Appendixes

Appendix A

Emissions and the Costs of Control

A.1 HISTORIC EMISSIONS OF SULFUR AND NITROGEN OXIDES

During **1980,** about **25** million to **27** million tons of sulfur dioxide **(SO_2)** and about **21** million to **23** million tons of nitrogen oxides (NO_x) were emitted nationwide by electric utilities, industry, highway vehicles, and other sources. **SO_2** emissions peaked around 1970 **at** about **29** million to **31** million tons per year; NO_x emissions peaked during the late **1970's** at about **21** million to **24** million tons per year.

Estimates such as these are calculated from data collected by the Environmental Protection Agency (EPA) and the Department of Energy (DOE) on a large variety of emitting sources. Pertinent information includes, for example, fossil fuel consumption, sulfur content of fuels burned, and average NO_x emissions rates from various types of boilers and highway vehicles. Due to the extensive data collection and monitoring activities of both agencies, current emissions estimates are accurate to within **5** to 10 percent nationwide. However, the uncertainty around emissions estimates is larger for prior years. Reasonably complete data exist for the last three decades; emissions between 1900 and 1950 must be inferred using whatever historical records exist. Assumed values are necessary to fill in missing data to complete the calculations.

Tables A-1 and A-2 present estimates of 1980 SO_2 and NO_x emissions by State and sector. These estimates were calculated by EPA for the U.S.-Canada Memorandum of Intent on Transboundary Air Pollution.[1] Nonutility combustion (table A-1, co1. 3, table A-2, co1. 4) includes emissions from industrial, commercial, and residential combustion sources. Industrial process emissions of SO_2 (table A-1, co1. 4) include emissions from nonferrous smelters, petroleum refineries, cement plants, natural gas plants, iron and steel mills, and sulfuric acid plants. Transportation emissions of NO_x (table A-2, col. 2) include highway vehicles and such off-highway mobile sources as aircraft, railroads, vessels, and construction equipment.

Estimated historic emissions of SO_2 and NO_x from 1900 to 1980 are presented graphically below.[2] These estimates are from ongoing work by an EPA contractor, and are subject to further review and revision. (The estimates for 1980 agree to within about 5 percent with the emissions estimates presented in tables A-1 and A-2.)

Figure A-1 presents State-level SO_2 and NO_x emissions estimates for the period 1950 to 1980. Most of the data needed to calculate these estimates were available by State from various government reports;

[1] "Emissions, Costs and Engineering Assessment," Work Group 3B, *United States-Canada Memorandum of Intent on Transboundary Air Pollution*, June *1982.*

[2] The maps and graphs presented in this section are from the draft report "Historic Emissions of Sulfur and Nitrogen Oxides in the United States From 1900 to 1980," G Gschwandtner, K C Gschwandtner, and K Eldridge, October 1983 The work was performed by Pacific Environmental Services, Inc, under contract to EPA

Table A-1 .—Estimated 1980 SO_2 Emissions (thousands of tons)

State	Total 1980 SO_2 emissions	Utility combustion	Nonutility combustion	Process emissions	Other SO_2 emissions
Alabama.	759	543	86	95	35
Alaska	19	12	3	1	2
Arizona.	900	88	9	787	17
Arkansas	102	27	32	29	14
California	446	78	56	197	116
Colorado	132	77	24	17	13
Connecticut.	72	32	35	0	5
Delaware	109	52	26	25	6
District of Columbia	15	5	8	0	2
Florida	1,095	726	97	159	113
Georgia	840	737	44	14	45
Hawaii	58	42	8	6	3
Idaho	47	0	11	30	5
Illinois	1,471	1,126	188	119	38
Indiana	2,008	1,540	290	151	27
Iowa	329	231	57	27	13
Kansas	223	150	11	39	22
Kentucky	1,121	1,008	66	29	18
Louisiana	304	25	76	153	50
Maine	95	16	65	4	10
Maryland	338	223	56	42	17
Massachusetts	344	275	58	1	11
Michigan	907	565	154	152	35
Minnesota	260	177	44	18	22
Mississippi	285	129	48	75	32
Missouri	1,301	1,141	55	81	25
Montana	164	23	25	104	11
Nebraska	75	49	4	5	17
Nevada	243	34	2	203	5
New Hampshire	93	80	10	0	2
New Jersey	279	110	75	42	52
New Mexico	269	85	2	166	16
New York.....	944	480	335	71	59
North Carolina	602	435	116	23	28
North Dakota	107	86	13	4	5
Ohio	2,647	2,172	311	118	46
Oklahoma	121	38	15	52	16
Oregon	60	3	25	8	24
Pennsylvania	2,022	1,466	254	239	63
Rhode Island	15	5	8	0	2
South Carolina	326	213	84	13	16
South Dakota	39	29		3	4
Tennessee	1,077	934	83	27	33
Texas	1,277	303	106	719	148
Utah	72	22	16	27	6
Vermont	7	1	5	0	1
Virginia	361	164	142	14	41
Washington	272	69	41	132	29
West Virginia	1,088	944	84	43	16
Wisconsin	637	486	107	5	40
Wyoming	184	118	30	29	8
U.S. total	26,557	17,373	3,504	4,296	‘1,385
Percent of U.S. total	100	65	13	16	5

SOURCE: Emissions, Costs and Engineering Assessment, Work Group 3B, United States-Canada Memorandum of Intent on Transboundary Air Pollution, June 1982.

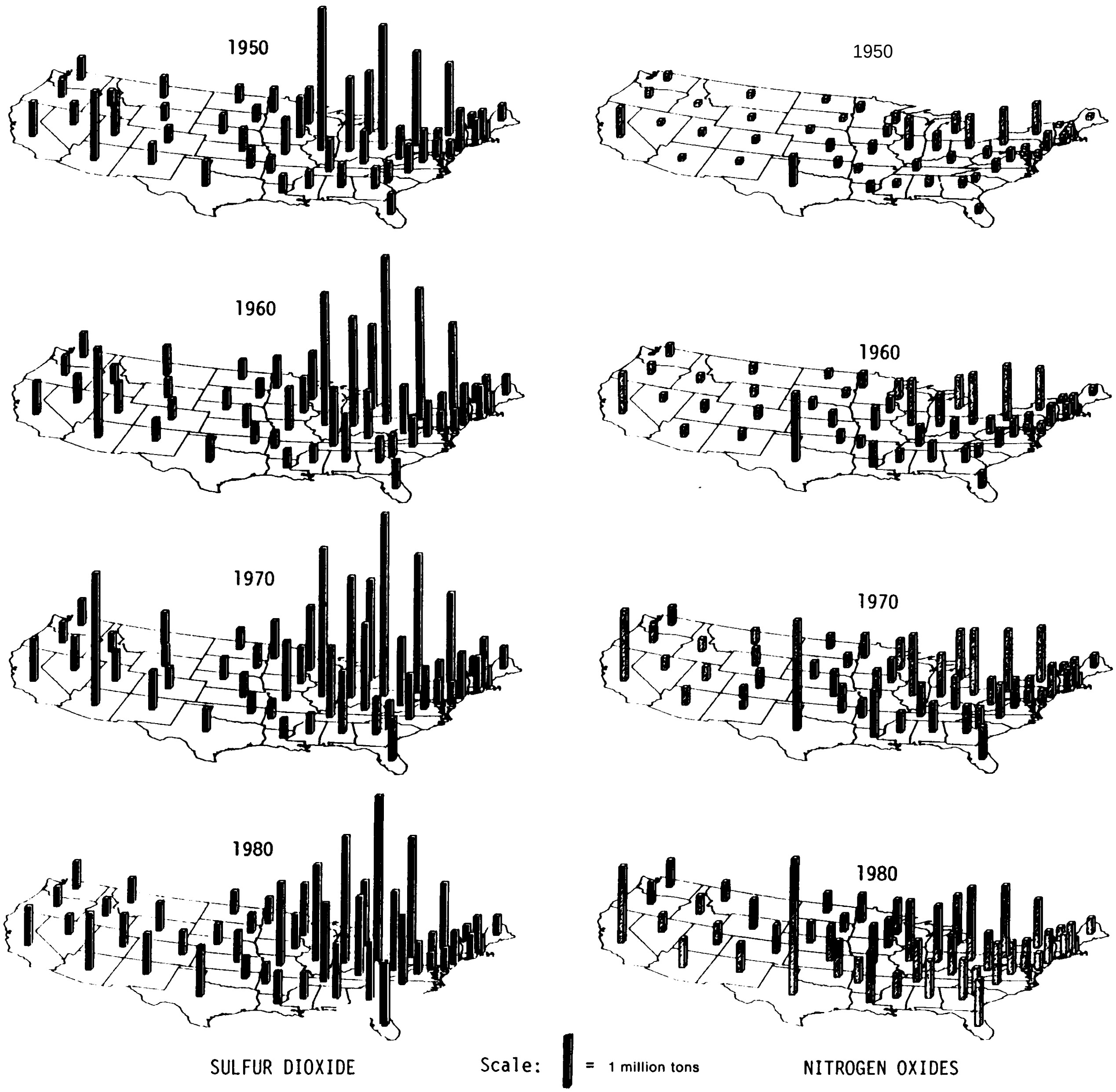
Table A-2.—Estimated 1980 NO_x Emissions (thousands of tons)

State	Total 1980 NO_x emissions	Transportation	Utility combustion	Non utility combustion	Other NO_x emissions
Alabama	450	164	172	83	31
Alaska	58	27	0	27	4
Arizona	258	119	91	40	9
Arkansas	217	131	26	45	15
California	1,225	820	115	205	85
Colorado	276	115	86	67	9
Connecticut	134	90	20	23	1
Delaware	52	22	19	9	2
District of Columbia	22	14	2	6	1
Florida	648	347	214	52	35
Georgia	494	236	189	39	31
Hawaii	45	26	13	3	3
Idaho	81	52	0	15	15
Illinois	1,005	425	416	129	35
Indiana	773	280	361	99	33
Iowa	321	165	98	47	9
Kansas	437	176	86	151	24
Kentucky	531	183	272	67	9
Louisiana	928	190	98	552	89
Maine	59	42	1	13	3
Maryland	248	143	61	37	7
Massachusetts	254	158	57	37	2
Michigan	690	302	237	121	29
Minnesota	373	200	112	53	8
Mississippi	285	125	50	79	31
Missouri	568	254	237	49	27
Montana	126	63	23	22	18
Nebraska	195	124	40	22	8
Nevada	83	35	43	4	1
New Hampshire	56	27	25	4	1
New Jersey	406	246	66	68	25
New Mexico	290	97	80	109	4
New York	680	385	130	139	26
North Carolina	536	253	214	50	19
North Dakota	125	60	53	11	1
Ohio	1,145	438	516	162	29
Oklahoma	526	181	105	216	24
Oregon	192	144	3	25	20
Pennsylvania	1,037	434	390	164	49
Rhode Island	36	28	3	5	0
South Carolina	260	127	84	39	10
South Dakota	89	58		4	7
Tennessee	517	224	200	69	25
Texas	2,544	745	522	1,113	163
Utah	144	65	39	33	7
Vermont	25	22	1	2	0
Virginia	405	250	62	65	28
Washington	289	193	25	32	39
West Virginia	452	87	302	55	9
Wisconsin	420	208	145	57	11
Wyoming	255	69	103	78	6
U.S. total	21,267	9,367	6,225	4,595	1,080
Percent of U.S. total	100	44	29	22	5

SOURCE. Emissions, Costs and Engineering Assessment, Work Group 3B, United States-Canada Memorandum of Intent on Transboundary Air Pollution, June 1982.

99-413 0 - 84 - 11 : QL. 3

Figure A.1.—SO_2 and NO_x Emissions From 1950 to 1980, By State



when data were missing, information from the nearest year of record was used.

During 1950, between 18 million and 21 million tons of SO_2 were emitted nationwide. By 1970, annual SO_2 emissions had increased by about 10 million tons over 1950 levels; between 1970 and 1980, emissions declined by about 4 million tons per year.

Figure A-1 also illustrates the geographic pattern of NO_x emissions. During the 1950's, nationwide NO_x emissions were about 8 million to 10 million tons per year. By 1980, nationwide NO_x emissions were over twice 1950 levels.

Figure A-2 graphically illustrates SO_2 and NO_x emissions from 1900 to 1980 by sector and geographic (multi-State) region. For SO_2, the sectors include: electric utilities; industry (including industrial boilers and—for 1950 and later—copper smelters and cement plants); commercial and residential boilers; and other sources, including railroads, vessels, and off-highway vehicles. The sectors for which NO_x emissions are estimated include those listed above, plus highway vehicles and natural gas pipelines. The regions are single or grouped EPA Federal regions, as shown on the accompanying map.

Emission trends for SO_2 show a consistent pattern in each of the regions. While pre-1950 trends are uncertain, SO_2 emissions appear to have increased until about 1925, decreased during the Depression, increased once again during World War II, and then declined until the 1950's. After 1950, annual emissions increased through about 1970, and then declined. In some regions, for example, New York and New England (regions 1 and 2), this historic pattern of emissions increases and decreases appears as variations around a fairly constant long-term average. In other regions, for example, the Mid-Atlantic and Southeastern regions (regions 3 and 4), short-term variations accompany a longer term trend of increasing annual SO_2 emissions.

Annual NO_x emissions have increased throughout the century in ail regions. New York and New England (regions 1 and 2) show the lowest rates of increase, while the Southeast and South Central regions (regions 4 and 6) show the most rapid increases.

A.2 CONTROL TECHNOLOGIES FOR REDUCING SULFUR AND NITROGEN OXIDE EMISSIONS

Acid deposition and ozone result primarily from the chemical transformation of three pollutants: oxides of sulfur, oxides of nitrogen, and hydrocarbons. This section discusses the techniques available for controlling emissions of oxides of sulfur and nitrogen. Where possible, for each emission control approach, the following information will be presented:

- the processes involved in the technique;
- its stage of development, i.e. , whether the technology is currently commercially available or requires further research and development (R&D);
- the effectiveness of the technique, i.e. , the degree of reduction it can reliably achieve;
- costs; and
- secondary effects.

The major source of nitrogen oxides and sulfur dioxide is the combustion of fossil fuels. During the combustion process, sulfur contained in the fuel reacts with oxygen to form sulfur oxides, primarily sulfur dioxide gas (SO_2) and, after sulfate. Nitrogen—contained in both the air used for combustion as well as in the fuel—reacts with oxygen to form gaseous nitrogen oxides (NO_x). There are three general approaches to controlling these emissions:

- precombustion: the amount of sulfur or nitrogen in the fuel being burned can be reduced, either by using fuels naturally lower in sulfur or nitrogen content, or by subjecting the fuels to some kind of physical or chemical process to remove sulfur and nitrogen;
- during combustion: the combustion process can be altered to reduce the amount of sulfur and nitrogen compounds released in the gas stream; and
- postcombustion: the products of combustion can be treated to remove pollutants before they are released into the atmosphere.

All three of these approaches have been successfully used to reduce emissions from existing sources.

In addition to these differences among approaches to control, the stage of development of the emissions control techniques discussed in this appendix varies considerably. Technologies may be characterized as:

- In-use technologies.—Those with demonstrated control capabilities currently sold on a commercial scale in the United States.
- Available technologies.—Those that have been tested and proven but are not currently operational in the United States on any significant scale.

Figure A-2.—Regional SO_2 and NO_x Emissions by Source Category From 1900 to 1980

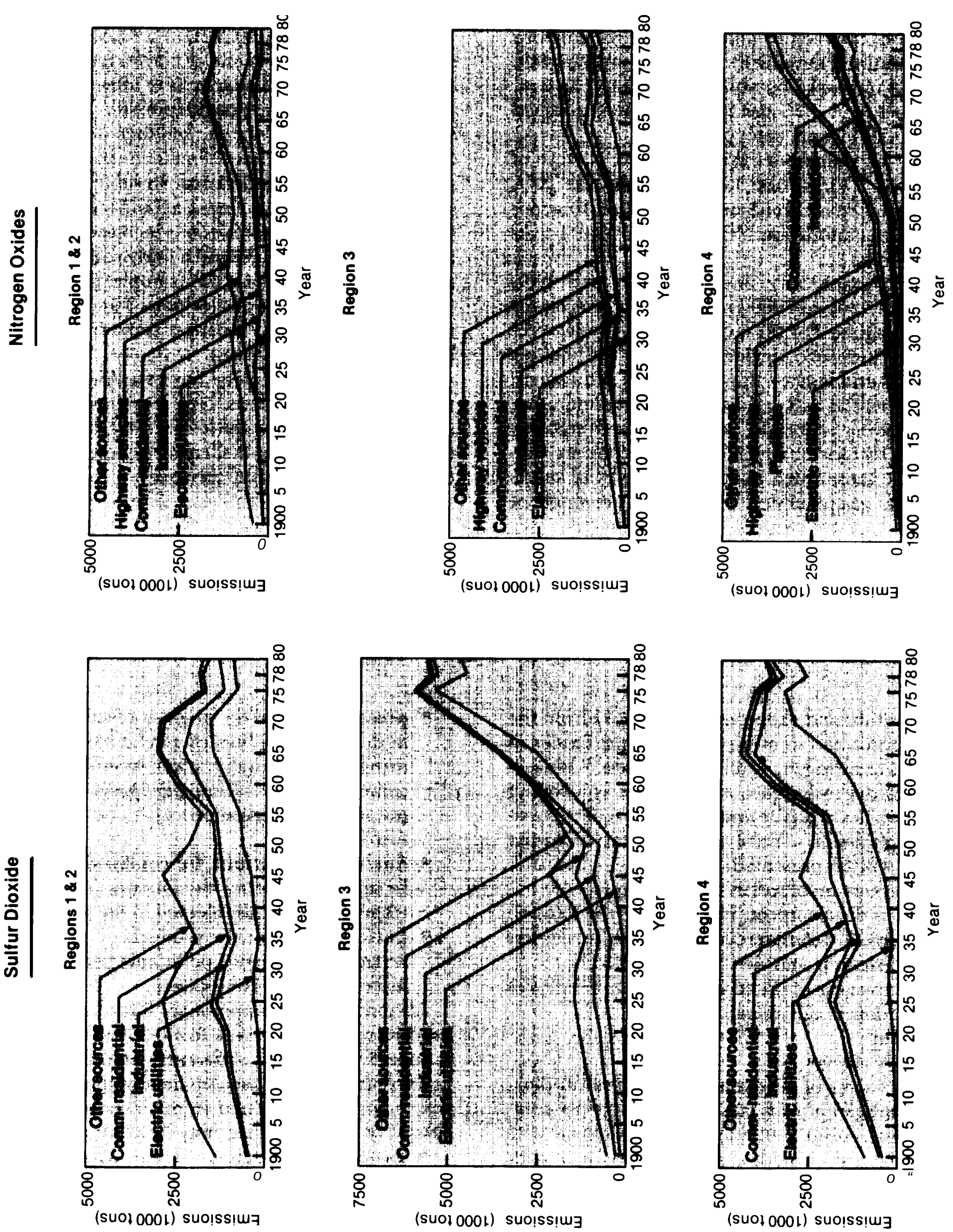


Figure A-2.—Regional SO_2 and NO_x Emissions by Source Category From 1900 o 980—Continued

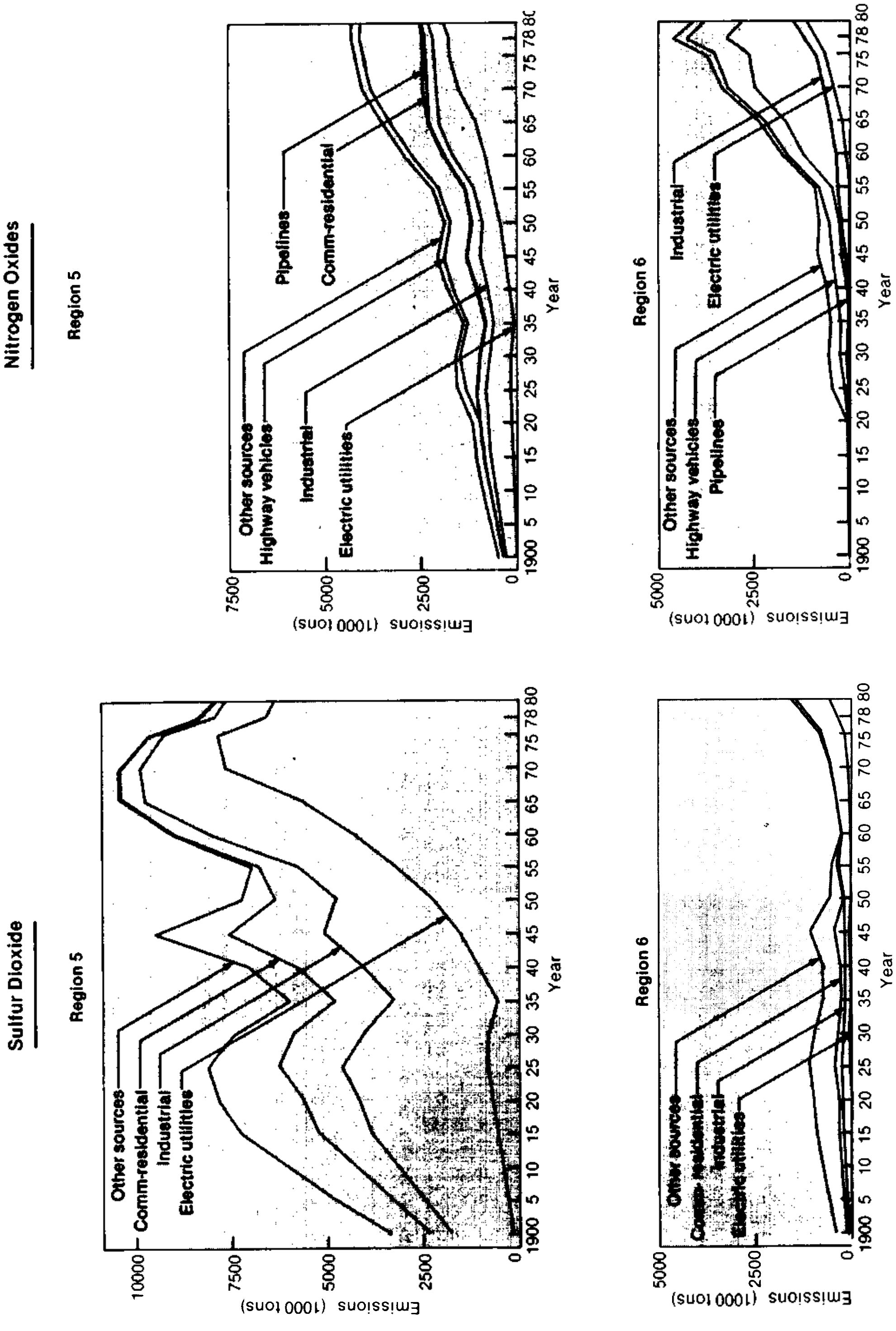
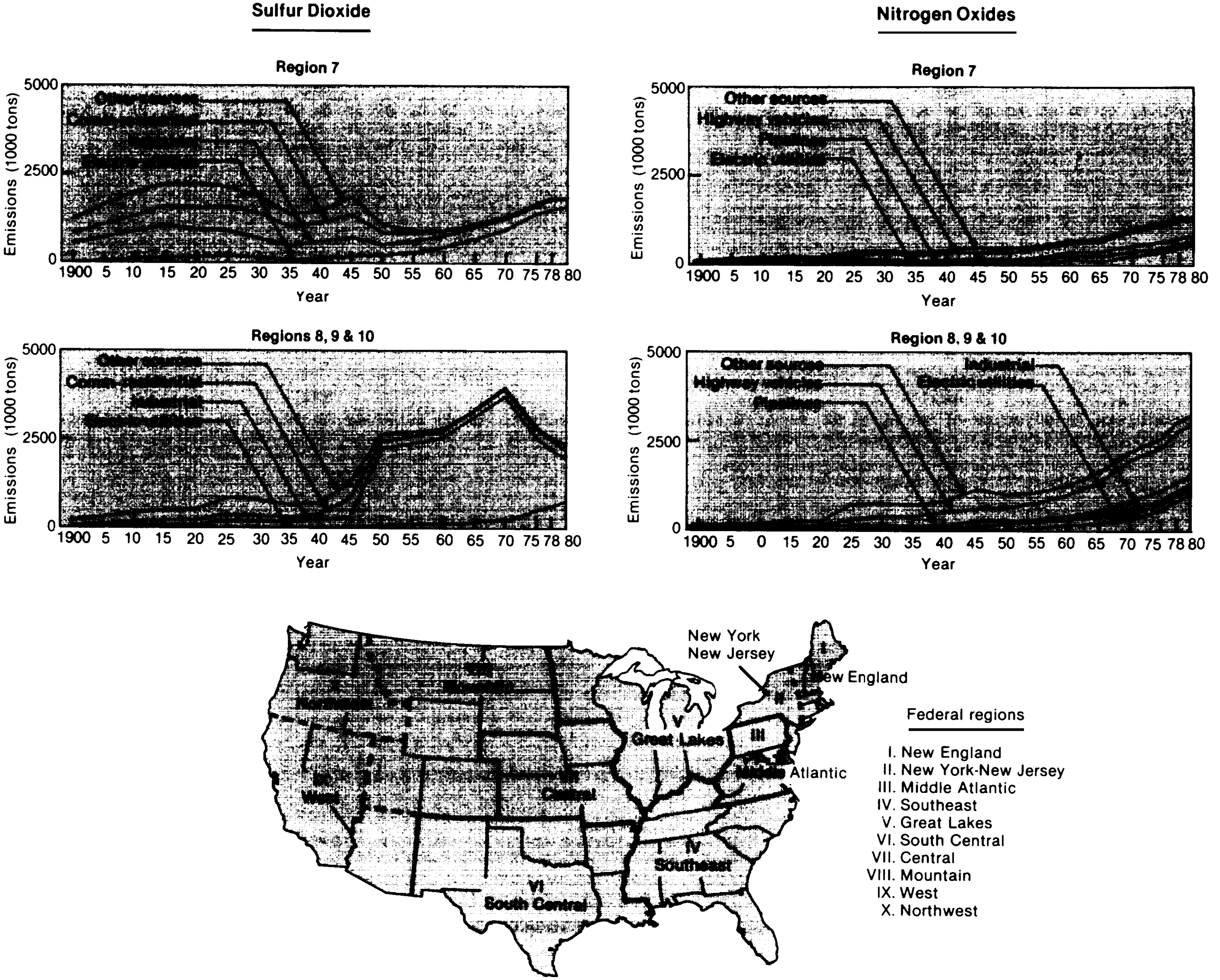


Figure A-2.—Regional SO_2 and NO_x Emissions by Source Category From 1900 to 1980—Continued



NOTE: Emission estimates for years prior to 1950 may not account for all emissions due to data which were unavailable. The industrial category includes industrial boilers, cement plants, and copper smelters. The emissions from the latter are unaccounted for prior to 1950.

- Emerging technologies.--Those still primarily in the R&D phase, but have undergone testing on at least a pilot scale. *

Control approaches also differ widely in the amount of emissions reductions they are capable of achieving and in their cost effectiveness. Each technology is most cost effective in a particular range of emissions reductions. For instance, the precombustion approach of physical coal cleaning is technically feasible only for SO_2 reductions of less than 40 percent. On the other hand, the postcombustion approach of flue-gas desulfurization is cost effective in the 50- to 95-percent SO_2 removal range. The control technique appropriate for a given facility thus depends a great deal on the level of reduction desired.

Table A-3 presents summary information on the control technologies described in this appendix. Due to site-specific conditions, the removal efficiency levels given are intended for approximation only.

