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CHAPTER 9

RATEMAKING AND ACCOUNTING FOR ALLOWANCES AND COMPLIANCE COSTS

As was illustrated in Chapter 7, the regulatory treatment of compliance costs and allowances will significantly affect both the utility's CAAA compliance decisions and the cost of compliance. The ratemaking treatment in particular can influence, for example, the decision whether to invest in pollution abatement technology (scrubbers or clean coal), 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. Indeed, for reasons explained in Chapters 3 and 7, it is in the ratepayers' interest to adopt incentive mechanisms that foster the development of a market. It is now apparent to many observers that the actions of the state commissions and FERC will greatly influence the success or failure of the allowance market.

A major difference between the 1990 Clean Air Act Amendment's Title IV provisions and earlier command-and-control environmental regulation is that now the utility is allowed considerable discretion in how to comply. A utility, facing an array of compliance options, will base its decisions in part on expected future regulatory conditions. Because the utility and commission have no previous experience with a mechanism like the allowance system or with the treatment of compliance cost when the utility is given this level of discretion, the utility will likely consider three sources of information about the possible future regulatory treatment when assessing its options.

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 or bias the options of the utility. The commission (or state legislature, as has occurred in one state) could

intentionally do this by stating directly what options are to be considered. An unintentional bias could occur if the commission states, for example, that pollution control equipment will be ratebased. Then some uncertainty is removed from this choice and thus there is a corresponding reduction in risk--hence, 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 the widest array of suitable options, including the purchase of allowances and the sale of allowances to reduce compliance costs when it is cost effective.

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, as was illustrated in Chapter 7 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 investment. 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

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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, D.C.: 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.

rates, fuel prices, construction costs, and so on.

This emphasizes the need for the utility to select flexible compliance strategies 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 provides an incentive to the utility to minimize its compliance cost, does not bias the utility toward particular options, and allows flexibility for unforeseen events. To facilitate this, the commission can establish credible guidelines for the utility to consider when making its decisions.

Ratemaking Treatment of Allowances

Commissions may develop an array of rate treatments of allowances and compliance cost to suit a variety of situations. These situations include the rate status of the electric generating unit that receives the original allocation and the system-wide investment required to comply with the CAAA.

The commission may use the rate base status as a guide to determine the beneficial ownership of the allowances, as discussed in Chapter 8. This would explicitly recognize the manner in which the CAAA allowances are allocated; that is, to a generating unit based on emissions and fuel use from 1985 to 1987 (except for special provisions or appeal to EPA). If, for example, the unit is not ratebased at all or is being phased-in over time, the commission may decide that the original allocated allowances are owned either entirely or partially by the utility. Conversely, if the unit is in the rate base and depreciation expenses have been or are being passed through to ratepayers, then the commission may determine that all of the benefit from the unit's allowances belong to ratepayers or in proportion to the amount depreciated.

The commissions may consider the circumstances of their particular state or utility, recognizing that there is considerable variation across states and across utilities of the amount of required reduction or allowance purchases. As illustrated in Chapter 2, some states are required to make considerable adjustments while others have relatively little or no immediate adjustments. Commissions may consider this overall compliance requirement when deciding on the rate treatment. Even within a particular state the treatment may vary since utilities are affected differently. It may be appropriate for states with little or no immediate impact to consider their

options now, rather than waiting until future capacity expansion or legislation (for example, global warming legislation with carbon dioxide trading) brings the issue before them.

Developed below are two general approaches to ratemaking treatment of allowances and compliance costs. These approaches were developed to be consistent with current regulatory practices in the country while being consistent with the particular characteristics of allowances and the nascent allowance market. Two different approaches are discussed here. The first takes a traditional regulatory approach to allowances and compliance costs. This approach was developed by analogy, to the extent possible, with similar assets. However, recognizing that there may be no perfect analogy and that a traditional method may cause perverse (albeit sometimes unintended) incentives, a second alternative is developed. This alternative builds on the market oriented nature of the allowance system and the intent of the CAAA to minimize the cost of compliance. This second alternative is based on an incentive regulatory approach.

Traditional Regulatory Approach

This first ratemaking treatment of allowances is based on how commissions have dealt with similar issues and 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 (as in Chapter 8) that ratepayers are the source of the initial allowances because these allowances reflect the past emissions of a particular unit necessary to meet the utility's 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) 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 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 device would most likely be included in the utility's rate base. Proceeds from the sale of allowances 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. (Later in this chapter, a method is presented to share the gains between ratepayers and the utility.) A commission could maintain this regulatory approach until the utility's pollution control facilities in rate base become zero.

