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Simplified Models of U.S. Acid Rain Control Costs

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Simplified algorithms are presented for estimating the cost of controlling sulfur dioxide (SO_2) emissions from existing coal-fired power plants on a state-by-state basis. Results are obtained using the detailed Utility Control Strategy Model (UCSM) to calculate the impacts of emission reductions ranging from approximately 30 percent to 90 percent of projected 1995 emissions for 18 different scenarios and 36 states. Scenarios include the use of two dry SO_2 removal technologies (lime spray dryers and LIMB) as potential options for power plant retrofit, in addition to currently available emission control options including coal switching, coal cleaning and wet flue gas desulfurization (FGD). Technical assumptions relating to FGD system performance and the upgrading of existing cold-side electrostatic precipitators (ESP) for reduced sulfur levels are also analyzed, along with the effects of interest rates, coal prices, coal choice restrictions, plant lifetime, and plant operating levels. Results are summarized in the form of a 3-term polynomial equation for each state, giving total annualized SO_2 control cost as a function of the total SO_2 emissions reduction for each scenario. Excellent statistical fits to UCSM results are obtained for these generalized equations.

The strategies and cost of reducing sulfur dioxide (SO_2) emissions are prime concerns in the national debate over "acid rain" control. A number of computer models have been used to estimate the cost of SO_2 emission reductions,[1-4] particularly for coal-fired power plants, which bear the burden of acid rain controls proposed by Congress. The complexity and computational requirements of state-of-the-art models, however, inevitably limit their direct use by persons interested in cases other than those reported in a particular study.

To obtain more general results, the present study uses a detailed computer simulation model to derive simpler models covering a wide variety of cases of interest in acid rain analysis. These analyses are performed at the state level, which is the focus of most emission control proposals, and the level at which emission control authority for existing sources resides. The emphasis of this paper is on the total statewide cost of SO_2 reductions from coal-fired power plants not currently equipped with flue gas desulfurization (FGD) systems. Reductions ranging from approximately 30 percent to 90 percent of expected future emissions are examined for a variety of scenarios reflecting different technology, coal supply and economic assumptions. Results are presented in the form of simplified algorithms derived from statistical analysis of results from the detailed model.

The Utility Control Strategy Model

The model used in the present study is the Utility Control Stragegy Model (UCSM) developed at Carnegie Mellon University for acid rain analysis.[4] The UCSM is a detailed simulation model which assesses control strategy decisions for individual power plants based on site-specific plant and fuel characteristics, while also considering various economic parameters and technological choice constraints. It incorporates a number of significant refinements over currently available emission control technology performance and cost models, as well as a number of data base enhancements important for rigorous analysis. Decisions at the individual plant or unit level are made on the basis of technical and economic constraints, considering the type and remaining lifetime of each unit. Available control strategies for SO_2 include coal switching, coal blending, coal cleaning, installation of emission control devices, combinations of coal switching and control devices, no action, and early retirement. In addition to its current coal, eleven alternative coals are considered by the UCSM for each plant. These include both washed and unwashed coals determined by a separate coal supply module which considers 35 U.S. coal supply regions and transportation costs to 66 demand nodes. More detailed descriptions of the UCSM and its associated data bases can be found elsewhere.[4-9]

In analyzing control strategy selections, the UCSM can be used either to find the least expensive means of meeting emission standards for a single facility (i.e., a plant or unit), or to minimize the cost for a collection of facilities (e.g., all plants in a state or multi-state region). Although power plant emission standards in the U.S. currently are specified on a unit-by-unit basis, most acid rain control proposals specify an overall SO_2 emission reduction for individual states. This is the mode of analysis used in this paper. Thus, in running the UCSM, the options chosen for individual power plants are based on achieving an overall least cost solution for the entire state. Only those plants not currently fitted with FGD systems are considered in this analysis since these are the principal candidates for SO_2 control.

