

# Report of the Committee on the Environment

## I. ENVIRONMENTAL REVIEW AT THE FERC

### A. National Environmental Policy Act

On August 2, 1990, in conjunction with its interim regulations governing construction of replacement facilities and construction pursuant to section 311 of the Natural Gas Policy Act (NGPA),<sup>1</sup> the Federal Energy Regulatory Commission (FERC or Commission) issued proposed regulations intended to expedite review of natural gas pipeline construction applications and to update and codify environmental review procedures.<sup>2</sup> At this writing, comments on the proposed rule have been received, and a final regulation is pending.

Comments on this proposed rulemaking generally hailed the Commission's goal of reducing the time necessary for regulatory review of pipeline construction. Industry commenters such as the Interstate Natural Gas Association of America provided extensive observations, supporting efforts to speed the review process, while expressing concern about additional environmental or siting requirements that could add to delay. Commenters such as the states of California and New York and the Council on Environmental Quality expressed concern that aspects of the proposed rulemaking might detract from the adequacy of the FERC's environmental review.

#### 1. Proposals to Streamline Environmental Review

The proposed regulations would, among other things, revise Optional Expedited Certificate (OEC) procedures. OEC regulations now require that OEC projects have no significant adverse impact on a sensitive environmental area.<sup>3</sup> The FERC has waived this requirement in several OEC cases in which an Environmental Impact Statement was used to satisfy National Environmental Policy Act (NEPA) requirements.<sup>4</sup> In the proposed regulations, the FERC would abolish that requirement and prepare an Environmental Assessment or Environmental Impact Statement where appropriate.<sup>5</sup>

The FERC is also proposing means of streamlining more traditional pipeline certification under section 7(c) of the Natural Gas Act. The cost limits for automatically-authorized "budget" blanket construction certificate authority would be increased.<sup>6</sup>

Further, the proposed rules provide that, if an existing natural gas pipeline company satisfies certain standards, it can obtain authorization for uncon-

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1. For a discussion of these interim regulations, see *infra* § (II)(A)(1).

2. Notice of Proposed Rulemaking, *Revisions to Regulations Governing Certificates for Construction*, 19 F.E.R.C. Stats. & Regs. ¶ 32,477, 55 Fed. Reg. 33,027 (1990) [hereinafter *Revisions to Regulations*].

3. 18 C.F.R. § 157.206(d)(4) (1990).

4. *E.g.*, Wyoming-California Pipeline Co., 44 F.E.R.C. ¶ 61,001, *vacated in part*, 44 F.E.R.C. ¶ 61,210, *reh'g granted in part*, 45 F.E.R.C. ¶ 61,234 (1988); Kern River Gas Transmission Co., 50 F.E.R.C. ¶ 61,069, *reh'g denied*, 51 F.E.R.C. ¶ 61,195 (1990).

5. *Revisions to Regulations*, *supra* note 2, at 32,469-70, 55 Fed. Reg. at 33,034.

6. *Id.* at 32,474, 55 Fed. Reg. at 33,037.

tested expansions of its system more quickly under part 157, subpart F—even if a major construction project is involved. The minimum criteria include various open access transportation and rate or cost requirements. To be eligible for this approach, applicants must provide a complete environmental report. Based upon an Environmental Assessment performed during the initial comment period, the FERC staff must be able to find that the project will have no significant environmental impact. If such a finding cannot be made, the staff will protest the application.<sup>7</sup>

Additionally, the proposed rules would expedite approval of new pipeline construction (as opposed to expansions of existing systems) by acting first on economic aspects of the application and then by addressing environmental considerations in a second phase. This sequence is intended to assist with financing and contracting for services using the new pipeline. Before the environmental review is completed, the FERC would issue an initial order on economic considerations, which would be subject to rehearing.

After completion of the environmental analysis, the FERC would then issue a final order resolving all aspects of an application. Presumably the environmental review would be rolled into the final order. That final order would also be subject to rehearing.<sup>8</sup> Phasing of the environmental analysis along these lines has met with approval in the United States Court of Appeals for the District of Columbia Circuit upon review of the FERC's orders approving new pipeline construction into California.<sup>9</sup>

Further, the FERC proposes adding certain items to those categorically excluded from review under NEPA. Proposed additions to the list of categorical exclusions include:

- [1.] natural gas storage service where no facility construction is involved,
- [2.] acquisition of facilities,
- [3.] abandonment of facilities by sale,
- [4.] abandonment of any service that does not involve abandonment of facilities other than by sale, and
- [5.] Commission action on complaints not raising environmental issues, declaratory orders disclaiming jurisdiction, and Presidential Permits [for imports/exports] not involving facilities construction.<sup>10</sup>

## 2. Proposals to Re-examine, Codify, and Update Environmental Review

More construction of larger pipelines occurred under section 311 of the NGPA—and thus without any prior FERC approval, environmental review, or other regulation—than the FERC had anticipated. Thus as part of the proposed rulemaking, the FERC is rethinking the concept of allowing nonjurisdictional construction of interstate pipelines under section 311.<sup>11</sup> The rulemaking states that the FERC is considering the following options:

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7. *Id.* at 32,473, 55 Fed. Reg. at 33,036.

8. *Id.*

9. *Public Utils. Comm'n of Cal. v. FERC*, 900 F.2d 269 (D.C. Cir. 1990).

10. *Revisions to Regulations*, *supra* note 2, at 32,479, 55 Fed. Reg. at 33,039.

11. *Id.* at 32,478, 55 Fed. Reg. at 33,039.

1. Rescinding automatic construction authority under section 311 and requiring pipeline construction to be approved under section 7 procedures,
2. Requiring prior notification to the FERC prior to beginning section 311 construction, or
3. Limiting section 311 construction authorization to the cost ceilings and other restrictions imposed on blanket "budget" construction certificates.

Commissioner Moler dissented on this point. The Commissioner believes that the FERC's options are more limited under NEPA. NEPA, she contends, requires FERC environmental review for section 311 construction. Commissioner Moler also argues that recent case law involving the statutory "on behalf of" test for section 311 transportation activities requires the FERC to abandon the section 311 construction authorization in favor of certification.<sup>12</sup>

The proposed rule would also impose more stringent environmental requirements on intrastate pipeline construction under section 311. At least 45 days before constructing section 311 facilities, intrastate pipelines would have to file a report with the FERC showing how the construction would comply with statutes concerning endangered species, historic preservation, and other similar requirements. In the proposed rulemaking, the Commission emphasized that it was extending its review of intrastate pipeline activities only for purposes of environmental protection.<sup>13</sup>

To ensure compliance with environmental protection statutes, the Commission is also proposing to restrict interstate pipeline construction under "budget" blanket construction certificate authority. If "budget" facilities otherwise automatically approved under blanket authority are located in built-up areas, the automatic authorization would no longer be available. The pipeline could proceed with prior notice procedures, or with other certificate procedures. Additionally, local property owners would have to be notified of pipeline construction occurring under the automatic blanket "budget" authority. Notification would be by publication. The notice requirement is intended to provide the landowners an opportunity to protest early in the proceedings.<sup>14</sup>

Because of environmental concerns, the proposed regulations provide that replacement facilities would no longer be completely exempt from prior FERC certification requirements. Replacement projects that would (1) cost less than \$10 million and (2) neither involve removal of facilities contaminated with toxic materials nor occur within 50 feet of an existing residence would be automatically authorized. Replacement projects costing more than \$10 million could use either traditional section 7(c) authorization or the OEC procedures. As required in the interim rule discussed elsewhere, the FERC has imposed a 30-day prior notice requirement for any new construction.<sup>15</sup>

Finally, the FERC's new rules would codify and refine requirements for Environmental Reports submitted by applicants proposing to construct new facilities or recommission liquefied natural gas facilities. Among other items,

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12. *Id.* at 32,521, 55 Fed. Rev. at 33,064.

13. *Id.* at 32,478-79, 55 Fed. Reg. at 33,039.

14. *Id.* at 32,475, 55 Fed. Reg. at 33,037.

15. *Id.* at 32,471-72, 55 Fed. Reg. at 33,035.

related nonjurisdictional facilities would have to be reported to the FERC so they could be examined for environmental and historic preservation considerations. Project-specific consultation (and not blanket approval) would be required for compliance with the Endangered Species Act. The FERC's proposed rules would also include generic erosion control and wetland protection procedures. The standard plan for handling these items would be incorporated into the pipelines' construction contracting practices.<sup>16</sup>

## B. National Historic Preservation Act

### 1. Historic Preservation Issues in Pipeline Construction

Compliance with the requirements of the National Historical Preservation Act (NHPA)<sup>17</sup> persists as an issue in pipeline construction projects. The Commission addressed this matter at some length in Opinion No. 357, authorizing the Iroquois project.<sup>18</sup> In that proceeding, several parties, most notably among them Dr. Joyce Brothers, contended that the Commission failed to comply with section 106 of the NHPA insofar as the FERC authorized the Iroquois project without first completing required cultural surveys and consultation procedures.<sup>19</sup> The Commission dismissed these arguments, noting (1) that section 106 provides only that agencies such as the FERC must "take into account" impacts on historic areas, (2) that the FERC's flexible approach of granting overall approval, while requiring more detailed NHPA compliance on a segment-by-segment basis, is consistent with regulations of the Advisory Council on Historic Preservation, (3) that the certificate contains mitigation measures intended to prevent harm to protected historic or cultural areas, and (4) that judicial and Commission precedent have found the FERC's procedures to be in compliance with the NHPA.<sup>20</sup>

As noted in the July 1989 Report of the Committee on the Environment,<sup>21</sup> the Commission issued a notice of proposed civil penalty against Transcontinental Gas Pipe Line Corporation (Transco) for alleged violations of the NHPA in the construction of two Mobile Bay area pipeline facilities built in 1987.<sup>22</sup> Transco responded in August of 1989 with submissions contending that the pipeline was legally constructed pursuant to section 311 of the NGPA, which did not impose NHPA requirements. Transco stated further its intention to work with local State Historic Preservation Officers.<sup>23</sup>

Although the FERC has not yet acted on this matter, on November 30, 1990, the state of Alabama and its attorney general filed further objections

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16. *Id.* at 32,479-84, 55 Fed. Reg. at 33,040-42.

