

PART II

COMPLIANCE PLANNING ISSUES

CHAPTER 4

THE ROLE OF FEDERAL AND STATE REGULATORS IN ADMINISTERING TITLE IV OF THE CLEAN AIR ACT

Four significant actors are involved in the implementation of the CAAA. First, there is the federal EPA with authority to administer most of the Act's provisions including allocating allowances and tracking them. Second are the state air quality or environmental protection agencies, which will play a significant role in the permitting process of phase II. Third are the affected utilities which, acting through their "designated representatives," have specific reporting requirements as well as emission limits. Fourth are the economic regulators, the state public utility commissions, and FERC. While they have some direct responsibilities outlined in the CAAA, they also play a significant role as economic regulators in the utility planning process that is not specified by the CAAA.

This section addresses the role of these actors in CAAA implementation by outlining the main regulatory reporting relationships they have as described in EPA's proposed rules. These relationships are diagrammed in Figure 4-1. In general, the federal EPA is the most directly involved regulatory agency, although important ancillary roles exist for state commissions. What's more, the state air quality board or state EPA plays a more direct role in CAAA administration in phase II.

The Designated Representative and Filing Responsibilities

While the owner or operator of an affected unit has the responsibility to ensure its compliance with the requirements of the CAAA, the federal EPA is the main administrator. Each owner and operator of an affected source and unit will interact with the EPA exclusively through a "designated representative." The designated representative would not be personally liable (in the absence of any criminal wrongdoing) should difficulties arise, and could be, but does not have to be, the plant

Fig. 4-1. Flow chart of regulatory reporting relationships

(Source; Authors' construct).

manager. As a prerequisite to obtaining a permit, the designated representative must file a Certificate of Representation with the EPA which includes a binding agreement of representation and a binding agreement regarding the holding and distribution of allowances. The permit is an authorization from EPA under Title V of the CAAA and is distinct from Title IV allowances. The Certificate states, among other things, that the designated representative was selected by an agreement binding on all owners and operators. The Certificate also must identify an alternative designated representative to act when the designated representative is unavailable. The designated representative would represent the owners and operators of each affected unit in matters pertaining to the acid rain program, including submitting and complying with acid rain permits, permit applications and compliance plans, and holding, transferring, and disposing of allowances.

During phase I and phase II of the CAAA, copies of all acid rain filings are sent simultaneously to the state environmental protection agency, the Regional Air Program Division of the EPA, and the EPA Acid Rain Program headquarters. The current proposal does not specify whether the Regions or Headquarters will issue permits, but instead uses the term "Administrator." Although EPA's current thinking is that the Agency would employ a team approach where EPA Headquarters, Regional Office, and State would work together, the regulatory stance of the EPA historically suggests the Regional Air Program Division as the most likely candidate for Administrator. The designated representative is to file the *Acid Rain Permit Application and Proposed Compliance Plan* with the EPA Administrator by February 15, 1993. This representative must also submit, prior to or along with the source's permit application, a proposed monitoring plan. Phase I emission-monitoring-system verification test results would not be required by this deadline. The CAAA allows flexibility to utilities when choosing from a variety of options for their affected units to achieve the most cost-effective means of complying with the mandated SO₂ and NO_x emissions reductions. The state commissions and FERC, in their review of the long-range planning of utilities, may influence a utility's plan as they attempt to comply with the acid rain program requirements. To date, approval or acknowledgment of the compliance process or the compliance plan itself appears to be an important role for the state commission in the administration of the CAAA. This involvement by the commission, however, is not mandated by the CAAA.

Conservation and Renewable Energy

The CAAA does not require the designation of a compensating unit when reduced utilization occurs at a phase I unit as a result of a program of energy conservation or improved efficiency measures. However, to get credit for such measures, these programs should be described in the unit's proposed compliance plan and the kilowatthour savings resulting from these measures must be verified by an independent auditor, by the state commission, or by the entity with utility-rate regulatory authority. Only states that have adopted least-cost planning and net-income neutrality rules for investments in energy conservation would be qualified under the CAAA to verify demand-side measures. DOE must certify that the state regulatory authority has implemented provisions that guarantee net income neutrality. In the case of qualified renewable energy generation, the state commission must certify that the applicant has, and is, implementing a least-cost plan. Finally, all applications for allowances from the conservation and renewable energy reserve (described in Chapter 1) must be certified as to the truth and correctness of the information submitted to EPA. The CAAA requires that utilities submit their applications to their state commission for review of accuracy and compliance with the requirements of the Act and the proposed regulations. EPA requires in the application a signed certification by a state regulatory authority that this review was completed. For repowering of a unit, the designated representative must obtain DOE and EPA approval of the repower technology during the repowering application process (this too may be considered eventually by the state commission, but again is not mandated by the CAAA).

