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Executive Summary

This report estimates the impact of proposed federal regulations aimed at reductions in carbon dioxide (CO_2) emissions on the projected prices of electricity and the use of electric energy in the state of Indiana. The analysis is based on the Lieberman-Warner Climate Security Act (S. 2191), which places a declining cap on greenhouse gas emissions; however, it does not attempt to model the full details of the proposed legislation. Although the bill places limits on six greenhouse gases (CO_2, methane, nitrous oxide, sulfur hexafluoride, perfluorocarbons, and hydrofluorocarbons) from a number of producers, this report solely focuses on CO_2 emissions from Indiana's electric utility industry. The analysis focuses on the impacts of the legislated limitations on CO_2 emissions on the electric energy sector of the economy and does not address the benefits of reduced emissions.

The analysis is performed using a traditional regulation forecasting model developed by the State Utility Forecasting Group (SUFG) at Purdue University. This is a sector model that takes the overall economic activity in the state as a given (e.g., the level of gross state product, employment, etc.) and projects changes in electricity usage reflecting demand growth and conservation. The analysis applies the implied percentage national reductions in CO_2 emissions required by S. 2191 to Indiana utilities as a whole. Compliance strategies that are considered in the analysis include purchases of emissions allowances and offsets, shifting production technology from coal-fired baseload resources to a combination of wind and natural gas generation, retirement of older coal-fired units that have not been retrofitted with equipment to remove other pollutants, and banking of allowance early in the planning horizon for later use. Due to limitations in the design of the modeling system, the planning horizon is through 2025.

The analysis leads to projected changes in electricity prices across residential, commercial, and industrial sectors. Percentage price changes are similar for the residential and commercial sectors but larger for the industrial sector. This difference arises for two reasons. First, prices for the industrial sector are lower than the other sectors, making the base for the percentage changes relatively small, and second, the industrial sector is heavily dependent upon the coal-fired baseload resources, some of which must be either replaced or retrofitted to achieve compliance.

Residential and commercial pricing is projected to be on the order of 13 percent higher by 2012 relative to the base case (without caps on greenhouse gas emissions). This percentage difference rises to about 16 percent by 2015, 28-29 percent by 2020, and 39-40 percent by 2025 in the residential and commercial sectors. In the industrial sector, prices are projected to be 25 percent higher than the base case by 2012, 26 percent higher by 2015, 38 percent higher by 2020, and 49 percent higher by 2025.

Due to the state's heavy reliance on coal as a fuel source for electricity generation, Indiana is expected to experience larger price increases than those projected on a national level. Similar studies by other entities have shown projected national electricity price increases of 15 to 25 percent in 2025, while this study projects a 45 percent increase (averaged across all sectors) for Indiana.

The impacts on demand are also significant. The annualized growth rate in total electricity demand over the 2011-2025 period falls from 2.5 percent in the base case to 1.3 percent with restrictions on CO_2 emissions. In the residential sector, the annualized growth rate declines from 2.4 percent to 1.8 percent; in the commercial sector, the decline is 2.3 percent to 1.9 percent; and in the industrial sector, the decline is from 2.6 percent to 0.6 percent. These demand reductions imply a substitution of alternative energy sources, the use of more efficient energy-consuming technology, and energy conservation.

Given the complexity and uncertainty associated with predicting twenty years worth of utility and consumer behavior in a carbon constrained environment, it is not possible to model everything that may affect electricity prices. Thus, a number of caveats are provided. First, the reliance on large amounts of wind capacity introduces questions about the need for additional transmission system investment, the impact of operating in conjunction with the existing steam-powered generators, and the ability of equipment manufacturers to produce enough turbines at a reasonable cost. Next, the price increases will provide greater incentives for utility-sponsored conservation measures; the amount and cost of these programs are not known. Also, the analysis does not capture the effect of large price increases on the overall economic activity in the state. Finally, while the restrictions imposed by the bill are likely to spur new technological developments, it is not possible to predict what developments will occur and when they will be commercially available.

This document reflects the analysis, understanding, and opinions of the authors, and does not reflect official policy of Purdue University.

Introduction

This paper examines the impact of proposed federal reductions in carbon dioxide (CO_2) emissions on the projected prices of electricity in the state of Indiana. Due to the state's large reserves of Illinois Basin coal, Indiana depends quite heavily on coal as a fuel source for electricity generation. Approximately 73 percent of the electric power generating capacity in the state is coal-fired and over 92 percent of the electricity generated in-state is derived from coal. Because of this reliance on coal, Indiana ranked fifth in the United States in the amount of CO_2 emitted annually as of 2006 [1]. Therefore, CO_2 emissions reduction regulations would significantly affect Indiana.

While the analysis is based on the Lieberman-Warner Climate Security Act (S. 2191), which places a declining cap on greenhouse gas emissions, it does not attempt to model all aspects of the proposed legislation. Although the bill places limits on six greenhouse gases (CO_2, methane, nitrous oxide, sulfur hexafluoride, perfluorocarbons, and hydrofluorocarbons) from a number of producers, this report solely focuses on CO_2 emissions from Indiana's electricity industry.

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. This paper does not attempt to compare the costs of emissions controls with the benefits of reduced emissions.

The price projections here are the 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 and 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 presented here are only for the investor-owned utilities.

The emissions control scenarios included here were developed using the same set of electricity usage growth assumptions that SUFG employed for its *Indiana Electricity Projections: The 2007 Forecast* [2]. SUFG then changed the parameters affected by the carbon control scenarios analyzed for this report. Thus, a direct comparison of the 2007 SUFG base case price projections and the CO_2 limited scenario price projections is valid. Like the 2007 SUFG projections, this analysis does not go beyond 2025.