17. 16 U.S.C. §§ 470 to 470w-6 (1988).

18. Iroquois Gas Transmission Sys., 53 F.E.R.C. ¶ 61,194 (1990).

19. *Id.* at 61,758-59.

20. *Id.* at 61,759-64.

21. 11 ENERGY L.J. 313, 313-14 (1990).

22. Transcontinental Gas Pipe Line Corp., 48 F.E.R.C. ¶ 61,189, at 61,699 (1989).

23. *Transco Rejects Charges that Construction of Mobile Bay System Damaged or Destroyed Historical Sites and Claims Facilities Were Used Solely for the Purpose of Delivering Gas on Behalf of Eligible Customers Under NGPA Section 311(a)(1)*, Foster Natural Gas Report (Foster Associates) No. 1738, at 1 (Aug. 31, 1989).

with the Commission in connection with Transco's construction of facilities in the Mobile Bay area. Among other things, Alabama seeks an increase in the proposed civil penalties, an investigation into additional alleged violations of the Clean Water Act and the Endangered Species Act, and Commission denial of NGA section 7(c) authorization for Transco's participation in a settlement of pipeline projects to transport gas from the Mobile Bay region.<sup>24</sup>

Moreover, on December 19, 1990, the attorney general of Alabama filed suit against Transco Energy Company and others. In this case, Alabama seeks damages under the Racketeer Influenced and Corrupt Organization Act, the Endangered Species Act, and other statutes in connection with Transco's alleged malicious destruction of archaeological sites, wetlands, and endangered species during pipeline construction.<sup>25</sup>

## 2. Historic Preservation Issues for "Qualifying Facilities"

Although disagreements continue over pipeline construction projects, the Commission has clarified its NHPA role with respect to qualifying small power production facilities.<sup>26</sup>

In *Northeast Maryland Waste Disposal Authority*, the National Trust for Historic Preservation<sup>27</sup> and several citizen groups asserted that Commission certification of a qualifying facility (QF) is a federal "undertaking" within the meaning of section 106 of the NHPA.

Before reaching the NHPA issues, the Commission first determined that neither an Environmental Impact Statement nor an Environmental Assessment was necessary for QF certification "because neither the regulations nor an order granting certification authorizes construction or relieves a facility of any other requirements of local, state, or federal law involving siting, construction, operation, licensing, or pollution abatement."<sup>28</sup>

The Commission likewise concluded that QF certification does not constitute a federal "undertaking" under the NHPA.<sup>29</sup> In its discussion of the

24. *State of Alabama Registers Protest Regarding Transco's Construction and Operation of Mobile Bay Pipeline System; Asks Commission to Bar Transco from Settlement with Other Interstate Pipelines*, Foster Natural Gas Report (Foster Associates) No. 1803, at 1 (Dec. 6, 1990).

25. *Alabama ex rel. Siegelman v. Transco Energy Co.*, No. 90-H-1333 (M.D. Ala. filed Dec. 18, 1990).

26. *Northeast Md. Waste Disposal Auth.*, 53 F.E.R.C. ¶ 61,161, at 61,587 (1990), *reh'g denied*, No. QF90-185-001, (Jan. 24, 1991).

27. The National Trust for Historic Preservation is a private, non-profit corporation chartered by Congress in 1949 that is supported by memberships and donations. Act of Oct. 26, 1949, ch. 755, 63 Stat. 927 (1949).

28. 53 F.E.R.C. ¶ 61,161, at 61,587 (quoting *Virginia Turbo Power Systems-II LP*, 51 F.E.R.C. ¶ 61,079, at 61,178, *reh'g denied*, 51 F.E.R.C. ¶ 61,356, *appeal docketed sub nom. Andrews v. FERC*, No. 90-3127 (4th Cir. 1990)).

In its Order Denying Rehearing, the Commission distinguished various cases in which courts have found that agencies must comply with NEPA in connection with granting approval of facilities or operations which could not go forward without agency approval. *Mimeo* at 3. According to the Commission, those cases involved situations "where the activity in question *require[d]* agency approval," whereas QF certification is optional. *Id.* at 3-4 (emphasis added).

The Commission stated that the "same logic applies equally to NHPA procedures." *Id.* at n.12.

29. 53 F.E.R.C. ¶ 61,161, at 61,587.

NHPA, the Commission cited *Duke Power Co.*,<sup>30</sup> wherein the Commission determined that the NHPA did not apply to its review of a proposed interconnection agreement because such activity does not involve federal funding or licensing. The Commission cited *Lee v. Thornburgh*<sup>31</sup> to say that an agency action is subject to the NHPA only when the agency initiates, approves funds for, or otherwise controls the project. The Commission also quoted from *Techworld Development Corp. v. D.C. Preservation League*:<sup>32</sup> "[A] federal undertaking is where a federal agency has direct or indirect jurisdiction over a project involving the expenditure of federal funds or the issuance of a federal license."<sup>33</sup> Based on these precedents, the Commission determined that the NHPA does not apply to QF certification because such certification does not constitute licensing, nor does it authorize or restrict federal funding. The Commission noted that its role with respect to QF certification is merely to make a factual finding that the facility satisfies the Public Utility Regulatory Policy Act of 1978<sup>34</sup> and the Commission's regulations, and therefore qualifies for the benefits conferred thereunder.

### C. *Clean Air Act: Mergers, Natural Gas, and Hydro Facilities*

The FERC may also need to review applications for compliance with air quality requirements under section 176(c) of the Clean Air Act, which until recently stated in part:

No department, agency, or instrumentality of the Federal Government shall (1) engage in, (2) support in any way or provide financial assistance for, (3) license or permit, or (4) approve, any activity which does not conform to a plan [i.e., State Implementation Plan] after it has been approved or promulgated under section 7410. . . . The assurance of conformity to such a plan shall be an affirmative responsibility of the head of such department, agency, or instrumentality.<sup>35</sup>

The state of California and others have contended that the FERC must comply with section 176(c) of the Clean Air Act in its review of the proposed merger between Southern California Edison Company and San Diego Gas & Electric Company. In an order on rehearing in that case, the Commission decided to perform an Environmental Assessment pursuant to NEPA to review alleged adverse impacts that may result from changed operating and generating patterns resulting from the merger.<sup>36</sup> In the same order, the Commission declined at that time to reach the issue of whether section 176(c) is in any way applicable to a proceeding under section 203 of the Federal Power Act.<sup>37</sup>

With the recent enactment of the Clean Air Act amendments, section 176(c) now states:

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30. 43 F.E.R.C. ¶ 61,001 (1988).

31. 877 F.2d 1053 (D.C. Cir. 1989).

32. 648 F. Supp. 106 (D.D.C. 1986).

33. 53 F.E.R.C. ¶ 61,161, at 61,587-88.

34. 16 U.S.C. §§ 2601-45 (1988).

35. 42 U.S.C. § 7506(c) (1988).

36. Southern Cal. Edison Co., 49 F.E.R.C. ¶ 61,091 (1989).

37. *Id.*

(1) No department, agency, or instrumentality of the Federal government shall engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to an implementation plan after it has been approved or promulgated under section 110. . . . The assurance of conformity to such a plan shall be an affirmative responsibility of the head of such department, agency, or instrumentality. Conformity to an implementation plan means—

(A) conformity to an implementation plan's purpose of eliminating or reducing the severity and number of violations of the national ambient air quality standards and achieving expeditious attainment of such standards; and

(B) that such activities will not—

- (i) cause or contribute to any new violation of any standard in any area;
- (ii) increase the frequency or severity of any existing violation of any standard in any area; or
- (iii) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.

The determination of conformity shall be based on the most recent estimates of emissions, and such estimates shall be determined from the most recent population, employment, travel and congestion estimates as determined by the metropolitan planning organization or other agency authorized to make such estimates.<sup>38</sup>

The extent to which this provision applies to Commission actions, as well as the meaning, if any, that the FERC gives to this provision, remains to be seen. Nonetheless, this Clean Air Act section could provide additional statutory support for the Commission's efforts to expedite approvals of energy projects offering beneficial air quality impacts, such as natural gas pipeline expansion or hydroelectric development. Arguably, action at the FERC that delays or thwarts such approvals could be in conflict with clean air objectives stated in section 176(c). By contrast, the FERC has in many instances approved natural gas pipeline construction<sup>39</sup> and hydroelectric projects<sup>40</sup> on the basis of clean air benefits, among others.

38. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 101(f), 104 Stat. 2399, 2409-10.

39. Opinion No. 500, Transwestern Pipeline Co., 36 F.P.C. 176, 186 (1966) (basing natural gas certification determination in large part on Los Angeles air quality issues and Commission "conclusions as to the effect the use of greater volumes of natural gas in Los Angeles is likely to have on air pollution, which we can weigh along with the other factors we are required to consider under Section 7 of the Natural Gas Act"), *aff'd per curiam*, Southern Cal. Edison Co. v. FPC, 387 F.2d 619 (3d Cir. 1967), *cert. denied*, 392 U.S. 909 (1968); Opinion No. 439, El Paso Natural Gas Co., 32 F.P.C. 423, 426 (1964) ("air pollution considerations . . . suggest that the availability of additional gas for southern California is in the public interest"); *see also* Opinion No. 560-A, Chandeleur Pipe Line Co., 44 F.P.C. 1747, 1756 (1970); *but cf.* Lakeland, Tallahassee & Gainesville Regional Utils. v. FERC, 702 F.2d 1302, 1313 (11th Cir. 1983) (affirming Commission's curtailment plan priority order which found that boiler fuel users have the greatest ability to control pollutants at least cost when required to switch from natural gas to alternate fuels); *see also* City of Willcox v. FPC, 567 F.2d 394, 405-06 (D.C. Cir. 1977), *cert. denied*, 434 U.S. 1012 (1978).

40. *E.g.*, City of Pasadena Water & Power Dep't, 46 F.E.R.C. ¶ 61,004, at 61,010 (1989) (approving a hydroelectric project with the observation that alternative power generation sources would produce atmospheric pollution in Southern California, "where air pollution regulations are very stringent").

