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THE ACID RAIN AMENDMENTS AND THE PROJECT FINANCING OF NON-PUBLIC UTILITY ELECTRIC GENERATOR PROJECTS

By

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I. INTRODUCTION

THE new acid rain title of the Clean Air Act[1] could pose significant problems for the financing of non-public utility fossil fueled electric generator projects, including so-called qualifying cogeneration facilities (QFs) and independent power projects (IPPs).[2] This segment of the electric utility industry, which has been the nation's cleanest, most efficient producer of electric energy while providing a competitive alternative to elec-

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1. Pub. L. No. 88-206, 77 Stat. 392 (1963), Title IV, as added by The Clean Air Act Amendments of 1990, Pub. L. No. 101-549,—Stat.— (1990).

2. Qualifying cogeneration facilities (QFs) must meet efficiency and operating standards as prescribed by Federal Energy Regulatory Commission (FERC) regulations. *See* 18 C.F.R. § 292.205 (1990). These criteria "carry the burden of assuring that QFs mode of generation is socially desirable," that is, is efficient and innovative. FERC Docket No. RM 88-6-000, IV F.E.R.C. Statutes & Regulations ¶ 32,457 at 32,163 (March 16, 1988). *See also infra* text accompanying notes 39-40 (discussing cogeneration). Independent power projects (IPP's) are non-QF wholesale producers that are unaffiliated with franchised utilities in their market area and lack significant market power. IPP's do not possess transmission facilities and do not sell power in any retail service area in which they have a franchise. FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at 32,103 (March 16, 1988) (providing detailed description of an IPP). Under proposed FERC regulations, a non-QF IPP sells electric energy produced by a facility that is not regulated on a cost-of-service basis, *i.e.*, is not regulated as a public utility to ensure investors a reasonable return on their investments. 53 FED. REG. 9328 (1988) (to be codified at 18 C.F.R. § 38.103(b),(k)) (proposed March 16, 1988). *See also* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at 32,110 (March 16, 1988) (providing expanded discussion). QFs can also include so-called small power production facilities, which use as their primary fuel biomass, waste, renewable resources, geothermal resources, or any combination thereof. 18 C.F.R. § 292.204(a)(1),(3)(b)(l)(i) (1990). Until recently, small power production facilities could not be QF's if they exceeded 80 megawatts in size. The Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990, Pub. L. No. 101-575 (1990) has abolished this requirement unless FERC reinstates it by rule. Pub. L. No. 101-575, § 4. Since small power production facilities are not fossil-fueled, they are not subject to the emissions allowance provision of the Amendments.

tric public utility generation,[3] has flourished largely as a result of initiatives of the Federal Energy Regulatory Commission (FERC) that stem from the Public Utility Regulatory Policies Act of 1978 (PURPA).[4] One of a number of laws passed on the same day in response to the energy crisis of the late 1970s,[5] PURPA has helped change the face of an industry once dominated by quasi-monopolistic public utilities. Recent events in the Middle East have again focused attention on the vulnerability of the nation's energy supply and accentuated the continuing relevance of policies related to the goals of PURPA.[6]

The creation of potential hurdles to the financing of non-public utility generators[7] is an unintentional result[8] of the ambitious objective of title IV, which mandates drastic reductions in emissions of acid rain precursors[9] from the fossil fuel-fired electric generating industry[10] by means of stringent emissions limitations enforced in part through an "allowance" system. Under this system, fossil fuel-fired electric plants will be permitted to emit sulfur dioxide ("SO_2") only to the extent that they have obtained "allowances" to do so.[11] As of January 1, 2000, the date on which most non-public utility generators that commence commercial operation after November 15, 1990, will begin to be regulated under title IV,[12] the number of al-

3. *See* Clean Air Act Amendments of 1989, Report of the Committee on Environment and Public Works, United States Senate, on S. 1630, S. REP. No. 228, 101st Cong., 1st Sess. 296 (1989) (cogeneration plants can achieve 85-90% efficiency compared to 33% for current power plants); *see also* 45 FED. REG. 12214, 12215 (1980) (FERC preamble to 18 C.F.R. Part 292 implementing section 210 of PURPA) (final rule).