If gains from the sale of allowances were to reduce the utility's ratebased investment to zero, a commission might provide for sharing the excess between 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, if ever, 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 that free allowances. 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 ratepayers and shareholders.

If the allowances were freed because of fuel switching, one could 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 utility's earlier fuel procurement policies.) 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 using 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, a traditional regulatory approach would suggest that 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, commissions may not care to become involved in the appropriateness of the price of an individual allowance. Since allowances may be bought and sold many times over the course of a year, the accounting alone could become quite burdensome. Commissions may consider, therefore, more general measures of allowance inventory for ratemaking purposes, that indicate the general effectiveness of the utility's allowance

procurement practices.

Limitations to the Traditional Methods

These traditional ratemaking treatments may introduce an unintended bias in favor of compliance options that are not necessarily the lowest cost solution. The analysis of Chapter 7 illustrates how there can be, under certain conditions (primarily when the rate of return exceeds the cost of capital), a bias toward large capital expenditures. In addition, if the initial allowances earn no return but the commission states up front that large capital expenditures for compliance, such as scrubbers, will be ratebased, a great deal of the uncertainty associated with that decision (whether it will be ratebased) is removed. As noted earlier, at this writing, all state commissions except one allow pollution abatement investment into rate base. Therefore, if there is a virtual guarantee that the investment will be ratebased, 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 will 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 expected future cost of allowances and fuels and not on a distortion created by the ratemaking treatment.

Also, there is the possibility that the utility will have a preference for purchased allowances and attempt to replace zero-cost, nonratebased allowances with market-priced allowances that earn a return. That is, they simply try to increase their rate base (and return) by increasing the value of the allowance inventory. This, of course, depends on the inventory method used for ratemaking purposes, such as last-in, first-out; first-in, first-out; or average. FERC has proposed a weighted average inventory method to avoid a possible distortion in incentives caused by the inventory method. (This proposal is discussed later in this chapter.)

Another example, also noted earlier, is the unintended bias that could arise from a fuel adjustment clause (FAC). If future cost increases in low-sulfur coal are allowed to be passed through to ratepayers, then utilities may favor fuel switching, even though this is not necessarily the lowest cost option.

Careful attention should be given to the incentives the utility receives from the ratemaking process. In general, traditional methods could foster a "go-it-alone" strategy of overcontrol by the utility since it cannot benefit, or may even be harmed, by using the allowance system as intended (as described in the "ideal world" of Chapter 3). An incentive-based ratemaking system, in contrast, can be designed to give the utility an incentive to adopt a compliance strategy that is in ratepayers' interest by allowing the utility to benefit from its good decisions, but still be held accountable for faulty ones.

Incentive Ratemaking Treatment of Allowances

Based on Chapters 7 and 8, a three-step incentive ratemaking treatment of allowances can be developed. Five assumptions are made about allowances and the ratemaking treatment of allowances: (1) allowances will be valuable assets to the utility (and hence ratepayers), (2) the commission is neutral with respect to the utility's particular compliance options--including technology and fuel choice,[3] (3) an economic incentive provided to the utility can induce the utility to adopt the lowest-cost option, (4) an allowance market will develop and provide regulators with useful price information, and, (5) the regulators' (state and FERC) actions will influence the development of the allowance market, including the price and availability. This alternative is suggested as a means to develop a ratemaking procedure that introduces no bias favoring any particular compliance option, gives the utility an incentive to minimize its CAAA compliance costs, and is designed specifically to take advantage of the market-based system of allowances.

While no one can be certain of the future price and availability of allowances, there are several indications that they are likely either to hold their value or 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

[3] Several states have enacted legislation to ensure the use of in-state coal and protect miners' jobs. Such political decisions and how states factor this into their decisionmaking process is not dealt with here. In this analysis it is assumed that the commission is not interested in a specific technology or fuel, except the lowest cost ones.

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, 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 (which appears to be the case so far with phase I units), the increased number of allowances on the market would cause the price to fall below the incremental control cost for many fossil fuel users (as explained in Chapter 3). 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 banked allowances.