Permitting Process

During phase I the EPA will process permit applications, write and issue permits, and process permit revisions. (Again, a permit is an authorization to emit SO₂ granted by EPA as stipulated by Title V, and should not be confused with Title IV allowances.) In cooperation with state and local air quality agencies, the EPA will monitor compliance and, when necessary, take appropriate enforcement action. As mentioned, the designated representative is required to submit the acid rain permit application and proposed compliance plan. The permit application contains both a certification for each affected unit indicating it will meet the applicable emissions limitation requirements in a timely manner and a certification indicating it will hold enough allowances to cover emissions for the year. EPA will review these applications, and if approved, issue the permits by August 15, 1993. The permits have a term of five years (the first term being 1995-1999) and will take effect on January 1, 1995.

As noted in Chapter 1, phase I units may apply for a two-year extension of this compliance deadline provided that they install 90 percent sulfur dioxide removal technology or transfer their emissions to a unit or units that have such technology. In this case, the designated representative would also submit a Compliance Certification annually, quarterly, or as otherwise mandated. The Compliance Certification is a departure from traditional methods of determining compliance (that is, on-site inspections and source-specific investigatory letters).

The appeal procedures include an administrative appeal and judicial review. Disputes involving phase I acid rain permits will be handled first through an EPA Regional Office administrative law judge. If not resolved at this level, the Federal Circuit court will offer the next level of recourse for the owners and operators of an affected unit.

During phase II, which begins January 1, 2000, the state Environmental Protection Agency will be the permitting authority unless it is not adequately administering or enforcing the program, in which case the federal EPA will be the permitting authority. The Regional Air Program Division would be responsible for reviewing state permit programs beginning in 1993 for consistency with the acid rain program and for reviewing proposed state-issued operating permits. The state agency will make a "determination of completeness" and forward the "proposed permit"

to the EPA for review. Standardized forms for permit applications, compliance plans, permits, and compliance certifications will ensure national consistency and a smooth transition from phase I to phase II. EPA will write a "draft permit," give public notice, and allow for public comment. Following submission of all comments, the proposed permit will then be revised. Assuming the EPA does not veto the permit application, the acid rain permit would then be issued. The state permitting authority is required to issue Title V permits containing phase II SO₂ requirements to all affected sources by December 31, 1997. The state permitting authority must also begin to process NO_x permit applications in 1998. Within four years after the state permitting authority receives EPA approval of its Title V permits, it must complete the process of issuing permits for all CAAA requirements to all affected sources in its jurisdiction.

Appeals of the state-issued permits are carried out through state administrative and judicial appeal procedures. The EPA reserves the right to intervene in any challenges to acid rain conditions brought in the state courts and proposes that it be given notice of any such challenges. Further appeals can be made through administrative review at the EPA and judicial review in the Federal Circuit Court.

Allowance Tracking System

The federal EPA will establish an Allowance Tracking System no later than January 30, 1993. EPA will determine a unit's compliance by deducting from the unit's subaccount allowances equal to the SO₂ emission tonnage reported for the unit each year. As mentioned, the "allowance transfer deadline" is proposed as January 30 of the calendar year following the year for which compliance is being established.

The allowance market participants themselves will make the market work and the EPA has eschewed any option that would expand its role beyond those expressly prescribed by the CAAA. As mentioned, the Chicago Board of Trade has announced its intention to create an allowance exchange. The market activities of the affected units (that is, cash price paid for allowances and other terms of the contracts, such as coal deliveries or power purchase arrangements) may come under the scrutiny of the state commission's economic regulation. Price information will be

available from EPA auction results, while price and contract terms may be reported to FERC and state commissions.

Continuous Emissions Monitoring Systems

Owners and operators of an affected unit or units are required to install a continuous emissions monitoring system (CEMS). The proposed rules include requirements for (1) a monitoring plan for compliance plan and permit, (2) written notification of monitoring performance tests thirty days prior to conducting the tests, (3) maintenance of records of emissions and flow, (4) reports of performance certification tests, (5) reports of quality assurance and quality control tests, and (6) quarterly submissions of monitoring data.

