INDIANA ELECTRICITY PROJECTIONS: THE 2002 FORECAST UPDATE

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Summary

- Despite the recent economic slowdown, Indiana's electricity energy use is expected to return to its pre-slowdown trajectory by 2006; peak demand is now predicted to be higher than expected pre-slowdown levels through the forecast period.
- On the supply side, additional utility-owned capacity to shortly come on-line offsets the closing of one major station, leaving utility-owned capacity roughly where it was previously.
- As a result, statewide short-term need for new capacity, driven by the higher peak demand estimates, is larger than that predicted prior to the slowdown. The State Utility Forecasting Group (SUFG) now expects an additional 1,200 MW to be needed by 2003, with 3,770 MW needed by 2005.
- A cumulative total of 10,900 MW (a 50 percent increase in state generating capacity) will be needed by 2020, including 2,910 MW of peaking capacity.
- Real electricity prices are predicted to decline shortly early in the forecast, then begin to rise gradually starting in 2005.

Overview

In November 2001, SUFG released its eighth set of projections of future electricity requirements for the state of Indiana. That forecast was based on a forecast of economic activity that was produced in February 2001. Since that economic activity forecast was released, the national economy has weakened due to several factors, including the terrorist attacks of September 11. Therefore, SUFG has produced an update to its forecast, so that the current economic climate is more accurately reflected. This report, which is based on the February 2002 macroeconomic forecast from the Center for Econometric Modeling Research (CEMR) at Indiana University, summarizes that update.

The updated projection of electricity usage is significantly below the 2001 projection for the first five years. After 2006, the two projections are nearly identical. This forecast projects electricity usage to grow at an average yearly rate of 2.14 percent. This growth rate is somewhat higher than the 1.87 percent growth projected in SUFG's 2001 forecast, with the difference resulting from the lower usage at the beginning of the forecast and the subsequent recovery. Peak electricity demand is projected to grow at an average rate of 2.00 percent annually, which is virtually the same as the 1.95 percent growth projected in the 2001 forecast. This corresponds to about 400 megawatts (MW) of increased peak demand per year.

In addition to having a slightly higher long-term growth rate, the peak demand projections are higher in the first years of this forecast as compared to the previous forecast. This is a result of a combination of two factors: re-calibrating the peak demand models using more recent data and a reduction in the amount of interruptible load reported by the utilities.

SUFG's peak demand projections are based on "normal" weather patterns. In order to calibrate the peak demand forecast, the actual peak demand numbers are weather normalized, resulting in an approximation of the peak demand under normal conditions. In general, the weather normalization process is more accurate for actual weather conditions that are closer to normal and less accurate for extreme conditions. The previous forecast started from two years with extreme summer weather: first, 1999 had a prolonged heat wave at the time of the system peak demand and second, 2000 had an exceptionally cool summer. This forecast is calibrated to the summer of 2001, which was cooler than normal, but not extremely so. The combined effect of the re-calibration and the reduction in interruptible loads is an increase from the previous forecast to this update of approximately 600 MW in peak demand in 2002.

Real electricity prices decline early during the forecast period and are offset by increases during the last three-fourths of the forecast period. Since the change in prices is relatively small, price has little impact on the electricity requirements projections.

In the 1999 forecast, SUFG identified a concern regarding whether sufficient new capacity would be available to meet expected growth in usage. In the 2001 forecast, SUFG noted that while additional capacity would still be required, the overall concern had been alleviated to some extent due to increased merchant capacity being available and increased usage of interruptible loads. Since that report, both the estimates of total merchant plant capacity and the amount of interruptible load have decreased, and the schedule of merchant plant availability has been delayed.

At the time of SUFG's last forecast, there were 11,680 MW of new merchant capacity either planned, approved or installed within Indiana. SUFG now estimates that only 11,039 MW are planned, approved, or installed, and of that total, two plants, totaling 1,140 MW, are currently delayed. Further, interruptible load data provided by the utilities indicate that there will be 840 MW classified as interruptible, down from 1,030 MW in the previous forecast.

While those two factors are still important, significant changes in utility-owned capacity have occurred since the 2001 forecast was released. First, with Northern Indiana Public Service Company's (NIPSCO) shutdown of its Mitchell Generating Station, utility-owned capacity was removed from the state's generating fleet for the first time since 1993. Second, new utility-owned combustion turbine generators--owned by Indianapolis Power & Light Company (IPL) and Southern Indiana Gas and Electric Company (SIGECO)--were brought on line for the first time since 1994. Additionally, the Noblesville repowering by PSI Energy and Indiana Municipal Power Association's (IMPA) new combustion turbine will increase the amount of generation owned and controlled by Indiana utilities. The reduction in capacity from the Mitchell shutdown (528 MW) and the increase in capacity from the new combustion turbines and the Noblesville repowering (499 MW) tend to offset each other.

