tors affect regional utility costs. First, the allocation formula, or specified emission limits, can affect regional generating costs unevenly, depending on its severity relative to emission rates that would prevail under current policy. Second, actual generation can change, based on the least costly combination of generation and interregional transmission (importing or exporting electricity) needed to satisfy regional demands. Finally, the amount of installed retrofit scrubbing capacity can effect the relative prices of high-and low-sulfur coal, which, in turn, can influence utility costs in regions not necessarily affected directly by emission reduction policies. Utilities would purchase retrofit scrubber equipment worth nearly $1.9 billion and $3.6 billion under Options VI-1 and VI-2, respectively. These figures are small, however, when compared with the $24.4 billion that would be invested in scrubbers under Option VI-3.

Effect on Electricity Rates

Average electricity rates nationwide in 1995 would rise by 1.5 percent under Option VI-1, 2.0 percent under the default provision of Option VI-2, and 5.7 percent under Option VI-3, compared with the 2.5 percent increase expected under Option II-2A. The national average, however, obscures the regional variation in predicted rate increases, as Table 46 shows.

Option VI-1 would lead to fairly uniform rate increases, with even the most heavily affected midwestern and eastern states typically experiencing rate increases in the 2 percent to 4 percent range, which are slightly below those expected under Option II-2A. One state, Utah, could experience an average rate increase of over 10 percent. Only part of the rate increase would arise from the cost of reducing utilities' emissions, however. The largest part of the increase would result from the higher prices utilities would have to pay for the low-sulfur coal they regularly use. Increased nationwide demand would push up the price of this coal as utilities switched from the more polluting high-sulfur coal. In addition, Utah utilities would receive less revenue from interstate sales.

Under Option VI-2, rate increases by 1995 would tend to be slightly higher--in the 3 percent to 6 percent range--and would be closer to those expected under Option II-2A. Wisconsin (11 percent) and West Virginia (23 percent) would both exceed the subsidy threshold of 10 percent under H.R. 4567, a provision that does not apply under Option VI-2.

The subsidy clause contained in H.R. 4567 has two important aspects. First, the model used by CBO to predict the electricity rate effects of acid rain legislation computes only statewide averages--a simplifying assumption that could overlook the possible variation in rate increases within a state and between residential and industrial customers. Therefore, some utilities

TABLE 45. ANNUAL UTILITY COSTS AS OF 1995 OF THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of 1985 dollars)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama, Mississippi	4,224	4,364	4,305	4,364	4,628	-59	0	264
Arizona	1,944	1,943	1,938	1,926	1,949	-4	-16	6
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,784	9,601	9,793	61	-122	70
California	10,565	10,822	11,038	10,562	10,567	216	-260	-255
Carolinas, North and South	4,759	4,895	4,900	4,986	5,427	5	91	531
Colorado	1,093	1,100	1,097	1,051	1,068	-3	-49	-32
Dakotas, North and South	567	565	565	577	589	0	12	24
Florida	6,127	6,198	6,181	6,234	6,510	-17	36	312
Georgia	2,555	2,622	2,629	2,640	2,883	6	18	260
Idaho	221	221	221	221	221	0	0	0
Illinois	4,189	4,432	4,328	4,321	4,508	-105	-111	76
Indiana	3,095	3,233	3,253	3,265	3,625	19	31	392
Iowa	1,230	1,327	1,295	1,304	1,393	-32	-23	66
Kansas, Nebraska	1,854	1,862	1,860	1,853	1,928	-2	-9	67
Kentucky	3,103	3,499	3,277	3,228	3,812	-222	-272	313
Maine, Vermont, New Hampshire	1,123	1,123	1,120	1,129	1,150	-3	6	27
Maryland, Delaware	1,885	1,654	1,658	1,929	2,170	4	275	516
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,670	3,534	3,745	-8	-144	67

(Continued)

