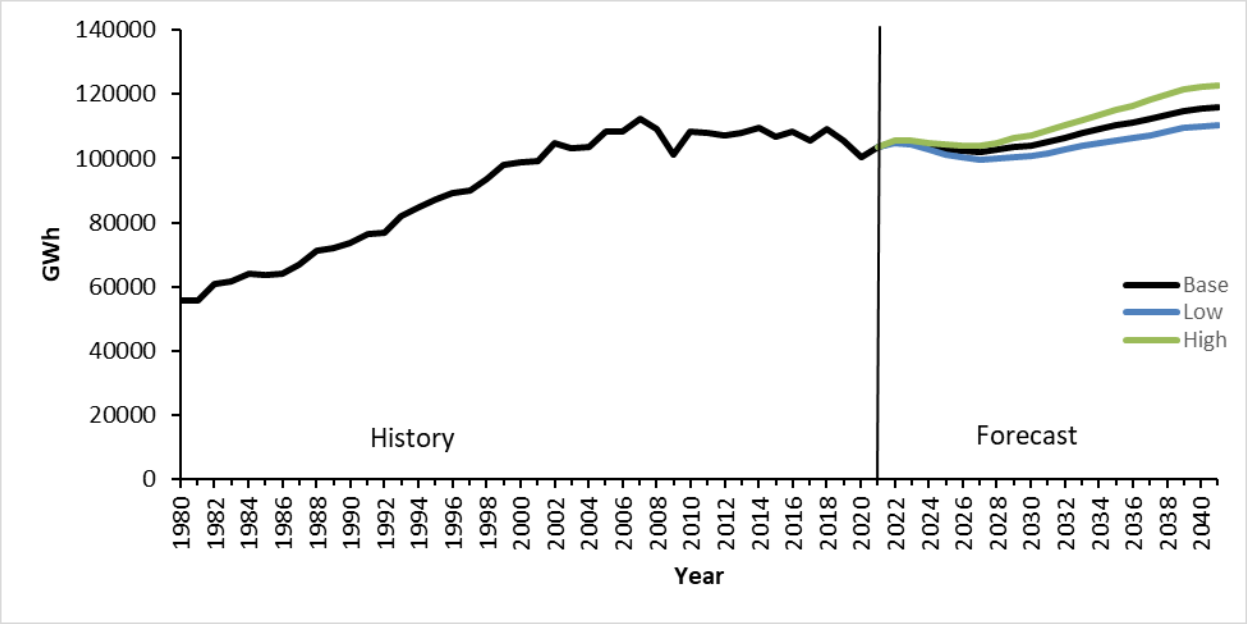
Figure 1-4. Indiana Real Price Projections in cents/kWh (2021 Dollars) (Historical, Current, and Previous Forecasts)



Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 0.51, 0.27, and 0.79, respectively. These differences are driven by economic growth assumptions in the scenario-based projections and differences in assumed growth of electric vehicles. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

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



Chapter 2

Overview of the SUFG Electricity Modeling System

Modeling System Changes

For this forecast, SUFG incorporated seasonal reserve requirements consistent with the Midcontinent Independent System Operator (MISO) seasonal capacity construct. For this, monthly reserve requirements were determined using a similar process to the one SUFG has used previously for annual requirements. A more detailed explanation can be found in the Reserve Requirements section of this chapter.

Also, SUFG specifically incorporated projected impacts of electric vehicles (EVs). An overview of the EV forecasting methodology can be found in the Electric Vehicle Projections section of this chapter.

Finally, the tax credits that are available through 2032 as a result of the Inflation Reduction Act of 2022 are modeled in this forecast. Since SUFG lacks the information necessary to determine whether utilities will receive bonus credits[1] or reduced credits[2], the standard credits are modeled.

Regulated Modeling System

The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various models until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics.

A distinctive characteristic of the modeling system is its ability to capture the interaction between future electricity demand and electricity prices through an iterative process. During each cycle of the process, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the utility finance & rates model to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the models until equilibrium is attained as is illustrated in Figure 2-1.

[1] Bonus tax credits are available for meeting domestic content criteria, locating in an energy or environmental justice community and for locating in a low-income economic development project.
[2] The available tax credit rate is reduced for failing to meet prevailing wage and apprenticeship conditions.

Figure 2-1. Cost-Price-Demand Feedback Loop

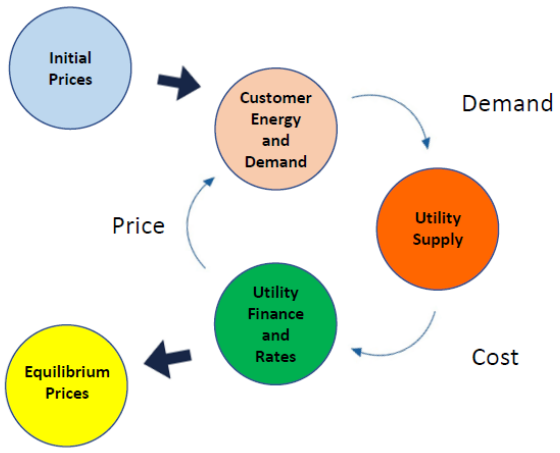
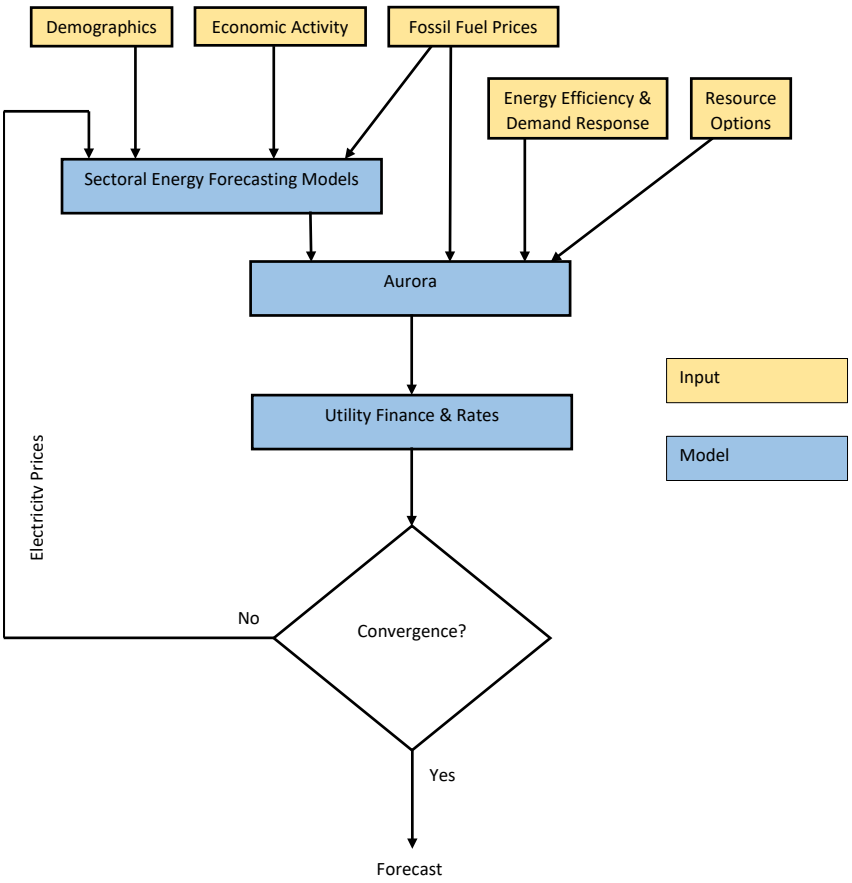


Figure 2-2 is a flowchart that illustrates how the modeling system functions. Projections of demographic, economic, and price drivers are inputs to utility and customer sector specific forecasting models. The energy and peak demand forecasts are inputs to Aurora, a commercially licensed optimization program that simulates economic dispatch, trade among the utilities, and determines future resources. Cost information from Aurora is passed to the utility finance models to determine the resulting prices. The energy forecasting models are then rerun with the new prices, starting the next iteration. The process is repeated until prices from one iteration to the next are stable, indicating that convergence has been achieved.

Figure 2-2. Forecasting Modeling System Flowchart



Energy Forecasting Models

The energy forecasting models are used to develop projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, AES Indiana, Northern Indiana Public Service Company, and CenterPoint Energy. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy, Indiana Municipal Power Agency, and Wabash Valley Power Alliance.

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

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

Electric Vehicle Projections

In order to produce the EV load forecast, the historical total car stock by utility in Indiana was derived. The data of total car stock by county of Indiana from 2017-2022 were collected first from the Indiana Bureau of Motor Vehicles (BMV) and then mapped to each utility based on the estimated fraction of load in each county that is served by each utility. Projections of total car stock by utility were developed using Indiana population projections from the Indiana University Center for Econometric Model Research (CEMR). It is assumed that the total car stock by utility grows at the same rate as the state population using year 2022 as the starting point.

The EV penetration can be calculated by dividing the EV stock by the total car stock. Based on data collected, EV penetration by Indiana utility by year for each year of 2017-2012 was calculated. At the national level, the history and projection of the total car stock and EV car stock were retrieved from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2022 and AEO 2023. This was used to calculate the U.S. EV penetration history and projection into the future.

By comparing the state and national EV penetration levels, it is apparent that Indiana EV penetration for each utility is substantially behind the U.S. level. For year 2022, the U.S. EV penetration is 3.34%, while at the same time Indiana EV penetration by utility ranges from 1.46% to 2.25%. Three scenarios were developed based on Indiana's pace to catch up with the U.S. penetration over time. The scenarios started with mapping the 2022 penetration for each Indiana utility to the national EV penetration history and finding the starting point for each utility on the national EV penetration trajectory. For example, in 2022, one Indiana utility's penetration was slightly higher than where the nation was in 2019 (or about 2.85 years behind the national level) while another Indiana utility was about halfway between where the nation was in 2014 and 2015 (or about 7.58 years behind the national level). For the Low Case, it is assumed that the EV penetration grows at the same rate as the national EV penetration from the starting point identified for each utility. The assumption means each Indiana utility will remain the same number of years behind the U.S. EV penetration level as identified at the starting point throughout the forecast period. For the Base Case, it is assumed that the Indiana utilities gradually catch up to the national level and get to the same level in 2050. For the High Case, it is assumed that the Indiana utilities catch up to the national level faster and get to the same level in 2040. By applying the EV penetration projection by utility to the total car stock projection by utility, projections of the total number of EV for the three scenarios were derived.

In order to develop projections of weekly load profile by hour, the Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite from the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy [DOE] was used. This tool provides a simple way to estimate how much electric vehicle charging you might need and how it affects your charging load profile. Some basic assumptions used to generate the load profile follows.

1. The average daily miles traveled per vehicle is assumed to be 35 miles.
2. The average ambient temperature is assumed to be 50°F for March to May and September to November, 68°F for June to August, and 32°F for December to February[3]. By using different ambient temperatures, generic load profiles by month were obtained.
3. The percentages of EVs and plug-in hybrid electric vehicles (PHEVs) are 50% each.
4. 50% of plug-in vehicles are sedans.
5. The mix of workplace charging includes 50% level 1 and 50% level 2.

[3] A limited number of options were available for average ambient temperature.

6. 75% have access to home charging and 25% have no access. In addition, the distribution of charging power for drivers with access to home charging includes 50% Level 1 and 50% Level 2.
7. 80% of drivers in the fleet prefer primarily charging at home.
8. The home charging strategy assumes vehicles begin charging as soon as possible upon arriving at a charging location and charge at full power/speed until fully charged or the vehicle departs.
9. The workplace charging strategy also assumes vehicles begin charging as soon as possible upon arriving at a charging location and charge at full power/speed until fully charged or the vehicle departs.

The Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite provided generic weekly load profiles by month for an Indiana city/urban area resulted from a fleet of 30,000 plug-in electric vehicles. The weekly load profiles by month were then scaled by the EV adoption level forecast previously derived for each utility and each forecast year. Finally, the weekly load profile for each Indiana utility and each month of a forecast year was obtained for each one of the three scenarios.

Aurora

Energy Exemplar's Aurora is an optimization program that can perform economic dispatch of generators, allowing for trade among utilities, and determine least-cost resource expansion. Within the SUFG integrated modeling system, it is used to determine the operating costs associated with meeting future loads and the costs of expanding the future set of resources necessary to meet future reserve requirements.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, battery storage, natural gas-fired combustion turbines and combined cycle units, nuclear, and pulverized coal. Costs and operating characteristics were taken from the Energy Information Administration (EIA). Due to data limitations, demand-side resources were not modeled as a resource option. Utility energy efficiency programs and DR were modeled as fixed quantities based on utility-provided information. See Chapter 4 for more information on the modeling of demand-side resources.

Aurora has the functionality to allow for construction of partial resources. Thus, the model may select to add a fraction of a unit rather than being limited to full units. SUFG has elected to use this option since it facilitates finding an equilibrium solution.

Utility Finance and Rates Models

As part of the upgrades to the modeling system starting with the 2017 forecast, SUFG incorporated new financial models to project future electric rates. The current financial model is a modified version of the ORFIN model that was developed by Oak Ridge National Lab. The models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts.

Resource Requirements

To determine future resource requirements, SUFG used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the seasonal reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 18.0 percent for summer, 25.6 percent

for fall, 39.5 percent for winter and 37.8 percent for spring. This requirement is based on the installed capacity value of the resources, with a modification for the capacity credit for intermittent resources.

The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC) at the time the inputs to the modeling system were finalized[4].

The numbers presented in this report for future resource requirements are the installed capacity selected by Aurora and are not modified for intermittent resources. While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Scenarios

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

Presentation and Interpretation of Forecast Results

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

References

U.S. Department of Energy Office of Energy Efficiency & Renewable Energy Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite, https://afdc.energy.gov/evi-pro-lite

[4] The inputs to the model were finalized in the summer of 2023.

Chapter 3

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

Introduction

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

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 0.51 percent for electricity requirements and 0.40 percent for peak demand. As shown in Table 3-3, the overall growth rate for electricity sales in this forecast is about 0.30 percent higher than the 2021 forecast. The 2023 forecast grows more rapidly than the previous one despite generally lower economic projections. The increase is primarily due to increased electrification, including growth in the number of electric vehicles, and lower projected electricity prices. Additionally, projected utility-sponsored energy efficiency is lower in this forecast. Higher growth is seen in two of the three major sectors (residential and commercial), while the projection for the industrial sector is lower. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

The growth in peak demand is also higher than that projected in the previous forecast. Forecast peak demand growth is a little lower than that of electricity requirements (0.40 versus 0.51 percent). Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is about 85 MW compared to about 5 MW per year in the previous forecast.

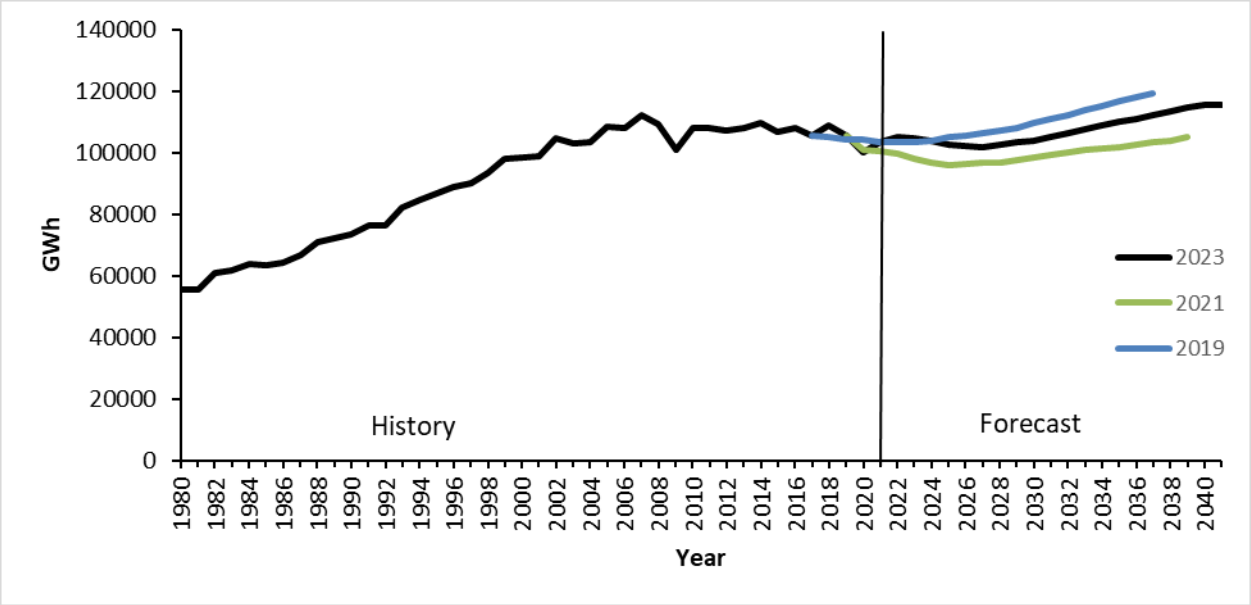
Demand-Side Resources

Beginning with the 2017 forecast, SUFG adjusted the manner in which demand response (DR) programs are modeled and how they are reported. This was necessitated due to the manner in which DR is modeled within Aurora. DR programs are now treated as a resource within the modeling system; previously an adjustment of peak demand was done to account for them outside the utility simulation model. Thus, the peak demand numbers reported in this report have not been adjusted for DR, while the existing resource numbers now include them. DR programs are projected to remain between 800 MW and 1000 MW over the forecast horizon. As in the past, energy efficiency (EE) programs are treated as a reduction in demand. The current projection includes the energy and demand impacts of existing or planned utility-sponsored EE programs. Incremental EE programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 150 MW at the beginning of the forecast period and by about 940 MW at the end of the forecast. See Chapter 4 for additional information about DR and EE.