Penalty for Excess Emission

As noted in Chapter 1, there is a statutory-based penalty of \$2,000 a ton for excess emissions (that is, emissions beyond allowances held). In addition, the source must cover this excess with allowances in the following year (to maintain the tonnage cap). This is intended to eliminate any financial benefit owners and operators of affected units might otherwise derive from exceeding their emissions limitations as required by the CAAA. This penalty is estimated to be more than twice the expected market value of an allowance.

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 § 404(f), which must be fulfilled for utilities to receive bonus allowances for qualified conservation and renewable energy sources. (See preceding discussions on the conservation and renewable bonus reserve.)

CAAA compliance planning strategies, including emission allowance trading, would likely be a part of least-cost or integrated resource plans in those states that have these programs. 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 SO₂-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 SO₂/million Btu, because the utility receives emissions allowances for the unit's baseline emissions times 120 percent. Excess 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 SO₂ 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, nuclear energy, or both 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 (to the extent that the plan deals with externalities), the effect of SO₂ 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 for phase I, to consider initially what the least-cost compliance planning options are outside of a comprehensive least-cost planning process. However, it makes sense to include CAAA compliance options in future least-cost planning processes, particularly since new supply side options that rely on fossil fuel will require emission allowances and, as noted, true least-cost planning requires a systemwide comprehensive approach.

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 may consider and 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.

An option commissions may consider as part of a least-cost plan is 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 SO₂ emissions--either 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 fuel switching, or all of these. 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 as competitive bidding for generation 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 there was sufficient competition in the bidding process.

Overview of Compliance Planning

Range of Available Options

Emissions allowance trading needs to be examined in the context of the diverse range of options a utility has to comply with the CAAA. They broadly fall under options that directly reduce emissions, those that reduce emissions by modifying generation requirements, and those that meet compliance standards by making use of emission allowances (Figure 4-2). These options are neither mutually exclusive nor independent, and they may have to be integrated to develop a comprehensive compliance strategy.¹ Compliance plans and strategies, therefore, may be best developed on a systemwide basis.

¹ For a more comprehensive overview of clean air compliance options and strategies, see Electric Power Research Institute, *Clean Air Response: A Guidebook to Strategies* (Palo Alto, CA: Electric Power Research Institute, 1990), RP 3199-1.

Fig. 4-2. Range of clean air compliance options

(Source: Authors' construct).

Compliance options that directly reduce emissions include scrubbing and other clean coal technologies (CCTs), coal conversion, switching to a lower sulfur coal, switching to a natural gas fuel, making greater use of nonfossil power technologies such as nuclear, hydro, solar and other renewables, and redispatching existing fossil-fueled plants to reduce emissions.² Compliance options that reduce emissions by modifying generation requirements include conservation, load management, and other demand-side management (DSM) options. Finally, use and management of emission allowances, the focus of this current report, constitute a compliance option. A utility may choose to overcomply on certain of its plants using perhaps a combination of options from the first two categories and the surplus allowances to meet compliance requirements on other plants. It also can purchase allowances from the market to do the same.

Factors that Govern the Choice of Options

A comprehensive compliance strategy that considers a mix of compliance options is more likely to identify lower cost strategies than a more limited approach. A comprehensive approach would require examining the options with an array of interrelated factors that include, among others, technological feasibility and performance history, capital (including retrofit, repowering and replacement) costs and operating expenses, potential revenues from implementing an option (such as revenues from selling the byproducts of a wet scrubbing process), the projected price of emission allowances, state commission policy on the recovery of compliance costs and the sharing of possible allowance profits, and the uncertainty and the risks attending each of the aforementioned factors. In general, a utility is likely to prefer options that have a proven record of technological performance, involve low retrofit costs, have capital and operating costs that are likely to meet with state commission approval, and carry small uncertainties and risks. It is unlikely that any given option will satisfy all or even most of these desirable criteria. An optimal

² For a detailed discussion of clean coal technologies, see U.S. Department of Energy, *Clean Coal Technology Demonstration Program* (Washington, D.C.: U.S. Department of Energy, 1990).

compliance strategy will try to balance the costs, benefits, and risks to maximize the net gain to the utility. To develop such a strategy, it is important to examine the factors that characterize each compliance option.