Summary of proposed legislation

The proposed Lieberman-Warner Climate Security Act (S. 2191) would establish a "cap and trade" system for U.S. greenhouse gas emissions. The broad outline of this bill is used as a point of departure for the analysis in this report. Cap and trade systems, including the system proposed in the bill, rely on two instruments to create a private property rights structure for emissions: the *cap* is a ceiling on total allowable emissions;

and the *trade* reflects the creation of emissions permits (also called *allowances*) which can be exchanged between emitters for cash or other considerations. These allowances grant the holder the right to emit one unit of pollution (e.g., a ton of CO_2) in a given year. The main attraction of such a system is that it can reduce the overall costs of meeting the emissions target, compared with other approaches. Allowances are tradable among emitters, allowing them to equalize their costs at the margin, thereby achieving the overall environmental goal (i.e., the cap) at least total cost to society.

In terms of historical precedent, in 1990 Congress created the largest U.S. experiment with emissions trading to date. Under Title IV of the Clean Air Act Amendments of 1990, Congress created a cap and trade program for electricity utilities emitting sulfur dioxide (SO_2). The cap was set at approximately 8.9 million tons of SO_2 per year. Each emissions allowance was equivalent to one ton of SO_2. Utilities were provided free allowances based on a series of formulas that sought to strike a rough balance between existing levels of energy consumption and a benchmarked level of pollution per unit of energy produced. Once initiated, the program allowed utilities flexibility in complying with the law. Firms could buy allowances from other utilities, install flue gas desulfurization equipment (scrubbers) or other pollution control equipment, burn lower sulfur-content coal in their boilers, or combine these and other strategies.

S. 2191 has many similarities to previous SO_2 legislation, in terms of setting a cap, allocating allowances, and facilitating trade. Important differences are that the proposed legislation has a more complex allowance allocation mechanism, it provides a mechanism for *offsets* (reductions in non-covered sectors to compensate for emissions in covered sectors), and also applies to a larger class of covered facilities. These covered facilities include all fossil-fuel electricity generating units that emit more than 10,000 CO_2-equivalents of greenhouse gas in a year, and also industrial and other similarly-sized facilities.[1] Importantly, the analysis of this report focuses only on facilities in the electric power sector.

The main feature of the proposed legislation that is relevant to this analysis is the overall emission allowance. The bill establishes a carbon cap for each year from 2012 to 2050. This allowance schedule is presented in Table 1. As the data indicate, the cap starts out high and is gradually reduced over time. Enforcement of the allowance caps is to be ensured through financial penalties for annual noncompliance. Owners of covered facilities would be required to submit emission allowances in each year equal to actual emissions for that year, or pay a penalty, with proceeds to be deposited into the U.S. Treasury. Provisions allow free transfer and exchange of allowances, banking of allowances for future use, and – subject to restrictions and repayment with interest – allowance borrowing. It also allows a percentage of emissions to exceed the cap, provided CO2-equivalent emissions are offset in other ways, for example through

[1] These include facilities that produce or import petroleum- or coal-based transportation fuel, or non-fuel chemicals at a scale that would lead to the emission of more than 10,000 CO_2 equivalents of greenhouse gas in a year.

domestic or international projects established to permanently sequester carbon. The legislation establishes a new institution (the *Carbon Market Efficiency Board*) to oversee the implementation of the allowance trading system and to ensure the carbon cap does not adversely harm the U.S. economy.

Table 1 – Emission Allowances for Each Calendar Year, 2012-2050

Calendar Year	Emission Allowances (in millions)	Calendar Year	Emission Allowances (in millions)	Calendar Year	Emission Allowances (in millions)
2012	5,200	2025	3,952	2038	2,704
2013	5,104	2026	3,856	2039	2,608
2014	5,008	2027	3,760	2040	2,512
2015	4,912	2028	3,664	2041	2,416
2016	4,816	2029	3,568	2042	2,320
2017	4,720	2030	3,472	2043	2,224
2018	4,624	2031	3,376	2044	2,128
2019	4,528	2032	3,280	2045	2,032
2020	4,432	2033	3,184	2046	1,936
2021	4,336	2034	3,088	2047	1,840
2022	4,240	2035	2,992	2048	1,744
2023	4,144	2036	2,896	2049	1,646
2024	4,048	2037	2,800	2050	1,560

Source: S. 2191, Title I, Subtitle B, section 1201 (DEC07762.xml)

The proposed legislation contains guidelines for the allocation and distribution of emission allowances. The two most important features of this allocation and distribution mechanism are (i) direct allocations to greenhouse gas emitters and (ii) the use of annual auctions. The percentage of emission allowances to be allocated via auction is initially set at 18 percent; the percentage rises over time, to a maximum of 73 percent in 2036 (see Table 2).

The proposed legislation does not specify the exact rules and regulations for direct allocation of remaining (non-auctioned) allowances to owners and operators of covered facilities, or other organizations. Instead, the bill requires the U.S. Environmental Protection Agency to establish these rules and provides detailed language to guide this rulemaking. To facilitate the analysis of this paper, it is assumed that annual reductions in CO_2 emissions from Indiana electricity generators (relative to a 2005 baseline) will be made proportionate to the reductions implied by the annual caps listed in Table 1.