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

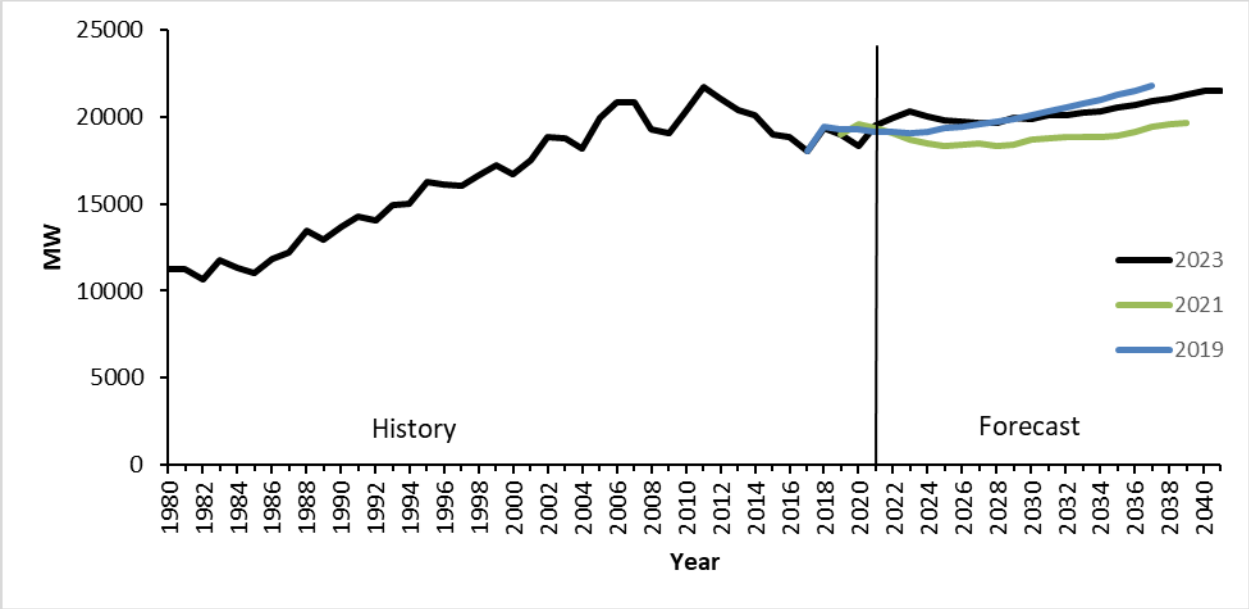
Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	0.51	2022-2041
2021	0.21	2020-2039
2019	0.67	2018-2037

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



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

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



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

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

Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	0.40	2022-2041
2021	0.02	2020-2039
2019	0.60	2018-2037

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current Forecast vs. 2021 and 2019 Projections)

Sector	Current (2022-2041)	2021 (2020-2039)	2019 (2018-2037)
Residential	1.28	0.61	0.45
Commercial	-0.19	-1.02	-0.10
Industrial	0.20	0.53	1.26
Total	0.51	0.21	0.67

Supply-Side Resources

SUFG's base resource plan includes all planned capacity changes at the time the model inputs were finalized[1]. Planned capacity changes include: certified, rate base eligible generation additions,

[1] The inputs to the model were finalized in the summer of 2023. As of the time that this report was published, about 1,000 MW of additional wind and solar projects have been approved by the IURC. Also, the retirement of one large coal-fired unit, Gibson 5, has been postponed since the inputs were finalized. The impact of those changes would be to reduce or defer some of the resource additions selected by Aurora.

retirements, changes in the amount of demand response that is available, 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 new generating units are added as necessary during the forecast period to meet seasonal reserve requirements of approximately 18.0 percent for summer, 25.6 percent for fall, 39.5 percent for winter and 37.8 percent for spring. The level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization and the diversity of peak demand across utilities in the state. Note that this is the first SUFG forecast to incorporate seasonal reserve margins. See Chapter 2 for more information on the seasonal reserve requirements.

Aurora can consider a variety of future supply-side and demand-side resource options. For this forecast, SUFG included utility-scale solar and wind, battery storage, natural gas-fired combustion turbines and combined cycle units, nuclear and pulverized coal. Costs and operating characteristics were taken from Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL) sources. Due to data limitations, demand-side resources were not modeled as a selectable resource option. Utility energy efficiency and demand response loads were modeled as fixed quantities based on utility-provided information.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario for the summer season. This forecast indicates that additional resources are needed throughout the forecast period. Additional resource needs in the first half of the forecast are driven by the need for replacement capacity for units that will be retiring in that time. Additional resource needs in the second half of the forecast are driven by both retirements of existing units and increasing demand. It should be noted that in most years, the Aurora model is adding more new resources than what is strictly necessary to meet the seasonal reserve requirements. This is because the model finds it to be more economical to add additional wind and solar, especially to take advantage of tax credits when they are available. This forecast indicates a need for a mix of natural gas-fired combined cycle units, wind, solar and battery storage capacity. Natural gas combined cycle and wind resources are added first, while battery storage and solar are not added until 2025 and 2029, respectively. While no natural gas-fired combustion turbine resources were selected in the final forecast run, some were selected in earlier iterations and some were selected in the final versions of the low and high scenarios. New coal and nuclear options were never selected. In the long term, the projected required additional resources are higher than in previous forecasts, due to more scheduled retirements of existing units and a higher peak demand projection.

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

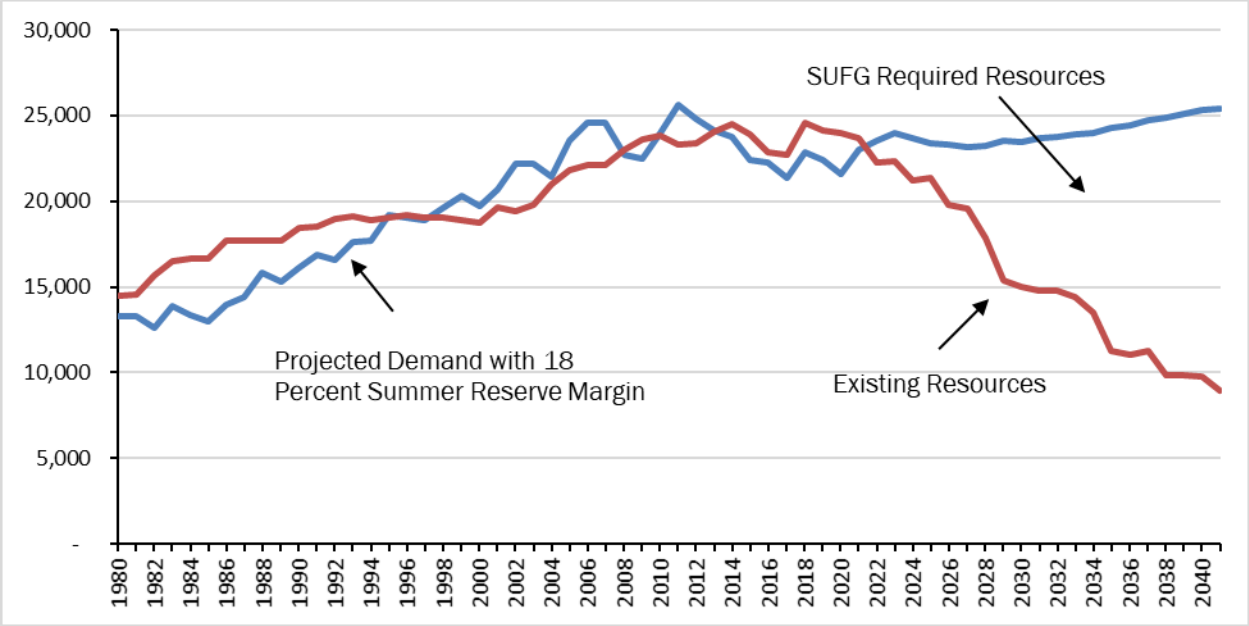
Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of historical data was 2021. Therefore, 2022 and 2023 numbers do not include short term purchases and any longer-term purchases of which SUFG was not aware at the time the forecast was prepared.

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

Year	Peak Demand[1]	Existing/ Approved Resources[2]	Incremental Change in Resources[3]	Required Additional Resources[4]	Additional Selected Resources[5]					
					CT	CC	Wind	Solar	Battery	Total
2022	19,955	22,284		1,261	0	1,415	0	0	0	1,415
2023	20,317	22,302	19	1,670	0	2,345	0	0	0	2,345
2024	20,051	21,198	-1,104	2,458	0	2,345	3,547	0	0	5,893
2025	19,847	21,374	176	2,038	0	2,345	6,076	0	353	8,774
2026	19,742	19,766	-1,608	3,522	0	2,345	6,693	0	824	9,862
2027	19,649	19,559	-207	3,619	0	3,363	6,819	0	824	11,006
2028	19,679	17,876	-1,683	5,336	0	4,811	8,072	0	824	13,707
2029	19,933	15,354	-2,523	8,159	0	5,541	8,928	304	1,397	16,171
2030	19,889	15,034	-320	8,427	0	5,541	8,928	9,805	1,604	25,879
2031	20,086	14,817	-217	8,877	0	5,541	8,942	10,343	1,604	26,430
2032	20,112	14,804	-13	8,920	0	5,952	8,942	10,773	1,630	27,297
2033	20,293	14,389	-416	9,549	0	6,461	8,942	10,773	1,632	27,808
2034	20,356	13,503	-886	10,509	0	7,284	8,942	10,773	1,652	28,651
2035	20,574	11,294	-2,209	12,974	0	9,939	8,942	11,033	1,652	31,566
2036	20,722	11,042	-252	13,401	0	10,255	8,942	11,095	1,652	31,944
2037	20,955	11,299	258	13,419	0	10,490	8,942	11,180	1,652	32,264
2038	21,091	9,845	-1,454	15,033	0	12,220	8,942	11,315	1,652	34,129
2039	21,312	9,838	-7	15,301	0	12,471	8,942	11,455	1,652	34,520
2040	21,489	9,810	-29	15,538	0	12,608	8,942	11,724	1,652	34,926
2041	21,532	8,965	-844	16,434	0	13,356	12,000	11,735	1,864	38,955

1 Peak demand reflects utility-sponsored energy efficiency programs but is not adjusted for demand response loads.
2 Existing/approved resources include installed capacity plus approved new capacity plus demand response plus firm purchases minus firm sales.
3 Incremental change in resources is the change in existing/approved resources from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, changes in available demand response loads, and changes in firm purchases and sales.
4 Required additional resources represent the amount of additional resources that are needed to meet the target statewide reserve margin.
5 Additional selected resources are the cumulative amount of additional resources chosen by the optimization model to meet future demand at least cost.

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



Equilibrium Price and Energy Impact

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

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 27 percent from 2021 to 2028 and then level off until the end of the forecast period. While prices are affected by a number of different factors, the change in prices early in the forecast horizon results primarily from the significant capital investment in transmission, distribution, and newly approved generation that is modeled in the first few years.

While the price increase is smaller than in the previous forecast, it is still significant. Thus, the electricity requirements projection for this portion of the forecast period is affected. Since electricity prices are an input to the forecasting models, the price increases in the early years cause the projected sales to decrease. In turn, this can cause further price increases if sales decline more than revenue requirements.

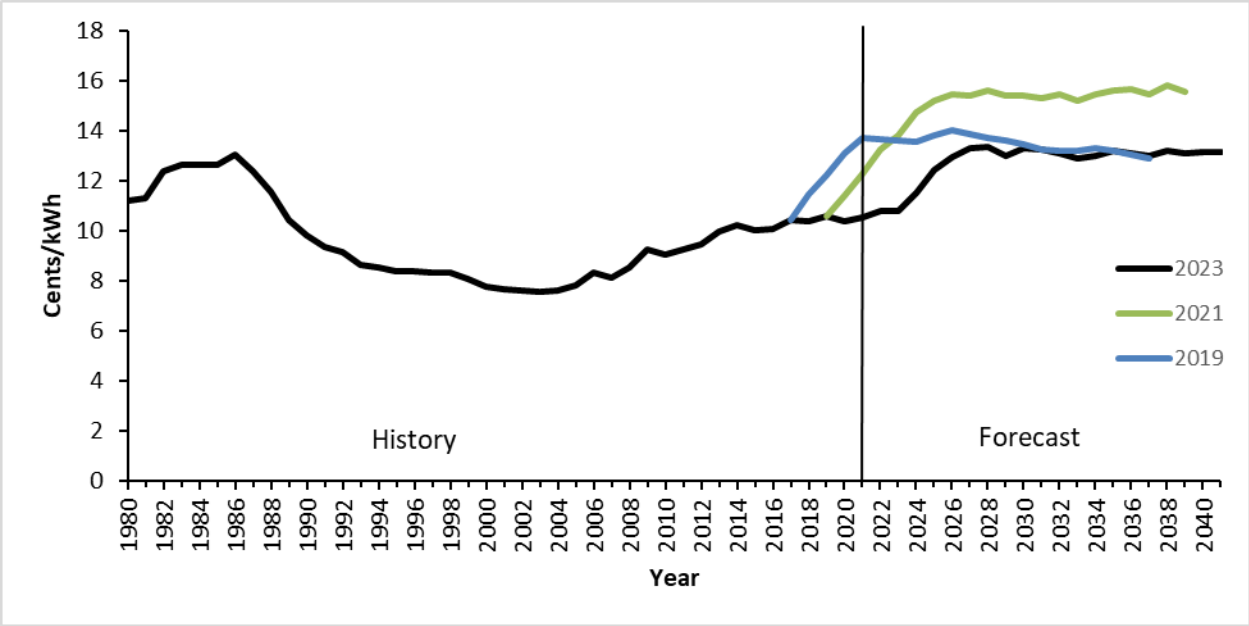
SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2019" is the base case projection from SUFG's 2019 forecast report and the one labeled "2021" is the base case projection from SUFG's 2021 report. For the prior price forecasts, SUFG rescaled the original price projections to 2021 dollars (from 2017 dollars for the 2019 projection, and from 2019 dollars for the 2021 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

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

Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	1.04	2022-2041
2021	1.64	2020-2039
2019	0.61	2018-2037

A number of factors determine the price projections in Figure 3-4. These include costs associated with future resources required to meet future load, costs associated with continued operation of existing infrastructure, and fuel costs. Costs are included for the transmission and distribution of electricity in addition to production. Environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not.

Figure 3-4. Indiana Real Price Projections in cents/kWh (2021 Dollars) (Historical, Current, and Previous Forecasts)



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

Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, population, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion, of possible future trajectories but do not represent limits. The addition of very large new users of electricity could result in sales that exceed the high scenario. Similarly, the closure of existing large users could result in sales below the low scenario. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for energy requirements for the low and high scenarios are 0.24 percent lower and 0.28 percent higher, respectively, than the base scenario. These differences are driven by economic growth assumptions in the scenario-based projections and differences in assumed growth of electric vehicles.

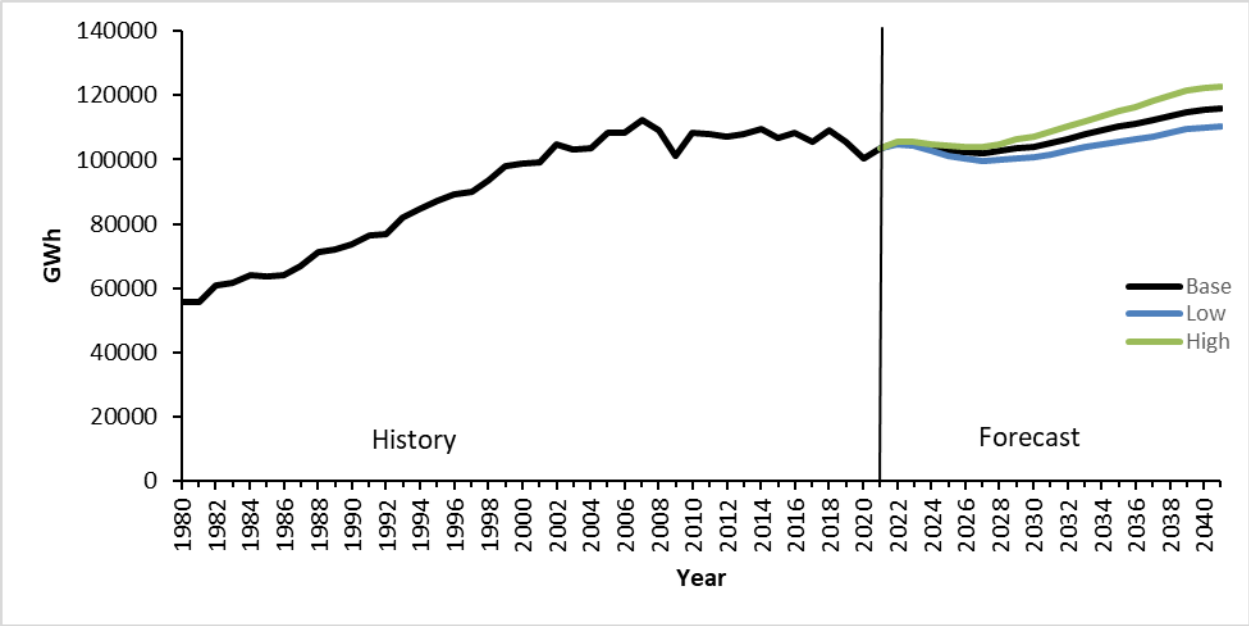
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including energy efficiency and demand response loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the resources selected by the optimization model for the high and low scenarios (the same information for the base scenario can be found in Table 3-4). Approximately 40,400 MW over the horizon are added in the high scenario compared to 33,900 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about four and a half percent of those projected in the base case. This is because the higher costs associated with meeting the increased load for the high case are spread over a greater amount of energy. For the low case, the lower costs are offset by the lower amount of energy.