*This typology is used to characterize technologies in *Emissions, Costs and Engineering Assessment*, Work Group 3B, "United States-Canada Memorandum of Intent on Transboundary Air Pollution, 1982."

Controlling Sulfur Dioxide Emissions

Precombustion Approaches

FUEL-SWITCHING

Sulfur dioxide is formed when sulfur, an element naturally present in coal and oil, is oxidized during the combustion process. The greater the concentration of sulfur in the fuel being burned, the greater the production of SO_2 gas. One way to reduce SO_2 emissions is, therefore, to use fuels with lower concentrations of sulfur.

The amount of emissions reductions attainable by fuel-switching at a given plant depends on: 1) the amount of sulfur in the fuel currently being used, and 2) the amount of sulfur in the fuel available for replacement. The sulfur content of coal currently being used for electricity generation varies considerably, from about 0.2 to 5.5 percent sulfur by weight (from about 0.4 to 10 lb SO_2 per million Btu of coal).[3]

[3]*Steam Electric Plant Factors* (Washington, D.C.: National Coal Association, 1978)

Table A-3.—Overview of Control Technologies

Control technology	Reduction efficiencies (percent)	Revenue Requirements (mills/kWh)	Stage of development
Sulfur dioxide			
Fuel-switching	30-90 "/0	o-7	In use
Physical coal cleaning	5-40	1-5	In use
Chemical coal cleaning	60-85	NA	Emerging
Wet flue gas desulfurization	70-95	10-17	In use
Dry flue gas desulfurization	40-90	9-15	In use
Regenerable flue gas desulfurization	70-90	12-25	Available
Oil desulfurization:			
Indirect	30-40	4-6	In use
Direct	70-90	NA	In use
Nitrogen oxides:			
Low-NO_x burner—commercial	30-50	0-3	In use
Low-NO_x burner—developmental	50-80	0-3	Emerging
Thermal DeNox	50-65	NA	In use
Flue gas treatment without catalyst	35-40	NA	Available
Flue gas treatment with catalyst	80-90	NA	Available
Combined sulfur dioxide/nitrogen oxides:			
Limestone injection multistage burner:			
Sulfur dioxide	50-90	3-5	Emerging
Nitrogen oxides	50-70	3-5	Emerging
Fluidized bed combustion:			
Sulfur dioxide	<90	NA	Emerging
Nitrogen oxides	20-30	NA	Emerging

SOURCE' Office of Technology Assessment, primarily from EPA estimates.

The two principal components of the costs of fuel-switching are: 1) the "fuel-price differential, " i.e., the difference in price between the high- and low-sulfur fuel; and 2) the type of fuel-handling facilities, boilers, and emissions control devices at the plant. Low-sulfur coal is typically more expensive than high-sulfur coal, especially in the East and Midwest.

Figures A-3 and A-4 illustrate the cost differences between high- and low-sulfur coal. Figure A-3 shows the costs of a high-sulfur, Illinois coal at various distances away from the mine. Similar costs are presented for an Appalachian low-sulfur coal in figure A-4. The costs of the low-sulfur coal are shown to be 50 percent higher than the high-sulfur coal even in the areas closest to the mines. The cost differential confronting specific utility plants will vary considerably, depending on site-specific factors and market arrangements.[4]

Many Western low-sulfur coals contain more ash than Eastern high-sulfur coals and can potentially emit greater amounts of particulate. Therefore, particulate emissions control devices (electrostatic precipitators or baghouses) generally have to be upgraded if low-sulfur fuels are used at existing plants. Fuel-handling facilities may also have to be altered because Western coals are often more difficult to pulverize than Eastern coals. In addition, certain kinds of boilers are designed to burn coal with very specific characteristics (e. g., energy yield, ash, and moisture content). These boilers would have to be modified to burn low-sulfur coal efficiently or derated (i.e., produce less electricity). The capital costs of upgrading particulate controls, fuel-handling facilities, and boilers are relatively minor compared to the increased fuel costs involved in fuel-switching. One estimate of the cost of achieving a 6-million-ton SO_2 emissions reduction by fuel-switching at the ***50*** largest emitters is $1.4 billion per year (1982 dollars), or about $250 per ton of SO_2 removed. '

There are 217 billion tons of 'compliance" coal (i. e., capable of meeting an SO_2 emissions rate limitation of 1.2 pounds per million Btu (lb/MMBtu) without the application of control technologies) in the demonstrated reserve base. [G] This quantity of coal could support U.S. production for a period of about 50 years (assuming 50 percent recoverability and 3 percent annual growth in consumption). Therefore, achieving substantial emissions reductions through fuel-switching would not be constrained by the resource base over the near future.

However, 85 percent of the Nation's ''compliance' reserves are located West of the Mississippi, while 63 percent of coal consumption and 72 percent of coal production occurs East of the Mississippi.[7] In order to be viable, a large-scale emissions reduction program relying primarily on fuel-switching would have to significantly expand Western coal production and transportation capacity. *

COAL CLEANING: PHYSICAL OR CHEMICAL

The second precombustion approach involves physically or chemically treating coal to remove some of the sulfur it contains. Sulfur in coal exists in two major forms: inorganic and organic. Inorganic or "pyritic" sulfur can be removed relatively inexpensively by exploiting differences in the physical properties of pyrite and coal particles. Organic sulfur is chemically bound to the carbon molecules of coal, and can be removed only by breaking the bonds through some chemical process. These chemical processes are less developed and more expensive than the physical processes that remove pyritic sulfur, but their sulfur removal potential is higher. * *

Physical Coal Cleaning.—Physical coal cleaning (often called coal washing) takes advantage of differences in the sizes, densities, and surface properties of pyrite and coal particles. The first step of the cleaning process is to separate raw coal into different size ranges. Breakers and crushers are used to separate the softer coal from the harder rock and other debris contained in the coal entering the treatment plant. After breaking and crushing, the coal is typically filtered through screens to divide it into coarse, intermediate, and fine size ranges.

The method used to extract the pyritic sulfur from the coal depends on the size of particles. Coarse and intermediate size particles allow differences in the specific gravity of pyritic sulfur and coal particles to be used (pyrite has a specific gravity of 5—i. e., is five times heavier than water; coal is approximately 1.4). The coal mixture is immersed in a fluid, where the heavier pyritic particles sink and the lighter particles float. The coal product and refuse material can then be removed separately.

Fine mineral particles cannot be effectively separated by the specific gravity techniques. Physical coal cleaning

'E H, Pechan & Associates, information supplied to OTA, October 1981

[5]PEDCo Environmental Inc, *Acid Rain: Control Strategies for Coal-Fired Utility Boilers—Volume I, Summary Report,* prepared for the Department of Energy, May 1981, tables 3-1 and 3-2.

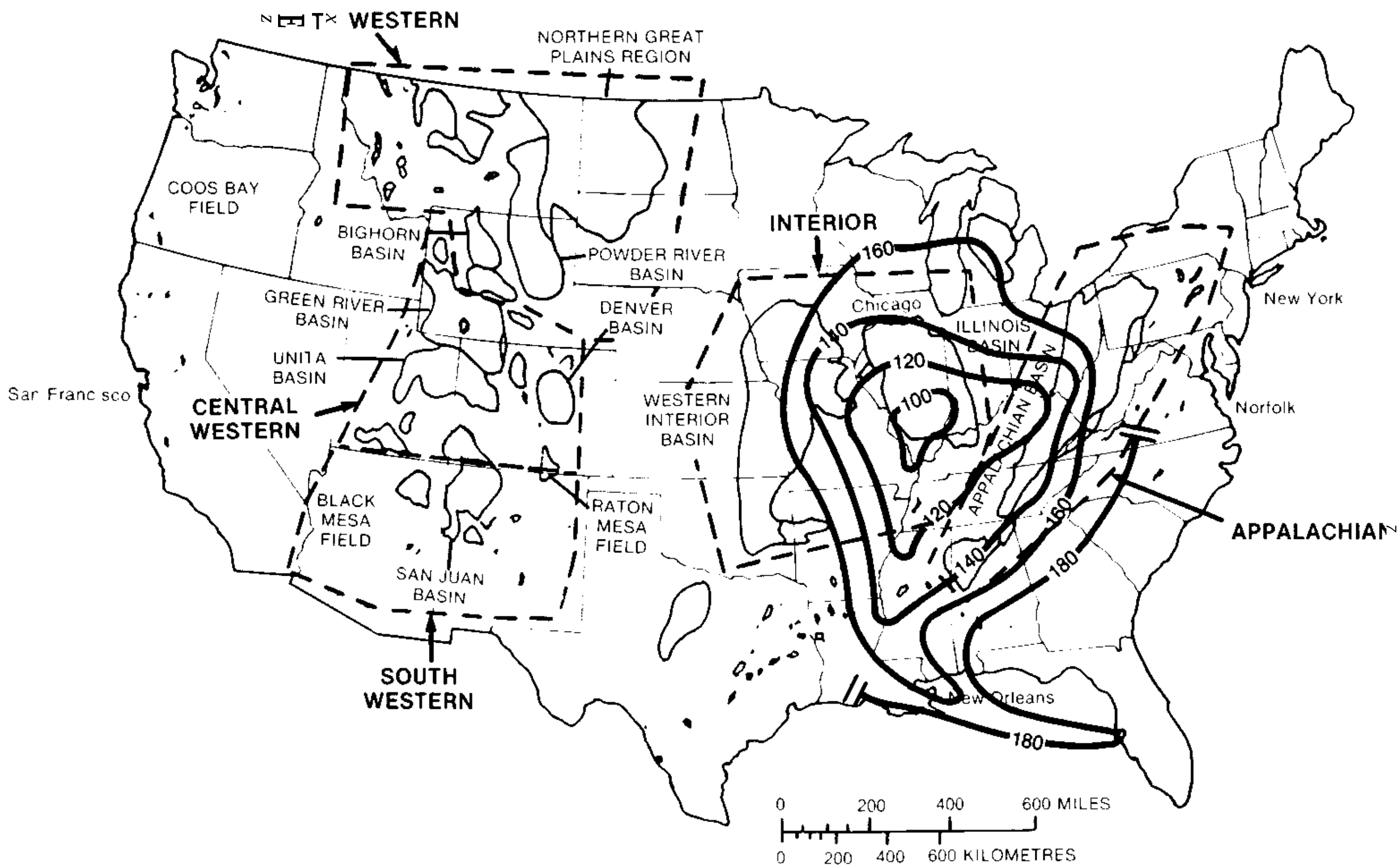
[6]E. H Pechan & Associates, information supplied to OTA, April 1982.

'U.S. Department of Energy, Energy Information Administration, Coal *Production—1979,* DOE/EIA-01 18(79), Apr. 30, 1981

*See Office of Technology Assessment, *Direct Use of Coal,* OTA-E-86, April 1979, O'TA, *An Assessment of Development and Production Potential of Federal Coal* Leases, OTA-M- 150, December 1981, especially ch. 12. For an account of the socioeconomic' effects of the decline of coal production, see T. R Ford (cd,), *The Southern Appalachian Region, A Survey* (Lexington, Ky. University of Kentucky Press, 1960)

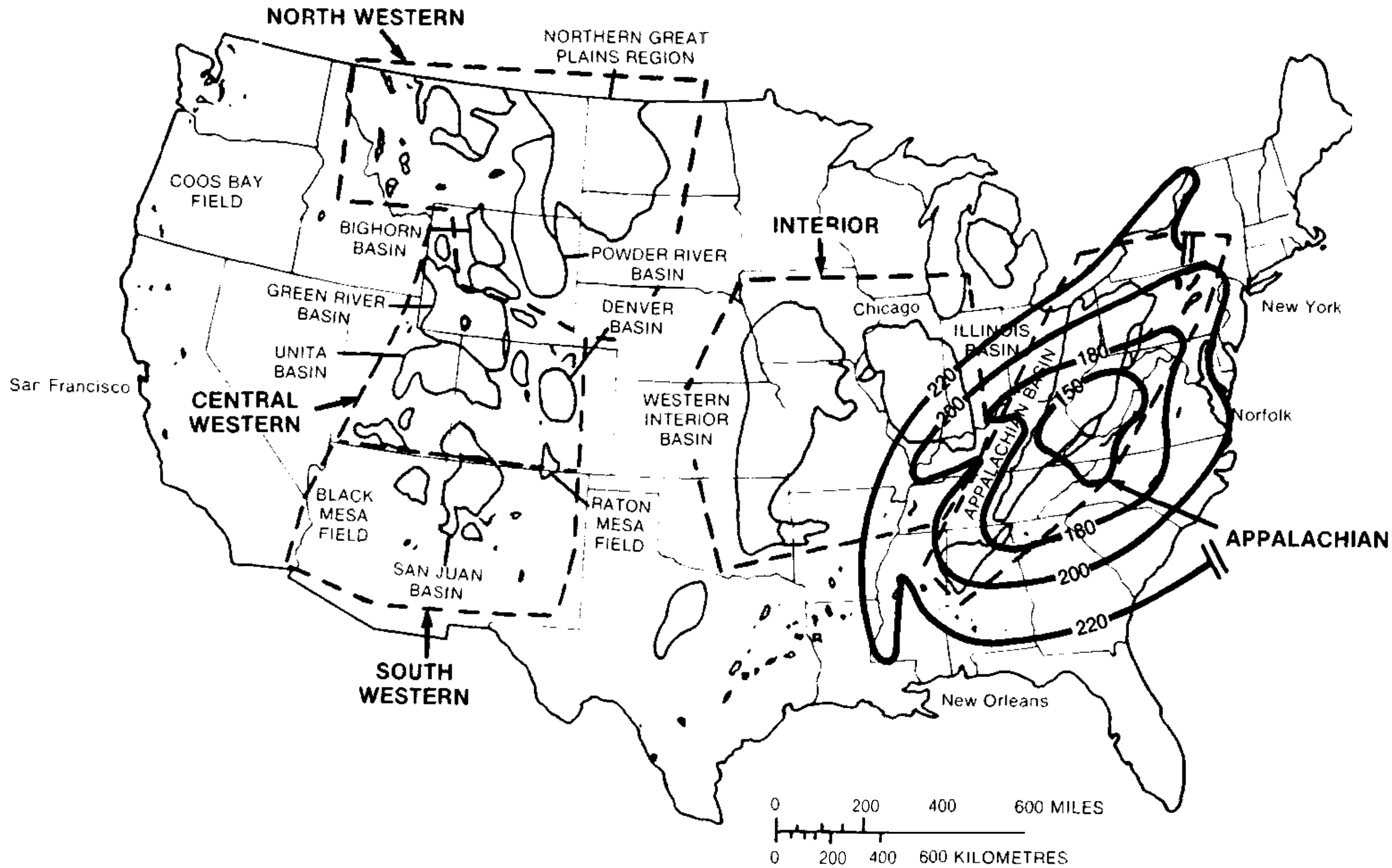
• "FoI a survey of coal-cleaning techniques, see James D.Kilgroe, "Coal Cleaning for Sulfur Cioxide Emission Control, " paper submitted to the Acid Rain Conference, Springfield, Va , Apr 8-9, 1980 The description of physical coal cleaning in this section relies heavily on Kilgroe's paper Other surveys of coal-cleaning techniques can be found m EPA-450/3-81 -004, *Control Techniques for Sulfur Oxide Emissions From Stationary Sources, 2d* ed , April 1981, and F, PA-600/7-78-002, *Engineering/Economic Analyses of Cod Preparation With SO_2 Cleanup Processes,* January 1978,

Figure A-3.—Cost of Illinois High-Sulfur Coal 1980 (delivered prices in nominal cents per million Btu)



SOURCES: FPC Form 423. P. Averitt, *Coal Resources of the United States, Jan. 1, 1974,* U.S. Geological Survey Bulletin 1412, at 5, 1975.

Figure A-4.—Cost of Eastern Kentucky/West Virginia Low-Sulfur Coal, 1980
(delivered prices in nominal cents per million Btu)



SOURCES: FPC Form 423. P. Averitt, *Coal Resources of the United States, Jan. 1, 1974*, U.S. Geological Survey Bulletin 1412, at 5, 1975.

of fine particles relies on a process in which the raw coal particles are treated with a chemical that, because of differences in surface properties, adsorbs differently on the surface of coal particles than other substances in the mixture. Air bubbles introduced into the chamber attach to the coal particles and carry the coal to the surface, where they can be skimmed off. The pyrite and other particles sink, and are removed separately.

Table A-4 shows the extent to which coal produced for the utility market by eight Eastern and Midwestern coal-producing States is physically cleaned. One-third of the coal produced by these States for utility was washed in 1979, resulting in an estimated 1.8-million-ton reduction in the potential SO_2 emissions (approximately equivalent to a 10-percent reduction in the potential SO_2 emissions).[8]

The emissions reduction potential of physical coal cleaning depends primarily on: 1) the initial sulfur level in the raw coal, 2) the ratio of pyritic to organic sulfur, and 3) the coal-cleaning technique used. Pyritic sulfur accounts for between 30 and 70 percent of the total sulfur content of Coal.[9] Higher sulfur coals tend to have a larger proportion of pyritic sulfur than lower sulfur coals. Consequently, the higher the sulfur content of coal, the greater the percentage removal possible through this process. Table A-5 shows the results of an analysis prepared for the Environmental Protection Agency (EPA) on the potential for sulfur removal by coal cleaning in eight Eastern and Midwestern States. 10 As the first column of the table shows, reductions of between 8 and 33 percent are attainable. The second column lists the SO_2 emissions rate (in lb/MMBtu) achievable after coal washing.

Table A-6 shows the costs and emissions reduction potential of requiring all coal to be cleaned before its use. An additional reduction in SO_2 emissions of about 2.5 million tons could be achieved from the coals produced by these eight States (equivalent to a 17-percent reduction of emissions from coal produced by these States). As the table shows, coal cleaning is associated with a wide range of costs—from a low of $224/ton of SO_2 removed in Indiana to a high of over $3,000/ton removed in southern West Virginia (in 1982 dollars). Cleaning high-sulfur coals-those with the largest emissions reduction potential—is in general more cost effective than cleaning lower sulfur coals. The regionwide average cost (not including southern West Virginia and Virginia) is about $505/ton of SO_2 removed. Coal cleaning adds between $4 and $9/ton to the price of coal, and between 2 and 4 mills/kWh in annual revenue requirements.[11] This compares with an average price of residential electricity of about 50 to 60 mills/kWh.[12]

A Department of Energy contractor has assessed the costs and emissions reduction potential of washing the coal delivered to the 50 largest emitters in the United States. SO_2 removal efficiencies range from 3 to 34 percent. Costs range from $4 to $7/ton of coal cleaned, $170 to $4,900/ton of SO_2 removed, and from 0.8 to 4.4 mills/kWh (1980 dollars). Cleaning the coal used by these 50

[8] Versar, Inc, *Coal Resources and Sulfur Emission Regulations: A Survey of Eight Eastern and Midwestern States*, prepared for EPA, PB8 1-240319, May 1981

[9] James D Kilgroe, "Coal Cleaning for Sulfur Dioxide Emission Control," paper submitted to the Acid Rain Conference, Springfield, Va , Apr 8-9, 1980

[10] Versar, op cit

[11] Ibid

[12] U. S Department of Energy, Energy Information Administration, *1980 Annual Report to Congress, Volume II*, DOE/EIA-0173-80/2.

Table A-4.—Reductions in 1979 SO_2 Emissions Achieved by Cleaning Utility Coal From Eight States

Region and State in which coal was mined	Coal delivered to utilities in 1979 (10^3 tons)	Utility coal cleaned in 1979 (percent)	Sulfur content of coal (expressed as 10^3 tons SO_2): As mined (10^3 tons)	Sulfur content of coal: delivered (10^3 tons)	Average SO_2 reduction by coal cleaning in 1979 (percent)
Northern Appalachia:					
Pennsylvania	47,400	30	2,100	1,860	12
Ohio	38,300	11	2,750	2,670	3
Northern West Virginia	31,300	23	1,760	1,690	4
Southern Appalachia:					
Southern West Virginia	17,500	9	300	290	1
Virginia	13,400	7	280	270	1
Eastern Kentucky	68,600	22	1,630	1,570	4
Eastern Midwest:					
Western Kentucky	38,100	34	2,880	2,600	13
Indiana	25,300	52	1,620	1,410	13
Illinois	49,500	72	3,570	2,780	22
Alabama:					
Alabama	14,600	32	460	440	5
Eight-State total/average	344,000	33	17,350	15,580	10

SOURCE: Versar, Inc., Coal Resources and *Sulfur Emission Regulations: A Survey of Eight* Eastern *and Midwestern States,* prepared for EPA, PB 81-240319, May 1981.

Table A-5.—Average SO_2 Emission Reductions and Emission Rate Potentials for Coal From Eight States (1979 data)

Region and State	Average emission reduction using physically cleaned coal[a] (percent)	Average emission potential (lb SO_2/MMBtu)	Number of washability samples
Northern Appalachia			
Pennsylvania	33.2	4.0	170
Ohio	25.9	5.8	90
Northern West Virginia	28.9	4.9	30
Southern Appalachia:			
Southern West Virginia	10.1	1.4	16
Virginia	7.6	1.1	8
Eastern Kentucky	15.9	2.3	13
Eastern Midwest:			
Western Kentucky	31.5	6.6	37
Indiana	26.4	5.9	21
Illinois	29.3	6.6	40
Alabama	10.8	2.0	10

%Coal crushed to 1/12 inch top size and separated at 1.6 specific gravity.

SOURCE: Versar, Inc., Coal *Resources and Sulfur Regulations: A Survey of Eight Eastern and Midwestern States,* prepared for EPA, PB 81-240319, May 1981.

Table A.6.—Typical Cost Effectiveness of Additional Coal Cleaning for Eight Eastern and Midwestern States

Region and State	Additional annual SO_2 reduction: 10^3 ton	Additional annual SO_2 reduction: Percent	Levelized cost of cleaning (1982 $/clean ton)	Cost effectiveness (1982 $/ton SO_2 removed): Without benefits	Cost effectiveness (1982 $/ton SO_2 removed): With benefits
Northern Appalachia:					
Pennsylvania	450	24	$6.90	$476	$301
Ohio	720	27	8.36	369	233
Northern West Virginia	250	15	6.70	564	398
Eastern Midwest:					
Western Kentucky	530	20	5.44	243	101
Indiana	170	12	3.79	224	49
Illinois	210	5	5.64	330	155
Southern Appalachia:					
Southern West Virginia	—	O	6.70	c	c
Virginia	—	O	7,09		
Eastern Kentucky	150		8.45	991	680
Alabama	6 5	1 5	6.51	845	437
Eight-State total/average[d]	2,545	16	6.56	505	294

aOver current practice.
[b]Of raw coal.
cThese coals typically have a cost effectiveness exceeding $3,000/ton
dAverages do not include States where insufficient data are given.

SOURCE: U.S. Environmental Protection Agency, draft memorandum, Coal Cleaning Background Paper, May 19, 1963. (Note: this memo has not been formally released by the U.S. Environmental Protection Agency and should not be construed to represent Agency policy.)

plants is estimated to yield a 1.5-million-ton reduction in SO_2 emissions (about 7 percent of total SO_2 emissions in the Eastern United States) at an average annual cost of $870 million, or $580/ton of SO_2 removed. 13 This study does not account for the emissions reductions or costs of coal used by these utilities that is currently being cleaned.

Coal cleaning has several benefits in addition to reduced SO_2 emissions. First, cleaning reduces the ash content of coal, reducing ash disposal requirements at the power facility. Second, the removal of impurities (sulfur, ash, and others) increases the "heating value" (energy per unit of weight) of coal, Increased heating value reduces coal transportation costs and pulverization requirements at the plant. Finally, because cleaning creates a fuel with more uniform characteristics (e. g.; ash, moisture, sulfur, and energy content), increased efficiency of boiler operation is possible. 14 These benefits

[13]PEDCo, *Op. cit.*, May 1981

[14]*Engineering/Economic Analyses of Coal Preparation With SO_2 Cleanup Processes,* U S. Environmental Protection Agency, EPA-600/7 -78-O02, January 1978; see also, Cost *Benefits Associated With the Use of Physically Cleaned Coal*, prepared by PEDCo, EPA-600/7-80-105, May 1981,

can in many instances offset a large portion of the costs of coal cleaning.

Physical coal cleaning may produce a substantial amount of solid waste. The cleaning process causes approximately one-fourth of the mined material to be discarded as waste.[15] Moreover, some coal (approximately 5 to 10 percent of the energy value) is lost in the process of removing impurities.[16]

Chemical Coal Cleaning.—Chemical coal cleaning can remove higher percentages of sulfur contained in coal because it can in some cases remove organic as well as pyritic sulfur. These processes, however, have only been successfully operated at the laboratory scale, and are estimated to be 5 to 10 years away from commercial viability. Chemical coal-cleaning processes vary widely from relatively simple methods that use chemical solutions to leach sulfur and other impurities out of coal, to processes such as solvent-refined coal, which alters the characteristics of coal so much that it is usually considered a coal-conversion process.[17]

Two of the chemical coal-cleaning processes receiving the greatest amounts of current research attention are the Meyers process and microwave desulfurization. The Meyers process, developed by TRW, Inc., is a chemical leaching process that combines coal with a ferric sulfate or sulfuric acid solution to remove sulfur. This process can remove 80 to 99 percent of the pyritic sulfur in coal (larger removal efficiencies than physical coal cleaning), but cannot remove organic sulfur.[18]

One of the several coal-cleaning processes that remove organic as well as pyritic sulfur is microwave desulfurization. Developed by General Electric, this process begins by wetting crushed coal with a sodium hydroxide solution; the mixture is then briefly irradiated with microwave energy. During irradiation, the sodium hydroxide reacts with pyritic and organic sulfur to form sodium sulfide. The coal is immersed in water to remove the sulfur-laden sodium sulfide, and the process is repeated again. Laboratory tests have achieved total sulfur removals in excess of 90 percent.[19]

Because chemical coal-cleaning techniques are in the early stages of development, costs are difficult to estimate. It is not yet clear whether chemical coal cleaning will be economically competitive with flue-gas desulfurization (described under "Postcombustion Approaches' in the future. Chemical coal cleaning can be expected to produce the same side effects-waste disposal requirements, removal of ash and other impurities, increased heating value, and improved boiler efficiency— as physical coal cleaning.

OIL DESULFURIZATION

Oil desulfurization is a widely applied method for reducing SO_2 emissions. The primary method is called hydrodesulfurization; oil is treated with hydrogen, which partially removes the sulfur by combining with it to form hydrogen sulfide gas. Oil is first distilled to separate the crude into various petroleum products. Most of the sulfur concentrates in the heavier residues. The lighter fractions, or distillate, are redistilled under a vacuum. In one variant of hydrodesulfurization, referred to as the indirect method, the second distillate is hydrotreated (i.e., reacted with hydrogen) to remove the sulfur as hydrogen sulfide gas. The product is reblended with the vacuum residue to yield low-sulfur fuel oil. This method can reduce the sulfur content by 30 to 42 percent.[20]

In another variation of hydrodesulfurization, referred to as the direct method, the residue from distillation is hydrotreated, and then reblended with the distillate to form a lower sulfur fuel, or both the residue and distillate from vacuum distillation are separately hydrotreated before relending. This technique can achieve a degree of desulfurization as high as 70 to 90 percent, but is not yet commercially available. Indirect hydrodesulfurization is presently the predominant method for producing low-sulfur (less than 1 percent sulfur) fuel oil from high-sulfur crudes. Both the indirect and direct methods are similar to coal cleaning in that the higher the degree of desulfurization, the higher the costs. Estimated costs for desulfurizing oil containing 3-percent sulfur content to 1 -percent sulfur content, range from $17 to $40/ton in 1980 prices, depending on the choice of process.[21]

Disadvantages of hydrodesulfurization are the high investment and operating costs, and the high energy requirements. Since fuel oil combustion is not expected to increase significantly in the United States, the present desulfurization capacity is expected to remain at current levels for the near future.