4. Pub. L. No. 95-617, 92 Stat. 3117.

5. Laws passed the same day as PURPA include the Energy Tax Act of 1978, Pub. L. No. 95-618, 92 Stat. 3174 (codified as amended in scattered sections of 26 U.S.C. (1988); the National Energy Conservation Policy Act, 42 U.S.C. § 8201 (1988); the Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C. § 8301 (1988); and the Natural Gas Policy Act of 1978, 15 U.S.C. 3301 (1988).

6. In enacting PURPA, Congress found that the programs authorized by the act were needed, among other things, to encourage increased conservation of electric energy and increased efficiency in the production of electric energy. *See* FERC Docket No. RM88-5-000, IV F.E.R.C. Proposed Regs. ¶ 32,455 at 32,049 n.7 (March 16, 1988).

7. Under the terminology of title IV, "utility units" are regulated, and the term "utility unit" is defined broadly enough to include most fossil fuel-fired QFs and IPPs. *See* title IV, § 402(17). For clarity in this article, we distinguish franchised public utilities from QF's and IPP's. *See* 16 U.S.C. § 824(e) (defining "public utility"); *see also* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at 32,135 nn. 4,5 (March 16, 1988) (distinguishing a public utility from an IPP).

8. A search of the legislative history of tiile IV produces no evidence of a Congressional intent to discourage construction of IPP and QF facilities.

9. Title IV regulates emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). SO_2 results from the burning of fossil fuels, which contain sulfur. As the SO_2 is emitted into the atmosphere, it combines with oxygen to form SO_4. When SO_4 settles out of the air, it attracts water, which converts it into H_2SO_4, sulfuric acid. Similarly, nitrogen in fossil fuels combines with oxygen during burning to form oxides of nitrogen, which eventually can combine with water to produce HNO_3, nitric acid. S. REP. 228 at 261-62.

10. Electric public utilities accounted for two-thirds of the SO_2 emissions in the United States in 1987. Interim Report, National Energy, 128 (Department of Energy 1990), *citing* U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1940-87 (1989).

11. 1990 Amendment §§ 403, 408.

12. 1990 Amendment §§ 403(e), 405(g)(C).

lowances will be strictly limited to ensure reductions in emissions by nearly fifty percent from 1980 levels.[13] New non-public utility generators (and new generating units of utilities) will be required to obtain allowances, to the extent they are available, by purchasing them in one of a number of emission allowance "markets" envisaged by title IV.[14]

The need to purchase emission allowances in the future may pose significant problems for the financing of many QF and IPP projects that are projected to come on-line during the 1990s. These problems stem from the fact that both the *availability* and the *price* of the allowances that will be required will be difficult to determine with any precision at the time of a project's financial closing. These problems are of particular concern because the development of non-public utility generators for the foreseeable future will be undertaken largely through project financing mechanisms. In a project financing, the lender relies upon project revenue, rather than the creditworthiness of the project developer, to assure debt service.[15] Consequently, the lender must be assured that the project will go on-line on schedule and produce an income stream sufficient to meet the project's debt service.

Uncertainties as to the availability and cost of allowances pose at least two significant threats to non-public utility projects. First, an insufficient amount of allowances will serve to limit output and thus reduce the revenue stream available for debt service. Second, assuming that sufficient allowances are available, it is not clear that sales agreements will provide for an automatic flow-through of the costs incurred by a non-public utility generator in obtaining emission allowances to assure uninterrupted operation throughout the life of the project. From a lender's perspective, such uncertainties present unprecedented issues of cost exposure, including the degree of risk that may be incurred and how such risks can be "hedged."

These potential adverse effects on project financing of non-public utility generators are similar to problems seemingly resolved by PURPA and relevant FERC decisions. Prior to 1978, project financing for cogeneration plants was problematic because traditional regulated electric utilities were often unwilling to provide a firm market for non-public utility generated electric energy, including some degree of indexing of the price paid to the non-public utility generator to reflect variations in fuel costs.[16] Non-public utility electric generator projects often could not obtain financing because their revenue stream could not be assured. The passage of PURPA helped create a viable non-public utility generating industry by *requiring* utilities to purchase from qualifying cogenerators.[17]

It would be a strange and unfortunate twist in the development of the

13. *See* Clean Air Amendments of 1990, Report of the Committee on Energy and Commerce, United States House of Representatives on H.R. 9030, H.R. REP. No. 490 (Part 1), 101st Cong., 2d Sess. 355 (1990).