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

Average Compound Growth Rates (ACGR)			
Forecast Period	Base	Low	High
2022-2041	0.51	0.27	0.79

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

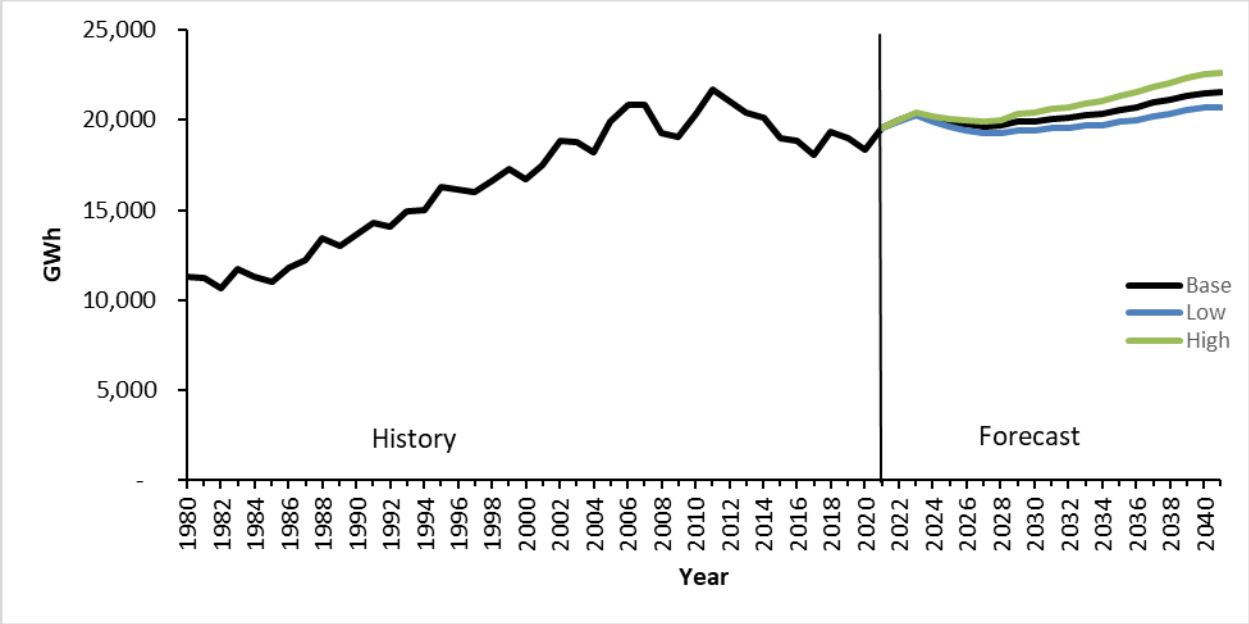


Note: See the Appendix to this report for historical and projected values.

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

Average Compound Growth Rates (ACGR)			
Forecast Period	Base	Low	High
2022-2041	0.40	0.20	0.66

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



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

Table 3-8. Indiana Selected Resources for High and Low Scenarios in MW

Year	High						Low					
	CT	CC	Wind	Solar	Battery	Total	CT	CC	Wind	Solar	Battery	Total
2022	0	1,415	0	0	0	1,415	0	1,415	0	0	0	1,415
2023	0	2,300	731	0	0	3,031	0	1,613	0	120	647	2,380
2024	0	2,300	3,860	0	106	6,266	0	1,613	2,630	120	753	5,115
2025	0	2,324	5,630	0	106	8,061	0	1,613	3,227	120	2,018	6,977
2026	0	3,829	5,987	0	106	9,922	0	1,613	4,161	120	2,018	7,911
2027	36	3,852	6,329	0	106	10,323	0	2,041	4,239	120	2,018	8,417
2028	44	5,541	8,098	0	106	13,789	0	3,873	4,239	207	2,018	10,337
2029	200	6,997	8,098	0	300	15,595	0	4,758	4,239	304	2,221	11,522
2030	200	6,997	8,098	9,655	447	25,397	0	4,758	4,239	5,598	2,221	16,816
2031	200	6,997	8,098	10,658	447	26,401	0	4,823	4,358	5,873	2,221	17,275
2032	200	7,443	8,098	10,955	495	27,191	0	5,022	5,889	6,277	2,221	19,408
2033	200	8,051	8,098	10,955	495	27,799	0	5,393	5,889	6,277	2,221	19,779
2034	200	9,096	8,098	11,137	495	29,027	0	6,370	5,889	6,277	2,221	20,756
2035	200	11,832	8,098	11,242	495	31,867	0	8,932	5,889	6,541	2,221	23,583
2036	200	12,251	8,098	11,314	495	32,358	0	9,156	5,889	6,631	2,221	23,897
2037	200	12,581	8,098	11,418	495	32,792	0	9,313	5,889	6,737	2,221	24,161
2038	200	14,416	8,098	11,576	495	34,785	0	11,020	5,889	6,902	2,221	26,032
2039	200	14,755	8,098	11,743	495	35,291	0	11,253	5,889	7,048	2,221	26,412
2040	200	14,924	8,098	11,919	495	35,636	0	11,370	5,889	7,318	2,221	26,798
2041	200	15,706	12,000	11,919	621	40,447	23	12,112	12,000	7,327	2,481	33,943

Chapter 4

Major Forecast Inputs and Assumptions

Introduction

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

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

Macroeconomic Scenarios

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

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

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

Economic Activity Projections

National and state economic projections are produced by CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2023 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

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

The CEMR model of the U.S. economy is a large scale quarterly econometric model. The model has a detailed aggregate demand sector that determines output. It also has a fully specified labor market sub model. Output determines employment, which then affects the availability of labor. Labor market

tightness helps determine wage rates, which, along with employment, interest rates and several other variables determine personal income. Fiscal policy variables, such as spending levels and tax rates, interact with income to determine federal, state and local budgets. Monetary policy variables interact with output and price variables to determine interest rates.

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

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

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from "Long-Range Projections 2022-2043" [CEMR] are:

> "Federal payroll tax rate is assumed to increases through the entire projection by a total of 2.5 percent. Federal grants to state and local governments are assumed to grow at an average rate of 4.7 percent over the projection period. Growth in government purchases is low. This produces a reduction in the federal government deficit from 3.9 percent of GDP in 2022 to 2.5 percent at the end of the projection period. By comparison over the period 1960-1999 the deficit averaged 2.8 percent of GDP.
>
> State and local tax rates rise by a total of 4.6 percent over the projection period. This allows these governments to have budgets that are essentially in balance.
>
> Real exports are assumed to grow at about 3.7 percent through the projection period. This exceeds the growth of imports, resulting in a real net export deficit that declines somewhat from its 2022 level (from 6.8 percent of real GDP to 4.7 percent)."

As a result of these assumptions, real GDP for the U.S. economy is projected to grow at an average annual rate of 1.92 percent and U.S. employment growth averages 0.68 percent over the 2022 to 2041 period.

In Indiana, total employment is projected to grow at a compound annual growth rate of 0.57 percent from 2022 through 2041. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 1.24 percent annual rate for Indiana.

Non-manufacturing employment (the commercial sector model driver) is expected to grow at a 0.77 percent annual rate over the forecast horizon.

Despite a small decline in manufacturing employment (at a compound annual growth rate of -0.59 percent for the period of 2022-2041), manufacturing GSP (the industrial sector model driver) is expected to rise at a 1.14 percent annual rate as gains in productivity far outpace the drop 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. It should be noted that some historical data has been revised by CEMR based on changes from federal sources, particularly the Bureau of Economic Analysis.

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

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2019	Feb 2021	Feb 2023
	1995-2000	2000-2005	2005-2010	2010-2015	2015-2021	2018-2037	2020-2039	2022-2041
United States								
Real Personal Income	4.78	2.29	2.14	2.03	3.25	2.29	2.14	2.03
Total Employment	2.37	0.83	0.89	0.68	0.50	0.83	0.89	0.68
Real Gross Domestic Product	4.31	2.40	2.45	1.92	2.02	2.40	2.45	1.92
Personal Consumer Expenditure Deflator	1.73	2.06	2.17	2.18	1.92	2.06	2.17	2.18
Indiana								
Real Personal Income	4.44	1.73	1.45	1.24	3.28	1.73	1.45	1.24
Employment								
Total Establishment	1.50	0.72	0.88	0.57	0.30	0.72	0.88	0.57
Manufacturing	0.35	-0.57	-0.52	-0.59	0.23	-0.57	-0.52	-0.59
Non-Manufacturing	1.77	0.95	1.11	0.77	0.18	0.95	1.11	0.77
Real Gross State Product								
Total	4.78	1.91	0.49	1.07	1.66	2.31	2.29	1.86
Manufacturing	4.68	2.07	2.39	-0.61	1.80	2.01	1.44	1.14
Non-Manufacturing	4.84	1.85	-0.25	1.75	1.60	2.42	2.57	2.11

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
Note: The growth rates for manufacturing GSP and total GSP for the 2021 forecast reflect the adjustments made by SUFG to the transportation equipment industry forecast. Those adjustments were made, but not shown in the 2019 forecast. For 2023 forecast, no adjustments were made to the transportation equipment industry forecast.

To capture some of the uncertainty in energy forecasting, CEMR provided low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of real personal income is increased by about 0.35 percent per year (to 1.59 percent), non-manufacturing employment growth increases 0.11 percent (to 0.88 percent) while Indiana real manufacturing GSP growth is increased by 0.81 percent (to 1.95 percent). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 0.90, 0.66 and 0.36 percent, respectively).

Demographic Projections

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

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The compound annual growth rate for the IBRC population growth forecast for Indiana is 0.29 percent for the period of 2022-2041.

The historical growth of household formations (number of residential customers) has slowed significantly from slightly over 2 percent during the late 1960s and early 1970s to 0.63 percent from 2011-2021. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.19 percent over the forecast period.

Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. About 47% of the state's electricity was generated from coal in 2022, while 29% was generated from natural gas [IURC]. Thus, when coal or natural gas prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices change, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

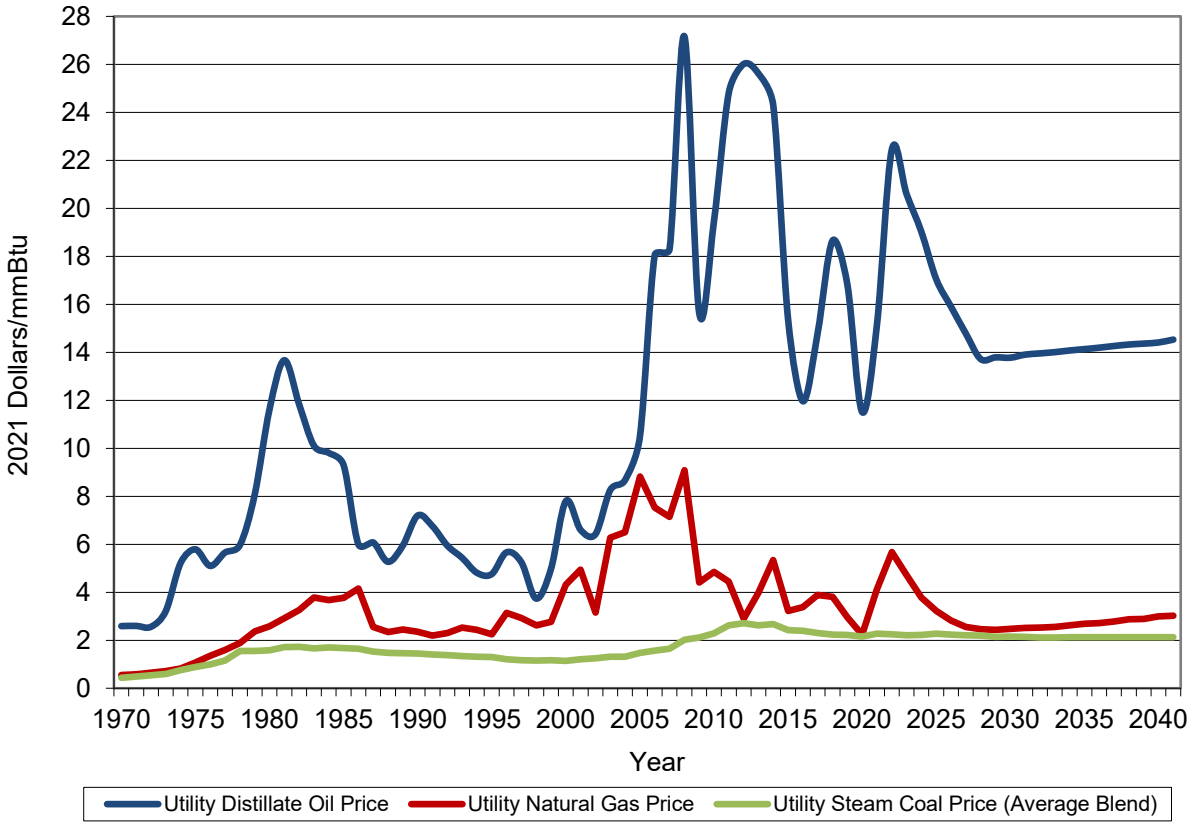
SUFG's modeling system incorporates separate fuel price projections for utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used the March 2023 fossil fuel price projections from Energy Information Administration (EIA) for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2021 dollars/mmBtu), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are as follows:

- Coal price projections are relatively flat in real terms throughout the entire forecast horizon as coal consumption decreases due to more natural gas and renewable generation observed in the electric power sector.
- Natural gas prices decreased significantly from 2008 to 2012. Prices then rebounded slightly in 2013 and 2014 before another dip since 2015. During the pandemic, the price hit a low level around $2/mmBtu but rebounded to exceed the pre-pandemic level in 2022. The natural gas price is projected to decline in the short run and slowly increase from about $2.50/mmBtu to $3/mmBtu over the rest of the forecast horizon.
- Distillate prices decreased significantly in 2009 from the high prices of 2008. Prices then rebounded significantly through 2012 before declining again in 2013, followed by substantial decreases in 2016. They rebounded quickly in 2017 and 2018, and then hit another low during the pandemic. The price rebounded to $22.44/mmBtu in 2022. It is

projected to decline to around $14/mmBtu in 2028, then grow slightly over the remaining forecast period.

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

Figure 4-1. Utility Real Fossil Fuel Prices



Demand-Side Management, Energy Efficiency and Demand Response

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

Incremental energy efficiency, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are modeled within Aurora by effectively changing the utility's demand by the appropriate level of energy and peak demand for the EE program. EE programs that were in place in 2021 are considered to be embedded in the calibration data, so no adjustments are necessary.

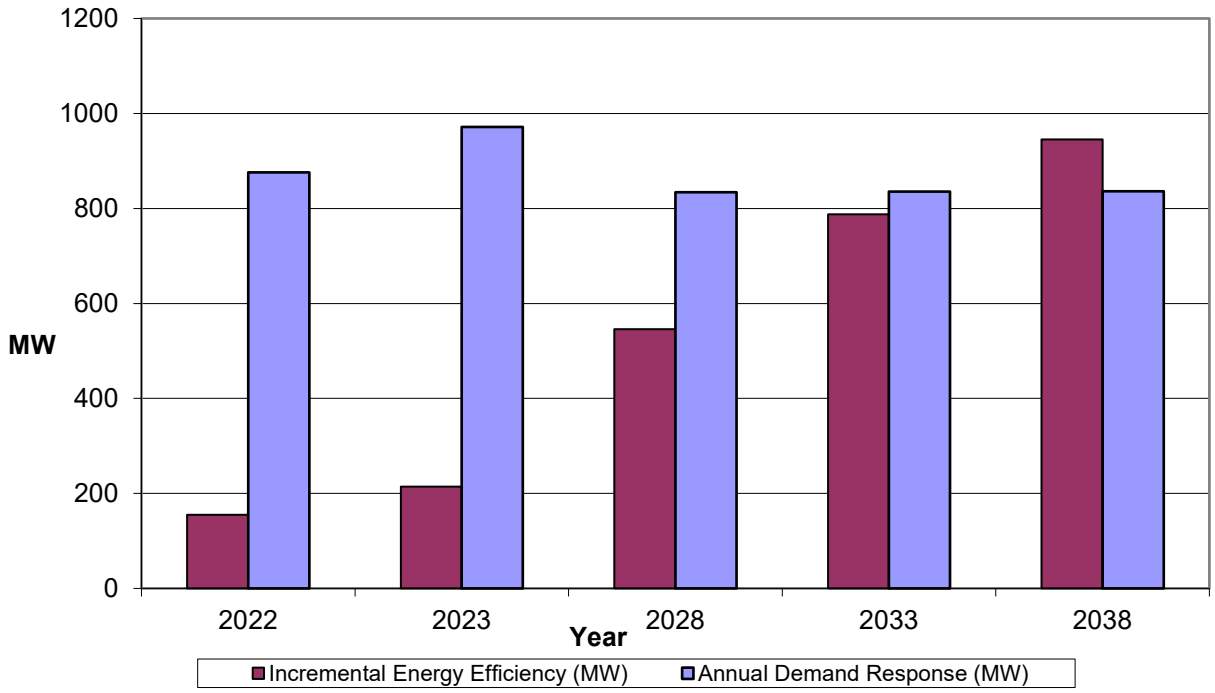
Demand response can include interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, and direct load control, where the utility has the ability to directly turn off a customer's load for a specified amount of time. DR is typically treated differently than energy efficiency. In previous forecasts, the amount of demand response was subtracted from the utility's peak demand in order to determine the amount of new capacity required. Beginning with the 2017 forecast, demand response is modeled within Aurora as a resource instead of as an after-the-fact adjustment.

