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AN INTERIM REPORT

OVERVIEW AND DISCUSSION OF THE KEY REGULATORY ISSUES IN IMPLEMENTING THE ELECTRIC UTILITY PROVISIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1990

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EXECUTIVE SUMMARY

Title IV of the Clean Air Act Amendments of 1990 (CAAA) created a new regulatory instrument that electric power producers (utilities and others) will be required to possess and expend in order to emit sulfur dioxide (SO_2) into the atmosphere. The emission allowance system created by the CAAA will be grafted onto an already complex system of state and federal electric utility regulation. How public utility commissions (PUCs) and the Federal Energy Regulatory Commission (FERC) regulate these allowances will greatly affect the decisions that electric utilities under their jurisdiction make to comply with the CAAA and, therefore, the cost of compliance to ratepayers.

While individual commissions may not regard the development and success of an allowance market as their responsibility, it will likely benefit ratepayers if it does work. PUCs will play an important role in determining the success of the allowance market. If successful, it will provide utilities with a means that should lead to lower compliance costs than a command-and-control-type requirement of the same reduction in SO_2. One estimate of the savings ranges from \$1 to \$2 billion per year in compliance costs, representing as much as 25 percent of the total estimated compliance costs.

The creation of an allowance trading market can generate these savings because it provides a means through which affected sources with relatively high compliance costs can purchase allowances from sources with relatively low compliance costs. Affected sources unable to install pollution control equipment or other control options for less than the cost of purchasing allowances will be potential buyers of allowances. Sources whose compliance cost is lower than the cost of allowances will be potential suppliers. The price of allowances, therefore, will be determined by the cost of available alternatives to affected sources.

Regulatory guidelines can be developed by the state PUCs and FERC to help ensure that their jurisdictional electric utilities make compliance decisions in the long-term interest of ratepayers. This can be structured such that the commission's involvement in the utility's actual compliance decisions is minimized and, given the goal of minimizing the impact of compliance on ratepayers, provides the utility with an incentive to minimize its own costs.

Three elements should be considered for the guidelines. First, they should provide the utility with a reasonable degree of predictability. Second, the guidelines should allow utilities flexibility in choosing a compliance option. Third, commissions can adopt a ratemaking treatment that does not bias the utility toward a particular compliance option. These elements will help ensure that the utility will make decisions that are in the long-term interest of ratepayers.

It is assumed here that allowances will be valuable assets and that their regulatory treatment should recognize this and determine who owns and should benefit from them. While EPA will allocate the initial allowances at no cost, commissions can determine their value along with what proportion belongs to ratepayers and what belongs to the utility. Current allowance holdings (or inventory) of the utility and all future gains and losses from the transfer of allowances could use this commission-determined proportion.

Congress created the new asset when it passed the CAAA, and the national allowance market itself, if it develops successfully, will determine the price of the allowances. State PUCs and FERC, however, will be determining the value of the allowances for ratemaking purposes and, therefore, the value to utilities. This will have a significant impact on the compliance decisions that utilities make, the ultimate cost of CAAA compliance to ratepayers, and, in turn, the allowance price.

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FOREWORD

Understanding the electric utility provisions of the Clean Air Act Amendments is a formidable task. Gaining a good grasp of the key regulatory issues to which they give rise is even more so. This report is intended to assist regulators on both counts. The first part is a clear exposition of the features of the law; the second presents major issues regulators face and examines how they might be handled. The objective result is the meeting of the Institute's goal--to help elevate the discussion and debate on complex regulatory matters for our NARUC clientele.

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PART I

SUMMARY AND OVERVIEW OF THE ELECTRIC UTILITY PROVISIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1990

Synopsis of the Clean Air Act Amendments of 1990

Title IV of the Clean Air Act Amendments of 1990 (CAAA), "Acid Deposition Control," is intended by the year 2000 to reduce annual sulfur dioxide (SO_2) emissions by 10 million tons below the 1980 level and nitrogen oxides (NO_x) emissions by 2 million tons below the 1980 level. The intent is to limit emissions of SO_2 to 8.95 million tons. The title also includes provisions to encourage the use of energy conservation, renewable energy (biomass, solar, geothermal, and wind), and clean coal alternative technologies and pollution control to reduce emissions and "other adverse impacts of energy production and use" (§401(b)).

Title IV stipulates the creation of a market-based system of emission allowances. The allowances will be issued and tracked by the U.S. Environmental Protection Agency (EPA). The allowances will permit the holder to emit one ton of SO_2 and can be either used in the designated year or "banked" (saved) for future use (this includes selling futures allowances "forward" before delivery). Existing "affected units", units that were in operation before the CAAA passed, and new units specified in the CAAA will receive an allocation of allowances based on the fossil fuel consumption or the cap specified by the CAAA, depending on which is lower. New units that begin operation after December 31, 1995 will not be allocated allowances, but will need to acquire allowances to cover their emissions beginning in January 2000. Affected units or sources are essentially all fossil fueled boilers that serve an electric generator with a capacity greater than 25 megawatts (MW).

All affected sources will be required to hold sufficient allowances to cover their emissions. Each allowance will be identified as being issued for a specific year. While existing units will be issued allowances up to the emission requirement, units may exceed this limit if the owner or operator holds sufficient allowances. However, all sources are still subject to the National Ambient Air Quality Standard limits, notwithstanding the number of excess allowances held.

Industrial and other sources not affected by Title IV may become affected sources by electing to "opt-in" to the allowance system. These sources would be allocated allowances sufficient to cover their current emissions. These sources would consider opting-in if their expected reduction cost is below the expected allowance price. Their gain would then be the allowance price minus the reduction cost and any transaction costs.

EPA is required to create special reserves of allowances for special programs mandated by CAAA. In one program, EPA will redistribute the allowances for adopting energy conservation measures or using renewable energy resources to displace emissions. In a second, EPA will provide direct sales of allowances for a fixed price (with priority given to independent power producers) and create an allowance auction system. These reserves will be created by reducing affected sources' initial allocations on a pro rata basis (in proportion to their share of all allowances).

The CAAA establishes a comprehensive permitting system (§408) and requires compliance planning by affected sources. Permits for a period of five years will be issued to affected sources that comply with the provisions of the CAAA. Compliance plans, which will be required to accompany the permit application, should describe how the owner or operator will comply with the emission requirements of the CAAA. Owners or operators of phase I affected units are required to file a permit application and a compliance plan with EPA for their sources by February 1993. Phase II permits will be issued either by EPA or by states with approved permit programs. Phase II sources must submit permit applications by January 1, 1996 and approved states must issue permits by December 31, 1997. If there is no approved state program, affected sources must submit applications to EPA by July 1, 1996 and EPA must issue permits by January 1, 1998. New affected units must submit permit applications two years before January 1, 2000 or the date when the unit commences operation, whichever is later.

Other provisions of the CAAA include:

- Utilities and others will be allowed to form "allowance pools," where a group of affected sources can take advantage of their different system resources and requirements.

- There will be a penalty of $2,000 per excess ton for sources that exceed allowances held. These sources will still be required to offset the excess tons in the following year.
- In general, all affected sources will be required to install and operate continuous emissions monitors (CEMs) on each affected unit (multiple units using a single stack will not be required to have unit specific CEMs). Phase I sources must have CEMs operational by November 1993. Phase II affected sources must have CEMs operational by January 1, 1995. New units must meet the requirements at the start of commercial operation (§412).
- Affected sources will be required to transfer to EPA at the end of each year allowances to cover their SO_2 emissions. EPA will determine in its rulemaking the length of any grace period for this transfer after the end of the year (EPA has indicated that thirty days is likely) and the method of transfer.
- In general, the phase II allowances will be calculated based on each generating unit's 1985 emission rate times its fuel consumption for 1985 through 1987. Utilities can petition the EPA for a different base period if 1985-87 can be shown to be atypical.
- EPA is required to develop procedures and requirements for an allowance tracking system for issuing, recording, and tracking allowances. This is to facilitate "an orderly and competitive functioning of the allowance system."

EPA is required to issue most of the rules implementing the CAAA. Table 1-1 provides some of the key deadlines for the proposed and final rules and other activities.

Phase I

The SO_2 reduction program is divided into two phases. Phase I requires that by the beginning of 1995, 110 plants (261 units) will be allocated the number of allowances listed in Table A of the CAAA. In general, these units have a capacity of

TABLE 1-1

KEY EPA ACTIVITIES AND TARGET DATES

EPA Activity	EPA Target Date
Propose auctions and sales regulations	May 1991
Propose allowance system regulations	September 1991
Propose conservation and renewable energy reserve regulations	September 1991
Propose permit and monitoring regulations	September 1991
Promulgate auctions and sales regulations	November 1991
Publish proposed list of phase II allowance allocations	December 1991
Compute and establish phase I reserve	December 1991
Propose election source program regulations	May 1992
Promulgate allowance system regulations	May 1992
Promulgate conservation and renewable energy reserve regulations	May 1992
Promulgate permit and monitoring regulations	May 1992
Promulgate regulations for election source program	December 1992
Publish final list of phase II allowance allocations	December 1992

Source: U.S. Environmental Protection Agency, "Background Paper on Allowances," EPA document number A-1, 1990 and discussions with EPA personnel.

100 MW or more with emission rates of 2.5 lbs. of SO_2 per mmBtu or more (based on the average fossil fuel consumed in the years 1985, 1986, and 1987). The number of phase I units by state, the affected capacity, and the percent of total state capacity are shown in Table 1-2. The total SO_2 emissions (from all sources),

TABLE 1-2

AFFECTED NUMBER OF UNITS AND CAPACITY BY STATE IN PHASE I

State	Affected # of Units	Affected Capacity MW	Affected Capacity % of Total
Alabama	10	3,363	16.4
Florida	5	2,286	6.3
Georgia	19	8,443	36.6
Illinois	17	5,969	16.2
Indiana	37	11,192	48.9
Iowa	6	976	11.5
Kansas	1	145	1.3
Kentucky	17	4,664	27.8
Maryland	6	2,364	22.7
Michigan	2	650	2.7
Minnesota	1	163	1.8
Mississippi	2	750	10.4
Missouri	16	6,550	39.2
New Hampshire	2	460	32.7
New Jersey	2	299	2.0
New York	10	2,408	7.2
Ohio	41	14,131	51.3
Pennsylvania	21	7,674	20.8
Tennessee	19	6,332	34.8
West Virginia	14	7,352	48.8
Wisconsin	13	2,742	24.9
TOTAL	261	88,913	

Source: Based on data from Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1989* (Washington, DC: Edison Electric Institute, 1990), Table 3; unpublished 1991 EPA, Acid Rain Division data; Clean Air Act Amendments of 1990, Table A; and authors' computations.

allocated allowances, and the required reduction are listed by state in Table 1-3.[1] Figure 1-1 maps the percent of the total SO_2 reduction required for each state.

As the tables and figure indicate, the impact is concentrated in the eastern half of the continental United States. Three states, Indiana, Missouri, and Ohio, each have over 10 percent of the total SO_2 reductions and together account for just over 50 percent of the total required reduction. In Ohio over 50 percent of the state's total capacity is affected and both Indiana and West Virginia have just below 50 percent of their capacity affected. Again, however, it should be noted that while most of the reduction is located in the eastern half of the United States, additional fossil capacity in any state will be required to obtain allowances from the current owners or EPA (see discussion below on auctions and sales).

The owner or operator of a phase I unit may substitute one or more of its unaffected units for some or all of an affected unit's emissions reduction (§404(b)). In order to qualify for the substitution, documentation must be given to EPA that shows that total emissions would be reduced the same or more with substitution than the total emissions that would occur from the original affected unit and substitute unit(s) without substitution. If approved by EPA, both the original and substitute unit(s) would be affected units and subject to the phase I emission requirements.

Qualified phase I units will be allowed to apply for a two-year extension from the phase I deadline to January 1, 1997 (§404(d)). A "qualifying phase I technology" will be one that reduces SO_2 emissions by 90 percent from what would have resulted if the same fuel and unit were left unaltered. The allowances needed for the extension will be drawn from a reserve that will equal the reduction of SO_2 (tons) emissions projected for 1995 up to a limit of 3.50 million allowances (§404(a)(2)). In addition, adopting these qualifying technologies will make sources eligible for any remaining allowances from this same reserve as an incentive for early phase II reductions (from 1997 through 1999). EPA has indicated that these allowances will likely be allocated on a first-come-first-served basis using a phone-in lottery system.