Technological Feasibility and Performance History

The compliance requirements of each individual utility and plant owned by a utility may vary. Some compliance options will be technologically more effective in controlling pollutant emissions from plants of a certain design and fuel type than others. Also, the various technologies for controlling emissions may vary with regard to their performance history. As examples, wet scrubbing technologies are capable of removing 90 percent or more SO₂ on a wide variety of coals with reagent utilization ratios (which measure the efficiency of the sulphur absorbing chemical) between 1.0 and 1.2, while dry scrubbers are more effective on low sulphur western coals achieving 70 to 90 percent SO₂ removal at reagent ratios of 0.8 to 1.1. Also, wet scrubbers have been used much longer and more extensively than dry scrubbers, accounting for about 92 percent of total scrubbed capacity in the United States.³ Other things being comparable, a utility is more likely to choose a compliance technology with a proven performance record to minimize the risks of underperformance.

Capital and Operating Costs

Implementing a compliance option may involve retrofit, repowering, and replacement costs depending on the extent of changes needed to equip an existing plant with emission control devices. Switching to a different fossil fuel (such as natural gas), clean fossil alternatives, or nonfossil alternatives (such as nuclear, hydro, and renewables) involves new construction costs. In addition to capital costs, each compliance option changes the operating costs of existing plants or introduces new operating costs. Depending on the existing generation mix of a utility and

³ Electric Power Research Institute, *Clean Air Response*, Part II, III-6.

prevailing/expected regulatory treatment of various costs, a utility may favor one type of option or technology over another. For example, if a utility is burdened with an excess capacity problem, it is unlikely to choose options that add new capacity to the system, even if such options appear favorable on the basis of pure cost. Besides direct capital and operating costs, each option may involve indirect costs such as those due to potential reduced availability that also may influence a utility's compliance choices.

Revenues and Earnings

A compliance option may generate additional revenues for a utility. The best example is, of course, potential earnings from sale of allowances. Another example is the revenues from the sale of byproducts such as sulfuric acid from the use of certain "regenerable" scrubber technologies.⁴ Regulatory treatment of such earnings will govern whether such options are favored by a utility. For example, if a utility is allowed to retain a significant part of earnings resulting from implementing an option, the option is more likely to be favored over another that generates no additional earnings. On the other hand, if the utility is allowed to retain little or no part of its earnings, it is more likely to choose options on the basis of cost alone.

Regulatory Treatment of Options

The choice of an option, it has been noted, is governed not only by its cost, technological performance, and effect on the existing system, but by the regulatory treatment of each of these factors. In addition to the issues already mentioned, others merit discussion.

A utility subject to traditional rate-of-return (ROR) regulation characterized by strong oversight and scrutiny in the form of prudence reviews and strict application of the "used-and-useful" standard is likely to favor those options that minimize regulatory risks rather than those having the best potential to minimize overall costs. For example, scrubber technologies generally

⁴ Ibid.

have higher capital costs relative to other options, but exhibit a lower operating cost.⁵ A utility is, however, likely to shy away from scrubbers if it perceives a significant risk of future disallowance of investment costs. At the other extreme, if a state commission preapproves a compliance plan, it relieves the utility of any significant risk of underrecovering its costs and impedes future adjustments or innovations that would improve the efficiency of the system within the preapproval period (this limitation to preapproval is discussed more fully in Chapter 6). The effect can be dramatic if allowance prices turn out to be low relative to scrubbing costs, and the preapproved compliance plan included significant investments in scrubbers.⁶ The effect of regulatory treatment on the decisions of a utility is the main focus of Chapters 7 and 9.

Future Allowance Prices

Perhaps the most critical factor governing the choice of a compliance strategy is the expected price of emission allowances and its attendant uncertainty. In Chapter 1, the effect on the choice of compliance option of the assumed allowance price was demonstrated. This provided a simplified and static approach to optimal compliance planning under the projected scenarios of high, medium, and low allowance prices relative to the costs of various compliance options. The conclusions regarding the role of allowance prices derived from the simple illustration would generally be valid even if actual compliance planning would involve significantly more complex analysis. One such conclusion is that a utility should only use compliance options that have unit incremental costs lower than the allowance price and only when all such options are exhausted should it purchase allowances to meet any remaining compliance requirements. What makes more complex analysis essential is the fact that a compliance plan or strategy has to be designed *before* any of the costs or prices and regulatory treatment of any of the related expenses are known. The utility's compliance strategy needs to account for such uncertainties and their

⁵ Ibid., Part II, III-5.

