The Projected Impacts of the Clean Air Interstate Rule on Electricity Prices in Indiana

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1. Introduction

This paper examines the impact of various nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emission control scenarios on the projected prices of electricity in the state of Indiana. The scenarios represent different methods for achieving the reductions in NO_x and SO_2 emissions mandated by the United States Environmental Protection Agency (EPA) under its Clean Air Interstate Rule (CAIR). The analyses were performed using a traditional regulation forecasting model that equilibrates between price and demand. Thus, the effects of price changes on demand levels were captured. Price impacts are presented at an overall average level as well as by customer class. The impacts of various assumptions made in the selection of the scenarios are analyzed. This paper does not attempt to compare the cost of emissions controls to the benefits of reduced emissions.

The price projections here are an average retail regulated rate paid by the consumer. Therefore, non-utility generators are not included. While the State Utility Forecasting Group (SUFG) models both the investor-owned not-for-profit utilities in the state, the prices for the not-for-profit utilities are only known at the wholesale level (i.e., the price at which the utility sells to its member cooperative or municipal member). Thus, the price projections are only for the investor-owned utilities.

The emissions control scenarios included here were developed using a different set of electricity usage growth assumptions than those that SUFG uses for its own projections. Since some of the costs modeled are included per unit of output for the generator, this results in total costs being somewhat different from those in the original scenarios. The results presented here are subject to a number of assumptions regarding the compliance strategies used by the utilities to meet the CAIR standards, the capital and operating costs associated with emissions control devices, the future market price of emissions allowances, and any reduction in overall plant efficiency resulting from the addition of pollution control devices. Two alternative scenarios are presented that were developed using different sets of assumptions.

2. Background

Reductions in the emissions levels of NO_x and SO_2 were called for by the Clean Air Act Amendments of 1990. Both NO_x and SO_2 are considered to be the primary causes of acid rain. Acid rain affects the acidity of soil and water, which can be harmful to plants and aquatic animals. Acid rain can also damage buildings and other structures and reduce visibility. Furthermore, NO_x reacts with volatile organic compounds in the presence of heat and sunlight to form ozone. In the upper atmosphere, ozone occurs naturally and shields the earth from the sun's harmful ultraviolet rays. When found closer to the ground, however, ozone poses significant risk to human and plant health. Exposure to ozone irritates human lungs, reducing lung function and exacerbating respiratory diseases such as asthma. Ground-level ozone interferes with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised. It is also a major component of urban smog [1].

Table 1 summarizes the main legislation on which the EPA acts. In conjunction with United States laws, EPA issues regulations regarding various emissions and timelines for meeting the regulations. The regulations are often legally challenged and revised as needed in response to court decisions.

1963 Clean Air Act (Original)	
1967 Clean Air Act Amendments	• Requires New Source Performance Standards (NSPS)
1970 Clean Air Act Amendments	• Requires National Ambient Air Quality Standards (NAAQS) • Required State Implementation Plans (SIPs) to achieve NAAQS • Requires National Emissions Standards for Hazardous Air Pollutants (NESHAPs) • Mandates New Source Reviews in non-attainment areas
1977 Clean Air Act Amendments	• Prevention of Significant Deterioration (PSD) of air quality
1990 Clean Air Act Amendments (complete rewrite of the old Clean Air Act)	• Revises the Titles and requires EPA to issue 175 new regulations, 30 guidance documents, and 22 reports • Requires EPA to establish interstate air pollution transport regions • Mandates maximum achievable control technology (MACT) for 189 airborne toxics by 2003 • Mandates reduction of SO_2 emissions by 8.9 million tons per year by 2000 • Requires EPA to establish an allowance trading and tracking system for SO_2 emissions • Mandates permit and emissions fee system for acid rain emissions • Basis for regulations including two phase SO_2 reduction program, Title IV NO_x reductions, NAAQS NO_x reductions, 2005 Clean Air Interstate Rule, and 2005 Clean Air Mercury Rule

Table 1. Major U.S. Laws and Regulations Regarding Air Emissions [2]