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[1] Total allowances are based on Table A of the CAAA plus the pro rata share for Illinois, Indiana, and Ohio of the 200,000 bonus allowances. However, this does not present the actual allowances that will be received by the affected sources because of other bonus allowances.

TABLE 1-3

SO_2 EMISSION AND ESTIMATED ALLOWANCE ALLOCATIONS BY STATE (PHASE I)

	Total SO_2 Emissions (Tons)	Total SO_2 Allowance* (Tons)	(%)	Required SO_2 Reduction (Tons)	(%)
Alabama	530,470	230,940	4.05	60,439	1.69
Florida	589,135	133,130	2.36	100,976	2.81
Georgia	989,422	581,600	10.20	234,688	6.55
Illinois	1,019,794	394,260	6.92	353,265	9.86
Indiana	1,441,336	716,867	12.58	555,937	15.51
Iowa	194,815	40,290	0.71	31,194	0.87
Kansas	100,219	4,220	0.07	3,593	0.10
Kentucky	788,651	278,250	4.88	178,140	4.97
Maryland	233,017	139,540	2.45	12,225	0.34
Michigan	418,411	42,340	0.74	17,091	0.48
Minnesota	117,537	4,270	0.07	532	0.01
Mississippi	104,448	54,610	0.96	18,545	0.52
Missouri	958,765	352,990	6.19	404,700	11.29
New Hampshire	71,036	32,290	0.57	13,626	0.38
New Jersey	92,255	20,780	0.36	12,306	0.34
New York	393,607	150,980	2.65	15,930	0.44
Ohio	2,261,039	960,210	16.85	858,144	23.95
Pennsylvania	1,177,924	534,140	9.37	147,766	4.12
Tennessee	786,522	386,430	6.78	238,201	6.64
West Virginia	946,444	497,870	8.73	246,813	6.89
Wisconsin	424,628	143,380	2.52	79,109	2.21
TOTAL	13,639,475	5,699,387	100	3,583,220	100

Source: Clean Air Act Amendments of 1990, Table A; unpublished 1991 EPA data, Acid Rain Division; and authors' computations.

*Includes bonus allowances of 200,000 allocated to Illinois, Indiana, and Ohio.

Fig. 1-1. Phase I SO_2 reduction by state--percent of total.

An additional 200,000 allowances will be allocated to units (except for units at three plants) in Illinois, Indiana, and Ohio each year from 1995 to 1999 on a pro rata basis (§404(a)(3)). These allowances are excluded from the calculation of the reserve of incentive allowances. Other provisions are made for units and utility systems that have reduced coal reliance (§404(e)) and for systems that reduced their emission rates (§404(h)). The deadline in this provision was March 1991.

Phase II

In general, beginning January 1, 2000 existing units will be required to reduce their emissions to 1.2 lbs. of SO_2 per mmBtu multiplied by their baseline fuel use (1985 through 1987), or hold allowances for the amount they exceed the cap (§405). These existing units will be allocated allowances either up to the cap or, if emissions are less than the cap, their actual emissions plus a 20 percent bonus (in general, coal, oil, and gas-fired units below 1.2 lbs/mmBtu--§§405(d), (e), and (f)). Again, new units (except specific units that commence operation between 1986 and before 1996 listed in Table B (§405(g)) will be required either to purchase allowances or reallocate allowances from the owner or operator's existing units. All affected sources must hold sufficient allowances to cover their emissions.

In addition, special provisions are included for units that primarily use lignite coal (§405(b)(3)), coal or oil-fired units below 75 MW and above 1.2 lbs/mmBtu (§405(c)), and oil and gas-fired units with fuel consumption of less than 10 percent oil (§405(h)). The number of phase II units, affected capacity, and the percent of total state capacity are shown in Table 1-4. Total emissions, estimated allowances, and the required reduction for phase II are listed by state in Table 1-5.[2] EPA is expected to announce the phase II allowance allocations in late 1991. Figure 1-2 maps the percent of total SO_2 reduction required for each state.

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[2] Total allowances are based on 1.2 lbs. of SO_2 per mmBtu plus the 20 percent bonus allowances for fossil units that are below 1.2 lbs. of SO_2 per mmBtu. Again, however, this does not represent the actual allowances that will be received by the affected sources in a state because of other bonus allowances and adjustments that EPA will be required to make to maintain the emissions limitation (§403(a)).

TABLE 1-4

AFFECTED NUMBER OF UNITS AND CAPACITY BY STATE IN PHASE II

State	Affected # of Units	Affected Capacity* MW	Affected Capacity* % of Total
Alabama	23	6,194	30.2
Delaware	4	455	21.4
Florida	22	7,376	20.4
Georgia	27	10,728	46.5
Illinois	29	8,453	22.9
Indiana	37	11,187	48.9
Iowa	10	2,032	23.9
Kansas	3	1,134	10.5
Kentucky	27	7,921	47.2
Maine	1	114	4.8
Maryland	13	4,222	40.5
Massachusetts	12	3,736	37.2
Michigan	24	6,734	27.9
Minnesota	11	1,766	19.2
Mississippi	2	750	10.4
Missouri	25	9,991	59.8
Montana	1	191	3.9
Nebraska	3	447	7.8
New Hampshire	3	874	62.2
New Jersey	5	1,611	10.9
New York	24	5,811	17.4
North Carolina	32	10,379	49.7
North Dakota	5	1,160	24.8
Ohio	61	19,365	70.4
Pennsylvania	36	13,987	37.9

TABLE 1-4--Continued

State	Affected # of Units	Affected Capacity*	
		MW	% of Total
South Carolina	20	3,816	23.4
South Dakota	1	456	17.2
Tennessee	33	9,782	53.7
Texas	10	6,493	10.0
Virginia	18	3,544	25.3
Washington	2	1,330	5.7
West Virginia	26	12,070	80.1
Wisconsin	26	4,308	39.2
Wyoming	3	713	12.1
TOTAL	579	179,130	

Source: Based on data from Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1989* (Washington, DC: Edison Electric Institute, 1990), Table 3; unpublished 1991 EPA, Acid Rain Division data; and authors' computations.

*Affected capacity is the total capacity of the units in a state that emit 1.2 lbs. of SO_2/mmBtu or greater and have a capacity of 75 MW or greater.

TABLE 1-5

SO_2 EMISSION AND ESTIMATED ALLOWANCE ALLOCATIONS BY STATE (PHASE II)

	Total SO_2 Emissions (Tons)	Total SO_2 Allowance* (Tons)	Total SO_2 Allowance* (%)	Required SO_2 Reduction (Tons)	Required SO_2 Reduction (%)
Alabama	530,470	298,292	3.63	229,869	2.90
Arizona	109,846	129,972	1.58	0	0
Arkansas	79,779	95,734	1.17	0	0
California	4,727	5,672	0.07	0	0
Colorado	76,185	86,720	1.06	0	0
Connecticut	60,885	73,061	0.89	0	0
Delaware	62,713	53,202	0.65	14,792	0.19
District of Columbia	1,130	1,355	0.02	0	0
Florida	589,135	364,621	4.44	228,658	2.88
Georgia	989,422	388,113	4.73	587,473	7.40
Illinois	1,019,794	394,850	4.81	619,399	7.81
Indiana	1,441,336	443,180	5.40	966,115	12.18
Iowa	194,815	99,997	1.22	64,144	0.81
Kansas	100,219	71,833	0.87	18,505	0.23
Kentucky	788,651	369,458	4.50	438,290	5.52
Louisiana	75,421	90,505	1.10	0	0
Maine	12,556	9,768	0.12	1,536	0.02
Maryland	233,017	132,543	1.61	103,892	1.31
Massachusetts	255,398	169,172	2.06	87,344	1.10
Michigan	418,411	360,298	4.39	65,656	0.83
Minnesota	117,537	83,521	1.02	29,168	0.37
Mississippi	104,448	62,062	0.76	46,943	0.59
Missouri	958,765	268,216	3.27	646,119	8.14
Montana	16,783	17,055	0.21	1,641	0.02
Nebraska	46,873	54,994	0.67	246	0
Nevada	53,585	64,302	0.78	0	0
New Hampshire	71,036	27,557	0.34	37,601	0.47
New Jersey	92,255	59,220	0.72	31,325	0.39

TABLE 1-5--Continued

	Total SO_2 Emissions (Tons)	Total SO_2 Allowance* (Tons)	(%)	Required SO_2 Reduction (Tons)	(%)
New Mexico	76,302	79,520	0.97	0	0
New York	393,607	202,556	2.47	161,983	2.04
North Carolina	331,548	287,427	3.50	49,179	0.62
North Dakota	134,183	134,518	1.64	15,023	0.19
Ohio	2,261,039	648,795	7.90	1,511,796	19.06
Oklahoma	87,223	104,667	1.27	0	0
Oregon	806	966	0.01	0	0
Pennsylvania	1,177,924	550,922	6.71	615,560	7.76
Rhode Island	3,368	2,372	0.03	0	0
South Carolina	154,052	99,670	1.21	55,885	0.70
South Dakota	24,859	13,116	0.16	11,996	0.15
Tennessee	786,522	298,597	3.64	487,924	6.15
Texas	574,868	582,011	7.09	48,357	0.61
Utah	22,622	27,144	0.30	0	0
Vermont	27	31	0.00	0	0
Virginia	144,499	125,902	1.50	21,553	0.27
Washington	62,802	45,019	0.50	17,782	0.22
West Virginia	946,444	423,142	5.15	517,943	6.53
Wisconsin	424,628	172,236	2.09	198,679	2.50
Wyoming	126,661	136,792	1.66	1,448	0.02
TOTAL	16,239,179**	8,210,676	100	7,933,824	100

Source: Based on data from Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1989* (Washington, DC: Edison Electric Institute, 1990), Table 3; unpublished 1991 EPA, Acid Rain Division data; and authors' computations.

*Based on §§405(a)(1); (b)(1); (d)(1) and (2); (e); and (f) of the Clean Air Act Amendments of 1990.

**Does not equal the sum of this column due to rounding.

Fig. 1-2. Phase II SO_2 reduction by state-percent of total.

While the total number of units affected increases (from 261 in phase I to 579), the relative distribution is similar. Ohio and Indiana together account for over 30 percent of the total required reduction in phase II. Five states have over 50 percent of their total capacity affected-Missouri (60%), New Hampshire (62%), Ohio (70%), Tennessee (54%), and West Virginia (80%). A total of ten states have over 40 percent of their capacity affected by the phase II requirements.

Other "bonus" allowances will be awarded in phase II, in addition to those indicated above. These include 50,000 for the phase I units (based on pro rata share for the unit in Table A of the CAAA, but allocated in phase II) in ten states, Illinois, Indiana, Ohio, Georgia, Alabama, Missouri, Pennsylvania, West Virginia, Kentucky, and Tennessee (exceptions are one unit in Illinois, one in Indiana, and one in Ohio--§405(a)(3)). Also receiving bonus allowances are units with actual 1985 emission rates below 2.5 lbs/mmBtu and capacity factors less than 60 percent in an amount equal to 1.20 lbs/mmBtu multiplied by 50 percent of the difference between the unit's baseline and the unit's fuel consumption at a 60 percent capacity factor (§405(b)(2)); units that converted to coal from oil between 1980 and 1985 located in states with more than 30,000 MW generating capacity (§405(b)(4)); units in high growth states (that is, having population growth in excess of 25 percent between 1980 and 1988 and having an installed generating capacity of more than 30,000 MW in 1988--§405(i)); specific municipally-owned power plants (§405(j)); and states with emission rates at or below 0.8 lbs/mmBtu (§406).

The bonus allowances allocated for units below 2.5 lbs/mmBtu and less than 60 percent capacity factor (§405(b)(2) and (c)(4)), coal units below 1.2 lbs/mmBtu (§405(d)(3)(A) and (B)), oil and gas-fired units with less than 10 percent oil consumed (§405(h)(2)), and for states with emission rates at or below 0.80 lbs/mmBtu (§406) will be allocated from a reserve of 530,000 phase II bonus allowances for the years 2000 through 2009. EPA will generate these allowances by deducting 53,000 allowances from each unit's basis phase II allowance allocation on a pro rata basis for each of the ten years this reserve will be in operation.