## II. WETLANDS—CLEAN WATER ACT SECTION 404

### A. FERC Proceedings

#### 1. Interim Rule Governing Construction and Replacement of Facilities

On August 2, 1990, the FERC issued Order No. 525, an interim rule revising title 18 of the Code of Federal Regulations, parts 2 and 284, which govern construction of facilities pursuant to section 311 of the NGPA and replacement of facilities.<sup>41</sup> Concurrently, the Commission issued a notice of proposed rulemaking pursuant to which the Commission "intends to review its current regulations governing the entire range of its authorizations for natural gas pipeline construction."<sup>42</sup>

The Order No. 525 interim rule requires pipeline planning construction or replacement of covered facilities to provide notification to the Commission at least thirty days prior to the commencement of the proposed construction activity so that the Commission may review projects to ensure compliance with environmental requirements.<sup>43</sup> The notification must include: (1) a description of the facilities to be constructed or replaced; (2) for facilities being constructed pursuant to section 311 of the NGPA, evidence of compliance with the environmental terms and conditions of title 18 of the Code of Federal Regulations, section 157.206(d); (3) United States Geological Survey topographic maps showing the location of the facilities; and (4) "[a] description of the procedures to be used for erosion control, revegetation and maintenance, and stream and wetland crossings."<sup>44</sup>

Various parties filed requests for rehearing and/or clarification of the interim rule. The Commission responded, *inter alia*, that commencement of replacement activity begins once a written contract has been executed by the relevant parties, and notification of replacement activity must include identification of the portion of pipeline covered by the activity, a list of repairs that might be required, and an estimate of the length of pipe that might need to be replaced as well as the cost. The thirty day notice requirement applies only to planned replacement of facilities and does not conflict with other Commission and Department of Transportation regulations dealing with emergency repairs needed to avoid injury or interruption of service.<sup>45</sup>

#### 2. District Court Jurisdiction to Review FERC Certificates During Condemnation Proceedings

*In Tennessee Gas Pipeline Co. v. 104 Acres of Land*, defendant landowners

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41. *Interim Revisions to Regulations Governing Construction of Facilities Pursuant to NGPA Section 311 and Replacement of Facilities*, III F.E.R.C. Stats. & Regs. ¶ 30,895, 55 Fed. Reg. 33,011 (1990).

42. *Id.* at 31,810, 55 Fed. Reg. at 33,012.

43. *Id.* at 31,809-10, 55 Fed. Reg. at 33,011.

44. 55 Fed. Reg. at 33,015 (revisions to 18 C.F.R. §§ 2.55(b), 284.11).

45. Order Addressing Requests for Clarification, *Interim Revisions to Regulations Governing Construction of Facilities Pursuant to NGPA Section 311 and Replacement of Facilities*, 52 F.E.R.C. ¶ 61,252 (1990); Final Rule, *Interim Revisions to Regulations Governing Construction of Facilities Pursuant to NGPA Section 311 and Replacement of Facilities*, 55 Fed. Reg. 47,457 (1990).



argued that condemnation proceedings for rights of way, easements, and land for the construction and maintenance of a pipeline were premature because Tennessee Gas had not yet obtained wetland permits required by the Commission's order granting the certificate and by state and federal law.<sup>46</sup> The district court noted that it did not have jurisdiction to review the Commission's issuance of a certificate and that the Commission must resolve on rehearing any dispute over the validity of the certificate due to a failure to require compliance with state or federal wetlands requirements. Furthermore, the court found that, while failure to comply with the terms of the Commission order could delay or prevent pipeline construction, the lack of a required permit does not prevent condemnation of land.<sup>47</sup>

## B. Environmental Protection Agency and Corps of Engineers Matters

### 1. EPA and Corps Memoranda of Agreement

The Environmental Protection Agency (EPA) and the United States Army Corps of Engineers (Corps) are granted authority under section 404 of the Clean Water Act<sup>48</sup> to regulate dredge and fill activities occurring in jurisdictional wetlands. In 1989 and 1990, the EPA and the Corps signed a series of Memoranda of Agreement (MOA) allocating regulatory authority between the two agencies. These included an agreement on allocation of authority to determine jurisdictional wetlands,<sup>49</sup> an agreement on allocation of enforcement authority,<sup>50</sup> and an agreement concerning the type of mitigation needed to obtain a section 404 permit to fill wetlands.<sup>51</sup>

The mitigation MOA sparked controversy. Mitigation ordinarily involves the creation of new wetlands or the enhancement of existing wetlands to compensate for the loss of wetlands through fill activities. The original mitigation MOA, issued in November, 1989, included language that was widely interpreted as requiring mitigation in most cases of at least one-to-one acreage replacement of wetlands. The two agencies appeared to take the position that such one-to-one acreage replacement was necessary to implement the "no-net-loss" policy adopted by President Bush during the 1988 presidential campaign. Following the release of the MOA, significant objections were raised, particularly by the oil and gas industry, to a number of provisions in the agreement. The revised MOA issued in February 1990 continued to

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46. *Tennessee Gas Pipeline Co. v. 104 Acres of Land*, 749 F. Supp. 427, 432 (D.R.I. 1990).

47. *Id.* at 433.

48. 33 U.S.C. § 1344 (1988).

49. Memorandum of Agreement between the Department of the Army and the Environmental Protection Agency Concerning the Determination of the Geographic Jurisdiction of the Section 404 Program and the Application of the Exemptions Under Section 404(f) of the Clean Water Act (January 19, 1989); see also W. WANT, *LAW OF WETLANDS REGULATION* § 2.02[4], at 2-11 to 2-12, app. 7 (1990).

50. Memorandum of Agreement between the Department of the Army and the Environmental Protection Agency Concerning Federal Enforcement for the Section 404 Program of the Clean Water Act (January 19, 1989); see also W. WANT, *supra* note 49, § 2.02[4], 2-11, app. 8.

51. Memorandum of Agreement between the Environmental Protection Agency and the Department of the Army Concerning the Determination of Mitigation under the Clean Water Act Section 404(b)(1) Guidelines (issued November 15, 1989; revised and effective February 7, 1990); see also W. WANT, *supra* note 49, § 2.02[4], at 2-11, app. 16.

emphasize the "no-net-loss" policy. The memorandum indicated, however, that one-to-one acreage replacement, while a reasonable surrogate for "no-net-loss" of wetland functions and values, will not necessarily be required. The preamble to the MOA published in the *Federal Register* further clarified that, in areas of the country (such as Alaska) where much of the land is wetlands, "minor losses of wetland functions" may not need to be mitigated.<sup>52</sup>

The February 7, 1990, mitigation MOA was challenged in federal district court by the state of Alaska. The District Court for the District of Alaska declined to review the challenge to the MOA, saying that the agreement should not be reviewed until it is actually applied.<sup>53</sup>

## 2. Federal Manual for Identifying and Delineating Wetlands

In 1989, the EPA and the Corps reached agreement on a federal manual to be used for the identification and delineation of wetlands.<sup>54</sup> The manual, which was also agreed to by the Soil Conservation Service and the Fish and Wildlife Service, generally makes it easier to assert that sites qualify as jurisdictional wetlands. The manual, by changing the procedures for identifying wetlands and redefining the characteristics of wetlands, appears to have increased the amount of land that the federal government will consider to be wetlands. Instead of requiring that wetlands vegetation, soils, and hydrology all be present at a site, the manual permits, under certain circumstances, that the presence of some of these conditions may be assumed from the presence of others.<sup>55</sup>

## 3. Takings Jurisprudence

In two recent cases, the United States Claims Court has awarded damages to developers denied section 404 permits to fill wetlands by the Corps. A developer denied a section 404 permit for a limestone mine was awarded \$1,029,000 plus interest in just compensation for the taking.<sup>56</sup> Another developer, denied a section 404 permit for a 12.5 acre housing development, was awarded \$2,658,000 in compensation.<sup>57</sup> If these two decisions stand up on appeal to the Federal Circuit, they may signal a coming wave of Claims Court awards for landowners denied section 404 permits by the Corps or the EPA.<sup>58</sup>

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52. Notice, *Memorandum of Agreement (MOA); Clean Water Act Section 404(b)(1) Guidelines*, 55 Fed. Reg. 5,510 (1990).

53. *Anchorage v. United States*, 32 Env't Rep. Cas. (BNA) 1199 (1990); see also *Wetlands Agreement Will not be Reviewed Until Applied in Permit Case, Court Rules*, 21 Env'tl. L. Rep. (Env'tl. L. Inst.) 1210 (October 26, 1990).

54. FEDERAL MANUAL FOR IDENTIFYING AND DELINEATING JURISDICTIONAL WETLANDS (1989).

55. W. WANT, *supra* note 49, § 2.02[4], at 2-11.

56. *Florida Rock Indus., Inc. v. United States*, 21 Cl. Ct. 161, 176 (1990).

57. *Loveladies Harbor, Inc. v. United States*, 21 Cl. Ct. 153, 161 (1990).

58. See L. Epstein, *Takings and Wetlands in the Claims Court: Florida Rock and Loveladies Harbor*, 20 Env'tl. L. Rep. (Env'tl. L. Inst.) 10,517 (1990).

## III. CLEAN AIR ACT AMENDMENTS OF 1990

A. *Introduction*

In 1990, Congress passed and the president signed the Clean Air Act Amendments.<sup>59</sup> Long anticipated and much debated, the Act is likely to fulfill its billing as the most comprehensive and far-reaching environmental statute ever enacted. The Act is an extensively revised version of the President's clean air proposal that engineered the break-through in the Clean Air Act legislative logjam. Because the new statute is so broad, the implementing regulations that must be developed by the EPA will be even longer and more complicated than the Act itself. Because the Clean Air Act Amendments will not be the exclusive province of environmental attorneys, a basic knowledge of it will be essential for all those who provide legal advice and counsel to power producers and for others in the energy industry.

While the goal of the Acid Deposition title (Title IV)—to reduce emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>)<sup>60</sup>—is not novel, the marketable allowance system instituted in that title ties the electric utility industry together in entirely new ways. In the past, the industry may have shared common concerns about clean air regulations but, in the end, each electric utility faced the costs and consequences of clean air regulation alone. Now, under the regime established by the 1990 amendments, a power producer may not be able to meet the emission reduction requirements without taking into account the plans and activities of other utilities or power producers. Moreover, it is difficult to conceive of any electric utility transaction that will not be affected by the new sulfur dioxide allowance provisions of the Acid Deposition title.<sup>61</sup>

In power sales, in pool operations, in sales of facilities, and in serving existing customers, a utility will have to take into account the Act's allowance requirements. In addition, just as under the 1977 Clean Air Act, a large number of utilities may have to install and operate pollution control devices or, in many cases, purchase cleaner fuel. Utilities will be forced to seek recovery of these compliance costs in proceedings before state regulatory commissions or the FERC. For practitioners before those commissions, it will be important to know how the Act, and the Acid Deposition title in particular, imposes the new requirements.