Table 2 – Annual Percentage of Emission Allowances to Be Auctioned, 2012-2050

Calendar Year	Auction Allocation (% of total allowances)	Calendar Year	Auction Allocation (% of total allowances)	Calendar Year	Auction Allocation (% of total allowances)
2012	18	2025	47	2038	73
2013	21	2026	49	2039	73
2014	24	2027	51	2040	73
2015	27	2028	53	2041	73
2016	28	2029	55	2042	73
2017	31	2030	57	2043	73
2018	33	2031	59	2044	73
2019	35	2032	61	2045	73
2020	37	2033	63	2046	73
2021	39	2034	65	2047	73
2022	41	2035	67	2048	73
2023	43	2036	73	2049	73
2024	45	2037	73	2050	73

Source: S. 2191, Title III, Subtitle B, section 3201 (DEC07762.xml)

SUFG Modeling System

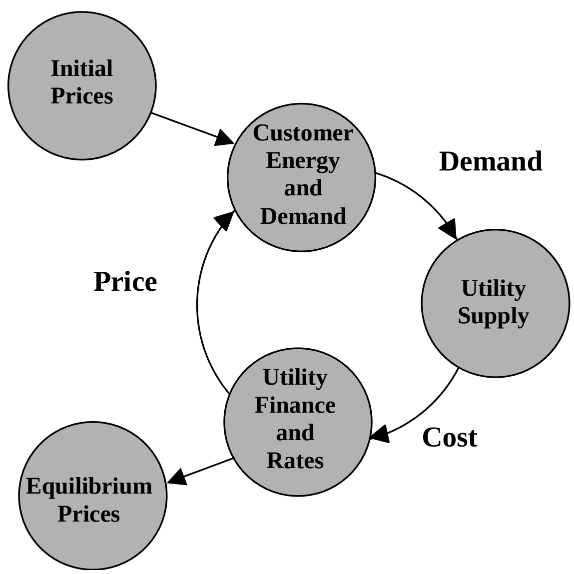
The analysis was performed for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Duke Energy Indiana, and Southern Indiana Gas & Electric Company) that supply electric power to Indiana customers. The statewide 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.

To determine the impacts of CO_2 restrictions on prices, scenarios were analyzed using a traditional regulation forecasting model developed by the SUFG [2]. 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. Under 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.

To maintain consistency in the analyses, the economic activity forecasts that form some of the primary drivers of these models were not changed from one scenario to another. Since fossil fuel consumption is expected to change significantly at the national level, the fuel prices, which are also primary forecast drivers, were adjusted accordingly. The other major electric energy driver, the price of electricity, is determined within the framework of the overall modeling system and 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 are consistent. 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



While the SUFG modeling system captures the impact of electricity price increases at the microeconomic level (i.e., a firm or individual's decision to use an alternate source of energy or a more efficient process), it does not capture the impact of price increases at the macroeconomic level (i.e., the effect of electricity prices on the state's economic development as firms decide where to locate new facilities). All scenarios included in this report were developed from the same set of macroeconomic assumptions.

Throughout these 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) affecting the rates accordingly. Since the demand levels in each scenario differ due to the price impacts, the amount of required resources changes as well. Furthermore, the technology and fuel assumptions that determine the costs associated with new resources change for the carbon constrained scenarios. However, the criteria for determining resource requirements are held constant to ensure consistency between scenarios.

Methodology

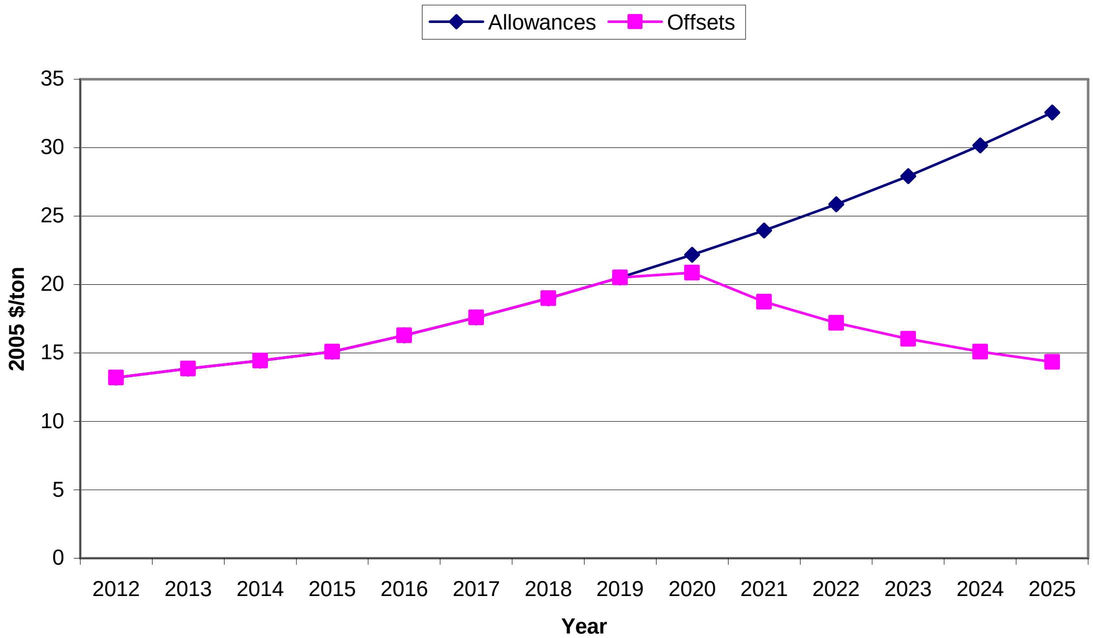
The Lieberman-Warner Climate Security Act limits national CO_2 emissions for each year beginning in 2012. It then assigns allowances to a variety of entities, ranging from fossil fuel-fired power plants and manufacturers to states and tribal governments to electricity and natural gas consumers. Due to time constraints in producing this analysis and the uncertainty of the final distribution of allowances, SUFG has not attempted to model the actual distribution of emissions allocations to each utility in Indiana. As a proxy, SUFG assumes that the Indiana utility reductions in CO_2 emissions will reflect those of the nation as a whole. For example, since the bill requires a four percent reduction in national CO_2 emissions from the 2005 level in 2012, SUFG has modeled a four percent reduction requirement for each utility from its 2005 level in 2012. Similarly, the national reduction requirements for other years were applied to the Indiana utilities.