14. *See* 1990 Amendment § 403(e).

15. The Amendments require the Secretary of Energy to define the term "nonrecourse project-financed" by February 15, 1991. 1990 Amendment § 416(a)(2)(B).

16. *See* 45 Fed. Reg. 12214, 12215 (February 25, 1980).

17. *See infra* text accompanying notes 43-54.

non-public utility generation industry if difficulties in obtaining, or recouping the cost of, allowances resurrected barriers to the construction and operation of non-public utility generating plants. Such a result would frustrate, if not effectively reverse, a hitherto successful Federal policy of encouraging the development of a robust non-public utility generator industry — a policy premised upon several objectives, including, ironically, enhancement of the environment.

A. The New Acid Deposition Cleanup Program

Title IV of the Clean Air Act Amendments utilizes two complementary approaches to reduce SO_2 emissions from fossil-fueled electric generating units: stringent emissions limitations on sources, combined with a marketable allowance system.[18] An allowance is defined as an authorization to emit one ton of SO_2 during or after a specified calendar year.[19] Plants subject to title IV will be allowed to emit only those amounts of SO_2 for which they have allowances.[20] New plants will generally have to obtain allowances from existing plants that received a free allocation of allowances and reduced their SO_2 emissions below the required number of allowances.

Under title IV, beginning in the year 2000 the total tonnage of allowances for fossil fuel-fired steam electric generating units will be permanently capped at 8.9 million tons of SO_2.[21] The EPA is directed to make annual distributions of the bulk of these allowances free of charge to existing generators.[22] For new plants that do not receive an allocation of allowances from the EPA, the primary source of allowances is expected to be existing high-emitting units (primarily those on a list of 110 designated plants)[23] that are able to make more cost-effective emissions reductions than required and are willing to sell their extra allowances to plants that require them.[24] Additionally, title IV creates a number of small EPA-administered allowance "reserves." Funded from the original allocations, these reserves are designed to meet certain contingencies and to keep the allowance market fluid.[25] From the most significant of these reserves, the EPA is authorized to

18. *See* S. REP. 228 at 322-23. With minor limitations, allowances are transferable among owners and operators of utilities and other persons. 1990 Amendment §§ 403(b), 410. "In fact, ownership of allowances by brokers, investors and other market makers will maintain fluidity in the allowance market, link ultimate utility buyers with original sellers and facilitate rational price-finding." S. REP. 228 at 320.

19. 1990 Amendment § 402(3).

20. 1990 Amendment §§ 404, 405, 408.

21. 1990 Amendment § 403(a). *But see* § 405(a)(3), adding 50,000 additional Phase II allowances to the allocations of certain phase I units. Allowances may also be created under the opt-in provisions of § 410. *See infra* note 22.

22. 1990 Amendment §§ 402(28), 402(29), 403, 405. In addition, industrial sources (who are otherwise exempt from the acid rain provisions of the legislation) may "opt-in" to the program and "create" allowances by reducing emissions from an operating facility on a voluntary basis. *Id.* § 410. Thus, for example, an industrial cogenerator could take credit for shutting down an existing steam boiler and apply a portion of the emission allowances thereby created to a cogeneration facility.

23. *See* 1990 Amendment § 404, Table A.

24. S. REP. 228 at 318.

25. S. REP. 228 at 325.

sell up to 50,000 allowances a year on a first-come, first-served basis for $1500 each, adjusted for inflation.[26]

Existing plants that receive allowances will also be subject to stringent emissions limitations. Certain specified plants, which are large, high-rate emitters of SO_2, will be required to reduce their emissions to a rate no greater than 2.5 pounds per million British thermal units of fossil fuel consumed ("lbs/MMBtu") by January 1, 1995.[27] This initial reduction requirement is referred to as the Phase I period.[28] These plants subsequently will be required to further reduce their emissions to a rate no greater than 1.2 lbs/MMBtu, by January 1, 2000.[29] This is referred to as the Phase II reduction period.[30] Phase II will also require existing plants which currently emit SO_2 at a rate less than 2.5 lbs/MMBtu to achieve reductions; they will be required to reduce their emissions to the 1.2 lbs/MMBtu level or below, depending on factors specified in section 405, by January 1, 2000.[31]