In March 2005, the EPA promulgated new regulations effecting electric power plant emissions. CAIR lowers allowed emissions of SO_2 and NOx by roughly 56 percent and 68 percent, respectively, from currently allowed levels. CAIR is a cap and trade type program for SO_2 and NOx emissions with new emissions caps to be fully implemented in two phases. The first phase takes place in 2009 (NOx) and 2010 (SO_2), and the second phase in 2015 for both SO_2 and NOx. At nearly the same time, the EPA also finalized a rule for mercury emissions called the Clean Air Mercury Rule (CAMR). The mercury rule is also a cap and trade, two-phase rule and is projected to reduce mercury emissions from electric power plants by approximately 70 percent by 2018. The first phase of CAMR depends upon the co-benefits of control measures implemented under phase one of CAIR, while the second phase is expected to require additional mercury specific control measures. This report focuses only on CAIR and does not attempt to measure the impact of the second phase mercury restrictions of CAMR.

The compliance options available to fossil generators fall into four distinct categories: emission control technologies, fuel switching, the use of emission allowances, and the retirement of affected generating units. There are two main categories of emission control technologies, combustion control and post-combustion technologies. Low NO_x burners, which work at the combustion stage, were installed in many generating units to meet compliance with the Clean Air Act Amendments of 1990. Other forms of combustion control technologies include flue gas recirculation, steam or water injection, and staged combustion. Post-combustion control is done using either catalytic or non-catalytic reduction for NO_x emissions and flue gas desulfurization systems, also known as scrubbers, for SO_2.

In Selective Catalytic Reduction (SCR) systems, ammonia vapor is used as the reducing agent and is injected into the flue gas stream downstream of the boiler. The mixture passes over a catalyst, reducing the NO_x to nitrogen and water. SCR is one of the few technologies capable of removing high levels (80% or more) of NO_x from the flue gas of coal-fired generators commonly used in the U.S. utility industry.

In Selective Non-Catalytic Reduction (SNCR) systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. Emissions of NO_x can be reduced by 30% for large boilers to 50% for smaller boilers. The NO_x and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. Both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_x reductions.

Low NO_x burners reduce NO_x formation in the combustion stage by reducing flame temperature and local oxygen concentrations. This is accomplished by controlling the fuel and air mixture to alter the size and shape of the flame.

Flue gas desulfurization (FGD) systems inject a sorbent, often crushed limestone, into the exhaust stream. The sorbent reacts with the SO_2, thus removing it from the exhaust gas and producing gypsum.

Fuel switching involves replacing coal or oil as a source of fuel with natural gas to lower NO_x emissions or switching to a lower sulfur coal to reduce SO_2 emissions. Fuel switching can involve a complete switch to a different fuel or partial fuel switching. Partial fuel switching can be accomplished in a number of ways, such as seasonal switching and natural gas reburn for NO_x and fuel blending for SO_2. Seasonal switching involves using natural gas as the fuel source during the summer, which is the primary ozone season. Natural gas reburn involves co-firing a small amount of natural gas (10-20%) with the other fuel source. The costs associated with fuel switching vary greatly depending on the boiler size and design as well as access to natural gas or low sulfur coal. It may result in higher fuel costs.

Retirement may be an option for older, smaller generating units where the cost associated with installing an emission control device or switching to a different fuel exceeds the expected economic benefit of keeping the unit in operation.

Due to its large reserves of Illinois Basin coal, Indiana depends quite heavily on coal as a fuel source for electricity generation. 79 percent of the electric power generating capacity in the state is coal-fired and over 93 percent of the electricity generated there is derived from coal. As a result of this reliance on coal, as of 2002 Indiana ranked second in the United States in the amount of NO_x emitted annually and third in SO_2 [3]. Therefore, the CAIR emissions reduction regulations will significantly affect Indiana.

The analyses were performed for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Cinergy, and Southern Indiana Gas & Electric Company) and three major not-for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association) that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined.