TABLE 45. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Michigan	2,817	2,944	2,898	3,053	3,215	-45	109	271
Minnesota	1,186	1,228	1,180	1,349	1,391	-48	121	164
Missouri	2,024	2,206	2,179	2,195	2,318	-27	-11	112
Montana	676	675	673	675	674	-2	-1	-2
Nevada	1,096	1,122	1,121	1,104	1,131	-1	-18	9
New Mexico	1,158	1,144	1,144	1,196	1,209	0	52	65
New York (Downstate), New Jersey	4,878	5,200	4,886	5,156	5,216	-314	-43	16
New York (Upstate)	2,395	2,236	2,367	2,282	2,390	131	46	154
Ohio	4,239	4,271	4,498	4,323	4,767	226	52	495
Pennsylvania	5,512	6,056	5,984	5,828	6,198	-72	-228	141
Tennessee	2,078	2,028	2,022	2,450	2,449	-5	422	421
Texas	15,852	15,844	15,843	15,838	15,923	-1	-6	79
Utah	1,345	1,368	1,357	1,355	1,363	-10	-13	-5
Virginia, District of Columbia	1,884	1,926	1,934	1,919	2,221	8	-8	294
Washington, Oregon	4,219	4,068	3,917	4,220	4,216	-151	152	148
West Virginia	1,784	2,278	1,987	2,259	2,638	-292	-20	360
Wisconsin	1,572	1,734	1,724	1,741	1,879	-11	7	144
Wyoming	1,026	1,039	1,035	1,030	1,048	-4	-8	10
U.S. Total	117,380	120,630	119,869	120,699	126,210	-761	69	5,580

SOURCE: Congressional Budget Office.

TABLE 46. ELECTRICITY PRICES IN 1995 UNDER THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama, Mississippi	46.6	45.6	45.9	47.8	49.6	0.7	4.9	8.8
Arizona	55.9	55.9	55.7	55.4	54.4	-0.3	-0.8	-2.6
Arkansas, Oklahoma, Louisiana	77.5	78.8	79.2	77.7	78.9	0.5	-1.4	0.2
California	78.3	78.3	78.4	78.2	78.3	0.1	-0.1	0.0
Carolinas, North and South	50.3	51.2	51.3	52.1	55.9	0.3	1.8	9.3 a/
Colorado	57.4	57.7	57.6	57.6	57.9	-0.2	-0.2	0.4
Dakotas, North and South	32.1	30.4	32.0	31.5	31.3	5.2	3.4	2.9
Florida	75.2	75.9	75.8	76.0	78.3	-0.1	0.1	3.2
Georgia	54.2	56.2	56.2	55.3	60.0	0.0	-1.6	6.8 a/
Idaho	43.0	43.5	43.2	43.1	43.4	-0.6	-0.8	-0.1
Illinois	59.3	62.4	61.2	62.6	64.3	-1.9	0.4	3.2
Indiana	53.9	55.5	55.3	56.5	61.3	-0.4	1.8	10.3 a/
Iowa	59.3	62.3	61.4	61.3	64.9	-1.5	-1.7	4.2
Kansas, Nebraska	57.9	58.4	58.1	57.9	59.5	-0.6	-0.9	1.9
Kentucky	55.0	55.0	55.5	56.3	59.1	1.0	2.5	7.6
Maine, Vermont, New Hampshire	80.9	80.3	80.2	80.9	81.9	-0.1	0.8	2.0
Maryland, Delaware	66.4	69.2	69.3	67.4	70.7	0.1	-2.5	2.2
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.0	81.0	84.8	-0.8	-4.4	0.1

(Continued)

TABLE 46. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Michigan	57.7	58.2	58.1	60.2	61.9	-0.2	3.5	6.3
Minnesota	54.2	55.1	53.9	58.4	60.1	-2.1	6.0	9.0 a/
Missouri	59.6	63.8	63.2	63.5	66.2	-0.9	-0.4	3.8 a/
Montana	41.1	41.0	40.7	41.0	40.8	-0.6	0.1	-0.3
Nevada	48.8	47.0	47.1	48.4	46.3	0.1	2.9	-1.5
New Mexico	68.2	67.2	67.2	67.0	68.1	-0.1	-0.4	1.3
New York (Downstate), New Jersey	99.3	100.3	99.8	99.5	100.8	-0.5	-0.8	0.4
New York (Upstate)	53.1	55.3	52.5	55.8	57.7	-5.0	0.9	4.2
Ohio	57.8	62.2	60.0	60.5	66.0	-3.5	-2.8	6.1 a/
Pennsylvania	58.2	60.0	59.3	61.0	64.7	-1.1	1.6	7.9 a/
Tennessee	46.9	50.7	49.0	48.5	50.6	-3.4	-4.3	-0.1
Texas	79.4	79.4	79.4	79.6	79.3	0.0	0.1	-0.2
Utah	39.0	44.7	45.4	39.6	40.1	1.6 a/	-11.4	-10.2
Virginia, District of Columbia	58.7	60.7	60.2	59.8	64.5	-0.8	-1.5	6.2
Washington, Oregon	35.4	35.4	35.7	35.1	35.1	0.7	-0.9	-0.9
West Virginia	27.2	46.7	25.5	33.5	68.1	-45.3	-28.2 a/	45.8 a/
Wisconsin	52.7	57.9	56.4	58.4	61.9	-2.5	0.9 a/	7.0 a/
Wyoming	43.0	43.5	43.2	43.1	43.4	-0.6	-0.8	-0.1
U.S. Average	62.0	63.5	62.9	63.3	65.6	-0.9	-0.4	3.2