Example of Utility Compliance Options with Allowances

Table 1-6 provides an example of several options available for a hypothetical coal unit. This is a simplified example to provide a means to illustrate a utility's compliance decision process for one unit. In reality the decision is considerably more complex. The utility must consider, among other things, its entire system's compliance, several scenarios of future fuel and allowances prices, regulatory treatment, and the possible offset of emissions with a conservation program. This, of course, introduces a great deal of uncertainty into the compliance planning process.

In this simple example the utility considers five options: (1) purchase allowances, (2) adopt a clean coal technology (CCT), (3) switch to low sulfur coal, (4) repower the unit, or (5) build a scrubber. Since this hypothetical unit is an existing unit, under the CAAA it will receive 6,623 allowances initially (based on the phase II limit of 1.2 lbs. of SO_2 per mmBtu). Given these unit characteristics, the estimated cost of allowances can be factored into the overall cost of compliance for each option. This unit would be an affected unit under phase I of the CAAA since it emits in excess of the 2.5 lbs. of SO_2 per mmBtu limit set in phase I of the CAAA; however, only phase II compliance is discussed below.

If the utility chooses not to modify the unit and purchases just the needed allowances, then it would be required to purchase 37,378 allowances, assuming the unit operated at the same level. Based on an allowance price of $650 a ton, this option would have an estimated cost of $24.3 million (37,378 times $650) or 2.3¢/kWh. The CCT option will remove 13,000 tons of SO_2, therefore 24,378 allowances are needed. Net compliance cost (total cost net of the value of allowances) is then $20.35 million ($15.85 plus $4.50 million or 1.94¢/kWh). Switching removes 37,000 tons of SO_2, so only 378 allowances are needed to comply with the CAAA. This option has, in this example, the lowest compliance cost at $12.02 million or 1.14¢/kWh.

The first three options in this example require the utility to purchase (or use from another unit) allowances; however, some options result in the unit being

TABLE 1-6

PHASE II COMPLIANCE EXAMPLE

UNIT	1
AGE	30 years
CAPACITY	200 MW
CAPACITY FACTOR	60%
HEAT RATE	10,500 Btu/kWh
TONS OF SO_2 EMITTED	44,000
INITIAL ALLOWANCE*	6,623

	OPTIONS				
	Allowances	CCT	Switch	Repower	Scrub
SO_2 REMOVED (tons)	-	13,000	37,000	40,000	40,000
UNIT COST OF REMOVAL ($/ton)	-	346	318	422	894
CAPITAL COST ($/kW)	-	14	60	800	200
OPERATING COST (¢/kWh)	-	4	1	-	3
ALLOWANCE NEEDED (tons)	37,378	24,378	378	(2,622)	(2,622)
VALUE OF ALLOWANCE (M$) @ $650/ton	24.30	15.85	0.25	(1.70)	(1.70)
TOTAL COST OF REDUCTION (M$)	0	4.50	11.77	16.88	35.76
NET COST OF COMPLIANCE (M$)	24.30	20.35	12.02	15.18	34.06
INCREMENTAL COST OF COMPLIANCE (¢/kWh)	2.31	1.94	1.14	1.44	3.24

Source: Based on data reported in "Clean Air Response: A Guidebook of Strategies," Electric Power Research Institute (1990) and NRRI calculations.

Note: Quantities in parentheses indicate excess allowances or the amount of overcontrol.

*Total generation = $200\ \text{MW} * \frac{1{,}000\ \text{kW}}{\text{MW}} * \frac{8{,}760\ \text{h}}{\text{yr}} * 0.6 = 1{,}051{,}200{,}000\ \text{kWh/yr.}$

Total allowance = $(1{,}051{,}200{,}000\ \text{kWh/yr}) * \frac{10{,}500\ \text{Btu}}{\text{kWh}} * \frac{1\ \text{mmBtu}}{10^6\ \text{Btu}} * \frac{1.2\ \text{lbs.}}{\text{mmBtu}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 6{,}623\ \text{tons/yr.}$

"overcontrolled" or a reduction in the emissions of the unit below the initial (phase II) allocation. Repowering the unit, for example, removes 40,000 tons and results in overcompliance. Since the utility can sell these generated allowances (the difference between its initial allocation and projected emissions for this option) they have some value to the firm--irrespective of whether the utility chooses to sell them, bank them for future use, or use them at another unit. While repowering has the highest unit capital cost ($800/kW), it has the second lowest net compliance cost for this scenario at $15.18 million or 1.44¢/kWh. Also, the utility can build a scrubber. This "frees-up" the same number of allowances as repowering since the emission levels after modification are the same (or the scrubber removes the same amount of SO_2). However, in this example, the scrubber is the most expensive option with a net compliance cost of $34.06 million, or 3.24¢/kWh.

The allowance price of $650 was chosen for this example because it represents the midpoint of several scenarios that others have projected. Table 1-7 illustrates the effect and importance of the forecasted allowance price on the estimated costs of the options in the above example. When the forecasted price of allowances is $300, the lowest cost option is to purchase allowances ($11.21 million and 1.07¢/kWh) while CCT and switching to low sulfur coal become, respectively, the next lowest cost options. When the price of allowances is $1,000, however, switching again becomes the lowest cost option ($12.15 million and 1.16¢/kWh).

It is interesting to note, however, that the differences between options are relatively small considering the length of time and the total investment involved for the $300 scenario. Four of the options in Table 1-7 (allowance purchase, CCT, switching, and repowering) have estimated incremental costs that vary by only a fraction of a cent. Given the uncertainty associated with any forecast, this difference is negligible. One implication of this is that the option chosen is very sensitive to the actual price of allowances. When the allowance price is low, the difference in costs between options is small. On the other hand, when the allowance price is relatively high the difference in costs become more significant for compliance planning purposes.

TABLE 1-7

EFFECT OF THREE DIFFERENT ALLOWANCE PRICES ON COMPLIANCE COST

Allowance Price $	Allowances	CCT	Switch	Repower	Scrub
	OPTIONS				
	Net Compliance Cost (M$)				
300	11.21	11.81	11.88	16.09	34.97
650	24.30	20.35	12.02	15.18	34.06
1,000	37.38	28.88	12.15	14.26	33.14
	Incremental Compliance Cost (¢/kWh)				
300	1.07	1.12	1.13	1.53	3.33
650	2.31	1.94	1.14	1.44	3.24
1,000	3.56	2.75	1.16	1.36	3.15

Source: NRRI calculation, based on Table 1-6.

Conservation and Renewable Energy Bonus Allowances

As mentioned, CAAA creates a conservation and renewable energy reserve of 300,000 allowances that will provide extra or bonus allowances for emissions avoided using a qualified energy conservation measure or a qualified renewable energy source. The reserve was designed to encourage the use of conservation and renewable resources to reduce emissions. A qualified conservation measure is defined as a cost effective measure that promotes the efficient use of electricity. Qualified renewable energy sources are biomass, solar, geothermal, or wind. The specifics of these definitions will be determined by EPA and DOE in their respective rulemakings.

The 300,000-allowance conservation and renewable energy reserve will be created by reducing each affected unit's basic phase II allowance allocation on a pro rata basis of 30,000 allowances a year beginning in 2000 and continuing through to 2009. Any remaining allowances in the reserve (after January 2, 2010) will be allocated on a pro rata basis back to the affected units. EPA has indicated that 40,000 allowances may be set aside from the reserve in 1998 for renewable energy projects. This floor will be established if it appears the reserve is about to be depleted without at least 40,000 allowances being used for renewable energy projects. Otherwise allowances will be allocated on a first-come-first-served basis.

Qualified energy conservation measures or qualified renewable energy sources must be saving or producing energy between January 1, 1992 and December 31, 2000. Conservation programs that are exclusively informational or educational are not eligible. Conservation measures or renewable energy sources that were in operation before January 1, 1992 are also not eligible. Phase I affected sources must apply from 1992 through 1995. Phase II affected sources can apply from 1992 through 2000. Allowances from this reserve will be awarded on an annual basis at the end of the year, beginning in 1992.

There are five requirements that an electric utility[3] must meet: (1) the utility must pay for the conservation measure or renewable energy either directly or from another source; (2) the emissions of SO_2 avoided are quantified in accordance with regulations promulgated by EPA; (3) the electric utility has adopted and is implementing a least-cost energy plan that evaluates a range of resources, including new power supplies, energy conservation, and renewable energy sources--the conservation or renewable energy source must be consistent with a plan approved by the jurisdictional state or federal ratemaking authority; (4) DOE must certify that the state jurisdictional PUC has established rates and charges that ensure that the net income of the electric utility after implementation is at least as high as the net

[3] An electric utility is defined as "any person, [s]tate agency, or [f]ederal agency, which sells electric energy." It is unclear if this definition includes industrial sources (e.g., cogenerators) that sell power and that own or operate an affected unit.

income would have been if the conservation measure had not been implemented (not required for qualification of renewable energy); and (5) the utility owns or operates at least one affected unit.

An electric utility must provide the following with its application for bonus allowances: (1) identify the qualified energy conservation measure implemented or the qualified renewable energy source used to avoid emissions, (2) calculate the number of tons of emissions avoided from implementation, and (3) demonstrate that all five of the above requirements have been met. The application is then given to the jurisdictional state or federal agency with ratemaking authority for approval.

The avoided emissions from qualified conservation measures and qualified renewable energy sources are calculated as the product of the kilowatt hours saved or generated in a year and 0.004, divided by 2000 (one ton or one allowance = (kWh saved or generated in a year x 0.004)/2000). This calculation is based on the emissions of an average "clean" coal unit that emits at a rate of 0.4 lbs of SO_2/mmBtu.

The CAAA does not specify the method for calculating the energy saved from a qualified conservation program. EPA has indicated that its rules will not prescribe specific methods for states to follow when verifying their jurisdictional utilities' applications for bonus allowances. However, a wide variety of methods is available.[4] This will most likely result in states adopting the broadest definition feasible for conservation program savings in order to maximize the number of bonus allowances.

It should also be noted that since the reserve is relatively small (the 30,000 to be awarded annually represents only 0.3 percent of the total 8.95 million allowances) and with a starting date of January 1, 1992 for qualified programs, most bonus allowances will go to states that already have qualified least-cost plans. States that do not already have a qualified least-cost plan or are not currently in the process of developing such a plan are unlikely to be able to meet these qualifications before the reserve is depleted.

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[4] See for example, *Impact Evaluation of Demand-Side Management Programs, Volume 1: A Guide to Current Practice* (Palo Alto, CA: Electric Power Research Institute, February 1991).

EPA Allowance Sales and Auctions

EPA is also required to create another special reserve of allowances for direct allowance sales and for an allowance auction (§416(b)). The reserve will be created by reducing the phase I affected sources' allocations (on a pro rata basis) by 2.8 percent between 1995 and 1999 and reducing phase II affected sources' allocation by 2.8 percent beginning in 2000. Congress included this reserve as a contingency to provide IPPs access to allowances (by providing direct sales) and to facilitate the development of an allowance market for private trading (by creating the auction).

Direct Sale

A portion of the reserve is to be used for direct sale of allowances, where EPA will offer allowances for $1500 per allowance (to be adjusted by the consumer price index--CPI) giving priority to Independent Power Producers (IPPs) as defined in the CAAA and interpreted by the Department of Energy. An IPP proposing construction of a facility that will require allowances before the first EPA allowance auction and that has not received responses to written requests to all affected sources to purchase allowances for $750 is entitled to an EPA written guarantee or "contingency guarantee" of allowances at $1500 per allowance (§416(c)(3)). Since potential lenders and the host utility (for example, in a competitive bid) will most likely either require allowances or a demonstration of an ability to secure them, this written guarantee can be used by the IPP in a bid to supply power and to secure financing for construction of the facility. The CAAA defines an IPP as "any person who owns or operates, in whole or in part, one or more new independent power production facilities." It then defines a "new independent power production facility" as a facility that

> (A) is used for the generation of electric energy, 80 percent or more of which is sold at wholesale;
> (B) is nonrecourse project-financed (as such term is defined by the Secretary of Energy within three months of the date

of the enactment of the Clean Air Act Amendments of 1990);
(C) does not generate electric energy sold to any affiliate (as defined in section 2(a)(11) of the Public Utility Holding Company Act of 1935) of the facility's owner or operator unless the owner or operator of the facility demonstrates that it cannot obtain allowances from the affiliate; and
(D) is a new unit required to hold allowances under this title.