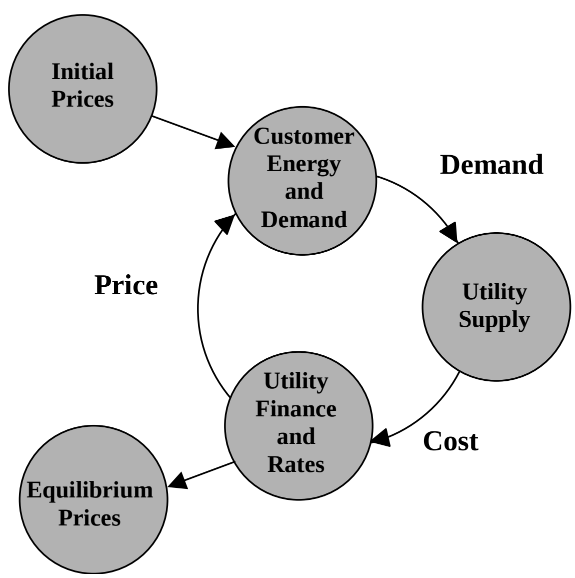
3. Methodology

To determine the impacts on prices of various levels of NO_x and SO_2 emissions restrictions, scenarios were analyzed using a traditional regulation forecasting model developed by the State Utility Forecasting Group (SUFG) [4]. This model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups -- residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out-of-pocket operating costs.

The fuel price and economic activity forecasts that form the primary drivers of these models were not changed from one scenario to another to maintain consistency in the analyses. The other major model driver, the price of electricity, varies according to the results of the scenario. Therefore, any changes in customer demand from one scenario to another result entirely from the emissions reduction requirements.

Using an initial set of electricity prices for each utility, a forecast of customer demands is developed. These demands are then sent through a generation dispatch model to determine the operating costs associated with meeting the demands. The operating costs and demands are sent to a utility finance and rates model that determines a new set of electricity prices for each utility. These new prices are sent to the energy and demand model and a new iteration begins. The process is repeated until an equilibrium state is reached where prices and demands do not vary from one iteration to the next for each year of the analyses. Thus, the model includes a feedback mechanism that equilibrates energy and demand simultaneously with electric rates (Figure 1).

Figure 1. Cost-Price-Demand Feedback Loop



In the later years of the analyses, new resources are needed for the utilities to adequately meet the load. This is accomplished through another iterative process with the costs associated with acquiring these resources (either through purchases, construction or conservation) impacting the rates accordingly. Since the demand levels in each scenario differ due to the price impacts, the amount of new requirements changes also. However, the criteria for determining resource requirements are held constant to ensure consistency between scenarios.

Emissions control technologies will affect the price of electricity in several ways. In this modeling system, the capital cost of equipment is captured in the rates and finance model, using a traditional regulated rate of return. The operating cost impacts are captured in the generation dispatch model. These impacts include changes in fuel costs resulting from changes in overall plant efficiency, increased maintenance costs, and changes to generation unit availability, for both emissions reduction equipment installation and maintenance.

4. Emissions Control Scenarios

SUFG analyzed two different scenarios for complying with CAIR emissions reductions: one developed by the Indiana Department of Environmental Management (IDEM) and one from the Indiana Utility Group (IUG). The scenarios use different combinations of compliance options (new equipment, fuel switching, allowance trading, and generating unit retirement). Options vary between the scenarios in terms of capital cost, operating cost, and the year implemented. Table 2 lists the amount of capacity affected and the installation costs for both scenarios.

Scenario	Capacity Affected (MW)			Installation Costs (million 2005$)
	SNCR	SCR	FGD	
IDEM	180	2611	4686	1617
IUG	0	2508	3698	1976

Table 2. Capacity Affected and Installation Costs

In addition to the scenario assumptions, SUFG made further assumptions in order to perform this analysis using SUFG's traditional (or regulated) modeling structure. These assumptions pertain to future capital costs for retrofit control equipment, expenditure streams for retrofit equipment installation, and the timing of retrofit installations. SUFG feels these assumptions are reasonable, but also recognizes that they should be subject to further refinement in subsequent analyses, as further information becomes available.

SUFG has assumed that capital costs for emissions control equipment will escalate at an annual rate of 2.5% per year from the 2005 dollar base year estimates provided by IDEM and IUG. While this escalation rate assumption is open to debate, it is consistent with the assumptions SUFG employed in preparing the 2005 SUFG report *Indiana Electricity Projections: The 2005 Forecast*, which is used as a base case in estimation of the additional costs to ratepayers of further emissions reductions.