SOURCE: Congressional Budget Office.

a. Electricity rates in these states would increase by over 10 percent compared with base case predictions. Such increases could trigger utility subsidies under one version of the House bill (Option VI-1), but not under Options VI-2 and VI-3.

could experience residential rate increases that would qualify for the subsidy, without driving the statewide average rate increase over the 10 percent threshold. Second, subsidies would be provided to offset either increased fuel expenses (for switching to low-sulfur coal) or the additional cost of scrubber installation. In this regard, the subsidy would not influence the choice of abatement strategy, as did the scrubber subsidies of previous options. 4/

As expected, Option VI-3 would raise rates substantially in most regions, and would outstrip the predicted rate hikes caused by Option II-2A in all eastern and midwestern state. Utilities in the states of North and South Carolina, Georgia, Indiana, Minnesota, Missouri, Ohio, Pennsylvania, West Virginia, and Wisconsin could raise 1995 rates by over 10 percent on average. Rate increases in West Virginia alone could be nearly 150 percent, although this would result mostly from lower revenues from exported electricity. This large increase, however, would make rates for West Virginia customers only slightly higher than the national average expected under Option VI-3, since their base case levels in 1995 would be the lowest in the nation.

Coal-Market Effects of Each Option

Table 47 shows the 1995 coal production, and Table 48 the mining employment expected under the three options (please note that Tables 47 and 48 compare the three options to the polluter pays, 10 million ton reduction (Option II-2A), while the following discussion examines differences from 1995 base case levels). The coal production and employment figures reflect the relationship between the level of emission control and the subsequent economies of scrubber use. As explained before, electric utilities would almost always use low-sulfur coal in order to meet emission limits under the 9.1 million ton reduction required under Option VI-1. While this approach would keep utility costs fairly low, it would also cause a significant decline in the use of high-sulfur coal by 1995. Total annual coal shipments from Illinois, Indiana, Ohio, and Pennsylvania would decline by 57.7 million tons from predicted 1995 levels under the base case, implying that 17,000 fewer mining jobs would be available in this region. This effect is even more pronounced under the reduction required under Option VI-2. This program could reduce expected 1995 production and employment in these states by 62 million tons and 18,100 jobs, respectively.

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4. If subsidies were necessary, the maximum 0.5 mill per kilowatt tax on fossil-fuel fired generation could produce nearly $1.0 billion in 1989, rising to over $1.2 billion annually by 1996, the maximum duration specified in the bill (all figures in undiscounted 1985 dollars).

The prospects for high-sulfur coal production would not worsen, however, as the level of emission reduction was further tightened under Option VI-3, since utilities would find scrubbing both necessary and economical to achieve such low emission rates. While the expense of installing and operating scrubbers would drive utility costs up dramatically, utilities could con-