DOE has proposed (10 CFR Part 715) that a "nonrecourse project-financed" facility be defined as an IPP that pledges its financed assets and part or all of the revenue from one or more of the power sales contracts covering the affected facility and expressly excludes financing that provide recourse to an electric utility with a retail service territory. However, an equity contribution by a utility in connection with the financing of a facility is not an obligation to repay debt and would therefore not disqualify the financing from being considered nonrecourse.

The proceeds of direct allowance sales will be returned to the affected sources on a pro rata basis. Purchasers are required to pay 50 percent of the total purchase price within six months after the approval of the request to purchase. The remainder will be due before the allowance transfer. Unsold allowances will be transferred to an auction subaccount. The direct sales can be terminated by EPA if less than 20 percent of the allowances available for sale are sold in any two consecutive years (§416(e)(7)). Any remaining allowances will be transferred to the auction subaccount. If the allowance market develops as expected, then the direct sales provisions will most likely be discontinued.

Table 1-8 shows the number of allowances available for direct sales. This table is taken directly from the CAAA (§416(c) Table 1).

Allowance Auction

EPA must also develop rules (within twelve months of enactment) for an auction with allowances from the 2.8 percent allowance reserve. This auction will be open to anyone interested in participating, will be a sealed bid auction with the sales based on the bid prices, and with no minimum bid. Auction proceeds will be

TABLE 1-8

NUMBER OF ALLOWANCES AVAILABLE FOR DIRECT SALE AT $1,500 PER TON*

Year of Sale	Spot Sale (same year)	Advance Sale
1993 - 1999	-	25,000
2000 and after	25,000	25,000

Source: CAAA Table 1 Sec. 416(c).

*Allowances sold in the spot sale in any year are allowances which may only be used in that year (unless banked for use in a later year). Allowances sold in the advance sale in any year are allowances which may only be used in the seventh year after the year in which they are first offered for sale (unless banked for use in a later year).

transferred to affected units contributing to the reserve on a pro rata basis. Allowances held for auction that were not sold in the auction will be returned to contributing affected sources, also on a pro rata basis. EPA may delegate or contract for auction services. EPA may terminate the auction after 2002 if less than 20 percent of the allowances available for purchase have been sold in any three consecutive years (§416(f)).

Table 1-9 shows the number of allowances available for auction between 1993 and 2000.

Any holder of allowances may submit its allowances and specify a minimum price to EPA for sale at auction. These allowances will be sold after the EPA auction is completed. Proceeds will be transferred by the purchaser to the seller; no funds are to be held by an officer or employee of the U.S. government (§416(d)(4)). EPA is required to make public the nature, prices, and results of each auction and record the transfer of allowances.

TABLE 1-9

NUMBER OF ALLOWANCES AVAILABLE FOR EPA AUCTION

Year of Sale	Spot Auction* (same year)	Advance Auction*
1993	50,000**	100,000
1994	50,000**	100,000
1995	50,000**	100,000
1996	150,000	100,000
1997	150,000	100,000
1998	150,000	100,000
1999	150,000	100,000
2000	100,000	100,000

Source: CAAA Table 2 Sec. 416(d).

*Allowances sold in the spot auction in any year are allowances which may only be used in that year (unless banked for use in a later year), except as otherwise noted. Allowances sold in the advance auction in any year are allowances which may only be used in the seventh year after the year in which they are first offered for sale (unless banked for use in a later year).

**Available for use only in 1995 unless banked for use in a later year.

Allowance Pooling

A significant provision in the CAAA is the ability of affected sources to create allowance pool agreements (§403(d)(2)). The act states that "to insure electric reliability" EPA should not prevent such agreements "that result from their operations, including emergencies and central dispatch." Affected sources in the pool will be required to limit their total emissions (of all affected units in the pool) in a year to the sum of emission limits allowed for each individual units. An individual unit within the pool therefore can exceed the emission limit, provided the total pool does not. If a unit does exceed its limit, another or several other units must be below their limit(s) for the pool to be in compliance.

While this could be of significant benefit to the members of an allowance pool, if pooling of allowances is not limited to just units in a power pool or connecting utilities with power transfer agreements the danger arises of large holders of allowances (such as two or more holding companies) forming an allowance pool not for reliability reasons but for market power reasons.[5] This will depend, of course, on how the allowance market develops and on EPA's rulemaking.

Election by Additional Sources

The acid rain control provisions of the CAAA, while applicable to most fossil-fuel electric generating units, are not applicable to simple combustion turbines, industrial boilers, or process sources, or existing fossil-fuel-fired electric generating units of twenty-five megawatts or less. Cogenerators with more than twenty-five megawatts of capacity and more than one-third of their potential electric output capacity sold to any utility distribution system most likely will be affected utility units which must comply with Title IV of the CAAA. Other sources, including small fossil-fuel utility and industrial units, appear to be unaffected but can opt-in to the allowance system. Allowances issued to units that elect to opt-in to the emission trading market are not considered part of the 8.9 million-tonnage cap.

Industrial boilers or other small existing fossil-fuel units that are not process sources and that elect to opt in are covered by section 410(c). The source will be issued allowances based on the lesser of the unit's 1985 actual or allowable emission rate. If the unit did not operate in 1985, the EPA will issue allowances based on the

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[5] For a discussion of market power in the allowance market see D. Bohi and D. Burtraw, "Regulatory Aspects of Emissions Trading: Conflicts Between Economic and Environmental Goals," *The Electricity Journal* 3 (December 1990): 47-55.

lesser of the actual or allowable emissions rate from a later baseline year. Full credit for decreased allowances can be given to these units even if their emission rate is greater than phase I or phase II rates if they are unaffected units. Thus, the opting-in unit receives credit for decreased emissions from the baseline year even though it may not opt-in until years later. A similar program will exist for process sources, however, the CAAA leaves it to EPA to define eligible sources, establish emissions limitations, and determine baseline years.

Opt-in units are subject to the other requirements of the emissions allowance trading provisions, including permitting, penalty, monitoring and record keeping, and enforcement provisions. In addition, allowances for opt-in units that are produced as a result of reduced utilization or shutdown can be transferred or carried forward for use in subsequent years only to the extent that the reduced utilization or shutdown results from the replacement of thermal energy from the opt-in unit, with thermal energy generated by other units subject to the allowance provisions of the CAAA.

Nitrogen Oxides Control

The two-million-ton reduction below 1980 levels by 2000 of nitrogen oxides (NO_x) prescribed by the CAAA is a control requirement, not an allowance based program. Within eighteen months of enactment, EPA is required to limit NO_x emissions for tangentially fired boilers to 0.45 lbs./mmBtu (§407(b)(1)(A) and for dry-bottom, wall-fired boilers (other than units applying cell burner technology) to 0.50 lbs./mmBtu (§407(b)(1)(B)). These standards will go into effect after January 1, 1995 and are applicable to all phase I sources. By January 1, 1997, EPA must promulgate emission limitations for wet-bottom wall-fired boilers, cyclones, units applying cell burner technology, and all other types of utility boilers (§407(b)(2)). All affected sources must meet these standards by the phase II deadline.

Some other NO_x provisions include: (1) by January 1, 1993 EPA must propose, and by January 1, 1994 promulgate, revised New Source Performance Standards (NSPS) for NO_x from all fossil fuel-fired steam generating units (§407(c)); (2) less stringent emission limitations may be authorized if the owner or operator can demonstrate that the applicable emission limitation can not be met using low NO_x burner technology or cannot meet the applicable rate using the technology on which EPA based the limitation; (3) an extension is possible if the required technology is not immediately available (§407(d)); and (4) an owner or operator of two or more units subject to the NO_x provisions may comply based on the average emission rate of all affected units (§407(e)).

Compliance Planning

Compliance plans will be required that describe what actions the owner or operator will take to have their units in compliance with the emission requirements of the CAAA (§408(g)). In addition to installing pollution control equipment and switching to low sulfur fuel, utilities can retire old capacity, purchase capacity from others, repower an existing plant, redispatch existing units, purchase or sell allowances, bank allowances, or invest in conservation and demand-side management. Most utilities have a wide range of compliance strategies from which to choose.

The cost of each option varies for each of the utility's units and across utilities (see preceding example of compliance options). For one unit, the least costly means of complying might be to fuel switch, for example, from coal to natural gas. For another, a scrubber might be the lowest-cost option, and might result in overcompliance, which in turn frees allowances that can be used to bring other units into compliance. A utility should look not only at the cost of compliance on a unit-by-unit basis, but at the cost of compliance for the entire company since internal trades (that is, trades within a firm) will be possible. A utility should look beyond itself to the utility system it may belong to to see if there are opportunities for emission allowance trading, perhaps for reliability purposes as part of an allowance pool. Beyond its utility system, a utility should look for allowance trading opportunities nationwide.

In general, allowance trading is intended to allow sources with relatively low compliance costs to sell their allowances to sources with relatively higher compliance costs. These sources buy allowances since the cost of compliance is more than their expected price of allowances. In this way the price of allowances is based on the cost of complying and overcomplying. The price reflects the higher compliance costs that some utilities and other generators will encounter. Most new generating units (except those with special provisions under the law) will have to purchase allowances from existing sources either directly or through an intermediary. In theory, sources will tend to invest in compliance or overcompliance until the marginal cost of the strategy equals the expected value of the emission allowances. Overall compliance costs are expected to be lower than command-and-control environmental regulation because of the gains made possible from allowance trading. These gains will be realized so long as there is a healthy and liquid allowance market.[6]

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[6] The "gains from trade" is a fundamental principle of economics that results from the specialization by individuals, firms, or countries in the production of goods or services where they have a comparative advantage (e.g., wheat in the U.S.) and then exchange them for items that others have an advantage in producing (e.g., bananas in Central America). These gains accrue to both or all parties in the exchange and are possible because of the different resources available to each individual, firm, or country. Allowances act as an instrument or medium of exchange as exchange rates do in the international trade of goods and services; this will be addressed in more detail in a subsequent NRRI report.

PART II

REGULATORY POLICY ISSUES

Incentives from Regulatory Treatment

The regulatory treatment of compliance costs, including allowances, will significantly affect a utility's CAAA compliance decisions. It can influence, for example, the decision whether to invest in pollution abatement (scrubbers or clean coal) technology, to switch to low sulfur fuels, to invest in conservation to reduce emissions and earn bonus allowances, and/or to purchase allowances. The commission can develop a regulatory treatment of allowances that gives the utility an incentive to select compliance options that are in the long-term interest of ratepayers. This requires developing a regulatory treatment that does not bias the utility toward any particular option. It is important that the ratemaking process not introduce incentives to the utility other than to select the lowest-cost compliance options for its situation.

A utility, facing an array of compliance options, will base its decisions on three regulatory conditions. First, the commission's past treatment of capital expenditures and fuel price increases will likely be used in assessing and predicting future commission action. This includes the commission's past treatment of pollution control equipment, fuel cost recovery, and new plant construction. Second, the commission could also intentionally or unintentionally limit the options of the utility. The commission could intentionally do this by stating directly what options are to be considered. This could occur unintentionally if the commission states, for example, that pollution control equipment will be rate-based, then some uncertainty is removed from this choice and thus there is a corresponding reduction in the expected cost relative to other options making this option relatively more attractive. It is in the interest of ratepayers for the commission to encourage utilities to consider a wide array of suitable options.

And third, current ratemaking conditions also may affect the utility's choices; the commission again may not intend the final results. For example, if the market cost of capital is greater than the allowed rate of return (or the expected rate before a rate case), the utility may have a bias against capital investments.[1] Of course this bias can work in the opposite direction if the market cost of capital is less than the allowed rate of return--the Averch-Johnson bias.[2] Another example of a bias from current ratemaking practices can occur if a fuel adjustment clause can be used (or is believed able to be used) by the utility. In this case, some of the risk from switching to low sulfur coal or other fuel is reduced; this could bias the utility's decision in favor of fuel switching, which may not be the lowest cost option.

In all three of these cases the utility's perception of past and future regulatory treatment is as important as the events themselves. In the first case, past regulatory treatment, the utility may feel that it was treated unfairly with a large capital expenditure. This may cause the utility to be reluctant to take on a large investments. In the second case, the utility may be reluctant to accept the commission's stated intentions because of the length of time involved with these decisions and the uncertainty of future commission actions. The third case can involve the utility's own perception of future events that are beyond its and the commission's control, such as interest rates, fuel prices, construction costs, and so on.