Table 4-2 shows the peak demand reductions from embedded DSM in 2021 and from incremental EE and annual DR available in 2022 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings, from utility filings with the EIA and from information collected by SUFG directly from the utilities. SUFG does not attempt to project additional DSM savings beyond those identified by the utilities at the time this report was prepared. It should be noted that SUFG does not advocate any specific means for meeting future resource requirements, with additional energy efficiency being one of the options available for meeting those requirements. Figure 4-2 shows projected values of peak demand reductions for incremental energy efficiency and demand response for 2022 and at five-year intervals starting in the year 2023. This forecast reflects lower levels of utility-sponsored EE (about 940 MW of savings late in the forecast period as compared to about 1,400 MW in the 2021 forecast), while DR peak demand reductions are also lower.

Table 4-2. 2021 Embedded DSM and 2022 Incremental Peak Demand Reductions from Energy Efficiency and Annual Demand Response Programs (MW)

2021 Embedded DSM	2022 Incremental Energy Efficiency	2022 Annual Demand Response
331	155	876

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



Changes in Forecast Drivers from the 2021 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies therefore have direct effects on the forecast. This section compares the CEMR's projections used in SUFG's 2021 and 2023 forecasts.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2014 through 2020 and for 2025, 2030, 2035 and the last year of the forecast period 2041. The tables show long-run projections of real values and percentage change at annual rates for non-manufacturing employment, real personal income, and total real manufacturing GSP. The tables also show the percentage change between CEMR2021 and CEMR2023. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2013 through 2043. Some historical values differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

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

Table 4-3 and Figure 4-3 show that the current CEMR projection for non-manufacturing employment is lower than that in the 2021 projection.

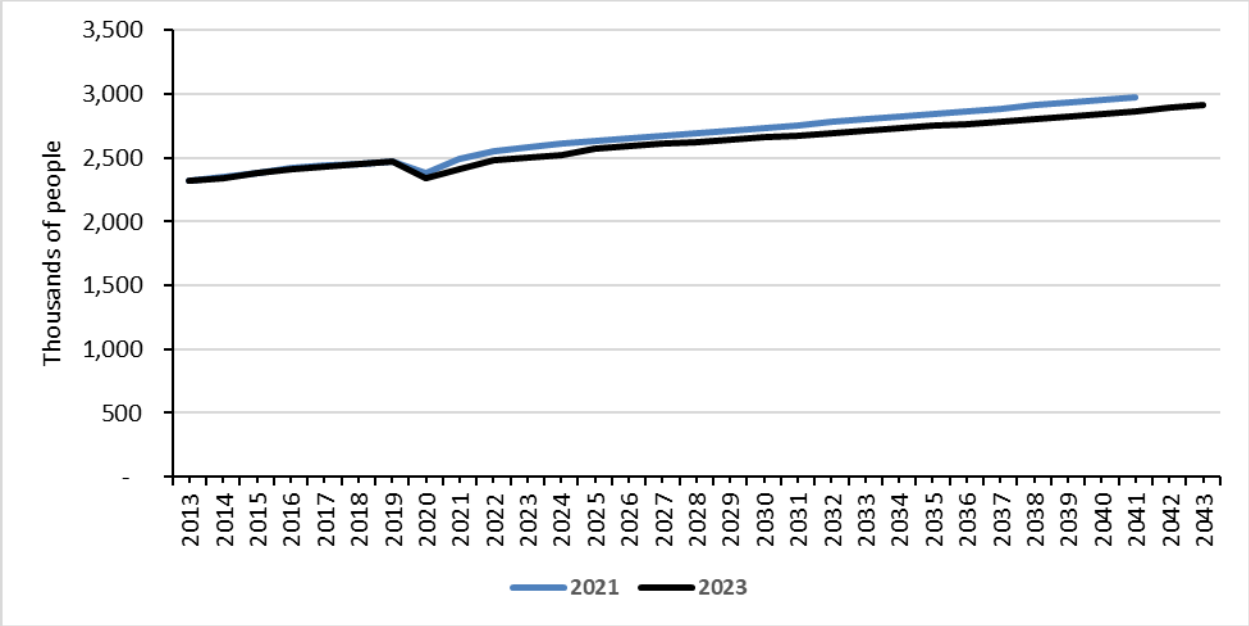
Table 4-3. 2021 and 2023 CEMR Projections for Indiana Non-manufacturing Employment

	Year										
	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2041
	Thousands of persons										
CEMR 2021	2345.64 (1.15)	2385.83 (1.71)	2417.07 (1.31)	2436.19 (0.79)	2456.18 (0.82)	2472.62 (0.67)	2376.54 (-3.89)	2631.88 (0.78)	2736.48 (0.77)	2844.35 (0.77)	2978.18 (0.78)
CEMR 2023	2342.83 (1.14)	2382.26 (1.68)	2412.44 (1.27)	2431.29 (0.78)	2449.33 (0.74)	2467.05 (0.72)	2339.08 (-5.19)	2573.04 (1.85)	2658.29 (0.61)	2748.45 (0.68)	2868.12 (0.74)
Percentage change between two projections	-0.12	-0.15	-0.19	-0.20	-0.28	-0.23	-1.58	-2.24	-2.86	-3.37	-3.70

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

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



Real Personal Income

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

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2023 has a lower projection for real personal income over the forecast period. CEMR2023 indicates real personal income $17.88 billion (4.24 percent) lower than that in CEMR2021 for 2041.

Figure 4-4 illustrates that the CEMR2023 real personal income is projected to be lower than that in CEMR2021 over the forecast horizon.

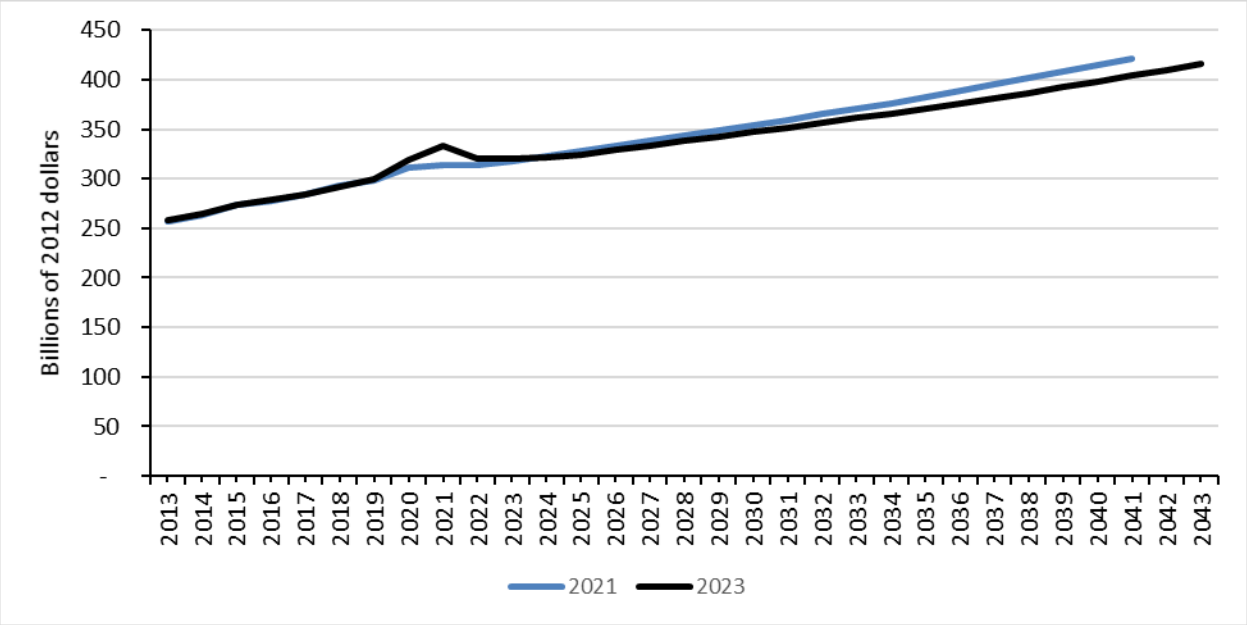
Table 4-4. 2021 and 2023 CEMR Projections for Indiana Real Personal Income

	Year										
	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2041
	Billions of 2012 $										
CEMR 2021	263.53	273.53	278.27	284.23	292.72	298.33	310.88	328.12	354.02	382.18	421.84
	(2.55)	(3.79)	(1.73)	(2.14)	(2.99)	(1.92)	(4.21)	(1.67)	(1.50)	(1.49)	(1.63)
CEMR 2023	264.61	274.28	279.03	283.79	291.50	299.85	318.87	324.84	347.42	371.07	403.95
	(2.48)	(3.66)	(1.73)	(1.70)	(2.72)	(2.86)	(6.34)	(1.03)	(1.34)	(1.32)	(1.48)
Percentage change between two projections	0.41	0.27	0.27	-0.16	-0.42	0.51	2.57	-1.00	-1.86	-2.91	-4.24

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Figure 4-4. Indiana Real Personal Income (billions of 2012 dollars)



Real Manufacturing Gross State Product

Changes in manufacturing GSP will have significant implications for electricity use in the industrial sector. Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. It should be noted that SUFG made adjustments for the transportation sector and reflected the adjustments in the manufacturing GSP for the 2021 forecast. However, for the 2023 forecast, SUFG decided not to adjust the transportation sector. Therefore, as the figure illustrates, the CEMR2023 projection without adjustments is slightly higher than the CEMR2021 projection with adjustments.

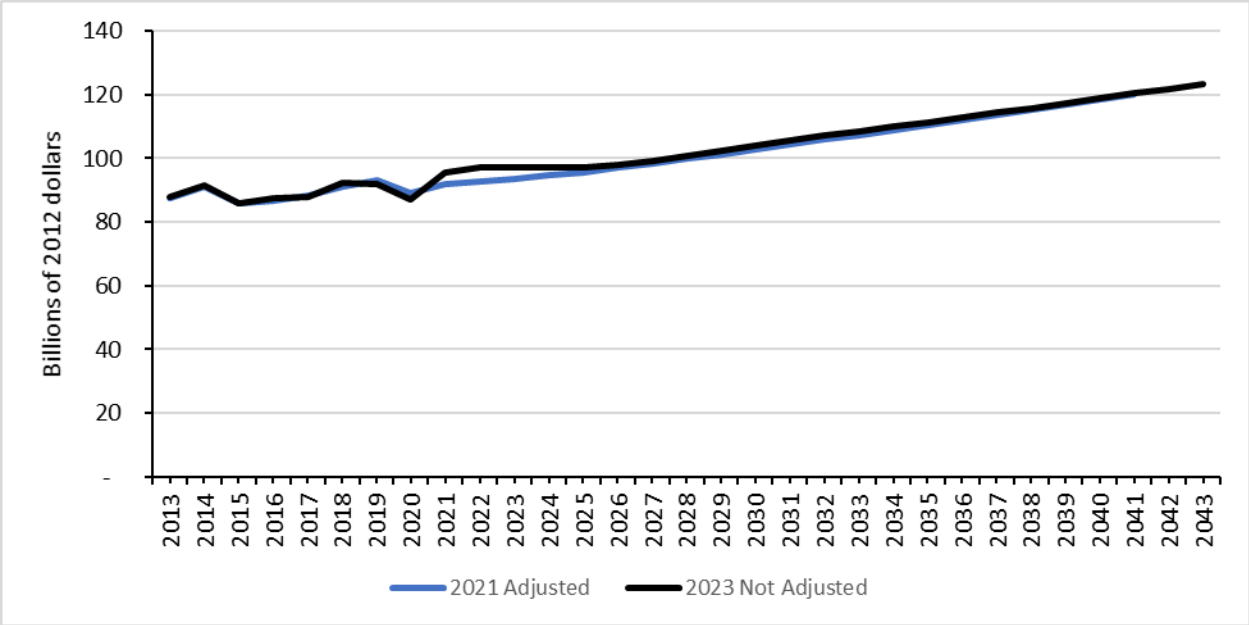
Table 4-5. 2021 Adjusted and 2023 CEMR Projections for Indiana Real Manufacturing GSP

	Year										
	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2041
	Billions of 2012 $										
CEMR 2021 Adjusted	91.11	85.90	86.86	88.13	90.97	93.22	89.06	95.60	102.84	110.48	119.92
	(4.00)	(-5.71)	(1.11)	(1.47)	(3.22)	(2.47)	(-4.47)	(1.03)	(1.44)	(1.43)	(1.34)
CEMR 2023	91.35	85.73	87.63	88.00	92.22	92.08	87.21	97.27	104.00	111.39	120.34
	(3.68)	(-6.15)	(2.22)	(0.43)	(4.79)	(-0.15)	(-5.28)	(0.07)	(1.59)	(1.32)	(1.29)
Percentage change between two projections	0.26	-0.21	0.89	-0.15	1.37	-1.23	-2.07	1.74	1.13	0.83	0.35

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

Notes: 1. Numbers in parentheses indicate percentage change from the previous year of the same projection.
2. Projections were adjusted to reflect the adjustments made by SUFG to the transportation equipment sector for CEMR 2021. However, SUFG did not make adjustments to the transportation equipment sector for CEMR 2023.

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2012 dollars)



Transportation Equipment Industry

The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2021, this sector represented 23 percent of the total real value of products manufactured in the state.

SUFG deemed that CEMR's forecasts showed too much growth over the long term for this sector for CEMR2021 and before, so those forecasts were tempered. However, for the 2023 forecast, SUFG did not make adjustments to the transportation equipment industry due to new developments in the state. The CEMR2023 projection indicates an annual compound growth rate of 2.26 percent for the forecast period of 2022-2041

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment GSP for both CEMR2021 and CEMR2023. The industry is projected to keep growing for the entire forecast period. Since the CEMR2023 projection was not tempered, it shows growth over time substantially higher than that in the CEMR2021 projection (34.05 billion vs 25.19 billion for the year 2041).

Table 4-6. 2021 Adjusted and 2023 CEMR Projections for Indiana Real Transportation Equipment GSP

	Year										
	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2041
	Billions of 2012 $										
CEMR 2021 Adjusted	14.41	14.55	15.27	16.16	16.69	17.10	16.42	18.32	20.24	22.36	25.19
	(5.75)	(0.92)	(4.98)	(5.80)	(3.31)	(2.42)	(-3.93)	(1.66)	(2.00)	(2.03)	(1.99)
CEMR 2023	14.52	14.60	15.41	16.06	16.55	16.67	15.86	23.14	26.36	29.70	34.05
	(5.94)	(0.57)	(5.57)	(4.20)	(3.04)	(0.76)	(-4.91)	(1.68)	(2.61)	(2.35)	(2.29)
Percentage change between two projections	0.72	0.37	0.93	-0.59	-0.86	-2.47	-3.46	26.31	30.25	32.79	35.16

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Primary Metals Industry

While the primary metals industry, including production of steel and aluminum, represented approximately 10 percent of Indiana manufacturing GSP in 2021, it accounted for 29 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2021 and 2023 for the primary metals industry. The primary metals industry is projected to be decreasing over the forecast period of 2022-2041. The CEMR2023 projection for the primary metals industry is slightly higher than that in the CEMR2021. In 2041, the projected GSP level for the primary metals industry in the CEMR2023 is about 3.16 percent higher than that in the CEMR2021.

Table 4-7. 2021 and 2023 CEMR Projections for Indiana Real Primary Metals GSP

	Year										
	2014	2015	2016	2017	2018	2019	2020	2025	2030	2035	2041
	Billions of 2012 $										
CEMR 2021	9.47	11.50	12.21	10.54	10.79	11.91	10.93	7.61	7.34	7.08	6.70
	(-5.25)	(21.43)	(6.14)	(-13.65)	(2.38)	(10.35)	(-8.27)	(-7.55)	(-0.74)	(-0.76)	(-1.02)
CEMR 2023	9.49	11.26	12.27	9.70	10.77	10.74	11.21	8.62	7.40	7.21	6.91
	(-5.12)	(18.60)	(8.94)	(-20.92)	(10.99)	(-0.25)	(4.40)	(-7.43)	(-0.19)	(-0.63)	(-0.74)
Percentage change between two projections	0.21	-2.13	0.46	-8.00	-0.26	-9.85	2.60	13.22	0.74	1.74	3.16

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

Note: Numbers in parentheses indicate percentage change from the previous year of the same projection.