SUFG used CO_2 levels calculated from its forecasting modeling system as the 2005 baseline rather than similar numbers published by the Energy Information Administration (EIA) for two reasons. First, EIA uses a geographical perspective in assigning generators and emissions to each state, while SUFG uses a jurisdictional perspective. This is an important distinction because some utilities operate in more than one state and because some generators that are physically located outside Indiana are owned and operated by Indiana utilities. Similarly, some generators located inside Indiana provide energy to out-of-state customers. Second, using CO_2 numbers calculated from the modeling system allows for a consistent treatment of emissions reductions since the annual limits are based on the same set of assumed operating characteristics as the base year.

As time progresses, an increasing fraction of the allowances are auctioned instead of directly allocated. In 2012, 18 percent of the allowances are to be auctioned and the remainder to be directly allocated. In the last year of this analysis, 2025, 47 percent are to be auctioned. SUFG has included the cost associated with purchasing the non-allocated allowances. The cost per allowance was taken from EIA's analysis of an earlier proposed climate change bill, the Climate Stewardship and Innovation Act of 2007, S. 280 [3]. While the earlier bill is not identical to S. 2181, it is similar in the amount of CO_2 reductions required. An analysis of an early version of the Lieberman-Warner bill by Duke University's Nicholas Institute for Environmental Policy Solutions project somewhat higher prices for emissions allowances under S.2181 than in EIA's S. 280 analysis [4], as does a similar analysis by CRA International (formerly Charles River

Associates) [5]. A preliminary analysis of S. 2181 by the Clean Air Task Force shows allowance prices similar to those in EIA's S. 280 analysis [6]. The Duke study did not provide a projection of offset prices. Figure 2 shows the price projections of allowances and offsets used in this report.

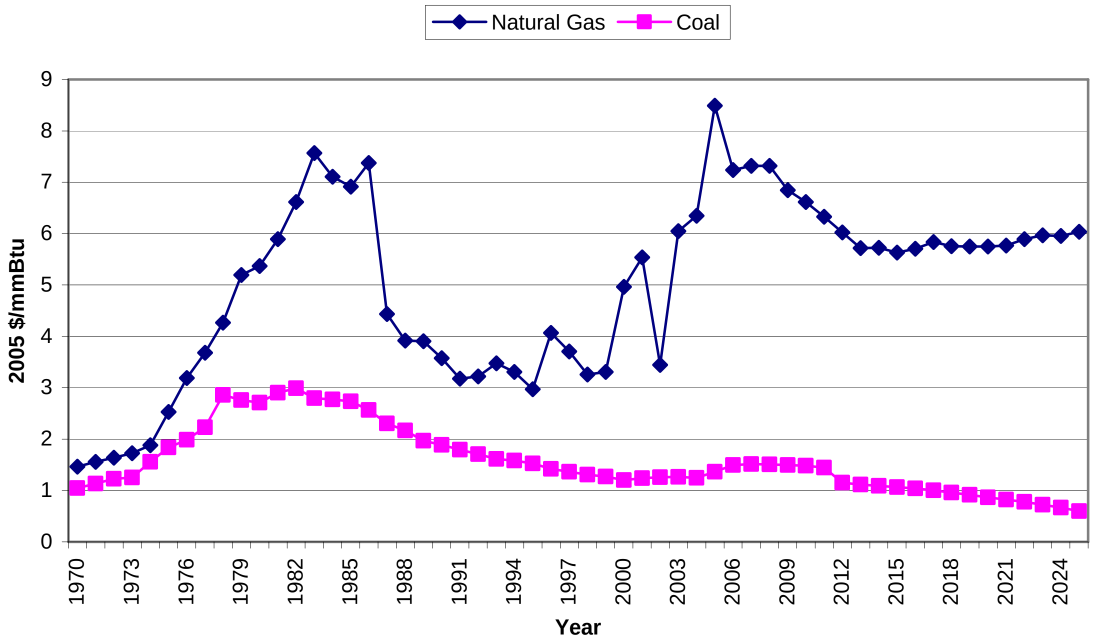
Figure 2 - Prices of Allowances and Offsets per Ton of CO2 [3]



A reduction in CO_2 emissions will have a significant impact on the supply and demand balance of fossil fuels, as consumers across the country change their consumption behavior. This will change the expected prices of these fuels, which in turn will impact the costs incurred by Indiana's utilities when they generate electricity. SUFG used EIA's prices from the S. 280 analysis [3] for the price of coal, natural gas, and oil. EIA's numbers included an increment for the cost of CO_2, which SUFG removed from the price projections in order to avoid double-counting the CO_2 allowance costs. The CO_2 increment to the fuel cost was then put back into the SUFG modeling system as an indirect shadow cost. This shadow cost is included in the generator dispatch order for each utility but is not included as an out-of-pocket cost for purposes of determining rates. Thus, carbon-intensive generators are used less frequently and CO_2 allowance costs are properly captured. Figure 3 shows the price projections for utility coal and natural gas without the carbon increments. From the EIA analysis, it is apparent that carbon control legislation will result in a reduction in the national demand for coal, which in turn results in lower prices.

While changes in fossil fuel prices have a direct impact on electricity prices since the fuels are inputs in the process of making electricity, they also have indirect impacts since they are also a competing source of energy for end users. A reduction in the price of natural gas may cause more customers to opt for natural gas, thus reducing electricity consumption. Therefore, the prices of fossil fuels at the residential, commercial, and industrial level were also adjusted according to the results of the S. 280 analysis. The price trajectories for those sectors follow a similar trajectory as the one shown for the utility sector in Figure 3.

Figure 3 - Utility Fossil Fuel Prices [3]



In summary, the adjustments to the modeling system inputs were:

- Reduce utility CO_2 emissions at the overall national rate specified by the proposed legislation.
- Incorporate emission allowance purchase costs.
- Incorporate emission offset purchase costs.
- Adjust fossil fuel price projections.

In order to limit the price impacts specifically to the carbon control costs, SUFG maintained the same set of available generation resources that were used in the 2007 forecast. Thus, resources that have been approved since the 2007 forecast was prepared are not included. This consists primarily of Duke Energy's Integrated Gasification Combined Cycle facility and some wind power purchases. Likewise, more recent conservation and demand-side management estimates were not included.