Combustion Alteration Approaches

LIMESTONE INJECTION MULTISTAGE BURNER (LIMB)

Many in the United States consider the LIMB to be one of the most promising control technologies under development today. The technique controls both SO_2

[15] Kilgroe, op. cit.
[16] *Control Techniques for Sulfur Oxide Emissions From Stationary Sources*, EPA-450/3-81-004, December 1979. See also PEDCo, op. cit.
[17] Work Group 3B, op. cit.
[18] Versar, Inc., *Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal*, prepared for EPA, EPA-600/7-79-178C, December 1979.
[19] Ibid.

[20] N Elam and Trichen Consultants, Ltd , *Present and Future Levels of Sulfur Dioxide Emissions in Northern Europe*. Swedish Ministry, June 1979
[21] Ron Jones, Director, Environmental Affairs, American Petroleum Institute, Washington, D C , personal communication

and NO_x emissions. The LIMB is based on the use of staged burner techniques for NO_x control, in combination with sorbent (normally limestone) which is injected through the burners for SO_2 control. SO_2 reacts with the limestone to form solid calcium sulfate.

This technology is still under development; its removal efficiencies and costs are very uncertain at this time. Planning goals established by EPA set objectives of 50 to 70 percent removal of SO_2 and NO_x, at a capital cost of $30 to $40/kW.[22] If these goals are achieved, the LIMB would offer substantial cost improvements over existing technologies. It is very possible that the LIMB, because it may be retrofitted into existing plants at a competitive cost, may emerge as a particularly attractive control technology option. However, EPA plans to limit the LIMB research program to basic bench- and large pilot-scale R&D through 1985, since funding is unavailable for Government sponsorship of a full-scale demonstration at this time.[23]

FLUIDIZED BED COMBUSTION

Another technique that removes SO_2 during the combustion process is fluidized bed combustion. For this process, crushed coal is fed into a bed of inert ash mixed with limestone or dolomite. The bed is held in suspension (' 'fluidized' by the injection of air from the bottom of the bed. SO_2, formed during combustion, reacts with the limestone or dolomite to form solid calcium sulfate, which can be removed from the boiler without interrupting the combustion process.

Fluidized bed combustion can remove up to 90 percent of the SO_2. Available estimates, though preliminary, show the cost effectiveness of fluidized bed combustion to be about equal to conventional boilers using flue-gas desulfurization.[24] Further research is still needed before large-scale use could be justified; however, for small facilities (up to 250 MW), fluidized bed combustion is a feasible method today. Oil may also be burned in a fluidized bed, but no such plant is yet in operation.

Aside from lower emissions, fluidized bed boilers have the advantages of greater energy efficiency, lower combustion temperatures keeping the formation of nitrogen oxides down, and smaller boiler size. Fluidized bed boilers can burn both high- and low-sulfur coals.

[22]James Abbott and Blair Martin, U S Environmental Protection Agency, Research Triangle Park, N C , personal communication

[23]Julian Jones, U S Environmental Protection Agency, Research Triangle Park, personal communication

[24]Work Group 3B, op. cit.

Postcombustion Approaches

FLUE-GAS DESULFURIZATION

Flue-gas desulfurization (FGD) technology removes the SO_2 produced during combustion by spraying the exhaust gases in the stack with a chemical absorbent, typically lime or limestone. This process is popularly referred to as "scrubbing. Of the three types of FGD systems—wet, dry, and regenerable—wet processes are most widely used. Presently there are over 100 scrubbers using all three methods in operation in the United States.

WET SCRUBBERS

The most common absorbents used for wet scrubbing are lime and limestone. The absorbent is dissolved or suspended in water to form a slurry that can then be sprayed or forced into contact with escaping gases. The slurry converts SO_2 into calcium sulfite and calcium sulfate (gypsum) solids. Limestone scrubbing is the simplest, cheapest, and most developed SO_2 wet-removal process available.

Technology to wet-scrub the flue gas with a lime or limestone slurry has been commercially available for about 10 years. As of March 1981, 5.1 percent of installed generating capacity (and 14 percent of coal-fired capacity) was controlled by wet scrubbers. By 1990, the figure is projected to increase to 9.4 percent of installed capacity.[25]

Wet lime or limestone scrubbers can remove between 70 to 90 percent of the SO_2 formed during combustion. With the addition of another chemical--adipic acid—removal efficiencies can be increased to 95 percent, while limestone requirements can be reduced by up to 15 percent.[26] However, adipic acid additives may present additional sludge disposal problems.

A Tennessee Valley Authority (TVA) study conducted in 1980 estimated the capital costs of a wet limestone system using low-sulfur Western coal (O. 7 percent sulfur, 9,700 Btu/lb) to be $168 to $176/kW. For high-sulfur Eastern coal (3. 5 percent sulfur, 11,700 Btu/lb) capital costs range from $236 to $244/kW. These estimates are based on costs for a new 500-MW plant, operating at a 63-percent lifetime capacity. The range in cost estimates is due to variations in bids from different con-

[25]U S Environmental Protection Agency, "EPA Utility FGD Survey October-December 1980, EPA-600/7-81 -012b, January 1981,

[26]U S Environmental Protection Agency, *Research Summary Controlling SO_2*, Office of Research and Development, August 1980

tractors and the specific considerations for each site. Annual revenue requirements from the TVA study range from 10.5 to 10.9 mills/kWh for low-sulfur coal and 16.4 to 16.7 mills/kWh for high-sulfur coal. 27

The annual revenue requirements for FGD units depend on several factors, including coal sulfur content, size of the unit, age of the plant, and desired percentage reduction. The costs per ton of sulfur dioxide removed by scrubbers rise steeply as the uncontrolled emission rate drops. For example, removing 90 percent of the sulfur from a coal emitting 2 lb of sulfur dioxide per million Btu is about 75 percent *more* expensive (on a dollar/ton basis) than scrubbing a 4 lb/million Btu coal for the same size unit. Likewise, scrubbing a 1 lb/million Btu coal is about 75 percent (or more) costlier than scrubbing a 2 lb/million Btu coal in a similar unit.

Costs for retrofitting a scrubber onto an existing plant depend on the lifespan of the plant; the shorter the remaining lifetime of the plant, the higher the annual revenue requirements to recover the capital costs of the FGD. Also, because of economies of scale in construction, retrofitting a scrubber onto a larger unit is less expensive than onto smaller ones. Units smaller than about 100 MW are typically quite expensive to retrofit with scrubbers.

Operating problems associated with wet systems are corrosion/erosion of metal surfaces, scaling (where hard sulfate and sulfite deposits form on equipment), and plugging (where soft deposits form). Ways of minimizing these problems are currently being researched. In addition, operation of wet scrubbers requires approximately 3 to 5 percent of a plant's energy output. 28

The major environmental disadvantage of wet FGD systems is that they produce large amounts of sludge. Limestone scrubbing produces a compound (mainly calcium sulfite and sulfate) that has the consistency of toothpaste, making it difficult to dewater, store, and handle. The total amount of FGD waste produced in a typical 1,000-MW plant burning 3.5 percent sulfur coal is about 225,000 tons annually. A recent report concluded that in the future the United States will produce more sludge from FGD scrubbing than from treating municipal sewage. [29]

Sludge may, however, be chemically treated to reduce its water content and improve its compressive strength. Forced oxidation converts the waste calcium sulfite to calcium sulfate, which precipitates as large crystals with better settling characteristics. Other means of improving the sludge's properties, such as fixation with lime and fly ash, are still being developed.

Another problem associated with sludge disposal is the leaching of toxic metals from the residual fly ash into nearby ecosystems. EPA is currently conducting research on the characteristics of leaching of metal compounds from sludge disposal sites to evaluate the seriousness of the problem .30

DRY PROCESSES OF FGD

Dry scrubbers are a new and fast growing segment of the FGD market. The process involves injection of a lime slurry or soda ash solution into a spray dryer concurrently with the flue gas. The lime or sodium carbonate reacts with the SO_2 to form a dry, solid product which is subsequently collected along with the fly ash in an electrostatic precipitator or fabric falter (baghouse).

Dry scrubbers offer several advantages over wet scrubbing. Although they generate more waste than wet systems, they produce a dry waste product that is easier to handle and recycle than wet sludge, and involve simpler equipment, less maintenance, lower capital costs, and lower energy requirements. In addition, dry systems require less water than wet systems, and thus are especially desirable in Western areas of the United States where water supplies are limited. [31]

There are, however, some disadvantages to using a dry scrubber over a wet system. First, dry systems require lime, which is more expensive than limestone. Second, dry scrubbers are in the early stages of commercialization and have not demonstrated as high a degree of removal as wet scrubbers. Their use has generally been limited to medium- and low-sulfur coals. However, pilot demonstration and commercial plant tests have shown sulfur removal efficiencies exceeding 90 percent for high-sulfur coal.

As of October 1983, six dry scrubber systems were in operation, five at industrial plants, and one at a utility plant generating 430 MW of electricity. Four more units will be installed on utility boilers in 1984, and approximately 16 units have been ordered for industrial use.[32] A TVA study estimates that capital costs for dry FGD systems range from $144 to $ 160/kW for low-sulfur Western coal, and from $180 to $188/kW for high-sulfur Eastern coals. Annual revenue requirements are estimated to range from 8.7 to 9.8 mills/kWh for Western low-sulfur coal, and 14.5 to 14.9 mills/kWh for high-sulfur coal. These annual costs are between 10 and 25 percent lower than wet systems, as reported by the same TVA study. An EPA survey of dry systems sold to util-

[27] T A Burnett, et al , "Spray Dryer FGD: Technical Review and Economic Assessment," Tennessee Valley Authority, presented at U S Environmental Protection Agency Sixth FGD Symposium, Houston, Tex, Oct 28-31, 1980

[28] W Nesbit, "Scrubbers The Technology Nobody Wanted," *EPRI Journal*, vol 7, No 8, October 1982

[29] U S Environmental Protection Agency, *Sulfur Emissions Control Technology and Waste Management*, Office of Research and Development, May 1982

[30] Work Group 3 B , op cit.

[31] EPA-4 50/3-8 1 -004, op cit

[32] Theodore Brna, U S Environmental Protection Agency, Research Triangle Park. NC, personal communication

ities, however, suggests that actual capital costs might be lower. Reported capital costs for these systems range from $80 to $130/kW.[33]

EPA is currently conducting research on the use of other dry injected minerals to be used in place of lime. If the research results are successful, dry scrubbing costs could be considerably lower than wet systems.

REGENERABLE PROCESSES

Major research efforts by various Government agencies have gone into regenerable FGD processes, which reclaim the SO_2 in powerplant flue gases using chemicals to produce a marketable product. The major benefit of regenerable control systems is that the captured sulfur can be sold, avoiding waste-disposal problems associated with wet and dry processes. Eight regenerable FGD systems are currently operating in the United States, accounting for about 8 percent of the total FGD-controlled electricity generation. The most prominent regenerable FGD process in use in the United States is the Wellman-Lord process. It involves scrubbing the exhaust gas with sodium sulfite solution, resulting in sodium sulfite-bisulfite, which is then heated to give off concentrated SO_2 gas that can be used to produce either sulfuric acid or elemental sulfur. This process is already in use by the New Mexico Public Service Co. One disadvantage of this process is its high 'energy requirements, which are approximately 8 to 12 percent of boiler energy input. 34

Other regenerable systems under development are the Magnesia scrubbing process, which produces sulfuric acid, and the Rockwell process, which produces sulfur. Unfortunately regenerable processes cost approximately 30 to 50 percent more than nonrecoverable processes.

Controlling Nitrogen Oxides Emissions

Oxides of nitrogen are formed during combustion by two processes. Like sulfur dioxide, NO_x are formed as a result of the oxidation of nitrogen present in the fuel (“fuel NO,”). NO_x are also formed by the oxidation of nitrogen in the surrounding air (''thermal NO_x' '). Both processes are controlled by the amount of oxygen present; additionally, the thermal NO_x formation is controlled by temperature. The proportion of thermal to fuel NO, produced during combustion varies from fuel to fuel. For coal, the Electric Power Research Institute estimates that 20 to 40 percent of NO_x emissions are ' 'thermal' and 60 to 80 percent are ' 'fuel. '[35]

NO_x emissions, being dependent on the amount of oxygen present and the temperature of the combustion process, can be most directly controlled by modifying combustion conditions. The majority of NO_x control techniques focus on the combustion process. Postcombustion techniques (flue-gas treatment) are also being developed to achieve even lower emission rates. Today the two most promising combustion technologies for reducing NO_x emissions are certain types of fluidized bed combustion units, for plants up to 250 MW, and the low-NO_x burner. One precombustion technique, the denitrogenation of fuel oil, is being researched, but will not be discussed because of its early stage of development and limited potential.

Combustion Modifications

Thermal NO_x formation can be minimized by regulating the combustion temperature through delayed mixing of fuel and air in the combustion chamber. Limiting fuel NO_x, is somewhat different, requiring control of the fuel-air ratio throughout the entire combustion process. Two of the major techniques used in combustion modification, low excess **air** (LEA) and low-NO_x burners, are presented below. Other combustion modification techniques include: staged combustion (off-stoichiometric firing), overfire air, flue-gas recirculation, low air preheat, and water injection.[36]

LEA involves reducing the combustion air to the minimum amount required for total combustion. Thus, less oxygen is available for the formation of both thermal and fuel NO_x. LEA requires no new hardware and can achieve emissions reductions merely through changes in operating practices. Also, the reduced airflow can improve boiler efficiency.

The second-generation, low-NO_x burners under development, which employ a staged combustion process, have been shown to significantly reduce the formation of both fuel and thermal NO_x in experimental systems and limited boiler applications. During the first stage of combustion, less air is supplied to the burner than is required to completely burn the fuel. Fuel-bound nitrogen is then released—but as nitrogen gas, because it cannot be oxidized. The subsequent addition of air causes the remaining fuel to be burned.

The amount by which NO_x emissions can be reduced depends on very site-specific factors, including the type of fuel burned, the type of boiler in use, and the age of the plant. Installed on an existing coal-fired plant which does not control NO_x emissions, the low-NO_x burner can reduce NO_x emissions by as much as 50 percent. Potential NO_x emissions reductions from retrofitting an oil-fired burner range from 60 to 80 percent. 37

[33]U .S Environmental Protection Agency, ' 'Survey of Dry SO_2 Control Systems, 11 I, EPA-60017-81-097.

[34]EPA-450/3-81-004, op cit

[35]Ralph Whitaker, ' 'Trade-offs in NO_x Control, *EPRI Journal*, vol 7, No 1

[36]*An Analysis of the Economic Incentives To Control Emissions of Nitrogen Oxides From Stationary Sources*, EPA-600/7-79-178[, January 1981, p A3.

[37]EPA-600/7-79-178!. op cit

The low-NO_x burner can achieve emissions reduction at relatively low cost. Capital costs for coal-fired plants are approximately $1 to $5/kW if integrated into new boilers, and $2 to $10/kW if retrofitted onto existing plants.[38]

Potential problems such as corrosion and high maintenance requirements could delay large-scale use of the low-NO_x burner. Retrofitting old boilers can be difficult, but NO_x controls on new boilers can be made an integral part of boiler design without adding substantially to cost.

Another combustion modification approach for the control of NO_x is the LIMB, which is discussed in further detail in the section on combustion alteration approaches for SO_2. EPA research goals for the LIMB are to achieve a 50- to 70-percent removal of SO_2 and NO_x, at a cost of $30 to $40/kW; however, the LIMB is not expected to be commercially available for about 3 to 5 years.[39]

Postcombustion Approaches

FLUE-GAS TREATMENT

Flue-gas treatment (FGT) is an emerging postcombustion process for high levels of NO_x removal. FGT has been developed and applied extensively in Japan for use on oil-fired boilers. But due to its operational complexities and high costs for use on coal-fired boilers, FGT has not become as popular as the low-NO_x burner in the United States.

At least 50 different types of FGT technologies are available today. Of these, selective catalytic reduction (SCR) achieves the highest reductions. SCR is a dry process, produces no solid waste, and in most cases can be retrofitted to existing burners. In SCR, flue gases are mixed with ammonia and then passed over a catalyst. The catalyst assists in the reaction of ammonia and NO_x to form nitrogen gas and water vapor. While 90-percent NO_x removal during combustion is possible, 80-percent removal is preferable in order to minimize capital and operating costs and maximize the burners' reliability and lifespan. One estimate places the costs of FGT at between $75 and $100/kW for a 60- to 80-percent reduction in NO_x emissions.[40]

Two problems associated with SCR are the disposal of spent catalysts, such as vanadium and titanium, and the condensation of bisulfate and bisulfite residuals onto equipment.[41]

[38] Ibid

[39] James Abbott and Blair Martin, U S Environmental Protection Agency, Research Triangle Park, N C, personal communication

[40] *EPRI Journal*, op. cit

[41] J.D. Mobley, *Assessment of NO_x Flue Gas Treatment Technology*, U.S. Environmental Protection Agency, Research Triangle Park, presented at Symposium of Stationary Combustion NO_x Control, Denver, Colo., October 1980

A.3 ALLOCATION OF SULFUR DIOXIDE EMISSIONS REDUCTIONS AND THE COSTS OF CONTROL

Introduction

The costs and distributional consequences of various control strategies are important factors in decisions about controlling transported air pollutants. Costs are affected both by the amount of emissions to be eliminated, and by the manner in which emissions reductions are to be achieved. For a given emissions reduction strategy, the greater the reduction, the greater the cost. For a given emissions reduction target, alternative implementation strategies may entail different costs, i.e., one strategy may be more cost effective than another.

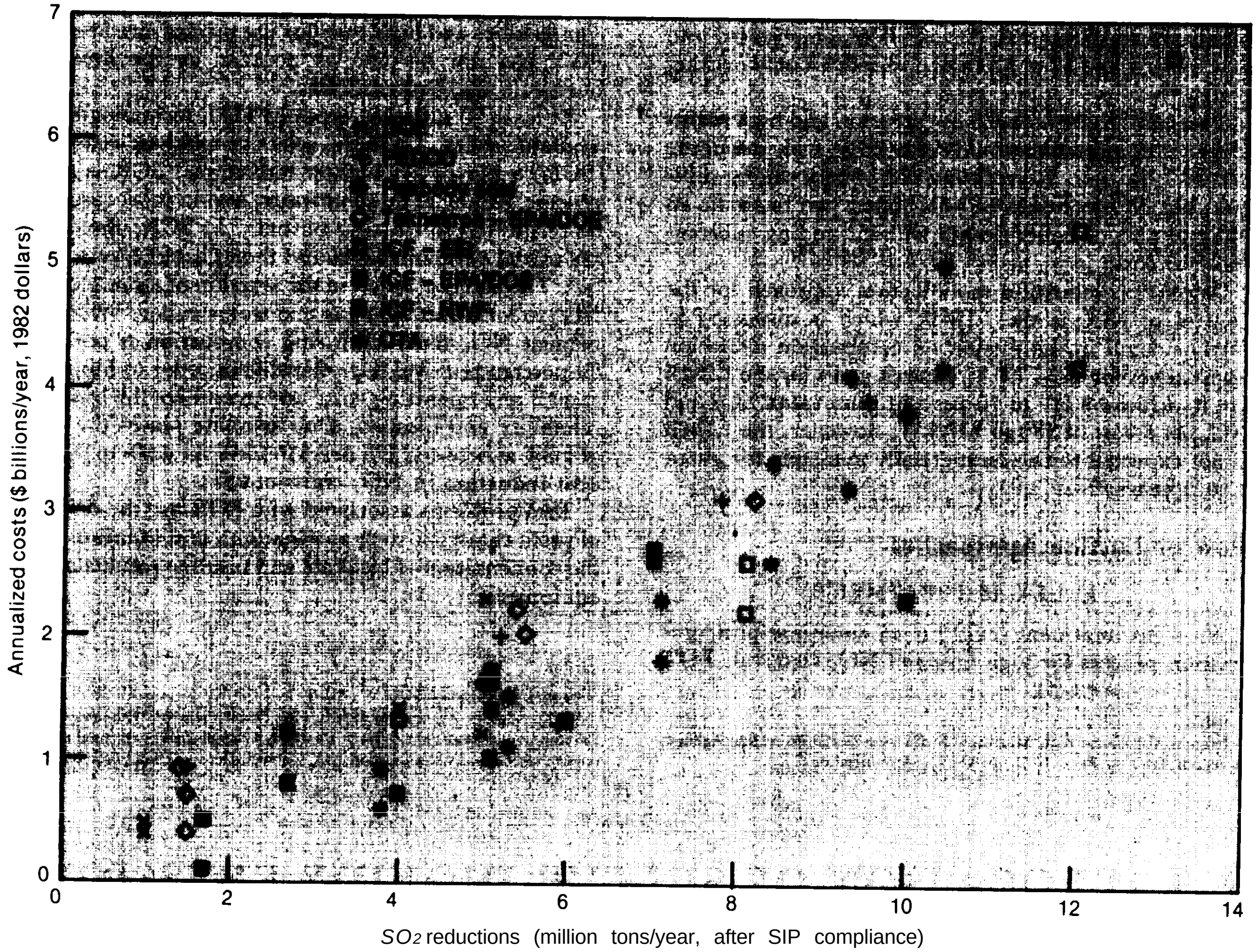
Alternative control strategies may also have different distributional consequences. Certain approaches assign a greater share of the emissions reduction burden to one region or State or economic sector than to others. This section examines the costs and distributional consequences of various emissions reduction strategies, concentrating on emissions reductions in the Eastern 31-State region. Due to analytical limitations, only the costs of reducing sulfur dioxide (SO_2) emissions from utilities are presented.

SO_2 emissions for 1980 are estimated to be about 26 million tons nationwide and about 22 million tons in the Eastern 31 States. Fossil fuel combustion by electric utilities accounts for about 17 million tons or 65 percent of the national total. In the Eastern 31 States, utilities produce 70 percent of the regional SO_2 emissions, or about 16 million tons. Under current regulations, EPA-approved State implementation plans (SIPS) require utilities to reduce these emissions by approximately 1 million tons.

OTA has estimated the cost of further reducing utility SO_2 emissions in the 31-State region below the SIP-

99-413 0 - 84 - 12 : QL 3

Figure A-5.—Comparison of Utility SO_2 Control Costs



SOURCE: Office of Technology Assessment from references listed in text.

compliance level under several different control strategies. The model used in generating these estimates is described briefly at the end of this section. *

The Costs of Various Levels of Emissions Reductions

To illustrate how the extent of emissions reductions affects the costs of controlling emissions, figure A-5 displays estimates of 31-State aggregate control costs made by OTA and several other groups. * * Costs are presented for reducing SO_2 emissions from utilities only, and are in 1982 dollars. To reduce emissions by approximately 5 million tons beyond SIP compliance, the vari-

● This analysis uses the AIRCOST model, run by E. H. Pechan & Associates, Inc AI RCOST was modified from a larger model used in several earlier major assessments, including the New Source Performance Standards (NSPS) review, the Obio River Basin Energy Study (OR BES), and the Acid Rain Mitigation Study (ARMS)

" "Most of these cost estimates are cited in ' 'Costs To Reduce Sulfur Dioxide Emissions,'' Department of Energy, DOE/PE-0042,1982. DOE adjusted each estimate using consistent economic assumptions, Cost estimates are also included from: "Summary of Acid Rain Analyses Undertaken by ICF for the Edison Electric Institute, National Wildlife Federation, and Environmental Protection Agency, prepared by ICF, Inc., for the Edison Electric Institute, 1982; and Chris Farrand, Peabod, Coal Co , testimony before the Senate Environment and Public Works Committee, October 1981. OTA estimates are based on analyses prepared by E H Pechan & Associates, Inc. , 1983. The PEDCo study was prepared for DOE, the Teknekron analysis was prepared for EPA and DOF., and the ICF analyses were performed for EPA, DO F., the Edison Electric Institute, and the National Wildlife Federation OTA's estimates are presented as the costs of' reductions beyond SIP compliance. The Peabody, PEDCo, and DOE estimates are reductions below actual 1980 emissions, amf the ICF and Teknekron model est imates are displayed as emissions reductions below projected 1990 emissions levels ous estimated annual costs range from about $1 to $2 billion per year. For reductions of 8 million tons beyond SIP compliance (about 55 to 60 percent below current utility emissions), the range increases to $2 to $3.5 billion annually. The largest emissions reduction calculated—a 13-million-ton reduction below projected 1990 levels— is estimated to cost approximately $7 billion per year.

Table A-7 displays OTA's control cost estimates for a series of emission rate limitations ranging from 0.8 to 2.5 lb of SO_2 emitted per million Btu (MMBtu) of fuel burned. Eastern 31 -State emissions reductions range from 4.6 million to 11.4 million tons per year, including reductions already required under current law. However, the costs presented consider only those reductions that would be required beyond SIP compliance.

For each emission rate limitation, two sets of cost estimates are presented. The cost estimates in the top half of the table assume that each utility chooses the least expensive control method among those applicable to plant conditions. This typically results in a statewide mix of coal washing, switching to (or blending with) lower sulfur fuels, and wet and dry scrubbers. Cost estimates presented in the bottom half of table A-7 assume that the legislation mandates the use of pollution control technologies such as wet scrubbers. Several recent bills have included such a control technology restriction to minimize job dislocations among high-sulfur coal miners. (Section A.5 of app. A discusses the magnitude of potential coal production and related employment changes due to acid rain control legislation.)

As expected, costs increase as emissions reduction requirements increase. As shown in the top-half of table A-7, the ' 'least-cost' method of control ranges from less than $1 billion annually to eliminate less than about 5 million tons per year, to between $4 and $5 billion to eliminate 11.4 million tons. * Moreover, the marginal costs of control increase when larger emissions rollbacks are required. That is, the cost of eliminating an additional 1 million tons of SO_2 per year is greater for an increase from 8 million to 9 million tons (approximately $700 million per year) than for an equal increase from 7 million to 8 million tons (approximately $450 million per year).

As shown in the bottom half of table A-7, mandating the use of control technology to achieve all required emissions reductions increases the cost of control. For emissions reductions in the range of 5 million tons per year, such a requirement about doubles control costs. For greater levels of emissions reductions (9 million to

*All cost estimates are first -year, annualized costs in 1982 dollars (capital costs and interest payments are spread evenly over each year of the life of the investment Because fuel and operation and maintenance costs can vary from year to year (i e. real energy and labor costs might either increase or decrease over the next two decades), current fuel and operation and maintenance costs (rather than an average based on assumed trends) are added to capital costs to calculate yearly total control costs

Table A-7.—Costs of Reducing SO_2 Emissions in the Eastern 31 States (excludes costs to meet current SIPS or to offset future emissions growth; all costs in 1982 dollars)

*A. Assuming **each utility chooses the most cost-effective control** method:*

Emission rate limitation (lb SO,/MMBtu)	Emissions reduction (million tons S0,)	Total cost (billions of dollars/yr)	Average cost of reductions ($/ton)	Marginal cost of reductions ($/ton)
2.5	*4.6*	*$0.6-0.9*	*$170-240*	*$320*
2.0	6.2	1.1-1.5	200-280	440
1.5	8.0	1.8-2.3	260-330	700
1.2	9.3	2.6-3.4	310-400	740
1.0	10.3	3.2.4.1	350-440	830
0.8	11.4	4.2-5.0	400-480	1,320

B. Assuming utilities are required to install control technology (wet scrubbers):

Emission rate limitation (lb SO_2/MMBtu)	Emissions reduction (million tons SO_2)	Total cost[b] (billions of dollars/yr)	Average Cost of reductions ($/tons)	Increased costs due to control technology requirement	
				(billions of dollars/yr)	(percent increase)
2.5	4.6	1.4	360	0.7	110
2.0	6.2	2.0	380	1.0	90
1.5	8.0	3.1	430	1.2	70
1.2	9.3	4.0	480	1.4	55
1.0	10.3	4.8	510	1.6	50
0.8	11.4	5.9	570	1.8	40

aCost (in dollars per ton) to achieve the next increment of reductions.
bAssumes statewide emissions reductions are from those utility plants that **can install scrubbers most cost effectively. Old and Small Units are exempt from the requirement to install scrubbers, but equivalent emissions reductions are obtained from other plants within each State,**
cCompared to "least cost' estimate in part A of this table

SOURCE Office *of* Technology Assessment, based on analyses by E H. Pechan & Associates, Inc.