⁶ The effect of ratemaking on compliance choices is discussed in more detail in Chapter 7. The issues of prudence and preapproval are discussed in Chapter 6.

attendant risks. Also, since the expected price of allowances becomes more uncertain over time, any strategy that relies on purchasing allowances, that is, one that requires the purchase of a stream of allowances over time, would have to factor this temporal uncertainty into the analysis.

Uncertainties and Risks

Each of the factors discussed so far involves market-related uncertainties and risks. The impact of uncertainties was dramatically demonstrated during the 1970s when electric demand failed to grow according to earlier forecasts resulting in a large number of utilities being burdened with excess capacity and stranded investments. The utilities may be faced with the same difficulties if future load growth, fuel prices, capital and operating costs of emission control technologies, and allowance prices depart significantly from forecasts used to develop compliance plans.

Developing an Optimal Compliance Strategy

The General Approach

To develop an optimal compliance plan, the general approach of solving any forward-looking optimization problem can be used. That means defining an objective function or performance index to be optimized (maximized or minimized), choosing the decision variables that constitute the utility's menu of choices, identifying the constraints

that must be met, and finally setting the planning horizon over which the optimization is to take place.

In the case of clean air compliance, there are a number of choices for the objective function. Two such choices that immediately suggest themselves are the net or incremental cost of compliance and the net cost of generation (including the cost of compliance). Given the adoption of the least-cost standard by most state commissions, it is reasonable to assume the latter (net cost of generation) is a more appropriate choice for an objective function.

The constraints include the electric loads that must be satisfied, the emission caps that must be met, other environmental requirements to be met, and constraints imposed by scheduled plant maintenance and unscheduled plant outages.

The planning horizon can be as short as one year or as long as thirty (or more). Choosing either short or long planning horizons has its respective advantages and disadvantages. Shorter planning horizons mean that the actual conditions are unlikely to deviate significantly from forecasts. The disadvantage is that short-term compliance plans are likely to turn out to be suboptimal over the long run. This becomes critical when compliance choices involving either long construction periods or long payback periods are excluded, even when they are optimal because a short planning horizon is chosen.

Use of a longer planning horizon captures the cost savings and benefits of investments with long payback periods. However, a long-term plan is more sensitive to forecast errors and uncertainties. Another factor to consider is the lack of flexibility with respect to large investments that may involve either long construction periods or long useful lives. Investments in options with long construction periods may be faced with premature abandonment if the investment, for example, on hindsight turns out to be imprudent. Options that have long useful lives may have to be written off prematurely if the costs of continuing to operate them become prohibitive relative to other options. In both cases, a state commission may be confronted with the predicaments of allocating the costs of abandonment of a project that is either incomplete or completed but underutilized and of having to decide the appropriate recovery of such costs.

An optimal compliance plan needs to account for uncertainties and risks inherent in implementing any forward-looking plan.

Accounting for Uncertainties and Risks

The need to account for uncertainties and risks in utility planning has been recognized following the failure of many planning parameters to meet forecasts in the 1970s and early 1980s. More important among these parameters include load growth, fuel prices, construction lead times, and inflation rates. When considered in the context of least-cost and integrated resource planning, other parameters subject to uncertainty include customer response to DSM initiatives, costs of DSM options, potential energy savings from DSM measures, and regulatory treatment of DSM options. To this list of uncertain parameters a utility planner devising a clean air compliance plan must add all construction and operating costs of compliance, technological performance, allowance prices, and the regulatory treatment of compliance costs and savings.

Uncertainties mean that a unique "least-cost" plan cannot be defined, since a plan which achieves the lowest cost under some circumstances may perform poorly under others.⁷ It is now generally held by utility analysts that a utility plan should be "robust" enough to perform reasonably well under many possible scenarios and circumstances although it may not be the best plan under any one of them.⁸ Several methodological approaches are available to address the problem of planning under uncertainty.⁹

⁷ Eric Hirst, *Regulatory Responsibility for Integrated Resource Planning* (Oak Ridge, TN: Oak Ridge National Laboratory, 1988).