Most fossil fuel steam plants that commence operation between October 1, 1990 and December 31, 1995, are also classified as existing Phase II units, but will be subject to a lower emissions limit.[32] These plants will be permitted to emit SO_2 at a rate no greater than 0.30 lbs/MMBtu computed at a 65% capacity factor following commencement of the Phase II period.[33]

B. The Non-Public Utility Electric Generating Industry

New capacity in the non-public utility steam electric generating industry consists primarily of qualifying cogeneration production plants, which have flourished as a result of sections 201 and 210 of PURPA[34] and corresponding FERC regulations,[35] and IPPs, which have received favorable regulatory treatment in a series of FERC decisions in recent years.[36] QFs were given a favored status by PURPA, because they represent a cleaner, more efficient source of electric energy than the traditional public utility steam electric generator.[37] The success of QFs has contributed to the current market for IPPs, which in many cases have proved to be more efficient electricity producers than traditional utilities.[38]

26. 1990 Amendment § 416(b), (c). The amendments also create a special fund for new IPPs. § 416(c)(3),(4).
27. 1990 Amendment § 404 and § 404 Table A.
28. 1990 Amendment § 404.
29. 1990 Amendment § 405(b).
30. 1990 Amendment § 405.
31. While the bill does not impose any additional emissions standards on new plants (i.e. those not grandfathered or exempt), such plants still will be required to comply with all existing state and federal laws, including the New Source Performance Standards. *See* 40 C.F.R. Part 60 (1990).
32. 1990 Amendment § 405(g)(3),(4).
33. *Id.*
34. 16 U.S.C. §§ 796 and 824a-3 (1988).
35. *See* 18 C.F.R. Part 292 (1990).
36. *See* Doswell Limited Partnership, Doc. No. ER90-80-000 (February 28, 1990) and cases cited therein.
37. *See supra* note 6.
38. FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at

Cogeneration is the production of electric energy and useful thermal energy (typically steam) through the sequential use of energy.[39] Typically, QFs are small facilities relative to traditional regulated electric utilities, because, as a practical matter, they require a nearby industrial facility that can utilize the produced thermal energy. The industrial facility usually contracts to purchase a significant percentage of the plant's electric energy.[40] Although cogenerators supply electricity primarily to a single industrial user, variations in usage and in the cogenerator's ability to produce electricity mean that to be economically viable, the cogenerator must have the ability to sell or purchase electricity at favorable rates from larger electric utilities. An IPPs technology ranges from those utilized in existing public utilities to highly innovative fossil-fuel technologies that do not fall within the rubric of cogeneration.[41] IPPs sell their output wholesale to utilities.[42]

Because PURPA (combined with a variety of cost factors) was instrumental in creating the market conditions for IPPs as well as for QFs,[43] a brief discussion of the reasons for the enactment of PURPA will be helpful in understanding the potential impact of the Clean Air Amendments on the non-public utility steam electric industry. Prior to the passage of PURPA, two main problems had to be resolved before the financing of a cogeneration project was likely to proceed. First, traditional electric public utilities were reluctant to purchase power from non-public utility generators, whom they perceived as rivals.[44] Second, some utilities charged discriminatorily high rates for back-up power to such generators.[45]

PURPA and FERC regulations address these problems[46] by requiring regulated electric utility companies to purchase electricity from, and sell electricity to, QFs, and to make any interconnections required for such purchases or sales.[47]In addition, FERC regulations generally require the regulated utility to purchase the QFs energy at a preferential rate that is equal to the costs the public utility avoids by not having to produce electric energy

32,115-116 (March 16, 1988). IPPs may include subsidiaries or affiliates of public utilities offering electricity outside their parent's service territory. *See id.* at ¶ 32,112-115.

39. *See* 18 C.F.R. § 292.202(c) 1990.