This emphasizes the need for the utility to select flexible compliance plans and for the commission to provide as much predictability and flexibility as feasible in its regulatory treatment. From the commission's standpoint, this involves employing a regulatory treatment that does not bias the utility toward particular options and allows flexibility for unforseen events. To facilitate this, the commission can establish credible guidelines for the utility to consider when making its decisions.

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[1] Paul L. Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics* 17 (October 1974): 291-327. This is explored with respect to the CAAA in D. Bohi and D. Burtraw, "Utility Investment Behavior and the Emission Trading Market," Discussion Paper ENR91-04 (Washington, DC: Resources for the Future, January 1991).

[2] H. Averch and L. L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-69.

Regulatory Treatment of Allowances: Two Alternatives

Alternative 1: A Traditional Regulatory Approach

The first alternative regulatory treatment is based on how commissions have dealt with similar issues with analogous assets. Commissions are likely to draw upon these previous experiences when establishing a policy for allowances. For example, commissions have often dealt with the treatment of gains and losses of land held for future use. In those cases, the regulatory treatment of gains and losses was determined by the source of funding for the sold asset. In the case of allowances, an argument can be made that ratepayers are the source of the initial allowances because these allowances reflect the past emissions of the utility necessary to meet customer demand during the base-line period. Of course others would argue that since the utility assumed the risk when building these plants and in some cases did not earn a return on the investment until the plant was completed and selling power to ratepayers then the utility should share at least a portion of any gains or losses.

Allowances from the utility's initial endowment or allocation created by the CAAA will not necessarily result in an accounting gain or loss if used internally by the utility. Because those initial allowances have an initial zero-cost basis, they could simply be expensed at their cost, zero, when used internally. When allowances are "freed" for a sale because of a utility investment or because of switching to lower sulfur fuel, any gain could be applied first to offsetting the cost of compliance (or overcompliance) strategy.

For example, if the compliance strategy involved a scrubber, the scrubber would most likely be included in the utility's rate base. Proceeds from the sale freed due to overcompliance would offset the cost of the scrubber in rate base. This is because ratepayers, in effect, provide the source of funding for the pollution abatement facilities by providing a return on the utility's prudent investment in those facilities. Any additional return to the utility from the facilities should benefit the ratepayers through a deduction from the utility's rate base of the gains from the sale of allowances. A commission could maintain this regulatory approach until the utility's cost of pollution control facilities necessary for compliance becomes zero.

If gains from the sale of allowances reduces the utility's rate-based investment to zero (that is, use the gains to offset the utility's revenue requirement derived from the investment) and still produce additional gains, a commission might provide for a sharing of those gains between the shareholders and ratepayers. Shareholders would benefit from the utility's prudent investment decisions that freed up the pollution allowances in the first place. Ratepayers would share in the gains because the source of the initial allowances was underwritten by rates. It is likely, however, that it would be several years before the cost of the compliance investments could be completely offset by allowance sales (depending on the cost and depreciation rate).

A similar approach could be taken for utility investments in conservation. Some type of split-the-savings approach might provide the utility with a "revenue neutral" and economically appropriate incentive to invest in the most effective conservation methods first. Allowances produced by a utility's investment in conservation should offset the cost of the conservation, and then be split between the ratepayers and the shareholders.

If the allowances were freed because of fuel switching, one can argue that the proceeds from the sale of allowances should be applied against the expected higher cost of low sulfur coal and the cost of any capital improvements necessary to allow the utility to switch fuels. In particular, it is conceivable that the long-run price of low sulfur fuel will include a premium because of increased demand stemming from the CAAA. At the same time, high sulfur fuels could be discounted. Commissions may pass through to ratepayers gains from the sale of allowances to the extent that the prices paid for low sulfur fuel exceed those for high sulfur fuel. This is because ratepayers provide the source of funding for the switch from high sulfur to low sulfur fuels. (In the unlikely event that switching from a high sulfur fuel to a low sulfur fuel results in decreased costs, a commission might wish to reexamine the prudence of the earlier fuel procurement policies of the utility.) If the sale of emission allowances results in profits in excess of the difference in price between high sulfur and low sulfur fuels, a regulatory commission might again consider rewarding the utility for its fuel procurement policies by allowing the shareholders to benefit in some share of the remaining gains. Gains from freed allowances due to fuel switching could be partially or fully flowed-through to ratepayers through the fuel adjustment clause.

A utility that purchases allowances may realize a gain or loss from the allowance if it is resold. For example, an allowance might be purchased for $600 and sold at the end of the year for $550, a net loss. Because the allowance was bought and sold as a security and not used internally, the utility should bear the loss below the line. Similarly, if the utility bought an allowance for $550 and sold it at the end of year at $600, the utility should receive a below-the-line gain.

However, if a utility uses allowances internally that it purchased for $600 at a time that the market price of allowances was $550, a commission might choose to impute the market price as the cost of the allowance for ratemaking purposes. If the commission were to adopt such an approach, it would be important to maintain symmetry and allow a utility a below-the-line gain if it bought an allowance for $550 and expended it when the market price was $600.

This treatment may introduce, however, an unintended bias in favor of large capital expenditures. If the initial allowances earn no return but the commission states up front that large capital expenditures for compliance, such as scrubbers, will be rate-based, a great deal of the uncertainty associated with that decision is removed. At this writing, all state commissions except one allow pollution abatement expenditures into rate base.[3] Therefore, if there is a virtual guarantee that the investment will be rate-based, initial allowances will not be, and the sale of any allowances will be used to deduct the value of the pollution control asset, then the profit maximizing firm will tend toward large capital investments and sell or bank excess allowances. The decision on how many to sell and convert to cash and how many to bank will depend, in part, on the utility's rate of return on capital. Ideally, the utility would base its sell/bank decision on its forecast of its own future need and

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[3] National Association of Regulatory Utility Commissioners, *Annual Report on Utility and Carrier Regulation* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1989).

expected future cost of allowances and fuels and not on a distortion from the ratemaking treatment.

Also, there is the possibility that the utility will have a preference for purchased allowances and attempt to replace zero-cost, non-ratebased allowances with market-priced allowances that earn a return. This, of course, depends on the inventory method used for ratemaking purposes, that is, last-in, first-out; first-in, first out; or average.

Alternative 2: Unbiased Ratemaking Treatment of Allowances

An alternative ratemaking treatment is presented here that assumes allowances will be valuable assets to the utility (and hence ratepayers) and that the ratemaking treatment should be neutral with respect to the utility's compliance decisions. Thus, the ratemaking process should only encourage the utility to adopt the lowest-cost compliance plan. This alternative is suggested as a means to develop a ratemaking procedure that introduces no bias favoring any particular compliance option--except the one with the lowest cost.

While no one can be certain of the future price and availability of allowances, there are several indications that they are likely to increase in value over time. First, many utilities will require more than their initial allotment of allowances and will be required either to purchase them in the market or reduce their emissions. Since not all units face the same reduction costs, utilities with relatively high-cost units should either purchase from others with comparatively low compliance costs, overcontrol at their own lower-cost units and use them first, or both. Second, all future fossil fuel power plants (not provided for in the CAAA) will have to purchase all of their needed allowances. These allowances will have to be obtained from affected sources willing to sell allowances they generate through overcontrol or retirement of their units. Since allowances are a factor in the production of electric power from fossil fuels, any future growth in the demand for fossil power facilities will increase the demand for allowances. Third, the dynamics of the market (as with any competitive market) should be that even with considerably more utility overcontrol than expected, the increased number of allowances on the market would cause the price to fall below the control cost for many fossil fuel users. Conversely, if the uncertainty causes many to retain their allowances, then the price should rise, freeing additional allowances both from those where it is now feasible to overcontrol (because of the higher price) and from those holding allowances.

This alternative treats allowances, for accounting and ratemaking purposes, held by the utility as nondepreciating assets with a *nonzero* value. This would be similar to an inventory account such as for coal. Like coal, the utilities will expend allowances in the production of electricity that involves SO_2 emissions and will have to hold sufficient allowances to cover their emissions. These allowances will come from the utility's system-wide initial allocation and purchases. The allowances that are purchased, again like coal inventory, can be valued at the contracted price, if considered reasonable by the commission. Also, the number of allowances counted in inventory (and included in rate base) would be the amount determined to be reasonable by the commissions for normal operation of the utility's facilities plus some amount for unforeseen circumstances. The more difficult problem, and a likely source of distortion, is how the treatment of the initial allocation of allowances is valued.

One means of creating an unbiased ratemaking treatment would allow the utility to "buy-in" to the allowance system as a rate-based asset. The commission would determine the proportion of the value of the asset that belongs to ratepayers and what should go to the utility's shareholders (based on past ratepayer contribution to the generation of the asset, as in the above example of land). Also the commission would determine the fair market value of the allowances, based on actual contracts signed by the utility, external market information, or the EPA auction prices (provided sufficient information is made available). This value (the determined fair market price times the quantity of allowance) would be entered as a rate-based asset. This could be balanced with a deferred liability to ratepayers (asset value times the proportion determined to go to ratepayers).

It is important that a fair market price for allowances be determined rather than the utility's own internal control cost. This way the utility will base its decision on the number of allowances to buy, sell, and bank on external factors and not on its own cost of emission control. Basing it on the utility's control cost could also provide the utility an incentive either to inflate its control costs or not minimize them.

There are two alternative methods that could be used for the utility to buy the ratepayers proportion of allowances. First, the utility could purchase the allowances for one year from ratepayers. In exchange, the utility will be able to earn a return on the allowances. In this case, the value in rate base to the utility would be the difference between the commission determined value of the allowances and the balance still owed to ratepayers. Over time the utility would own more of the allowances as the liability is reduced, either in successive rate cases or through periodic adjustments. The commission may determine that all of the initially allocated allowances belong to ratepayers--this may apply particularly to older fully depreciated plants--or split the ownership between ratepayers and the utility.

Using the hypothetical affected unit shown in Table 1-6, assume the commission has determined that 100 percent of the initial allocation is owned by ratepayers and the fair market value of the allowances are $600 per allowance. Then $3,973,800 (6,623 x $600) is the asset value and amount of the deferred credit.[4] Initially, the utility will be deducting from rates more than its return on the asset (that is, earning a negative return). Over time, however, as the deferred credit is reduced the utility will begin to earn a positive return. If the commission determined that 80 percent belonged to ratepayers, then there would still be $3,973,800 as the asset value. The deferred credit would now be $3,179,040 and the remainder, $794,760, would go to stockholders' equity (the utility would then decide whether to pay it out as dividends, retained earning, or some combination of the two). Also, the utility would be allowed to earn a return on the $794,760 since this represents the net capital value to the utility ($3,973,800 - $3,179,040).

A limitation to this method is that it treats the allowances as a stock and not as a stream of allowances over time, which they are in reality. In effect then, the utility is making a one-time investment in exchange for the future return. This can

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[4] This could be paid out to ratepayers either as a lump sum (if the utility could provide it) or over several years in the form of reduced rates or deferred credit. It is assumed here that it is a deferred credit.

be viewed as the utility purchasing the right to the initial allowances. Another limitation to this method is that once the commission has made its determination on proportion of ownership and allowance price is becomes difficult to make adjustments should circumstances change sometime in the future (as is likely). This of course could be a limitation for either ratepayers or utility. The advantage to this alternative is that it would be relatively uncomplicated to implement.

Alternatively, a more sophisticated but complex method for a utility to buy the ratepayers' share is for the commission to determine a value for the entire stream for the life of the unit or for the unit that will receive the allocation. It is unlikely that the utility could or would purchase the entire allocation each year (in the above example, this would mean paying almost $4 million each year for a specified number of years). Rather, the commission may determine the value of the stream of allowances, with the payments declining each year until the utility owned the allowances completely. Again, as with the previous alternative of buying one years' allocations, the utility's return would be the difference between its allowed return on the asset value of the allowances less the liability owed to ratepayers. The utility would not earn a net return in the early years but would begin to earn a positive return over time.

For either of these alternatives, if there is a sale of allowances before the utility has paid the ratepayers' share, then cash is debited and allowance inventory is credited. The liability to ratepayers remains. It is critical, therefore, that the interest rate charged the utility (for the deferred liability) be about the same as the current market cost of capital. Therefore, the utility will base its compliance decisions on the projected cost of the option and not on what it perceives will be the benefit from strategic action designed to take advantage of this ratemaking treatment. This also will minimize the possibility of an Averch-Johnson-type bias or its opposite (discussed above).