This alternative treats allowances for ratemaking purposes held by the utility as nondepreciating assets with a *nonzero* basis. 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 systemwide initial allocation and purchases. The allowances that are purchased, again like coal inventory, can be valued at the contracted or historical 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 incentive mechanism described below, however, will give the utility an incentive to bank only the number of allowances needed for future use or hold because of an expected future rise in the price of allowances. Also, this method is intended to remedy a source of distortion in incentives to the utility from the ratemaking treatment and valuation of the initial allocation of allowances.

Step One: Utility Buy-In

One means of creating an unbiased and incentives-based ratemaking treatment would allow the utility to "buy in" to the allowance system as a ratebased asset. In the first step of this proposed allowance treatment, 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 a method for determining ratepayer beneficial ownership of the generation asset described in Chapter 8). 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 ratebased asset. This could be balanced as a regulatory liability to ratepayers (asset value times the proportion determined to go to ratepayers; the accounting for this, as proposed by FERC, is discussed at the end of this chapter).

It is important that for the valuation of allowances a fair market price for allowances be determined rather than using 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 the relative cost of allowances compared with its own cost of emission control. Basing the allowance value on the utility's control cost alone could provide the utility an incentive either to inflate its control costs or not minimize them. (This external price signal is important in the next step of this incentive treatment as well.)

Table 9-1 provides an example of how the first step of this method would work for the allocated allowances. In this example, the utility will receive an allocation of

TABLE 9-1

EXAMPLE OF INITIALLY ALLOCATED ALLOWANCE INCENTIVE TREATMENT

Year	Allowance Value ($)	Annual Return ($)
1995	20,000,000	1,600,000
1996	20,000,000	1,600,000
1997	20,000,000	1,600,000
1998	20,000,000	1,600,000
1999	20,000,000	1,600,000
2000	10,000,000	800,000
2001	10,000,000	800,000
2002	10,000,000	800,000
2003	10,000,000	800,000
2004	10,000,000	800,000
2005	10,000,000	800,000
2006	10,000,000	800,000
2007	10,000,000	800,000
2008	10,000,000	800,000
2009	10,000,000	800,000
2010	10,000,000	800,000
2011	10,000,000	800,000
2012	10,000,000	800,000
2013	10,000,000	800,000
2014	10,000,000	800,000

Assumptions:

Phase I allocation = 80,000
Phase II allocation = 40,000
Allowance Fair Market Value = $250

Allowed Rate of Return = 8.00%
Discount Rate for NPV calculation = 5.00%
Net Present Value of Income Stream = $13,433,350

80,000 allowances in phase I and be reduced to 40,000 in phase II. The commission determines that ratepayers are the beneficial owners of all the allocated allowances. The commission also determines that the fair market value for allowances should be $250 and that the discount rate for calculating the stream of allowances' net present value is 5 percent and the planning period is twenty years. This discount rate can be based on, for example, long-term government bonds, utility's cost of capital, or some other means of determining long-run opportunity cost. The planning period can be any length in time, but should be sufficiently long to allow long-term compliance decisions to be made by the utility. At this time or in a previous rate case, the commission in this example determines that the utility's rate of return should be 8 percent. The allowance value in rate base would be the commission determined price times the number of allowances allocated for the year (column 1 in Table 9-1)[4]. The income stream is then the allowance value times the allowed rate of return (column 2). In this example given these assumptions, the net present value (NPV) would be $13,433,350.

Under this proposed method, the utility would "purchase" this stream of income by paying ratepayers the NPV (as, for example, a reduction in rates over time). The commission can determine the number of ratepayer allowances using the reasoning of Chapter 8. This is similar to the utility purchasing a coupon bond with an annual or some other periodic payment. Once the utility has purchased this income stream, it would be allowed, within certain limitations, to use them at their own discretion for compliance. This would include sharing any profit on their sale or incurring a loss. Beneficial ownership of the allowances, unless purchased outright by the utility, would remain with the ratepayers. Utilities may be given the option of purchasing some or all of the allowances in exchange for more discretion in their use. This could lead to a policy option that is essentially a deregulation of the firm's compliance actions. However, for many utilities this would impose a heavy financial burden and commissions would have to guard against

[4] In order to keep this example simple, it has been assumed that all the allocated allowances in a given year are used or sold, that is, no banked allowances are carried over from previous years. In actuality, of course, there will most likely be some banked allowances. It is also assumed that the allowances are received at the beginning of the year and deducted or sold at the end. Relaxing either of these assumptions, while making the problem more complex, would not change the analysis.

cross-subsidization between the regulated and unregulated activities of the firm. Under such a policy, the utility may attempt to maximize the number of allowances for sale and shift cost to the regulated activities of the utility.