The general contours of the Act are clear: The title is designed to reduce annual emissions of sulfur dioxide in the forty-eight contiguous states and the District of Columbia by ten million tons from 1980 emissions levels. With respect to nitrogen oxides, the Act's goal is to reduce emissions by approximately two million tons from 1980 emissions levels. Under the Act, emissions of SO<sub>2</sub> are ultimately controlled so that emissions from all utilities do not exceed an annual aggregate of 8.9 million tons.

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59. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, 104 Stat. 2399.

60. Note that despite new reductions in SO<sub>2</sub> and NO<sub>x</sub> emissions, power producers will still be liable for meeting other Clean Air Act requirements, including long-standing restrictions as to emissions of sulfur and nitrogen oxides.

61. A sulfur dioxide allowance is an authorization to emit one ton of SO<sub>2</sub> in a single year.

To accomplish this goal, the Act provides a two-phased program of reductions. For purposes of Phase I, the Act identifies 107 high emitting units—those emitting over 2.5 pounds of sulfur dioxide per mmBtu of fuel heat input—and mandates that by January 1, 1995, annual sulfur dioxide emissions from these units be reduced by approximately 2.5 to 4.5 million tons.

The emissions limitations in Phase II, on the other hand, capture virtually every steam-electric utility unit in the forty-eight contiguous states and effectuate the ten million ton reduction in annual sulfur dioxide emissions. Under the Phase II program, after January 1, 2000, utility units may emit no more than 1.2 pounds of sulfur dioxide per mmBtu collectively.<sup>62</sup> In general, affected utility units in Phases I and II will have emissions limitation obligations, monitoring and reporting requirements, permitting requirements, allowance allocations, and excess emissions liabilities.

### *B. Who Will be Subject to the Provisions of the Act?*

Under the Act, a "utility unit" that can be an "affected unit" (and, therefore, subject to the SO<sub>2</sub> cap and other provisions) is defined as a unit which serves as a generator that produces electricity for sale.<sup>63</sup> While this is a broad definition, it is limited elsewhere in the Act by provisions dealing specifically with qualifying facilities, combustion turbines, small utility units, and industrial sources.

First, unless they opt voluntarily to participate in the allowance program, industrial sources of sulfur dioxide and nitrogen oxides will not have to reduce emissions in either Phase I or Phase II of the Acid Deposition program.<sup>64</sup> Second, current simple combustion turbines or units which serve a generator with a capacity of twenty-five megawatts or less are not deemed "existing units,"<sup>65</sup> and, thus, unlike most other utility units, will not be required to hold allowances. Third, a unit that cogenerates steam and electricity is not a "utility unit" unless the unit is constructed for the purpose of supplying, or commences construction after the date of enactment (November 15, 1990) and supplies, more than one-third of its potential electric output capacity and more than twenty-five megawatts electrical output to any utility-powered dis-

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62. Under the allowance trading regime, individual units will be permitted to emit in excess of the 1.2 pound limit to the extent owners or operators possess necessary allowances. Units that employ designated clean coal technologies would be eligible to obtain an extension beyond the Phase II deadline—to December 31, 2003. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 409, 104 Stat. 2399, 2619-21 (to be codified at 42 U.S.C. § 7651h).

63. *Id.* § 402(17)(A), 104 Stat. at 2587 (to be codified at 42 U.S.C. § 7651a).

64. *Id.* § 402(24), 104 Stat. at 2588 (to be codified at 42 U.S.C. § 7651a). These units may have to make NO<sub>x</sub> reductions under the nonattainment provisions of the Act. Non-utility units not subject to the Acid Deposition may opt in under § 410 of the title. They may do so if the owners and operators of those sources believe that they can benefit from holding SO<sub>2</sub> allowances. But note that non-utility units may be subject to controls that based on an inventory of emissions will exceed 5.6 million tons of SO<sub>2</sub> annually. Then, the EPA must implement a program maintaining that cap. *Id.* § 406(b), 104 Stat. at 2632-33 (to be codified at 42 U.S.C. § 7651).

65. *Id.* § 402(8), 104 Stat. at 2586 (to be codified at 42 U.S.C. § 7651a).

tribution system for sale.<sup>66</sup>

### C. *The Allowance System*

To comply with the Act, a power producer will have a range of options: It can reduce or end utilization of a high emitting unit, install emission control technologies, switch to "cleaner" fuels, and/or rely upon the allowance system to provide offsets for emissions at a facility. The only constant is that the power producer must hold emission allowances equal to the tons of SO<sub>2</sub> emitted from all of its units. Through the system of marketable allowances, the SO<sub>2</sub> reduction program is intended to maximize the range of choices that sources have in complying with the emissions limitation requirements. To reduce compliance costs and increase flexibility, electric utilities across the country may in fact rely upon the sulfur dioxide emission allowance trading system to obtain additional allowances and, thus, meet the compliance goals of the Act. Section 403 of the Act, which is discussed below, lays out the basic design of the allowance allocation and transfer systems.

#### 1. What is an Allowance?

An allowance is an authorization issued to an affected source by the EPA Administrator that permits the source to emit, during or after a specified calendar year, one ton of sulfur dioxide.<sup>67</sup> If a utility or power generator does not have any units eligible to receive emission allowances as "existing units," its new projects will have to obtain allowances from other sources in order to operate. New units may meet their obligations under these subsections of the Act by acquiring allowances from any source or person lawfully holding allowances anywhere in the country.<sup>68</sup>

##### a. Exemption of Certain Independent Power Production Facilities

It is worth noting, however, that not all new independent power projects will be required to hold allowances. An independent power production facility (IPP) will earn an exemption from the requirements of the Acid Deposition title if it, as of the date of enactment: a) has an applicable power sales agreement; b) is the subject of an order requiring an electric utility to enter into a power sale with the facility; c) has a letter of intent or similar instrument from a utility committing to purchase power from the facility; or d) has been selected as a winning bidder in a utility competitive bid solicitation.<sup>69</sup>

##### b. Duration of an Allowance's Existence

As noted, the Act specifies that an allowance is a limited authorization to

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66. *Id.* § 402(17)(C), 104 Stat. at 2587-88 (to be codified at 42 U.S.C. § 7651a).

67. *Id.* § 402(3), 104 Stat. at 2585 (to be codified at 42 U.S.C. § 7651a).

68. *Id.* § 403(e), 104 Stat. at 2591 (to be codified at U.S.C. § 7651b).

69. *Id.* § 405(g)(6)(A), 104 Stat. at 2611 (to be codified at 42 U.S.C. § 7651d).

emit, during or after a specified calendar year, one ton of sulfur dioxide.<sup>70</sup> Once created, an annual allowance does not expire until used. Thus, for example, an allowance allocated to an existing unit under the Act in 1996 could be "banked" and used to offset one ton of SO<sub>2</sub> emissions during the year 2001. While allowances are issued to the owners and operators of existing utility units, the Act specifically states that an allowance does not constitute a property right and may be limited or terminated, impliedly, without compensation from the government.<sup>71</sup>

Allowance transfers are to be designed to carry out the "full menu" of prerogatives enjoyed by parties to conventional commercial contracts. In other words, parties will be able to transfer allowances between and among themselves through commercial arrangements such as leases, sales agreements, and exchanges of emission allowances for electric power or capacity. In fact, "ownership" of allowances by brokers, investors and other market makers is encouraged to maintain fluidity in the allowance market, to link buyers with sellers, and to facilitate rational price-finding.

### c. Who May Revoke an Allowance?

Some commentators have suggested that the Act's definition of an allowance—that it is a limited authorization to emit sulfur dioxide that does not constitute a property right—could cast a shadow over the allowance market.<sup>72</sup> The Act states that "[n]othing in this title or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization."<sup>73</sup> Those who create excess allowances by voluntarily overcontrolling SO<sub>2</sub> emissions, at some point, may lose them without obtaining just compensation, thus upsetting the stability of the allowance transfer system.<sup>74</sup>

Critics of this result argue that, because overcontrol is a voluntary action, giving unspecified agents of the United States the power to revoke allowances could have unintended results. Utilities may not overcontrol to "free up" allowances if they are subjected to the risk of having those allowances appropriated by the EPA. Even if utilities are willing to take such a risk, the rate-payers and stockholders, who ultimately pay for overcontrol (which may be more expensive than simple compliance), may not be willing to accept that risk. Critics also suggest that there are serious questions about the wisdom of

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70. *Id.* § 402(3), 104 Stat. at 2585 (to be codified at 42 U.S.C. § 7651a).

71. *Id.* § 403(f), 104 Stat. at 2591-92 (to be codified at 42 U.S.C. § 7651b).

72. *Id.* § 402(3), 104 Stat. at 2585 (to be codified at 42 U.S.C. § 7651a).

73. *Id.* § 403(f), 104 Stat. at 2591-92 (to be codified at 42 U.S.C. § 7651b).

74. The legislative history of the Senate language, which was the language adopted in the final bill, clearly indicates that the bill is designed to make certain that allowances are not subject to the fifth amendment "takings clause." Allowances, at least in the original Senate formulation, "are but the means of implementing an emissions limitation program, which can be altered in response to changes in the environment or for other sound reasons of public policy." S. REP. NO. 228, 101st Cong., 1st Sess. 321, *reprinted in* 1990 U.S. CODE CONG. & ADMIN. NEWS 3385, 3704.

allowing the United States to confiscate, perhaps without just compensation, allowances for which a utility's ratepayers and stockholders have paid. Public service commissions and environmental agencies may be reluctant to permit utilities to overcontrol their emissions if benefits of that locally-financed overcontrol are subject to appropriation by a federal agency. Finally, if a utility does attempt to create excess allowances, it may have a difficult time obtaining financing for such an overcontrol project. At a minimum, a utility may have the obligation to inform potential investors that the government could seize some portion of the allowances created by the project.