This accounting method explicitly recognizes that the allowances are valuable assets to the utility and others and that the utility should not be the sole beneficiary of the CAAA's creation of this new asset. This method allows flexibility to the commission in determining explicitly what portion of the new asset's value should accrue to the utility and what should accrue to ratepayers. The purpose of allowing the utility an eventual return on the initial allowances is so the utility will not have a preference for large capital expenditures or purchased allowances over those initially allocated at zero (assuming that purchased allowances are allowed into rate base at the market price). While this method may not eliminate all distortions in the ratemaking process, it does remove the bias from options involving allowance transactions.

A commission adopting this method must then decide: 1) the fair market price for the allowances, 2) the portion of ownership of allowances belonging to ratepayers and shareholders, 3) the number of years that the utility will take to purchase the determined ratepayers' allowances, and 4) the discount rate for the purchase of the asset from ratepayers.

Prudence, Preapproval, Risk, and Utility Accountability

Title IV of the CAAA introduces a new concept to most commissions of environmental regulation, namely, supplanting command-and-control methods for a market-based approach. If allowance trading is successful an estimated $1 billion to $2 billion-a-year savings in compliance costs will result, as much as 25 percent of all estimated compliance costs.[5] If trading is unsuccessful, these savings will not materialize and the cost of compliance will be approximately the same as if each utility planned and invested in compliance in isolation--about the same costs as would have occurred through a command-and-control method.

Utility compliance planning is inherently risky. A compliance plan is extremely complex and involves looking fifteen or twenty years into the future. Once a plan is made, it can affect an entire utility system for many years. Utilities face the same uncertainties as in long-term capacity planning, but there are at least two additional uncertainties peculiar to CAAA compliance. First, increased demand for low sulfur

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[5] Andrew Weissman at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 30, 1991.

coal and other substitute fuels is expected to place an as-yet undetermined premium on them. Second, the price of future emission allowances is also unknown, making it difficult for utilities to compare the marginal cost of compliance or overcompliance strategies with the expected price of future emissions allowances.

Some analysts feel utilities are not willing and should not be required to take risks associated with compliance planning unless there are "guarantees" from regulators that utility costs and investments will be recoverable.[6] Otherwise, it is argued, utilities will take a conservative approach, planning for compliance on a stand-alone basis, planning to comply for phase I only, and not overcontrolling for phase II. If all utilities were to be so conservative, as mentioned, the cost of compliance would likely be the same as for command-and-control approaches, and the benefits of a market-based approach would be lost. Guarantees of this sort, however, run counter to at least one hallmark of public utility regulation--prudence requirements and their reviewability.

The Prudent Investment Test[7]

As part of the traditional regulatory compact, state commissions have provided utilities a reasonable opportunity to recover prudent investments and expenditures. Prudent investments are allowed into rate base for capital recovery and are permitted to earn a return. Similarly, a utility is allowed to recover its prudent expenditures. The prudence test dates back to a concurring opinion of Supreme Court Justice Louis Brandeis in 1923. State commissions have developed four guidelines in applying the prudence test. They are that (1) there is a presumption of prudence, (2) there is a standard of care that is reasonable under the circumstances at the time, (3) there is a proscription *against* hindsight (no Monday-morning quarterbacking), and (4) there is a retrospective, factual review.

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[6] For example, ibid.

[7] Much of this subsection is drawn from Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985).

The presumption of prudence resulted in few prudence cases before 1973. The Brandeis guideline basically states that every investment and expenditure is presumed to be the result of reasonable judgment unless the contrary is shown. State commissions have interpreted this as requiring a rebuttable presumption of prudence. Without such affirmative evidence showing mismanagement, inefficiency, or bad faith, an investment decision is presumed to be prudent. The presumption of prudence makes for efficient regulation in that commissions are not required or allowed to review the prudence of all utility decisions regardless of their number, importance, or outcome. This saves commission resources by allowing staff and commissioners to concentrate their oversight efforts on utility decisions the prudence of which are in doubt. While final results or outcomes of an investment or expenditure might overcome the presumption of prudence, they do not necessarily address the question of whether the investment or expenditure was reasonable at the time decisions were made.

Once the presumption of prudence has been rebutted, however, the utility has the burden of proving that the investment decision alleged to be imprudent was in fact prudent, and is held to a standard of reasonableness-under-the-circumstances that were known or reasonably knowable *at the time*. Perfection is not required. However, when the risk of harm to the ratepayer is greater than normal, the standard of care expected from a reasonable person is higher. In applying the standard of reasonableness-under-the-circumstances, which in some instances means highly risky and expensive projects, the utilities are held to a higher than normal standard of care to compensate for the risk and added expense associated with project decisions. State commissions have, understandably, sometimes held utilities to a high standard of care when applying the reasonableness-under-the-circumstances test to the completion of a nuclear power plant, for example.

The proscription against using hindsight is a corollary to the reasonableness-under-the-circumstances test. Decisions made by the utility are not subject to "Monday-morning quarterbacking." Instead, they are to be judged in light of the conditions and circumstances that were known or should have been known *at the time* of the decision. The final outcome is not relevant.

This guideline is familiar to members of the legal profession. In most litigation, the issue of liability focuses on the facts and circumstances at the time an expenditure or decision occurred, and not on the final outcome. This allows for a time-proven, "fair," and reasonably efficient assignment of risk between investors and ratepayers, with investors bearing "unsystematic" risks and ratepayers bearing "systematic" risks.

Unsystematic risk is related to the circumstances of a particular company, such as the risks associated with imprudent expenditures and decisions. Systematic risks are economy- or industry-wide, say, a prolonged or deep recession. The prudent investment test allows regulators to hold utility management responsible for unsystematic risks, while sheltering them (at least in part) from systematic risks beyond utility management control. Thus, commission use of the prudent investment test has held the utility accountable for risks that are particular to it (most of which are within the control of the utility management) and have held the utility relatively harmless for most industrywide risks outside of its control. This system of accountability seems sensible and consistent with the public interest. Many other systems of risk allocation and accountability, described later, might result in risk allocations that shift more risks to ratepayers.

The fourth guideline provides that once the presumption of prudence is overcome there be a retrospective, factual review to develop evidence about whether the investment decision was prudent at the time it was made. To do this, it is necessary that the evidence be backward-looking. (No ongoing or periodic inquiry occurs because the presumption of prudence makes such an inquiry unnecessary.) The retrospective inquiry is factual; the commission is seeking facts, not merely opinions. These facts should cover all the elements that did or could have entered into the decision, including all relevant information, decisionmaking tools, and the circumstances at the time. For example, it would be improper to use past data in a current computer model to review a past decision if the model was not reasonably available in the past. The facts should also be aimed at helping the commission separate systematic from unsystematic risks.

Although one financial analyst[8] has labelled the prudence test a form of "predatory regulation," it cannot fairly be said that state regulators on the whole abused or misused the test. A study by Oak Ridge National Laboratory set the total disallowance from 1980 to 1986 for nuclear power plant construction at $6.6 billion, of which $3.4 billion was disallowed as imprudent. The remainder was disallowed as not being "used and useful" or as being excess capacity. At the same time, $70 billion of capital investments was made in nuclear plants. Disallowances due to imprudence therefore represent only 4.8 percent of the capital expenditures eligible for rate base inclusion during this period.[9]

A later paper by Dr. John Anderson of the Electric Consumers Resource Council recounts that many utilities and their advocates claim that prudence disallowances have averaged 12 to 15 percent of construction costs. Dr. Anderson showed that the $9.8 billion in prudence disallowances between 1980 and 1988 amounted to 6 percent of *all* steam-electric plant entering operation ($156 billion) during that time.[10] Given the increased risks that utilities faced in constructing nuclear power plants, this does not seem to be an unreasonable amount that utility stockholders were called upon to bear.

Section 403(f) of the CAAA specifically permits state commissions to engage in prudence reviews of utilities' allowance trading and compliance plans. If the prudent investment test were applied to compliance planning, one might expect state commissions to assume the utilities' compliance plan is the lowest-cost alternative. But given the uncertainties of the cost of premium low sulfur fuels, the as-yet uncertain cost of advanced coal burning technologies, the marginal cost of conservation and energy efficiency, the marginal cost of scrubbers, and the unknown

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[8] Charles M. Studness, "Excess Capacity and Imprudency," *Public Utilities Fortnightly*, March 15, 1991, 41-42.

[9] Oak Ridge National Laboratory, *Prudence Issues Affecting the U.S. Electric Industry* (Oak Ridge, TN: Oak Ridge National Laboratory, 1987).

[10] A Presentation by Dr. John A. Anderson at the 102nd Annual Convention and Regulatory Symposium of the National Association of Regulatory Utility Commissioners, Orlando, Florida, November 15, 1990.

and uncertain future value of emission allowances, the presumption of prudence could be overcome. Again, the standard of review is not one of perfection, but one of making a reasonable decision given the facts and uncertainties that were part of the circumstances at the time. The process is similar to that faced by utilities preparing least-cost plans in states requiring them. Given the presumption of prudence and the consistent record of state commissions not applying hindsight in retrospective prudence reviews, utilities engaging in CAAA compliance planning have little to fear from the prospect of state commission scrutiny unfairly using the prudent investment test. The prudent investment test would only "punish" a utility for failing to consider all options in attempting to make reasonable efforts to seek a least costly strategy for compliance. One certain way a utility would be held imprudent is to take the approach of planning compliance on a stand-alone basis without considering the effect of selling or buying emission allowances.

Preapproval[11]

Alternatives to the prudent investment test have been suggested, most involving a preapproval process, whether a preapproval of the utility's planned actions or of expenditures. Preapproving planned actions means a state PUC reviews a utility's investment proposal and agrees to support those expenditures prudently and reasonably undertaken to complete the project. Indeed, preapproving planned actions would not differ greatly from certifications of convenience and necessity, preapproval of security issuances, or least-cost planning processes already in place at state commissions. The only difference is that preapproving planned actions would specifically find that the utility's planning is prudent. Legislative action that contains a form of preapproval of utility compliance decisions for the CAAA has passed in Indiana and is now being discussed in several other states.

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[11] Much of this subsection is drawn from Russell J. Profozich et al., *Preapproval of Major Utility Investments* (Columbus, OH: The National Regulatory Research Institute, 1981) and Robert E. Burns et al., *The Prudent Investment Test in the 1980s*.

In the context of a commission reviewing a utility's CAAA compliance plan, preapproving planned actions would involve the commission making certain that the utility examined all of the options and arrived at a least-cost plan.[12] Commission approval of the *plan* then would guarantee commission support for reasonable and prudent expenditures made toward the completion of the compliance plan. The commission decision that the plan is prudent would be made contemporaneously when all of the uncertainties that are part of the facts and circumstances known at the time are still fresh in mind. There is little or no danger of hindsight from such a strategy. However, the state commission still may reserve the right to examine the reasonableness and prudence of expenditures toward the completion of the plan, and it can require the utility to update periodically its compliance plan to reflect facts and circumstances as they change. This periodic updating might become part of the state's integrated or least-cost utility planning process.

A preapproval of *expenditures* refers to a state PUC's approving the recovery of expenditures on a utility investment without the traditional retrospective, factual inquiry into whether the expenditures were prudent. Thus, a preapproval of expenditures could prove to be quite different from current commission practices. Preapproval of expenditures would seem unlikely to be implemented by a state commission, unless it were accompanied by a contemporaneous assessment of the prudence and reasonableness of the utility's expenditures by the commission or its staff. Such a close involvement by the commission or its staff might result either in the commission becoming coopted by the utilities or with the commission staff taking over the utility's management tasks, neither of which is generally thought to be desirable. Moreover, most commissions do not currently have the resources to commit to a detailed analysis of utility compliance plans that would seem to be required for preapproval.

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[12] Given the uncertainties involved in this type of prospective decisionmaking, the use of innovative administrative procedures--such as joint problem solving or the collaborative process--might be appropriate. See Robert E. Burns, *Administrative Procedures for Proactive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1988).

The potential financial impact of preapproval stems principally from its potential for risk reduction and the shifting of risk from stockholders to ratepayers. Among the types of risk faced by investors are technological risk, demand risk, and regulatory risk. Technological risks are the hazards associated with a change in technology that may leave current plant and equipment economically obsolete. Demand risk is associated with an unexpected change in the demand for electricity, which may require abandoning plant under construction.