⁸ Narayan S. Rau, Mohammad Harunuzzaman, Daniel J. Duann, Benjamin Hobbs, and Pravin Maheshwari, *Uncertainties and Risks in Electric Utility Resource Planning* (Columbus, OH: The National Regulatory Research Institute, 1988), 23.

⁹ Howard Raiffa, *Decision Analysis: Introductory Lectures on Choices Under Uncertainty* (New York: Random House, 1968).

Methods that Optimize Expected Values

These methods attempt to formulate the objective function as an expected value or statistical expectation rather than as a precise value to be determined. The general approach of these can be illustrated using a decision tree. Figure 4-3 is a decision-tree representation of the clean air compliance problem when future reduction requirements, compliance costs, and emission allowance prices are uncertain.¹⁰ This assumes that the planning process is risk-neutral.

The decision tree shows the utility can choose to overcomply significantly, only moderately, or not at all. For each of these choices, there are certain probabilities for each future event such as high or low reduction requirements, high or low compliance costs, and high or low allowance prices. Each of these probabilities is shown as decimal numbers next to the fork associated with a given event. Each of the endpoints, labelled as a whole number, represents a possible outcome. The expected value of some objective function, such as net compliance cost, can be calculated for each endpoint.¹¹ The expected cost of each option is the sum of expected costs of all endpoints originating from that option. For example, the option labelled "significant overcompliance" has an expected cost which is the sum of expected costs of endpoints 20 through 27. The option with the lowest expected cost will be chosen.

¹⁰ Reduction requirements depend on load growth. Future reduction requirements are uncertain because load growth is uncertain. The decision tree example is taken from Electric Power Research Institute, *Clean Air Response*, Part II, II-28.

¹¹ For example, the expected cost of compliance for endpoint 16 is $(0.5 \times \text{compliance cost in } \$/\text{ton}) - (0.3 \times \text{allowance price in } \$/\text{ton}) + (0.5 \times (\text{actual reduction in tons} - \text{required reduction in tons}))$.

Fig. 4-3. A decision tree of compliance options (Source: Electric Power Research Institute, *Clean Air Response*, 1990).

Methods that Minimize Risks

These risk-minimizing methods reflect a risk-averse approach to planning and have their origins in financial portfolio management analysis.¹² The objective is to minimize risk by bounding the range of possible outcomes, rather than maximize expected profits or minimize expected costs. One widely used method is to minimize the statistical variance (a measure of uncertainty) of some objective function. In the compliance planning context, this can translate into minimizing the variance of the net compliance cost or the net generation cost.

The Role of Flexibility in Compliance Planning

Flexibility can improve performance when actual events diverge from expectations. Explicit consideration of flexibility is appropriate in utility planning. The more latitude the utility has during the course of implementing a plan to introduce changes, the easier it is to respond to events as they materialize. Some options are less amenable to such "midcourse correction" than others. Building scrubbers, for example, locks up a large amount of capital and makes it difficult for the utility to abandon this option or switch to other options in the future.¹³ It is also difficult to switch *to* scrubbers if none are in place already, even when it is desirable economically to do so because of the relatively long construction time involved. At the other extreme, the liquidity of emission allowances should make buying and selling them easy in response to market conditions and costs of other options. Indeed, if flexibility were the only criterion, perhaps a utility would never opt for scrubbers. But one cannot ignore the possibility that allowance prices may, indeed, be high relative to scrubbers. This possibility, coupled with the fact that building scrubbers has superior economies of scale, makes it imperative that a compliance plan does not exclude scrubbers, and any other option for that matter, on the basis of a single criterion.

The best possible approach is to build enough flexibility into a compliance plan to allow a

¹² H. Levy and M. Sarnat, *Portfolio and Investment Selection: Theory and Practice* (Englewood Cliff, NJ: Prentice-Hall, 1984).

¹³ Steven Mitnick, "To Scrub or Not to Scrub: The Hidden Risks of Inflexibility," *The Electricity Journal* (January/February, 1992): 44-49.

utility to respond well to all predicted scenarios. The flexibility of any individual option or technology is less important than the flexibility of the total plan. The methods that optimize expected values or minimize variances already allow some of this desired flexibility to be incorporated. They, however, do not adequately capture the value of flexibility or provide a precise standard for comparing the flexibility of different compliance plans. This is due to the fact that unlike expected values or statistical variances, a precise, quantifiable, and commonly accepted definition of flexibility is as yet unavailable. A qualitative assessment of flexibility, based on the planner's experience and best judgement, may have to be used to evaluate compliance plans. Even the best quantitative evaluations do not capture all the relevant variables and factors, and need to be supplemented with good judgement to design effective compliance strategies.