TABLE 47. 1995 COAL SHIPMENTS UNDER THREE OPTIONS BASED ON TWO RECENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of tons)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama	23.8	22.1	26.3	22.4	19.5	4.2	0.3	-2.6
Arizona	14.2	13.9	13.8	13.8	14.2	-0.1	-0.2	0.3
Colorado	19.1	23.5	23.1	21.4	50.0	-0.4	-2.1	26.5
Illinois	56.4	37.6	41.8	39.5	47.4	4.2	2.0	9.8
Indiana	29.2	19.7	23.8	23.8	23.6	4.1	4.1	3.8
Iowa	1.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Kansas	2.5	0.4	0.4	0.4	1.1	0.0	0.0	0.7
Kentucky	208.9	195.9	196.6	202.8	179.1	0.7	6.9	-16.9
Maryland	2.5	1.5	1.5	1.5	1.5	0.0	0.0	0.0
Missouri	8.1	5.3	5.4	5.4	5.6	0.1	0.1	0.3
Montana	34.0	26.0	26.1	29.0	31.9	0.2	3.0	5.9
New Mexico	31.9	31.9	31.9	31.7	39.5	0.0	-0.1	7.6
North Dakota	22.7	22.7	22.7	19.9	17.0	0.0	-2.8	-5.7
Ohio	24.3	4.0	4.0	1.3	6.6	0.0	-2.7	2.5
Oklahoma	7.7	7.0	7.0	7.0	7.0	0.0	0.0	0.0
Pennsylvania	82.3	56.3	64.9	65.6	68.8	8.5	9.2	12.5
Tennessee	5.3	4.9	6.9	4.9	4.8	2.0	0.0	-0.2
Texas	109.4	108.8	108.8	108.8	108.8	0.0	0.0	0.0
Utah	31.6	32.8	32.0	33.2	36.8	-0.8	0.4	4.0
Virginia	50.6	56.0	56.4	58.0	49.9	0.4	2.0	-6.0
Washington	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
West Virginia	232.2	274.6	269.9	279.5	227.6	-4.7	4.9	-47.0
Wyoming	130.5	191.2	169.1	153.7	204.2	-22.1	-37.4	13.0
U.S. Total	1,128.9	1,137.1	1,133.2	1,124.5	1,145.6	-3.9	-12.6	8.5

SOURCE: Congressional Budget Office.

tinue to purchase high-sulfur coal and still attain low emission rates. Consequently, the decrease in base case 1995 coal production under Option VI-3 for the same four-state region would be only 45.8 million tons, or 13,400 jobs. Therefore, 1995 coal production and employment under Option VI-3 could actually exceed the levels expected in this region under the three less stringent programs, Options VI-1, VI-2, and II-2A.

TABLE 48. DIRECT COAL MINING EMPLOYMENT IN 1995 UNDER THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In miner-years)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Differences from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama	8,124	7,543	8,961	7,640	6,639	1,418	97	-903
Arizona	1,177	1,155	1,146	1,141	1,177	-9	-13	22
Colorado	3,288	4,062	3,986	3,694	8,627	-77	-368	4,564
Illinois	14,733	9,823	10,926	10,333	12,392	1,103	510	2,569
Indiana	5,342	3,611	4,355	4,355	4,311	744	744	700
Iowa	344	110	110	111	111	0	1	1
Kansas	753	129	129	129	343	0	-1	214
Kentucky	63,014	59,098	59,303	61,170	54,010	205	2,072	-5,088
Maryland	695	417	417	419	419	0	2	2
Missouri	1,948	1,276	1,296	1,296	1,337	20	20	61
Montana	1,251	955	961	1,065	1,172	6	110	216
New Mexico	2,846	2,846	2,846	2,835	3,525	0	-11	679
North Dakota	1,375	1,374	1,375	1,204	1,031	0	-171	-343
Ohio	7,136	1,183	1,183	382	1,933	0	-800	750
Oklahoma	2,344	2,146	2,148	2,148	2,148	1	1	1
Pennsylvania	29,299	20,042	23,084	23,333	24,482	3,042	3,291	4,441
Tennessee	2,010	1,859	2,614	1,859	1,794	755	-1	-65
Texas	6,890	6,854	6,854	6,854	6,856	0	0	1
Utah	7,978	8,282	8,074	8,377	9,297	-207	96	1,015
Virginia	19,339	21,375	21,527	22,153	19,067	152	778	-2,307
Washington	48	48	48	48	48	0	0	0
West Virginia	89,473	105,792	103,982	107,681	87,673	-1,810	1,888	-18,119
Wyoming	5,768	8,451	7,474	6,796	9,027	-977	-1,655	576
U.S. Total	275,172	268,431	272,797	275,022	275,418	4,366	6,591	-11,013

SOURCE: Congressional Budget Office.