Utility managers and investors are compensated for bearing technological and demand risks in their rate of return. Regulatory risks are associated with unexpected changes in costs due to changes in regulatory policy. While regulatory risk potentially can be reduced by preapproval, preapproval in no way reduces technological and demand risks; it merely shifts these risks from utility stockholders to utility ratepayers. Because of this, there may be deterioration in the efficiency with which society bears risks. To avoid the socialization of risks (and losses) accompanied by the privatization of undue profits, any decrease in risk bearing on the part of the utility should be reflected by a decrease in the equity portion of the utility's rate of return.

However, it may be that the concept of preapproval is inconsistent with most current regulatory practices. Most states regulate their jurisdictional investor-owned utilities with rate-base/rate-of-return or cost-based regulation. A major and often cited disadvantage to cost-based regulation is that the utility has little or no incentive to minimize its cost where the firm's return on investment is not based on its performance. Retrospective reviews of utility actions evolved to (among other things)counteract this lack of incentive. Removing the possibility of retrospective reviews with preapproval only serves to remove this rectification of cost-based regulation. Therefore, lowering the rate of return with preapproval does not, in itself, insure cost minimizing behavior by the utility.[13]

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[13] For a discussion of incentive-based regulatory methods see K. Costello and S. B. Cho, *A Review of FERC's Technical Reports on Incentive Regulation* (Columbus, OH: The National Regulatory Research Institute, May 1991).

Critics of the traditional prudence test are exploring another option sometimes called a "rolling prudence review."[14] A rolling prudence review involves preapproving the utility's planned actions and making a contemporaneous, periodic approval of the prudence of the utility's expenditures; very closely akin to the preapproval of expenditures just described. The only major difference is the periodic, contemporaneous prudence reviews of expenditures--perhaps at significant construction milestones. For a state commission to engage successfully in a rolling prudence review, it would seem to need an independent, highly experienced engineering staff member on site to oversee all utility construction expenditures as well as other experts (financial) qualified to judge the prudence of expenditures on a contemporaneous basis.

Even so, the lack of lengthy retrospection could create problems. Without some retrospection, a commission probably could not separate systematic from unsystematic risks. Also, there might be the problem of "hidden imprudence," an example of which, in another context, was bad welds in a nuclear power plant that went undiscovered until the plant was close to completion. Because of the seriousness of the hidden imprudence in that particular case, the plant was converted from nuclear to coal at considerable additional expense.

Acknowledging that it is desirable for state public service commissions to take action to decrease regulatory risks, an alternative method is for a commission to issue clear guidelines stating the rules of the game "up front" for CAAA compliance. A specific statement outlining the commission's regulatory approach would tend to reduce regulatory risks to the utilities by making regulatory action *more predictable* but without the downside of shifting to ratepayers technological and demand risks that might be associated with a preapproval process.

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[14] At this writing, a paper, *New Approaches to Prudence Reviews for Utility Construction of Major Generating Facilities*, that includes this concept is before the NARUC. Time did not permit treating this initiative in this discussion. Moreover, it should be noted that prudence and preapproval in their varying forms are taken up here as <u>concepts</u> that have application in CAAA implementation; their possible future application to new generation additions is not the subject of this report.

State/Federal Interaction and Multistate Issues

Section 403(f) of the CAAA leaves federal and state jurisdictions unaffected by Title IV, the emissions trading provisions. Specifically, the section states that

> . . .Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such regulation or as limiting such a State regulation (including any prudence review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under the Act. Nothing in this title shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established. . .

The CAAA maintain existing state and federal commission jurisdictions for the oversight of utility compliance with emissions trading provisions. As one commentator stated "the Congress punted on how the EPA and the emissions trading provisions would fit in with state public service commissions and the Federal Energy Regulatory Commission."[15]

With existing state and federal jurisdictions maintained, the CAAA creates a new opportunity for state commissions to cooperate among themselves and with the FERC. Should this opportunity not be realized, a new area of jurisdictional conflict could result. Under a "business as usual" scenario, the FERC would have clear jurisdiction over registered multistate holding companies operating centrally dispatched systems and having capacity and energy allocation agreements approved by the FERC. Registered multistate holding companies could amend their allocation agreements to provide for the equitable division of compliance costs. Although there is no explicit statutory authority for it, the FERC might preapprove the costs of CAAA compliance and require pass-through of expenses to the state commissions without a thorough

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[15] Reinier Lock at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991.

prudence review. Under this scenario, state commissions cannot second-guess FERC decisions on matters covered by such allocation agreements.[16]

Registered multistate holding companies could also amend their allocation agreements to provide for the equitable division (allocation) of emission trading allowances among member companies. FERC's policies could significantly impact the health of the allowance market because the nine existing registered multistate holding companies under the FERC's jurisdiction will have 25 percent of the allowances by the year 2000.

A registered holding company petitioning the FERC to amend its allocation agreement would be subject to a hearing to decide whether the agreement was just and reasonable, nonpreferential, and not unduly discriminatory under the Federal Power Act. State public service commissions could be parties to such a hearing. Most (about 90 percent) FERC cases result in a settlement. If a case dealing with amending an allocation agreement to distribute allowances was settled, it is likely that tate commissions would have an ample opportunity to participate in the FERC settlement process and seek a prudence review of subsequent utility expenditures of the costs of CAAA compliance.

Multistate utilities that are not registered holding companies could apply for an exemption from state regulation if they meet the provisions of PURPA section 205. To be exempt the utility must show that state law prevents voluntary utility coordination, including central dispatch, if the coordination is designed to achieve economical use of facilities and resources in the area. No exemption is permitted if the state law is designed to comply with federal law or to protect health, safety, welfare, or the environment; to conserve energy; or to mitigate the effects of an energy shortage. However, a state commission could argue its oversight of CAAA compliance plans and allowance trading does not prevent the voluntary coordination of utilities if the regulation requires least-cost compliance planning, including buying and selling emissions allowances when economically feasible. As an integral part of a state commission's least-cost planning process, economic regulation of allowance

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[16] Mississippi Power & Light Co. v. Mississippi Ex Rel. Moore, 108 S.Ct. 2428 (1988).

trading would be designed to protect the health, safety, welfare, and the environment as well as to encourage economic conservation of energy.

Without federal preemption of unregistered multistate utilities and holding companies, inconsistent CAAA compliance planning strategies among state jurisdictions are possible. Disagreements could also arise between states on jointly owned plants and other multistate utilities. These inconsistencies could lead to trapped, unrecovered costs, double recovery of costs, or the inability of the utility to comply with an effective CAAA compliance plan because of conflicting regulatory requirements.

In this new context, state commissions and the FERC may find it useful to explore methods of regional regulation. Regional regulation could be as formal as a state compact, but could also entail informal agreements among states, a conference to develop regional uniformity, or informal methods, such as joint state problem solving workshops, informal information trading on a regional basis, and consultative mechanisms between state commissions and the FERC. Collaborative and innovative administrative procedures would enhance the ability of agencies to cooperate with one another. (Some available procedures are reviewed in a previous NRRI report.[17]) The objective should be consistent treatment among the states in a regional context to the extent possible, particularly for multistate utilities.

Any regional regulation approaches placed into operation should not simply become another layer of regulation. Regulators need to reach an agreement on a uniform approach to utility compliance planning to avoid this outcome. If a form of regional regulation among state commissions (and with the FERC where registered multistate holding companies are involved) were in place, regulators might better achieve a liquid, transparent, and smoothly operating emissions trading market. To encourage such regional regulation and coordination, FERC Commissioner Charles

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[17] Burns, *Innovative Administrative Procedures*.

Trabandt suggested that "FERC regulators should exercise maximum reasonable regulatory restraint *at this time*."[18]

Ownership Rights of Allowances

Section 403(b) of the Act, states that the EPA will issue regulations that will "permit . . .transfer of allowances prior to . . .issuance." The preallocation transfer of allowances will be deducted from the allowances otherwise allocated to the transferor and added to those of the transferee. If the allowance market develops as envisioned the market will ensure that CAAA compliance will be accomplished in an economically efficient fashion.

For an efficient and effective allowance market to develop, utilities must feel satisfied that allowances represent transferrable property rights. Congress, however, explicitly stated in section 403(f) of the Act that "allowances do not constitute a property right." Rather, sections 402(3) and 403(f) provide that an allowance is merely a "limited authorization to emit sulfur dioxide." In spite of the bill's explicit language, allowances are, in fact, a form of property right. What's more, the Congress also has held that allowances are assets of the utilities.[19]

The language placed in the CAAA almost certainly reflected two concerns. First, for political reasons, Congress did not want to appear to be creating a property right to pollute. Second, it did not want allowances to be compensable property rights under the Fifth Amendment.

The Fifth Amendment prohibits the taking of private property for public use without just compensation. Rights and benefits created by the federal government, which could have existed independently, may be compensable property. The property

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[18] Charles Trabandt at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991. For a complete text of his remarks see, "Remarks of Charles A. Trabandt, Commissioner Federal Energy Regulatory Commission," *NRRI Quarterly Bulletin*, 12, 2 (June 1991): 209-16.

[19] Report of the House Committee on Energy and Commerce on H.R. 3030 at 366.

interest need not be tangible. However, rights and benefits which could not have existed without government action usually are not compensable property interests, because they are wholly created and defined by federal statute and may be terminated or altered at any time.

Congress intended emissions trading allowances to be treated as a revocable permit or license. Courts have held that where a license or permit is expressly revocable, there can be no reasonable expectation that compensable property interest can arise.[20] However, where a permit is issued that is not expressly revocable, courts have held that a compensable property interest exists.[21] Until a permit or license is actually issued, there is no compensable property interest in the permit.[22]

In the case of emissions allowances, the EPA will begin issuing allowances to phase I plants in 1995 and to all plants in 2000. Until an allowance is issued, it is revocable even if it can be traded. Hence, there is no compensable property interest in the allowance should the Congress or EPA revoke the allowances through legislation. Once allowances are issued, however, there may be more than a mere expectation in the allowance: there may be a compensable property right.

Whether emissions trading allowances represent compensable property or not, potential allowance brokers need to design a model contractual provision that copes with the minimal risk that Congress or the EPA would revoke the allowances either before or after they are issued. Model contractual language would help minimize the transaction costs of transferring allowances and facilitate the goal of economically efficient compliance of CAAA's provisions.

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[20] American International Group v. Iran, 657 F.2d 430, 449 (D.C. Cir. 1981).

[21] Scott v. Greenville County, 716 F.2d 1409, 1421 (4th Cir. 1983).

[22] Nuclear Transport & Storage, Inc. v. United States, 703 F.Supp. 660,671 (E.D. Tenn. 1988).

Brokering Allowances

The CAAA does not restrict who can purchase, sell, or own allowances. Because an SO_2 emission allowance is essentially fungible, brokers can play a key role in helping arrange emission allowance trading. Brokers can quickly match buyers and sellers without the buyer and seller needing to engage in extended contract negotiations. Indeed, it is not even necessary for the buyers and sellers to be identified to each other, although they would need to be identified to the EPA for the purpose of recording the transfers. Once a standard contract is drafted to deal with the minimal risk that the EPA might in the future partially or fully rescind allowances (see the discussion on allowance ownership rights), brokers can help make the market liquid and lower transaction costs within the market. Because of the positive role that brokers can play in emission allowance trading, state commissions should encourage, and do nothing to discourage, the use of brokers in emissions allowance trading.

Tax Treatment of Allowances

The tax treatment of emissions allowances, while as yet unknown, will have important regulatory implications.[23] The tax decisions that the Internal Revenue Service makes will affect utility behavior and the regulatory treatment of the allowances.

The primary tax issues involve the receipt of the allowances, the sale or exchange of allowances, and the purchase and cost recovery of allowances. What follows is some speculation as to the most likely tax treatment of allowances.

The receipt of allowances is likely to be regarded as a taxable event, because the emission allowances have value and are expected to be traded and to have a

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[23] This section of the discussion draws freely on the presentation of Donald W. Kiefer on "The Tax Treatment of Emission Allowances," presented at the National Regulatory Research Institutes Workshops on Emission Trading in Arlington, Virginia, January 30, 1991, and Chicago, Illinois, May 9, 1991. The reader can obtain a copy of the presentation from NRRI.

market-based price. However, most phase I and phase II initial allowances will be issued to utilities based solely on their baseline fuel use. No income is received unless the allowances actually increase net worth. Thus, the receipt of the basic emission allowances is not likely to be regarded as taxable income. Rather, it is a zero-basis intangible asset on the utility's tax books until used internally or sold when, of course, it has a value. This approach is analogous to that used in EPA's program of lead rights trading which existed from 1982 through 1987.