Scenario Selection

The "base case" assumptions for this study are shown in Table I. Further discussion of these assumptions is found in Reference 10. Based on these assumptions, SO_2 emissions from all existing plants not currently equipped with FGD systems and not retired before 1995 are first estimated using the assumed capacity factors shown in Table I. From this "Base 1995" emission levels, the cost of SO_2 emission reductions is then calculated using the UCSM.

Given the large number of parameters available in a complex model like the UCSM,* an initial screening was undertaken to select those of greatest importance to control strategy cost. For the initial assessment of parameters, eight states were chosen as a representative subgroup: Illinois, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia. These states are the largest SO_2 emitters in the country, accounting for over 60 percent of the total projected SO_2 emissions in 1995 from uncontrolled coal-fired power plants.[6] Selected scenarios were analyzed individually for each of the states in this subgroup. These 25 scenarios included parameters suspected to substantially affect costs or control strategies decisions.[4] This included the future availability of dry SO_2 removal systems (lime spray dryer FGD and limestone injection with multistage burners, or LIMB) in addition to conventional wet FGD

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* These include 22 economic parameters, 123 technical parameters, and 4 policy parameters restricting the choice of alternative coals.

Table I. Selected base case assumptions.

Parameter	Value
Compliance year	1995
Inflation rate[a]	6%
Nominal return on debt[a]	12%
Nominal return on equity[a]	14%
Debt/equity ratio	52.6/47.4
Federal tax rate[b]	46%
State tax rate[b]	4%
Value-added tax charges	4.5%
Investment tax credit rate[b]	11.75%
Tax credit eligibility[b]	100%
Tax life (retrofits)	100%
Real escalation rates	
Capital cost	0.0%/yr
Variable cost	0.0%/yr
Energy cost	0.0%/yr
Coal prices	0.0%/yr
Transportation prices	1.5%/yr
Retrofit cost factors[c]	1.3
Electric energy cost	62 mills/kWh (1985)
Limestone cost	14 $/ton (1985)
Lime cost	63 $/ton (1985)
FGD options[d]	Wet FGD w/90% removal
FGD construction time	3 yrs (specified schedule)
Capacity factor	35%–65% (based on age)[e]
Unit lifetime	45 yrs (or database value)
Amortization period	Remaining plant life (maximum 30 years)

[a] Nominal values are shown for convenience. The equivalent real interest rate before taxes is 3.7% (weighted cost of capital).
[b] These values have been altered by the recent 1986 tax code revisions. Results of the analysis, however, are not materially affected.
[c] Applies to all equipment capital cost for SO_2 and TSP Control.
[d] Plants with multiple small units are assumed to consider FGD for larger aggregates to capture economies of scale.
[e] Assumes remaining lifetime capacity factor is 35% for units with one year of life, increasing linearly to 65% for units with a life of 20 years or more.

processes for retrofit applications. For all 25 scenarios, the UCSM was exercised for nine SO_2 reduction levels in each of the eight states (i.e., 1800 cases). The SO_2 reductions ranged from approximately 30 percent to 90 percent of the projected uncontrolled SO_2 emissions in 1995 from coal-fired power plants not already equipped with FGD.

Results for these initial scenarios showed that certain cases produced only small differences in total abatement cost relative to the base case, while other scenarios produced more pronounced differences. Figure 1 illustrates this for the state of Indiana. Similar results were obtained for each of the other states analyzed. In these figures, the cost of SO_2 control refers to the total levelized annual cost for plants to meet the statewide SO_2 reduction requirement. Capital costs for new pollution control equipment, or modifications to existing equipment (such as ESP upgrades), are levelized over the remaining life of each plant or unit. This annualized capital cost is added to any additional operating and maintenance costs incurred. The operating costs include adjustments in the cost of fuel if a new coal is selected. All SO_2 control costs are reported in constant 1985 dollars.