While SUFG acknowledged in the 2001 forecast that the concern over the sufficiency of capacity had been alleviated in part, it did also note that Indiana would still need additional capacity. That need is still present in this update and is even more pronounced as a result of the higher peak demand trajectory in the updated forecast. SUFG now expects an additional 1,200 MW to be needed by 2003, with 3,770 MW needed by 2005. A cumulative total of 10,590 MW, including 2,910 MW of peaking capacity, will be needed by 2020. This represents a 50 percent increase in statewide generating capacity. In recent years, utilities have used a combination of relatively short-term purchase contracts (one to two years in duration) and acquisition of additional generating facilities to meet increased demand. While SUFG does not attempt to determine which strategy is best for a particular utility, that strategy is expected to continue to be used.

The Regulated Modeling System

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

Resource needs are determined on a statewide basis by matching existing statewide resources to projected diversified statewide peak demand plus reserves. For planning purposes, SUFG assumed a 15 percent reserve margin[1] for the state. Due to diversity in demand among the utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. When the state reserve margin falls below 15 percent, resource additions are chosen from a list of resource options based on an analysis of load versus existing capacity for individual utilities.

The dynamic interactions between customer purchases, a utility's operating and investment decisions and customer rates are captured by cycling through the various submodels until an equilibrium, or balance, among demand, supply and price is attained.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables.[2] These assumptions are summarized below.

Economic Activity Projections. One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by CEMR. SUFG used CEMR's February 2002 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 0.92 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.18 percent. Other key economic projections follow:

- Real personal income (the residential sector model driver) is expected to grow at a 2.11 percent annual rate.
- Non-manufacturing employment (the commercial sector model driver) is expected to average 1.71 percent annual growth rate over the forecast horizon.
- Despite the continued decline of manufacturing employment, manufacturing Gross State Product (GSP) (the industrial sector model driver) is expected to rise at a 0.95 percent annual rate as gains in productivity offset declines in employment.

SUFG's energy models for the industrial sector operate at the two-digit Standard Industrial Classification (SIC) code level. In preparing this forecast, SUFG used the CEMR projections of GSP for SIC code 33, a large, intensive user of electricity composed largely of steel production, as the driver in the NIPSCO service area model and used aggregate manufacturing in all other service areas. The logic behind this is that the downturn in steel production has had a larger effect on the integrated mills than the mini-mills and the integrated mills are concentrated in the NIPSCO service area.

1. SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 15 percent reserve margin is equivalent to a 13 percent capacity margin.

   Capacity Margin = [(Capacity - Demand) / Capacity]

   Reserve Margin = [(Capacity - Demand) / Demand]
2. Exogeneous variables are those variables that are determined outside the modeling system and are then used as inputs to the system.

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

Demographic Projections. Population growth for all scenarios is 0.25 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University.

The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 0.65 percent over the forecast period.

Fossil Fuel Price Projections. All SUFG projections are in terms of real prices, i.e., projections with the effect of inflation removed. SUFG's current assumptions are based on the December 2001 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price projections are as follows:

- *Natural Gas Prices*: Gas price projections for all customers stop increasing after the year 2001, fall in 2002, then increase over the remainder of the forecast horizon.
- *Utility Price of Coal*: Coal prices will decline slightly in real terms throughout the entire forecast horizon.

The Base Scenario

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 assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG developed low and high growth scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first. The statewide results for the base scenario are presented in this section, along with the associated resource and equilibrium price implications.

As shown in Figures 1 and 2, SUFG's current base scenario projection indicates annual growth of electricity requirements and peak demand of 2.14 and 2.00 percent, respectively. The shaded numbers in the tables and the heavy line in the graphs indicate historical values.

The increased growth rates in the projections of electricity requirements can be traced to substantially higher growth in industrial sales, which is offset somewhat by lower growth in the residential sector sales, as shown in Table 1. The growth rates for projected commercial sector sales is similar to that reported in SUFG's previous forecast.