Compliance Strategy

After adjusting the modeling system input assumptions, it was necessary for SUFG to develop a strategy for complying with the limits. Given the time limitations for the analysis and the uncertainty regarding future technology advancements, SUFG did not attempt to develop a truly optimal compliance strategy. Instead, the compliance strategy described here might be considered to be one of a number of potential reasonable methods for meeting the CO_2 limits. To the extent possible, the compliance options that were expected to have the smallest price impacts were selected.

A number of options exist for meeting the prescribed emissions limits. The proposed legislation allows for the purchase of offsets from non-covered sources to satisfy up to 15 percent of a given year's compliance. Additionally, a similar amount of foreign emission allowances can be purchased. Facilities can bank allowances indefinitely by holding unused allowances from one year to the next. They can also borrow from future allowances to meet their current year's obligation, subject to a ten percent interest penalty and a five year limit.

From an operational standpoint, a utility can reduce its CO_2 emissions by switching to less carbon-intensive fuels. This can be accomplished by retrofitting an existing facility to burn a different fuel, such as switching from coal to natural gas. It can also be accomplished by retiring a carbon-intensive generator and replacing it with a less carbon-intensive one. Additionally, a utility may capture the CO_2 produced by a generator and place the CO_2 in long-term storage.

The feasibility and cost of switching to less carbon-intensive fuels could not be determined for this analysis due to considerable variability from one site to another. A National Energy Technology Laboratory analysis of the cost of capturing CO_2 at an existing coal-fired generator indicates a mitigation cost of roughly 80 to 100 dollars per ton [7]. Since this is more than twice the cost of purchasing allowances, retrofitting existing plants for CO_2 capture was not included in the analysis.

The compliance strategy used in this analysis consists of:

- Purchase the maximum amount of offsets allowable.
- Switch the basis for new baseload resources from pulverized coal-fired to a combination of wind and natural gas.
- Retire older coal units that have not been retrofitted with equipment to remove SO_2 and nitrogen oxides (NO_x).
- Bank allowances in the early years for use in the later years.

Since offset prices are always equal to or less than allowance prices, it is preferable to purchase offsets instead of allowances when possible. Purchasing the maximum amount allowable in the early years facilitates building a bank of allowances for use in the later years when allowances are more scarce and expensive.

SUFG does not assume that utilities will meet future resource needs via any particular method. Resources can be met through increased conservation and efficiency programs, new generator construction, purchase of existing generating facilities, or through purchases of electricity either through a market or bilaterally. It is likely that future resource needs will be met through a combination of sources. It is important for SUFG to capture the cost implications of new resource requirements in its forecasts in order to project electricity prices and demand.[2]

In its 2007 forecast, SUFG modeled future resource needs as wholesale purchases based on the cost characteristics of new generators. For baseload needs, pulverized coal-fired generators were the model for those purchases. In order to capture the price impact of reducing CO_2 emissions, a different generation source was needed. A number of less carbon-intensive options exist, including nuclear power and advanced coal-fired technologies with and without CO_2 storage. Each of these options has inherent advantages and disadvantages.

While nuclear power is carbon free, it is expensive to build and has a very long lead time for new construction. Since there are currently no proposed nuclear plants for Indiana, it was assumed that none could be completed until very late in the forecast period. Thus, nuclear was not a factor in this analysis.

Integrated gasification combined cycle (IGCC) technologies have construction costs somewhere in between traditional pulverized coal and nuclear and do not face as long a construction period as nuclear does. It burns coal more efficiently than pulverized coal, and thus it produces less carbon dioxide per unit of energy produced. CO_2 capture is also believed to be more economically achieved with IGCC than with pulverized coal. However, carbon capture is still a capital and energy intensive process, even when combined with IGCC. Also, a great deal of uncertainty exists regarding the cost of capturing carbon.

Like nuclear power, wind energy is carbon free while being less expensive to build and operate. Furthermore, it does not face the long construction time of nuclear. The major disadvantage of wind is the intermittent nature of the energy produced, since the generators only produce when the wind blows. The uncertainty of the wind production was overcome in this analysis by combining wind with natural gas-fired combined cycle generators. The wind provides energy throughout the year when the wind blows. When the wind is not blowing, the natural gas unit could operate and the combination operates much like a baseload unit. Analysis of wind speed data for the state of Indiana indicates that 100 megawatts (MW) of wind combined with 50 MW of natural gas generation provide the equivalent of 60 MW of baseload generation. This combination is

[2] SUFG assumes the long-run marginal cost of new facilities (including CO_2 costs for this analysis) will be the primary determinant of the cost of meeting new resource requirements, independent of the means used for meeting the requirements.

considerably more expensive than traditional pulverized coal, having about twice the capital cost on an equivalent MW basis. However, it produces only about 1/10 of the amount of CO_2 per energy output as compared with traditional pulverized coal.

Thus, two primary candidates for determining the basis for the price of future resources were analyzed: (i) IGCC with carbon capture and storage and (ii) wind in conjunction with natural gas combined cycle. A comparison of costs for the two options, assuming coal and natural gas prices at 2005 levels and with similar CO_2 emissions per unit output, results in the wind plus natural gas option having a levelized cost of electricity about 12 percent lower than the IGCC with carbon capture and storage. While it is possible that the IGCC option may prove more economic in the future, especially given the uncertainty surrounding fossil fuel prices and carbon capture and storage costs, wind in conjunction with natural gas was used as the basis for long-run costs of new resources.