Participants in the allowance transfer system will probably argue, however, that only Congress and the President, acting through legislation, should have the authority to limit or to revoke allowances and that the Congress should be extremely reluctant to do so. Moreover, allowance holders may contend that even though the revocation of allowances may not require the federal government to compensate holders of those allowances, contracts involving the use of allowances should be fully protectable under commercial law and subject to the takings clause of the Constitution.

In light of these concerns, doubts may be raised whether a utility's reliance on the allowance system to design a workable compliance program would be misplaced. If the Congress does not compensate holders of allowances for the loss of an individual allowance, will the holders and users of allowances have reason to rely upon the continued existence and value of allowances as they design and undertake their compliance efforts? The short answer is that no one knows.

## 2. How Many Allowances Will a Power Plant Have?

Existing utility units are allocated allowances in Phase I and Phase II. The Act establishes a "baseline" for each unit. Based upon a calculation of baseline fuel consumption and emission rates, each Phase I unit is allocated allowances in a table provided in the Act. The baseline is the annual quantity of fossil fuel consumed by an affected unit, measured in millions of British thermal units over a given period—generally 1985 through 1987 for most existing units.<sup>75</sup> The baseline is then multiplied by an emissions rate—the 1985 emission rate for most existing facilities—to yield the number of allowances to which a unit is entitled. In Phase II, allowances are allocated on the basis of this same type of calculation, with some variations in the formula to take into account the special circumstances of various types of utilities and utility units. For example, many "clean" coal-fired units were underutilized during their baseline period. Accordingly, the Act attributes to some existing units either a higher capacity factor or a higher emission rate in order to increase the number of allowances available for the units and, thus, permit

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75. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 402(4), 104 Stat. 2399, 2585-86 (to be codified at 42 U.S.C. § 7651a).

increases in emissions from those units.<sup>76</sup>

### 3. Will Allowances Be "Traded"?

The theory underlying the allowance system is straightforward. The Act, in stages, reduces the amount of sulfur dioxide that can be emitted at the nation's fossil-fired power units. To meet those new emission rates, an owner or operator of a unit can either reduce tons of emissions through some form of pollution control or purchase allowances that "cover" the emissions a utility unit produces in excess of those allowed by law. Again, in theory, allowances will be available to "cover" these excess emissions because the installation of controls at a given plant will reduce sulfur dioxide emissions to a point below the new emission standard.

The Senate report on the original version of Senate Bill 1630 gave this hypothetical to explain the incentive underlying a possible allowance transfer transaction:

Unit A emits 25,000 tons of SO<sub>2</sub> annually and is allocated 10,000 allowances, requiring it to remove 15,000 tons of emissions to meet a 10,000 ton emissions limit. Unit A can remove 18,000 tons of emissions at a cost of \$500 per ton. If it did so, it would need only 7,000 annual allowances to cover its own operations, leaving it with 3,000 unused allowances. Unit B emits 15,000 tons per year and is allocated 12,000 allowances. To remove 3,000 tons to meet its 12,000-ton/allowance limit would cost it \$1,000 per ton. Unit B would clearly save money by purchasing unit A's 3,000 allowances at a price somewhere between \$500 (unit A's cost) and \$1,000 (unit B's cost) rather than incurring the \$1,000 per ton cost of removing the emissions itself.<sup>77</sup>

The incentive to profit through sale of allowances should exist in those instances in which the market price for allowances exceeds the incremental cost of control at a particular unit. Thus, those utilities capable of controlling emissions relatively cheaply may "produce" and sell allowances.

According to its sponsors, the allowance market should be structurally competitive because ownership of allowances will not be concentrated. To emphasize this lack of market concentration, the authors of the Senate report, citing the Council of Economic Advisers, suggested that of the 5.1 million allowances issued to existing units with affirmative reduction obligations in Phase II (representing only approximately fifty-six percent of the total allowances issued), only twenty-six percent would be awarded to the top three public utility holding companies. In turn, according to the Senate report, the top thirteen holding companies together would be granted only fifty-seven percent of this partial total, and the six states holding the most allowances would account for less than half of this partial total.<sup>78</sup>

In Phase I, the Act also provides incentives for overcontrol through the installation of scrubbers that may generate excess allowances which could also

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76. Some 300,000 allowances will be available on a first-come-first-serve basis to utilities that utilize energy conservation measures and renewable energy technology. *Id.* § 404(f)(2)(A), 104 Stat. at 2602 (to be codified at 42 U.S.C. § 7651c).

77. S. REP. NO. 228, 101st Cong., 1st Sess. 318-19, *reprinted in* 1990 U.S. CODE CONG. & ADMIN. NEWS 3385, 3701-02.

78. *Id.*



be marketed.<sup>79</sup> As noted above, the Act does not limit a purchaser's ability to bank allowances for use in years subsequent to those for which they are issued. Thus, many believe that the allowance cap, the durable nature of allowances, the lack of market power on the part of major allowance holders, and the variations in the costs of emission controls will combine to create a market for allowances.

#### 4. How Much Will Allowances Cost?

According to some authorities, the estimated cost of each allowance available in the open market could range between a low of \$650 and a high of \$1500 (based on the allowance price set in a direct sale provision of the Act). There is, however, a surprising consensus of opinion on a narrower range in the value of Phase II allowances. The various consulting firms that have worked on allowance issues generally seem to agree that a Phase II allowance is currently worth between \$700 and \$900 (in today's dollars). There is no reason to assume, however, that each private sale of allowances in any given year will be at a uniform price.

#### 5. When and Where Can a Producer of Electricity Purchase Allowances for the Operation of a Project?

Throughout the clean air debate, there were a number of IPPs concerned that the market for allowances would not be as robust as the designers of the allowance system might wish. Under the original House and Senate bills, few IPPs would have been eligible to receive allowances as existing units, and IPP representatives believed that they would be denied allowances by those who are eligible to receive the most allowances—traditional utilities.<sup>80</sup> Thus, they argued that the law should set aside a number of allowances for use by the Administrator to stimulate the sale of allowances and to protect the interests of IPPs. Both the House and Senate bills contained provisions that would withhold a fixed number of allowances for government run auctions and sales. The final bill accomplishes this end as well, but its approach to distributing allowance from those reserves is somewhat different from either the House or Senate bills.

##### a. Contingency Guarantee; Auctions and Reserves

Section 416 of the Act sets up a Special Allowance Reserve for the purpose of insuring a ready supply of SO<sub>2</sub> allowances to IPPs and others. The reserve is created by withholding 2.8% of the allowances that affected units would otherwise receive under the bill. The resulting 300,000 annual

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79. Owners and operators of Phase I plants that elect to install continuous systems of emission reduction, in part, can qualify for a two year compliance extension and receive early-reduction bonus allowances for reductions achieved between 1995 and 1997. Clean Air Act Amendments of 1990, § 404(d), 104 Stat. at 2594-96 (to be codified at 42 U.S.C. § 7651c).

80. It should be noted that the Act contains a provision preserving the application of the antitrust laws to allowance transactions. *Id.* § 403(i), 104 Stat. at 2592 (to be codified at 42 U.S.C. § 7651b).

allowances tonnage held in the reserve are to be made available for direct sales and auctions.

b. Direct Sale at \$1500 Pool

Beginning in 1993, the Administrator is authorized to offer and sell 25,000 Phase II allowances annually in an advance sale at a price of \$1500 per ton.<sup>81</sup> Generally, the sales are to be on a first-come-first-served basis. Allowances sold in the advance sale may only be used in the seventh year after the year in which they are first offered for sale, unless banked for use in a later year. In addition, beginning in the year 2000, the amount of fixed price allowances will increase to 50,000 in total.

These fixed price allowances are to be sold in two forms: 25,000 in spot sales and 25,000 in advance sales as stated above.<sup>82</sup> Allowances sold in the spot sale are allowances that may be used in the year in which they are purchased or can be banked for later use. The rationale for holding two types of sales is that (1) spot allowances will ensure that allowances are available in each year, while (2) advance sales provide assurance to electric producers and, most importantly, to potential investors, that a power producer will be able to operate after the year 2000.

Before these allowances can be offered to any other type of power producer, the Administrator must give IPPs the opportunity to purchase these 50,000 allowances. In that regard, the Act provides a definition of what constitutes an "independent power producer" and an "independent power production facility." An IPP is one who will be the owner or operator of a new unit that will generate electric energy (eighty percent or more of which is sold at wholesale), is nonrecourse project-financed, does not generate electric energy sold to an affiliate, and, except as otherwise provided by the Act, is required to hold allowances.<sup>83</sup> While the Administrator is required to provide an IPP a written guarantee that these allowances will be made available, he or she only need do so if the IPP applies for financing to construct the facility after January 1, 1990, (and before the first auction) and if the IPP has submitted a written offer to each affected Phase I unit offering to buy allowances for \$750 per ton and has not, within 180 days of the offer, received an acceptance.

The Act recognizes, of course, that the 50,000 fixed price allowances may be exhausted, and if an application would exhaust the supply of allowances in a given year, the Administrator is only authorized to sell whatever remains of the 50,000 allowances. Each applicant is required to pay earnest money equal to one-half of the estimated purchase price within six months of the approval of the application. The remainder is paid on or before the transfer of the allowances. Receipts of the sale are to be dispersed on a pro rata basis to the

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81. *Id.* § 416(c)(2), 104 Stat. at 2627-28 (to be codified at 42 U.S.C. § 7651o).

82. *Id.* § 416(d)(2), 104 Stat. at 2629-30 (to be codified at 42 U.S.C. § 7651e).

83. *Id.* § 416(a)(1), (2), 104 Stat. at 2626-27 (to be codified at 42 U.S.C. § 7651o).

owner/operators of the affected units from whose allocations the allowances were deducted.<sup>84</sup>

### c. Open Auction Pool

Section 416 of the Act provides a second means for assuring liquidity in the allowance market. It requires that the Administrator conduct auctions in each calendar year beginning in 1993. The auctions are open to all parties. Between 1995 and 1999, some 150,000 annual allowances will be available, 50,000 of which will be available for use in 1995 (unless banked for use in a later year) and 100,000 of which will be usable after the year 2000. After that year, 250,000 allowances may be purchased in the auction. Once again, the allowances sold are divided into allowances usable in a calendar year in which an auction is held and allowances which are not usable until seven years following the auction.