Table 1. Annual Electricity Sales Growth (%) By Sector (Current vs. 2001 Projections)

	Electricity Sales Growth	
Sector	**Current (2001-20)**	**2001 (2000-19)**
Residential	1.62	2.02
Commercial	2.55	2.57
Industrial	2.30	1.32
Total	**2.14**	**1.87**

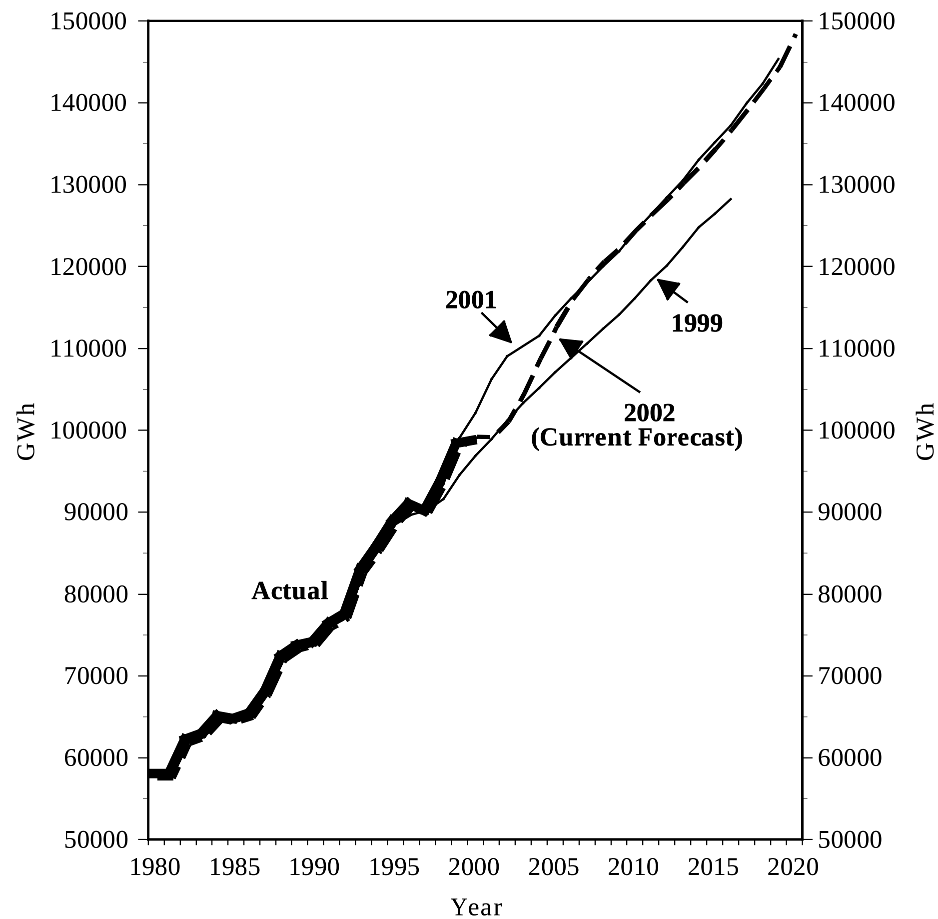
The increased growth rate for industrial sales is due to a lower starting point with slow growth in the first few years of the forecast, then substantial growth as the manufacturing sector of the Indiana economy recovers with strong improvement in those industries that make intensive use of electricity (chemicals, primary metals, transportation, as well as fabricated metals and industrial machinery).

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

Year	Year of Forecast 1999	2001	2002
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	88514	88514	88514
1996	90637	90637	90637
1997	90237	89773	89773
1998	91634	93429	93429
1999	94561	98001	98001
2000	96867	102116	98332
2001	98922	106257	99326
2002	101170	109014	101240
2003	103298	110294	104729
2004	105179	111515	108905
2005	107058	113997	112798
2006	108833	116118	116068
2007	110601	118017	118603
2008	112433	120012	120742
2009	114148	121892	122483
2010	116124	124225	124547
2011	118291	126317	126512
2012	120130	128418	128365
2013	122389	130497	130421
2014	124797	133048	132350
2015	126406	135161	134541
2016	128237	137244	136855
2017		139973	139326
2018		142342	141866
2019		145333	144522
2020			148534