SUFG has assumed that NO_x and SO_2 retrofit control equipment for all affected generation units will be installed over an 18-month period for all retrofit options including SNCR, SCR, and FGD. SUFG has further assumed that the stream of expenditures for such retrofit is evenly divided across this 18-month period. Since the SUFG model is an annual model, SUFG has allocated the control retrofit costs to specific years based upon the assumed on-line date of the control equipment. Capital costs are escalated from the 2003 dollar base year to the middle of the 18-month construction period and then allocated to specific years. For example, if a control device is assumed to be on-line in the spring of 2009, capital cost are escalated from 2003 dollars to mid-year 2008 dollars and then allocated to 2007 expenditures (1/6 of the total), 2008 (2/3 of the total), and 2009 expenditures (1/6 of the total). The same procedure is used for fall installations, with capital escalation through the beginning of the on-line year and capital cost allocations of 50 percent (prior year) and 50 percent (on-line year). Fixed operations and maintenance costs are assumed to be incurred immediately following the installation of a control device even if the control is installed prior to the compliance requirement date.

The 18-month installation period used in these analyses does not represent the total time needed for planning, design and engineering. These processes take a considerable amount of time before the actual physical construction begins. Likewise, the 18-month time period does not represent the time that the generating unit must be taken out of service for the installation process. The downtimes used in these analyses were 2 weeks for SNCR and 8 weeks for SCR and FGD installations.

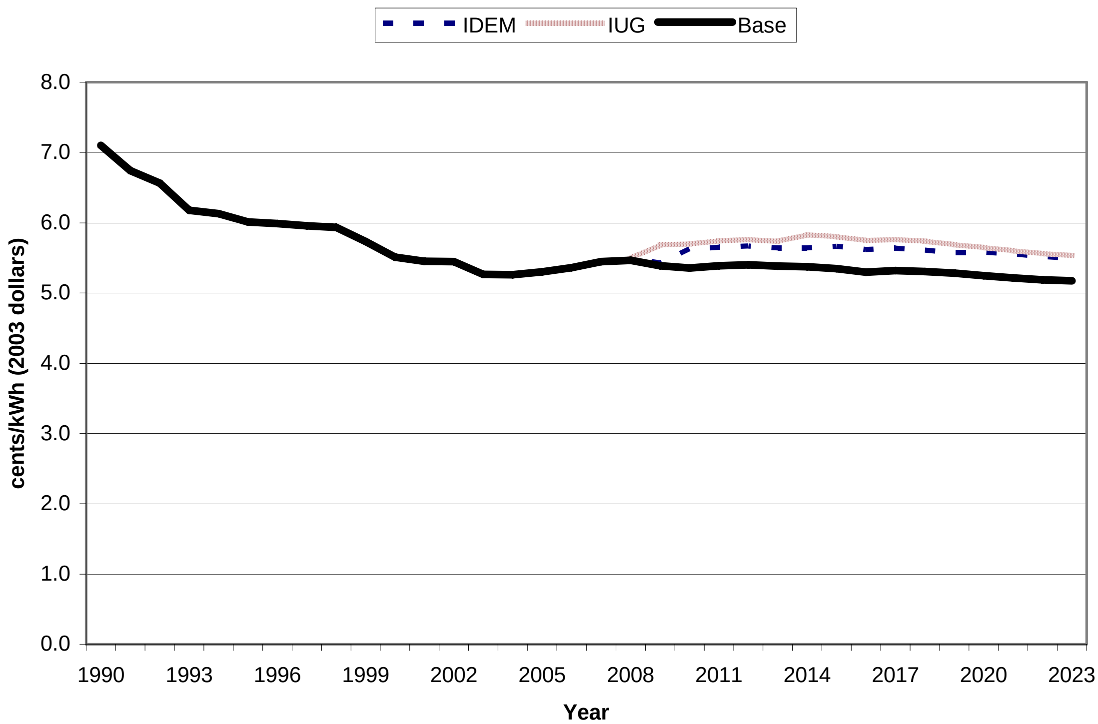
Since detailed installation schedules for emissions control devices were unavailable, SUFG assigned installation dates for all retrofit controls. The procedure used to assign on-line dates is somewhat arbitrary and should be refined in future analysis. SUFG assigned on-line dates by attempting to minimize the capacity off-line for retrofits and delaying retrofits until required for compliance on an individual utility basis. For example, if a utility is required to retrofit two large coal units, the units were assigned retrofit periods of Fall and Spring; three large units were assigned retrofit periods of Spring, Fall, and Spring and so forth. A more reasonable allocation of retrofit dates would explicitly incorporate the utilities' maintenance schedules and attempt to overlay final installation with major maintenance periods as well as attempt to coordinate installation outages across utilities where possible.