Steps 2 and 3: Market Test of Compliance Costs and Utility Incentive

As with any ratemaking treatment, the commission will still need to remain vigilant concerning the utility's compliance costs to insure that unnecessary costs are not passed through to ratepayers. In the second step of this proposed incentive method, compliance expenditures would be tested against the market value of allowances to determine whether the least-cost strategy is or was adopted. This would be based on the system-wide average compliance cost of the utility.[5] In the third step, if the average compliance cost (scrubber, switching, CCT, and so on) is less than the market price of allowances, then the utility is allowed to profit on its sale. The gain to the utility would be up to the allowance price minus the compliance cost minus the return that would have been received if the allowances were retained by the utility. Applying the same discount rate, this return would be allowance price times the allowed rate of return, or $20 (8% x $250) in the above example. (The gain from selling allowances when the control cost is below the market price of allowances is illustrated in Figure 3-2 in Chapter 3. It would be this gain, net of transaction costs, that would be shared under this proposal.

Again applying the above example, if the utility's control cost was $225 per ton of sulfur dioxide and it could sell allowances for $250, then, if the utility believed that the price of allowances would remain the same or fall in the future, the utility would sell the available allowances and receive a gain of up to $5 ($250 - $225 - $20) per sold allowance (presumably, the utility would still need to retain some allowances for its own use). If the utility sold half its allocation for each of the twenty years then, using the same discount rate of 5 percent, the net

[5] Note that if the utility is using incremental control cost in its planning process, as described in Chapters 3 and 4, to determine which compliance option to adopt, then the average control cost across the utility's system would actually be the average of the incremental control costs. It is referred to here, for ratemaking purposes, as simply the average control cost and assumed that in the planning process incremental cost was used.

present value of the gain on the sale would be up to $1,679,169. How much of this the utility would be allowed to retain would depend on the portion the commission allows the utility to retain and what is to be given to ratepayers. A percentage sharing arrangement could be determined in advance.

Therefore, if the utility can earn more than its rate of return by selling its freed allowances, then it would be allowed a below-the-line gain on the sale (also net of any transaction costs and ratepayer share). If on the other hand, the control costs are above the market price, the utility can only recover the market price from ratepayers. The difference in this case would be a below-the-line loss to the utility.

Since the utility under this method is allowed to retain some or all of the gain or incur any loss on the sale of allowances, there is an incentive to reduce the capital and operating cost of compliance. The lower the control cost (and the higher the sale price) the greater the gain on the sale. If the utility does nothing with the allowances, it will earn just its rate of return until the allowances are used. When allowances are used, they would be deducted from the rate base (at the value the allowances were entered at) that can be adjusted periodically (as discussed below, FERC is proposing a monthly adjustment). A periodic adjustment would avoid delays that would result with no adjustment until a rate case. What is driving the utility's decisionmaking and planning now is decreasing the cost of compliance and maximizing the price of sold allowances, which is also in the interest of ratepayers.

The utility would no longer, of course, receive the income from sold or used allowances as a ratebased asset. Sale or use of allowances would likely involve deducting the amount from an allowance inventory account (this has also been proposed by FERC). Any purchased allowances would simply be added to the allowance inventory and deducted as used. Purchased allowances would be evaluated the same as any other compliance option; in this case the purchase price would be compared to the commission determined fair market value. The commission would have to make adjustments to the rate base for any allowances deducted by EPA for the auctions and sales (as described in Chapter 1).

With this type of incentive mechanism, the commission does not prescribe or approve the specific control technology planned or used by the utility, which is only measured against the

average compliance cost and an assumption of prudence unless shown otherwise (Chapter 6). This gives the utility an incentive to reduce its costs by adopting or developing innovative technology and operating its compliance assets in an efficient manner.

Under this incentive mechanism the commission determines the allowance price based initially on an estimation of the value of the allowances and, eventually, on the market price. This value or price becomes a benchmark or a standard of prudence to measure the performance of the utility and the reasonableness of their allowance purchases and sales. This standard can be used with the traditional method described above as well. Commissions may want to wait and see how the market develops first before committing to such a standard. As noted earlier, however, the commission's own actions will determine the allowance market's outcome. Committing to such a system early may help induce economic compliance and allowance trades as well as facilitate the market's development.