11 million tons per year), mandating the use of scrubbers increases total control costs by about 50 percent.

State-by-State Emissions Reductions and Costs of Control Strategies

Thus far, only aggregate, regional control cost estimates have been presented. Costs of control would vary considerably from State to State, depending on each State's emissions reduction requirements, and the costs of available emissions reductions in each State. The specific control strategy chosen affects both regional costs and their State-by-State distribution.

Actual State-level costs are determined by: 1) the amount of reductions allocated to each State, which depends on the chosen control strategy; and 2) the costs of available emissions reduction opportunities in each State, which depend on the type and number of electric-generating plants in service, and their levels of current emissions. States which already have relatively low utility emissions rates may not have as many opportunities to use less expensive control options as States with higher emissions rates. The latter States may be able to achieve relatively large reductions at lower costs per ton.

Table A-8 presents data on utility SO_2 emissions and electricity generation. The first column displays 1980 utility SO_2 emissions by State; the second column ranks the 30 highest emitting States according to these emissions. States that generate more electricity from fossil-fuel-fired utilities would be expected to emit more SO_2 (all other factors being equal); thus, columns 3 and 4 present 1980 fossil-fuel-generated electricity and corresponding rank for the top 30 States. The last two columns present average SO_2 emissions rates—the quantity of SO_2 emitted per million Btu of fuel burned, and the corresponding rank of States with average utility emissions rates greater than or equal to 1.2 lb/MMBtu. In general, the higher the emissions rate, the greater the opportunity for reducing emissions and the lower the cost per ton of SO_2 removed.

However, statewide average emissions rates mask the variation among plants within a given State. Table A-9 examines the potential for reducing utility SO_2 emissions in each State in greater detail. The table displays the percentage of utility emissions that could be eliminated by mandating various emissions rate limitations, ranging from 1.0 to 4.0 lb of SO_2 per million Btu of fuel burned. These estimates are calculated by assuming no facility may exceed the specified emissions rate.

Table A-10 displays the average cost, in dollars per tons of SO_2 removed, for reducing utility SO_2 emissions by 50 percent in each of the Eastern 31 States. While much of the State-level variation is due to differences in emissions rates, considerable variation results from such other factors as distance from low-sulfur coal supplies, dependence on oil, and size and age of the utility plants.

Comparison of Alternative Approaches to Emissions Reductions

OTA has analyzed a number of approaches to allocating an 8-million-ton reduction of utility SO_2 emissions among the Eastern 31 States. The regional costs and distributional consequences of eight different allocation formulae—in terms of the reductions allocated to each State and the cost of achieving those allocated reductions—are discussed below.

Table A-11 presents the overall cost of these eight alternative allocation approaches for the 31 -State region. The costs are shown to range from a low of $1.8 billion to $2.3 billion per year for reductions based on a maximum emissions rate (1. 5 lb of SO_2 per MMBtu) to a high of $3.7 billion to $3.9 billion per year for an allocation formula based on total SO_2 emissions per land area. Each approach eliminates about 8 million tons of SO_2 per year; future emissions growth—estimated to be about 1 million to 2.5 million tons per year by 1995—is not offset. Cost to achieve emissions reductions already required under current regulations (SIPS) are not included.

Table A-12 shows the State-by-State emissions reductions required under each allocation approach; table A-13 estimates State-average control costs, expressed as a percentage of residential electricity costs. Some States are consistently allocated relatively large costs— in particular, Georgia, Indiana, Kentucky, Missouri, New Hampshire, Ohio, Pennsylvania, and West Virginia. For other States—e. g., Delaware, New Jersey, and Rhode Island—control costs are strongly influenced by the allocation approach used. The approaches that allocate the widest State-by-State variations in required emissions reductions—e. g., those based on emissions per person or land area—cause State-level costs to vary a great deal. In these cases, some States are allocated very large costs and others incur no costs at all.

These estimates illustrate that both the regional and State-by-State costs of control depend on the way in which emissions reductions are allocated to States. Therefore, the choice of allocation policy involves both the political issue of who should bear the burden of reducing emissions as well as the national economic issue of total cost.

A later section of' this appendix (A.4) discusses an alternative method of allocating control costs. A trust fund based on a tax on emissions or electricity generation could be established to help pay for part of the costs of

Table A-8.—Fossil-Fuel-Fired Electric Utilities: SO_2 Emissions, Electricity Generated, Average SO_2 Emission Rate, 1980

	Utility SO_2 emissions		Electricity generation (fossil-fuel-fired)		SO_2 emission rate	
State	10^3 tons/yr	Rank (top 30)	10^9 kWh/yr	Rank (top 30)	lb/MMBtu	Rank (top 30)
Alabama	543.1	12	45.4	17	2.3	12
Alaska	11.7		2.6		0.6	
Arizona	87.5	27	27.0	20	0.6	
Arkansas	26.6		10.2		0.5	
California	77.9		89.6	4	0.2	
Colorado	77.5		21.2	28	0.7	
Connecticut	32.1		12.6		0.5	
Delaware	52.5		6.7		1.5	21
District of Columbia	4.6		0.7		1.0	
Florida	725.9	10	79.0	5	1.7	18
Georgia	736.7	9	50.5	14	2.9	7
Hawaii	41.6		6.5		1.2	28
Idaho	0,0		0.0		0.0	
Illinois	1,125.6	5	75.7	6	2.7	9
Indiana	1,539.6	2	70.1	8	4.2	2
Iowa	231.3	18	18.3		2.2	13
Kansas	150.1	23	25.1	22	1.0	
Kentucky	1,007.5	6	54.2	12	3.6	5
Louisiana	24.8		45.8	16	0.1	
Maine	16.3		2.1		1.4	24
Maryland	223.2	19	20.0	30	2.1	14
Massachusetts	275.5	17	31.6	19	1.8	16
Michigan	565.4	11	57.9	11	1.8	16
Minnesota	177.4	21	21.0	29	1.5	21
Mississippi	129.2	24	18.5		1.3	27
Missouri	1,140,5	4	48.4	15	4.5	
Montana	23.4		5.5		0.7	
Nebraska	49.5		9.3		1.0	
Nevada	39.5		11.7		0.6	
New Hampshire	80.5	30	5.1		2.9	7
New Jersey	110.2	26	22.1	27	0.9	
New Mexico	84.6	28	24.6	23	0.6	
New York	480.3	14	63.2	9	1.4	24
North Carolina	435.4	15	60.8	10	1.5	21
North Dakota	82.5	29	11.8		1.2	28
Ohio	2,171.6	1	108.1	3	3.8	3
Oklahoma	37.7		43.3	18	0.2	
Oregon	3.3		0.8		0.7	
Pennsylvania	1,466.1	3	109.7	2	2.5	11
Rhode Island	5.2		1.0		1.0	
South Carolina	213.1	20	21.5	26	1.9	15
South Dakota	28.6		2.8		1.7	18
Tennessee	933.7	8	51.0	13	3.7	4
Texas	302.8	16	201.9	1	0.3	
Utah	22.1		11.3		0.4	
Vermont	0.5		0.0		1.2	28
Virginia	163.7	22	21.9	25	1.4	24
Washington	69.4		7.3		1.7	18
West Virginia	944,2	7	70,4	7	2.7	9
Wisconsin	485.7	13	26.0	21	3.4	6
Wyoming	120.9	25	22.8	24	1.0	
National totals	17.378.5		1.754.4		1.9	

SOURCE: E. H. Pechan &. Associates, inc., "Estimates of Sulfur Oxide Emissions From the Electric Utility Industry;' prepared for the Environmental Protection Agency, 1982,

Table A-9.-SO_2 Emission Reductions Achieved by Emission Rate Limitations (percent reduction in 1980 utility SO_2 emissions)

State	SO_2 emissions (10^3 tons)	Percent reduction with emission limit (lb SO_2/MMBtu)						
		1.0	1.2	1.5	2.0	2.5	3.0	4.0
Alabama	543	57	49	38	24	11		o
Alaska	12	51	44	37	25	12	0	0
Arizona	88	0	0	0	0	0	o	0
Arkansas	27	5	2	0	0	0	0	0
California	78	0	0	0	0	0	0	0
Colorado	77	1	0	0	0	0	0	0
Connecticut	32	0	0	0	0	0	0	0
Delaware	52	37	30	20	7	0	0	0
District of Columbia	5	0	0	0	0	0	0	0
Florida	726	50	44	34	23	16	10	3
Georgia	737	65	58	48	32	17	6	0
Hawaii	42	31	22	9	0	0	0	0
Idaho	0	3	0	0	0	0	0	0
Illinois	1,126	67	63	58	50	42	34	20
Indiana	1,540	76	72	66	55	45	35	19
Iowa	231	58	51	47	39	31	24	12
Kansas	150	53	47	38	23	8		0
Kentucky	1,008	72	66	58	45	36	28	15
Louisiana	25	0	0	0	0	0	o	0
Maine	16	29	15	9	4	0	0	0
Maryland	223	54	46	35	18	4	0	0
Massachusetts	276	44	36	24	6	0	0	0
Michigan	565	48	39	31	20	10	1	0
Minnesota	177	42	34	25		5	0	0
Mississippi	129	58	53	45	32	19	9	0
Missouri	1,141	78	74	68	59	51	43	28
Montana	23	11	6	0	0	0	0	0
Nebraska	49	21	14	5	0	0	0	0
Nevada	39	0		0	0	0	0	0
New Hampshire	80	65	58	48	30	20	11	0
New Jersey	110	37	32	24	17	11	6	0
New Mexico	85	13	0	0	0	0	0	0
New York	480	51	44	34	18	8	3	0
North Carolina	435	32	19	4	0	0	0	0
North Dakota	82	24	13	3	0	0	0	0
Ohio	2,172	74	69	62	51	41	32	19
Oklahoma	38	0	0	0	0	0	0	0
Oregon	3	0	0	0	0	0	0	0
Pennsylvania	1,466	62	55	45	30	17	8	0
Rhode island	5	0	0		0	0	0	0
South Carolina	213	50	42	30	12	2	0	0
South Dakota	29	40	29	13	0	0	0	0
Tennessee	934	73	67	59	49	40	30	16
Texas	303	10	4	0	0	0	0	0
Utah	22	0	0	0	0	0	0	0
Vermont	1	17	5	0	0	0	0	0
Virginia	164	27	15	4	0	0	0	0
Washington	69	41	29	12	0	0	0	0
West Virginia	944	64	57	50	39	29	19	7
Wisconsin	486	72	67	60	50	40	31	13
Wyoming	121	11	6	1	0	0	0	0
United States	17,379	61	55	47	36	27	19	10

SOURCE: E. H. Pechan &Associates, inc., ''Estimates of Sulfur Oxide Emissions From the Electric Utility Industry;' prepared for the Environmental Protection Agency, 1982.

Table A-10.—Statewide Average Cost of Reducing Utility SO_2 Emissions by 50 Percent (dollars/ton SO_2 removed, 1982 dollars)

Alabama	300-500
Arkansas	>1,500
Connecticut	>1,500
Delaware	750-1,000
District of Columbia	>1,500
Florida	350-450
Georgia	400-550
Illinois	250-350
Indiana	150-200
Iowa	100-250
Kentucky	300-450
Louisiana	1,000-1,500
Maine	1,000-1,500
Maryland	‘550-600
Massachusetts	950-1,000
Michigan	300-450
Minnesota	500-700
Mississippi	250-300
Missouri	<150
New Hampshire	500-600
New Jersey	700-800
New York	700-800
North Carolina	750-900
Ohio	200-300
Pennsylvania	450-500
Rhode Island	>1,500
South Carolina	450-800
Tennessee	<150
Vermont	—a
Virginia	900-1,100
West Virginia	450-500
Wisconsin	<150
31-State reason	320-410

a$ton costs not estimated

SOURCE: Office of Technology Assessment, based on analyses by E. H. Pechan &Associates, Inc.

Table A-11 .—Regional Costs of Alternative Approaches to Allocating an 8-Million.Ton Reduction in SO_2 Emissions (Eastern 31-State control region, ali costs in 1982 dollars)

Allocation approach[b]	SO_2 reduction (milliontons/yr)	Regional costs[a] (billions of dollars/yr)	($/ton)
I. Allocation based on utility SO_2 emissions:			
1. 50% reduction	8	2.3-2.9	320-410
2.1.5 lb/MMBtu rate limitation	8	1.8-2.3	255-325
3. Lower of:			
1.2 lb/million Btu rate limitation or 50% reduction	7.5	1.8-2.4	275-370
4. 1.3 lb/million Btu average	8	1.8-2.4	260-340
5.11 lb/MWhr (total) average	8	1.9-2.5	270-350
II. Allocation based on total SO_2 emissions:			
1. 35% reduction	7.6	2.6-3.1	385-465
2. 16 tons/square mile	8	3.7-3.9	560-585
3. 200 lb/person	8	2.6-3.0	370-415

aCosts precalculated on the basis of emissions reductions below SIP compliance levels.
bAlternative approaches explained in text.

SOURCE Office of Technology Assessment, based on analyses by E. H. Pechan &Associates, Inc

Table A.12.—Emissions Reductions Required by Alternative Allocation Approaches

	I: Formulae based on utility SO_2 emissions (percent below 1980 emissions)										II: Formulae based on total SO_2 emissions (percent below 1980 emissions)					
	500/0 reduction		1.5 lb/MMBtu cap		Lower of: 1.2 lb/MMBtu cap, 50°/0 reduction		1.3 lb/MMBtu avg.		11 lb/MWhr avg.		35% reduction		16 tons/mi^2		200 lb/person	
State	Percent below: Utility	Total	Percent below: Utility	Total	Percent below: Utility	Total	Percent below: Utility	Total	Percent below: Utility	Total	Percent below: utility	total	Percent below: Utility	Total	Percent below: Utility	Total
Alabama	50	35	38	27	48	35	42	30	20	14	48	35	4	3	65	46
Arkansas	50	13	35	9	35	9	35	9	35	9	>100	35	35	9	35	9
Connecticut	50	22	0	0	0	0	0	0	0	0	78	35	0	0	0	0
Delaware	50	24	44	21	44	21	44	21	44	21	73	35	>100	70	90	43
District of Columbia	50	15	0	0	0	0	0	0	15	4	>100	35	>100	93	0	0
Florida	50	33	34	22	43	28	24	16	26	17	52	35	21	14	16	10
Georgia	50	43	47	41	50	43	53	47	51	44	39	35	0	0	38	33
Illinois	50	38	58	44	50	38	51	39	47	36	45	35	50	38	27	21
Indiana	50	38	65	50	50	38	67	52	72	55	45	35	93	71	90	69
Iowa	50	35	46	32	50	35	40	28	46	32	49	35	0	0	15	10
Kentucky	50	44	58	52	50	44	62	56	66	59	38	35	47	42	71	64
Louisiana	50	4	0	0	0	0	0	0	0	0	>100	35	0	0	0	0
Maine	50	8	8	1	15	2	8	1	0	0	>100	35	0	0	0	0
Maryland	50	33	34	22	45	30	38	25	20	13	53	35	75	50		2
Massachusetts	50	40	24	19	35	28	25	20	27	22	43	35	77	61	20	16
Michigan	50	31	31	19	39	24	28	17	25	15	56	35	0	0	0	0
Minnesota	50	34	24	16	33	23	13	9	2		51	35	0	0	0	0
Mississippi	50	22	44	20	50	22	0	0	20	:	77	35	0	0	24	11
Missouri	50	43	67	59	50	43	69	61	73	64	39	35	16	14	67	59
New Hampshire	50	43	47	41	50	43	53	46	57	49	40	35	3	3	3	3
New Jersey	50	19	24	9	32	12	0	0	0	0	88	35	>100	55	0	0
New York	50	25	33	17	43	22	7	3	1	0	68	35	31	16	1	0
North Carolina	50	36	4	2	18	13	11	8	8	6	48	35	0	0	3	2
Ohio	50	41	62	50	50	41	65	53	69	57	42	35	91	75	69	56
Pennsylvania	50	36	44	32	50	36	48	34	51	37	48	35	88	64	54	39
Rhode Island	50	17	0	0	0	0	0	0	0	0	>100	35	0	0	0	0
South Carolina	50	32	29	19	41	27	32	21	0	0	53	35	0	0	6	4
Tennessee	50	43	59	51	50	43	63	55	61	53	40	35	43	37	63	54
Vermont	50	3	0	0	4	0	0	0	0	0	>100	35	0	0	0	0
Virginia	50	22	3	1	15	6	5	2	2	1	77	35	2	1	2	1
West Virginia	50	43	49	43	50	43	51	44	56	49	40	35	74	64	90	78
Wisconsin	50	38	60	45	50	38	60	46	55	42	45	35	0	0	32	25
Eastern 31-States	50	37	50	37	47	35	50	37	50	37	48	35	50	37	50	37

SOURCE. Office of Technology Assessment, based on analyses by E. H Pechan & Associates, Inc

Table A-13.—Costs of Alternative Allocation Approaches
(estimated percentage increase in residential electricity rates, assuming all emissions reductions from utilities)

	500/0 reduction (utility)	1.5 lb/M MBtu cap	1.2 lb/MMBtu cap or 50°/0 reduction	1.3 lb/MMBtu average	11 lb/MWhr average	35 "/0 reduction (total)	16 tons/ Mi²	200 lb/ person
Alabama	•••	•	••	•	•	••	—	••••
Arkansas	•	—	•	—	—	•••	—	
Connecticut	•			—	—	••	—	
Delaware	•	•	•	•	•	••••	••••••	•••••
D.C.	••••••			—	••••	••••••	••••••	
Florida	•••	•	••	•	•	•••	•	•
Georgia	•••••	•••••	•••••	•••••	•••••	••••		••••
Illinois	••	•••	••	•••	••	••	••	•
Indiana	•••	••••	•••	•••••	•••••	•••	••••••	••••••
Iowa	••	•	••	•	•	••		•
Kentucky	•••	••••	•••	•••••	•••••	•	•••	•••••
Louisiana	•	—	—	—	—	•••••		
Maine	••	•	•	•	—	•••••		
Maryland	•••	••	••	••	•	•••	•••••	
Massachusetts	••	•	•	•	•	••	•••••	
Michigan	•••	•	••	•	•	•••		
Minnesota	•••	••	••	•	•	••••		
Mississippi	••	•	••	—	•	••••		•
Missouri	••	••••	••	••••	••••	•	•	••••
New Hampshire	••••	••••	••••	••••	••••	••••		•
New Jersey	•	•	•	—		••••	•••••	
New York	•	•	•	•	—	•••	•	
North Carolina	••••	•	••	•	•	••••		•
Ohio	••••	•••••	••••	•••••	•••••	•••	••••••	•••••
Pennsylvania	•••	•••	•••	•••	•••	•••	••••••	••••
Rhode Island	••••			—		•••••		
South Carolina	••••	•	•••	•	—	••••		•
Tennessee	•	•	•	••	•	•	•	••
Vermont	•			—		•		
Virginia	•••	•	•	•	—	•••••		
West Virginia	•••••	•••••	•••••	•••••	•••••	••••	••••••	••••••
Wisconsin	•	•	•	•	•	•		•
31-State region	2.4-3.10/0	1.9-2.5%	1.9-2.6%	2.0-2.6°\o	2.0-2 .6%	2.8-3.30/o	4.0-4 .20/o	2.8-3.20/o

— = No reduction required
• = 0-2 "/0
•• = 1-3%
••• = 2-4%
•••• = 3-60/0
••••• = 5- 10 "/0
•••••• = > 10 "/0

SOURCE Off Ice of Technology Assessment, based on analyses by E.H. Pechan and Associates, Inc

control. Costs could then be distributed to a larger group than those required to reduce emissions under each of the scenarios discussed below.

Key aspects of each allocation approach—including its rationale, costs, and distributional consequences—are outlined below.

1. Equal percentage reduction in each State—utility emissions only.

   Description: Each State is required to reduce its utility SO_2 emissions by an equal percentage.

   Rationale: Requiring an equal percentage reduction in utility SO_2 emissions distributes relative emissions reductions fairly uniformly among States.

   Formula for achieving an 8-million-ton reduction: Eliminating 50 percent of 1980 utility emissions in each of the Eastern 31 States.

   Cost: Reducing utility SO_2 emissions by 50 percent in each State is estimated to cost $2.3 to $2.9 billion annually, at an average cost of $320 to $410 per ton of SO_2 removed (1982 dollars).

   Distributional consequences: This formula requires an equal percentage reduction from each State regardless of: 1) the relative costs of emissions control, or 2) the stringency of the State's existing emissions regulations. Five States—Arkansas, Connecticut, Louisiana, Maine, and Rhode Island—would not be able to reduce utility emissions by the necessary 50 percent without setting extremely stringent emission rate limitations (less than 0.4 lb/MMBtu of SO_2).

2. Utility emission rate limitation (limiting emissions per fuel burned).
   Description: This approach sets some maximum emissions limits (an emissions "cap' for each fossil-fuel electric-generating plant. In this case, the limit is an emissions rate specifying the amount of allowable emissions per quantity of fuel burned.
   Rationale: Setting an emissions cap would require emissions reductions in States with powerplants emitting over a certain rate. It would thus target States with plants emitting large quantities of SO_2 per quantity of fuel burned, but not penalize States simply for generating large quantities of electricity.
   Formula *for achieving an 8-million-ton reduction:* Limiting emissions rates for all plants in the Eastern United States to 1.5 lb of SO_2 per MMBtu of fuel burned.
   Cost: Estimated annual costs under this approach are $1.8 to $2.3 billion, at an average cost of $255 to $325/ton.
   Distributional consequences: The largest costs and percentage reductions are distributed to States whose plants emit relatively large amounts of pollutants per unit of energy consumed—e. g., Missouri, Indiana, Ohio, and Tennessee. States with plants emitting at low rates (usually through the use of less polluting fuels, e.g., oil and natural gas) —e. g., Louisiana, Arkansas, and Connecticut —are allocated the smallest reductions.

3. Utility emission rate limitation, with a maximum reduction of 50 percent below current utility emissions.
   Description: This approach modifies the cap approach by limiting any State's required reductions to 50 percent of 1980 utility emissions.
   Rationale: By placing a ceiling on reductions, this approach reduces the impact on those States most heavily targeted under a cap approach. It reduces regional variations in cost by setting a maximum relative reduction requirement for all States.
   Formula for achieving a 7.5-million-ton reduction: A cap of 1.2 lb of SO_2 per MMBtu, with a maximum reduction of 50 percent below 1980 emissions for each State. An alternative method of stating the formula is a 50-percent reduction in a State's 1980 utility emissions, but requiring no existing source to reduce emissions below 1.2 lb of SO_2 per MMBtu. Thus, the formula achieves less than the 8-million-ton reduction of the first allocation approach.
   Cost: This approach is estimated to cost between $1.8 and $2.4 billion per year, at an average cost of $275 to $370/ton.
   Distributional consequences: By placing a limit on percentage reductions, this approach lessens the impact on States required to reduce the most under a cap approach. The States that benefit by this approach as compared to a simple emissions cap are Indiana, Kentucky, Missouri, and Ohio.

4. Average utility emissions per fuel burned.
   Description: Each State is required to achieve a specified average utility emissions rate. Under this averaging approach, some plants within a State are allowed to exceed the specified emissions rate (unlike the cap case) as long as the State has compensating plants emitting below the rate.
   Rationale: Unlike the cap, the average emission rate approach gives credit to States with plants emitting below the specified emissions rate.
   Formula for achieving an 8-million-ton reduction: Each State is required to eliminate sufficient emissions to achieve a statewide utility emissions average of 1.3 lb of SO_2 per M MBtu of fuel burned (based on 1980 emissions).
   Cost: This strategy is estimated to cost $1.8 to $2.4 billion per year at an average cost of $260 to $340/ton.
   Distributional consequences: Emissions reductions are allocated in a manner similar to the cap case. States in which a substantial number of plants emit at rates below the specified average (e. g., New York, Minnesota, and Mississippi) would tend to prefer the average rate approach over the cap; States in which most plants emit at rates well above the average used for allocation (e.g., Missouri and Kentucky) would tend to favor the cap over the average (assuming that identical regional reductions are required).

5. Average utility emissions per total electricity ouput.
   Description: This approach allocates emissions reductions on the basis of the amount of SO_2 emitted per unit of electricity generated by **all** plants, including hydroelectric and nuclear powerplants,
   Rationale: Allocating emissions reductions on the basis of total electricity generation gives credit to those States that generate electricity with fuels that do not produce SO_2 emissions.
   Formula for achieving an 8-million-ton reduction: States are required to reduce utility emissions to meet an average rate of 11 lb of SO_2 per megawatt-hour of **total** electricity output.
   Cost: This approach is estimated to range in cost from $1.9 to $2.5 billion annually, at an average cost of $270 to $350/ton of SO_2 reduced.

Distributional consequences: This approach favors States in which relatively high proportions of electricity produced by hydroelectricity or nuclear power—e. g., Alabama, Maine, Maryland, Minnesota, and New York.

6. Equal percentage reductions in each State—total SO_2 emissions.

   Description: Each State is required to reduce total SO_2 emissions (i. e., emissions from all sectors, not just utility emissions) by an equal percentage from some baseline level.

   Rationale: Each State participates equally in reducing aggregate emissions.

   Formula for achieving a 7.6-million-ton reduction: Each State reduces total 1980 SO_2 emissions by 35 percent.

   Cost: This approach is estimated to cost $2.6 to $3.1 billion annually, at an average cost of $385 to $465/ton of SO_2 removed.

   Distributional consequences: This allocation formula requires an equal percentage reduction in each State regardless of relative costs of emissions control or stringency of the State's existing emissions regulations. Those States: 1) with the highest proportion of emissions from sources that are difficult to control (e. g., certain industrial processes and small residential, commercial, or industrial boilers), and 2) that have relatively low SO_2 emission rates, would incur the highest per-ton costs. This includes such States as Louisiana, Maine, Rhode Island, and Virginia.

7. Total emissions per land area.

   Description: This approach is based on emissions densities, i.e., the amount of SO_2 emitted per unit of land area. Emissions densities are calculated from an area's total emissions, rather than just its utility emissions.

   Rationale: To the extent that acid deposition is produced by local sources, limiting the density of SO_2 emissions would help to limit the amount of sulfur deposited in the surrounding area.

   Formula for achieving an 8-million-ton reduction: Reductions are allocated by setting a maximum average emissions density of 16 tons of SO_2 per square mile.

   Cost: This approach would cost $3.7 to $3.9 billion per year, at an average cost of $560 to $585/ton of SO_2 removed.

   Distributional consequences: The States with the highest emissions densities, and thus the largest proportional reductions and costs under this approach, are Delaware, D. C., Indiana, Massachusetts, Ohio, Pennsylvania, and West Virginia.

