

## CHAPTER 5

### STATE/FEDERAL INTERACTION AND MULTISTATE ISSUES

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

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

The CAAA maintains existing state and federal commission jurisdiction for the oversight of utility compliance with emissions trading provisions. As one commentator stated "the Congress punted on how the EPA and the emissions trading provisions would fit in with state public service commissions and the Federal Energy Regulatory Commission."<sup>1</sup>

With existing state and federal jurisdictions maintained, the CAAA creates a new opportunity for state commissions to cooperate among themselves and with the FERC. Should this opportunity not be realized, a new area of jurisdictional conflict could result. Under a "business as usual" scenario, the FERC would have clear jurisdiction over registered multistate holding companies operating centrally dispatched systems and having capacity and energy allocation agreements approved by the FERC. Registered multistate holding companies could amend their allocation agreements to provide for the equitable division of compliance costs. Although there may be no explicit statutory authority for it, the FERC could possibly preapprove

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<sup>1</sup> Reinier Lock at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991.

the costs of CAAA compliance. As result of the preemption doctrine, passthrough of expenses to the state commissions would be required, possibly without a thorough prudence review. Under this scenario, state commissions cannot second-guess FERC decisions on matters covered by such allocation agreements.<sup>2</sup>

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

A registered holding company petitioning the FERC to amend its allocation agreement or submitting a new one would be subject to a hearing to decide whether the agreement was just and reasonable, nonpreferential, and not unduly discriminatory under the Federal Power Act.<sup>3</sup> State public service commissions could be parties to such a hearing. Most (about 90 percent) of FERC's cases result in a settlement. If, for example, a case dealing with amending an allocation agreement to distribute allowances was settled, it is likely that state commissions would have ample opportunity to participate in the FERC settlement process and seek a prudence review of subsequent utility expenditures of the costs of CAAA compliance.

Multistate utilities or a pool of utilities that are not registered holding companies could apply for an exemption from state regulation if they meet the provisions of PURPA § 205 and FPA § 205. To be exempt the utility must show that state law prevents voluntary utility coordination, including central dispatch, if the coordination is designed to achieve economical use of facilities and resources in the area. In effect, the utilities must show that they have formed a

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<sup>2</sup> Mississippi Power & Light Co. v. Mississippi Ex Rel. Moore, 108 S.Ct. 2428 (1988).

<sup>3</sup> Federal Energy Regulatory Commissioner Charles Trabandt noted that FERC's jurisdiction over allocation agreements is not discretionary. If a plan or an amendment to a plan is filed, the FERC must take jurisdiction over the matter. Charles Trabandt, "State/Federal Issues: FERC Review of Multistate Utility and Holding Company Compliance Plans," presented at the NRRI Workshop on Developing Public Utility Commission Rules and Procedures for Electric Utility Compliance with the Clean Air Act Amendments of 1990 for Midwestern States, St. Louis, Missouri, May 8, 1992.

power pool. No exemption is permitted if state law is designed to comply with federal law or to protect health, safety, welfare, or the environment; to conserve energy; or to mitigate the effects of an energy shortage. However, a state commission could argue its oversight of CAAA compliance plans and allowance trading does not prevent the voluntary coordination of utilities if the regulation requires least-cost compliance planning, including buying and selling emissions allowances when economically feasible. As an integral part of a state commission's least-cost planning process, economic regulation of allowance trading would be designed to protect the health, safety, welfare, and the environment as well as to encourage economic conservation of energy.

Federal Power Act § 205 requires power pool interconnection agreements to be filed with the FERC. While power pool agreements developed prior to passage of the Clean Air Act Amendments do not explicitly deal with allowances (whether or not in an allowance pool), utilities in a pool might file amendments to their pool agreement with the FERC to specify the treatment of allowances.

A third, significant context in which FERC jurisdiction might arise is wholesale power sales. The Federal Energy Regulatory Commission has jurisdiction over the wholesale power market for both requirements and coordination sales. FERC would tend to have jurisdiction over any allowances associated with wholesale power sales, subject to a possible "Pike County review" of the prudence of the wholesale purchase decision (but *not* the price) by the purchasing utility.