Average Compound Growth Rates

Forecast Period	1997-16	2000-19	2001-20
	1.87	1.87	2.14



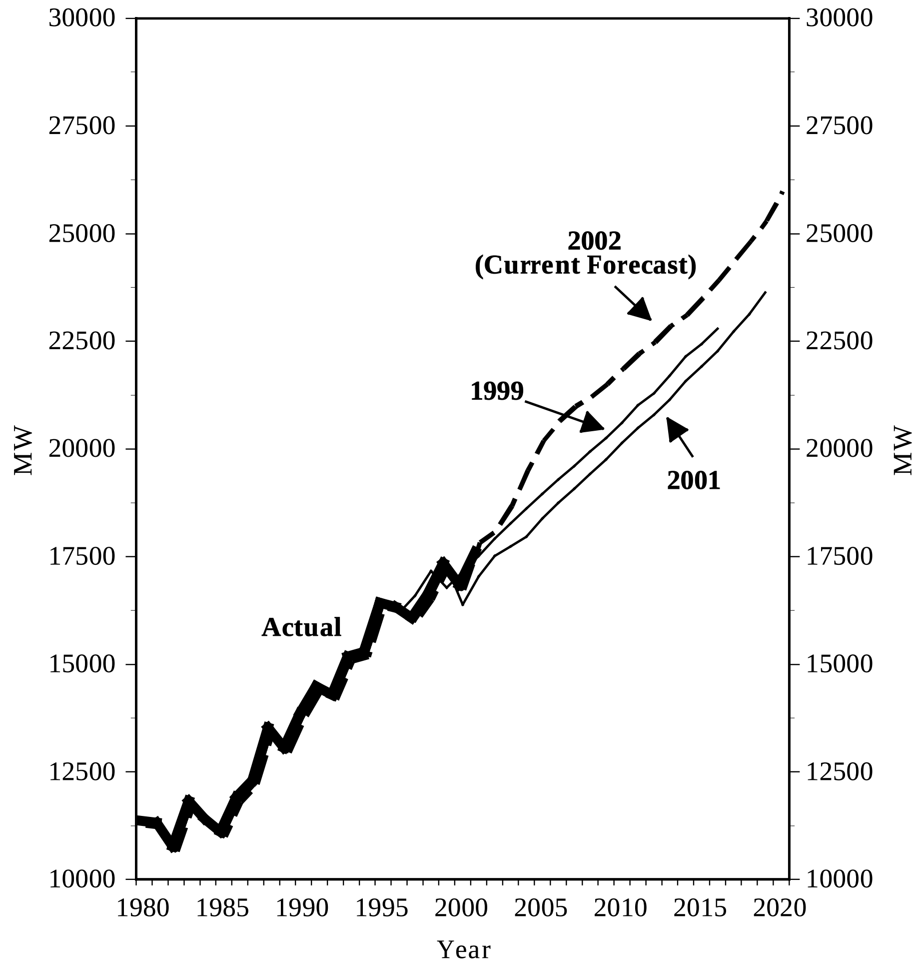
Notes: The shaded numbers in the table and the heavy line in the graph are historical values.

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

Year	Year of Forecast 1999	2001	2002
1990	13775	13775	13775
1991	14403	14403	14403
1992	14209	14209	14209
1993	15103	15103	15103
1994	15198	15198	15198
1995	16342	16342	16342
1996	16254	16254	16254
1997	16596	15993	15993
1998	17168	16527	16527
1999	16779	17266	17266
2000	17145	16383	16757
2001	17514	17038	17863
2002	17917	17519	18129
2003	18279	17739	18708
2004	18620	17964	19528
2005	18962	18385	20227
2006	19288	18748	20684
2007	19604	19080	21013
2008	19936	19422	21236
2009	20248	19756	21538
2010	20614	20143	21891
2011	21019	20493	22243
2012	21290	20795	22517
2013	21703	21146	22888
2014	22142	21568	23142
2015	22443	21912	23537
2016	22789	22269	23952
2017		22729	24396
2018		23133	24853
2019		23633	25328
2020			26016

Average Compound Growth Rates

Forecast Period	1997-16	2000-19	2001-20
	1.68	1.95	2.00



Notes: The shaded numbers in the table and the heavy line in the graph are historical values.

The growth in peak demand is almost identical to that projected in 2001. The rate of growth reported in Figure 2 is somewhat higher earlier in the forecast horizon. The projections of peak demand are for normal weather patterns, and projected peak demand for long-run planning is reduced by interruptible loads. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 2, the annual increase is about 400 MW.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources (firm purchases) to meet forecast demand. Demand-side management (DSM) impacts and interruptible loads are netted from the demand projection and supply-side resources are added as necessary to maintain a 15 percent reserve margin. Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are least cost.

Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs are projected to reduce peak demand by approximately 10 MW.

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Approximately 840 MW of large load is classified as interruptible in this forecast, about 200 MW less than in the 2001 forecast.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, deratings due to NOx control retrofits and net changes in firm out-of-state purchases and sales. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added as necessary during the forecast period to maintain a statewide 15 percent reserve margin. The 15 percent reserve margin is a "rule-of-thumb" that reflects recent national average reserve margins. Due to diversity in demand between utilities, a statewide 15 percent reserve margin occurs when individual utility reserve margins are roughly 11 percent. In some instances, firm purchases have been added to maintain individual utility reserve margins at 6 percent, even if the state as a whole does not need new capacity.