This benchmark standard should be posted in advance and the utility given reasonable assurance that it will be applied objectively. The benchmark could be set and adjusted annually at the beginning of the year during EPA's true-up period. The usual standard of prudence would still apply to costs that are within the control of the utility, as described in Chapter 6. That is, the utility would not be responsible for factors beyond its control but accountable for the things that are within its control.

Other incentive mechanisms, of course, can be developed. For example, a commission may decide that the bias problem caused by the initial allocation of allowances is not a problem since the state or utility will receive only a small number of allowances. In this case, the commission may skip step 1 of this mechanism and adopt

some form of steps 2 and 3. Most likely, however, any incentive mechanism will involve some kind of benchmark standard that is compared with the utility's actual control cost.

In summary, this incentive-based ratemaking approach has three steps. First, the utility pays ratepayers for their beneficial interest in the allowances. In exchange the utility receives a stream of income from the allowances based on the value determined by the commission. This has the consequence of neutralizing the negative effect of having the allowances in the rate base at zero value. Second, the utility is allowed to recover from ratepayers the compliance cost *up to* the benchmark value of allowance determined by the commission. And third, the difference between the benchmark and the actual compliance cost, if the control cost is less than the benchmark, is shared between the utility and ratepayers in a proportion determined by the commission. If the control cost is greater than the benchmark, the utility can only recover the benchmark value.

Application of an Allowance Incentive Mechanism

This mechanism can be applied broadly to a wide variety of situations. In the case of a utility that will be receiving a relatively large amount of allowances from EPA and faces considerable compliance costs, it is likely that a commission would find that most of the units are older, ratebased, and are partially or fully depreciated. This method, therefore, would provide the correct incentives to the utility and help hold down the cost to ratepayers. In this situation, a utility with relatively high control costs would benefit from purchasing allowances. Conversely, a utility with allocated allowances and relatively low control costs would be encouraged to overcontrol and sell allowances.

A few utilities, because of state environmental laws, have already overcomplied with phase II of the CAAA and incurred and possibly recovered or are recovering the cost in the traditional manner. This mechanism would free the utility in this situation, once its ratepayers have been compensated, to sell its excess allowances or hold them if it believes the price will rise in the future. Alternatively, in the situation where the control costs of the utility have already been recovered from ratepayers, the commission could decide to simply pass the revenue from the

allowance sale to ratepayers, net of transaction costs.

In the case of utilities with few allowances and little or no compliance cost in the near future, the focus is on the optimal number of allowances to bank. Again, this method will give the utility an incentive to hold what it believes to be the best number of allowances given its assumptions about the future. Since it is now in the interest of the utility to be careful and because the utility is in a position to know its system's opportunities, this method should result in decisions that are also in the interest of ratepayers.

Some units receiving allowances are "requirements" units or plants; that is they are dedicated to specific requirements customers such as an industrial or municipal power authority. In these situations the utility would compensate that customer directly since they would likely be determined by the commission to be the beneficiary.

Finally, this method may be well suited to the case of a multistate utility or holding company. In cases involving wholesale transfers of power, FERC will have to determine the beneficial ownership and beneficiaries of the allowances received and held by these companies. It may be considerably less complex to determine first the beneficiaries and arrange for their compensation than doing it on a case-by-case basis. Presumably, the ratepayers determined to be the beneficiaries would be compensated, and the cost of the allowance added to the cost of providing and generating the power. This would require, however, a considerable amount of cooperation between the states (and, perhaps FERC) that the utilities operate in, since the states may have different views of who "owns" the allowances and should receive the compensation. At the very least, this method makes this process more explicit and transparent to the parties involved. The benchmark standard described above could be applied regionally, with several states agreeing on the price or estimated value.

The purpose behind this incentive mechanism is to allow the utility to earn a return on the allocated allowances and avoid the perverse incentives that occur when they are not included in rate base, and also compensate ratepayers (the beneficial owners) for the allowances that the commission determines "belong" to them. As noted, the method presented here to determine the gain or loss on an allowance transaction (that is, taking the difference between the posted allowance value or price and the utility's compliance cost) can be implemented without the step of

including the allocated allowances in the rate base. The commission would simply use the difference between its benchmark and the utility's control cost and then determine the share of the gain or loss to the utility and ratepayers. In this case, however, the distortion described in Chapter 7 and earlier in this chapter will not be corrected.