Compared with other programs, Option VI-3 would reduce the demand for all but the lowest-sulfur coals (that is, those that emit less than 0.8 pounds of SO_2 per million Btus). Although scrubber operation is most economical when used with high-sulfur coal, scrubbers would also be needed to allow medium- and many low-sulfur coals to meet emission limits. In West Virginia, this would mean that expected 1995 coal production would decline by 4.7 million tons, erasing the large gains expected there under the other policies examined in this chapter. In Kentucky, expected production would drop by almost 30 million tons. This shortfall would reduce base case 1995 mining employment in these two states by 10,800 job slots, although it would represent a gain of about 47,000 jobs from current levels, since both states are expected to increase coal production substantially, regardless of policies instituted to decrease SO_2 emissions.

CONCLUSIONS

As emission reduction targets become more ambitious, the costs of achieving them would rise sharply. Average abatement costs would rise from $270 per ton under the 8 million ton reduction (Option II-1A) to $368 per ton under the 10 million ton reduction (Option VI-2). They would increase further to $779 per ton under the 12 million ton reduction (Option VI-3). These increments imply that the cost of abating the final ton of SO_2 (the "marginal" cost) would be substantially higher than the average cost at all levels of control.

In contrast to emission rollback levels in the 8 million to 10 million ton range, demand for high-sulfur coal would not inevitably fall when more exacting rollback targets are sought through very strict emission standards. Increasing the level of emission reduction from 8 million tons to 10 million tons would substantially reduce the production of high-sulfur coal and associated mining employment in the Midwest and Pennsylvania. This effect, however, would be partially offset under the 12 million ton reduction, since some utilities would have no other option but to use scrubbers to achieve the strict emission standards. Because scrubbers are most economical when used with high-sulfur coal, demand for this type of coal would maintain the production level expected under the more lenient 8 million ton rollback.

APPENDIX

APPENDIX

THE NATIONAL COAL MODEL AND CBO ANALYSIS AND ASSUMPTIONS

This appendix describes the analytical approach and assumptions employed by the Congressional Budget Office (CBO) in preparing this report. The appendix is organized into two main sections. The first section explains how the National Coal Model was adapted for this study, and the second discusses additional analysis that CBO performed to transform the output from the National Coal Model into the results reported in the text.

THE NATIONAL COAL MODEL

The National Coal Model Version 5 (NCM5) provides the basis for the analysis performed by CBO. The NCM5 is maintained by the Energy Information Administration (EIA), an independent statistical and analytical agency within the Department of Energy. Three EIA publications describe the NCM5. *Model Description and Formulation* (September 1983) contains an overview of the essential structure of the NCM5, as well a listing of some key data inputs. The *User Manual* (June 1984) explains how to operate the basic version of the NCM5 and how to change input data. Finally, the *Software Manual* (September 1984) documents the source code language and programs that generate the basic model.

The National Coal Model: General Description

The NCM5 is a large linear program (LP) designed to simulate the behavior of the domestic coal market under a variety of assumptions, with particular attention devoted to regional coal demands by electric utilities. The NCM5 generates an equilibrium solution that balances the supply of coal (from 31 regions) and the demand for each coal type (in 44 regions) through an extensive transportation network. The solution of the model minimizes the total cost of coal mining and preparation, coal transportation, and electricity generation and transmission required to satisfy given regional levels of electricity demand and nonutility demands for coal. A set of linear inequalities that constrain the solution represents the physical and technical relationships among the individual activities represented in the model. In addition, bounds on certain activities capture the effect of other exogenous factors, such as currently prescribed emission limits.

By using an LP modelling approch, this analysis assumes that production costs are minimized either through competition or (for electric utilities) by the requirements of regulating authorities. If all coal producers and electric utilities individually minimize cost, then the total cost of all their activities will be minimized as well. Because, under other strict assumptions, market forces essentially solve the allocative problem in the same way that a linear program would, an LP can simulate or predict market outcomes as well as provide prescriptive solutions to resource allocation problems. Of course, the real world does not operate at the level of efficiency suggested by an LP solution and an LP cannot capture all real world subtleties. The biases inherent in such modelling persuade analysts to place more faith in the **differences** among solutions (that is, different policy options) than in the absolute numbers predicted by the model. Such comparative emphasis is reflected in the text of this study.

To examine the underlying structure of the NCM5, it is useful to discuss the coal supply and demand sectors separately, and then explain how an equilibrium solution is attained through the transportation network.