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

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

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

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

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods. SUFG is committed to identifying and correcting potential errors in model specification, data measurement, and appropriate estimation methods.

References

Center for Econometric Model Research, “Long-Range Projections 2022-2043,” Indiana University, February 2023.

Energy Information Administration, “Annual Energy Outlook 2023,” March 2023.

Indiana Utility Regulatory Commission, “Annual Report 2023,” September 2023.

Chapter 5

Residential Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project residential electricity sales. These different modeling approaches have specific strengths and complement each other. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been updated periodically. After the release of the 2007 SUFG forecast, SUFG acquired a proprietary end-use model, Residential Energy Demand Model System (REDMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REDMS was obtained to replace an older residential sector end-use oriented model known as REEMS. Both end-use models are descendants of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Starting with the 2011 forecast, SUFG adopted REDMS as the primary residential sector energy model, and it is used to project residential electricity sales in this forecast. REDMS is actively supported by the vendor, Jerry Jackson Associates, with the model being re-estimated in 2020. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model residential energy for the not-for-profit utilities (NFPs) with an econometric approach.

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

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

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

Historical Perspective

The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Over time, these market factors have exhibited distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions.

The explosion in residential electricity sales during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices and rising incomes. This period also was marked by a boom in the housing industry as the number of residences increased. In the decade following the embargo, the growth in residential electricity sales

slowed dramatically. Except for some softening in electricity prices during the late-1970s and early-1980s, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. Growth in real household income was miniscule and the housing market went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices was reflected in a dramatic decline in the growth of residential electricity sales to around two percent per year as opposed to nearly nine percent previously. Events turned again during the mid-1980s. Real household income grew faster than in the pre-embargo era and real electricity prices declined. Growth in the number of households was largely unchanged and annual electricity sales increased slightly during this period.

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

For the early-2000s period, residential household growth decreased slightly, real electric rates continued to decline, but the growth in personal income, while positive, slowed markedly. Despite the slow growth in income, electricity sales continued to grow at roughly the rate observed during the mid-1980s to late-1990s period.

More recently, beginning in the mid-2000s, real electricity prices increased reversing the trend of the previous twenty years. These rising electricity prices coupled with the effects of the economic downturn in the late-2000s and increased efficiency have resulted in much lower growth in electricity sales. Growth of the number of households slowed to about one-fourth the rate observed over the preceding twenty years. Real household income slowly increased over this period. The net effect of these changes was to reduce the electricity sales growth rate to essentially flat over the period.

Model Description

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

Figure 5-1 depicts the structure of the residential end-use model. As the figure shows, REDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

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

vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.

REDMS projects energy use for each dwelling vintage according to the following equation:

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

where

* = multiplication operator;
T = forecast year;
Q = energy demand for fuel i, end use k, dwelling type l and vintage t in the forecast year T;
t = dwelling vintage (year);
U = utilization, relative to some base year;
e = energy use index, kWh/year or Btu/year;
a = fraction of dwelling served by fuel i, end use k, and dwelling type l for dwelling additions of vintage t;
A = dwelling additions by vintage t and dwelling type l; and
d = fraction of dwellings of vintage t still standing in forecast year T.

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

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

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

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

Figure 5-1. Structure of Residential End-Use Energy Modeling System

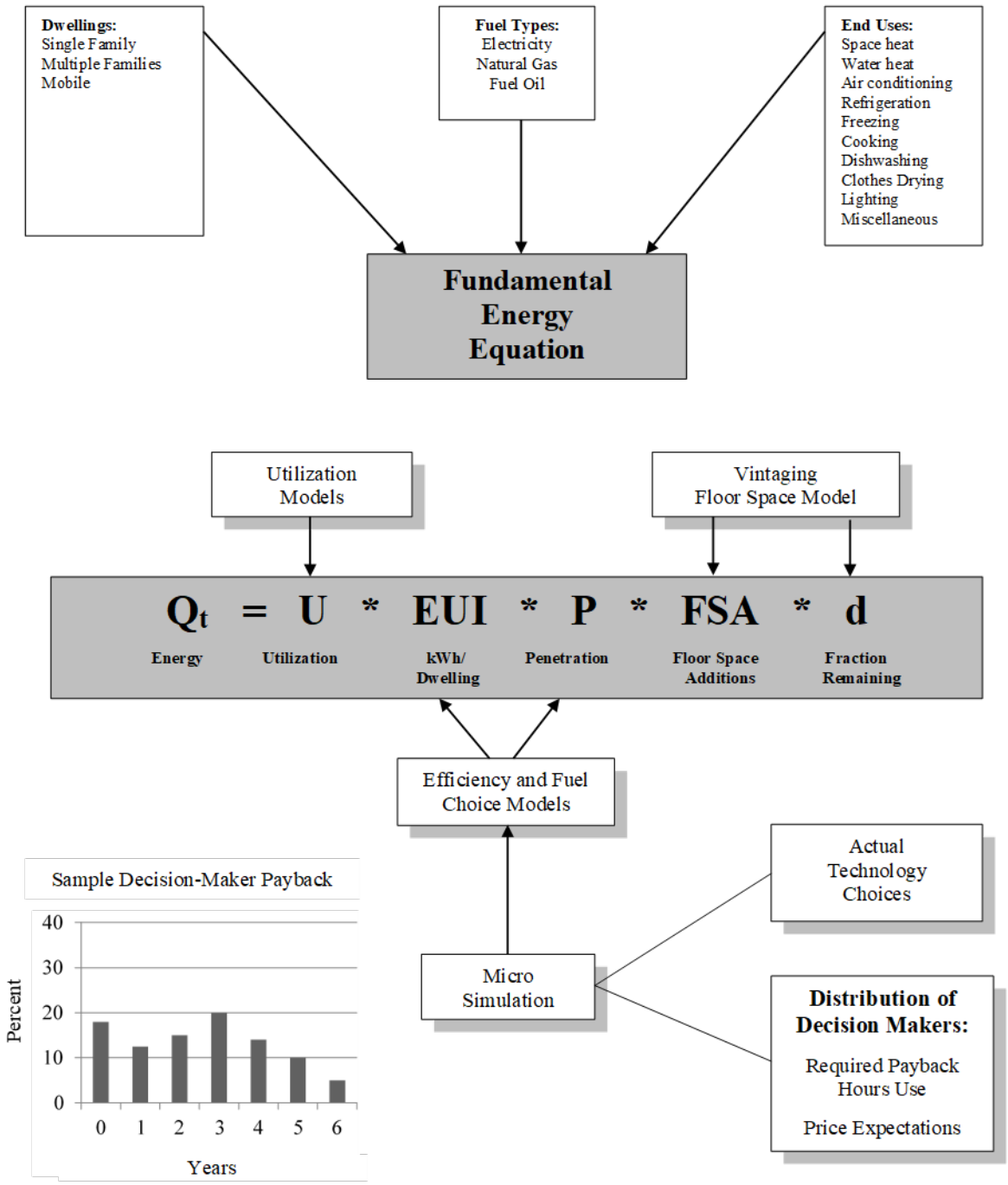


Table 5-1 provides the breakdown of the share of households in the service territories of the IOUs by type in the first column. The second column shows the share of electricity sales for the household types. The last three columns provide projected compound annual growth rates over the 2022-2041

forecast horizon for the number of households, electricity intensity as measured by annual sales per household, and growth in electricity sales.

Table 5-1. Selected Statistics for Indiana's Residential Sector (Without DSM) (Percent)

Dwelling Type	Current Share of Total Households	Current Share of Electricity Sales	Forecast Growth in Number of Households	Forecast Growth in Electricity Intensity	Forecast Growth in Electricity Sales
Single Family	78	84	1.18	-0.29	0.89
Multi-Family	18	11	1.21	-0.22	0.99
Mobile Home	4	5	1.15	-0.54	0.61
Total	100	100	1.19	-0.30	0.89

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.

Model Sensitivities

The major economic drivers in the residential end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-2. Electricity consumption increases with the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an initial space heating (and subsequently water heating) fuel for a new dwelling is chosen retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital expense of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. During the period used for model calibration 2009-2018, penetration for most electric end uses were very consistent, with some of the less significant ones like cooking and dishwashers increasing. Electric space heating penetration was constant at 29 percent with natural gas and LPG largely capturing the remainder. Real electricity prices increased, real natural gas prices decreased, and oil prices drifted upward with considerable volatility.

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

Table 5-2. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	10.6
Electric Rates	-2.7

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-3 and Figure 5-2. The growth rate for the current base projection of Indiana residential electricity sales is 1.28 percent, which is 0.67 percent higher than SUFG's 2021 projection of 0.61 percent. The historic and 2023 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection lies above both the 2019 and 2021 projections. Table 5-4 summarizes SUFG's base projections of residential electricity sales growth since 2019.

Table 5-4 breaks these projections down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, with and without DSM. As the table shows, more than one half of projected sales growth is attributable to customer growth and the remainder to increases in utilization, which is the amount of energy used per household. Use per household increases because of increasing electrification, particularly electric vehicles. It can also be seen from the table that residential DSM cuts the sales growth rate by approximately one-fifth, reducing it from 1.62 percent to 1.28 percent.

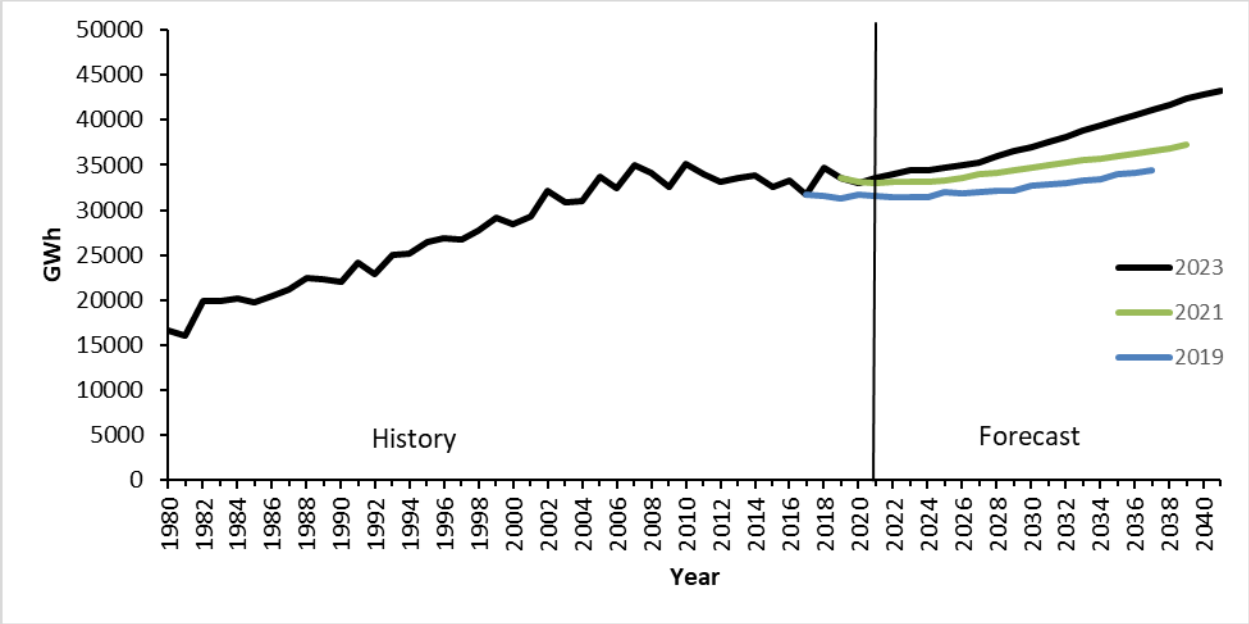
Table 5-5 shows the growth rates of the major residential drivers for the current scenarios and the 2019 and 2021 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic projections in all five cases are very similar. While there are some small variations in personal income among the cases, they are not sufficiently large as to result in a significant difference in growth rates for the base and high scenarios.

As shown in Table 5-6 and Figure 5-3, the growth rates for the high and low residential scenarios are about 0.10 percent higher and 0.13 lower, respectively, than the base scenario. This difference is due to differences in the growth of household income and the number of electric vehicles.

Table 5-3. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	1.28	2022-2041
2021	0.61	2020-2039
2019	0.45	2018-2037

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



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

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

Forecast	No. of Customers	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2023 SUFG Base (2022-2041)	1.19	0.43	1.62	0.09	1.28
2021 SUFG Base (2020-2039)	1.14	-0.22	0.92	-0.53	0.61
2019 SUFG Base (2018-2037)	1.09	-0.41	0.68	-0.64	0.45

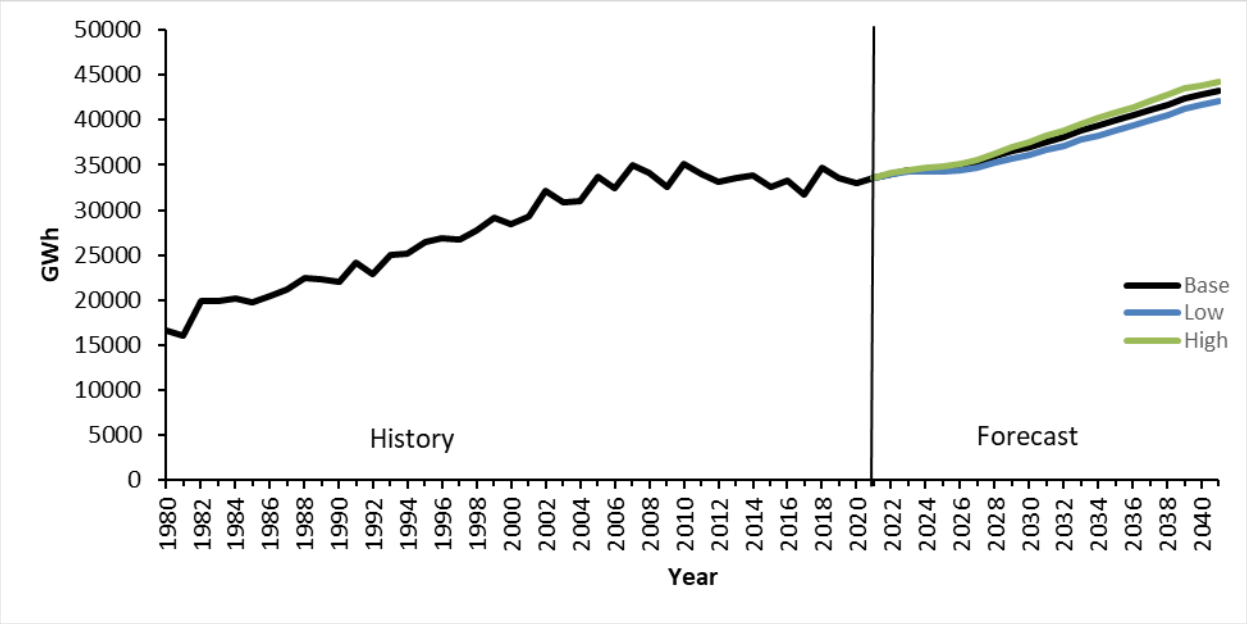
Table 5-5. Residential Model Growth Rates (Percent) for Selected Variables (2023 SUFG Scenarios and 2021 and 2019 Base Forecasts)

Forecast	Current Scenarios (2022-2041)			2021 Forecast (2020-2039)	2019 Forecast (2018-2037)
	Base	Low	High	Base	Base
No. of Customers	1.19	1.17	1.19	1.14	1.09
Electric Rates	0.97	1.06	0.79	1.99	0.92

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

Average Compound Growth Rates (ACGR)			
Forecast Period	Base	Low	High
2022-2041	1.28	1.15	1.38

Figure 5-3. Indiana Residential Electricity Sales by Scenario in GWh



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

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-4, with growth rates provided in Table 5-7. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise through 2027 before leveling off for the rest of the forecast period. SUFG's real price projections for most of the individual IOUs follow similar patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 5-4. Indiana Residential Base Real Price Projections (in 2021 Dollars)

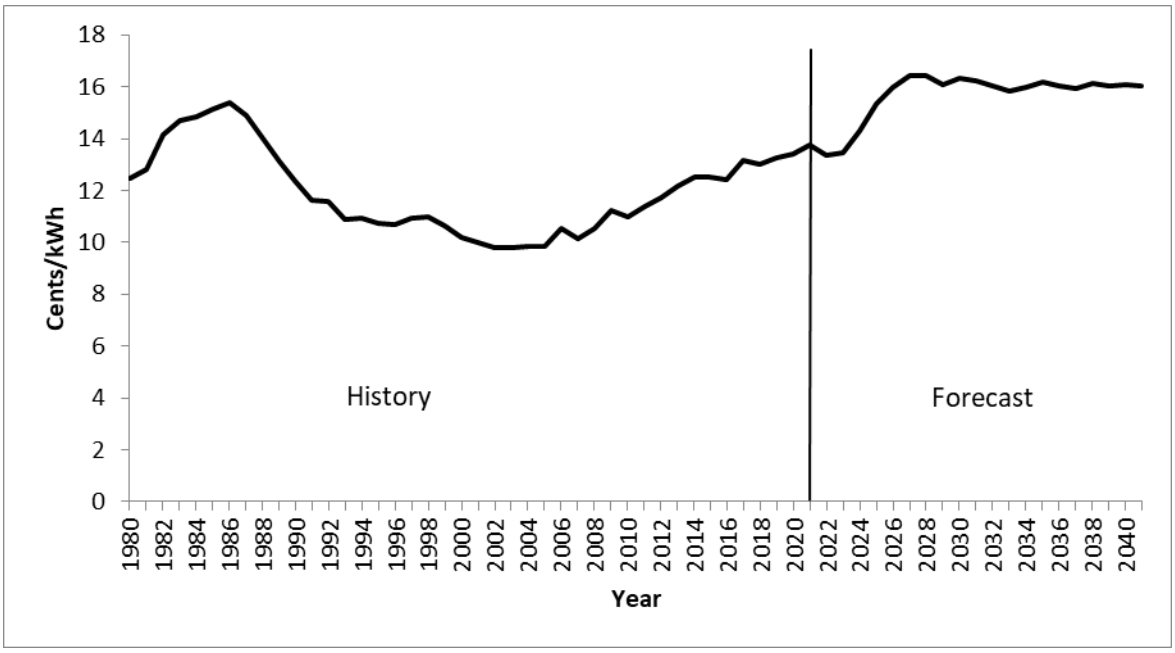


Table 5-7. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	%
2000-2005	-0.72
2005-2010	2.22
2010-2015	2.61
2015-2020	1.40
2020-2025	2.76
2025-2030	1.25
2030-2035	-0.17
2035-2041	0.15
2022-2041	0.97

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

Chapter 6

Commercial Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project commercial electricity sales. These different modeling approaches have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy. CEDMS, however, bears little resemblance to its ORNL ancestor. Like the residential sector end-use model REDMS, Jerry Jackson Associates actively supports CEDMS, with the model re-estimated in 2020. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model commercial energy for the not-for-profit utilities (NFPs) with an econometric approach.