8. Total emissions per person.

   Description: Emissions reductions are calculated on the basis of the amount of pollution emitted per person residing in the State. Reductions are based on the region's total emissions, not just utility emissions.

   Rationale: Giving credit to States with lower emissions-to-population ratios takes into account a wide range of factors, including reliance on clean fossil fuel combustion, non-SO_2-emitting electricity generation, higher energy efficiency, and presence of fewer SO_2-producing industrial activities.

   Formula for achieving an 8-million-ton reduction: Reductions are allocated according to an average rate of 200 lb of SO_2 per capita.

   Cost: The costs of this approach are estimated to range from $2.6 to $3.0 billion annually, with an average cost of $370 to $415/ton of SO_2 reduced.

   Distributional consequences: Those States with a relatively high proportion of total SO_2 emissions to the population supported by emissions-generating activities (both industrial and electricity generation) are allocated the largest reductions. These States include Indiana, Kentucky, Missouri, Ohio, Tennessee, and West Virginia.

Comparison of Utility Estimates of Emissions Reductions Costs to Various Regional-Model Estimates

The Edison Electric Institute (EEI) requested its member utilities to estimate the cost of implementing a control proposal reported by the Senate Committee on Environment and Public Works during the 97th Congress (S.3041, reintroduced as S.768 during the 98th Congress). The acid rain control sections of this bill would require eliminating about 9 million to 10.5 million tons of SO_2 per year in the Eastern 31-State region—8 million tons per year allocated to States based on utility SO_2 emission rates and an additional 1 million to 2.5 million tons per year to offset expected emissions growth by 1995. * (S. 768 was subsequently amended to require an additional 2-million-ton emissions reduction.)

* The amount by which a State must reduce its SO_2 emission was determined by the following formula Calculate the difference between a State's 1980 utility emissions and the emissions that would result if no electric-generating plant in that State emitted SO_2 at a rate greater than 1.5 lb/MMBtu. Repeat this calculation for the Eastern 31-State region as a whole. The State proportion of the total regional difference, multiplied by 8 million tons, is the amount of SO_2 emissions that must be eliminated in that particular State Any additonal growth in emissions due to new facilities or increased use of existing ones by 1995 must also be offset

Twenty-four utilities responded, accounting for about 3.5 million tons (about 45 percent) of the 8-million-ton reduction specified by the bill.[42] Table A-14 compares these cost estimates to regional model-based estimates prepared for EPA[43] and OTA. * In general, the utilities projected higher costs than the model-based statewide averages. The OTA estimates are typically higher than the EPA estimates. There are several reasons for these differences. First, some of the utilities surveyed have higher SO_2 emissions rates than the statewide average. As a result, these utilities will have higher emissions reduction costs than the statewide averages estimated by the models.

Second, EEI, EPA, and OTA used different accounting procedures. One major difference is the number of years over which capital costs are averaged. The EEI estimates reported in table A-14 are averaged (''levelized' over 5 years;* both EPA and OTA average capital costs over time periods equivalent to the life of the facility (about 20 years). The shorter averaging time makes the utility estimates of annual costs somewhat higher.

The estimates also make different assumptions about scrubber costs, low-sulfur coal prices, and the choice of control method. Some utilities project scrubber capital costs about equal to the average costs assumed by the models (about $150 to $250 per kilowatt of generating capacity); however, several estimate costs almost twice as high. EEI assumes that most of the emissions reduction would occur through scrubbing, whereas the model used by EPA projects that most emissions reductions would be achieved by fuel-switching at a considerable cost savings over scrubbing. The OTA model calculates a fairly even mix of scrubbing and fuel-switching to achieve the required emissions reductions, with costs typically between the EPA and utility estimates.

Overview of Model Used in Cost Analyses

OTA's cost estimates are based on a computer model that calculates the cost of reducing emissions at each major utility generating unit in the 31 -State region (about 2,000 units in about 900 powerplants). For each unit, the model determines the combination of emissions reduction measures that minimizes the costs of complying with a series of alternative emissions rate limitations, ranging from SIP compliance to a 0.4 lb SO_2/MMBtu limit. Emissions reduction opportunities are then ranked on the basis of costs per ton of SO_2 removed. For each alternative rate limitation, the model considers the costs of the following control options for each unit:

For coal-fired powerplant emissions:

- blending presently used coals with low-sulfur coals,
- switching to low-sulfur coals,
- physical coal cleaning to reduce the sulfur contents of presently used coals,
- installing dry scrubbers in conjunction with either current or alternative coal types, and
- installing wet scrubbers in conjunction with either current or alternative coal types.

For plants burning residual oil:

- switching to a lower sulfur oil.

These results are in turn used to generate State and regional cost estimates of various emissions reduction measures. These costs can be calculated in two ways:

1. **State Least Cost:** Reduction opportunities are selected in ascending order of per-ton costs within each State until the reduction target is achieved. Trading of emissions reductions among sources is allowed within States, but not among States. This approach assumes a "perfect market for the exchange of emissions reductions obligations throughout the State and provides a lower bound model estimate.
2. Plant Cap: Each plant is required to comply with a specified emissions limit. This approach to estimating costs chooses the least-cost approach at each plant, but assumes no trading of reduction obligations among plants or States.

The cost model considers only SO_2 emissions from utilities. No estimates of the cost of reducing emissions of NO_x, nor estimates for controlling SO_2 or NO_x from the industrial sector, are calculated. Furthermore, existing utilities are the only sources considered, and are assumed to be operating at their current level of capacity utilization. The OTA analysis assumes that all reductions occur immediately, without accounting for new plants being built, or old plants being retired. Finally, the model does not include the following possible control alternatives:

1. early retirement of major sources,
2. energy conservation,
3. selective use of lower emitting plants, and
4. advanced control technologies.

In calculating cost increases, OTA's model assumes that each plant chooses the most cost-effective method of reducing emissions. However, State regulatory poli-

[42] National Economic Research Associates, Inc, "A Report on the Results From the Edison Electric Institute Study of the Impacts of the Senate Committee on Environment and Public Works Bill on Acid Rain Legislation" (S.768), 1983.

[43] ICF, Inc , ''Analysis of a Senate Emission Reduction Bill" (S 3041) Prepared for EPA, 1983

* OTA'S cost estimates are from the AIRCOST model, E. H Pechan & Associates. These estimates include the costs of emissions reductions required to offset future emissions growth, based on projections prepared for the United States-Canada Memorandum of Intent, the Edison Electric Institute, and EPA

* EEI also reports utility estimates of rate Increases based on first-year revenue requirements; though typically about 25 percent higher than the 5-year averages, these are not representative of average costs for the life of the program

Table A-14.—Comparison of Estimates of Residential Electricity Rate Increases (8-million-ton SO_2 reduction program, plus offsets for future growth)

1. Utilities located in single States			
Florida:	Florida Power & Light Co.		5%
	Tampa Electric Co.		230/o
	Statewide averages	EPA: 2-30/o, OTA:	3-7 "/0
Illinois:	Illinois Power Co.		18°/o[b]
	Central Illinois P.S.		21 "/0
	Statewide averages	EPA: 1-2°/0, OTA:	2-11 "/0
Indiana:	Public Service Indiana		250/o
	Indianapolis P. & L.		26°/o[b]
	Statewide averages	EPA: 7-80/o, OTA:	8-130/o
Massachusetts:.	New England Power Co.		4%
	Statewide averages	EPA: 1% OTA:	0-50/0
Michigan:	Detroit Edison		12 "/0
	Statewide averages	EPA: 2-40/o, OTA:	2-60/o
Missouri:	Union Electric Co.		180/0
	Statewide averages	EPA: 5-7°/0, OTA:	8-21 0/0
North Carolina:	Duke Power Co.		4%
	Statewide averages	EPA: 1-2°/0, OTA:	2-50/o
Ohio:	Cincinnati G. & E.		14 "/0
	Statewide averages	EPA: 6-70/o, OTA:	8-120/o
Pennsylvania:	Pennsylvania Electric		200/0
	Pennsylvania P. & L.		100/0
	Statewide averages	EPA: 3-5°/0, OTA:	30/0
Wisconsin:	Wisconsin Power & Light		11 .30/0
	Wisconsin Electric Power		12.30/o
	Statewide averages	EPA: 5-60/o, OTA:	1 1-120/0

II. Multi-State utilities:			
Florida, Georgia, Mississippi:			
The Southern Company		12 "/0	
Statewide averages:		EPA	OTA
	FL	2-30/o	3-70/0
	GA	4-5 "/0	9-120/o
	MS	3%	5-200/o
Virginia, West Virginia			
VEPCO		60/0	
Statewide averages:		EPA	OTA
	VA	1-20/0	2-70/o
	WV	5-60/o	10-13 "/0
Indiana, Kentucky, Michigan, Ohio			
American Electric Power (AEP)		180/0 (6-38 °/o)[b]	
Statewide averages:		EPA	OTA
	IN	7-80/o	8-130/o
	KY	4-60/o	5-90/0
	MI	2-40/o	2-60/o
	OH	6 - 7 %	8-120/o

aEstimates are for a control program requiring SO_2 emissions reductions in the Eastern 31-State region such that 1995 emissions are 8 million tons below 1980 levels. Emission limits for each State are allocated by a 1.5 lb SO_2/MMBtu emission rate limitation for utilities. Including reductions to offset future growth, about 9 to 10.5 million tons of SO_2 per year must be eliminated from existing sources

bFor these utilities, about one.third to one-half of capital costs are for new utility construction to replace Prematurely retired plants, or to compensate for electricity losses due to scrubbers

SOURCE Compiled by Off Ice of Technology Assessment See text for references.

cies can affect this choice—and hence the costs—in ways not treated by the model. For example, in most States, ‘‘automatic fuel adjustment clauses’ allow utilities to pass on increased fuel costs due to fuel-switching to consumers within a few months. However, for emissions controls requiring capital investment, such as scrubbers, most States require utilities to wait until the equipment becomes operational before charging ratepayers. This practice may create a bias against capital investment in pollution control equipment in utility management decisionmaking, and increase a plant's lifetime control costs.

The model used by OTA also assigns all control costs to the State whose utility owns the facilities required to reduce emissions. The accuracy of this assumption depends on the policy chosen for allocating costs. To relieve utilities or States that are allocated particularly large emissions reductions, costs could be shared by electricity consumers in other areas.

A.4 ALTERNATIVE TAX STRATEGIES TO HELP FUND ACID RAIN CONTROL

Several acid rain control bills introduced during the 98th Congress proposed establishing a trust fund to help finance the costs of emissions reductions for controlling acid deposition. The proposals were based on one of two alternative approaches for raising revenues: a tax on pollutant emissions, or a tax on electricity generation. Each of these approaches could be implemented in several ways.

This section considers two alternative pollution taxes: 1) a tax on both sulfur dioxide (SO_2) and nitrogen oxides (NO_x), and 2) a tax on SO_2 emissions only. Both apply to nationwide pollutant emissions. The section analyzes the distribution of the two taxes by emissions source, and the electricity portion of the tax by State, and compares them to two electricity-based approaches: 1) a tax on total electricity generation, and 2) a tax on nonnuclear electricity generation.

All four tax schemes are possible alternatives to requiring those sources that must reduce emissions to pay the entire costs of control. Funds raised by a tax can be used to pay part or all control costs. A pollution tax would apportion control costs to a larger group of emitters, not just those required to reduce emissions. However, because so few sources are actually monitored, such an approach would be administratively complex. An electricity tax would also distribute control costs to a larger group of emitters, but is not directly related to actual emissions. However, because electricity generation is carefully monitored, this approach would be much easier to implement.

The analyses presented below are approximate, intended to illustrate the relative distribution of costs for raising an arbitrary $5 billion per year under each approach. The actual amount of the tax, and to some extent the distribution of the tax, varies with each specific control plan and trust-fund design.

Distribution of Emissions, Tax Rates, and Tax Revenues by Source

About 90 to 95 percent of the Nation's manmade SO_2 emissions originate from utility and industrial sources. About 95 percent of the Nation's manmade NO_x emissions originate from utility, industrial, and transportation sources. Emissions from these sectors can be considered the potentially ‘ ‘taxable’ pollutant inventory (though in practice assessing emissions from all sources in each category with sufficient accuracy for tax purposes would be difficult). Emissions from residential, commercial, and other small dispersed sources are not considered taxable for this analysis.

For example, to raise $5 billion per year, by deriving two-thirds of the revenues from SO_2 and one-third from NO_x emissions, * the tax must be set at about $135/ton of SO_2 and $85/ton of NO_x emitted. A tax on SO_2 emissions alone must be set at about $200/ton. These rates are based on 1980 taxable emissions; revenues from a fixed tax rate would increase as emissions increase, and would decrease if acid rain control legislation were enacted. To raise $5 billion per year through taxes on electricity generation, the following rates must be set: 2.2 mills/kWh for all electricity generated and 2.5 mills/kWh for nonnuclear electricity only. Total revenues in future years would follow changes in electricity demand.

Table A-15 displays each sector's contribution to an acid rain control trust fund based on the above rates. The two-pollutants tax (i. e., on both SO_2 and NO_x) would raise about $2.8 billion (55 percent) from utilities, about $1.4 billion (30 percent) from industry, and

* About twice as much precipitation acidity currently originates from sulfur compounds as from nitrogen compounds in the Eastern United States.

Table A-15.—Annual Contribution to Acid Rain Control Trust Fund From Alternative Tax Approaches (billions of dollars/yr, see text for explanation of alternative taxes)

	Emissions tax (before control-1980 emissions)		Emissions tax (after control-1995 emissions)		Electricity tax	
	SO_2 & NO_x	SO_2 only	SO_2 & NO_x	so* only	Total electricity	Nonnuclear electricity
Electric utilities	2.8	3.5	1.8	1.6	5.0	5.0
Industry	1.4	1.5	1.6	1.8	0.0	0.0
Transportation	0.8	0.9	0.9	0.0	0.0	0.0
Total United States	5.O	5.0	4.3	3.4	5.0	5.0

SOURCE: Office of Technology Assessment, based on data from Emissions, Costs and Engineering, Work Group 3B, United States-Canada Memorandum of Intent on Transboundary Air Pollution, June, 1982 and the Statistical Year Book of the Electric Utility Industry, Edison Electric Institute, 1980

$0.8 billion (15 percent) from transportation sources. If only SO_2 were taxed, about 70 percent of the fund would come from utilities and about 30 percent from industry.

The third and fourth columns in table A-15 estimate tax revenues in 1995 after a hypothetical acid rain control program, assuming that the tax rates remain unchanged. Utility SO_2 emissions in the Eastern 31 States are assumed to be 10 million tons below 1980 levels. All other emissions are assumed to grow at rates calculated from emissions projections developed under the *United States-Canada Memorandum of Intent on Transboundary Air Pollution*. The share of annual trust fund revenues derived from utilities would decline to about 40 percent of the total for the two-pollutants tax, and to about 45 percent of the total for the SO_2 tax. Because total nationwide pollutant emissions decline, the total tax collected drops by 15 and 30 percent, respectively.

A tax on electricity generation (either total or nonnuclear) is assumed to come entirely from the utility sector (i. e., industrial generation of electricity for internal use is not taxed).

Geographic Distribution of Electricity Rate Increases

Table A-16 presents State-by-State costs of the alternate tax approaches for the electric utility sector only. Costs to industry are often borne by consumers from a much larger area than the State in which the industry is located, since many manufactured goods are distributed nationwide. A tax on mobile source emissions (e. g., a sales or registration tax) would be distributed on a roughly per-capita basis.

The large variation in current pollution emission rates among utility plants would cause a pollution tax to distribute costs unevenly both within a State and from State to State. As shown in table A-16, though a pollution tax to raise $5 billion per year would increase average residential electricity rates by about 2 percent, State-average increases would range from virtually no increase to about 9 percent. Because utilities emit a larger share of nationwide S02 than NO_x emissions, electricity rate increases are typically somewhat lower for a tax on both S02 and NO_x emissions (co1. 1) than on S02 emissions only (co1. 2).

Assuming that emissions reductions are achieved, * Eastern States would experience smaller rate increases due to the pollution tax in 1995 (cols. 3 and 4) than in 1980. Western-State rate increases would be higher in 1995 than in 1980 due to projected increased emissions. The tax rate is assumed to be indexed to inflation, so that rate changes shown in 1995 are due solely to emissions changes and not to changes in the price of electricity.

The last two columns of table A-16 estimate residential rate increases from a fixed kilowatt-hour tax on all electricity, and on nonnuclear electricity, generated in each State. State-to-State variations are due solely to differences in the average electricity rate currently paid by consumers in each State. Large percentage increases imply low current rates for electricity. Nationwide, the rate increases from a tax on electricity generation are greater than for a pollution tax under which a significant share of the total $5 billion per year tax comes from other sectors. However, in several Midwestern States (e. g., Indiana, Kentucky, Missouri, and Ohio) with high rates of pollutant emissions, an electricity tax would be less costly than an emissions tax during the years before emissions reductions are achieved.

*Eastern 31-State utility SO_2 emissions in 1995 are assumed to be 10 million tons below 1980 levels. Reductions in each State are allocated based on utility SO_2 emissions in excess of 1.2 lb/MMBtu of fuel burned.

Table A-16.—5O.State Taxes Raising $5 Billion per Year During the Early 1980's

Average residential electricity rate increase (percent) from alternative tax approaches						
	Emissions tax (before control-1980 emissions)		Emissions tax (after control-1995 emissions)		Electricity tax	
	S 0_2 & NO_x	so* only	so* & NO_x	SO_2 ony~	Total electricity	Nonnuclear electricity
Alabama	2.0	2.5	1.3	1.2	4.0	3.1
Alaska	0.9	1.4	1.2	1.8	4.0	4.4
Arizona	0.7	0.7		0.9	3.1	3.5
Arkansas	0.6	0.5	0.5	0.3	4.4	3.0
California	0.2	0.2	0.3	0.2	3.0	3.3
Colorado	1.3	1.2	1.7	1.5	3.7	4.0
Connecticut	0.3	0.3	0.3	0.3	2.5	1.5
Delaware	1.4	1.8	1.0	1.0	2.4	2.7
District of Columbia	2.2	2.7	2.3	2.7	4.5	5.0
Florida	1.7	2.2	1.2	1.2	3.1	2.9
Georgia	3.5	4.5	1.8	1.7	4.2	4.1
Hawaii	0.8	1.1	1.1	1.4	1.8	2.0
Idaho	0.0	0.0	0.0	0.0	8.2	9.2
Illinois	2.9	3.6	1.5	1.2	3.6	2.9
Indiana	5.9		2.3	1.8	3.8	
Iowa	3.0	3.5	1.9	1.6	3.6	3.6
Kansas	1.8	2.0	2.4	2.6	3.7	4.1
Kentucky	5.7	7.3	2.6	2.2	4.5	5.0
Louisiana	0.5	0.2	0.6	0.2		4.7
Maine	0.4	0.6	0.4	0.6	3.3	1.6
Maryland	1.8	2.3	1.1	1.2	3.6	2.6
Massachusetts	1.6	2.1	1.1	1.3	2.9	2.9
Michigan	2.5	3.0	1.9	1.7	4.3	3.8
Minnesota	1.8	2.0	1.6	1.3	3.8	2.9
Mississippi	2.1			1.1	4.0	4.5
Missouri	6.6	8.8	2.3	1.9	4.1	4.6
Montana	0.9	0.9	1.3	1.1	6.4	7.2
Nebraska	1.3	1.3	1.7	1.7	4.7	3.4
Nevada	1.0	0.9	1.4	1.1	3.9	4.4
New Hampshire	2.9	3.6	1.6	1.4	2.9	3.3
NewJersey	0.8	0.9	0.7	0.6	2.6	2.1
New Mexico		0.9			2.9	
NewYork	0.7	0.9	0.4	0.5	2.1	2.0
North Carolina	1.8	2.1	1.7	1.7	3.7	3.9
North Dakota	1.9	2.0	2.5	2.6	4.1	4.6
Ohio	4.5	5.9	1.9	1.6	3.3	3.6
Oklahoma	0.6	0.3	0.9	0.5	4.5	5.0
Oregon	0.1	0.1	0.1	0.1		6.9
Pennsylvania	2.7	3.5	1.5	1.5	3.1	3.2
Rhode Island	1.3	1.5	1.5	1.5	3.0	3.3
South Carolina	1.4	1.7	1.0	0.9	3.6	2.4
South Dakota	1.1	1.1	1.4	1.4	3.6	4.1
Tennessee	5.3	7.0		2.0	4.9	5.5
Texas	0.7	0.5	0.9	0.7	3.7	4.1
Utah	0.8	0.6	1.1	0.8	3.6	
Vermont	0.1	0.0	0.1	0.0	3.5	0.9
Virginia	1.2	1.4	1.1	1.2	3.3	2.5
Washington	0.5	0.7	0.7	0.9	9.5	10.5
West Virginia	4.1	5.1	2.3	2.0	4.2	
Wisconsin	4.1	5.2	1.9	1.5	4.4	3.6

SOURCE: Based on data from Emissions, Costs and Engineering, Work Group 3B, United States-Canada Memorandum of Intent, June 1982; and the Statistical Year Book of the Electric Utility Industry, Edison Electric Institute, 1980,

A.5 OTHER EMISSION SECTORS

This section addresses major nonutility sources of SO_2 and NO_x emissions. It presents estimates of current emissions, potential emissions reductions, and control costs, where possible, for: 1) industrial and large commercial boilers, 2) industrial process emitters (e, g., smelters and petroleum refineries), and 3) mobile sources. Together, these source categories account for approximately 30 to 35 percent of SO_2 and 65 to 70 percent of NO_x. emissions in the continental United States.

In general, data needed to estimate emissions from these sources are scanty and of questionable accuracy. In addition, emissions control methods, particularly for industrial processes, are in earlier stages of development than for utilities. Consequently, the estimates of emissions, potential emissions reductions, and estimated control costs presented in this section are subject to greater uncertainty than those presented earlier for the utility sector.

Industrial and Commercial Boilers

Industrial and large-commercial boilers emitted about 3.5 million tons of SO_2 in 1980; table A-17 provrides State-by-State emissions estimates for these sources. Two estimates are presented; one is calculated from State-levcl fuel deliveries, the other from data reported to EPA .[44] Though the national totals are quite close, the difference at the State-levrel is often quite large. Largest emitting States were New York (about 350,000 to 450,000 tons), Ohio (about 300,000 to 400,000 tons), and Pennsylvania (about 250,000 to 300,000 tons); nine additional States had nonutility boiler emissions greater than about 100,000 tons of SO_2 per year.

Table A-17 also indicates the percentage of this sector's 1980 emissions that would have to be eliminatcd under various emission rate limitations. In comparison to the utility sector, SO_2 emission rates from industrial and commercial boilers are relatively low. Thus, control strategies based on emission rate limitations would reduce emissions from this sector by a smaller proportion than comparable controls on the utility sector. For example, an emission rate limitation of 1.5 lb of SO_2 per million Btu would eliminate slightly over a quarter of this sector's 1980 emissions (slightly under 1 million tons of' SO_2 annually); an identical cap on utility emissions would eliminate slightly less than half of that sector's SO_2 emissions (about 8 million tons of SO_2 annually).

[44] Data are from EPA's National Emission Data System, analyzed for OTA by E. H. Pechan & Associates, Inc.

The lower SO_2 emission rates from nonutility boilers are due to the lower sulfur content of the fuels burned. A 1979 Department of Energy (DOE) survey[45] found that natural gas (which emits almost no SO_2) supplied about 32 percent of the energy requirements of industrial boilers. Coal and oil each accounted for about 17 percent of boiler fuels (as compared to 58 and 12 percent, respectively, of fuels used by utilities). The remainder came from such fuels as wood, bark, coke oven gas, and paper-pulping liquor.

Many nonutility boilers are capable of burning a wide variety of fuel types. Thus, if emissions controls were required for nonutility boilers, reductions in SO_2 emissions could be met by substituting lower sulfur fuels or even changing fuel types. Boilers currently burning high-sulfur oil might switch to low-sulfur oil. Natural gas, which accounted for over 30 percent of commercial and industrial boiler fuel use in 1979, might also be substituted, Federal and State regulations permitting.

For boilers equipped to burn coal, available strategies for reducing emissions include switching to lower sulfur coal, and cleaning exhaust gases with scrubbers. Switching to low-sulfur oil or gas may be possible in many cases, but would probably not be as cost effective as low-sulfur coal. Table A-18 estimates per-ton costs associated with three fuel-switching and two scrubber-installation scenarios.

*Industrial Processes **

Industrial processes are estimated to account for approximately 15 to 20 percent of the SO_2 emitted nationwide and about 7 to 12 percent of those emitted in the Eastern 31 -State region of the United States. Less than 5 percent of U.S. NO_x emissions came from industrial processes. Data on emission rates for individual sources are scanty. Moreover, relatively little literature is available on the technical feasibility and costs of controlling emissions from these sources. Consequently, emissions and control cost estimates are subject to greater uncertainty than those associated with utility, industrial, and commercial boiler operations. A study produced for OTA by Energy & Resource Consultants, Inc., provides preliminary estimates of SO_2 emissions and control costs for five major industrial sectors: 1) pulp and paper,

[45] U.S. Department of Energy, Energy Information Administration, "Survey of Large Combustors: Report on Alternative-Fuel Burning Capabilities of Large Boilers in 1979," DOE/EIA-0304.

*This subsection is based primarily on: "An Assessment of Reducing Emissions in Five Critical Industries for the Purpose of Acid Deposition Mitigation," Energy & Resource Consultants, Inc., contractor report submitted to the Office of Technology Assessment, 1982.

99 413 0 - 84 - 13 : QL · 3

Table A-17.-Potential SO_2 Reductions From Nonutility Boilers

State	Non utility boiler SO_2 emissions (thousand tons/yr)		Percent reduction in emissions with emission limit (lb/MMBtu)				
	U.S./Canada [a]	NEDS [b]	1.0	1.2	1.5	2.0	2.5
Alabama	86	119	51	44	35	23	15
Arizona	9	4	32	29	27	22	15
Arkansas	32	7	0	0	0	0	0
California	56	153	15	6	3	2	1
Colorado	24	19	16	13	10	6	5
Connecticut	34	14	1	1	1	1	1
Delaware	26	20	3	2	1	0	0
District of Columbia		14	11	4	2	1	0
Florida	97	97	48	41	31	17	9
Georgia	44	66	56	48	38	22	10
Idaho	11	5	22	16	8	0	0
Illinois	188	111	45	40	34	26	19
Indiana	290	129	59	53	45	35	28
Iowa	57	56	72	67	59	47	35
Kansas	11	0	0	0	0	0	0
Kentucky	66	32	52	46	41	33	27
Louisiana	76	78	13	11		7	6
Maine	65	93	59	51	38	19	2
Maryland	56	23	0	0	0	0	0
Massachusetts	58	33	0	0	0	0	0
Michigan	154	122	50	43	35	26	21
Minnesota	44	49	47	38	26	14	
Mississippi	48	46	0	0	0	0	0
Missouri	55	17	40	35	28	20	15
Montana	25	9	80	77	71	65	60
Nebraska	4	4	34	29	20	11	6
Nevada	2	2	15	10	5	0	0
New Hampshire	10	20	51	43	29	7	0
New Jersey	74	78	0	0	0	0	0
New Mexico	2	9	58	53	48	40	33
New York	334	455	14	7	5	3	2
North Carolina	116	130	47	37	24	7	1
North Dakota	13	5	32		9	4	4
Ohio	310	403	70	66	61	53	46
Oklahoma	15	13	32	27	20	8	5
Oregon		14	0	0	0	0	0
Pennsylvania,	254	314	12	11	10	7	6
Rhode Island	8	4	7	0	0	0	0
South Carolina	84	76	45	35	22	8	1
South Dakota	3	2	19	13	6	0	0
Tennessee	83	97	50	44	37	27	21
Texas	106	121	5	3	1	0	0
Utah	16	16	27	18	7	1	0
Vermont	5	2	39	30	17	0	0
Virginia	142	129	49	40	27	10	1
Washington	41	28	24	18	13	9	7
West Virginia	84	94	57	50	41	31	22
Wisconsin	107	150	60	55	49	38	30
Wyoming	30	32	45	36	24	7	2
National totals	3,491	3,514	37	32	26	18	13

SOURCES: Office of Technology Assessment, based on: [a]dmissions, Costs and Engineering Assessment, Work Group 3B, United States-Canada Memorandum of intent on Transboundary Air Pollution, June 1982; and [b]EPA's National Emissions Data System.