40. Many cogeneration facilities are constructed on land leased from a host industrial facility. Often, the host facility retires some or all of its boiler capacity when the cogeneration facility goes on line.

41. FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes and Regulations ¶ 32,456 at § 32,116 and nn. 105-06 (March 16, 1988).

42. *See supra* note 2.

43. *See* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at 32,105.106 (March 16, 1988).

44. *See* 45 Fed. Reg. 12214, 12215 (1980) (FERC preamble to 18 C.F.R., pt. 292) (final rule); Fed. Energy. Reg. Comm'n. v. Mississippi, 456 U.S. 742, 750 (1982).

45. Fed. Energy Reg. Comm'n., 456 U.S. at 750.

46. PURPA and FERC regulations also address a third problem — that a QF "which provided electricity to a [public] utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility." 45 Fed. Reg. at 12215; *see* H.R. REP. No. 1750 H.R. 4018, H. REP. No., 95th Cong., 2d Sess., *reprinted in* 1978 U.S. CODE CONG. & ADMIN. NEWS 7659, 7797. Under 16 U.S.C. § 824a-3(e), the FERC may exempt QFs from certain regulations applying to traditional electric utilities. In 1990, the FERC promulgated exemption regulations at 18 C.F.R., pt. 292, subpart F.

47. 18 C.F.R. § 292.303(a)-(c)(1990).

supplied by the QF.[48] At the same time, the FERC regulations enable the QF to purchase from the regulated utility at the same rate as the public utility's other customers with similar load or other cost-related characteristics.[49]

In effect, traditional electric public utilities are required to subsidize QFs, which receive any difference between their own cost and the avoided cost rate.[50] Indeed, the regulation enables the QF to separate the production aspect of its facility from its consumption aspect,[51] so that a QF can simultaneously sell electric energy to a regulated utility at a rate based on avoided costs, and purchase from the same utility at the ordinary retail rate.[52] The purpose of allowing the QF to obtain economic rent for the production of electric energy is to fulfill the Congressional mandate of encouraging cogeneration.[53] By all measures, the regulations have been successful.[54]

The success of QFs in meeting the energy needs of electric utilities has led recently to the proliferation of IPPs, which have been favored by a series of decisions by the FERC in which these non-public utility sellers of power have been allowed to depart significantly from the traditional cost-of-service standard in establishing rates for power sales.[55] The issuance of a proposed regulation on IPPs,[56] which has been substantively reflected though never

48. 18 C.F.R. § 292.304. The regulation states generally that the rate for purchases from a QF by a regulated utility satisfies the requirements of the PURPA "if the rate equals the [purchaser's] avoided costs . . . ." *Id.* § 292.304(b)(2). The term avoided costs means "the incremental costs to an electric utility of electric energy or [production] capacity which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). Energy costs are the "variable costs associated with the incremental production of electric energy . . . . They represent the cost of fuel, and some operating and maintenance expenses." Capacity costs "may be incurred by a utility in order to build generating facilities, institute conservation and load management programs, or purchase power on the wholesale market." FERC Docket No. RM88-6-000, IV F.E.R.C. Statutes & Regulations ¶ 32,457 at 32,163 (March 16, 1988). The term "incremental" emphasizes that rates for purchases must reflect the costs of obtaining energy from highest cost units, such as those that are turned on last, and the costs of obtaining new capacity. Purchase rates based on avoided costs are higher than rates based on average system costs for energy or average embedded system cost for capacity. 45 Fed. Reg. at 12216. The Supreme Court upheld 18 C.F.R. § 292.304(b)(2) in American Paper Inst. v. American Elec. Power Serv. Corp., 461 U.S. 402, 413-17 (1983).

49. 18 C.F.R. § 292.305.

50. *See* FERC Docket No. RM88-6-000, IV F.E.R.C. Statutes & Regulations 32,457 at 32,163 (March 16, 1988).

51. 45 Fed. Reg. 12214, 12223 (1980) (FERC preamble to 18 C.F.R., pt. 292) (final rule).

52. *Id.*

53. *Id.*; *see* H. R. REP. NO. 95-1750 at 98, *reprinted in* 1978 U.S. CODE CONG. & ADMIN. NEWS at 7831.