Three types of generic firm wholesale purchases are included:

1. gas-fired combustion turbine peaking units;
2. gas-fired combined cycle cycling units; and
3. SO_2 and NOx controlled pulverized coal-fired base load units.

The type of generic wholesale purchase included is determined at the individual utility level by comparing the mix of existing capacity to the amount of electricity needed by type. SUFG assigns existing capacity to one of the types according to unit size, operating costs, and historical usage. Capacity need by type is determined from historical annual load duration curves.

The costs for these purchases are determined using cost-based capacity and energy charges, rather than by attempting to predict hour by hour market clearing prices in Midwest wholesale markets. The capacity charge is determined using the fixed operation and maintenance (O&M) costs and an appropriate return on investment costs to the owner of the generation. The energy charge is determined by the variable O&M costs and fuel costs for the appropriate generator type.

Table 2 and Figure 3 show the statewide resource plan for the SUFG base scenario. Over the first half of

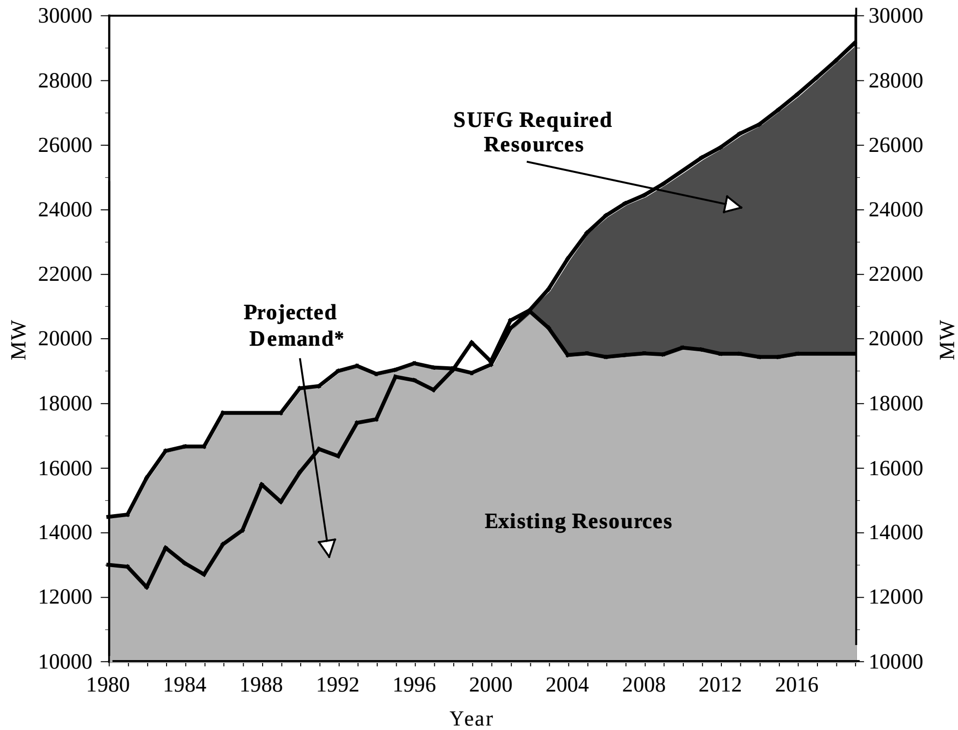
Table 2. Indiana Resource Plan (SUFG Base)

Year	Uncontrolled Peak Demand [1]	Interruptible Loads	Net Peak Demand [2]	Existing/ Approved Capacity [3]	Incremental Change in Capacity [4]	Projected Additional Capacity Requirements [5]				Total Capacity [6]	Reserve Margin
						Peaking	Cycling	Baseload	Total		
2000			16757	19170						19170	14
2001	18540	677	17863	20294	1124	0	0	0	0	20294	14
2002	18818	689	18129	20825	531	90	30	0	120	20945	16
2003	19422	714	18708	20305	-520	460	300	440	1200	21505	15
2004	20292	764	19528	19473	-832	1080	900	990	2970	22443	15
2005	21006	779	20227	19514	41	1290	990	1490	3770	23284	15
2006	21468	784	20684	19414	-100	1410	1080	1890	4380	23794	15
2007	21812	799	21013	19466	52	1500	1080	2120	4700	24166	15
2008	22044	809	21236	19516	50	1440	1060	2400	4900	24416	15
2009	22367	829	21538	19488	-28	1550	1120	2610	5280	24768	15
2010	22735	844	21891	19693	205	1500	1140	2830	5470	25163	15
2011	23087	844	22243	19633	-60	1620	1250	3070	5940	25573	15
2012	23361	844	22517	19508	-125	1750	1390	3260	6400	25908	15
2013	23732	844	22888	19508	0	1880	1440	3490	6810	26318	15
2014	23986	844	23142	19408	-100	2000	1520	3690	7210	26618	15
2015	24381	844	23537	19405	-3	2150	1580	3940	7670	27075	15
2016	24796	844	23952	19505	100	2240	1630	4160	8030	27535	15
2017	25240	844	24396	19505	0	2360	1700	4490	8550	28055	15
2018	25697	844	24853	19505	0	2470	1760	4850	9080	28585	15
2019	26172	844	25328	19505	0	2580	1830	5200	9610	29115	15
2020	26860	844	26016	19342	-163	2910	1910	5770	10590	29932	15