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

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different in the most recent decades.

Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electricity intensity increased rapidly during the era of cheap energy prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during the mid-1970s to mid-1980s period, which resulted in a decrease in energy intensity. As electricity prices fell again during the mid-1980s to late-1990s period, electricity intensity rose but at a slower rate than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average, but these efficiency improvements are offset by an increased demand for energy services.

Over the early- and mid-2000's timeframe, a decrease in economic activity stunted growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. The 2008 economic recession coupled with increasing real electricity prices accelerated these trends, with the notable exception of the stock of commercial floor space. From the mid-2000s on, real electricity prices rose,

commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline and commercial sector electricity use stagnating.

Model Description

Figure 6-1 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the commercial sector as it is for modeling the residential sector. CEDMS categorizes commercial buildings into 21 building types. It also divides energy use in each building type among 9 possible end uses, including a residual use category (labeled "other"). For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-1.) 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:

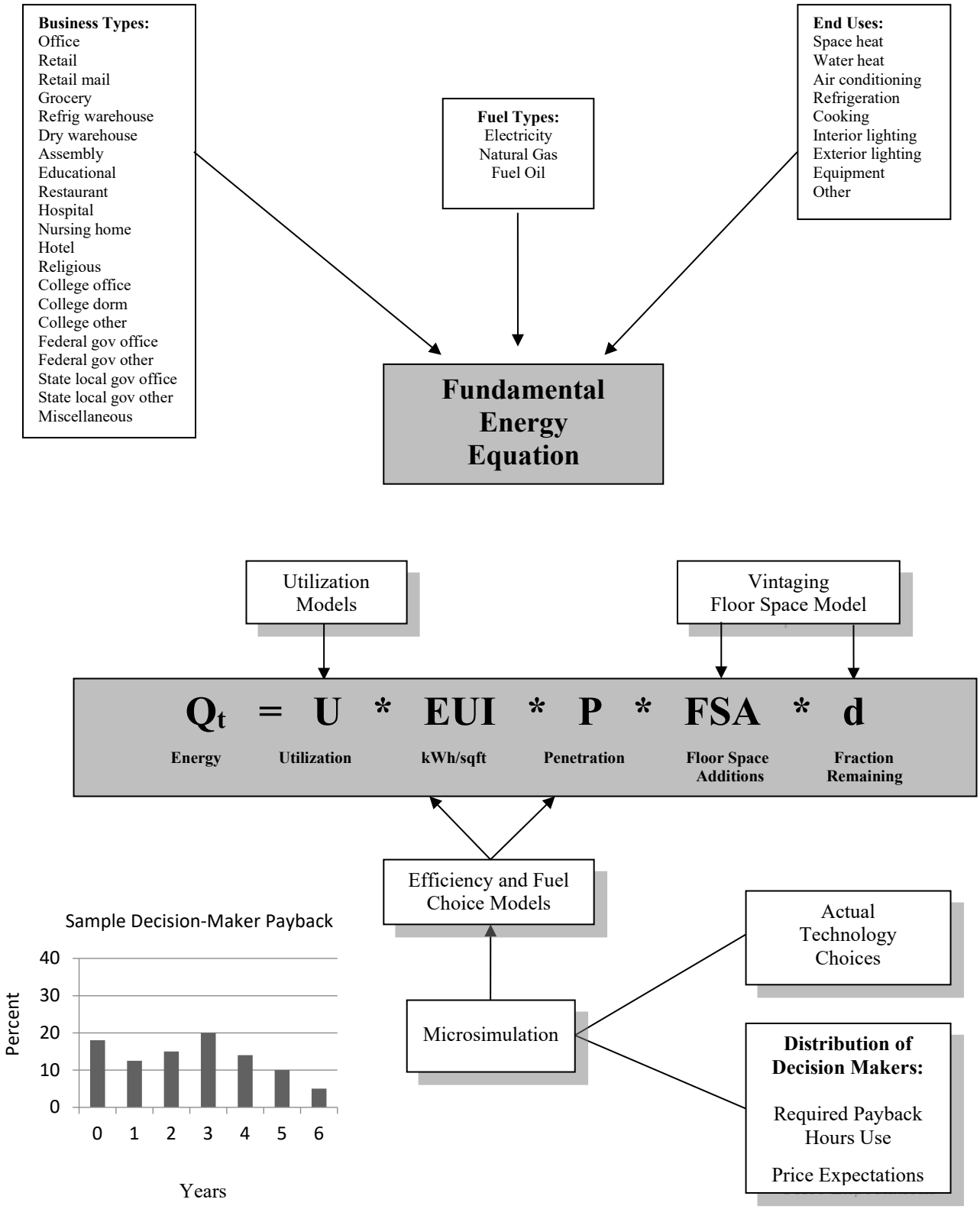
$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

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.

Figure 6-1. Structure of Commercial End-Use Energy Modeling System



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

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

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 offset each other since the total cost of producing the end-use service is unchanged.

Table 6-1 provides the breakdown of the share of square footage of various commercial building types in the service territories of the investor-owned utilities in the first column. The second column shows the share of electricity sales for the building types. The last three columns provide projected compound annual growth rates for the square footage, electricity intensity as measured by annual sales per square foot, and growth in electricity sales.

Table 6-1. Selected Statistics for Indiana's Commercial Sector (Without DSM) (Percent)

Building Type	Current Share of Square Footage	Current Share of Electricity Sales	Forecast Growth in Square Footage	Forecast Growth in Electricity Intensity	Forecast Growth in Electricity Sales
Office	15	16	0.87	-0.49	0.37
Retail	19	22	-0.38	-0.84	-1.22
Grocery	1	4	-0.39	-1.31	-1.69
Warehouse	18	7	-0.47	-0.73	-1.20
Assembly & Religious	13	9	0.49	-0.53	-0.05
Educational	10	7	1.74	-0.53	1.20
Restaurant	3	9	0.72	-0.88	-0.17
Hospital & Nursing Home	5	10	1.60	-0.97	0.61
Hotel	3	3	0.72	-0.44	0.28
College	3	3	0.27	-0.48	-0.21
Government	9	8	0.73	-0.52	0.20
Miscellaneous	1	2	0.05	-0.51	-0.45
Total	100	100	0.45	-0.61	-0.17

Summary of Results

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

significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population) and electricity prices. The sensitivity of the electricity sales projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-2. Changes in commercial floor space have a significant effect on electricity sales, while increases in electricity prices dampen sales.

Table 6-2. Commercial Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Floor space	9.7
Electric Rates	-2.5

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-3 and Figure 6-2. As can be seen, the current base projection of Indiana commercial electricity sales growth declines annually by 0.19 percent. As shown in Figure 6-2, the current projection lies well above the 2021 forecast update although somewhat below the 2019 forecast.

Floor space growth is offset by decreases in utilization. Utilization, the amount of electricity used per unit of floor space, decreases because of increasing electricity prices, low natural gas prices and the implementation of new efficiency standards. Incremental DSM programs have a significant effect on electricity sales.

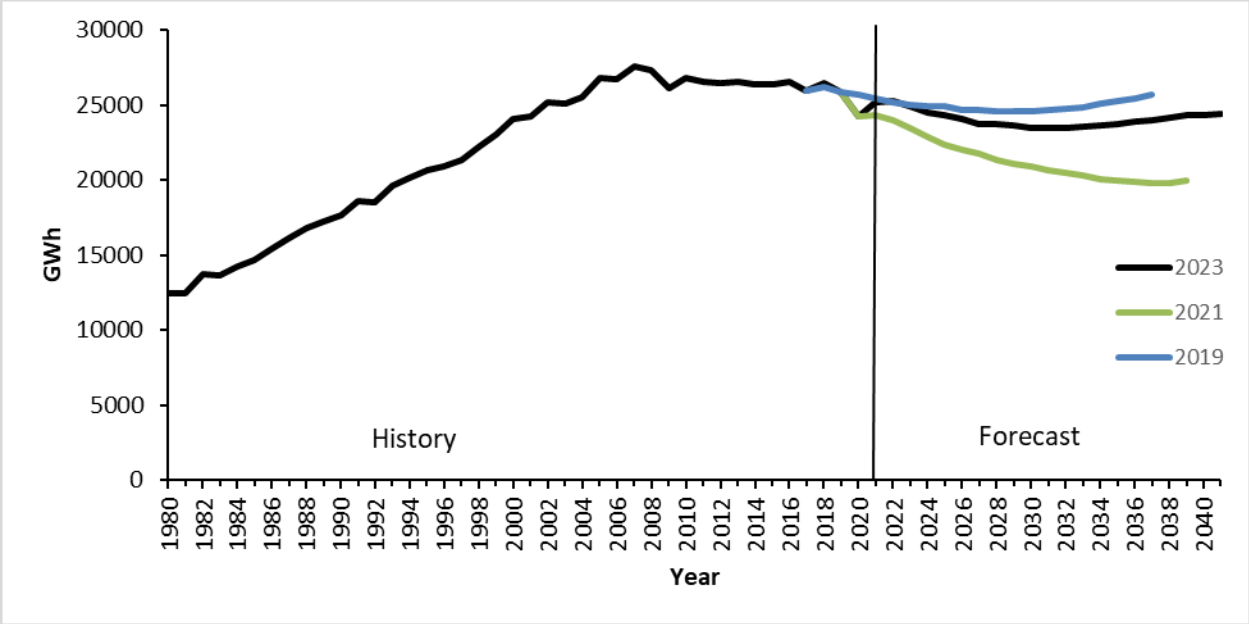
Table 6-4 shows the growth rates for the major explanatory variables. Table 6-5 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG projections. While this forecast has less growth in commercial floorspace than the 2021 forecast had, the electricity sales forecast is higher because of a more moderate reduction in utilization resulting from a lower electricity price projection, lower DSM reductions and the inclusion of electric vehicle charging. The historical and 2023 forecast values are provided in the Appendix to this report.

As shown in Table 6-6 and Figure 6-3, the growth rates for the low and high scenarios are about 0.15 percent lower and 0.14 percent higher than the base scenario, respectively. These differences are primarily due to a difference in floor space growth, with a lesser impact from different amounts of electric vehicles.

Table 6-3. Indiana Commercial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	-0.19	2022-2041
2021	-1.02	2020-2039
2019	-0.10	2018-2037

Figure 6-2. Indiana Commercial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



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

Table 6-4. Commercial Model Growth Rates (Percent) for Selected Variables (2023 SUFG Scenarios and 2021 and 2019 Base Forecasts)

Forecast	Current Scenarios (2022-2041)			2021 Forecast (2020-2039)	2019 Forecast (2018-2037)
	Base	Low	High	Base	Base
Electric Rates	0.89	0.99	0.72	1.59	0.74
Natural Gas Price	-1.06	-1.06	-1.06	0.81	1.44
Energy-weighted Floor Space	0.53	0.43	0.62	0.90	0.78

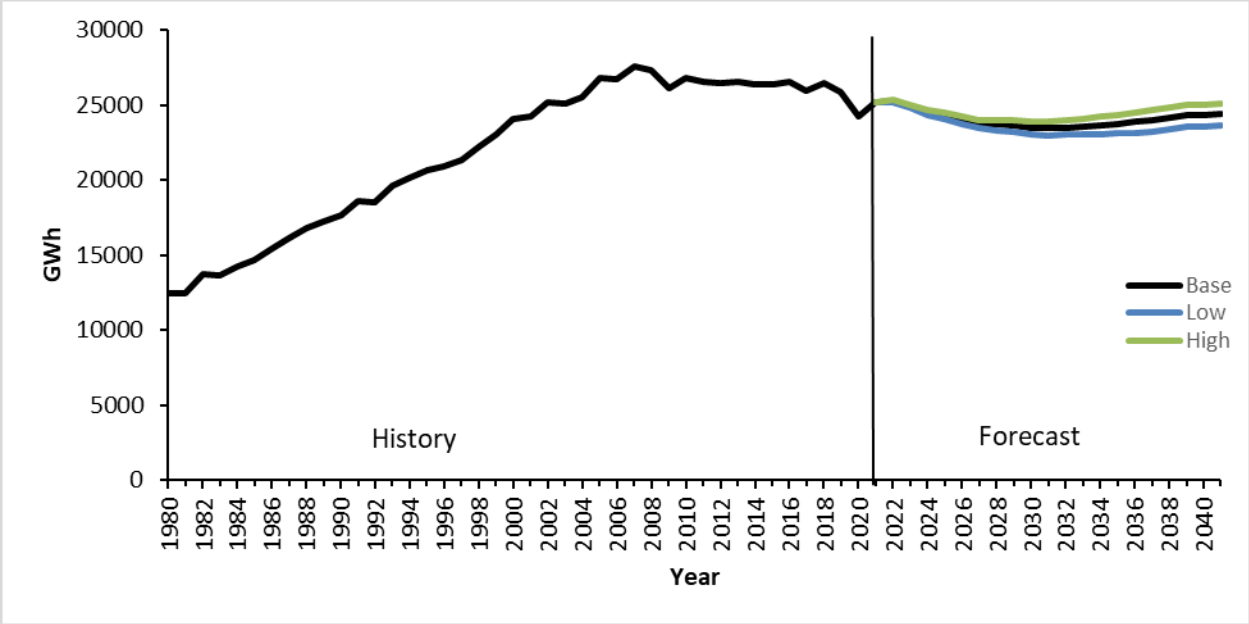
Table 6-5. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-Weighted Floor Space	Without DSM		With DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2023 SUFG Base (2022-2041)	0.53	-0.20	0.33	-0.72	-0.19
2021 SUFG Base (2020-2039)	0.90	-0.75	0.15	-1.92	-1.02
2019 SUFG Base (2018-2037)	0.78	-0.44	0.34	-0.88	-0.10

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

Average Compound Growth Rates (ACGR)			
Forecast Period	Base	Low	High
2022-2041	-0.19	-0.34	-0.05

Figure 6-3. Indiana Commercial Electricity Sales by Scenario in GWh



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

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-4, with growth rates provided in Table 6-7. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to a combination of factors, including increases in fuel costs and stagnant load growth. SUFG projects real commercial electricity prices to rise through 2027 before leveling off for the rest of the forecast period. SUFG's real price projections for most of the individual IOUs follow similar pattern as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix to this report.