One might expect that the FERC would graft the price of allowances onto its existing policies of having cost-based rates for requirements customers and most coordination sales, and market-based rates available for coordination sales where the seller demonstrates that neither it nor its affiliates have market power in generation or transmission, or that such market power has been adequately mitigated, and that the seller has not engaged in "affiliate abuse." However, because the tying of allowances to bulk power sales might lead to a less liquid and transparent allowance market, as well as bulk power market, the FERC might choose to require that purchases of allowances be unbundled from wholesale power sales.

Without federal preemption of unregistered multistate utilities and holding companies, inconsistent CAAA compliance planning strategies among state jurisdictions are possible.

Disagreements could also arise between states on jointly owned plants and other multistate utilities. These inconsistencies could lead to trapped, unrecovered costs, double recovery of costs, or the inability of the utility to comply with an effective CAAA compliance plan because of conflicting regulatory requirements.

In this new context, state commissions and the FERC may find it useful to explore methods of regional regulation. Regional regulation could be as formal as a state compact, but could also entail informal agreements among states, a conference to develop regional uniformity, or other methods, such as joint state problem solving workshops, information trading on a regional basis, and consultative mechanisms between state commissions and the FERC. Collaborative and innovative administrative procedures would enhance the ability of agencies to cooperate with one another. (Some available procedures are reviewed in a previous NRRI report.<sup>4</sup>) The objective should be consistent treatment to the extent possible among the states in a regional context, particularly for multistate utilities.

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

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<sup>4</sup> Robert E. Burns, *Innovative Administrative Procedures for Proactive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1988).

that "FERC regulators should exercise maximum reasonable regulatory restraint *at this time*."<sup>5</sup>

### **Options for Regional Regulation**

As just noted, in speaking about regional regulation the authors use the term in its broadest sense. Regional regulation is any means by which state public service commissions, and the Federal Energy Regulatory Commission where appropriate, can regulate on a multistate, regional basis.<sup>6</sup> Regional regulation spans a host of options, from informal, ad hoc state coordination on individual issues, through more stable coordination efforts of state commissions to share information and act in tandem when mutually beneficial, to more formal mechanisms such as a FERC-state joint board mechanism or a congressionally approved compact establishing a regional regulatory body.<sup>7</sup>

Each of these regional regulatory options has advantages and disadvantages. For example, informal, ad hoc coordination by states on a single issue might be unlikely to provide

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<sup>5</sup> Charles Trabandt at The National Regulatory Research Institute's Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990, Arlington, Virginia, January 31, 1991. For a complete text of his remarks see, "Remarks of Charles A. Trabandt, Commissioner Federal Energy Regulatory Commission," *NRRRI Quarterly Bulletin* 12 no. 2 (June 1991): 209-16.

<sup>6</sup> At least one commentator has denounced the idea of regional regulation. See Charles A. Patrizia, "Regional Solutions to Power Supply Planning and Clean Air Act Compliance on a Multistate Utility System--A Solution in Search of a Problem?" presented at the Fifth Annual American Bar Association Conference on Electricity Law and Regulation, Denver, Colorado, March 12, 1992; and Charles A. Patrizia, John Rice, and Greg Wortham, "Can the Arkansas-Entergy-New Orleans Regional Planning Body Pass Muster? No," *The Electricity Journal* (January/February 1991): 40-43. However, when examining his remarks one finds that he is against regional regulatory compacts, such as the Entergy plan, but is supportive of more informal regional regulatory mechanisms.

<sup>7</sup> For a full explanation of these regional regulation options, see Douglas N. Jones et al., *Regional Regulation of Public Utilities Issues and Prospects* (Columbus, OH: The National Regulatory Research Institute, 1980); and Linda G. Stuntz, "Is It Time to Consider Regional Solutions to Power Planning Problems? One Federal View," *The Electricity Journal* (January/February 1992): 14-19.

state commissions with the degree of oversight they might desire, particularly if the utilities in question are either a registered multistate holding company or are involved in an allowance pool. More stable coordination efforts by state commissions, such as the New England Conference of Public Utilities Commissions (NECPUC), have the potential advantage of allowing state commissions to coordinate their policies and exchange information about emission allowances. Further, if there were a case for an allocation of allowances brought before the Federal Energy Regulatory Commission by a multistate regional holding company, the FERC has indicated that it would give substantial deference to any voluntary arrangements negotiated among the affected states.<sup>8</sup> However, such voluntary, albeit stable, arrangements are no stronger nor more effective than the degree of agreement between the state commissions. In these circumstances, the will of a majority or a supramajority of commissions would not be binding on a minority or lone dissenter. Further, even when there is substantial agreement among the state commissions, circumstances arise where emission allowance issues might be brought before the FERC. Even if the FERC were to give substantial deference to voluntary agreements of state commissions, state commissions technically have no greater standing in a FERC settlement proceeding than any other intervenor.