Another implementation problem would be measuring the compliance cost. While the calculation is somewhat straightforward[6], the commission should be alert to the potential of understatement or shifting of costs by the utility.

Thus far, commissions are finding that their own decisions are having a profound effect on the market. Because of the more than expected overcontrol for phase I compliance, the forecasted price of allowances has fallen considerably (one organization's surveys found that the respondents' expected 1995 price of allowances fell from about $650 early in 1991 to about $450 in early 1992.[7]) If utilities continue to adopt a go-it-alone strategy and fail to consider allowances as an option (both buying and selling), then the failure of the market may become a self-fulling prophecy. The irony is that in order to have this market oriented system work and realize at least some of the projected cost savings, it will have to be used more. However, utilities have indicated a reluctance to use the market because of the uncertainty of its success. Unless a commitment to use the market is made by utilities and commissions, it probably will not develop to its fullest potential. (As of this writing, there have been two allowance transactions.)

For these reasons, commissions may want to consider at this early stage in the development of the allowance market the use of modelling techniques to forecast a close approximation of a fair market value. Alternatively, the commission may choose to set the benchmark at the firm's control cost. In either case, the disadvantage is that the benchmark may be set too low or too high relative to the actual allowance price. For example, if it is set too high, this could induce more scrubbing at a higher cost than purchasing allowances. Conversely, if the benchmark is set too low, then opportunities to sell allowances, and reduce overall compliance

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[6] Calculation of compliance costs will be discussed in a subsequent NRRI report.

[7] AER*X, Inc., "Expected Allowance Price Levels Continue To Drop," *Air Credit Advisor* 2 no. 1 (First Quarter 1992).

cost, may be missed. For this reason, it is important that these means be viewed as temporary. As the market develops, a shift to actual market prices could take place. This could "seed" the market and foster its development by encouraging utilities to use the allowance market. This would require some early cooperation between the commission and its jurisdictional utilities to determine a fair estimate of the market value or control costs. The long-term benefit to ratepayers of a successful trading system could be worth the risk and effort.

This method explicitly recognizes that the allowances are valuable assets to the utility and others and that neither the utility or ratepayers should be the sole beneficiary of the CAAA's creation of this new asset. It also 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 (of course, this could be achieved under a traditional approach as well). 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 and gives the utility an incentive to act in the best interest of ratepayers.

A commission adopting this method must then decide: (1) the fair market price for the allowances, (2) the portion of beneficial ownership of allowances belonging to ratepayers and shareholders (as in Chapter 8), (3) the number of years that the utility will be allowed to use the determined ratepayers' allowances, (4) the discount rate for the NPV calculation for the purchase of the asset from ratepayers, and (5) what portion of the gain the utility should be allowed to retain and what should be returned to ratepayers.

Accounting Treatment of Allowances and Compliance Costs: FERC Proposed Changes to the Uniform Systems of Accounts

FERC has issued a Notice of Proposed Rulemaking[8] (NOPR) to revise the Uniform Systems of Accounts (USOA) to account for allowances, compliance costs, other "regulatory-created" assets and liabilities, and amend FERC form numbers 1, 1-F, 2, and 2-A. A stated objective of the NOPR is to achieve rate neutrality by not dictating or suggesting a specific ratemaking treatment to state commissions or FERC. The NOPR states that it "does not bar regulatory commissions (including [FERC]) from adopting any particular ratemaking treatment."

The FERC believes that the allowance program of Title IV of the CAAA is sufficiently novel to warrant revising the USOA and FERC's utility reporting requirements. Also, the Commission points out that there are a number of possible alternative accounting approaches that could be adopted by utilities and state public utility commissions. The FERC NOPR, therefore, proposes revisions to the USOA to provide "guidance, uniformity and consistency in accounting and reporting for the allowances." The changes pertain to the classification, valuation, expense recognition, sale or other disposition, and reporting of allowances.

Account Classification

The Commission wants a classification of allowances that best reflects the nature of the allowances and promotes uniformity of accounting practices. FERC proposes to create two new inventory accounts for allowances: Account 158.1 Allowance Inventory, and Account 158.2 Allowances Withheld. These accounts would be included in "Current and Accrued Assets" section of the balance sheet.