The major conclusions from the initial 25 scenario runs are that:

- The availability of lime spray dryers and LIMB for tangential and wall-fired units without the ability to upgrade existing cold-side ESPs for particulate control (in lieu of installing a fabric filter collector) has little or no effect on the statewide cost of reducing SO_2 emissions.
- Cold-side ESP upgrade capability with lime spray dryer and LIMB systems significantly reduces the cost of controlling SO_2 emissions with statewide savings of up to about 35 percent. The magnitude of statewide savings is approximately the same for all ESP upgrade costs examined.
- Variations in the reagent requirements for lime spray dryer and LIMB systems result in little or no change to the total statewide cost of controlling SO_2 emissions (though it may affect the preferred strategy for individual facilities).
- Restrictions on coal choice cause the largest increases in the total cost of controlling SO_2 emissions. A requirement to burn only current (1980) coals leads to the largest increases, which are as high as 50 percent to 100 percent for the eight midwestern states analyzed. A restriction to only "local" coals produced in-state can also lead to increases of 50 percent in statewide costs, but the magnitude of these increases varies from state to state with costs for some states increasing by only a few percent.
- Changes in the assumed real interest rate alter the total cost of SO_2 control by approximately 10 percent (increasing or decreasing depending on whether a higher or lower rate is assumed). This reflects the effects of debt and equity payments associated with capital expenditures for pollution control equipment.
- Assumptions concerning future coal price escalation rates as a function of sulfur content can vary moderately without substantially altering the total statewide cost of reducing SO_2 emissions. However, a few states are more sensitive with increases or decreases in total cost of up to about 10 percent for some reduction levels. Shifts in the usage of particular coals, however, may be significant in all cases.
- Extending the lifetime of coal-fired power plants decreases the annualized cost of reducing SO_2 emissions (when compared on an absolute SO_2 reduction scale) with savings of about 30 percent to 50 percent. This decrease is due to a longer amortization period, not to any inherent reduction in control costs.

Again, it should be recalled that the above conclusions apply only to total cost at the state level. Significant changes in cost and control strategies can occur at individual plants or units under the scenarios presented without significantly

Table II. Final 18 scenarios selected for analysis.

SO_2 removal technology options	Non-technical parameters (for each technology option)
Present technology: Wet FGD systems only, with conventional ESP upgrades for coal switching.	All parameters at base case value Real interest rate at 2%[c] Real interest rate at 6%[c]
Advanced technology: Wet FGD systems, lime spray dryers[a] and LIMB[b] for SO_2 control with cold-side ESP upgrade available for TSP control at $6.25/kW for coal switching/wet FGD, and $18.75/kW for dry FGD and LIMB.	Real coal price escalation rate 1%/yr Real coal price escalation rate varies by sulfur content (1.5/0.75/0/0%/yr)[d] Coal switching limited to in-state coals only No coal switching (current coal only) Unit life extension of 20 years[e] All plants at 65% capacity factor

[a] SO_2 removal efficiency is 70%; 1.1 moles lime/mole SO_2 input.
[b] SO_2 removal efficiency is 50%; 3.0 moles limestone/mole SO_2 removed.
[c] Base case real interest rate is 3.7% (calculated).
[d] Refers to coal sulfur content in lbs SO_2/MBtu for four ranges; <1.2; 1.2–1.8; 1.8–3.0; and >3.0.
[e] Only for units larger than 100 MW.