Two additional formal regional regulation mechanisms are federal-state joint boards and conferences, and a congressionally approved regional regulatory compact. Some have criticized these options as merely adding another layer of regulation or replacing existing voluntary and flexible arrangements with rigid, formalistic structures that shift authority from federal and state officials to regional bodies of uncertain authority and accountability.<sup>9</sup> A joint federal-state board is an option provided by the Federal Power Act § 209. However, this option has never been used by the FERC and would, therefore, need to be developed. For example, § 209 authorizes the FERC to "refer any matter arising in the administration of (Part II of the FPA) to a board composed of a member or members, as determined by the Commission, from the State or each

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<sup>8</sup> See *Northeast Utilities Co. (Re: Public Service Co. of N.H.)*, 58 FERC para. 61,200 (1992).

<sup>9</sup> See Stuntz, "Time to Consider," 19; and Patrizia, "Regional Solutions to Power Supply Planning."

State affected or to be affected by such matter." A narrow reading would let the FERC use the joint board mechanism only for FPA matters exclusively within its jurisdiction. State commissions could be represented on the joint board if they currently are affected or expect to be affected by the matter.

It is unclear what the jurisdictional powers of the joint board would be concerning matters over which the FERC and states have concurrent jurisdiction. Also, there might be an understandable reluctance to give up any decisionmaking authority (even if it is nonbinding) to representatives of state commissions when FERC can maintain authority and have the state commissions represented as intervenors in the more typical FERC settlement proceeding. The Federal Communications Commission has been effective in using its Federal Communications Act § 410 joint board powers to avoid outright federal preemption in areas where state and federal jurisdiction are concurrent. The FERC also might find it useful to explore its joint board powers as an alternative to federal preemption. Another option is for the FERC to use a joint-board-style mechanism to convene the states while requesting the Secretary of Energy to appoint a facilitator to help the parties find a solution to regional problems. The Secretary of Energy's role would be consistent with his role as voluntary coordinator of energy policy as assigned to the Secretary by the Department of Energy Act of 1977.<sup>10</sup>

The other option for regional regulation is the congressionally approved multistate compact, which might be desirable for state commissions that want to regulate the emission allowance trading of a regional holding company as a group. As pointed out elsewhere in the report, state commission regulation of allowances probably makes sense in the context of integrated resource planning. Recently, there has been a proposal for a congressionally approved regional compact that would allow for regional integrated resource planning by the City of New Orleans and the affected states, with FERC approval.<sup>11</sup> Use of a regional regulatory compact has

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<sup>10</sup> This suggestion was made by Charles Curtis, "Maintaining a Proper Balance Between Federal and State Authority--Is There a Place for Regional Regulation?" *The Electricity Journal* (January/February 1992): 32-33.

<sup>11</sup> S2607. See "Johnston Offers Utility Regional-Planning Bill; May Hearing Likely," *Inside F.E.R.C.* (April 20, 1992), 2-3.

the advantage of allowing state commissions to act consistently as a group on emission allowance trading policies, perhaps as a part of integrated resource planning. However, it has the disadvantage of needing congressional approval. It is possible that a bill allowing for a compact in a format acceptable to the state commissions would not survive congressional debate. Also, because compacts are voluntary organizations not all of the states might choose to belong. Finally, some opponents have claimed recently that because a compact is a matter of federal law when it comes to determining whether a federal court has jurisdiction over a case (that is, a compact raises federal questions that can be tried in a federal court) appointments to a compact must be federal officers appointed according to the Appointments Clause of the Constitution. The Appointments Clause requires that all federal officers be nominated by the President and confirmed by the Senate, appointed by the President alone, or appointed by the Judiciary or heads of departments.<sup>12</sup> However, a United States Court of Appeals case rejects this argument because state members to a compact ultimately empower their members to carry out their duties. Virtually all existing compacts have members appointed by participating states.<sup>13</sup> In either event, belonging to a federally approved state compact requires state commissions to yield a degree of autonomy and state sovereignty, which has the effect of diminishing a state commission's ability to take into consideration local concerns.