The Commission believes that there is no need to separately identify which allowances are

[8] Federal Energy Regulatory Commission, 18 CFR Parts 101, 141, 201, and 260, Docket Number RM92-1-000, "Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and Form Nos. 1, 1-F, 2 and 2-A," Issued December 2, 1991.

used because a utility can generally use any eligible allowance to comply with the CAAA. Rather, the Commission contends the allowance inventory need only be reduced by the number of allowances used times the unit inventory cost for each allowance. Also, according to the Commission, this type of inventory accounting is appropriate since allowances are not subject to depreciation or amortization as are long-lived assets (such as utility plant) used in the production process over a number of periods. It is their belief that "[t]he data derived from [this] inventory accounting approach will give utility regulators meaningful information that may be useful in ratemaking or other regulatory determinations." In this approach, the accounting records would not and could not associate specific allowances with the specific compliance strategy adopted by the utility. Therefore, these account classifications would "not suggest or dictate any particular ratemaking treatment for the allowances and would therefore be consistent with the Commission's stated objective of being 'rate-neutral'."

Measuring the Value of Allowances

For measuring the value of allowances FERC proposes that utilities use a historical cost basis. The NOPR states that historical cost is the generally accepted measure of the value of intangible assets, such as franchises, patents, trademarks and other rights. They argue that "[h]istorical cost is readily ascertainable and verifiable, free from bias and useful to regulators, investors and other users of a utility's financial statements." Under this method allowances received from EPA at no cost to the recipient would be recorded at zero cost, while purchased allowances would be recorded at their historical exchange price. Original cost, conversely, would require the originally allocated allowances to be recorded as zero even after a sale to another party. FERC points out that this type of arrangement may discourage the development of the allowance market and would not provide regulators with relevant information on the cost of traded allowances. Some limitations to this method are discussed at the end of this section.

The Commission also provides a proposal for dealing with affiliated transactions. In this case the Commission proposes that allowances acquired from an affiliated company should be recorded by the acquiring company at the inventory cost of the affiliated entity that first obtained

the allowance. The Commission bases this decision on the fact that affiliated companies cannot be presumed to be dealing at arm's length, and therefore these affiliated trades should not be presumed to be competitive, free-market dealings. Under this proposal, when a utility acquires allowances from an affiliate at a value other than the affiliated company's historical cost, the difference would be recognized as an equity contribution between affiliates.

The Commission proposes using the fair market value of allowances as the historical cost basis for allowances that are acquired as part of a "package" with equipment, fuel, or electricity. For determining the value of a stream of allowances, FERC proposes the use of the interest rate on a ten-year government bond.

FERC is also proposing accounting instructions to allow for possible allowance futures transactions by utilities. Their proposal would require utilities to defer the costs or benefits from hedging transactions and include these values in inventory when the related allowances are acquired or sold. FERC believes that allowance transactions entered into for speculation should not affect inventory pricing, since they do not relate to utility operations.

The Commission's NOPR proposes a method for utilities to account for allowances received in exchange for something other than a monetary payment. FERC is proposing that these transactions be based on the recorded inventory value of the allowances relinquished and the value of the "boot" (the dollars and/or asset(s) exchanged in a transaction). When a utility gives up boot in an allowance transaction, FERC proposes that the recordable cost of the newly-acquired allowances be the monetary equivalent paid in boot (for example, the fair market value of the asset surrendered) for the newly acquired allowances. For the utility giving up the allowance, the value would be based on the sum of the inventory cost of the allowances given up.

Inventory Methods for Allowances

FERC is concerned that since allowances are identical and interchangeable, a specific identification inventory method would allow management too much discretion in determining income and inventory balances by choosing particular allowances for use or sale. For this reason, the Commission believes that rather than a specific identification method, a weighted average cost method for allowance inventories should be used. The Commission argues that this method would provide "a rational, systematic, and objective measure of the cost of allowances used or sold during a period and would mitigate the effect of price changes on income and inventory balances." The Commission proposes that allowances in inventory be "vintaged" rather than grouped together in a single inventory. Under this approach, allowances eligible for use during the current year (including banked allowances from prior years) would be included in the determination of the weighted average cost of the vintage.

Since utilities will need to account for allocated allowances that are withheld by EPA for sale or auction, the Commission is proposing a separate, but parallel, inventory account. This would be Account 158.2, Allowances Withheld, and would be used to record the acquisition cost of allowances owned by the utility but withheld by EPA.