Coal Supply. The coal supply component of the NCM5 expresses the relationships between the annual production of various coals and their minemouth prices. These supply curves are produced by the Resource Allocation and Mine Costing (RAMC) model, also maintained by the EIA. 1/ In each of the 31 coal supply regions, the RAMC generates supply curves for each type of coal, based on demonstrated reserve data, mining techniques, regional factor prices, local regulatory requirements, taxes, royalties, and financial assumptions. Although coal is disaggregated into five energy-content categories (as measured by the British Thermal Unit or Btu) and six sulfur-content categories, no region contains more than 14 of these 30 possible coal types. The RAMC output consists of a step function that gives the minimum acceptable selling price for the coal type as a function of annual regional production, assuming that the coal mining industry is perfectly competitive. The NCM5 then converts the RAMC step functions into piecewise linear supply curves.

Coal Demand. The fundamental problem addressed by the NCM5 is satisfying regional coal demands at the lowest cost. Nonutility demands (metallurgical, industrial, residential-commercial, and export) are given exogenously as regional energy requirements, and remain completely inelastic with respect to the prices of coal or other fuels.

1. For a description of the basic methodology employed, see Department of Energy, Energy Information Administration, *Documentation of the Resource Allocation and Mine Costing (RAMC) Model* (September 1982).

Utility coal demands are derived from the model solution, which minimizes the cost of satisfying fixed regional electricity demands through generation and interregional transmission. Utility coal demand is responsive to the price of coal, the price of other fuels, emission regulations, and the fixed and variable costs of electricity generation and transmission. The primary determinant of overall coal demand, however, remains the assumed regional electricity consumption of base, intermediate, seasonal peak, and daily peak loads.

The NCM5 represents electric utilities in great detail; Table A-1 lists the 34 possible capacity categories. Coal-fired generation is characterized by capital costs (for new plants, retrofit scrubbers, or boiler conversion to subbituminous coal combustion), nonfuel operating and maintenance (O&M) costs, current pollution control equipment, energy efficiencies, allowable coal types, and applicable sulfur dioxide regulations--for example, emission limits set by the New Source Performance Standard (NSPS), Revised New Source Performance Standard (RNSPS), or State Implementation Plans (SIP). Although the NCM5 assigns individual power plants to homogeneous capacity types, fractions of these capacities can be dispatched to satisfy different loads while burning several coal types. Fractions of SIP capacity can be retrofitted as well. This approximates individual plant behavior, while retaining the analytical tractability that results from grouping similar plants together.

Other inputs into the utility component of coal demand include operating costs for hydroelectric, nuclear, oil-fired, and gas-fired generation. Capital costs are given for plant types that utilities are currently allowed to build. Utilities can purchase unlimited quantities of residual or distillate oil and natural gas at fixed regional prices. These fuels are used primarily to satisfy intermediate and peak loads. Lower bounds on new capacity reflect units currently scheduled to commence operation within 10 years, while upper bounds exist to reflect the time required to plan and construct certain plant types.

Transporation and Equilibrium. A transportation network connects the supply and demand components of the NCM5 and provides the mechanism by which the equilibrium solution obtains. Transportation links between specific supply and demand regions consist of a price (dollar per ton) for transport along that link. These tariffs are derived from existing truck, barge, and rail rates through a formula that takes into account the distance, mode, and terrain, as well as the likely effects of competition, congestion, and fuel prices.

The supply, demand, and transportation submodels are linked into an LP matrix. The objective function includes the annual real costs of coal production, coal transportation, coal mixing, electricity generation, electricity transmission, and nonutility consumption of coal. Capital expenditures are converted to annual flows (levelized) by a capital charge rate (capital recovery factor) that depends on the interest rate and asset durability. The sum of the objective function represents the annual real undiscounted cost of satisfying the national demand for electricity and nonutility coal in a given target year. By minimizing this sum--subject to technical, physical, environmental, and material balance constraints--the NCM5 solution provides both a detailed summary of utility decisions and an extensive origin-destination report of coal shipments.