Some degree of regional regulation, whether formal or informal, appears to be appropriate for state commissions that need to deal with regional emission allowance trading issues. Further study of regional regulation theory and structure must be conducted before providing state commissions with more guidance of which regional regulatory option might be worthy to pursue.<sup>14</sup>

### **Tax Treatment of Allowances**

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<sup>12</sup> See Patrizia, Rice, and Wortham, "Can the Planning Body Pass Muster?"

<sup>13</sup> *Seattle Master Builders v. Pacific Northwest Electric Power and Conservation Planning Council*, 786 F.2d 1359 (9th Cir. 1986).

<sup>14</sup> The National Regulatory Research Institute has undertaken such a study which is scheduled for completion later this year.

The tax treatment of emissions allowances, while as yet unknown, will have important regulatory implications.<sup>15</sup> The tax decisions that the Internal Revenue Service makes will affect utility behavior and the regulatory treatment of the allowances.

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

### **Receipt of Allowances**

One would normally expect the receipt of allowances to be regarded as a taxable event, because the emission allowances have value and are expected to be traded and to have a market-based price. However, most phase I and phase II initial allowances will be issued to utilities based solely on their baseline fuel use. No income is received unless the allowances actually increase net worth. Thus, the receipt of the basic emission allowances is not likely to be regarded as taxable income. Rather, it is a zero-basis intangible asset on the utility's tax books until used internally or sold when, of course, it

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<sup>15</sup> This section of the discussion draws freely on the presentation of Donald W. Kiefer on "The Tax Treatment of Emission Allowances," presented at The National Regulatory Research Institutes Workshops on Emission Trading in Arlington, Virginia, January 30, 1991, and Chicago, Illinois, May 9, 1991. The reader can obtain a copy of the presentation from NRRI.

has a value. This approach is analogous to that used in EPA's program of lead rights trading which existed from 1982 through 1987.

Besides emission allowances received by utilities as a means of imposing the basic emission tonnage limits, there are three other areas of concern. First are the allowances withheld for the EPA Administrator's reserve for auction. These should raise no tax consequences when withheld, and if returned in the form of allowances should present no tax consequences at that time. However, if the allowances are sold from the reserve and returned as income from their sale, that income would be taxable.<sup>16</sup>

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

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

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

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<sup>16</sup> If a utility must purchase allowances to replace those withheld for EPA's reserve, the cost of the allowances may be netted against the proceeds of the sale of the withheld allowances as an involuntary conversion.

## The Sale or Exchange of Allowances

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

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

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

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

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

A less desirable treatment (that is, having a higher tax liability) is that the allowances be

viewed as an intangible asset to be amortized over an assumed useful life.

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

### **Recent Developments**

After a letter request by the Edison Electric Institute for a Revenue Ruling on February 27th, 1992 the Internal Revenue Service issued Advance Revenue Ruling 92-16. It holds that the allocation of emission allowances by the Environmental Protection Agency pursuant to § 7651(b) does not cause a utility to realize gross income under § 61 of the Internal Revenue Code. In addition, under § 1013 of the Internal Revenue Code, a utility's basis in those emission allowances is not measured by reference to the market price of allowances.<sup>17</sup> The only reasonable interpretation is that the initial allocation of allowances by the EPA to the utility is not a taxable event, and that their taxable basis is zero. As noted later in this report, such an interpretation could tend to result in uneconomic banking (that is, hoarding). This would occur because there would be a weak incentive for the utility to realize a capital gain by selling the allowances. With a zero basis, a profit on the sale of an allowance would be certain so long as the allowance had any market value at all.

Also on February 27th, the IRS issued a Notice for Public Comment on the federal income tax consequences of emission allowance trading transactions, pursuant to Title IV of the Clean Air Act Amendments of 1990.<sup>18</sup> The IRS requested comments on the following issues: (1) How

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<sup>17</sup> See "IRS Issues Ruling on Emission Allowances," *Public Utility Executive Briefs* (Washington, D.C.: Deloitte & Touche, 92-2, February 28, 1992), 1-2; and Internal Revenue Rul., *Internal Revenue Bulletin*, 1992-12 (March 23, 1992).