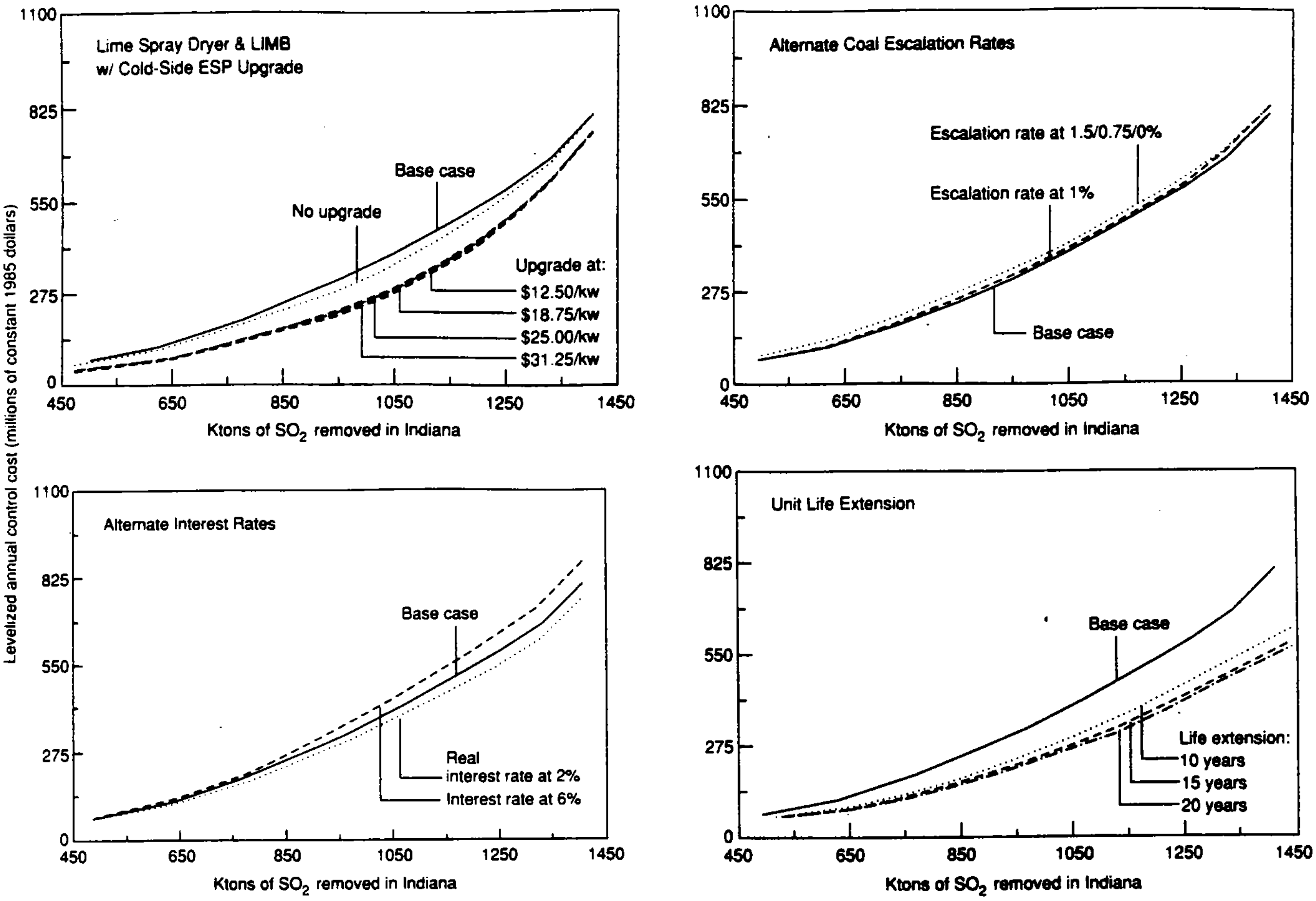

Figure 1. UCSM cost estimates for several scenarios: increase in annual costs in millions of constant 1985 dollars for Indiana.

altering the overall cost for the state as a whole. While an analysis of coal use patterns and emission control technology selection is outside the scope of this paper, other studies[4-7] provide insights in these areas.

In extending the analysis to all states, we eliminated scenarios in which alternative parameter values did not noticeably alter the total state-wide SO_2 control costs.[10] This reduced the total number of scenarios to nine. To more fully analyze the implications of possible technological advances in dry SO_2 removal systems, an "advanced technology" scenario was added to the "present technology" cases involving only wet FGD. Thus, a total of 18 scenarios (Table II) were run for all states using the UCSM. States expected to have negligible or no SO_2 emissions from uncontrolled coal-fired power plants in 1995 were not analyzed, reducing the total number considered from 50 to 36.