The CO_2 emissions reductions achieved by using a combination of wind and natural gas were not sufficient to meet the standards of the proposed legislation. Therefore, SUFG modeled the retirement of some of Indiana's existing coal-fired generation. The generators chosen for retirement were generally older, smaller units that have not been retrofitted with equipment to reduce the emissions of SO_2 and NO_x. About 2,300 MW was modeled as being retired. In order to maximize the CO_2 emissions reductions achieved, the retirements were all scheduled for 2012, the first year subject to limitations. This allowed for the greatest amount of allowances to be banked for later use. In some cases, units were already scheduled for retirements in the 2007 base forecast. In these cases, the retirement year was moved up to 2012.

Due to the retirement of older units that are not equipped with advanced pollution controls, the emissions of various pollutants, such as SO_2, NO_x, mercury, and particulates, were reduced. This allowed for some future emissions control expenditures to be avoided, either because the unit scheduled for retrofit was retired or because the emissions reductions due to retirement of other units made it possible to comply with the regulations without the scheduled retrofits. Approximately $650 million of future expenditures from the 2007 base case were eliminated in the CO_2 analysis.[3]

A major component of the compliance strategy used in this analysis is over-complying in the earlier years to develop a bank of allowances that can be drawn upon as emissions restrictions tighten in the later years. At the end of the forecast period, 2025, there are still some allowances remaining in the bank. While a lower cost could be achieved by using all of the banked allowances by 2025, it is not a realistic scenario. While the analysis ends at the end of 2025, the world does not. As modeled, the banked allowances will be used by 2029. Thus, additional measures would need to be undertaken to comply in 2029 and beyond.

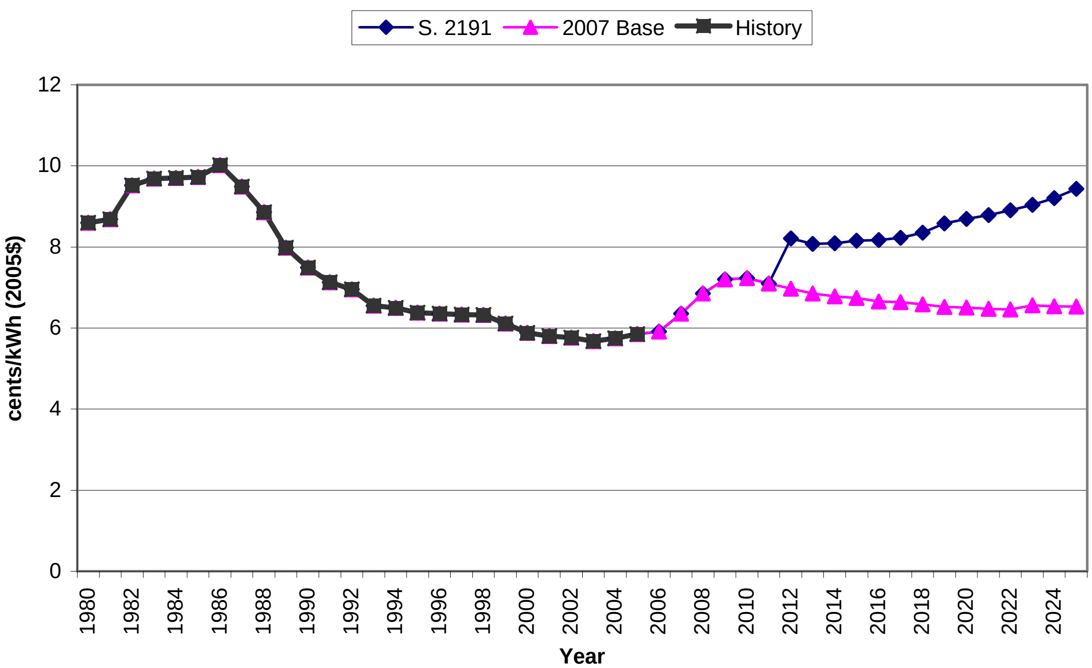
[3] The analyses presented here were completed prior to the February 8, 2008 U.S. Court of Appeals decision to vacate portions of the Clean Air Mercury Rule. It is expected that retirements of coal-fired units due to CO_2 restrictions would still result in avoided costs under future mercury rules, but the magnitude of those costs is uncertain.

Results

Price impacts

Figure 4 shows the projections of real (inflation-adjusted) electricity prices in cents per kilowatthour (kWh) for the 2007 Base Case and the scenario based on the Lieberman-Warner Act (S. 2191). These prices represent an energy-weighted average price for the five Indiana investor-owned utilities across the residential, commercial, and industrial sectors. The base case projects a 20 percent price increase from 2005 to 2010 due to a combination of increased costs of pollution controls for SO_2 and NO_x, increased fuel costs, and increased construction costs for new facilities. After 2010, prices slowly decrease in real terms (i.e., they grow at a rate that is slightly less than the rate of inflation). The S. 2191 case exhibits a large increase in 2012, the first year of CO_2 restrictions. This increase of about 18 percent is caused by the various steps taken to reduce CO_2 production, such as retirement of existing units, purchases of allowances and offsets, and switching to the higher cost mix of wind and natural gas for future baseload resources. After a period of relatively constant rates, a combination of higher allowance costs and a reduction in the fraction of allowances that are allocated to the utilities cause prices to increase from about 2018 through the end of the forecast period.

Figure 4 - Indiana Real Electricity Prices (2007 Base vs. S. 2191)



While the price increases resulting from S. 2191 affect each of the three major customer classes, the greatest impact occurs in the industrial sector. Having the most nearly constant load profile, the industrial sector relies most heavily on baseload generators, which tend to be most impacted by CO_2 limitations. Also, industrial rates are lowest, and thus a given price increase will represent a larger percentage gain. Tables 3 through 6 provide the energy-weighted sectoral and total prices for the five investor-owned utilities for 2012, 2015, 2020, and 2025.