The auction is to be open to any person who may hold allowances pursuant to the Acid Deposition title (which is essentially anyone) and a minimum price is not required or set. The Administrator must make information publicly available concerning the nature, price, and results of each auction including the prices of successful bids and must record the transfer of allowances as a result of each auction and purchase. Finally, any holder of allowances may contribute to this auction. Private parties, however, may specify a minimum sale price and the time of payment, provided the Administrator finds that doing so would not interfere with the purposes and function of the auction.

After public notice and comment, at any time after either the year 1998 in the case of advance sales or advance auctions, or the year 2005 in the case of spot sales or spot auctions, the Administrator may decrease the number of allowances withheld and sold. In addition, after the year 2000, the Administrator may decrease the number of allowances sold in the auction, if he or she determines that during any period after 2002 less than twenty percent of the allowances available in the auction subaccount have been purchased. The EPA Administrator is also given the authority to delegate or contract away the responsibility to conduct the auction and direct sales to another governmental agency or private entity.

### d. Open Market

The third means by which a producer might be able to obtain allowances is simply through contracting with holders of Phase I or Phase II allowances. A deal involving allowances could be completed relatively soon because the Act specifically permits the transfer of allowances prior to their issuance. In other words, prospective holders of allowances will be permitted to record "pre-issuance transfers" and deduct the allowances already sold or transferred from the number of allowances that they will receive in 1995. As noted ear-

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84. *Id.* § 416(d)(3), 104 Stat. at 2630 (to be codified at 42 U.S.C. § 7651o).

lier, in the Phase I the Act provides incentives for overcontrol that may generate excess allowances available on the open market.<sup>85</sup> These allowances may be available at far less than the \$1500 provided for in the Administrator's sale and, perhaps, even less than the price that may emerge from the 1993 auction. In any event, the market for allowances may open quickly and should remain open as long as there are willing buyers and sellers. Every utility in need of allowances will probably consider purchasing allowances not through an EPA sponsored auction or sale but through a private contract with an allowance holder.

## 6. Additional Facets of the Allowance System

Despite the steps taken in the Act to ensure the existence of a workable allowance transfer system, a number of other concerns exist about how the sulfur dioxide allowance system may affect the current framework of dual state and federal regulatory control of the electric utility industry.

### a. Role of the DOE and the FERC

Due to a concern about the impact of the allowance system on national energy policy, the House bill identified a need to ensure that both the Department of Energy (DOE) and the FERC were involved in developing and administering the allowance trading program found in the Clean Air Act Amendments of 1990.<sup>86</sup> This provision did not survive in the conference. Although the Secretary of Energy and the FERC may still be consulted in the development and promulgation of the allowance regulations, the federal agencies responsible for overseeing the nation's interstate electric supply system will have little statutory power to influence the shape of the regulations governing allowance trading.

Some utilities suggest that without active DOE and FERC involvement in the regulatory process leading to implementation of the Amendments, allowances associated with FERC jurisdictional transactions—e.g., off-system sales and unit power sales—may be at more risk from parochial interference since they may involve emissions of SO<sub>2</sub>, and “depletion” of valuable allowances, in one region to benefit the residents of other regions. In other words, some believe that states may disallow compliance costs or allowance purchase costs to serve native loads, if a utility company were to use current allowances in the generation of power for interstate bulk power sales and the like.

As a part of the allowance transfer system, the conference committee did add some new provisions permitting utilities to enter into allowance pooling agreements. Under such agreements, utilities would not have to transfer or record allowance transfers as long as tons of emissions ultimately equaled the

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85. See *supra* note 79 and accompanying text.

86. House Substitute for S. 1630, 101st Cong., 2d Sess. § 503(b)(3).

number of allowances available to the pool.<sup>87</sup> The existence of this provision may bolster the argument made by some that the FERC, rather than the state regulatory commissions, should have jurisdiction over compliance planning and allowance transfers when it comes to matters of cost recovery in multi-state utility systems and power tools. By including the pooling provision, they argue that Congress may have been signalling that it did not want state regulatory bodies to impose direct or indirect restrictions on the allowance system that could disrupt electric reliability. Regardless of how this provision is interpreted, the issue of regulatory jurisdiction over compliance planning and allowance transfers could prove to be contentious, with some arguing for a much greater role for the FERC.<sup>88</sup>

For example, a multistate utility could contend that FERC jurisdiction over "rates" extends to the components of those rates, including the costs associated with Clean Air Act compliance and the purchase of allowances. Thus, a multistate utility might amend its Intercompany Interchange Contract so that system dispatch took into account Clean Air Act compliance costs. If the FERC then approved the contract, such a utility could argue that its state commissions would be precluded from second-guessing the FERC determination. Beyond that scenario, the FERC, at a minimum, will have to decide how the costs and charges associated with issuance, receipts, and sales of allowances will be handled under the Uniform System of Accounts and whether to allow utilities to earn a profit on the sale of allowances associated with FERC's jurisdictional transactions.

With regard to renewable energy and energy conservation, the Act gives the FERC a definite role. In consultation with the EPA, the FERC is directed to calculate the "net" environmental benefits of renewable energy and energy conservation by May 15, 1992. Once these net benefits have been assessed, the FERC must propose model regulations to send to Congress by November 15, 1992.<sup>89</sup>

#### b. Tax Consequences of Allowance Sales

One of the factors that may determine whether or not an allowance market system develops will be the tax treatment of the revenues from allowance sales. The Act itself is silent on the tax consequences of allowance trading. Given congressional silence, tax authorities will first have to determine what, if any, basis an owner or operator will have in a given allowance. Typically,

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87. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(d), 104 Stat. 2399, 2591 (to be codified at 42 U.S.C. § 7651b).

88. On this point, § 403(f) of the Act somewhat ambiguously provides, "Nothing in this section [dealing with the nature of allowances] shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under that Act." *Id.* § 403(f), 104 Stat. at 2591-92 (to be codified at 42 U.S.C. § 7651b).

89. Section 808 of the Act provides for a FERC study of environmental benefits of renewable energy as compared to nonrenewable energy. *See id.* at § 808, 104 Stat. at 2690.

allowances will only be available for sale if an owner or operator takes some action to "free up" the allowance through fuel switching, scrubbing or reduced utilization. Therefore, will the basis of a given allowance be tied to the specific costs of "freeing it" up for sale? If so, how will allowances in large systems that employ more than one control technique at any number of plants track a given allowance in order to ensure that the proper value is assigned to an allowance? In the alternative, could the value of an allowance in a utility system be based on some average cost of controls?

However, once the means of determining the basis in an allowance is established, the next step will be to determine how revenues from sales will be treated. Some argue that to encourage the development of the allowance market the amounts received by utilities ought to be treated as a return of capital, to the extent of the basis in an affected unit or in the various equipment, rights, or processes acquired or replaced to comply with the Act. Obviously, if these revenues are not treated as ordinary income, utilities will perceive a bottom-line benefit that could help entice them to enter the allowance market. In addition, if allowances are treated as tangible utility property, and, thus, are subject to depreciation, utilities may have yet another reason to participate in the market.

### c. Role of State Regulatory Commissions

There have been reports that some state regulatory commissions have considered taking an active and restrictive approach toward allowance transfers by utilities within a given state. For example, a state commission dealing with a utility seeking to trade allowances could seek to do the following:

1. Determine whether an allowance has been "freed up."
2. Determine whether the utility needs that allowance elsewhere.
3. Determine whether any other utility in the pool needs the allowance.
4. Determine whether any other supplier in the state needs the allowance.
5. Determine whether an IPP or Cogenerator needs the allowance.
6. Determine whether the allowance should be used in the state before the allowance can be transferred out of state.

Whether or not state commission decisions of this kind would be an unconstitutional infringement upon interstate commerce, it is clear that these types of controls would limit the "free market in allowances." Viewed positively, the aim of this type of state decisionmaking could be to provide utilities with a system of rolling prudence reviews. In other words, state commissions would examine a utility's decisions about how to use allowances before the fact rather than question their prudence after a transfer is made. Potential opponents of this approach argue that state commissions will have the full range of regulatory powers they currently enjoy—prudence reviews and, perhaps, some degree of regulatory approval over compliance steps involving construction—and therefore, there is little need for intrusive state controls over the federally-devised allowance system.<sup>90</sup>

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90. Section 403(f) of the Act dealing with the nature of allowances provides: "Nothing in this section

Not surprisingly, opponents of state involvement have said that the EPA regulations establishing the allowance transfer system should prohibit the types of state regulatory controls mentioned above. They contend that otherwise several adverse consequences could occur. First, a multistate utility system could make it difficult to plan compliance on a system-wide basis. If one state attempts to restrict the transfer of allowances held by an operating company, attempts to coordinate generation planning and operation on a system-wide basis could be thwarted. Second, an individual state commission, implementing directives like those outlined above, could prevent utilities from participating fully in power pools by discouraging the use of in-state facilities, and by definition, allowances, for the benefit of an entire region. Finally, some argue, if allowances held by a utility subject to state commission jurisdiction are treated differently from allowances held by nonregulated entities, or are subjected to additional trade barriers, regulated utilities will perhaps miss opportunities to reduce overall compliance costs.

Undoubtedly, most state public utility commissions (PUCs) will demand that power producers find the lowest cost compliance system.<sup>91</sup> In a multistate utility system, a system-wide compliance approach to acid deposition compliance may meet that goal. In other words, least-cost fuel switching and control systems installed in one state could benefit an entire multistate system. If the cost recovery provided by allowance trading ultimately makes whole any initially disadvantaged state in a multistate system, there may be no difficulty in securing state PUC approval of a system-wide compliance approach. If, however, a utility in a particular state is not made whole and overcomplies to aid sister utilities, PUC approval obviously may be difficult to obtain.

Even if system-wide compliance is equitable in the eyes of all public service commissions in a region, an individual state environmental agency may decide that the plan will allow more emissions than desirable and may attempt to impose more stringent environmental controls than those required under the Clean Air Act Amendments. In short, compliance planning by multistate utilities will be doubly difficult given that multistate utilities will have to take into account the perhaps competing goals of a minimum of six regulatory agencies—the EPA, the FERC, two state environmental agencies, and two state PUCs (not to mention the regional offices of the EPA).