Developing Simplified Models

The relationship between total annualized SO_2 control cost and the absolute reduction level achieved was illustrated earlier in Figure 1. To represent these relationships analytically, results generated from the UCSM runs were statistically fit using multivariate and step regression methods. The statistical computer software package MINITAB[11] was used for this analysis.

Beginning with the base case scenario, the procedure used to determine an appropriate form of a cost algorithm was to begin with a simple linear model and add complexity until an acceptably "good" fit was found which accounted for most or all of the observed variation as reflected by a high coefficient of determination, (R^2 of 98 percent or more) with no other suggestion of an underlying relationship (i.e., a plot of the standard residuals is random).

The form of an acceptable algorithm selected from this analysis was a 3-term polynomial:

$$C = a_0 + a_1x + a_2x^b \tag{1}$$

where C is the levelized annual control cost in millions of constant 1985 dollars, and x is the statewide SO_2 emission reduction in millions of tons per year (Mtpy). Coefficients a_0, a_1, and a_2 are estimated for each scenario using multiple regression analysis. A value for b for each state was determined by a trial and error analysis using integer values. A value for b was judged to be appropriate when the resulting standard residuals were between -2 and $+2$. This ensures that the residuals are normally distributed about a mean value of zero, which is necessary in fitting models with multivariate regression analysis.

The complete set of algorithm coefficients for Equation 1 for the base case scenario and the "advanced technology" alternative is shown in Table III. The range of validity for SO_2 emission reductions also is shown, along with the projected 1995 emissions in the absence of SO_2 controls on existing coal-fired power plants without FGD in each state.

For low to moderate emission reductions (i.e., roughly 50 percent or less), the increase in total control cost is approximately linear in most states. This is due primarily to a shift toward lower sulfur coals. As FGD technology becomes necessary to achieve increasingly higher levels of SO_2 abatement, control costs increase non-linearly. This is reflected by the last term of Equation 1. The value of the exponent b in that term reflects the sulfur distribution of current coal use in each state. States like Illinois with a high value of b tend to have a "bi-modal" distribution of current coal sulfur content (e.g., half very low and half very high). This produces a relatively sharp increase in abatement cost once coal switching alone becomes inadequate to meet further emission reduction requirements. On the other hand, states with relatively low values of b reflect situations where coal sulfur content is relatively uniform for plants not yet equipped with FGD. Of particular interest are large emitting states

Table III. Equation 1 parameters for base case scenario.[a]