While these analyses capture the price effects of retrofit outages, they do not address the question of whether the reliability of the system will be impaired. In 2001, SUFG conducted a study for the NO_x retrofits associated with the National Ambient Air Quality Standards, in which it was determined that the state would likely have sufficient capacity to handle the necessary retrofits [5]. It is uncertain whether that conclusion would be reached for the first phase of CAIR retrofits. Since the second phase of CAIR does not take place until 2015, sufficient lead time should be available for utilities to complete the retrofits without compromising system reliability.

5. Results

SUFG's projections of future electricity rates for the two emissions control scenarios are compared with a base case from SUFG's 2005 report *Indiana Electricity Projections: The 2005 Forecast* in Figure 2. The base case was constructed assuming no emissions controls from CAIR, so the scenarios represent incremental changes to the base case. The rate projections in Figure 2 are an energy-weighted average for the residential, commercial, and industrial sectors for the five Indiana investor-owned utilities. The figure illustrates that average retail rates would be expected to increase 5 to 8.5 percent, depending on the time period and scenario.

Figure 2. Comparison of Rates by Scenario



The effect on the individual rate classes is similar to the average but differs somewhat due to cost-of-service allocation of capital recovery and fixed operating costs. The differences across customer classes for the scenarios for representative years are presented in Tables 3 through 5. Rates are provided in 2003 dollars in order to be consistent with the base scenario from SUFG's 2005 forecast.

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.79	7.11	+4.65 %	7.19	+5.92 %
Commercial	5.83	6.10	+4.66 %	6.15	+5.60 %
Industrial	4.10	4.34	+5.84 %	4.39	+7.11 %
Average	5.35	5.63	+5.16 %	5.70	+6.44 %

Table 3. Rate Comparisons by Sector in 2010 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.62	6.99	+5.67 %	7.13	+7.81 %
Commercial	5.74	6.05	+5.46 %	6.18	+7.61 %
Industrial	4.23	4.48	+6.03 %	4.61	+9.02 %
Average	5.35	5.67	+5.97 %	5.80	+8.55 %

Table 4. Rate Comparisons by Sector in 2015 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.34	6.74	+6.35 %	6.80	+7.27 %
Commercial	5.56	5.88	+5.83 %	5.94	+6.90 %
Industrial	4.29	4.56	+6.15 %	4.62	+7.69 %
Average	5.25	5.58	+6.34 %	5.65	+7.63 %

Table 5. Rate Comparisons by Sector in 2020 (in 2003 dollars)

The rate increase in ¢/kWh tends to be slightly higher in the residential sector and slightly lower in the industrial sector, with the commercial sector close to the average. In terms of a percentage increase, the industrial sector sees a higher increase due to the lower initial rates.

The difference between SUFG's base case and the IDEM scenario is about 0.32 ¢/kWh. Roughly 0.17 cents or slightly more than one half of the increase is due to increased out-of-pocket operating costs and the remainder of the increase, about 0.15 ¢/kWh, is due to recovery of equipment installation costs and fixed operating costs. For the IUG scenario, the price differential follows a similar pattern with a difference of about 0.45 ¢/kWh, of which about 45 percent is due to increased out-of-pocket operating costs and the remainder is due to recovery of equipment installation costs and fixed operating costs.

6. Summary and Conclusions

This paper presented the projected impacts of NO_x and SO_2 emissions reductions on Indiana electricity prices. Scenario analyses were performed using the SUFG traditional regulation modeling system. These scenarios depict various combinations of control technologies, such as SCR, SNCR, and FGD.

The results of these scenarios indicate that electricity prices can be expected to increase due to NO_x and SO_2 emissions reductions. Under the IDEM scenario, prices are expected to increase by roughly 5 to 6.5 percent due to the more stringent emissions controls of CAIR. In the IUG scenario, prices are expected to increase by roughly 6.5 to 8.5 percent.

Finally, the increase in electricity rates resulting from NO_x emissions reductions is felt by all three customer classes, with the increase to residential rates being slightly greater (and the increase to industrial rates being slightly lower) than the increase to commercial rates.

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