Expense Recognition of Allowances

The Commission believes that when allowances are used to comply with the CAAA, their inventory cost should be charged as an expense. The Commission proposes to require expense recognition of allowances on a monthly basis. Utilities would be required to charge allowances (including fractional amounts) to expense in the month in which the related sulfur dioxide emissions occurred. If a utility incurs a fine or penalty as a result of noncompliance with the CAAA, the USOA already requires that such a fine or penalty be charged to Account 426.3, Penalties.

The Commission also proposes classifying the expense account to record the expired cost of the allowances as a power production operating cost. The Commission would create a new

expense account for allowances, Account 509, Allowances, and include the cost of allowances used with the production cost of steam for electric generation. Utilities could then seek authorization to recover the cost of allowances through their base rates or fuel adjustment clause, or some other appropriate manner.

The Commission proposes a two-step process for accounting for gains and losses on the sale, exchange, or other disposition of allowances. The first step would be to recognize the gain or loss in income. Upon the sale of allowances, a gain or loss would be recognized for the difference between the net proceeds received for the allowances and their inventory value. Any gain would be recorded in new Account 411.8, Gains from Disposition of Allowances, and any loss would be recorded in new Account 411.9, Losses from Disposition of Allowances. Income taxes associated with the gain or loss would be recorded in the appropriate utility operating income tax accounts. The second step would be to recognize the economic effects of actions taken, or expected to be taken, by regulators in their ratemaking treatment of the gain or loss on the disposition of allowances through the use of new generic accounts for regulatory-created liabilities and assets. These are: Account 182.3, Other Regulatory Assets; Account 244, Other Regulatory Liabilities; Account 407.3, Regulatory Debits; and Account 407.4, Regulatory Credits.

Regulatory-Created Assets and Liabilities

The Commission is proposing additional changes to the USOA to produce financial statements that are more descriptive and informative regarding the economic effects of the ratemaking process. In addition to accounting for allowance transactions, the Commission provides other examples of the need for change to the USOA, such as plant phase-in, normalization of significant nonrecurring operating or maintenance expenses, and gains and losses on the sale of assets.

FERC is proposing that the new Account 182.3, Other Regulatory Assets, include costs incurred and charged as an expense that have been, or are soon expected to be, authorized for recovery through rates, and which are not specifically provided for in other accounts. The

regulatory-created assets would be recorded as charges to Account 182.3 and as a credit to new Account 407.4, Regulatory Credits. Account 182.3 would be amortized to new Account 407.3, Regulatory Debits, over the appropriate rate recovery period. If rate recovery is disallowed, the amount in Account 182.3 would be written off.

The proposed new Account 244, Other Regulatory Liabilities would include liabilities imposed by the ratemaking actions of regulatory agencies that are not specifically provided for in other accounts. Included in Account 244 would be revenues or gains realized and credited to income that the company is required, or is expected to be required, to use to reduce future rates. The regulatory-created liabilities would be established by credits to Account 244 and debits to new Account 407.3. The amount in Account 244 would be amortized to Account 407.4 over the appropriate period. If it is determined that the amount recorded in Account 244 will no longer be used to reduce future rates, then the remaining amount should be removed from the account.

Application of the FERC Proposal

There appears to be at least one limitation to the FERC's proposal. Specifically, with respect to the proposed use of a historical cost accounting basis for allowance valuation, there appears to be some confusion in the NOPR between "value" and cost. Recording the originally allocated allowances for accounting purposes at zero (the historical cost) while reflecting their cost, does not reflect their value to the utility or ratepayers. The accounting records should, some maintain, reflect their value as assets to the firm.

Moreover, there is the possibility that this accounting treatment could be translated to the ratemaking treatment of allowances. For the reasons discussed above, this would not necessarily be in the ratepayers' interest. It is important, therefore, that the ratemaking be determined first, then the accounting designed to reflect this treatment. There appears to be sufficient flexibility for states (and FERC) first to determine a ratemaking treatment separately and then determine an accounting treatment. The incentive ratemaking treatment proposed above, for example, could use the "Other Regulatory Assets" and "Other Regulatory Liabilities" accounts proposed by FERC. However, this would be somewhat cumbersome to implement and could result in

accounting records difficult to decipher.

Most likely, the traditional and incentive ratemaking approaches described above would require different accounting treatments. Both can be applied, however awkwardly, within this proposed framework. This flexibility, of course, is an advantage to the FERC proposal.

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