Notes:

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

Figure 3. Indiana Resource Plan (SUFG Base)



*Projected Demand includes 15% Reserve Margin

the forecast period, about 5,500 MW of wholesale purchases are required. The net change in generation includes the retirement of units as reported in the utilities' 2001 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 5,000 MW of resources are required to maintain target reserves.

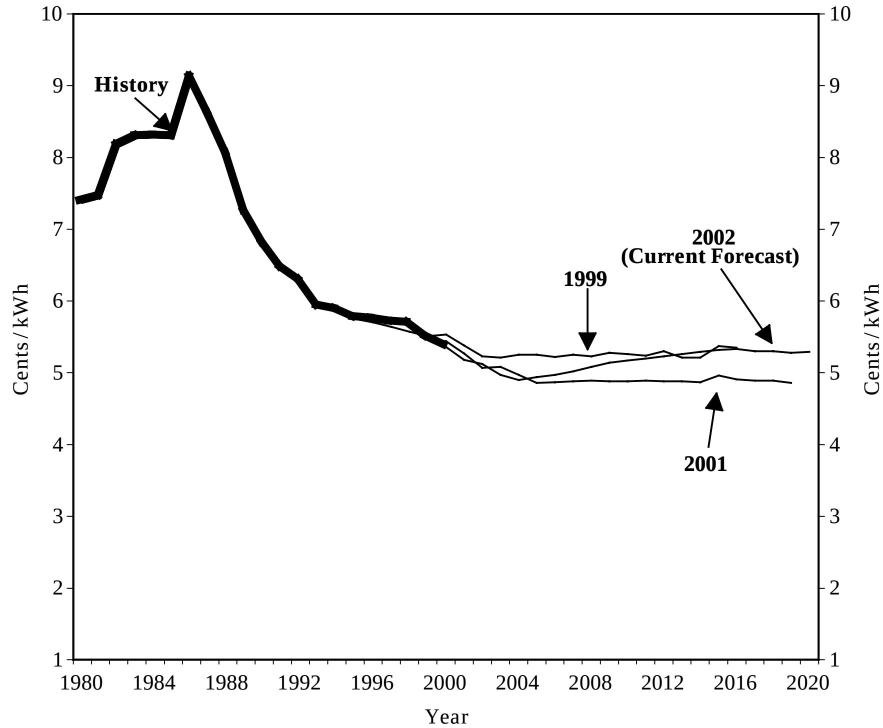
Equilibrium Price and Energy Impact

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

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 4. Early declines in the real price of electricity during the first few years of the forecast period are offset by increases during the last three-fourths of the forecast period. Since the change in prices over the forecast horizon is relatively small, price has little impact on the electricity requirements projection for this forecast. This price trajectory reflects the schedule of projected firm purchases in the base resource plan. Real prices decline through 2005 when mostly peaking capacity purchases are required to maintain a 15 percent reserve margin. Real prices increase after 2005 as capital-intensive NOx retrofits are completed and cycling and base load purchases are added to maintain adequate system reserves (see Figure 4).

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 4. The price projection labeled "2001" is the base from SUFG's 2001 forecast and the price projections labeled "1999" is the base case projection contained in SUFG's 1999 forecast. For the prior price forecasts, SUFG rescaled the

Figure 4. Indiana Real Price Projections (2000 Dollars) (Historical, Current and Previous Forecasts)



original price projections to 2000 dollars (from 1996 dollars for the 1999 projection, and from 1999 dollars for the 2001 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

One major factor produces the differences among the price projections in Figure 4; namely, the capital cost assumptions for new generation equipment. The capital cost estimates directly impact projected electricity prices. The 2001 base case and 1999 forecast capital cost assumptions were developed by SEPRIL and somewhat lower than those assumed in the current projections. For this update, SUFG has increased the capital cost assumed for peaking and cycling capacity slightly based on recent trends. Other factors such as energy and demand growth as well as fossil fuel price assumptions, especially coal, also influence the trajectory of future prices, but these have been relatively unchanged during SUFG's recent forecasts.