Table A-18.— Representative Costs for Reducing SO_2 Emissions From Coal-Fired Industrial Boilers

Industrial strategies	$/ton SO_2 removed (1982 dollars)
Shift from high[a]- to low[b]-sulfur coal . .	$ 250-$550
Shift from high- to medium[c]-sulfur coal.	300-500
Shift from medium- to low-sulfur coal	400-1,000
Shift from unscrubbed high to scrubbed high sulfur	800-1,000
Shift from unscrubbed medium to scrubbed medium sulfur[d].	1,200-2,000

aAbout 3 to 5 lb SO_2/MMBtu
bAbout 1.5 to 25 lb SO_2/MMBtu
CAbout 0.8 to 1.3 lb SO_2/MMBtu
dBased on the costs of retrofitting a scrubber on a 170 MMBtu/hr coal-fired in dustrial boiler

SOURCE Analysis of Senate Emission Reduction Bill (S 3041) Report prepared for EPA by ICF, Inc , 1983

2) cement, 3) sulfuric acid production, 4) iron and steel, and 5) nonferrous metal smelting. Emissions estimates (but not control costs) are also presented for petroleum refining.

Table A-19 presents estimates of SO_2 emissions from these six industries: 1) by EPA region for the 31 Eastern States, 2) for the remainder of the United States, and 3) for the Nation overall. In nearly all cases, SO_2 emissions have been estimated indirectly, by applying an emissions factor to estimated plant production or production capacities derived from industry surveys. For the cement and pulp and paper industries, in particular, the wide variability in potential emissions per unit of production capacity leads to a range of emissions estimates. Estimates for the iron and steel industry are derived from actual output levels, and are presented for years of differing iron and steel production, to illustrate the effects of production levels on emissions. Where available, estimates of emissions calculated for other studies are also included to further demonstrate the significant uncertainties in these estimates.

Production processes for five of these industries were examined in some detail to determine how much SO_2 could feasibly be eliminated from their emissions, and at what cost. As presented in table A-20, rough estimates show that about 1 million tons of SO_2 could be eliminated from process emissions in the Eastern 31-State region, at widely differing cost levels. Slightly more than half these emissions—primarily from sulfuric acid plants and coke ovens—could be eliminated at average costs of $500/ton or less; an additional 300,000 tons might be eliminated from cement plant emissions at an average cost of approximately $ 1,000/ton. However, estimates of potential emissions reductions, and associated costs, for several of these industries are based on technologies that are theoretically feasible but not commercially proven. The computation methods used to derive cost estimates mask significant variations from plant to plant within each industry; only in the pulp and paper industry was sufficient information available to present a range of per-ton cost estimates, based on differences in plant sizes, economies of scale, and differing production processes in use—the average per-ton cost of control is estimated to be $2,600, ranging from $450 to $14,800/ton of SO_2 removed.

Only the cement industry, of the five surveyed, was found to emit substantial quantities of NO_x—approximately 120,000 tons in the Eastern 31 -State region, and 80,000 tons in the Western portion of the United States.

Mobile Sources *

Automobiles and other mobile sources produce substantial amounts of two pollutants, NO, and hydrocarbons (HC). NO_x and HC are the primary pollutants that react in the atmosphere to form ozone and other oxidants. NO_x can also be converted to nitrates, a component of acid deposition.

Many recent studies suggest that ozone and ozone precursors (NO_x and HC) are transported long distances. The highest concentrations of ozone do not necessarily occur where emissions densities are greatest (i.e., in cities), but, because of chemical transformations over time, at locations that are several hours downwind.

The extent to which mobile sources contribute to acid deposition is uncertain. Tailpipe emissions may not disperse sufficiently to reach the mixing layer of the atmosphere, where they are readily transported and transformed into acid compounds. However, mobile sources have been linked to increases in acid deposition in urban areas, e.g. , the Los Angeles Basin.[46]

Current Emissions: Mobile sources account for major portions of both NO_x and HC emissions nationwide, and a very small portion of SO_2 emissions. As of 1978, mobile sources contributed 40 percent of national NO_x emissions (10.3 million tons), approximately 38 percent of total HC emissions (1 1.8 million tons), and 3 percent of national SO_2 emissions (0.9 million tons) .47

Of NO_x emissions from mobile sources, approximately 40 percent came from automobiles, 10 percent

● This subsection is based on M P Walsh, "Motor Vehicle Emissions of Nitrogen Oxides, " contractor report submitted to the Office of Technologv Assessment, 1981

46PEDCo Environmental, Inc., , and Paul W. Spaite Co., *Perspective on the Issue of Acid Rain, DOE* contract No DE-AC21-81 MC16361, June 1981

47*National Air Pollutant Emission Estimates, /970-J 978*, Office of Air Quality Planning and Standards, U S Environmental Protection Agency, EPA-4.50/4-80-002, January 1980

Table A-19.—SO_2 Emissions From Industrial Processes (estimates for 1980 in thousand tons/yr)

EPA region	Pulp and paper[ac]	Cement[a]	Sulfuric acid[ab]	Iron and steel: Coke ovens only[a]	Iron and steel: Total[ab]	Petroleum refineries[b]	Copper smelting[a]
1	7 (3-15)	3 (2-4)	1	4	—	o	0
II	7 (3-17)	36 (24-52)	8-22	7	20	42	0
Ill	10 (4-22)	84 (57-130)	12-22	66	165	79	0
Iv.	63 (23-140)	96 (58-120)	130-270	15	36	29	7
v	6 (3-15)	110 (75-160)	16-37	68	180	170	72
VI (partial).	18 (7-40)	13 (8-18)	39-83	0	0	105	0
Vll (partial)	1 (l-4)	63 (43-95)	5-11	1	1	8	0
Eastern 31-States . . .	110 (43-250)	410 (270-580)	210-450	160	250-400	430	79
West	26 (1 7-57)	240 (150-310)	53-160	16	23-26	565	1,380
United States total . .	150 (66-340)	650 (410-890)	263-610	180	280-400	1,000	1,460

NOTE Summed estimates have slight discrepancies from combining several sources of data.

SOURCES
aEnergy and Resource Consultants, Inc., "Background Documentation SO_x and NO_x Emissions From Five Industrial Process Categories, " OTA contractor report, 1982
bWork Group 3B, "Emissions, costs and Engineering Assessment " Report prepared under the Memorandum of Intent on Transboundary Air Pollution signed by the United States and Canada, 1982.
CMitre Corp. estimates published in *"Background Document on So_x and No_x Emissions From* Five Industrial *Process* categories. "

States within EPA regions: I—Maine, Vermont, Massachusetts, New Hampshire, Connecticut, Rhode Island; n-New York, New Jersey; 111—Pennsylvania, Maryland, Delaware, West Virginia; IV—Florida, Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia; V—Minnesota, Wisconsin, Indiana, Ohio, Michigan; Vi—Arkansas, Louisiana, VII —Iowa, Missouri.

Table A-20.—Potential SO_2 Emissions Reductions and Control Costs for Industrial Processes

	Pulp and paper	Cement	Sulfuric acid	Coke[a] ovens	Other iron[a] and steel	Copper[b] smelting
Total United States						
Current emissions (10[3] tons) ...	150	650	610	230	120	1,460
Potential emissions reductions (10[3] tons)	130[c]	520[d]	510[e]	185[f]	27[g]	350[h]
Eastern 31 States						
Potential emissions reductions (10[3] tons)	110	330	360	170	24	0
$/ton	2,600[i]	1,000	550	300	>3,000	—
West						
Potential emissions reductions (10[3] tons)	20	190	150	15	3	350
$/ton	2,600[i]	1,000	500	300	>3,000	200

[a]Emissions estimates for the Iron and **steel** industry are based on 1976 production levels rather than 1980 levels due to I he depressed production rates in 1980
bEmmissions estimates **for copper smelting assume that all smelters still operational are producing at near-full capacity**
‘Assumes that exhaust gases from recovery boilers are scrubbed with a removal efficiency of 85 percent
dAssumes that wet scrubbers are installed on cement kilns, with an 80. percent removal efficiency This is not a Commercially proven technology.
eAssumes sodium sulfite scrubbing to achieve a 3 lb/ton of acid emissions limit.
fAssumes coke oven gas desulfurization with 90 -percent removal efficiency
gAssumes that *wet scrubbers* **are installed on sinter plants with a 90-percent removal efficiency**
hBased on the use of double contact acid plants at the Phelps-Dodge Ajo and Douglas smelters in Arizona
I Estimates range from $450 to $14 800/ton

SOURCE Energy and Resource Consultants, Inc , OTA contractor report, 1982.)

from light-duty trucks, 25 percent from heavy-duty trucks, and 25 percent from other mobile sources such as trains and off-highway vehicles. Of HC emissions, 60 percent came from automobiles, somewhat greater than 10 percent each for light- and heavy-duty trucks, and 15 percent from other mobile sources. State-level estimates of NO_x emissions from mobile sources are shown in table A-2; NO_x emissions from highway vehicles alone—about 7.5 percent of total mobile source emissions—are presented in table A-21.

Trends in Highway Vehicle Emissions

Since 1940, nationwide NO_x emissions have approximately tripled; a fourfold increase in the number of motor vehicles since 1945 contributed significantly to this dramatic growth rate .48 In addition, NO_x emissions per mile driven increased during the late 1960’s and early 1970’s, due to the technologies used to implement the first generation of HC and carbon monoxide (CO) emissions control standards. Between 1970 and 1978, HC emissions from highway vehicles decreased by about 10 percent, from 11.3 million to 10.2 million tons, while NO_x emissions increased by 25 percent, from 5.8 million to 7.4 million tons.[49]

During the same period, vehicle miles traveled in the United States increased by about 37 percent, showing some decline in NO_x emission rates due to controls mandated by the Clean Air Act. Since the late 1970 ‘s, overall amounts of NO_x emissions from motor vehiclcs have also begun to decrease slight]?’ as the proportion of NO_x-controlled vehicles in the United States increases.

To estimate future NO_x emissions levels for highway vehicles, OTA has projected three alternative travel scenarios for 1995: a no-growth, a low-growth, and a medium-growth case. Estimates of \’chicle-miles traveled under the three scenarios were then used to project nationwide 1995 NO_x emissions from highway vehiclcs under a variety of control standards. Table A-22 summarizes the effects of the various growth cases and emissions standards on 1995 NO_x emissions projections.

Two cases have been selected from among the 18 projected emissions levels to represent a likely *lower and* upper bound for emissions estimates. The lower-bound

[48]*Nitrogen Oxides*, National Academy of Sciences, 1977, and *MVMA Motor Vehicle Facts and Figures '81*, September 1981.

[49]*National Air Pollutant Emissions Estimates, 1970-1978*, U.S. Environmental Protection Agency, EPA-450/4-80-002, January 1980.

Table A-21.—1980 U.S. NO_x Emissions From Highway Vehicles (10^3 tons)

Eastern region		Western region	
State	NO_x	State	NO_x
Alabama	127	Alaska	13
Arkansas	74	Arizona	87
Connecticut	87	California	696
Delaware	20	Colorado	87
District of Columbia	13	Hawaii	20
Florida	328	Idaho	33
Georgia	194	Kansas	74
Illinois	281	Montana	27
Indiana	174	Nebraska	54
Iowa	80	Nevada	27
Kentucky	120	New Mexico	47
Louisiana	100	Oklahoma	120
Maine	33	Oregon	80
Maryland	13	South Dakota	27
Massachusetts	154	Texas	482
Michigan	281	Utah	40
Minnesota	120	Wyoming	20
Mississippi	74		
Missouri	154		
New Hampshire	27		
New Jersey	221		
New York	341		
North Carolina	187		
Ohio	321		
Pennsylvania	308		
Rhode Island	27		
South Carolina	107		
Tennessee	147		
Vermont	13		
Virginia	127		
West Virginia	54		
Wisconsin	147		
31 + D.C. total	4,454	West total	1,934
		U.S. total	6,388

SOURCE: Michael P Walsh, "Motor Vehicle Emissions of Nitrogen Oxides," OTA contractor report, Nov. 30, 1981.

Table A-22.—1995 Highway Vehicle NO_x Emission Projections

Emissions standards			1995 nationwide emissions (1,000 tons)		
Auto[a]	Light truck[a]	Heavy truck[b]	No growth	Low gowth[c]	Medium growth[d]
1.0	1.2	1.7	3,067	3,759	4,767
1.0	1.2	4.0	3,633	4,608	5,725
1.0	1.2	6.0	4,104	5,287[a]	6,487
1.5	1.7	6.0	4,764	6,052	7,514
2.0	2.3	10.7	5,868	7,469	9,193[b]
None	None	None	7,950	9,880	12,438

%Grams/mile.
bGrams/brake horsepower-hour.
[c]Low growth:
Autos and light trucks grow 1% per year.
Heavy gasoline trucks decline 2% per year,
Heavy diesel trucks grow 4% per year.
'Medium growth:
Autos and light trucks grow 3% per year.
Heavy gasoline trucks decline 2% per year.
Heavy diesel trucks grow 5% per year.

SOURCE: Michael P. Walsh, "Motor Vehicle Emissions of Nitrogen Oxides," OTA contractor report, Nov. 30, 1981.

scenario assumes low growth, retention of the 1.0 gram per mile (gpm) automobile standard currently in effect for 1981 and later model cars, and a tightening of light- and heavy-duty truck standards to 1.2 gpm and 6.0 grams per brake horsepower-hour respectively, as the 1977 Clean Air Act Amendments require. By 1995, this would result in a 21 -percent reduction from current NO_x mobile-source emissions.

The upper-bound scenario assumes medium growth, retention of the current light- and heavy-truck standards rather than any tightening, and a rollback of the automobile standard to 2.0 gpm. This would result in a 37-percent increase in NO_x mobile-source emissions over 1980. Assuming a low-growth scenario with these same emissions standards would result in only a 12-percent NO_x increase over 1980 levels.

costs of Automobile Emissions Controls

Estimates of the costs and fuel-economy implications of emissions controls are highly controversial. The Bureau of Labor Statistics has estimated that between 1975 and 1979, pollution control devices have increased the cost of new automobiles by about $ 165—approximately 10 percent of the total cost increase for new cars during the same 5 years. EPA and manufacturers' estimates of the costs[50] of meeting statutory automobile emission standards of 0.4 gpm **HC,** 3.4 gpm CO, and 1.0 gpm NO_x are presented in table A-23. Control cost estimates vary widely; the General Motors' (GM) estimate of $720/car is about double that of EPA, and is 50 percent higher than Ford's. Differences in technology among manufacturers, and the difficulty of allocating the costs of multipurpose components to particular objectives (e. g., emissions reductions, as opposed to the resulting improvements in fuel economy or vehicle performance), probably account for a substantial amount of the variation. The differences narrow when NO_x controls are looked at alone: Ford, EPA, and Chrysler show only a $27/vehicle spread in estimates of savings associated with a change in standards from 1 to 2 gpm NO_x—ranging from $48 to $75/vehicle. GM's estimate is still substantially higher, at $188/vehicle.

Inspection and maintenance (1/M) programs offer an alternative approach to reducing NO_x emissions from mobile sources. A recent study concluded that adding NO, testing to an existing I/M program for HC and CO would add about $4/inspected vehicle, and that having 20 percent of the vehicles repaired (at an average cost of $50 each) could result in about a 10-percent reduction in NO_x emissions.[51] An EPA analysis concluded that the cost-effectiveness of an I/M program for NO_x control would range from $400 to $500/ton of NO_x eliminated if added to an existing HC/CO program, or $1,700 to $2, 700/ton if started up exclusively for NO_x control .52

[50]"The Cost of Controlling Emissions nf 1981 Model Year Automobiles," U S Environmental Protection Agenc y, June 1981; **testimony** bv **Michael** Walsh before **the** Health and Environment Subcommittee, **U S House of** Representatives, **Sept. 21, 1981,** and letter **from** Betsy Ancker-Johnson, General Motors to D ouglas Costle, U S Env ironmental Protection Agenc y, Sept **2,?,]980**

[51]"**A Study of the Relationship** Between **Motor** Vehicle Emissions and **Attainment of National Ambient Air** Quality **Standards, Part 1 Nitrogen** Dioxide, **SRI International,** February **1981.**

~? Internal EPA memo, Tom Cackette to **M** ichael **P** Walsh, Jan **9, 1981.**

Table A-23.—Costs of Emissions Controls for Automobiles

Autos	Cost differential per vehicle: 1983 cars v. uncontrolled	NO_x costs per vehicle: 1 gpm v. uncontrolled	NO_x costs per vehicle: 1 v. 2 gpm
EPA	370[c]	$123	50
Ford	500	167	48*
GM	725	242	188
Chrysler	—	—	75

a1983 car costs are based on emissions standards of 0,41 HC/3.4 CO/1.0 NO_x grams per mile.
bAssumes that emission control costs of 1963 cars are equally divided between HC, CO, and No_x.
cEPA estimates that this would drop to $330 by 1966 as systems are refined.
dAssumes that 613 percent of cost estimated by Ford for CO, high altitude and No_x control— $80 per car—is attributable to NO_x control, This is a high estimate, based on Chrysler's estimate that 60 percent of its costs for CO and NO_x control Is due to NO_x alone.

SOURCE: Michael P Walsh, "Motor Vehicle Emissions of Nitrogen Oxides," OTA contractor report, Nov. 30, 1961.

A.6 POTENTIAL SECONDARY ECONOMIC EFFECTS OF EMISSIONS CONTROL PROGRAMS

Emissions controls and the associated costs are likely to have the greatest effects on three sectors of the economy: high-sulfur coal mining, industries that depend heavily on electricity consumption, and the electric utility industry. This section discusses ways in which these industries might be affected by a major program to reduce sulfur dioxide (SO_2) emissions in the Eastern United States.

Potential effects on the coal industry are quantified on the basis of several hypothetical SO_2 emissions reduction scenarios; qualitative estimates of the degree of vulnerability are provided for electricity-intensive industries and the electric utility industry. However, it should be noted that both the degree and nature of the potential impact on these sectors would depend on the type and magnitude of the chosen control program, the way in which reductions are allocated, and the way in which control costs are allocated. Thus, the discussions provided below are intended to give only a general indication of these sectors' relative vulnerability to the effects of emissions controls.

Coal Production and Related Employment

Coal Reserves and Current Production

Many legislative proposals for controlling acid rain have focused on reducing SO_2 emissions in the Eastern United States. Emissions reductions designed to control acid rain might cause significant shifts in the coal market by increasing the value of low-sulfur coals as compared to high-sulfur coals. Because the sulfur content of coal varies from region to region throughout the United States, any emission reduction strategy that relies even in part on "switching' to lower sulfur coals can potentially affect the regional distribution of coal production and employment. Social dislocations could accompany these changes in the coal market, as some areas experience rapid economic growth while others decline.

Figure A-6 shows the location of the Nation's coal deposits. Three factors influence regional coal production from these reserves: 1) mine-mouth prices (the cost of production), 2) transportation costs (the distance between the mine and the consumer), and 3) fuel characteristics (primarily a coal's energy value and sulfur content). 53 Acid rain control measures would affect the existing production patterns by increasing the value of low-sulfur coal relative to high-sulfur coal, all other factors remaining equal.

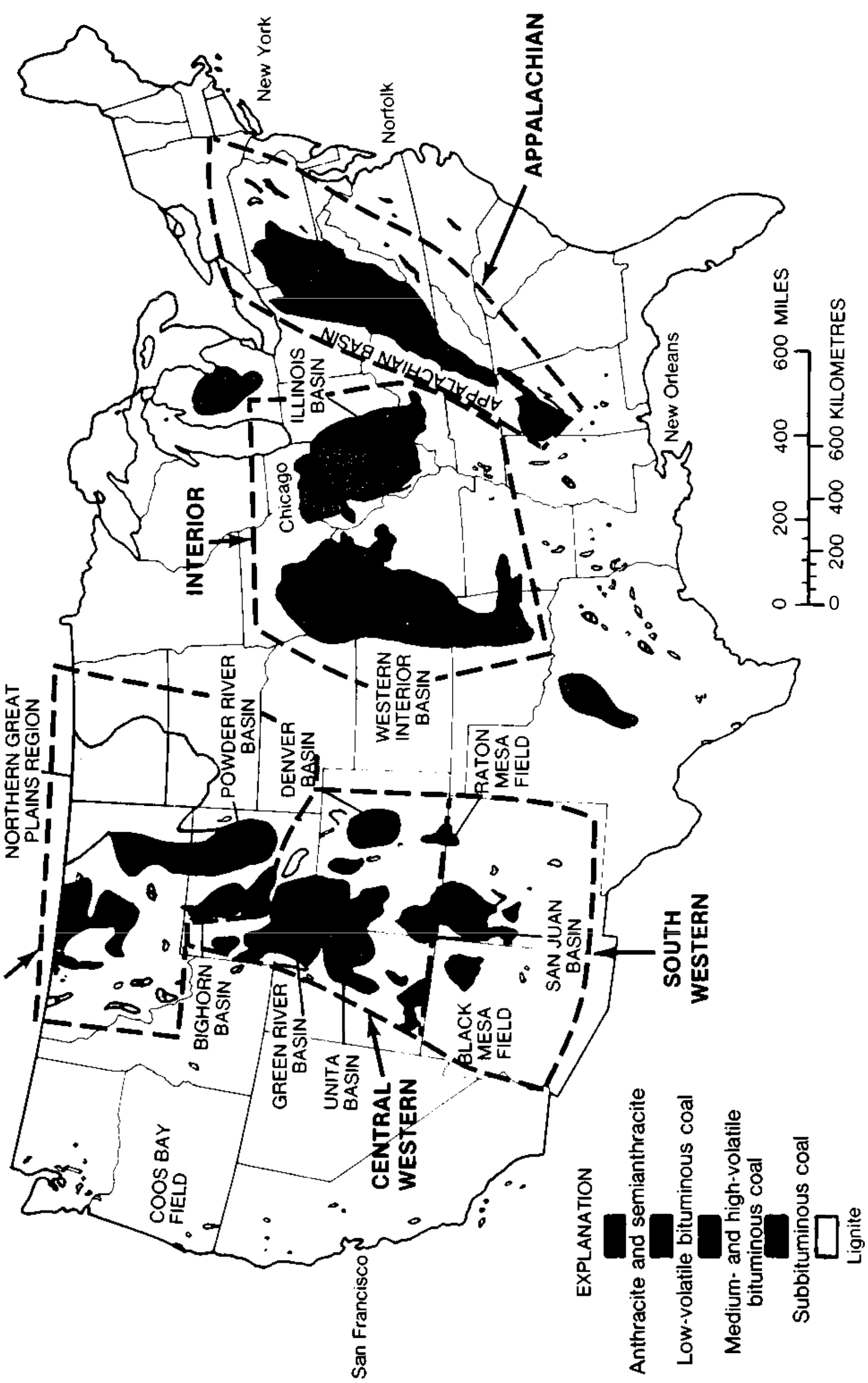
Table A-24 displays the distribution of each State's coal reserves by sulfur content category. Figure A-7 shows a distinctive difference in the sulfur content of coal reserves between the Eastern and Western United States. A large majority (74 percent) of coal reserves in the Eastern United States are high in sulfur (greater than 2.0 pounds per million Btu (lb/MMBtu) of SO_2). By contrast, the majority (72 percent) of Western reserves are low in sulfur (less than 1.2 lb/MMBtu). The two significant Eastern exceptions to this pattern are Kentucky and West Virginia, both of which have significant quantities of reserves above and below 1.2 lb/MMBtu.

Table A-25 displays each State's coal production for the utility market. The first column presents each State's coal production, in millions of tons, for the utility market in 1980. The second column shows what proportion of that production would not allow utilities to comply with a 1.2 lb/MMBtu SO_2 emission limit without applying control technologies. The third column presents the percentage of this ''noncompliance' coal sold on the spot market, i.e. , sales not covered by a long-term contract between a utility and a mining company. Noncompliance coal sold on the spot market is likely to be most vulnerable to more stringent SO_2 regulations. The final column shows the portion of noncompliance coal exported to other States—an indicator of the potential efficacy of State-level policies designed to minimize coal market disruptions.

[53] For a discussion of the factors affecting the choice of coal, see Congressional Budget Office, *The Utility Industry, the Coal Market, and the Clean Air Act*, April 1982; and Martin Zimmerman, *The U.S. Coal Industry: The Economics of Public Choice* (Cambridge, Mass.: MIT Press, 1981).

● The degree to which contracts constrain fuel-switching is a major uncertainty in this analysis. In 1980, 88.5 percent of coal purchased was purchased on contract. It is not clear whether changes in environmental regulations would absolve purchasers of their contractual obligations. A contract can contain provisions (e.g., "force majeure" clauses) which directly address the obligations of parties in the event of changes in environmental regulations. Buyer or seller could be relieved of all or part of the contractual obligations. See Scott, "Coal Supply Agreements," 23 *Rocky Mountain Law Institute* 107 (1979).

Figure A-6.—Coalfields of the Conterminous United States



SOURCE: P. Averitt, *Coal Resources of the United States, Jan. 1, 1974*, U.S. Geological Survey Bulletin 1412, at 5, 1975.

Table A-24.—Demonstrated Reserve Base by Sulfur Category (quantities in millions of tons, sulfur categories in lb SO_2/MMBtu)

State	<0.9	0.9-1.2	1.3-1.5	1.6-2.0	2.1-3.0	3.1-4.0	4.1-5.0	5.1-6.0	>6.0	Total
Alabama	5	1,775	1,712	1,074	1,756	438	0	0		6,760
Georgia	0	0	4	0	0	0	0	0	o	4
Illinois	0	0	0	4,359	1,581	3,151	3,107	14,248	41,260	67,705
Indiana	o	212	992	1,304	503	453	2,018	1,976	3,161	10,621
Kentucky	0	10,210	3,846	1,473	410	749	1,556	7,524	8,472	34,240
Maryland	0	1		296	65	175	178	107	0	826
Michigan	0	0	0	0	95		26	0		128
North Carolina	0	0	11	0	0	0	0	0	0	11
Ohio	0	0	0	0	1,119	1,294	6,684	4,429	5,509	19,035
Pennsylvania	16	568	587	1,992	8,581	12,203	3,757	1,684	1,039	30,428
Tennessee	0	189	135	154	154	62	234	31	39	998
Virginia	784	1,469	458	561	148	118	0	0	0	3,538
West Virginia	3,407	13,724	2,932	2,791	6,029	3,084	3,535	355	4,128	39,985
Eastern U. S. total	4,212	28,149	10,681	14,005	20,440	21,726	21,096	30,353	63,616	214,277
Alaska	5,805	18	332	0	0	0	0	0	0	6,155
Arizona	o	0	0	399	25	0	0	0	0	424
Arkansas	0	11	23	260	43	74	0	0	0	411
Colorado	7,800	2,212	4,841	213	1,150	0	0	0	0	16,215
Idaho	0	0	4	0	0	0	0	0	0	4
Iowa	o	0	0		0	0	0	71	2,127	2,199
Kansas	o	0	0	0	o	190	123	210	472	995
Missouri	0	0	0	0	0	0	518	0	5,559	6,077
Montana	84,247	32,786	1,410	1	1,527	0	0	0	499	120,469
New Mexico	1,277	508	2,701	7	48	0	0	0	0	4,541
North Dakota	564	165	1,961	2,908	2,244	1,524	604	0	0	9,971
Oklahoma	8	750	280	26	332	144	0	21	83	1,644
Oregon	12	0	0	6	0		0	0	0	17
South Dakota	0	0	193	74	0	99	0	0	0	366
Texas	o	0	0	0	12,693	o	0	0	0	12,693
Utah	399	4,733	158	0	178	1,033	0	0	0	6,502
Washington	843	16	0	578	0	143	0	0		1,580
Wyoming	33,527	8,560	1,007	24,214	2,606	4	0	0	95	70,014
Western U.S. total	134,482	49,761	12,911	28,685	20,845	3,212	1,246	302	8,835	260,279
United States	138,694	77,909	23,592	42,690	41,285	24,938	22,341	30,655	72.451	474.556

SOURCE: Adapted for Office of Technology Assessment by E. H. Pechan & Associates from U.S. Department of Energy, Demonstrated Reserve Base of Coal in the United States on Jan l, 1979, DOE/EIA-0280(79) May, 1981.