Table 3 - Indiana Real Electricity Prices in 2012 (2005 cents/kWh)

Sector	2007 Base	S. 2191	Change
Residential	8.766	9.915	13.1 %
Commercial	7.896	8.946	13.3 %
Industrial	5.294	6.662	25.1 %
Total	6.972	8.213	17.8 %

Table 4 - Indiana Real Electricity Prices in 2015 (2005 cents/kWh)

Sector	2007 Base	S. 2191	Change
Residential	8.327	9.671	16.1 %
Commercial	7.567	8.817	16.5 %
Industrial	5.280	6.647	25.9 %
Total	6.745	8.158	21.0 %

Table 5 - Indiana Real Electricity Prices in 2020 (2005 cents/kWh)

Sector	2007 Base	S. 2191	Change
Residential	7.803	10.101	29.4 %
Commercial	7.204	9.224	28.0 %
Industrial	5.318	7.315	37.6 %
Total	6.507	8.695	33.6 %

Table 6 - Indiana Real Electricity Prices in 2025 (2005 cents/kWh)

Sector	2007 Base	S. 2191	Change
Residential	7.637	10.670	39.7 %
Commercial	7.088	9.849	39.0 %
Industrial	5.513	8.209	48.9 %
Total	6.525	9.437	44.6 %

Comparison to national studies

Table 7 shows a comparison of the price impacts of this study to two studies performed on a national level: EIA's earlier analysis of S. 280 and Duke University's analysis of S. 2191. The preliminary analysis of S. 2181 by the Clean Air Task Force presents results in a graphical form rather than a numerical one, so exact percent price increases cannot be determined. The CRA International study shows the largest price increase of the national studies (32 percent in 2020). The results confirm the hypothesis that Indiana would experience a greater price impact than the nation as a whole.

Table 7 – Comparison of electricity price increases to other studies [3, 4]

Year	SUFG S. 2181 Indiana	EIA S. 280 National	Duke Univ. S. 2181 National
2015	21.0 %	6.5 %	18.2 %
2020	33.6 %	10.4 %	21.5 %
2025	44.6 %	14.7 %	24.7 %

Electric energy impacts

The SUFG modeling system captures the microeconomic effect of price changes on electricity consumption. For instance, some customers will react to an increase in the electricity price by switching to a different energy source or by using electricity in a more efficient manner. The sensitivity of consumption to price varies by customer class, with the industrial sector being the most sensitive. Table 8 shows the average compound growth rates (ACGR) by customer class for the 2007 Base and S. 2191 cases for the time period 2011-2025. While the residential and commercial sectors are impacted to some degree, the industrial sector is most heavily affected. These results should be used with caution because the magnitude of price increases seen in this analysis lie outside the historical experience that serves as the basis for calibration of the energy models and because there are no macroeconomic effects modeled (see the Caveats section for more information on these issues).

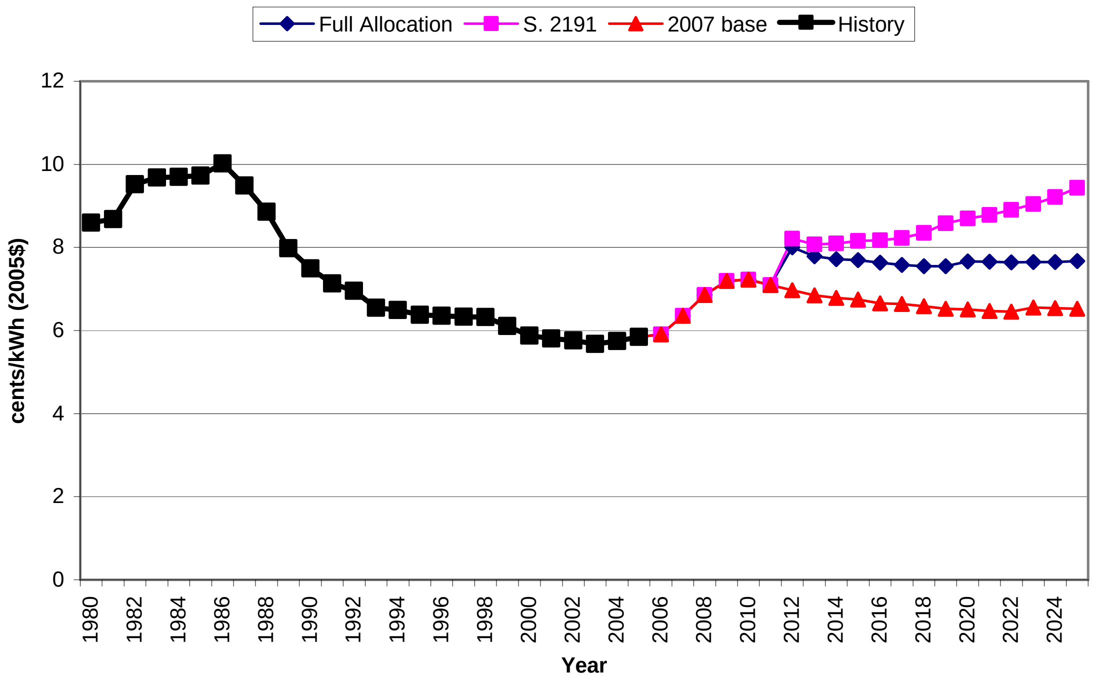
Table 8 - Electricity Sales for Indiana Investor-Owned Utilities (ACGR, 2011-2025)

Sector	2007 Base	S. 2191
Residential	2.44 %	1.79 %
Commercial	2.33 %	1.94 %
Industrial	2.58 %	0.58 %
Total	2.47 %	1.32 %

Impact of auctioning allowances

In order to estimate the impact of auctioning some of the allowances as opposed to a pure direct allocation method, a separate scenario assuming all allowances would be directly allocated (labeled as Full Allocation) was analyzed. To a large degree, the choice to auction versus directly allocate represents a transfer of money from the ratepayer to the taxpayer in a regulated environment like Indiana. In this case, the electricity price difference between the two scenarios reflects that with auctions, Indiana utilities can pass the cost of purchasing allowances through to ratepayers and the U.S. Treasury is increased by the auction proceeds, representing a savings for taxpayers. With allocation, utilities are able to comply with the CO_2 limits at a lower cost, representing a savings for ratepayers. Figure 5 compares the Full Allocation scenario to the 2007 Base and S. 2191 scenarios. The difference between the Full Allocation scenario and the S. 2191 scenarios is small initially (14.8 percent price increase in 2012 for Full Allocation versus 17.8 percent in S. 2191) and grow over time (17.6 versus 44.6 percent increase in 2025).