TABLE A-1. NCM5 CAPACITY TYPES

NCM5 Plant Type	NCM5 Plant Definition	Comments
	Coal	
1X	Old coal plant, no scrubber	Unregulated, typically small.
2X	Old coal plant with scrubber	Currently scrubbing.
5X	SIP-1 [a] plant, no scrubber	Up to three emission limits
5R	SIP-1 plant, retrofitted	per region; plants can
6X	SIP-2 plant, no scrubber	choose to meet current
6R	SIP-2 plant, retrofitted	limits by fuel choice or
7X	SIP-3 plant, no scrubber	retrofit scrubber
7R	SIP-3 plant, retrofitted	installation.
8C	SIP-1 convert to subbituminous	Capital cost of conversion
9C	SIP-2 convert to subbituminous	equals $90 per kw, O&M
AC	SIP-3 convert to subbituminous	penalty of 1.77 mills per kwh.
BX	NSPS [b] bituminous, no scrubber	
BR	NSPS bituminous, with scrubber	Plants can choose low-sulfur
CX	NSPS subbituminous, no scrubber	coal or scrubber to meet
CR	NSPS subbituminous, with scrubber	1.2 lb. SO_2 per million
DX	NSPS lignite, no scrubber	Btus SO_2 emission limit.
DR	NSPS lignite, with scrubber	
EN	RNSPS [c] bituminous (scrubber)	
FN	RNSPS subbituminous (scrubber)	Plants must install scrubbers.
GN	RNSPS lignite (scrubber)	

(Continued)

Conceptually, the demand regions seek the least expensive source of energy, given their assumed electricity consumption, specific generation technologies, regulatory constraints, and nonutility coal requirements. The transportation network coefficients convert tons of coal into delivered prices for coal energy (of specific grades and sulfur contents). The delivered price includes transportation and production costs and is expressed in dollars per Btu. All demand regions simultaneously solve the allocation problem--finding the lowest cost distribution of coal--by drawing different types of coal from several supply regions through the transportation network. The mine-mouth prices for coals of various heat and sulfur contents in all supply regions are determined simultaneously as well, and, by con-

TABLE A-1. (Continued)

NCM5 Plant Type	NCM5 Plant Definition	Comments
	Hydroelectric	
HX	Existing hydro (pondage), base	
HN	New hydro (pondage), base	Build limits for new capacity;
IX	Existing hydro (pondage), intermediate	1 kwh of pumped storage re-
IN	New hydro (pondage), intermediate	quires 1.38 kwh of baseload
JX	Existing hydro (pumped storage) peak	generation.
JN	New hydro (pumped storage), peak	
	Nuclear	
KX	Existing nuclear plant	Determined by current and
KN	New nuclear plant	planned capacity.
	Oil and Gas	
3X	Old oil steam plant	
4X	Old gas steam plant	No new oil and gas plants
LX	Existing combustion turbine	currently permitted,
LN	New combustion turbine	except for combustion
MX	Existing combined cycle	turbines.
MN	New combined cycle	

SOURCE: Congressional Budget Office.

a. Plants subject to individual State Implementation Plan (SIP).

b. Plants subject to the first New Source Performance Standard of 1971 (NSPS).

c. Plants subject to the Revised New Source Performance Standard of 1978 (RNSPS).

struction, equal the price needed to induce the total required production of the specific coal from each region. In equilibrium, each type of coal consumed in a demand region carries an identical price (in dollars per million Btus), irrespective of source, while only one regional supply price (in dollars per ton) exists for specific coal types, regardless of destination. [2] The solution also determines interregional electricity transmission based on the least-cost allocation of generation costs, including the resource cost of transmission and distributional losses.

The NCM5 generates solutions for three target years: 1985, 1990, and 1995. The 1990 and 1995 solutions require assumptions regarding future exogenous inputs, such as electricity demand growth, nonutility coal consumption, and rail rates. They also require information from previous solutions, such as the irreversible production decisions that created available capacity. The NCM5 utilizes such information in subsequent solutions, as well as constraining some activities to keep them close to their previous levels. Future solutions, however, have no effect on previous solutions; the model only considers the current annual costs of activities in selecting the cost-minimizing outcome. Therefore, the NCM5 is not a dymanic model in any sense, but rather three sequentially solved static equilibria.

NCM5 Modifications and Enhancements by CBO

Modifications to the Base case and All Policy Simulations. Some of the input cost data in the NCM5 were changed to reflect more current cost estimates or to conform with CBO financial assumptions. Table A-2 lists these changes, as well as several key assumptions retained from the EIA base case as of January 1985.

Of the data inputs not altered by CBO, one set deserves mention. The EIA base case of January 1985 assumed that the real price of residual fuel oil would rise about 3.5 percent annually over 10 years. [3] Very recent trends, however, suggest that oil prices, already lower, could remain stable, or even decline, during this period. This could affect three inputs used in the analysis: predicted electricity demand, utility fuel prices, and rail rates.