54. Through the mid-1980s electric capacity added under PURPA has far outstripped combined capacity added by investor-and publicly-owned electric utilities. U.S. Dep't. of Energy, *Energy Security: A Report to the President of the United States* 129, 157 (1987). *See also* FERC Docket No. RM88-6-000, IV F.E.R.C. Statutes & Regulations ¶ 32,457 at 32,186 n.42 (Mar. 16, 1988) (by 1985, nearly five times as much capacity had been added under PURPA as FERC had predicted in 1980).

55. *E.g.*, Commonwealth Atlantic, 51 FERC ¶ 61,368 (1990); Enron Power Enter., 52 FERC ¶ 61,193 (1990).

56. *See* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes and Regulations ¶ 32,456 (notice of proposed rulemaking on regulation of IPPs.

adopted in several individual cases,[57] foreshadowed this policy.

C. *How The New Acid Deposition Cleanup Program Will Impact the Financing of Non-Public Utility Generators*

As the legislative history of the Clean Air Amendments makes clear, the stringent emissions reductions, the permanent cap on emissions and the marketability of emission allowances are part of an integrated program to encourage fossil fuel-fired electric generators to reduce SO_2 emissions below mandated requirements.[58] The centerpiece of this program is the allowance system, which is designed to provide a profit incentive for the regulated industry to reduce emissions.[59] Unfortunately, the legislation does not address a number of questions concerning the impact of this regulatory regime upon the continued viability of PURPA/FERC policies that have helped stabilize project financing for the non-public utility steam electric generator industry.

The amendments pose a number of potentially serious problems for project financing of QFs and IPPs. First, it is not clear that adequate allowances will be available for developers of new plants, regardless of price.[60] There is reason to fear that public utilities and their state regulators will hoard excess allowances generated within a given state to accommodate future growth within that jurisdiction, rather than selling these allowances to out-of-state utilities and developers.[61] There are also concerns that public utilities will transfer such allowances to their unregulated generating subsidiaries, thereby providing their affiliates with a competitive advantage in relation to non-public utility developers.[62]

Moreover, even if allowances are obtainable by non-public utility generators, the question of who will bear the ultimate burden of paying for them is unclear. If non-public utilities are allowed to flow through their cost of allowances to the public utility purchaser, the public utility is in effect buying back allowances it previously generated and sold. This result might undermine the incentive provided by title IV to create excess allowances. Yet, if

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57. *See supra* note 55.

58. S. REP. NO. 228, 101st Cong., 1st Sess. 279 (1989).

59. In fact, the report states that "allowances are intended to function like currency that is sufficiently valuable to stimulate efforts to acquire it through innovative and aggressive efforts to reduce emissions more than required." *See* S. REP. NO. 228 at 324. The amendments make clear, however, that an allowance is not a property protected under the Constitution. 1990 Amendment § 403(f).

60. The amount of allowances required and the corresponding costs will be considerably greater for coal versus gas-fired projects of a similar scale. This is because coal has a much greater sulfur content than natural gas. *See* S. REP. NO. 228 at 292-93. Thus, from a project financing perspective, lenders may view new coal-fired projects as posing a somewhat higher degree of risk in that the uncertain costs of obtaining such allowances could jeopardize cash flow available for debt service. It is unclear, however, whether the greater certainty relating to future coal prices would tend to offset some of these lender concerns as compared with the much greater potential variability in future natural gas prices.

61. *See* "EPA Officials Predict Tough Time Ahead in Meeting Clean Air Bill Regulatory Schedule," 21 ENV'T REP. 429, 430 (BNA) (July 6, 1990) (reporting that the Florida Public Utilities Commission has forbidden state utilities from selling allowances to out-of-state utilities).

62. S. REP. NO. 228 at 325-26.

such costs cannot be flowed through, the non-public utility generator industry will in effect be partially subsidizing the public utility industry. This result would be inconsistent with both PURPA and with the goal of maintaining economic incentives for non-public utility generators.

Finally, if QFs and IPPs are able to flow through their costs of allowances to their public utility purchasers, public utilities will argue that they must be allowed to recover the costs of such allowances as an automatic pass-through to their ratepayers. Unquestionably, state rate-setters will have much to say on this question.