Changes in Regional Coal Production, Employment, and Economic Activity

METHODS OF PROJECTING REGIONAL COAL PRODUCTION

This appendix projects regulation-induced changes in regional coal production using results from a computer model modified by ICF, Inc., from the DOE National Coal Model. ICF's Coal and Electric Utilities Model (CEUM) makes it possible to compare: l) projected regional coal production in 1990 (and 2000) assuming that current SO_2 emissions standards are maintained, to 2) projected regional coal production in 1990 (and 2000) insignificant SO_2 emissions reductions, designed to control acid rain, are required. The ICF model has been used to project the effects of acid rain control proposals by: the Environmental Protection Agency, the Department of Energy, the Edison Electric Institute, and the National Wildlife Federation, and National Clean Air Coalition. ICF did not perform the model analyses discussed here for OTA, but for the other groups mentioned above.

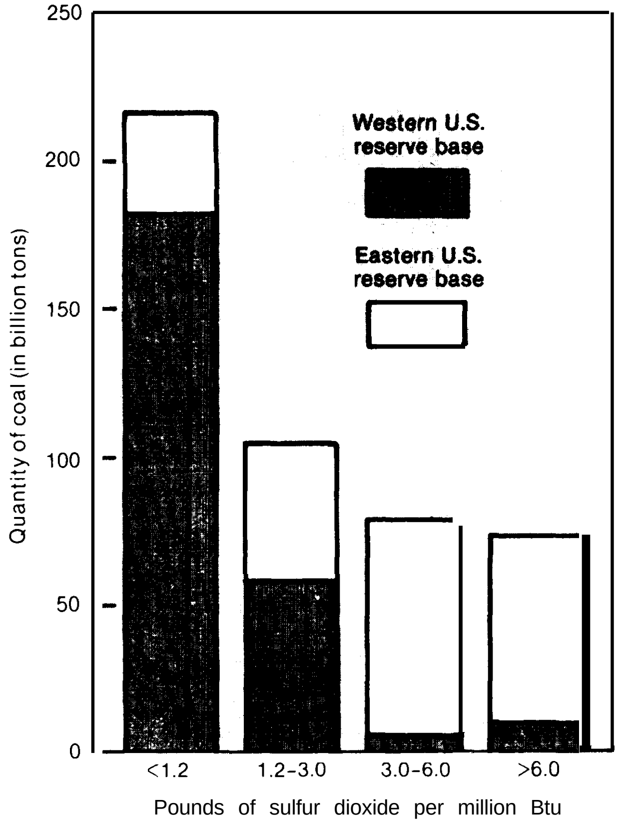
CEUM is a "least-cost optimization model" that chooses the combination of scrubbers, coal washing, and low-sulfur coal substitution or blending that minimizes the utility industry's emissions reduction costs. 54 Changes in utility coal consumption patterns alter regional patterns of coal production. These projected production shifts form the basis for OTA's estimates.

This report uses four ICF SO_2 emissions reduction scenarios, and their attendant regional coal production scenarios, to analyze the potential magnitude of coal market impacts:

1. Scenario I: a 5-million-ton decrease in utility SO_2

[54]For a description of ICF's Coal and Electric Utilities Model see the executive summary in ICF, Inc., *Capabilities and Experience in the Coal and Electric Utility Industries*, May 1981.

Figure A-7.—Demonstrated Reserve Base by Sulfur Content



SOURCES: Office of Technology Assessment, and E. H. Pechan Associates, 1982.

emissions by 1990, allocated according to a "regional (31-State) least cost" approach;

2. Scenario II: a 10-million-ton reduction of SO_2 emissions by 1990, allocated according to utility emissions in excess of an emissions rate of 1.2 lb/MMBtu;
3. Scenario III: a 13-million-ton reduction by 1990, allocated according to a formula similar to (2) above; and
4. Scenario IV: a 10-million-ton reduction, allocated according to a "regional least cost" approach, showing regional coal production shifts out to **2000.**[55]

[55]Scenario I was performed by ICF for DOE and EPA. See *Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions*, draft report, September 1981. Scenarios II and III were performed by ICF for the Edison Electric Institute. See the EEI memo dated Feb. 8, 1982, on ICF analysis of the Mitchell Bill (S. 1706). Scenario IV was performed by ICF for the National Wildlife Federation and National Clean Air Coalition. See *Cost and Coal Production Effects of Reducing Electric Utility Sulfur Dioxide Emissions*, Nov. 14, 1981.

The model cannot predict how various acid rain proposals would, in practice, be implemented. These scenarios merely illustrate the potential magnitude and direction of coal market shifts associated with various reductions in SO_2 emissions, when costs to the utility industry are minimized. Some analysts assert that the ICF model seriously underestimates the probable extent of fuel-switching, while others suggest that its fuel-switching estimates are overstated. *

In addition, changes in model assumptions cause future coal production estimates to vary considerably. OTA considers that the chosen scenarios reasonably represent the relative magnitude of fuel-switching and scrubber use.

Several important factors that might influence the accuracy of ICF's projections are:

- Innovation in pollution control technology: The likely extent of fuel-switching depends on the cost of that approach as compared to other emission reduction options. The ICF model reflects the best available estimates of current costs for various control options. If innovations were to significantly reduce the costs of control technology relative to fuel-switching, smaller changes in regional coal production would accompany any given level of emissions reductions.
- Utility regulatory policy: State regulatory policies may make certain emissions reduction options more attractive to utilities. For instance, provisions that allow utilities to pass increased fuel costs through to consumers without undergoing a rate hearing may make fuel-switching more attractive to utility managers than the ICF model would suggest.** The final section of this appendix addresses potential effects of State regulatory policies in greater detail.
- Transportation costs: Railroad rates govern the penetration of low-sulfur Western coal-into Eastern and Midwestern utility markets. A rapid escala-

*For analyses asserting that ICF underestimates fuel-switching, see the testimony of Chris Farrand of Peabody Coal Co. on S. 1706 to the Committee on Environment and Public Works, U.S. Senate, Oct. 29, 1981. If this is the case, the projections presented here have underestimated the magnitude of regional redistribution of production.

On the other hand, utility analyses of how this bill would be implemented for their systems show little evidence of potential coal market disruptions. An analysis by American Electric Power (the Nation's largest utility and coal consumer) states that only 4 of their 27 units would switch to lower sulfur fuels, while the others would retrofit scrubbers or be retired. See AEP, "Economic Impact Summary of Mitchell Bill (S. 1706) on Customers of the AEP System," Feb. 23, 1982.

**Many public utility commissions do not allow utilities to earn a return on capital investment (e.g., a scrubber) until it becomes operational. Thus, because changes in fuel prices can be passed on immediately to consumers, utilities might prefer fuel-switching. This could be counteracted somewhat by provisions allowing utilities to earn cash returns on "construction work in progress" before the equipment becomes operational. The final section of this appendix surveys and discusses State regulatory policies for public utilities in the Eastern United States.

Table A-25.—Coal Production for the Domestic Utility Market

State	1980 production for utility market (millions of tons)	Percentage noncompliance	Percentage noncompliance sold on spot market	Percentage noncompliance exported to other States
Alabama	15.8	82.50/o	17.3 "/0	10.1%
Arizona	10.5	0.0	0.0	0.0
Colorado	13.6	7.1	0.4	2.8
Illinois , ...	53,4	99.9	6.6	66.0
Indiana	27.3	99.9	8.3	22.1
Iowa	0.4	95.9	14.5	0.0
Kansas	0.7	100.0	29.3	81.7
Kentucky	112.4	89.9	16.5	72.9
East.	73.9	83.2	19.0	75.1
West	38.5	100.0	11.8	68.7
Maryland	1.2	100.0	22.8	24.7
Missouri	5.0	100.0	6.9	33.5
Montana	27.9	63.6	0.0	51.9
New Mexico	17.0	69.8	0.3	1.2
North Dakota. . . .	15.3	99.2	13.6	20.8
Ohio	34.3	100.0	18.9	26.5
Oklahoma.	2.7	98.6	17.3	98.6
Pennsylvania	50.9	99.1	29.9	30,1
Tennessee	7.6	86.7	17.6	34.6
Texas	27.0	100.0	0.0	0.0
Utah	8.5	20.0	1.1	7.1
Virginia.	13.8	87.5	10.6	71.0
West Virginia. . . .	53.1	81.3	8.1	39.4
North	30.8	97.8	7.5	46.1
South	22.3	58.5	8.8	30.1
Wyoming	89.7	16.6	0.9	9.9

a"Noncompliance" coal is defined as coal that would not permit utilities to comply with an emissions limit of 1.2 lb of SO_2/MMBtu without applying control technologies.

SOURCE: From DOE/EIA Form 423 data, supplied to OTA by E. H. Pechan & Associates.

tion in Western rail rates could raise the delivered price of Western coal, thereby reducing the magnitude of regional shifts.

- Electricity growth rates: While the rate of growth in electricity demand should not significantly affect the extent of fuel-switching as opposed to other control options, projected increases in the amount of coal produced by 1990 are highly dependent on assumptions about the rate of growth in electricity demand.

FORECASTING COAL MINE EMPLOYMENT AND ECONOMIC CHANGES

OTA combined production estimates from the ICF model with coal-miner productivity and income data to project the effects of acid rain control scenarios on regional employment and economic activity. Employment in the coal-mining industry is determined by two factors: the level of coal production (tons of coal) and the rate of worker productivity (tons of coal produced per miner). Historically, employment levels have been affected more by changes in productivity than by changes in production. * * * Therefore, employment forecasts must provide for uncertainties about future productivity levels. This analysis presents projected coal-mine employment changes as ranges reflecting different assumptions about future productivity levels: a lower bound of a 10-percent decline from 1979 productivity levels and an upper bound of a 30-percent increase. *

'•● Over the period 1960 to 1970, coal-mine employment declined from 190,000 to 144,000, a 3-percent average annual decrease. Over the same period, coal product ion increased from 434 million to 613 million tons, an average annual increase of 4 percent The discrepancy between employment and production trends is accounted for by increases in average coal-miner productivity during this period The average coal production per miner increased from about 12 to about 18.5 tons per day-an average annual increase of nearly 4 percent The inc reining proportion of surface mining—from 32 percent of annual production (or 139 million tons) in 1960 to 44 percent (or 270 million tons) in 1970 —accounts for some of the gains, since the average surface mmer produces about three times as much coal per day as the average underground miner

*These productivity ranges have been chosen somewhat arbitrarily The 30-percent increase in productivity was chosen as one bound because it reflects the historic al maximum The 10-percent decrease was chosen to account for factors that may contribute to decreased product ivity, such as more stringent mine health and safety or surface reclamat ion regulations, or a shift from surface to underground mrning After a steady decline over the past 12 years, productivity is finally beginning to rise again, but future trends are uncertain For a discussion of factors affecting worker productivity in coal mining see Office of Technology Assessment, *Direct Use of Coal*, OTA-E-86, April 1979, ch IV See also Electric Power Research Institute, *The Labor Outlook for the Bituminous Coal Mining Industry*, EPRI EA- 1477, final report, August 1980

These employment projections are combined with miner income data to estimate the "direct" income effects of acid rain controls.

However, direct income effects do not reflect the full impact of changes in coal-mine employment. Economic activities dependent on the coal-mining industry, such as rail transport and retail services to coal-mine industry employees, are also affected. These indirect economic effects are likely to be quite significant, but are extremely difficult to estimate. Indirect effects include reduced employment, reduced income to the employed, or some combination of both. In this analysis, direct income effects are combined with an income "multiplier" —a very rough approximation of the regional economic activity that depends indirectly on coal mining—to derive "total income effects of acid rain control scenarios.**

PROJECTED PATTERNS OF CHANGE

Table A-26 summarizes how 5-, 10-, and 13-million-ton SO_2 emissions reductions might affect regional coal production, employment, and economic activity. Several generalizations emerge from the analysis. First, the model projects significant growth in coal production nationwide (about 60 percent) between 1979 and 1990. Second, regulations designed to control acid rain, even those calling for the largest emissions reductions, do not alter the projected increases in national production. Even with the additional costs of acid rain controls, coal is projected to retain its competitive advantage over other fuels.

Third, while acid rain control measures are not projected to change nationwide production levels, the ICF model projects a redistribution of coal production among regions. Regions with low-sulfur reserves are projected to experience production growth beyond what would occur under current regulations. On the other hand, between 1979 and 1990, production in regions with high-sulfur reserves is projected to decline below currently projected 1990 levels, and—in the case of the 10-million-ton and greater reductions of SO_2 emissions—below 1979 production levels as well. The projected redistributions increase in magnitude as SO_2 emissions reductions increase, but by less than linear proportions.* Figure A-8 shows the projected change in regional coal production from 1979 to: 1) 1990 levels, assuming no change in SO_2 standards; and 2) 1990 levels, assuming a 10-million-ton decrease in SO_2 emissions.**

The areas most likely to experience significant growth in production are southern West Virginia, eastern Kentucky, and the regions west of the Mississippi (particularly Colorado). The regions most likely to experience significant production declines include northern West Virginia, Ohio, western Kentucky, and Illinois. However, available model projections for 2000 suggest that production declines below current levels may be reversed in the decade following 1990. Production levels are projected to rebound due to general trends in the energy market, such as growth in utility demand, and to the fact that an increasing number of new plants regulated under New Source Performance Standards will come online after 1990.

Employment patterns are projected to correspond to changes in production. However, uncertainties regarding future productivity trends create a larger range of uncertainty for employment effects than for production effects. The loss of portions of the market for high-sulfur coal could reduce employment opportunities in Midwestern and northern Appalachian regions by about 10 to 40 percent of projected 1990 coal-mining work force levels under current emissions standards. The areas of northern West Virginia, Ohio, western Kentucky, and Illinois are projected to experience actual employment decreases below 1979 levels for emissions reductions of 10 million tons and greater.

Future employment changes would be accompanied by proportional changes in direct miner income and total monetary effects. For each of the high-sulfur coal regions of northern Appalachia and the Midwest, these costs range from $250 million to $500 million in direct annual income losses to miners, and from $600 million to $1,100 million in total (direct plus indirect) annual monetary losses. The coal-related benefits in central Appalachia range from $400 million to $550 million annually in direct income gains, and total annual income gains of $750 million to $1,100 million. Estimates of benefits in the West range from $100 million to $150 million in direct income gains and total income gains of $500 million to $750 million per year. All estimates are in 1981 dollars. These figures, particularlyin the case of total monetary impacts, must be considered very rough estimates.

Changes in coal-related employment and income may cause some additional community-level social and economic repercussions. In areas projected to experience significant declines in employment, decreases in tax rev-

---

** To arrive at employment estimates, OTA divides projected production increases by State-by-State productivity data developed from DOE data. These employment changes are then combined with miner salary data to arrive at direct income effects. Indirect economic impacts were estimated using an "economic base technique." For each State, multipliers were developed by calculating the ratio of income derived from the "base" or "primary" sector to income derived from the "service" or "secondary sector."

* As emissions reduction requirements increase beyond a certain level, the proportion of reductions that are projected to be met by "fuel-switching" decreases relative to the proportion met by scrubbers.

** Of the 90 million tons of annual production lost by the Eastern and Midwestern high-sulfur coal market by 1990, about 50 million tons is gained by Eastern low-sulfur producers and 40 million tons by Western producers.

Table A-26.—Summary Table of Regional Coal Market Effects of Acid Rain Control Legislation

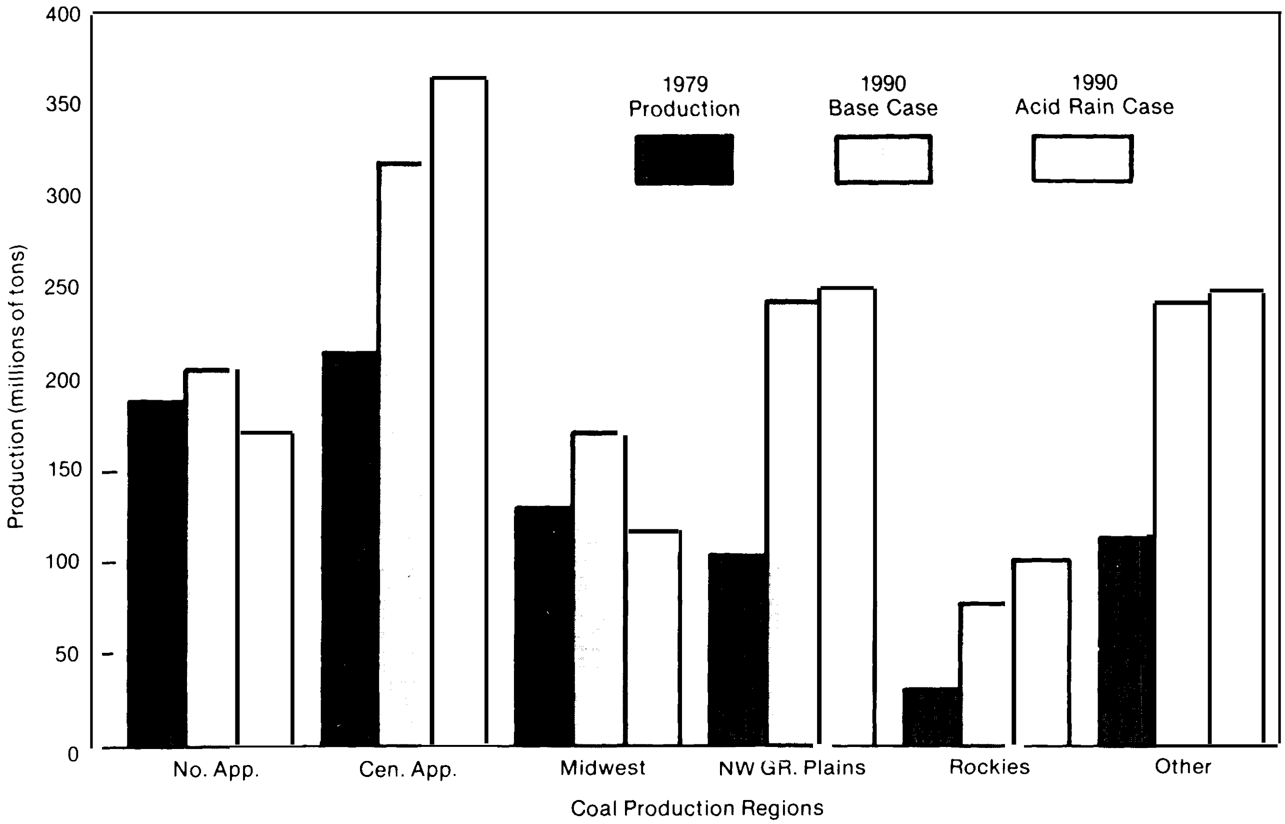
5-million-ton sulfur dioxide emission reduction	10-million-ton sulfur dioxide emission reduction	13-million-ton sulfur dioxide emission reduction
***North Appalachia Region (Maryland, northern West** Virginia, Ohio, and Pennsylvania)*		
Under current environmental regulations, annual coal production is projected to increase approximately 10 percent between 1979 and 1990; under a 5-million-ton acid rain control program no change in production is projected over this period. Employment opportunities foregone are projected to range from 6,300 to 9,100 jobs (a 10-percent reduction); because there is no projected production change, employment changes from 1979 levels will be a function of productivity changes only. Direct income opportunities foregone by the regional economy are projected to be $160 million to $230 million; total income opportunities lost could range from $450 million to $640 million.	Under a 10-million-ton acid rain control program, production is projected to decrease by about 10 percent between 1979 and 1990. Employment is projected to be 15 percent (9,800 to 14,100 jobs) less than it would have been under the 1990 base case; projected employment changes from 1979 levels range from no change to a 30-percent (23,000 job) decrease. Direct income opportunities foregone range from $250 million to $360 million; total income foregone ranges from $630 million to $910 million. Available projections for the year 2000 suggest these declines may only be temporary.	Under a 13-million-ton acid rain control program, production is projected to decrease by about 13 percent between 1979 and 1990.1990 employment levels are projected to be 20 percent (12,700 to 16,500 jobs) less than what they would have been in 1990 under current regulations, and 14 to 35 percent (10,800 to 26,100 jobs) below 1979 employment. Direct income opportunities foregone range from $330 million to $470 million; total income foregone is projected to be $810 million to $1,170 million.
Central** Appalachia **Region (eastern Kentucky, southern West Virginia, Tennessee, and Virginia)		
Under current environmental regulations, annual coal production is projected in increase by about 50 percent between 1979 and 1990); under a 5-million-ton acid rain control program, a 62-percent increase is projected over this period. Employment is projected to be about 10 percent (8,800 to 12,700 jobs) greater than it would have been in 1990 under current regulations; projected employment changes from 1979 levels range from 25- to 80-percent (21,800 to 69,900 jobs) increase. Direct annual income opportunities created in this region range from $230 million to $330 million; total annual income created ranges from $450 million to $840 million.	Under a 10-million-ton acid rain control program, production is projected to increase 70 percent between 1979 and 1990.1990 employment levels are projected to be about 15 percent (15,000 to 21,700 jobs) greater than they would have been in 1990 under current regulations, and 38 to 99 percent (33,200 to 86,500 jobs) greater than 1979 employment levels. Direct income opportunities created are projected to be $390 million to $560 million; total income generated ranges from $1,030 million to $1,490 million.	Under a 13-million-ton emission reduction, production is projected to increase 75 percent between 1979 and 1990.1990 employment levels are projected to be 16 percent (17,300 to 25,000 jobs) greater than what they would have been in 1990 under current regulations, and 40 to 100 percent (35,800 to 90,000 jobs) above 1979 levels. Direct income opportunities created by the projected increase in coal production range from $440 million to $640 million; total income generated ranges from $1,200 million to $1,700 million.

Table A-26.—Summary Table of Regional Coal Market Effects of Acid Rain Control Legislation (continued)

5-million-ton sulfur dioxide emission reduction	10-million-ton sulfur dioxide emission reduction	1 3-million-ton sulfur dioxide emission reduction
Midwest ***Region (Illinois, Indiana, and western Kentucky)***		
Under current environmental regulations, annual coal production is projected to increase 31 *to* 34 *percent between 1979 and 1990;* under a 5-million-ton reduction, production is projected to increase 12 percent over this period. 1990 employment levels are projected to be 16 percent (5,400 to 7,700 jobs) less than what they would have been in 1990 under current regulations, and between a 13-percent (4,200-job) decrease and a 25-percent (8,000-job) increase from 1979 levels. Direct income opportunities foregone range from $140 million to $200 million; total income foregone ranges from $370 million to $530 million.	Under a 10-million-ton acid rain control program, production is projected to decrease 10 percent between 1979 and 1990. 1990 employment levels are projected to be 33 percent (10,500 to 15,200 jobs) below what they would have been in 1990 under current regulations, and 6 to 35 percent (1,900 to 11,300 jobs) less than 1979 employment. Direct income opportunities foregone are projected to range from $270 million to $390 million; total income foregone ranges from $770 million to $1,100 million. Projections for the year 2000 suggest these declines may be reversed in the period 1990 to 2000.	Under a 13-million-ton sulfur dioxide emission reduction, production is projected to decrease by 17 percent between 1979 and 1990. Employment is projected to be 38 percent (12,100 to 17,400 jobs) below what it would have been in 1990 without an acid rain control program; projected employment decreases from 1979 levels range from 13 to 40 percent (4,200 to 12,900 jobs). Direct income opportunities foregone range from $.310 million to $480 million; total income foregone ranges from $870 million to $1,200 million.
The *Western United* States		
Under current environmental regulations, annual coal production is projected to increase approximately 138 percent between 1979 and 1990; under a 5-million-ton acid rain control program, production is projected to increase 145 percent over this period. 1990 employment levels are projected to be 3 percent (1,200 to 1,700 jobs) higher than what they would have been in 1990 under current regulations, and 80 to 160 percent (16,600 to 32,900 jobs) above 1979 levels. Direct income opportunities created by acid rain controls are projected to range from $30 million to $40 million; total income benefits are projected to be $120 million to $170 million.	Under a 10-million-ton acid rain control program, production is projected to increase 158 percent between 1979 and 1990.1990 employment is projected to be 13 percent (4,600 to 6,700 jobs) greater than what it would have been in 1990 in the absence of acid rain controls, and between 95 and 180 percent (19,100 to 36,300 jobs) greater than 1979 levels. Increases in direct income opportunities range from $120 million to $170 million; total income increases are projected to range from $510 million to $740 million.	Under a 13-million-ton sulfur dioxide emission reduction, production is projected to increase 165 percent between 1979 and 1990. Acid rain controls are projected to increase employment opportunities by 20 percent (6,800 to 9,800 jobs) over what they would have been in 1990 without any change in environment regulations. 1990 employment levels are projected to be 105 to 196 percent (21,000 to 39,300 jobs) greater than 1979 levels. Direct income opportunities created in the region are projected to range from $180 million to $250 million; total income benefits range from $750 million to $1,100 million.

SOURCE: Office of Technology Assessment, based on coal production estimates from ICF, Inc.

Figure A-8.— Regional Coal Production: Effects of a 10. Million. Ton Sulfur Dioxide Emission Reduction



SOURCE: Office of Technology Assessment, adapted from ICF, Inc

enues could cause the quantity or quality of community services to decline. In areas projected to experience rapid increases in employment, the capacity of communities to provide adequate health care, housing, education, etc. , may be strained.

RESULTS OF OTHER STUDIES

The United Mine Workers (UMW) has also calculated the potential effects of a 10-million-ton reduction in SO_2 emissions, allocated as in OTA's Scenario II. The UMW analysis presents three sets of estimates of effects on mineworker employment and economic activity in high-sulfur coal areas only, assuming that fuel-switching would account for 50, 75, or 100 percent of the required reductions. However, the UMW analysis made no calculation of gains in employment and economic activity in low-sulfur coal areas, or of the net effects of the 10-million-ton emissions cutbacks.