(a) Present technology[b]							
State	a_0	a_1	a_2	b	Valid Range for x (Mtpy)		1995 Base (Mtpy)
Alabama	36.07	−549.83	3468.10	2	0.150	0.400	0.450
Arkansas	−22.26	2973.33	0.00	0	0.015	0.025	0.030
Arizona	−28.07	2366.77	0.00	0	0.025	0.055	0.060
Colorado	−63.29	4601.10	0.00	0	0.020	0.050	0.060
Delaware	−46.29	2017.40	0.00	0	0.035	0.055	0.060
Florida	7.35	64.30	8543.00	4	0.150	0.400	0.440
Georgia	−32.99	414.87	2195.60	5	0.225	0.650	0.725
Iowa	521.50	−6692.51	21749.90	2	0.175	0.250	0.280
Illinois	−172.59	537.35	175.42	14	0.375	1.050	1.170
Indiana	−133.58	389.52	101.28	4	0.500	1.400	1.560
Kansas	89.54	−4548.40	62630.00	2	0.040	0.070	0.080
Kentucky	−63.60	200.18	447.81	3	0.350	0.975	1.080
Maryland	−12.94	0.10	5829.50	2	0.060	0.175	0.190
Michigan	−67.81	759.40	7677.60	5	0.175	0.500	0.570
Minnesota	12.22	−99.90	8992930.00	5	0.030	0.100	0.125
Missouri	17.75	−196.11	483.14	2	0.450	1.225	1.360
Mississippi	7.65	−92.30	5452170.00	5	0.040	0.100	0.120
North Carolina	96.81	411.70	8334.00	3	0.150	0.350	0.400
North Dakota	−54.59	2495.30	0.00	0	0.025	0.050	0.055
Nebraska	−87.42	3363.70	0.00	0	0.035	0.055	0.060
New Hampshire	−101.14	3422.50	0.00	0	0.035	0.040	0.045
New Jersey	−57.86	1779.21	0.00	0	0.055	0.090	0.100
New Mexico	10.99	715.00	8247.00	2	0.035	0.065	0.070
Nevada	−19.01	2243.50	0.00	0	0.025	0.045	0.050
New York	69.75	−2472.00	32499.00	2	0.040	0.120	0.130
Ohio	−269.30	403.15	13.06	6	0.700	1.875	2.045
Oklahoma	−38.56	2852.82	0.00	0	0.025	0.070	0.080
Pennsylvania	−84.50	458.30	472.80	4	0.325	0.925	1.040
South Carolina	42.82	−1348.50	16988.00	2	0.050	0.125	0.150
Tennessee	−170.59	613.59	2250.90	9	0.300	0.800	0.860
Texas	−64.11	−202.90	6732.60	2	0.125	0.275	0.310
Virginia	264.12	−6605.00	52018.00	2	0.065	0.125	0.140
Washington	−8.46	1300.69	0.00	0	0.040	0.065	0.070
Wisconsin	70.93	−643.10	2594.70	2	0.175	0.425	0.490
West Virginia	−108.18	645.77	515.63	5	0.300	0.825	0.940
Wyoming	−92.97	2627.20	0.00	0	0.045	0.090	0.100

(b) Advanced technology[c]							
State	a_0	a_1	a_2	b	Valid Range for x (Mtpy)		1995 Base (Mtpy)
Alabama	156.69	−1690.50	5422.40	2	0.175	0.400	0.450
Arkansas	−46.19	3859.60	0.00	0	0.015	0.025	0.030
Arizona	−66.86	3027.00	0.00	0	0.030	0.055	0.060
Colorado	−91.93	5016.60	0.00	0	0.020	0.050	0.060
Delaware	−46.53	1966.60	0.00	0	0.030	0.055	0.060
Florida	12.53	1.50	7784.00	4	0.150	0.400	0.440
Georgia	−25.83	319.31	2486.50	5	0.250	0.650	0.725
Iowa	1244.60	−13286.00	35690.00	2	0.200	0.250	0.280
Illinois	−180.79	508.85	167.12	14	0.375	1.050	1.170
Indiana	−15.07	110.97	158.63	4	0.475	1.400	1.560
Kansas	140.17	−6473.30	77998.00	2	0.045	0.070	0.080
Kentucky	−12.02	28.92	549.83	3	0.350	0.950	1.080
Maryland	37.34	−1117.70	10577.20	2	0.060	0.175	0.190
Michigan	−60.05	586.10	10812.60	5	0.200	0.500	0.570
Minnesota	22.15	−187.10	8272998.00	5	0.040	0.100	0.125
Missouri	182.76	−698.10	753.70	2	0.575	1.225	1.360
Mississippi	4.87	−49.07	3891919.00	5	0.040	0.100	0.120
North Carolina	7.58	459.30	10058.00	3	0.125	0.350	0.400
North Dakota	−85.43	3044.30	0.00	0	0.030	0.050	0.055
Nebraska	−95.81	3301.30	0.00	0	0.030	0.055	0.060
New Hampshire	−31.79	1583.50	0.00	0	0.035	0.040	0.045
New Jersey	−69.96	1809.20	0.00	0	0.040	0.090	0.100
New Mexico	−29.47	1010.00	13706.00	2	0.035	0.065	0.070
Nevada	−65.57	3164.70	0.00	0	0.025	0.045	0.050
New York	61.43	−2532.90	31400.00	2	0.045	0.100	0.130
Ohio	−183.18	232.27	16.34	6	0.875	1.875	2.045
Oklahoma	−96.07	3438.70	0.00	0	0.030	0.070	0.080
Pennsylvania	35.28	100.32	713.99	4	0.325	0.925	1.040
South Carolina	99.48	−2855.10	24891.00	2	0.060	0.125	0.150
Tennessee	−170.80	554.85	2489.80	9	0.325	0.800	0.860
Texas	279.70	−4189.00	16354.00	2	0.175	0.125	0.140
Virginia	120.89	−3903.70	39137.00	2	0.050	0.125	0.140
Washington	−37.25	1707.80	0.00	0	0.025	0.065	0.070
Wisconsin	82.41	−951.30	3068.10	2	0.175	0.425	0.490
West Virginia	−77.23	441.68	807.19	5	0.325	0.825	0.940
Wyoming	−145.34	3164.40	0.00	0	0.050	0.090	0.100