Figure 5 - Indiana Real Electricity Prices (2007 Base vs. S. 2191 vs. Full Allocation)



Caveats

Forecasting is by its very nature an inexact science. This is especially true of long-term forecasting and even more so when forecasting something with as much uncertainty as how utilities and their customers will respond to carbon constraints. While it is not possible to capture all of the uncertainty, or even to put boundaries on it, it is valuable to identify sources of uncertainty and their possible impacts.

Large-scale wind development

While SUFG does not advocate the means by which utilities should meet new resource requirements, this analysis does assume the development of significant wind resources or some substitute having similar qualities. If all of the baseload resources in the analysis were actually met by a mix of wind and natural gas generation as modeled, almost 3,400 MW of wind capacity would be needed in 2012 and about 9,800 MW would be needed in 2025. Given the likely need for wind power in other states in the region, either for carbon reduction purposes or to meet state renewable resource standards, the Midwest could be facing a significant introduction of wind onto the power network.

A number of questions surround the incorporation of wind on such a large-scale. First, the location of the best wind resources in relation to the load and the existing transmission facilities indicate that substantial investment in new transmission facilities may be needed. This analysis does not include transmission investment beyond the normal levels experienced recently. If significant investment in the transmission system were needed, electricity prices would increase. Next, the intermittent nature of wind power may cause operational issues with regards to traditional steam-powered generators. For instance, if the wind blows hard enough in the middle of the night when demand is low, should steam-powered generators be shut down? If so, will enough capacity be available during the day, especially if the wind lessens? If these operational issues force the overall system to be run in a less than economically optimal manner, electricity prices would increase. Finally, there are questions about the feasibility and cost implications of large-scale wind development. Will sufficient wind turbine equipment be available to develop that much wind power? If so, what will happen to the cost of wind turbines?

This analysis does not include a continuation of the federal production tax credit for wind power. The production tax credit has undergone a series of renewals and lapses over the past several years and is currently due to expire at the end of 2008. The continuation of the production tax credit would reduce the price impact of CO_2 control.

Demand-side management

This analysis does not include accelerated utility-sponsored conservation and load management measures. While these demand-side measures are more attractive economically under the higher electricity prices projected when CO_2 emissions are limited, quantifying the amount of demand reduction and the cost associated with achieving it was not feasible in the timeframe available for this analysis. Under the assumption that utilities would implement demand-side management when it is cost effective to do so, an increase in these measures would tend to reduce the price impact of CO_2 control. Also, since these measures would substitute for new generation as a resource option, they would also tend to alleviate some of the concerns regarding the development and integration of large-scale wind capacity.

Price elasticity

As is common in forecasting, SUFG's modeling system uses observations from the past to project what is likely to happen in the future. Many years worth of historical observations are used to estimate the relationship between a number of explanatory factors and the parameter of interest. In this case, the explanatory factors include such things as population, economic activity, fossil fuel prices, and electricity prices. These all represent inputs to the modeling system. The output of the modeling system is electricity usage. In general, the closer the projected input parameters match the observed historical values, the better the performance of the model will be. In this analysis, electricity price changes occur at a magnitude greater than previously experienced. While the modeling system will extrapolate the impact of smaller observed price changes to the larger projected one, the accuracy of that extrapolation is uncertain.

Macroeconomic effects
While the SUFG modeling system captures the impact of higher prices on a microeconomic level, it does not capture the macroeconomic effects. The modeling system uses projections of macroeconomic variables, such as gross state product at the individual industry level and demographics, as an input. If the electricity price increase causes a customer to switch to another fuel source or use electricity more efficiently, it is a microeconomic effect and the model captures it. If the price increase causes a consumer to shut down her business or decide not to locate in the state, it is a macroeconomic effect and it is not captured. Given the potential price impacts for industrial customers, the macroeconomic effects could be substantial.

Technological innovations
While it is likely that CO_2 restrictions will provide increased incentives for new technological developments, it is not possible to predict what developments will occur and when they will be commercially available. Examples of potential developments include more efficient, less costly carbon capture methods that reduce the cost of CO_2 reductions from fossil-fueled plants and energy storage technologies that may be used to overcome the intermittency problem of wind power. The development and implementation of new technological innovations would tend to reduce the price impact of CO_2 control.

Compliance strategy
As explained previously, the strategy used to comply with CO_2 restrictions should not be construed to be optimal. Furthermore, the strategy used here has not been discussed with the utilities. While the least cost options have been used when possible, the best strategy for individual utilities may be different. If a lower cost strategy exists, the price impact of CO_2 control would be reduced.

Modeling of S. 2191
While this analysis is loosely based on the proposed legislation, it does not attempt to explicitly model it. One major difference is that allowances are not allocated to the utilities according to the bill's specifications. Given the number of entities that are assigned emissions allowances in the bill, it is quite possible that fewer allowances would actually be allocated to Indiana's utilities than is modeled in this analysis. This would increase the price impact of CO_2 control above that shown in the analysis as Indiana utilities would either have to take additional control measures or purchase more allowances. Another difference results from the bill's provision for bonus allowances for CO_2 storage, which would improve the cost competitiveness of IGCC with carbon capture. Furthermore, the prices of fossil fuels, allowances, and offsets were taken from an earlier bill, S. 280, instead of S. 2191. These prices would differ to the extent that the national CO_2 emissions limits change between the two bills.

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