<sup>18</sup> Ibid. Comments are due thirty days after the date of publication of the Notice for Comments in the *Federal Register*.

are the costs of acquiring emission allowances treated for federal tax purposes? (2) What costs, if any, are included in the tax basis of an allowance? (3) Is the cost of acquiring emission allowances an indirect cost of producing property under Internal Revenue Code § 263A? (4) Can allowances be depreciated under § 167? (5) When and how would a taxpayer recover its basis in an emission allowance in each of the following circumstances: (a) a utility uses an emission allowance during a year, (b) a utility sells or exchanges an emission allowance, (c) a purchaser of an emission allowance which is not a utility sells or exchanges the allowance, (d) an emission allowance becomes worthless? (6) What is the character of any gain or loss realized in situations (b) through (d) in question 5? (7) Is an exchange of emission allowances a taxable event, and if so, are allowances issued in different years like-kind property under Internal Revenue Code § 1031? (8) Is a penalty paid to the EPA for emissions in excess of allowances deductible under IRC § 162(a)? (9) Will a secondary market be established for trading forward or futures contracts on emission allowances? (10) What is the likely accounting treatment of emission allowances; for example, will separate accounts be established for allowances held for use in electricity production and for allowances held for investment? and (11) What are the tax consequences of participating in the Environmental Protection Agency's emission allowance program by taxpayers who are eligible to opt-in?

The IRS invited all interested parties to comment on any or all of these or related issues, but especially solicited the comments and view of utilities affected by the emission trading program.

The comments on these tax issues will significantly affect how well the emissions trading program works. For a healthy and "economically sound" emission allowance trading market to develop, any regulations promulgated by the IRS should be consistent with the intent of Congress to encourage allowance trading when and where economical. Indeed, the greatest "threat" to successful implementation of the EPA's emission allowance trading program may be the tax treatment of allowances by the IRS.<sup>19</sup> For an emission allowance trading program to work in an

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<sup>19</sup> Remarks of Stanley Garnett, Chief Financial Officer, Allegheny Power System made at the "Living With the Clean Air Act Amendments and What's to Come: Utility Planning in the 1990s" Session of the Fifth Annual American Bar Association Conference on Electricity Law and

economically sound fashion, the tax consequences of different utility compliance strategies that involve the use, sale, or exchange of allowances initially allocated by the EPA should be neutral. To achieve this goal, first there must be a recognition that the revocable license granted by the EPA did not provide utilities with anything of value that they did not already have. The allowances merely provided utilities that were emitting sulphur dioxide with a revocable license to continue to do so. As such, there is no tax event on the initial issuance of allowances by the EPA. The IRS has reached this same conclusion.

However, the purpose of the emission allowances is to encourage utilities to trade them so that the overall cost of acid rain compliance is minimized nationally. This can occur only if utilities with a relatively low marginal cost of compliance overcomply and sell excess allowances to utilities with a relatively high marginal cost of compliance. It could be argued that for this to occur, the tax basis of the initial allocation of allowances should not be set at zero. Rather, there should be no tax basis for the initial allocation of allowances until the allowances are used, sold, or exchanged. Then the tax basis for the allowances should be set at the market price for that vintage allowance, which can be best determined when the allowances are sold by the price paid for the allowance. Otherwise, as observed above, a utility may tend to hold or bank their initial allocation of allowances uneconomically so that no gain will be realized when they are ultimately used by the utility.<sup>20</sup> Sales after the initial sale or exchange would have the tax basis of the allowance reflect the market price or the price paid for the allowance. Unless the IRS

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Regulation on March 12, 1992 in Denver, Colorado. One participant at the NARUC Mid-Winter Meeting characterized the lack of "extreme preapproval" (that is, preapproval of expenditures) as the greatest threat to successful emission allowance trading. This argument is countered in Chapter 6 where we show that extreme preapproval may itself be a threat to an economically sound and smoothly working emissions allowance market.

<sup>20</sup> By uneconomic hoarding, we mean that a utility with a relatively low marginal cost of compliance will be less willing to sell allowances to a utility with a relatively high marginal cost of compliance to the extent where the marginal cost of compliance for all utilities approaches equality. Instead, the utility will tend to hold the allowance for internal use because of its "zero" tax basis. A utility might still be willing to sell allowances if it thinks that its selling price (less the taxes) will be higher than the subsequent repurchase price or if it believes it will never need to use or to replace the allowances.

promulgates tax regulations consistent with the intent of Congress, it is likely that the emission trading market will not serve its purpose as Congress intended. Technical amendments to the Internal Revenue Code might then be required to accomplish this.