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

Low and High Scenarios

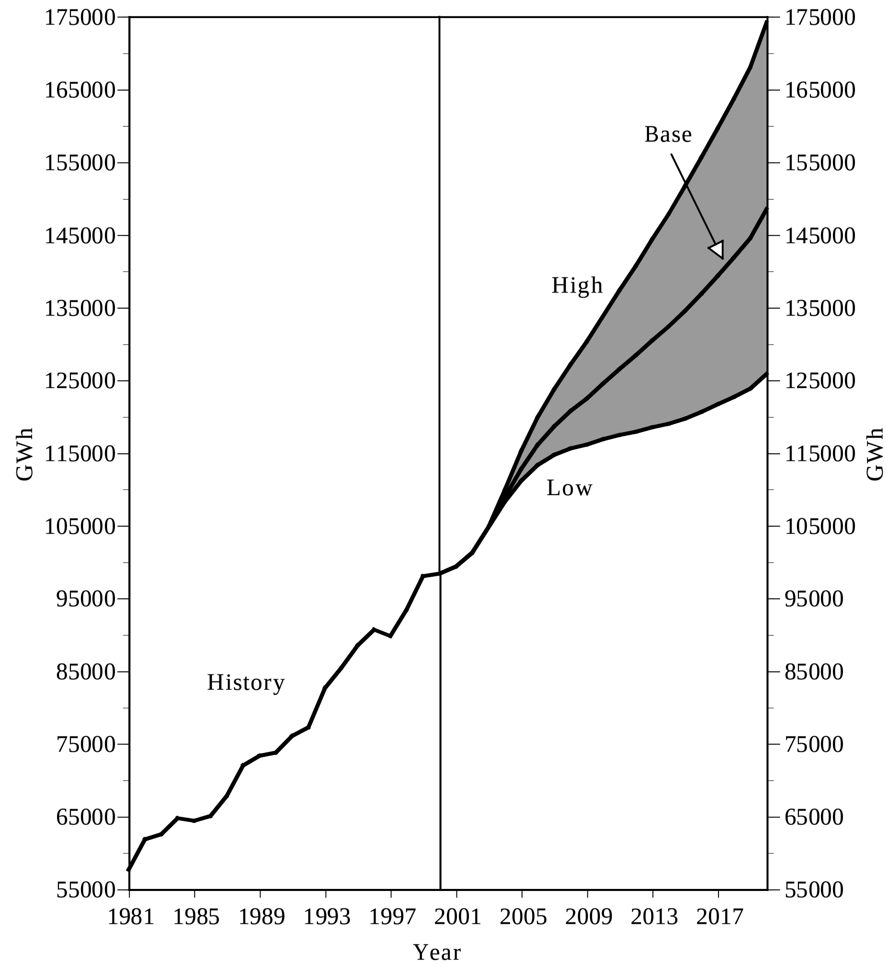
SUFG has constructed alternative, low and high growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figures 5 and 6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for the low and high scenarios are about 0.90 percent lower and 0.85 percent higher than the base scenario for both energy requirements and peak demand. These differences are due to economic growth assumptions in the scenario-based projections.

Figure 5. Indiana Energy Requirements by Scenario in GWh

Year	Base	Low	High
1996	90637	90637	90637
1997	89773	89773	89773
1998	93429	93429	93429
1999	98001	98001	98001
2000	99366	99366	99366
2001	99326	99324	99350
2002	101240	101236	101276
2003	104729	104724	104790
2004	108905	108298	109899
2005	112798	111150	115225
2006	116068	113308	119877
2007	118603	114669	123702
2008	120742	115603	127152
2009	122483	116113	130281
2010	124547	116853	133832
2011	126512	117439	137312
2012	128365	117903	140705
2013	130421	118491	144319
2014	132350	118978	147824
2015	134541	119677	151679
2016	136855	120586	155607
2017	139326	121622	159621
2018	141866	122685	163750
2019	144522	123797	168024
2020	148534	125855	174184

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	2.22	2.22	2.22
1985-90	2.75	2.75	2.75
1990-95	3.72	3.72	3.72
1995-00	2.34	2.34	2.34
2000-05	2.57	2.27	3.01
2001-20	**2.14**	**1.25**	**3.00**