[a] See Table I for definition of base case.
[b] Wet limestone FGD and conventional ESP upgrades.
[c] Wet FGD, dry FGD and LIMB with low cost ESP upgrades.

like Missouri, where high sulfur coal use predominates. Increases in control cost, while still non-linear, are far less abrupt over the range considered since there is greater potential for coal switching and washing to reduce SO_2 emissions by significant amounts before scrubbers are required.

The cost coefficients for Equation 1 and ranges of validity for sixteen additional scenarios reflecting the range of variables considered in this study (Table II) appear in Reference 10. Summary tables also are available from the authors. Since the selected value of b is dependent primarily on individual state characteristics, it is assumed that b remains constant for a given state in all scenarios.

In all cases, the statistical fits were extremely good, with R^2 values typically above 99 percent. Thus, within the stated ranges of validity the results of the UCSM are matched exactly by the simpler regression models presented here. This goodness of fit was achieved in part by restricting the lower limit of the regression to a removal efficiency of approximately 30 percent. Attempts to develop a single equation valid over a wide range of emission reductions were less successful owing to a linear variation of cost increases at low reductions, with non-linear behavior at higher reduction levels. Thus, a good approximation to the UCSM results for reductions below the ranges shown in Table III is a straight line from the lower limit to the origin. Although this range generally is of less interest for acid rain control policies, the linear variation of costs reflects a dominant strategy of coal switching to achieve relatively small emission reductions. At the high end of the range, reductions in excess of 90 percent at the state level were not modeled since this range is well in excess of acid rain control proposals for the U.S.

Conclusion

The parameters summarized in Table II reflect many of the key factors affecting the cost of reducing SO_2 emissions from existing coal-fired power plants. For each of two "technology" scenarios (wet FGD only, versus wet FGD, dry FGD and LIMB), several "non-technology" parameters were varied across a range of SO_2 emission reductions for each state to derive algorithms for cost as a function of emissions reduction. These parameters reflected changes from the base case assumptions (Table I) regarding alternative coal prices; requirements to use only local coals; changes in real interest rate; higher plant capacity factors; and an extended plant lifetime. Again, the cost results presented reflect a "least cost" strategy for each state as a whole (i.e., a statewide "bubble"). Other implementation schemes, such as the imposition of uniform emission caps of the sort now prevalent in most states, could lead to higher emission control costs.[4]

Several areas relevant to acid rain control cost analysis which also merit examination were beyond the scope of this paper. These include SO_2 emission reductions from oil-burning power plants; emissions from the industrial sector; effects of electricity demand and dispatch modifications; and the inclusion of NO_x reduction requirements in addition to SO_2. These areas are important to a more complete analysis of the utility sector and other sources of precursor emissions associated with acid deposition. However, the costs algorithms developed here do provide a basis from which a major portion of the cost of SO_2 emission reductions can be estimated under a variety of scenarios.

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