Table A-27 shows the UMW projections of job losses, direct annual economic losses, and total annual economic losses for the three levels of fuel-switching. Using a DOE estimate that between 50 and 75 percent of the reductions required under a major acid rain control program would be met by fuel-switching, the UMW 'calculated that between 40,000 and 60,000 coal mining jobs would be lost in high-sulfur coal areas, producing direct annual income losses of $1.1 billion to $1.6 billion, and total economic losses ranging between $3.0 billion and $4.6 billion.[56]

For comparison, OTA estimates of the net effects of the 10-million-ton reduction on high-sulfur coal areas are also presented in table A-27. Two factors must be considered in comparing these estimates:

1. OTA used projections of increases in coal production, including increases due to construction of new electricity plants, through 1990, and compared them to projections of how further emissions controls would affect these new production levels. UMW estimates are calculated from 1981 production levels, assuming that no changes in production occur up to the time that controls would be implemented.

[56]United Mine Workers, " Employment Impacts of Acid *Rain*. June 1983

Table A-27.—Employment and Economic Effects on High-Sulfur Coal. Producing Areas of a 10-Million-Ton Reduction in SO_2 Emissions—Comparison of UMW and OTA Analyses

	UMW estimates percent of emissions reductions achieved through fuel switching			OTA estimates	
	50	75	100	Change from 1990 base case[a]	Change from actual 1979 levels
Employment losses[b]	40,000	60,000	80,000	23,000-33,000	9,000-38,000
Direct annual economic losses (millions 1981 dollars)[c]	$1,100	$1,600	$2,100	$600-$800	$200-$1,100
Total annual economic losses	***$3,000***	***$4,600***	***$6,100***	***$1,600-$2,300***	***$600-$2,700***

aOTA assumes, based on ICF analyses, that the requisite emissions reductions will be met by a combination of fuel-switching and scrubbers The base case assumes no change in environmental regulations.
bThese employment losses occur over the period required to implement the pollution reductions. The ranges reflect uncertainty in future productivity levels OTA bounds employment and economic estimates by assuming that productivity might rise as much as 30 percent or decrease by as much as 10 percent between 1979 and 1990,
cAnnual monetary estimates assume implementation of emissions reductions over 10 years, and that shifts in coal production are distributed equally over that period

SOURCE Office of Technology Assessment, based on coal production estimates by ICF, Inc

2. In the OTA estimates, employment losses in high-sulfur coal areas are partially compensated for by employment gains. Thus, the OTA estimates are of the net effects in high-sulfur coal-producing regions. No projected employment increases are figured into the UMW analysis.

OTA's best estimates of potential effects on high-sulfur coal regions show employment impacts about half as large as those estimated by UMW, assuming 50 to 7.5 percent fuel-switching. * The most pessimistic of the OTA estimates—38,000 jobs lost from actual 1979 levels —approximates the low-end UMW figure of 40,000.

Possible means of' preventing or decreasing coal miner unemployment that may ensue from acid rain control legislation are discussed in chapter 7 under question 8. They include mandating control technologies to achieve emissions reductions, thereby prohibiting fuel switching and employing sect ion 125 of the Clean Air Act to restrict coal consumption to ''local or regional coals.

The net effect of acid rain legislation on nationwide coal product ion, employment, and economic activity, howevrer, also includes the offsetting increases in employment and economic activity in low-sulfur coal regions. When these are considered in aggregate, OTA estimates that no significant changes in employment and economic activity result from control-induced product ion changes.

Electricity-Intensive Industries

OTA used 1979 and 1980 data from the L[T]. S. Census Bureau's *Annual Survrey of Manufacturers* to assess the electrical energy dependency of approximate}' 450 types of industries.[57] Specific industries for which electricity represents 4 percent or more of the total value of shipments, and/or 10 percent or more of the total ''value added, * are listed in table A-28. The 17 industries identified in the table are largely concentrated in the areas of primary metals; chemicals—particularly industrial inorganic chemicals; and stone, clay, and glass products. The identified industries account for a disproportionate share of U. S. industrial electricity use—although they account for only 2 percent of total value of shipments and 2 percent of total value added by American manufacturers, they purchase approximately 25 percent of the electricity sold to industry, and account for about 16 percent of utility revenues from industrial electricity sales.

Five of these industrial categories—electrometallurgical products, primary zinc, primary aluminum, alkalies and chlorine, and industrial gases—are especially electricity intensive; the cost of purchased electricity equals about 40 percent or more of their total value added, and about 10 to 25 percent of their total value of shipments. These industries might be considered most

*UMW's estimate of 40,000 to 60,000 jobs lost is compared to OTA's estimate of 23,000 to 33,000. Although the estimation procedures differ somewhat, both estimates calculate changes from a hypothetical base case, and thus come closest to providing a reliable basis for comparison.

[57]U.S. Department of Commerce, Bureau of the Census, *1980 Annual Survey of Manufacturers: Fuels and Electric Energy Consumed*, August 1982.

*''Total value added'' is the difference between the value of goods and the value of the materials purchased to manufacture them.

Table A.28.—Statistlcs on Electricity-intensive industries

Industry	SIC code	Value of shipments (10° 1980$)	Electricity purchased (10^6 kWh)	Electricity cost as percent of: Value added	Value of shipments	Electricity rate ¢/kWh (1982$)	Ratio to industrial average rate (3.84¢/kWh)
Cotton seed oil mills	2074	1,033.7	540.7	10.7	2.0	4.61	1.20
Manufactured ice	2097	169.6	460.7	15.6	11.0	4.70	1.23
Particle board	2492	512.4	825.1	11.4	4.8	3.44	0.90
Alkalies and chlorine	2812	1,354.1	10,679.5	45.5	19.6	2.89	0.75
Industrial gases	2813	1,539.6	11,958.6	42.4	24.5	3.66	0.95
Other industrial inorganic chemicals	2819	12,095.9	37,092.0	13.9	7.5	2.86	0.75
Carbon black	2895	498.0	540.4	13.3	3.5	3.78	0.99
Reclaimed rubber	3031	38.3	75.4	12.2	7.8	4.62	1.20
Cement, hydraulic	3241	3,962.4	9,237.9	15.3	8.2	4.08	1.06
Lime	3274	598.8	813.8	10.8	5.1	4.38	1.14
Mineral wool	3296	2,235.4	2,703.5	7.3	4.0	3.82	0.99
Electrometallurgical products	3313	1,249.3	6,814.3	42.0	13.8	2.94	0.77
Malleable iron foundries	3322	521.2	1,015.5	11.9	7.0	4.17	1.09
Primary zinc	3333	413.1	1,487.8	51.7	8.3	2.67	0.70
Primary aluminum	3334	6,979.9	72,279.1	39.3	15.6	1.75	0.47
Other primary nonferrous metals	3339	1,906.6	4,279.4	15.6	5.1	2.66	0.69
Carbon and graphite products	3624	1,183.3	2,171.8	7.5	4.2	2.64	0.69

SOURCE: US. Census Bureau, 1980 *AnnualSurvey of Manufacturers: Fuels and Electric Energy Consumed*, August 1982.

sensitive to potential increases in the cost of electrical power resulting from further control of SO_2 emissions. For all five of these industries, a substantial proportion of production occurs in the 31 Eastern States.

Primary zinc is the most concentrated industrial category —only five producers currently operate in the United States. The three largest manufacturers are located in Pennsylvania, Illinois, and Tennessee, and account for approximately three-quarters of the Nation's current production. The zinc industry appears to be particularly vulnerable to increases in the cost of production —U.S. annual production capacity fell from about 1 million tons to 300,000 tons over the past decade, and foreign producers have captured a substantial share of domestic sales.[58]

Primary aluminum, by far the largest of these industries, is produced in 13 of the 31 Eastern States. Although two non-Eastern States—Texas and Washington—currently have the largest production capacities, the Eastern United States currently accounts for about 60 percent of national production capabilities. Major producers in the region include: Alabama, Arkansas, Indiana, Kentucky, Louisiana, Missouri, New York, Ohio, and Tennessee.[59]

Production of alkalies and chlorine is about equally divided between the Eastern and Western regions of the United States. Louisiana accounts for nearly one-quarter of national output; the 17 other Eastern States in which these chemicals are produced together account for a slightly smaller proportion of production.[60] Alabama, New York, Michigan, and West Virginia are the fifth, sixth, eighth, and ninth largest producing States in the country, respectively.

Information on the distribution of industrial gas production is limited, due in part to confidentiality requirements for protecting individual manufacturers. Available data indicate that Texas and California were the highest producing States in the late 1970's, and show substantial amounts of production in the following Eastern States: Alabama, Delaware, Illinois, Louisiana, New Jersey, New York, Ohio, Pennsylvania, and Tennessee.[61]

Over 90 percent of U.S. electrometallurgical products (i. e., specialized metal alloys made with such metals as molybdenum, manganese, and chromium) were produced in the 31 Eastern States in 1981. Ohio accounted for about one-third of national production; six additional States—Alabama, Kentucky, New York, South Carolina, Tennessee, and West Virginia—together accounted for slightly under one-half of national production. The industry is highly vulnerable to foreign competition, as countries with deposits of the necessary ores are rapidly developing their own production capabilities.[62]

[58]Personal communication, James Kennedy, Bureau of Industrial Economics, U S Department of Commerce, October 1983

[59]Ibid

[60]Personal communication, Frank Maxey, Bureau of Industrial Economics, U.S Department of Commerce, October 1983

[61]Ibid

[62]Personal communication, Tom Jones, Bureau of Mines, U S Department of the Interior. December 1983

Uncertainties about how utilities might apportion control-related increases in electricity rates make it difficult to assess the likely extent of financial effects on electricity-intensive industries. As shown in columns 3 and 6 of table A-28, many of these industries are large-scale electricity consumers, and pay relatively low electricity rates. If control costs were apportioned to users primarily on the basis of current rates (i. e., increasing existing rates by a uniform percentage for all users), effects on these industries, although potentially significant, would not be disproportionate to cost increases undergone by all electricity consumers. However, if control costs were apportioned primarily on the basis of electricity consumption (i. e., increasing existing rates by a uniform mill/kWh fee for all users), percentage rate increases would be highest for those industries currently paying low electricity rates. Effects could be particularly severe for those industries having both low rates and high electricity dependency-primary aluminum, alkalies and chlorine, electrometallurgial products, and primary zinc.

Utilities in the Eastern 31 States*

The amount of SO_2 that an individual utility must eliminate from its emissions is, of course, the primary determinant of the effect of acid rain control legislation on a given company's finances. Such factors as each utility's ability to raise capital to cover construction costs and regulatory policies in any given State further determine a utility's ability to pay for required reductions without adverse financial effects.

To address the utility sector's vulnerability to further emissions reductions, this section will: 1) present 1980 State-average SO_2 emissions rates for coal- and oil-burning plants to indicate the potential extent of additional control requirements, 2) use available financial indicators for 1980 to assess the health of each State's utility sector, 3) assess the implications of State regulatory policies in 1980-81 for utility finances, and 4) integrate the first three types of information in concluding observations, identifying areas of particular vulnerability, where possible.

Current Emission Rates and Generating Capacities

Figures A-9 and A-10 rank States in the Eastern United States according to their coal- and oil-fueled electrical generating capacities, and by average 1980 emission rates for all coal- or oil-fueled plants in the State. The greater a State's dependence on either of these fossil fuels, and the higher its average SO_2 emission rate, the greater the likelihood that proposed emissions controls would require additional utility expenditures to reduce emissions. States with the greatest probability of extensive expenditures for emissions control appear in the upper left portion of each table; those with the least, appear at the bottom right. Overall, emission rates for coal-fired utilities are substantially higher than for oil-fired facilities; thus, many more States would be exposed to significant control expenditures on the basis of current utility coal combustion than oil combustion. Detailed estimates of SO_2 emissions reductions required, by State, under a number of alternative control scenarios, are provided in section A. 3 of this appendix.

Utility Financial Positions

Ultimately, a utility recoups its emission-reduction expenditures by selling power to customers in its service area, or to other utilities. However, a utility must shoulder the burden of pollution control expenditures from the time they are made until it is allowed to begin charging customers for them. Substantial capital investment is required to retrofit existing powerplants with emissions control devices, or to build newer, cleaner powerplants. Capital investment may also be necessary to modify existing powerplant operations to permit the burning of low-sulfur fuel. The utility's capacity to finance these expenditures depends in large part on its ability to attract investment capital.

To place the potential capital-raising burden associated with acid rain control into perspective, estimated costs of major control programs can be compared to actual utility construction expenditures. Over 5 years (1978 through 1982), electric utilities spent approximately $180 billion (1982 dollars) for construction in the United States;[63] potential construction costs of major acid rain control proposals over a similar 5-year period might range from about 5 to 20 percent of this figure, depending on the particular proposal. Control costs would constitute a higher proportion of construction expenditures for particular States and/or utilities from which large emission reductions would be required. Such capital-raising burdens may be particularly critical for those utilities already scheduled to replace or retire a substantial proportion of plants over the period in which further emissions controls would be implemented.

A number of indicators are in use to assess utilities' competitive positions in capital markets, and no single measure of financial well-being can adequately charac-

*This section based primarily on Kathleen Cole, Duane Chapman, and Clifford Rossi, "Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control," prepared for the Office of Technology Assessment, U.S. Congress, August 1982

[63] Merrill Lynch, Pierce, Fenner & Smith, Inc., "Utility Industry, A Statistical Review (Preliminary), April 1983

Figure A-9.—Coal-Based Generating Capacities and SO_2 Emissions Rates

Coal dependency
(Share of total electric-generating capacity)

Average SO_2 emission rates from coal-fired utilities (lb per million Btu)

Missouri (4.6)[a] Indiana (4.2) Ohio (3.9) Kentucky (3.6)	Wisconsin (3.6) New Hampshire (3.6) Illinois (3.1)	Florida (3.5)
Georgia (2.9) West Virginia (2.7)	Pennsylvania (2.8) Delaware (2.4) Iowa (2.3) Alabama (2.3) Michigan (2.0) South Carolina (2.0)	New York (2.8) Maryland (2.5) Mississippi (2.3)
	Minnesota (1.6) North Carolina (1.5)	Massachusetts (1.6) Virginia (1.4)

a Numbers in parentheses are state-average SO_2 emission rates for coal-burning plants, expressed In lbs. of SO_2 Per million Btu

SOURCE Off Ice of Technology Assessment, from E H Pechan & Associates, Inc., and K. Cole, et al., "Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control, " OTA contractor report, August 1982.

Figure A-10.—Oil-Based Generating Capacities and SO_2 Emissions Rates

Oil dependency
(Share of total electric-generating capacity)

Average SO_2 emission rates from coal-fired utilities (lb per million Btu)

New Hampshire (2.1) Massachusetts (1.8) Florida (1.6)	South Carolina (2.0)	Mississippi (2.7) Georgia (1.9)
Maine (1.4) New York (1.3) Delaware (1.1) Vermont (1.1) Rhode Island (1.0)	Arkansas (1.5) Maryland (1.3)	Minnesota (1.5) Alabama (1.5) Virginia (1.4) Wisconsin (1.2) Ohio (1.2) Missouri (1.1) North Carolina (1.1) Indiana (1.1) Kentucky (1.1) Louisiana (1.0)
New Jersey (0.7) Connecticut (0.5)	Pennsylvania (0.8)	Illinois (0.8) Iowa (0.8) Michigan (0.8)

aNumbers in parentheses are State. average SO_2 emission rates for oil-burning plants, expressed in lbs. of SO_2 Per million Btu.

SOURCE Off Ice of Technology Assessment, from E. H Pechan & Associates, Inc , and K. Cole, et al., "Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control, " OTA contractor report, August 1982.

terize a utility's prospects. However, two major financial criteria were selected to describe utility financial conditions at the State level: 1) return on common equity (ROCE), and 2) bond ratings. The first represents common stockholders net earnings during a given year—indicating the utility's current profitability. The second represents experts' judgments about the utility's long-term ability to reliably repay debt. The lower a utility's bond rating, the higher the interest rate it will need to offer to induce investors to purchase bonds.

Table A-29 categorizes States according to 1980 data on whether more than 50 percent of their electrical power was generated by utilities with: 1) bond ratings of A or better, and 2) ROCEs above the 1980 national median of 11.1 percent per year. Column A lists States meeting both of these criteria; these States may be considered to have a relatively healthy investor-owned electric utility sector. Column D lists States that met neither of the above criteria. These eight States may be regarded as particularly' vulnerable to measures requiring utilities to generate additional capital for pollution-control purposes. Columns B and C show States failing to meet either of the two criteria.

Utilities may be at greater risk from capital-raising needs if control-related expenditures must be added to significant amounts of non-control-related construction—either to replace retired plants or to accommodate increasing electricity demand—during the period in which further controls would be implemented. While increasing demand for electricity could, in itself, positively influence utilities' positions in capital markets, requirements for replacing retired plants carry high capital costs without necessarily enhancing utility positions. States in which more than 20 percent of current generating capacity is scheduled for replacement by 1995 include: Arkansas, District of Columbia, Maryland, Massachusetts, New York, and Rhode Island.

State Regulatory Policies

Public utility commissions (PUCs) in each State make numerous regulatory decisions that affect a utilitys ability to pass on costs associated with emissions control. PUC regulatory policies vary widely from State to State; [65] they may also change over time in response to

[64]Personal communication, E. H. Pechan, from U.S. DOE Generating Unit Reference File (1981).

[65]Sally Hindman, Duane Chapman, and Kathleen Cole, *State Regulatory Policies for Privately Owned Electric Utilities in 1981*, University Research Group on Energy, New York State College of Agriculture and Life Sciences, Cornell University, Ithaca, N.Y., October 1982.

Table A-29.—Summary of 1980 Utility Financial Conditions by State[a]

A. High bond, high ROCE	B. High bond, low ROCE
States in which more than 50 percent of generated power was from utilities with bond ratings of Aa or A, and ROCEs of 11.1 percent or lower: (national median):	States in which more than 50 percent of generated power was from utilities with bond ratings of Aa or A, and ROCEs below the national median:
Iowa	Delaware
Kentucky	Illinois
Maryland[b]	Indiana
Massachusetts[b]	New York[b]
Minnesota	Rhode Island[b]
Mississippi	South Carolina
New Jersey	
Wisconsin	
C. Low bond, high ROCE	**D. Low bond, low ROCE**
States in which more than 50 percent of generated power was from utilities with bond ratings of Baa or lower, and ROCEs above the national median:	States in which more than 50 percent of generated power was from utilities with bond ratings of Baa or lower, and ROCEs below the national median:
Alabama	Arkansas[b]
Georgia	Connecticut
Louisiana	Florida
Missouri	Maine
New Hampshire	Michigan
North Carolina	Pennsylvania
Ohio	Vermont
West Virginia	Virginia

aBased on data from 106 surveyed utilities in the Eastern 31-State region Extremely small utilities, utilities with no generating capacities (electricity distributors), and utilities with no coal or oil generating capacities have been excluded.
bStates in which more than 21) percent of current generating capacity is scheduled for replacement by 19%,

SOURCE Office of Technology Assessment, adapted from K Cole, et al., 'Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control, " OTA contractor report, August 1982 changing economic and political conditions. Imposing stricter emissions controls at the Federal level might induce considerable changes in affected States' utility regulations; thus, current regulations may not reliably indicate how State-level policies would influence utility finances. However, to demonstrate the range of current regulatory conditions, survey information on five major regulatory policies for each of the Eastern 31 States during 1980-81 is outlined in table A-30.

Two of the surveyed policies directly concern the delay required before adjustments in utility costs can be passed on to consumers. Each involves short-term delays—the number of months required, on average, for State utility commissions to rule on requests for rate increases (co1. 4), and the number of times per year that utilities are allowed to adjust electricity rates according to changes in fuel costs (co1. 3). The frequency of allowable fuel cost adjustments is particularly significant to those utilities for which switching to more expensive, low-sulfur coal or oil is a potential means of meeting more stringent emissions limits.

Three of the policies assessed in table A-30 affect the manner in which utility rates are calculated. PUCs must determine a total amount of utility expenses and costs, or calculated revenue requirements, allowed to be passed on to consumers, in order to set a utility's electricity rates. One major component of these costs is the return on capital investments. The first column of table A-30, "allowed return on common equity" or ROCE, shows the maximum return to investors allowed by each State, calculated as a percentage of a utility's assets, or rate base. The second column of the table, ' 'amount of CWIP allowed in rate base, indicates the extent to which ' 'construction work in progress' (CWIP) is considered a part of the utility's assets for ratemaking purposes.

Table A-30.—Major State Regulatory Policies

State	Allowed ROCE (median: 14.25)	Amount of CWIP allowed in rate base	Frequency of adjustment for fuel price changes	Average number of months for rate decisions (median: 8.5)	Type of test year
Alabama	12.85	100 "/0	Quarterly	6	Historical
Arkansas	15.0	100%[a]	Monthly	10	Historical
Connecticut	14.8	0	Monthly	5	Historical
Delaware	15.0	100 "/0	Monthly	7	Forecast
Florida	15.5	Varies	Monthly	8	Forecast
Georgia	13.33	Varies	Quarterly	6	Forecast
Illinois	16.5	Varies	Irregular-as needed	11	Forecast
Indiana	15.83	0	Quarterly	6	Historical
Iowa	13.35	0	Monthly	12	Historical
Kentucky	14.25	100 "/0	Monthly	10	Historical
Louisiana	14.33	100 "/0	Monthly	12	Historical
Maine	15.13	0	Quarterly	9	Historical
Maryland	14.0	100 "/0	Monthly	7	Forecast
Massachusetts	14.31	0	Quarterly	6	Historical
Michigan	13.25	100%	Monthly	9	Forecast
Minnesota	14.0	100 "/0	Monthly	12	Forecast
Mississippi	12.85	Varies	Monthly	6	Forecast
Missouri	13.71	0	No clause	11	Historical
New Hampshire	14.75	0	Quarterly or monthly	6	Historical
New Jersey	14.0	Varies	Irregular-as needed	8	Forecast
New York	15.5	Small %[b]	Monthly	11	Forecast
North Carolina	13.87	100 "/0	3/year	7	Historical
Ohio	15.86	Varies	Biannually	9	Forecast
Pennsylvania	15.63	Small 0/0	Yearly	9	Forecast
Rhode Island	14.13	0	Quarterly	8	Historical
South Carolina	13.88	100%	Biannually	12	Historical
Vermont	14.5	Small 0/0	No clause	21	Historical
Virginia	15.0	100%	Biannually	5	Historical
West Virginia	14.0	Varies	Biannually	10	Historical
Wisconsin	12.72	0	Monthly	8.5	Forecast

aCWIP to be in service within 1 year is allowed.
b"Small %" indicates that less than 1O% of CWIP is allowed.

SOURCE. K. Cole, et al., "Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control, " Off Ice of Technology Assessment contractor report, August 1982.

If a State allows construction work in progress (CWIP) to be included in the rate base, utilities begin to earn returns on control-related expenditures as soon as they are made; if not, capital improvements must be financed by the utility until the scrubber or other plant modification is actually operating—a period of up to 4 or more years. For utilities in weak financial positions, the ability to recoup expenditures during a planning and construction period of 4 years or longer may be a significant factor in deciding what means to use to comply with stricter emissions controls. Consequently, States allowing little or no CWIP in the rate base may make capital-intensive approaches to SO_2 abatement less attractive, especially to financially troubled utilities. Such utilities could choose to switch to higher priced, lower sulfur fuels, even when costs for doing so are higher over the long run. Although State PUCs vary considerably in their CWIP expenditure policies, decisions on whether to allow C WI P in the rate base are often made on a case-by-case basis, except in States where allowing CWIP is prohibited by statute. Some analysts consider that States are considerably more likely to allow CWIP for pollution control expenditures to enter a utility's rate base.[66]

It should be noted, however, that some PUCs choose to substitute higher allowed rates of return for allowing CWIP in the rate base as a means of increasing utility revenues during periods of construction activity. For example, table A-30 shows that the States of Indiana, Maine, New York, and Pennsylvania allowed rates of return to exceed 15 percent in 1980, while including little or no CWIP in the rate base. Available data did not permit OTA to estimate the probable effects of such a substitution on control choices.

Finally, the kind of "test year' selected to provide data on expenses and costs (col. 5) can also influence calculated revenue requirements. In times of rising costs, historical test years may tend to understate utility expense estimates, while forecast test years can allow for the projected effects of inflation.

State regulatory policies for 1980-81 are, of course, an imperfect indicator of the probable regulatory climate over the decade or more required to implement further SO_2 restrictions. Public utility commissions could respond to control requirements by adopting policies more favorable to capital construction or fuel-switching, particularly in States burdened with large SO_2 reduction requirements. Such responses are virtually impossible to predict, however; PUCs are affected by a broad array of political and institutional conditions, and must, in their regulatory decision making, balance consumer and producer interests. Concurrently, coal-producing States could constrain utility options for meeting tougher emissions standards by requiring continued use of in-State produced coal. Despite these uncertainties, the information provided in table A-30 can be used as a general barometer of the favorableness or unfavorableness of a State's current regulatory climate.

Combined Indicators

In this section, the three sets of State-level indicators surveyed above- 1980 utility emission rates from coal- and oil-burning plants, measures of short- and long-term utility profitability for 1980, and State regulatory policies for 1980-8 1—are integrated to provide an overall picture of current utility-sector vulnerability to stricter emissions control. It is important to note, however, that this provides only a surrogate for assessing the financial effects of controls at the same time they would be implemented. In addition, changes in such factors as demand for electricity, financial viability of nonfossil fuel electricity generation, interest rates, inflation, and the price of coal, oil, and gas could greatly affect the relative vulnerability of the region's utility companies.

Eight States are identified in table A-29 as having financially weak utilities—Arkansas, Connecticut, Florida, Maine, Michigan, Pennsylvania, Vermont, and Virginia. Three of these States have coal-fired utility emission rates of at least 2 lb SO_2/MMBtu: Florida (3.5), Pennsylvania (2.8), and Michigan (2.()). However, less than a third of Florida's electricity-generating capacity is coal-fired; more than half depends on oil, with 1980 SO_2 emissions averaging 1.6 lb/M MBtu. When emission rates from all utility fuel sources are considered, only Pennsylvania is among the upper 15 States in the region, ranking 11th with an average rate of' 2.5 lb SO_2/MMBtu.

Pennsylvania utilities may also be of particular concern due to current State regulations governing fuel cost increases and calculated revenue requirements. While Florida and Michigan utilities are allowed monthly fuel cost adjustments, those in Pennsylvania are allowed only one per year.

Utilities in Michigan are allowed relatively low ROCEs, while 100 percent of CWIP is allowed in the rate base; both Florida and Pennsylvania allow' above-average ROCEs, but Florida allows ''varying' amounts of CWIP in the rate base, while Pennsylvania includes only small portions of CWIP. The remaining five States in the ' 'highly vulnerable' category rank so low in current emissions as to make the probable effect of additional control requirements on their utility sectors quite small.

Utilities in an additional eight States are characterized in table A-29 as having above-average rates of' return and relatively low bond ratings for 1980 (col. C), sug-

[66] Personal communication, Michael Foley, National Association of Regulatory Utility Commissioners, September 1983

gesting potential concerns for long-term profitability. Four of these States combine heavy reliance on coal-fired plants with high average $S0_2$ emission rates from these plants: Georgia (2.9 lb/MMBtu), Missouri (4.6), Ohio (3.9), and West Virginia (2.7). A fifth State, New Hampshire, relies on oil-fired plants for more than half its generating capacity, and has an average oil-fired emissions rate of 2.1 lb/MMBtu.

Six States are identified in table A-30 as having relatively high bond ratings, but low rates of return, for 1980. Of these, Indiana combines strong coal dependency with a very high coal-fired, $S0_2$ emissions rate (4.2 lb/MMBtu), while Illinois has both moderate coal dependency and a relatively high emissions rate (3.1 lb/MMBtu).