Besides emission allowances received by utilities as a means of imposing the basic emission tonnage limits, there are three other areas of concern. First are the allowances withheld for the EPA Administrator's reserve for auction. These allowances should raise no tax consequences when withheld, and if returned in the form of allowances, should also present no tax consequences at that time. However, if the allowances are sold from the reserve and returned as income from their sale, that income would be taxable. If a utility must purchase allowances to replace those withheld for EPA's reserve, the cost of the allowances may be netted against the proceeds of the sale of the withheld allowances as an involuntary conversion.

Second, extra "bonus" allowances will be given to some utilities under phase I and phase II under sections 404 and 405 of the CAAA. The tax treatment of these bonus allowances will be more problematic. Under phase I, utilities in Illinois, Indiana, and Ohio are to receive pro rata shares of a pool of 200,000 extra allowances annually. There are extra allowances for early reductions and for 90 percent removal scrubbers. Extra allowances also are to be given for emissions avoided through energy conservation programs and renewable energy sources.

Under phase II, a pool of 50,000 allowances annually will be shared on a pro rata basis by utilities in ten states, including the three states already sharing the special pool under phase I. There also is a special pool of 125,000 bonus allowances annually to be divided among utilities in "clean states." Finally, there is a larger pool of bonus allowances available for allocation to utilities in certain "high growth states."

One way of considering these bonus allowances is as a nontaxable, selective means of relaxing the generally stated emissions limitations. Another way that is perhaps more likely is as subsidies to help defray extraordinary pollution control costs, to induce extra pollution control efforts, and to piece together the political coalition necessary to pass the CAAA. If viewed as subsidies, the allowances would be considered taxable income equal to their market value at the time they were received. Alternatively, if bonus allowances are used to subsidize investment in specific pollution control assets such as scrubbers, the basis of the assets might have to be reduced by the value of the allowances.

The second taxable event occurs when the allowances are sold or exchanged. Sold allowances are likely to be considered capital assets under section 1221 of the Internal Revenue Code. As such, proceeds from the sale in excess of the tax basis would be taxed as a capital gain. Likewise, any excess of basis over the sales proceeds would be a capital loss.

The basis is likely to be zero for allowances received as part of the initial phase I and phase II distribution. If the receipt of bonus allowances is taxed, the basis would be the imputed (pretax) value of the allowances at the time of receipt. The basis for purchased allowances would be their cost.

Section 1030(a) of the Internal Revenue Code--the "like-kind exchange provision"--might allow exchanges of allowances usable in different years without any gain or loss on the exchange. If so, the allowances received in such a trade would assume the basis of the traded allowance.

The capital gains or loss treatment of allowances would make EPA recording and tracking allowances important, even though the EPA might choose not to develop specific inventory rules. A company holding allowances might prefer to determine which allowances are sold when, and hence determine their basis for the sale. Alternatively, the IRS may require a recognized accounting procedure such as first-in, first-out or some sort of average approach. The tax code allows last-in, first-out and certain other inventory methods so long as the same method is used in the firm's financial reports.

The primary tax issue when emission allowances are purchased is what kind of asset the allowances represent to the purchaser. This determines the type of cost recovery. The most widely held view is that emissions allowances should be deducted against the income they are used to produce on an as-used basis. How to derive this under the tax code is uncertain. One possibility is to view the allowance either as inventory or as deferred expenses--(IRC section 461(h))--to be deducted in the year used. Another appealing possibility is that the allowances might be considered intangible assets with no fixed life that are written off in the year they are exhausted or used.

A less desirable (that is, higher tax liability) treatment is that the allowances could be viewed as an intangible asset to be amortized over an assumed useful life.

Interperiod tax accounting issues could arise if tax and ratemaking treatments of allowances differ, particularly where allowances (specifically bonus allowances) are taxed on receipt, where state commissions allow recovery on allowances purchased and banked for future use, and where regulatory commissions do not allow rate base treatment of investments in overcontrol compliance strategies.

Least-Cost Planning Issues

Three major least-cost planning issues are associated with emissions trading and compliance planning. The first concerns whether state public utility commissions engaged in least-cost or integrated resource planning should incorporate CAAA compliance planning, including the use of emissions allowance trading, into their least-cost planning process. If the answer is yes, the second issue is how emissions allowance trading and compliance planning ought to be reflected in least-cost planning. The third issue concerns the least-cost planning requirements of CAAA section 404(f), which must be fulfilled for utilities to receive bonus allowances for qualified conservation and renewable energy sources. (See preceding discussion on conservation and renewable bonus allowances.)

CAAA compliance planning strategies, including emission allowance trading, would likely be a part of least-cost or integrated resource planning in those states that require them. Unless compliance plans and strategies are incorporated into the least-cost planning process, the result of least-cost planning would be something other than a least-cost plan. For a state commission to affirm, accept, or approve a least-cost plan, it must be able to assure itself that a utility's planned demand-side and supply side investments result in energy services being provided to the customer at the least cost. If a utility has any fossil fuel burning units that will be an affected SO_2-emitting unit under either phase I or phase II, then the utility's costs will be directly affected by the CAAA. This is true even if the utility's units all emit under 1.2 pounds of SO_2/million Btu, because the utility receives emissions allowances for the unit's baseline emissions times 120 percent. Those allowances can be banked or sold on the market. Also, the CAAA affects the dispatch priority of all affected units. The utility would need to factor in the opportunity cost of the emissions allowances before expending the allowance through generation that leads to SO_2 emissions. The opportunity cost of a current vintage-year allowance would be no less than its current market price. Even utilities that rely entirely on hydropower and/or nuclear energy and thus have no affected units would be affected indirectly by the CAAA because they would have to consider its effect in any future capacity planning decisions.

The second issue concerns how compliance planning would be integrated into least-cost or integrated resource planning. Actually, compliance plans make such planning a simpler process. CAAA compliance planning provides a means by which at least one externality, the effect of SO_2 emissions, becomes a partially if not completely internalized cost. The alternative resources in least-cost planning would each have a different compliance cost. Certain alternative resources could also produce offsetting revenues by freeing emission allowances. Capital and operating costs can be offset by revenues from the sale of emission allowances. These costs and potential revenues should be included for each demand- and supply side resource considered in a least-cost plan. For example, retrofitting an existing plant with a scrubber would increase the plant's capital cost, and affect its operating cost. If the scrubber resulted in overcontrol, however, the utility would be free to sell, use, or bank the allowances it would have otherwise used to run an unretrofitted plant. Similarly, the use of conservation or demand-side management practices has the potential of freeing allowances and producing revenues that would offset the cost of the option. Once the costs (including emissions compliance costs) of all demand- and supply side resource options are considered, a state commission can review a utility's least-cost plan following its normal procedure.

It may be necessary, as a matter of expediency, to consider initially what the least-cost compliance planning options are outside of a comprehensive least-cost planning process. However, it makes sense to subsequently include CAAA compliance options in future least-cost planning processes, particularly since a new supply side option that relies on fossil fuel will require the purchase of emission allowances.

The third issue concerns bonus allowances for qualifying conservation and renewable resources. To qualify for the available bonus allowances, as noted earlier, a utility must engage in least-cost planning. The least-cost plan must integrate demand-side and supply side resources on a consistent basis and be reviewed and approved or accepted on a regular basis by the state public utility commission or other applicable ratemaking authority. The plan should consider and may incorporate the social and environmental costs and benefits of the resource investment. The planning process must provide for public participation, and the utility must implement to the maximum extent practicable any plan or filing as approved or accepted.

Commissions may consider adopting, as part of a least-cost plan, a bidding program to reduce sulfur emissions. In such a program third parties could bid against each other (and perhaps the affected utility) to reduce the SO_2 emissions at a particular unit or system wide. Possible participants include scrubber manufacturers, coal and allowance brokers, or other utilities. The bidders would present a package of compliance options that may combine control technology, buying and selling of allowances, and/or fuel switching. If the strategy of the winning bidder involved overcontrol, then the bidder may take title to the freed-up allowances. Such a bidding program could be integrated into the least-cost plan in a similar manner that competitive bidding for generation has in some states. Compliance decisions made as a result of commission approved bidding could also be presumed prudent as an incentive to the utility provided the commission believes that there was sufficient competition in the bidding process.

Developing Regulatory Guidelines

From the above analysis and discussion several summary points can be made. When Congress established a market-based allowance system to limit SO_2 emissions in the CAAA, it created a new asset. The national allowance market, if it develops successfully, will determine the price or value of these allowances. State PUCs and the FERC, however, will be determining the value of the allowances for ratemaking purposes. While the individual commissions may not regard the development and success of an allowance market as their responsibility, it likely will benefit ratepayers if it does work. From the perspective of the individual commissions, the creation of allowances provides an additional means for utilities to comply with federal pollution control standards.

Public utility commissions can take several actions to ensure that their jurisdictional electric utilities make decisions that are in the long-term interest of ratepayers. One action is to develop regulatory guidelines that include the specific ratemaking treatment of the initially allocated allowances; purchased, sold, and banked allowances; and capital and fuel expenditures made for CAAA compliance. Developing guidelines can reduce the regulatory uncertainty associated with the utility's compliance decisions.

Three elements should be considered for the guidelines. First, they should provide the utility with a reasonable degree of predictability. The description of the regulatory treatment should be sufficiently detailed so the utility, when making its compliance decisions, can reasonably predict what the regulatory treatment will be. This treatment need not necessarily include a preapproval of a specific compliance plan. Preapproval may be inconsistent with the manner in which most utilities are regulated. Commissions may need to preserve a process of retrospectively reviewing compliance decisions. These procedures were developed, in part, to alleviate the lack of incentive that the utility has to minimize costs under cost-based regulation. Lowering the allowed rate of return to reflect the reduced uncertainty does not solve this problem with preapproval.

Second, the guidelines should allow utilities flexibility in choosing a compliance option. By allowing the utility flexibility in choosing compliance options, the commission increases the number of compliance options considered by the utility and permits it to seek feasible and innovative alternatives, including buying and selling allowances. Other possible options include repowering, redispatching existing units, purchasing power from others, switching to lower sulfur coal, installing scrubbers, adopting innovative clean coal technologies, and pursuing conservation to reduce demand.

Third, and perhaps most importantly, commissions can adopt a ratemaking treatment that does not bias the utility toward a particular compliance option while it provides the utility with an incentive to minimize its net compliance cost (for example, net of revenues from allowance sales as shown in the example in Table 1-6). The treatment can be structured in such a way that the commission's involvement in the actual compliance decisions of the utility is minimized. The primary goal is to minimize the cost of compliance to ratepayers by providing the utility with an incentive to minimize its own costs. This will help ensure that the utility makes decisions in the long-term interest of ratepayers.

If the utility believes or is told that large capital expenditures such as scrubbers will be included in the rate base and the initial allocation of allowances will not be added to rate base, the utility may be biased toward building the scrubber and selling its excess allowances. Another bias can result if a commission indicates that purchased allowances will be rate-based at the purchased price (if considered reasonable) but that the initially allocated allowances, issued at no cost by EPA, will not be included in rate base. In this case a utility may attempt to comply with the CAAA by purchasing allowances only and not considering other options or attempt to simply exchange its initial allocation for purchased allowances. This type of behavior may not be in the long-term interest of ratepayers.

It is here posited that allowances will be valuable assets to the utility and others, that the regulatory treatment affects the utility's compliance decisions, and that the regulatory process should have no bias toward any particular compliance option. Since it is assumed that allowances will be valuable assets, their regulatory treatment should recognize this and determine who owns them and who should benefit from them. Commissions can determine a value and the proportion of the value of allowances that belongs to ratepayers and to the utility. Current allowance holdings (or inventory) of the utility and all future gains and losses from the transfer of allowances would use this commission-determined proportion.

To properly value allowances in rate base the commission can also determine a fair market value. This ensures that the utility is basing its decision on an external price and not on its own compliance cost. The utility then can use this external information to decide on the optimal level of SO_2 control. One procedure for including the allowances into the rate base would be to enter the value of the allowance inventory as an asset and create a liability for the portion that represents the ratepayers' share. The value to the utility would be the difference between the asset value and the utility's liability. This value would increase over time as the utility "purchased" the allowances from ratepayers through a reduction in rates. A periodic adjustment process could be used to reflect the current value to the utility, avoiding a complete rate case.