#### d. Electrical Reliability and Emergencies

Another important issue concerning allowances is that the Act contains no specific force majeure provision allowing for suspension of emission limitations or allowance requirements for affected units when there is an emergency

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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 State regulation or as limiting State regulation (including any prudency review) under such a State law." *Id.* § 401, § 403(f), 104 Stat. at 2592 (to be codified at 42 U.S.C. § 7651b).

91. However, there may be cases where state political realities will militate against the development of a least cost compliance plan. For example, in order to save coal mining jobs, states could pass legislation to ensure that the state commissions, and the utilities they regulate, will take into account local coal supplies. Such efforts could result in more scrubbing or other hardware fixes and less fuel switching.

that affects or interrupts electric supplies. The general energy emergency provision, section 110(f) of the Act is to apply instead. Some believe that this provision is too general and cumbersome because it requires hearings and specific findings of fact before an emergency can be declared. A number of critics have argued that it was a mistake to omit a force majeure provision given that energy supply interruptions, fuel shortages, and natural disasters have occurred in the past and are virtually certain to occur again.

The Act, however, included only a provision that permits *temporary* increases and decreases in emissions within utility systems, power pools, and allowance pools that result from emergency requirements of the pool. At the end of each year, all units that are a part of these arrangements must have allowances to match emissions. If there are disruptions in the electric supply within a system because of the loss of units or abnormally high demand for electricity, and allowances are unavailable, a utility responding to that crisis by increasing power production and, thus, emissions, could ultimately find itself in violation of the law and could be subject to penalties because it was forced to exceed its emission limitations.

#### e. Regulation under the PUHCA of 1935

As originally proposed, the Clean Air Act Amendments contained two potential impediments to allowance transactions by registered holding companies subject to the Public Utility Holding Company Act of 1935 (PUHCA). One concern was the possibility that allowance sales and purchases could be declared an unrelated business subject to Securities and Exchange Commission (SEC) approval. The other concern was the requirement that allowance transactions between associate companies be consummated at cost.

To avoid these impediments, the conference committee approved an exemption from the PUHCA for allowance transactions, which provides that "[t]he acquisition or disposition of allowances pursuant to this title including the issuance of securities or the undertaking of any other financing transaction in connection with such allowances shall not be subject to the provisions of the Public Utility Holding Company Act of 1935."<sup>92</sup> The provision goes beyond simply exempting allowance transactions from SEC scrutiny; it also frees companies subject to the PUHCA from the obligation of securing approval of the financing transactions necessary to fund Clean Air Act compliance controls. This broad exemption should mean that the SEC will have virtually no role to play in the implementation of the Clean Air Act Amendments of 1990.

#### D. Permits and Compliance Planning

The provisions of the Acid Deposition title are to be implemented through permits issued by the Administrator, or by a state with an approved

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92. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(j), 104 Stat. 2399, 2592 (to be codified at 42 U.S.C. § 7651b).



permit program.<sup>93</sup> The permits will be issued for a period of five years and will prohibit annual emissions of sulfur dioxide in excess of the number of allowances an owner or operator holds. Each application for a permit must be accompanied by a compliance plan. The compliance plan may include the method by which the operator or owner intends to meet the requirements of the Act. Within twenty-seven months of November 15, 1990, owners and operators of first phase units must submit a compliance plan. Within six months of submission, the Administrator must approve or disapprove the plan.

In the second phase, an owner or operator must submit an application by January 1, 1996. If a utility becomes the owner/operator of a new unit, it must submit a permit application and a proposed compliance plan to the permitting authority—either the Administrator or a state with an approved permit program—not later than twenty-four months prior to January 1, 2000, or prior to commencing operation of the unit, whichever is earlier.

The permitting authority must issue a permit and approve the compliance plan if the affected unit satisfies the requirements of the Acid Deposition title and the separate permitting title. Permit applications required by the Act are to be submitted by a designated representative of the owner/operator and, among a host of other requirements, are to identify the schedule and means by which the source will comply with its annual tonnage emission limitation. With certain exceptions, utilities will be required to pay about \$25 per ton (perhaps up to only 4,000 tons) of each regulated pollutant it emits at a plant.

The owner or operator of any unit subject to the acid deposition title will be liable for penalties if they violate any prohibition concerning the operation of an affected unit in excess of the allowances it holds. If a utility emits in excess of the number of allowances that it holds, a civil penalty of about \$2,000 will be charged for *each* excess ton. This fine is due and payable without demand to the Administrator and it does not diminish any fine, penalty or fee that may be imposed under other sections of the Act. In addition, utilities will be required to offset the excess emissions by an equal tonnage for the following calendar year, or succeeding years, if the Administrator so prescribes.

To ensure compliance, the operators of affected units under the title will be required to install and operate Continuous Emission Monitoring Systems (CEMSs) on each affected unit. These instruments provide information on how much sulfur dioxide and nitrogen oxide is being produced by a unit.<sup>94</sup> While provisions are made for alternative monitoring systems, installation of a CEMS is clearly favored under the Act.

### *E. Nitrogen Oxides Controls*

#### 1. Controls under the Acid Deposition Title

Oxides of nitrogen, collectively known as NO<sub>x</sub>, are produced during fossil

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93. The permit program in the first phase is to be a federal permit program.

94. Clean Air Act Amendments of 1990, § 412(a), 104 Stat. at 2624 (to be codified at 42 U.S.C. § 7651k).

fuel combustion. Both the Senate and House versions of the Clean Air Act Amendments contained acid deposition provisions dealing with emissions of nitrogen oxides. Both bills were designed to achieve the emissions reductions through the application of low-nitrogen oxides burner (LNB) technology to wall-fired and tangentially-fired steam electric coal fired utility boilers through a traditional command and control approach.<sup>95</sup> There were, however, major differences between the two bills, particularly with regard to the timing of controls. In the end, the conferees accepted, with slight change, the Senate version of the bills.

As a result, the Act generally imposes NO<sub>x</sub> controls as soon as a unit becomes an affected facility. This means that NO<sub>x</sub> controls will be required by January 1, 1995, for Phase I units. Under subsection 408(b)(1) of the Act, operators of tangentially-fired and dry bottom wall-fired units may install commercially available LNB technology and if, upon installation of LNB technology, a boiler owner or operator finds that it is unable to meet the emission limitations established in the bill, the owner or operator has the right to obtain an alternative emission rate or to develop an emissions averaging program.<sup>96</sup> If the owner or operator cannot meet the mandated emission rate through the installation of LNB, the Act also provides that the Administrator may change the emissions limitations for these types of units only upon a determination that new LNB technology is available.

Under subsection 407(b)(2), operators of wet bottom wall-fired boilers, cyclones, and other types of boilers also will not be required to install SCR or other forms of post-combustion technology. The Administrator is limited to setting a rate that requires no more than the installation of technology that is comparable, on a cost basis, to the cost of installing LNB on coal-fired units pursuant to subsection (b)(1). The Administrator is required to take into account the commercial availability of technology that is equivalent to LNB technology. The Administrator must also determine that the direct and indirect costs of each possible alternative control technology in order to choose the least expensive among possible competing technologies. In that effort, the cost of installing LNB technology on a Phase I affected unit apparently will serve as a ceiling for the cost of a possible alternative control technology. To avoid imposing a requirement that utilities install technology that in itself will

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95. One of the major points of contention in the Congressional debate was whether utilities ought to be required to do more than install low nitrogen-oxide burners. The Administration's bill contained an approach to NO<sub>x</sub> reductions that required utilities to control NO<sub>x</sub> emissions through the use of "technology at the performance level of low NO<sub>x</sub> burners." LNBs have been and are being commercially developed and demonstrated for many types of boilers and appear to be a cost-effective and economical way to reduce NO<sub>x</sub> emissions. The Senate bill sought to limit NO<sub>x</sub> emission from coal-fired utility boilers to specific numerical standards. It was argued that these standards could double the NO<sub>x</sub> reductions sought by the Administration's bill and were so stringent that some sources would not be able to comply through the use of LNB technology. Instead, the use of selective catalytic reduction (SCR) technology could have been required. According to some estimates, SCR technology is roughly 10 times as expensive as LNB technology.

96. The maximum allowable NO<sub>x</sub> emission rates are .45 lbs/mmBtu for tangentially fired boilers and .50 lbs/mmBtu for dry bottom wall-fired boilers. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 407(b), 104 Stat. 2399, 2614 (to be codified at 42 U.S.C. § 7651f). The maximum allowance emission rates for other types of boilers, including cyclones, are to be established not later than January 1, 1997. *Id.*

have adverse environmental impacts (e.g., generation of waste products or use of hazardous substances), the Administrator is directed to take into account the environmental impacts of any technology and reject those that would present a risk to public health or the environment. Finally, the Administrator must select a technology that does not use large amounts of energy or significantly decrease a unit's commercial availability.

In making the foregoing findings, the Administrator may use the installation and operation of LNB technology as reference points for purposes of reaching a decision about whether to set rates based on the application of a technology other than LNB technology. If it can be shown that a boiler owner or operator cannot meet the applicable emission limitation, the owner or operator has the right to obtain an alternative emission rate or to develop an emissions averaging program.

During the course of the House/Senate conference, many utilities complained that the compliance dates of the Senate bill were unrealistic and that House compliance date (2000) should be used. Apparently persuaded, the conference committee allowed an extension of fifteen months for any unit unable to install, test or operate low-NO<sub>x</sub> burners on a unit, taking into account system reliability. Unlike sulfur dioxide controls under the Act, the costs of NO<sub>x</sub> controls will be determinable, nondiscretionary and, thus, probably, recoverable with little controversy.

## 2. Controls under Title I (Non-attainment)

Title I of the Act requires that major stationary sources, including utility units, in serious, severe, and extreme nonattainment areas are to be subject to the same restrictions for NO<sub>x</sub> as for Volatile Organic Compounds (VOCs). Whether reductions in NO<sub>x</sub> emissions will improve ozone air quality is an extremely site-specific issue. Under section 182(f), NO<sub>x</sub> reduction requirements, however, will not be mandated under Title I if the Administrator determines that the NO<sub>x</sub> controls will create substantial costs and will not improve air quality. Thus, through case studies, power producers in nonattainment areas may attempt to demonstrate that NO<sub>x</sub> reductions will not result in an improvement in air quality.