2. The existence of lower limits on specific coal shipments will violate the equilibrium condition of a single price for coal of certain types consumed in a particular region. See the discussion of the "RETAIN" feature later in this appendix.

3. For an overview of major assumptions, see Department of Energy, Energy Information Administration, *Annual Energy Outlook 1984* (January 1985). For the NCM5, the EIA adjusts the oil prices to reflect regional variation.

TABLE A-2. CBO ECONOMIC AND FINANCIAL ASSUMPTIONS USED IN THE NATIONAL COAL MODEL

Parameter	Value or Assumption	Comments or Source
Annual Electricity Demand Growth (In percent)		
1985-1995	3.1	EIA Base Case
Annual Nonutility Coal Energy Demand Growth (In percent)		
1985-1990	3.9	EIA Base Case
1990-1995	1.6	
Rail Rates 1985-1995	EIA Base Case	Based on 1984 unit train rates adjusted to reflect future competition, congestion, and lower oil prices.
Real Capital Charge Rate (In percent)	7.7	Based on CBO forecast of utililty financing at 6.5 percent real interest over 30 years.
Capital Charge for Retrofit Scrubbers (In percent)	7.7	Accelerated depreciation rules applied to retrofits offset shorter assumed life of 20 years.
Cost of New Coal-Fired Steam Capacity (In dollars per kilowatt (kw))	1,075	Source: CBO
Scrubber Costs for 90 Percent Control of High-Sulfur Coal, including Sludge Disposal and Spare Modules		Source: Current EPA estimates using the TVA scrubber cost model (except retrofit penalty).
Capital (in dollars per kw)	238	
O&M (in mills per kilowatt hour)	4.28	
Heat Penalty (in percent)	4.81	
Capacity Penalty (in percent)	2.41	
Retrofit Penalty and Boiler Refurbishment (in dollars per kw)	125	Source: CBO
Current Emissions	In compliance	EIA Base Case

SOURCE: Congressional Budget Office.
Note: All dollar figures are in 1985 dollars.

Lower oil prices could increase overall electricity demand by boosting economic growth beyond current projections. The EIA assumes that electricity demand between 1985 and 1995 will increase at an average annual rate of 3.1 percent, based on real gross national product (GNP) increases of 2.7 percent per year. If electricity demand exceeds these predictions, the costs of achieving a specified level of 1995 emissions might rise simply because more generation would be required. By the same reasoning, incentive-based policies could lead to higher emission levels.

On the other hand, power plants that burn oil and natural gas emit far less sulfur dioxide than coal-fired plants. To the extent that utilities could purchase cleaner fuel economically, the cost of an SO_2 abatement policy could decline. Large scale substitution of other fuels for coal, however, might be inhibited by uncertainty about future fuel prices, conversion costs, and regulatory decisions.

Whether overall costs of emission reductions increase or decline because of the two effects described above, it is doubtful that the relative costs of the options considered in this report would change significantly. Lower oil prices, however, could also reduce rail rates, particularly on the longer hauls in which fuel is a substantial component of cost. Lower rail rates could increase western low-sulfur coal shipments to the Midwest, particularly under emission reduction policies. This effect would reduce total utility costs unevenly across policies, as a higher cost differential between fuel switching and scrubbing would increase the relative cost of protecting midwestern high-sulfur coal production. Lower oil prices, therefore, would not alter the basic conclusions presented in the text, but absolute effects might differ.

The CBO adjusted the real capital charge rate (the factor that converts capital expenditures into levelized annual costs) to 7.7 percent. This figure assumes that utilities can finance an asset with a useful life of 30 years by borrowing at a real interest rate of 6.5 percent. No differential was included for retrofit scrubbers, since the current tax laws for accelerated depreciation for pollution control equipment virtually offset the shorter life (20 years) assumed for retrofit scrubbers. The retrofit penalty, however, for installing a scrubber was set at $125 per kilowatt (kw) to account for boiler modifications and additional particulate control that utilities would likely undertake.

Another important CBO modification to the basic model allowed existing state-regulated, coal-fired plants (SIP plants) to reduce emissions below their mandated limits. The SIP generating capacities are essentially defined by their emission limits, and the NCM5 will only allow enough construction