Figure 6-4. Indiana Commercial Base Real Price Projections (in 2021 Dollars)

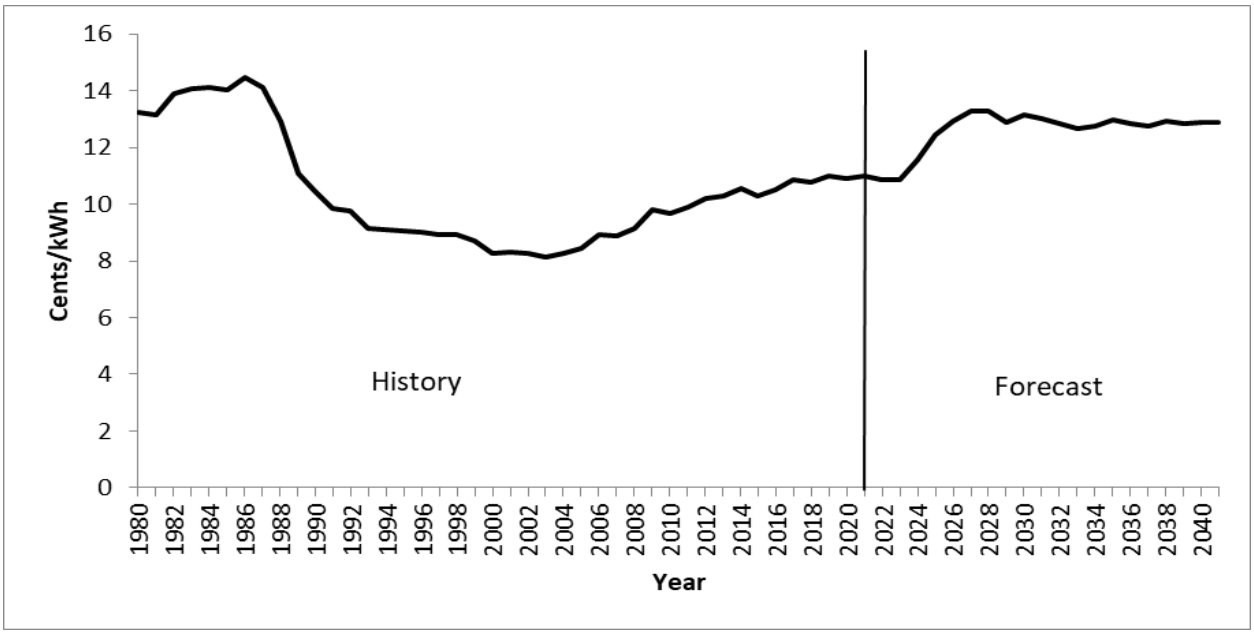


Table 6-7. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	%
2000-2005	0.36
2005-2010	2.76
2010-2015	1.31
2015-2020	1.18
2020-2025	2.66
2025-2030	1.08
2030-2035	-0.27
2035-2041	0.10
2022-2041	0.89

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

Chapter 7

Industrial Electricity Sales

Overview

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

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

Historical Perspective

SUFG distinguishes five recent periods of distinctly different economic activity for real manufacturing product, real electric rates and electric energy sales.

During the decade prior to the OPEC oil embargo, industrial electricity sales steadily increased. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices and growing manufacturing output. During the decade following 1974, sales growth slowed as real electricity prices increased and the state's manufacturing output declined. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" between the mid-1970s and 1980s. The mid-1980s to late-1990s period, experienced another dramatic turnaround. The growth rate of industrial output once again increased, and was substantially above the annual growth rate observed during the pre-embargo era. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales to grow moderately during this period.

The effect of the economic slowdown from late-1990s to mid-2000s was particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Since the mid-2000s real industrial electricity prices have increased, real growth in manufacturing output has continued to be modest, and overall growth in industrial electricity sales has remained stagnant.

Model Description

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

Each model is driven by projections of GSP for selected industries over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Seventy-three percent of state GSP is accounted for by the following industries: primary metals, 10 percent; fabricated metals, 5 percent; industrial machinery and equipment, 7 percent; chemicals, 10 percent; transportation equipment, 36 percent; and electronic and electric equipment, 4 percent.

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

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

Each industrial sector econometric model forecasts 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.

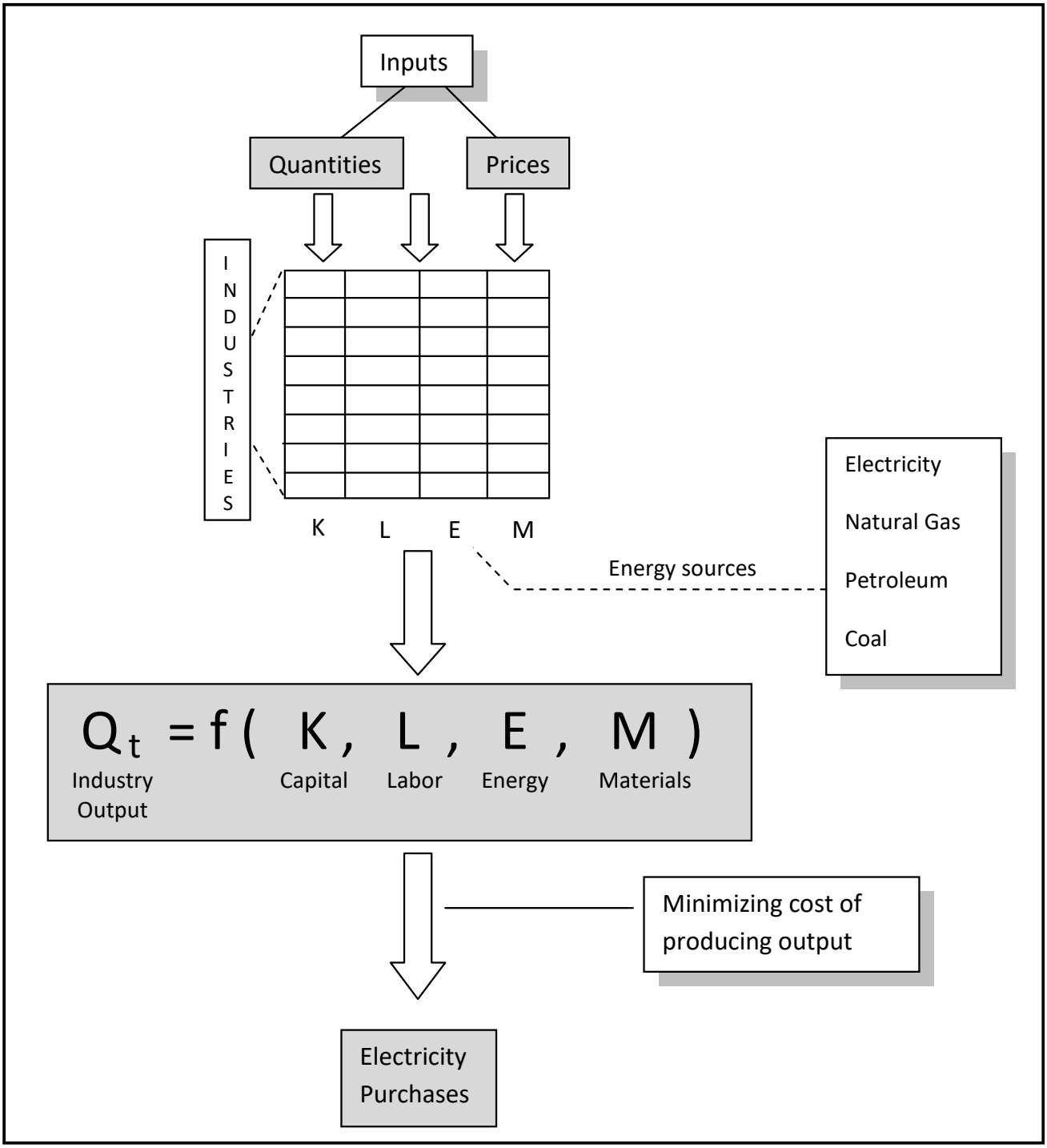
As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimizes the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices, SUFG uses the current EIA forecast, which assumes that real natural gas prices will decrease significantly over the first five years of the forecast horizon before slowly increasing. Distillate prices are projected to follow a similar trajectory of a short-term drop followed by a modest increase. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 0.25 percent per year, without DSM, over the forecast horizon.

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

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	2.97	6.47	0.69	0.84	-0.99	-0.15
21	Tobacco Products	0.001	0.03	9.08	0.84	-0.84	0.001
22	Textile Mill Products	0.05	0.10	0.61	0.84	-1.67	-0.83
23	Apparel & Other Textile Products	0.35	0.08	0.07	0.84	-0.95	-0.11
24	Lumber & Wood Products	1.65	0.81	0.15	0.84	-0.82	0.03
25	Furniture & Fixtures	3.06	0.52	0.05	1.06	-1.19	-0.13
26	Paper & Allied Products	1.14	3.54	0.97	0.84	-0.86	-0.01
27	Printing & Publishing	2.16	0.96	0.14	0.84	-1.25	-0.41
28	Chemicals & Allied Products	10.29	19.59	0.60	0.84	-1.17	-0.33
29	Petroleum & Coal Products	2.97	5.95	0.63	0.84	0.00	0.84
30	Rubber & Misc. Plastic Products	2.85	6.15	0.68	1.93	-1.05	0.88
31	Leather & Leather Products	0.09	0.01	0.03	1.06	-2.02	-0.95
32	Stone, Clay, & Glass Products	3.10	5.27	0.53	1.06	-0.96	0.11
33	Primary Metal Products	10.39	29.45	0.89	-2.20	1.55	-0.65
34	Fabricated Metal Products	5.17	4.45	0.27	0.77	-1.14	-0.37
35	Industrial Machinery & Equipment	7.33	4.39	0.19	1.32	-0.64	0.68
36	Electronic & Electric Equipment	4.39	1.81	0.13	-0.16	-0.57	-0.73
37	Transportation Equipment	35.63	7.97	0.07	2.26	-1.89	0.38
38	Instruments & Related Products	4.16	1.29	0.10	1.06	-1.44	-0.38
39	Miscellaneous Manufacturing	2.25	1.15	0.16	1.06	-1.81	-0.75
Total	Manufacturing	100.00	100.00	0.31	1.24	-0.99	0.25

Figure 7-1. Structure of Industrial Energy Modeling System



Summary of Results

The remainder of this chapter describes SUFG's industrial electricity sales projections. First, the current base projection of industrial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past

base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

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

Table 7-2. Industrial Model Long-Run Sensitivities

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

Indiana Industrial Electricity Sales Projections

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-2. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2019, 2021, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Industrial sector DSM programs are expected to have a small impact on retail sales, due in part to industrial customers having the ability to opt out. The effect of earlier conservation activities is embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2022 level of approximately 38,700 GWh to about 40,200 GWh by 2041. This growth rate of 0.20 percent per year is higher than the -0.19 percent rate projected for the commercial sector and significantly lower than the 1.28 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast shows a decline through 2027, then increases through the remainder of the forecast horizon. The early decline is driven by projected increases in electricity prices in those years.

Compared to the previous forecasts, the growth in industrial electricity sales is impacted by two counterbalancing factors: manufacturing output and electricity intensity (electricity usage per dollar of output). Both the projected growth in manufacturing output (1.24 percent per year vs. 1.31 percent in the last forecast) and the electricity intensity (-0.99 percent per year vs. -0.78 percent) are slightly lower than in the previous forecast. Thus, the growth in industrial sales is more modest in this

forecast than in previous ones. However, due to a higher starting value in this forecast, the industrial electricity sales are higher than in the previous forecast.

Table 7-5 and Figure 7-3 show how industrial electricity sales differ by scenario. Industrial sales, in the high scenario, are expected to increase to 44,940 GWh by 2041, 11.9 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 36,896 GWh sales by 2041, 8.16 percent below the base scenario.

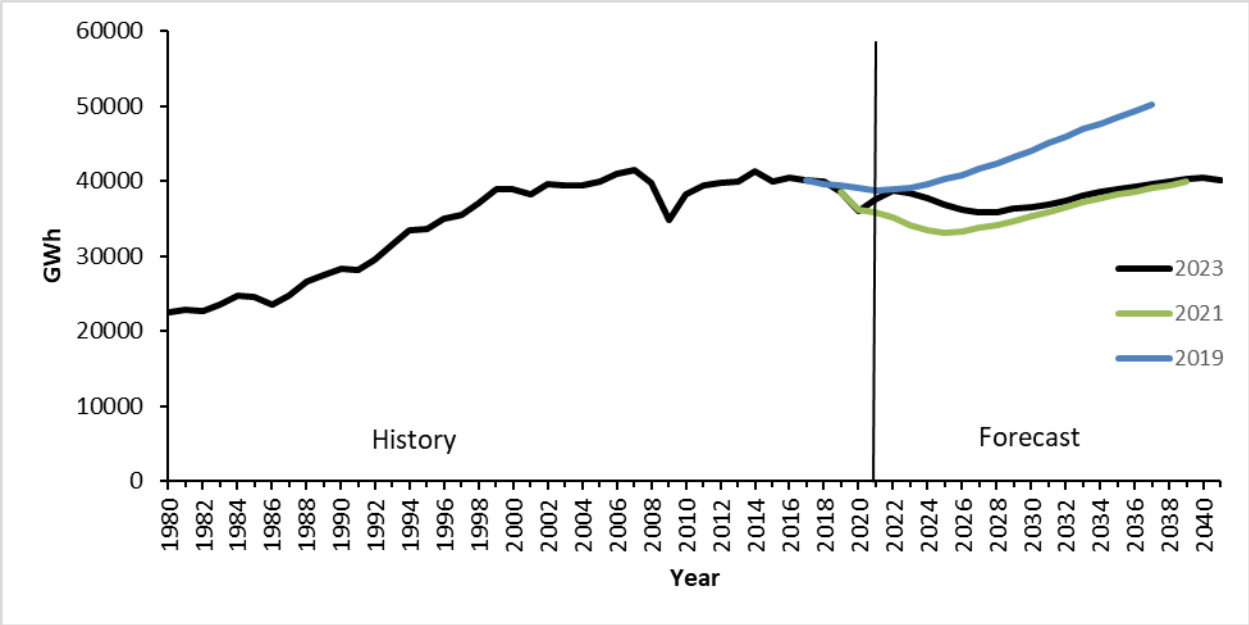
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 1.24 percent per year during the forecast period. That rate is 2.09 percent in the high scenario and 0.40 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

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

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

Average Compound Growth Rates (ACGR)		
Forecast	AGCR	Time Period
2023	0.20	2022-2041
2021	0.53	2020-2039
2019	1.26	2018-2037

Figure 7-2. Indiana Industrial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



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

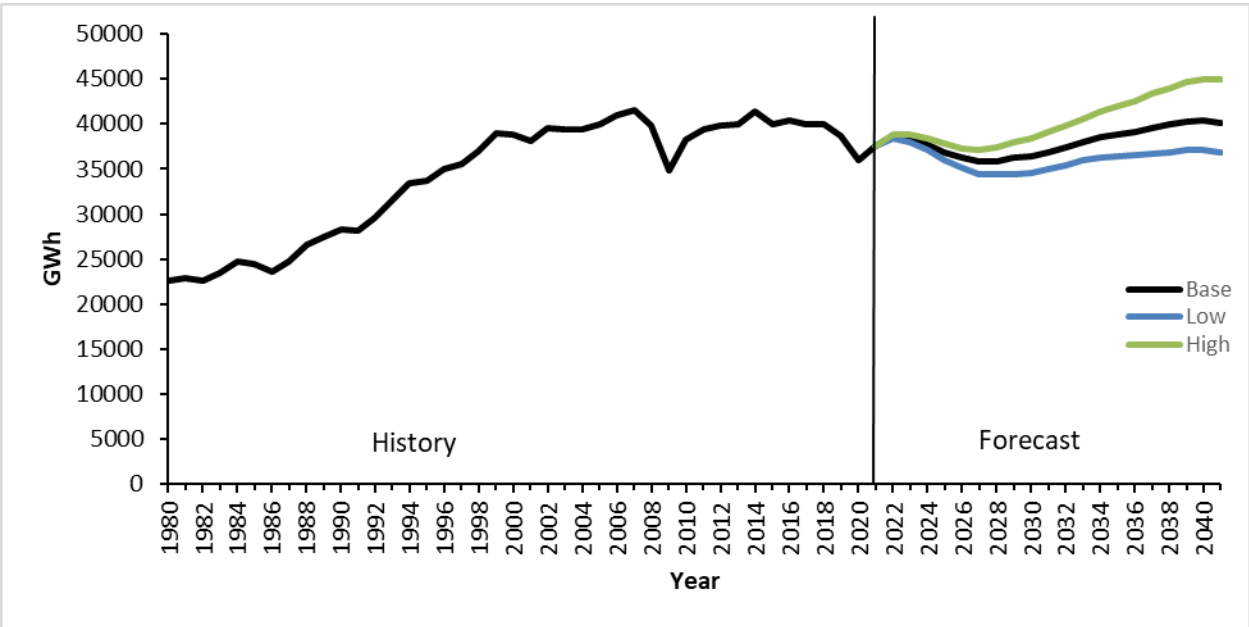
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-Weighted Output	Without DSM		With DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2023 SUFG Base (2022-2041)	1.24	-0.59	0.65	-0.40	0.25	-0.45	0.20
2021 SUFG Base (2020-2039)	1.31	-0.70	0.61	-0.08	0.53	-0.08	0.53
2019 SUFG Base (2018-2037)	1.35	-0.71	0.64	0.62	1.26	0.62	1.26

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

Average Compound Growth Rates (ACGR)			
Forecast Period	Base	Low	High
2022-2041	0.20	-0.22	0.76

Figure 7-3. Indiana Industrial Electricity Sales by Scenario in GWh



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

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-4. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise through 2027 before leveling off for the rest of the forecast period. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-4. Indiana Industrial Base Real Price Projections (Cents/kWh in 2021 Dollars)