## 3. Interpollutant Trading

In addition, under section 182(c)(2)(C), the Administrator is required to provide guidance concerning the conditions under which control of NO<sub>x</sub> may be substituted for, or combined with, control of VOCs in order to reach attainment of ozone air pollution. The utility industry will probably take an active role in the development of the studies to aid the Administrator in determining under what circumstances NO<sub>x</sub> controls, beyond those required in Title IV, can be avoided.

Finally, with regard to NO<sub>x</sub> controls, under subsection (c) of section 403 of the Act, the Administrator must, by January 1, 1995, evaluate the environmental and economic consequences of permitting trading of sulfur dioxide allowances for nitrogen oxide allowances. While some elements in the utility industry supported the concept of interpollutant trading, some expressed the

fear that an interpollutant trading program could lead to a cap on overall NO<sub>x</sub> emissions and, therefore, resisted interpollutant trading proposals on that basis. Little detail is provided as to how the study will be conducted and, thus, little can be predicted about the future of interpollutant trading.

#### *F. Power Producer Concerns About the Air Toxics Provisions*

##### 1. Title III and Fossil-fired Plants

The Act amends section 112 of the Clean Air Act by establishing a new program for regulating the emission of nearly two hundred "air toxics," or "hazardous air pollutants." The existing section 112 requires the EPA to list as a "hazardous air pollutant" any substance which may be reasonably anticipated to result in mortality or increase serious illness. Once a substance is listed as a hazardous air pollutant, the EPA, under the Act, must establish an emission standard to protect the public health.<sup>97</sup> Thus far, the EPA has listed eight such substances (mercury, beryllium, asbestos, vinyl chloride, benzene, radionuclides, inorganic arsenic, and coke oven emissions) and issued air emission standards for seven of those.

Title III of the Act fundamentally restructures section 112 by requiring the Agency to list nearly 200 specific substances as hazardous air pollutants and to regulate emissions of those substances through an initial technology-based regulatory scheme to be augmented by a subsequent standard based on health risk. Any facility that in the aggregate emits either (1) ten tons per year or more of any single pollutant or (2) twenty-five tons per year or more of any combination of pollutants would be a "major source" subject to regulation.<sup>98</sup> In addition, the Act permits regulation of an "area source," which it defines as any stationary source of hazardous air pollutants that is not a major source.<sup>99</sup> In the new program, the EPA would have to establish a list of all major sources of these pollutants and promulgate standards to achieve the maximum degree of reduction in emissions of each air pollutant, relying on the installation of the maximum achievable control technology (MACT).

During the course of the clean air debate, there was a heated controversy over whether or not electric utility boilers—which emit a range of substances subject to control under the air toxics titles, including mercury—ought to be subject to MACT requirements. The conference committee 1) accepted a modified version of the House provision that requires that any regulation of utilities under Title III be based on studies and 2) that the Administrator find such regulation to be "appropriate and necessary."<sup>100</sup> In that regard, the Act provides for a three year study of hazardous air pollutant emissions by electric utility steam generating units, with a decision on regulations to be made after the completion of that study.<sup>101</sup> The Act also contains a paragraph that provides for studies of mercury emissions from utility units, municipal waste

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97. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 112(d)(1), 104 Stat. 2399, 2539 (amending 42 U.S.C. § 7412).

98. *Id.* § 112(a)(1), 104 Stat. at 2531.

99. *Id.* § 112(a)(2); see also *id.* § 112(k), 104 Stat. at 2552-54.

100. *Id.* § 112(n), 104 Stat. at 2558.

101. *Id.*

combustion units, and other sources.<sup>102</sup>

In addition to the EPA studies on utility emissions and mercury, yet another study is required under the Act.<sup>103</sup> This study will be performed by the National Institute of Environmental Health Sciences, which is a part of the Center for Disease Control. The Institute is asked to determine the appropriate threshold level for mercury below which adverse human health effects are not expected to occur. Based on that study, the EPA will be able to determine if there is a need to set a human health based standard for mercury emissions under Title III.

Over the next three to four years, the EPA will determine the exact nature of air toxics emissions from utility boilers, the availability of control technologies, and the interplay between the air toxics and acid deposition provisions of the bill. At the end of that effort, the EPA may mandate immediate regulation of all or some utility boilers. Those regulations could require utilities to install "maximum achievable control technology" to control particulates and gases. According to some utility representatives, this could mean that utilities in every state may have to install baghouses and scrubbers on fossil-fired power plants, even those burning low-sulfur coal.<sup>104</sup>

## 2. Title III and Radionuclides

Title III of the Act also contains several provisions that deal specifically with the control of radionuclides from nuclear power plants. Section 112(d)(9)—the so-called Simpson Amendment, after its author Senator Alan Simpson (R-Wy)—provides that the EPA may forego issuing its own radionuclide standards under the Clean Air Act Amendments if, after consultation with the Nuclear Regulatory Commission (NRC), it finds that the NRC regulations provide "an ample margin of safety to protect the public health."

The intent of the Simpson Amendment was to end the problem of dual regulation at the federal level. The current NRC regulatory program extends from nuclear power plants to byproduct facilities, such as research reactors, hospitals, clinics using nuclear isotopes, and the radiopharmaceutical industry. The EPA had found that some Agency regulations under the Clean Air Act were necessary for certain radionuclide sources, but it had consistently determined that no additional regulations were required for the facilities licensed by the NRC. As the result of litigation, however, the EPA was forced to issue independent standards for these sources under the Clean Air Act. Given that history, proponents of the Simpson Amendment predict that it is highly likely that EPA will find that the regulatory program under the Atomic Energy Act regulations protects the public with an adequate margin of safety

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102. *Id.* § 112(n)(1)(B).

103. *Id.* § 112(n)(1)(C), 104 Stat. at 2558-59.

104. Even if the Administrator does not impose controls on electric utilities pursuant to § 112(n), the Act requires the Administrator to examine the health and environmental effects from atmospheric deposition of hazardous air pollutants to the Great Lakes, the Chesapeake Bay, Lake Champlain, and coastal waters. *Id.* § 112(m)(6), 104 Stat. at 2558. Based on that report, the Administrator may within five years promulgate further emission standards or control measures as may be necessary to prevent such harm, presumably including the imposition of controls on electric utilities.

and will decide that there is no need to promulgate a standard pursuant to section 111 or 112 of the Clean Air Act.

Section 112(d)(9) also provides that nothing in the subsection shall prevent states from adopting or enforcing more stringent standards than the standard or limitation in effect under either section 111 or section 112. In essence, this clause provides that nothing in the new subsection (d) of section 112 would alter section 116. Under section 116 of the Clean Air Act, states or political subdivisions may adopt or enforce any standard or limitation respecting emissions and control of air pollutants. When, however, there is a standard or limitation in effect under either section 111 (New Source Performance Standard) or section 112 (National Emission Standards for Hazard Air Pollutants), a state or political subdivision cannot adopt an emission standard of limitation which is less stringent than the federal standard. The savings clause signals that the possible elimination of dual regulation by the NRC and the EPA will not affect any retained authority the state may have under existing section 116 of the Clean Air Act.

### G. Gas Industry Compressors

The general NO<sub>x</sub> and VOC provisions of the Clean Air Act Amendments of 1990 may impact natural gas compressors, however three provisions may limit affects on such gas compressors. These new provisions clarify how a regulatory agency should categorize compressors as the agency calculates what are "major sources," "area sources" and "nonroad engines." Generally, the effect of these provisions is to help exempt many of the gas compressors from several costly emission control requirements which could apply to non-exempt sources.

First, Title III provides that emissions from any pipeline compressor or pump station shall not be aggregated to determine if the units or stations are "major sources." Such units shall not be aggregated though they are in a contiguous area or under common control.<sup>105</sup> This provision limits the number of gas compressors which will be subject to major source requirements.

Second, Title III requires that the EPA not list as "area sources" oil and gas production wells and associated equipment such as gas compressors. However, wells and associated equipment may be listed as area sources if (1) the wells and equipment are located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of one million, and (2) the EPA determines that emission from such wells present more than a negligible human health risk.<sup>106</sup> This provision limits the number of gas compressors which will be affected by regulations developed to control area sources.

Third, Title I exempts stationary internal combustion engines from the Title II provisions relating to nonroad engines.<sup>107</sup> As a result, gas compres-

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105. *Id.* § 112(n)(4)(A), 104 Stat. at 2559-60.

106. *Id.* § 112(n)(4)(B), 104 Stat. at 2560.

107. *Id.* § 108(f), § 111(a)(3), 104 Stat. at 2467 (amending 42 U.S.C. § 7411(f)(1)).

sors powered by internal combustion engines are unaffected by EPA emission standards promulgated under section 213.

#### *H. Alternate Fuels for Certain Fleet Vehicles*

Title II provides that the EPA shall prescribe clean fuel standards for certain fleets of ten or more vehicles capable of being centrally-fueled, in order to reduce emissions of pollutants believed to worsen ozone (smog) pollution in many metropolitan areas. These provisions could affect electric or gas utilities as owners or operators of such fleets. These provisions could also affect demand for gas or electricity as clean vehicular energy sources.

#### IV. CONCLUSION

Given the scope of the Act and the effect that it is destined to have on the operations of electric utilities, most power producers are or should be planning how they intend to comply with it.<sup>108</sup> In that effort, there are a number of uncertainties that power producers and their counsel may confront: Will allowances prove to be marketable; will the EPA design a workable allowance transfer system; what role should the FERC play in reviewing implementation plans that may affect interstate sales of electricity; will state environmental agencies and public service commissions work cooperatively to develop a system for reviewing compliance plans; and, will the compliance efforts made now be wasted if the Administrator determines that utilities should be regulated under the Air Toxics title of the Act? To a limited extent, the EPA may be able to resolve some of these questions in upcoming rulemakings; in most instances, answers will emerge only as the industry gains experience in dealing with the Clean Air Act Amendments of 1990.

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108. We also note that the Act provides for a FERC study of environmental benefits of renewable energy as compared to nonrenewable energy. *Id.* § 808, 104 Stat. at 2690.