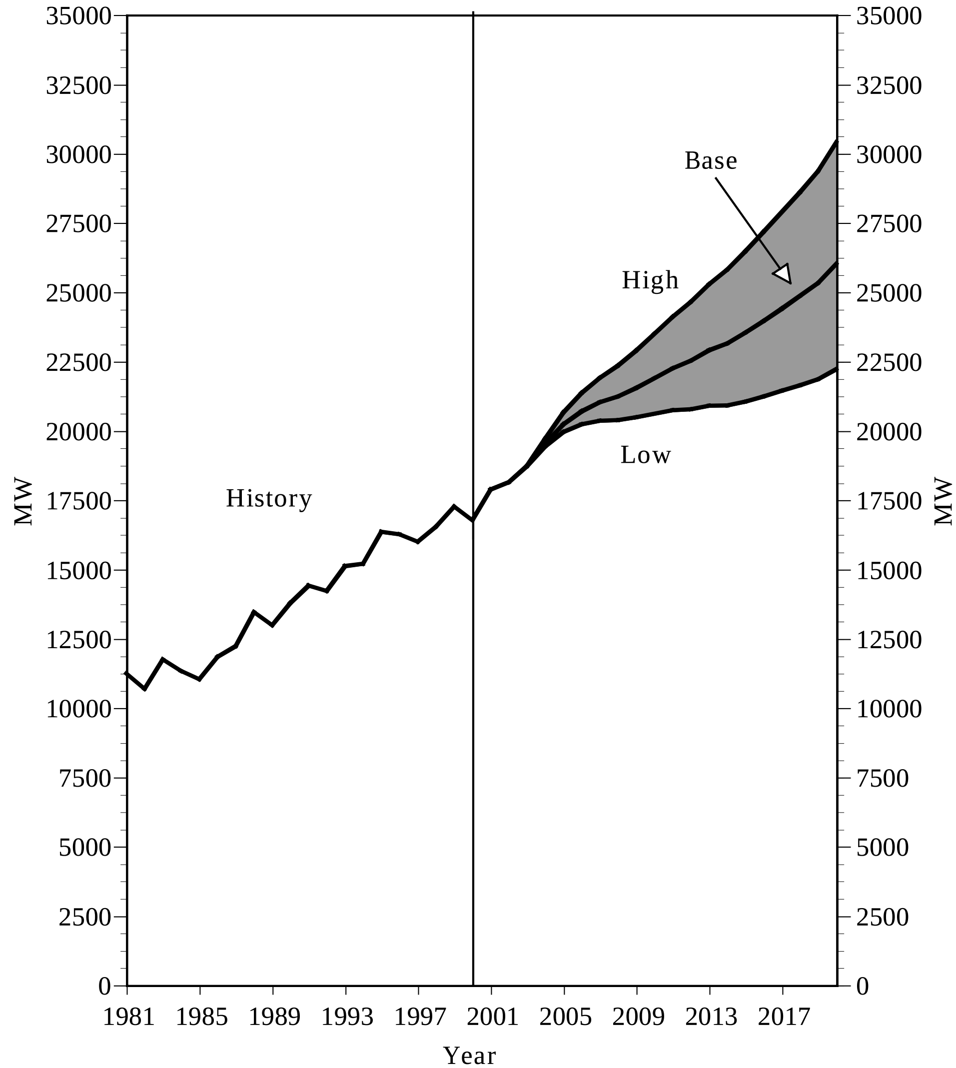
Notes: The shaded numbers in the table and the heavy line in the graph are historical values.

Figure 6. Indiana Peak Demand Requirements by Scenario in MW

Year	Base	Low	High
1996	16254	16254	16254
1997	15993	15993	15993
1998	16527	16527	16527
1999	17266	17266	17266
2000	16757	16757	16757
2001	17863	17862	17868
2002	18129	18129	18136
2003	18708	18707	18720
2004	19528	19426	19707
2005	20227	19947	20656
2006	20684	20220	21353
2007	21013	20353	21901
2008	21236	20373	22344
2009	21538	20469	22885
2010	21891	20602	23491
2011	22243	20722	24102
2012	22517	20763	24640
2013	22888	20886	25277
2014	23142	20900	25801
2015	23537	21044	26477
2016	23952	21225	27168
2017	24396	21428	27878
2018	24853	21636	28604
2019	25328	21854	29355
2020	26016	22215	30398

Average Compound Growth Rates

Selected Periods	Base	Low	High
1980-85	-0.45	-0.45	-0.45
1985-90	4.55	4.55	4.55
1990-95	3.48	3.48	3.48
1995-00	0.50	0.50	0.50
2000-05	3.84	3.55	4.27
2001-20	**2.00**	**1.15**	**2.84**



Notes: The shaded numbers in the table and the heavy line in the graph are historical values.