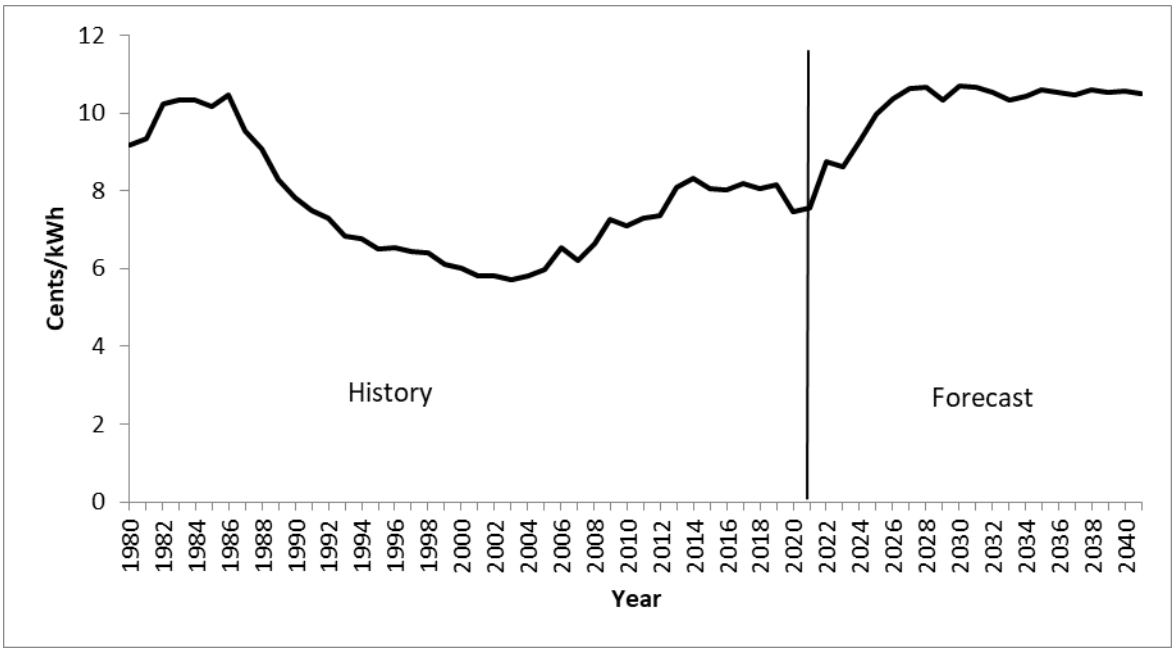


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	%
2000-2005	-0.12
2005-2010	3.54
2010-2015	2.57
2015-2020	-1.53
2020-2025	6.02
2025-2030	1.41
2030-2035	-0.18
2035-2041	0.19
2022-2041	0.97

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

Appendix

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

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

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

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

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

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. I&M's load is split approximately 86-14 percent between Indiana and Michigan. While the majority of WVPA's load is in Indiana, 73 percent, it does have members in Illinois and Missouri. IMPA has a wholesale member in Ohio although approximately 99 percent of their load is in Indiana. Hoosier Energy serves members in Indiana and Illinois. Approximately 95 percent of Hoosier's load is currently in Indiana. These utilities have provided SUFG with data pertaining to their Indiana load.

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

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

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

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

Summer peak demand estimates are based on a combination of FERC Form 1 data and company sources.

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

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

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

SUFG 2023 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	2000	28,489	24,090	38,853	524	91,955	6,759	98,714	16,738
Hist	2001	29,250	24,247	38,175	521	92,193	6,778	98,970	17,511
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Frcst	2022	34,002	25,265	38,671	539	98,478	6,679	105,157	19,955
Frcst	2023	34,351	24,910	38,362	542	98,165	6,659	104,824	20,317
Frcst	2024	34,478	24,503	37,701	545	97,227	6,603	103,830	20,051
Frcst	2025	34,633	24,299	36,866	548	96,347	6,554	102,901	19,847
Frcst	2026	34,948	24,038	36,210	552	95,748	6,517	102,265	19,742
Frcst	2027	35,294	23,753	35,802	555	95,405	6,496	101,901	19,649
Frcst	2028	35,960	23,694	35,890	563	96,107	6,550	102,656	19,679
Frcst	2029	36,586	23,650	36,295	568	97,098	6,620	103,718	19,933
Frcst	2030	36,950	23,428	36,462	568	97,409	6,637	104,046	19,889
Frcst	2031	37,559	23,448	36,906	573	98,486	6,710	105,195	20,086
Frcst	2032	38,145	23,484	37,383	575	99,588	6,782	106,369	20,112
Frcst	2033	38,837	23,583	37,974	579	100,974	6,873	107,846	20,293
Frcst	2034	39,439	23,662	38,500	582	102,184	6,956	109,140	20,356
Frcst	2035	39,972	23,727	38,852	583	103,134	7,019	110,153	20,574
Frcst	2036	40,535	23,856	39,189	584	104,163	7,086	111,249	20,722
Frcst	2037	41,141	24,008	39,614	585	105,347	7,165	112,513	20,955
Frcst	2038	41,719	24,134	39,942	587	106,382	7,232	113,614	21,091
Frcst	2039	42,382	24,310	40,288	589	107,569	7,309	114,878	21,312
Frcst	2040	42,824	24,341	40,393	592	108,150	7,349	115,499	21,489
Frcst	2041	43,282	24,387	40,176	592	108,438	7,368	115,806	21,532

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2000-2005	3.39	2.15	0.58	3.15	1.90	1.84	1.90	3.57
2005-2010	0.86	0.01	-0.87	1.59	-0.04	-0.02	-0.04	0.37
2010-2015	-1.49	-0.34	0.89	-2.23	-0.27	-0.29	-0.27	-1.32
2015-2020	0.30	-1.65	-2.09	-2.25	-1.17	-2.63	-1.27	-0.74
2020-2025	0.93	0.05	0.48	0.74	0.53	0.54	0.53	1.61
2025-2030	1.30	-0.73	-0.22	0.72	0.22	0.25	0.22	0.04
2030-2035	1.58	0.25	1.28	0.52	1.15	1.13	1.15	0.68
2035-2041	1.34	0.46	0.56	0.27	0.84	0.81	0.84	0.76
2022-2041	1.28	-0.19	0.20	0.50	0.51	0.52	0.51	0.40

SUFG 2023 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	2000	28,489	24,090	38,853	524	91,955	6,759	98,714	16,738
Hist	2001	29,250	24,247	38,175	521	92,193	6,778	98,970	17,511
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Frcst	2022	33,923	25,221	38,465	538	98,147	6,655	104,802	19,950
Frcst	2023	34,207	24,826	38,002	540	97,575	6,615	104,189	20,236
Frcst	2024	34,227	24,333	37,087	543	96,190	6,529	102,719	19,892
Frcst	2025	34,263	24,061	35,966	545	94,835	6,448	101,283	19,602
Frcst	2026	34,456	23,746	35,068	548	93,818	6,383	100,201	19,424
Frcst	2027	34,734	23,442	34,488	551	93,216	6,344	99,559	19,293
Frcst	2028	35,255	23,312	34,371	558	93,496	6,368	99,864	19,248
Frcst	2029	35,734	23,198	34,475	561	93,969	6,401	100,370	19,416
Frcst	2030	36,100	23,018	34,624	561	94,303	6,421	100,724	19,384
Frcst	2031	36,630	22,997	35,028	565	95,220	6,484	101,703	19,563
Frcst	2032	37,187	23,006	35,476	568	96,237	6,553	102,791	19,592
Frcst	2033	37,804	23,052	35,944	572	97,372	6,629	104,001	19,733
Frcst	2034	38,318	23,058	36,261	574	98,211	6,688	104,900	19,733
Frcst	2035	38,850	23,101	36,462	577	98,990	6,740	105,730	19,931
Frcst	2036	39,356	23,164	36,561	578	99,660	6,783	106,443	20,000
Frcst	2037	39,915	23,256	36,727	579	100,478	6,837	107,315	20,181
Frcst	2038	40,539	23,375	36,901	582	101,397	6,898	108,294	20,313
Frcst	2039	41,236	23,544	37,160	585	102,526	6,973	109,499	20,529
Frcst	2040	41,663	23,584	37,173	589	103,009	7,008	110,017	20,684
Frcst	2041	42,139	23,649	36,896	590	103,274	7,027	110,302	20,705

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2000-2005	3.39	2.15	0.58	3.15	1.90	1.84	1.90	3.57
2005-2010	0.86	0.01	-0.87	1.59	-0.04	-0.02	-0.04	0.37
2010-2015	-1.49	-0.34	0.89	-2.23	-0.27	-0.29	-0.27	-1.32
2015-2020	0.30	-1.65	-2.09	-2.25	-1.17	-2.63	-1.27	-0.74
2020-2025	0.72	-0.15	-0.01	0.63	0.22	0.22	0.22	1.36
2025-2030	1.05	-0.88	-0.76	0.57	-0.11	-0.08	-0.11	-0.22
2030-2035	1.48	0.07	1.04	0.56	0.97	0.97	0.97	0.56
2035-2041	1.36	0.39	0.20	0.38	0.71	0.70	0.71	0.64
2022-2041	1.15	-0.34	-0.22	0.49	0.27	0.29	0.27	0.20

SUFG 2023 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	2000	28,489	24,090	38,853	524	91,955	6,759	98,714	16,738
Hist	2001	29,250	24,247	38,175	521	92,193	6,778	98,970	17,511
Hist	2002	32,168	25,195	39,580	534	97,478	7,182	104,660	18,831
Hist	2003	30,912	25,131	39,355	584	95,982	7,052	103,034	18,794
Hist	2004	31,005	25,482	39,458	638	96,582	7,083	103,665	18,193
Hist	2005	33,654	26,787	39,988	612	101,042	7,406	108,447	19,944
Hist	2006	32,488	26,711	41,006	596	100,801	7,382	108,182	20,855
Hist	2007	34,972	27,611	41,477	638	104,698	7,671	112,369	20,858
Hist	2008	34,099	27,274	39,800	625	101,798	7,463	109,260	19,275
Hist	2009	32,611	26,127	34,867	631	94,236	6,921	101,157	19,054
Hist	2010	35,119	26,800	38,271	662	100,852	7,396	108,248	20,315
Hist	2011	33,994	26,551	39,440	640	100,625	7,378	108,003	21,729
Hist	2012	33,077	26,452	39,842	597	99,968	7,330	107,298	21,048
Hist	2013	33,596	26,517	39,930	602	100,644	7,373	108,017	20,423
Hist	2014	33,843	26,360	41,350	614	102,167	7,468	109,635	20,111
Hist	2015	32,573	26,346	40,002	592	99,513	7,289	106,802	19,013
Hist	2016	33,230	26,546	40,463	598	100,837	7,396	108,233	18,872
Hist	2017	31,773	25,909	40,025	595	98,301	7,215	105,516	18,076
Hist	2018	34,633	26,478	39,980	595	101,686	7,280	108,966	19,367
Hist	2019	33,559	25,832	38,649	567	98,607	7,012	105,619	19,012
Hist	2020	33,062	24,237	35,986	528	93,814	6,379	100,193	18,323
Hist	2021	33,536	25,179	37,607	525	96,847	6,544	103,392	19,524
Frcst	2022	34,078	25,313	38,895	541	98,827	6,705	105,531	19,959
Frcst	2023	34,488	25,003	38,834	544	98,869	6,709	105,578	20,407
Frcst	2024	34,669	24,636	38,408	548	98,262	6,675	104,936	20,200
Frcst	2025	34,859	24,474	37,766	551	97,649	6,644	104,293	20,046
Frcst	2026	35,173	24,222	37,256	555	97,206	6,617	103,823	19,964
Frcst	2027	35,609	24,009	37,064	558	97,241	6,621	103,862	19,937
Frcst	2028	36,328	23,987	37,362	566	98,243	6,694	104,936	20,019
Frcst	2029	36,990	23,967	37,909	571	99,437	6,776	106,213	20,307
Frcst	2030	37,538	23,864	38,413	576	100,391	6,841	107,232	20,378
Frcst	2031	38,204	23,917	39,075	579	101,776	6,933	108,710	20,633
Frcst	2032	38,878	23,998	39,811	583	103,270	7,032	110,302	20,716
Frcst	2033	39,578	24,103	40,587	586	104,853	7,135	111,989	20,927
Frcst	2034	40,216	24,201	41,346	589	106,352	7,238	113,590	21,044
Frcst	2035	40,801	24,286	41,932	588	107,607	7,319	114,926	21,306
Frcst	2036	41,454	24,453	42,592	590	109,089	7,416	116,504	21,542
Frcst	2037	42,137	24,647	43,355	592	110,731	7,525	118,256	21,847
Frcst	2038	42,793	24,825	44,028	594	112,240	7,623	119,863	22,063
Frcst	2039	43,501	25,038	44,707	596	113,842	7,727	121,569	22,358
Frcst	2040	43,832	25,018	44,927	594	114,371	7,759	122,130	22,532
Frcst	2041	44,216	25,052	44,940	595	114,803	7,788	122,590	22,608

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
2000-2005	3.39	2.15	0.58	3.15	1.90	1.84	1.90	3.57
2005-2010	0.86	0.01	-0.87	1.59	-0.04	-0.02	-0.04	0.37
2010-2015	-1.49	-0.34	0.89	-2.23	-0.27	-0.29	-0.27	-1.32
2015-2020	0.30	-1.65	-2.09	-2.25	-1.17	-2.63	-1.27	-0.74
2020-2025	1.06	0.19	0.97	0.83	0.80	0.82	0.81	1.81
2025-2030	1.49	-0.50	0.34	0.89	0.56	0.59	0.56	0.33
2030-2035	1.68	0.35	1.77	0.44	1.40	1.36	1.40	0.89
2035-2041	1.35	0.52	1.16	0.18	1.08	1.04	1.08	0.99
2022-2041	1.38	-0.05	0.76	0.50	0.79	0.79	0.79	0.66

Indiana Base Average Retail Rates (Cents/kWh) (in 2021 Dollars)

Year	Res	Com	Ind	Average
2000	10.21	8.27	6.00	7.77
2001	10.01	8.32	5.82	7.69
2002	9.80	8.25	5.81	7.64
2003	9.77	8.14	5.72	7.55
2004	9.84	8.27	5.80	7.65
2005	9.85	8.42	5.96	7.82
2006	10.56	8.92	6.53	8.36
2007	10.15	8.89	6.22	8.15
2008	10.55	9.12	6.64	8.54
2009	11.22	9.79	7.25	9.25
2010	10.99	9.65	7.09	9.06
2011	11.39	9.91	7.30	9.29
2012	11.70	10.18	7.38	9.46
2013	12.15	10.29	8.09	9.98
2014	12.53	10.55	8.33	10.24
2015	12.50	10.30	8.05	10.04
2016	12.41	10.51	8.03	10.09
2017	13.18	10.86	8.19	10.44
2018	12.99	10.77	8.05	10.39
2019	13.28	11.01	8.15	10.59
2020	13.40	10.92	7.45	10.40
2021	13.73	11.01	7.57	10.54
2022	13.37	10.88	8.74	10.80
2023	13.47	10.85	8.62	10.79
2024	14.28	11.55	9.27	11.53
2025	15.35	12.45	9.98	12.44
2026	16.00	12.92	10.37	12.96
2027	16.43	13.26	10.63	13.33
2028	16.45	13.27	10.66	13.37
2029	16.07	12.89	10.32	13.01
2030	16.33	13.14	10.71	13.32
2031	16.23	13.03	10.66	13.25
2032	16.05	12.85	10.52	13.09
2033	15.83	12.65	10.33	12.88
2034	16.00	12.76	10.43	13.01
2035	16.19	12.96	10.61	13.20
2036	16.05	12.86	10.54	13.10
2037	15.93	12.76	10.45	13.01
2038	16.13	12.94	10.61	13.19
2039	16.02	12.84	10.53	13.11
2040	16.07	12.88	10.56	13.16
2041	16.05	12.88	10.49	13.14
Average Compound Growth Rates (%)				
Year-Year	Res	Com	Ind	Average
2000-2005	-0.72	0.36	-0.12	0.12
2005-2010	2.22	2.76	3.54	2.97
2010-2015	2.61	1.31	2.57	2.09
2015-2020	1.40	1.18	-1.53	0.70
2020-2025	2.76	2.66	6.02	3.65
2025-2030	1.25	1.08	1.41	1.38
2030-2035	-0.17	-0.27	-0.18	-0.18
2035-2041	0.15	0.10	0.19	0.08
2022-2041	0.97	0.89	0.97	1.04

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

List of Acronyms

ACGR	Average Compound Growth Rates
AEO	U.S. Energy Information Administration Annual Energy Outlook
BMV	Indiana Bureau of Motor Vehicles
Btu	British thermal unit
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CT	Combustion Turbine
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVI-Pro	U.S. Department of Energy Electric Vehicle Infrastructure Projection Tool
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatt-hour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatt-hour
LPG	Liquefied Petroleum Gas
mmBtu	million British thermal units
MISO	Midcontinent Independent System Operator
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
NREL	National Renewable Energy Laboratory
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
REDMS	Residential Energy Demand Modeling System
REEMS	Residential End-Use Energy Modeling System
RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SIC	Standard Industrial Classification
sqft	square feet
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association