Compliance Survey

In the fall of 1991, the NRRI conducted a survey of state public utility commissions on their actions concerning the CAAA. The survey questions focused on the activities of four groups: state public utility commissions, utilities in their jurisdiction, state legislatures, and environmental or related state agencies. The summarized responses to this survey are in Appendix C.

Most of the state public utility commissions have undertaken some action concerning compliance with the Title IV provisions of the CAAA. Over half of the responding commissions have conducted staff training on CAAA requirements. Nearly 40 percent of the respondents indicated that they have begun a preliminary review of draft electric utility compliance plans. Almost a quarter of the respondents have begun developing policies for the regulatory treatment of allowances, but most have not drafted rules or procedures yet. Twenty percent either have sponsored a workshop or opened generic cases on the subject. A little over a quarter of the responding commissions have taken no action to date. One action that is decidedly not on the commissions' agenda is limiting utility activity in an SO₂ emissions allowance market: 95 percent of the respondents said they were contemplating no such action.

Two issues were generally identified as the most important from the standpoint of the commissions in addressing the implementation of Title IV. First was the integration of least-cost

planning and integrated resource planning with CAAA compliance. The second major issue was the regulatory treatment of emission allowances (for example, determining the market value and allocating the allowances between ratepayers and shareholders and between operating and holding companies). Several other issues were raised, including the economic effect of compliance on rates and on other industries, especially coal mining, the coordination with state and federal environmental protection agencies and other commissions in multistate matters, and the environmental effect of secondary wastes.

Only 20 percent of respondents felt that implementation of the Title IV provisions would not require their commissions to undertake new activities or adopt new methods. Not surprisingly, over half of the respondents stated that their commissions would have to develop regulations covering the treatment of allowances. Almost 40 percent felt there is a need to alter their current integrated resource planning process. Almost a quarter of the responding commissions indicated that they would initiate or change the preapproval process to accommodate compliance plans.

Although the concern is high, most responding commissions had not begun formally to consider how shareholders and ratepayers will be allocated the costs and benefits of compliance with Title IV requirements. Five commissions (Delaware, Florida, Illinois, Maryland, and Pennsylvania) reported that current decisions would have some bearing on this issue. Eighty-six percent of the respondents said that their commission has not decided or begun to consider how to treat costs and revenues related to SO₂ emission allowances for ratemaking purposes. Although multistate issues were not frequently cited as a major issue, over 90 percent of the respondents anticipated having to address interstate or multistate issues. Several standing coordinating vehicles appear to be in place already for some commissions. Examples include the AEP Regional Coordinating Committee (with six state members), the Power Planning Committee of the New England Governor's Conference, and the PacifiCorp Interjurisdictional Task Force on Allocations (PITA).

Over half of the responding commissions have not undertaken research projects concerning the implementation of, or compliance with, Title IV provisions. Of those currently involved in research, cost-benefit studies of fuel-switching and conservation and renewable energy were frequently cited. However, many commissions indicated that while they were not currently

conducting research themselves; instead, they were monitoring information on the subject. To assist their commissions in decision-making on Title IV implementation, commission staffs appeared to favor newsletters and training workshops and seminars almost two-to-one over electronic bulletin boards and PC-based compliance planning models. However, the latter two sources of information were requested by over 40 percent of the respondents.

Almost two-thirds of the responding commissions reported that utilities in their jurisdiction have at least identified the specific units affected by Title IV provisions. Almost half of the respondents say the utilities already have proposed or stated what action will be required to comply with the CAAA. Over a quarter of the respondents have received systemwide compliance plans, compliance options analyses, or had the affected utilities indicate how allowances would be used.

Most states apparently do not have preexisting statutes that are in conflict with, or inconsistent with Title IV. As a result, 83 percent of the respondents reported no legislative activity addressing this issue. The others have reconciled their laws with the CAAA. The state air agencies appear to have imposed few requirements on utilities since the CAAA enactment. Finally, most commissions are or anticipate interacting--at least informally--with their respective state air agency regarding issues associated with the Clean Air Act compliance.