Ultimately, both the EPA and the FERC, as well as state public utility regulators, may be called upon to provide remedies to the project financing problems created by title IV. One attempt at preventing such problems from occurring already is part of title IV. This is the allowance reserve, controlled by the EPA, which is designed to accommodate the needs of IPPs and others who cannot obtain allowances on reasonable terms through the market.[63] It seems unlikely, however, that this reserve, even if it temporarily addresses the problem, can provide a permanent solution for a growing industry. Further, this reserve only addresses the issues of availability, and no other provision of title IV offers clear answers to the questions of costs and their flow-through to purchasers.

II. Possible State and Federal Initiatives On Allowances

A number of potential federal and state legal authorities may be available to ensure that non-public utility power developers have access to, and mechanisms to recoup, the cost of allowances. Following so soon after enactment of the amendments, and years before promulgation of implementing regulations, this section is necessarily somewhat speculative in nature.

A. Federal Authorities to Ensure the Availability and Recoupability of Allowances

1. EPA Regulations

The amendments directing the EPA to promulgate regulations implementing the allowance trading system[64] require the agency to take into account several objectives that are designed to enable the system to work as Congress intended.[65] These objectives appear to reflect Congressional awareness of the need for rules that will facilitate access to allowances for non-public utility developers, who are a primary force for competition in electric power markets.

The EPA has a wide range of options to ensure that allowances are accessible. These range from procedural rules governing the transferability of al-

63. 1990 Amendment § 416.

64. *Id.* § 403(b).

65. One of these objectives is that allowances be reasonably transferable, temporarily or permanently, by purchase, lease, or otherwise. Another objective is that allowances not be used to impede access to, or competition for, electric energy in any market.

lowances to more intrusive measures that would encourage, if not require, those who possess excess allowances to offer them for sale. One possible difficulty with the latter approach is the potential conflict with the primary role of the states in regulating the activities of franchised utilities.[66] Congress was well aware of this state role during its deliberations on the acid rain title, and the amendments in fact provide that nothing in the statute is intended to diminish the scope of state authority over retail power sales.[67] Nonetheless, the amendments clearly assign primary responsibility over the functioning of the allowance system to the EPA.[68] Would or should the EPA promulgate a mandatory offer for sale requirement for excess allowances? Is the fact that no such requirement is present in the statute persuasive of the position that Congress did not intend it to exist? These are critically important questions, the answers to which are, at this time, highly uncertain.

Another area where the EPA may feel pressure to protect the non-public utility generator involves the recoupability of allowance purchase costs. Even if allowances are available, and at a reasonable price, non-public utility project developers will be looking for mechanisms to flow through the costs of obtaining such allowances.

Rulemaking by the EPA is unlikely to address this issue for at least two reasons. First, the issue of whether the prices that public utilities pay for non-public utility power include amounts for allowance costs directly implicates the ratemaking jurisdiction of the FERC and the state utility commissions as set out in the Federal Power Act[69] (FPA) and PURPA.[70] The Amendments give the EPA no ratemaking authority, nor do they amend the FPA or PURPA to diminish the ratemaking jurisdiction of regulators under those statutes. Second, while the EPA is responsible for promulgating rules to protect the liquidity, integrity, and fairness of the allowance trading market, flow-through of allowance purchase costs is clearly a post-market issue. So it seems fair to conclude that flow-through would be more appropriately addressed under the statutes mentioned above.[71]

2. *Possible Regulation by the FERC*

In recent years the FERC, under authority of the FPA,[72] has pursued a policy of encouraging the development of non-public utility electric genera-

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66. *See infra* text accompanying notes 82-88.
67. 1990 Amendment § 403(f).
68. *See generally* 1990 Amendment § 403 (generally allocating responsibility over allowance system to EPA).
69. 16 U.S.C. §§ 791a, 797-800 (Supp. 1990).
70. Pub. L. No. 95-617, 92 Stat. 3117 (1978).
71. *See infra* text accompanying notes 71-87.
72. The FPA establishes the standard that rates charged for sales of electricity for resale must be "just and reasonable," and requires the FERC to enforce this standard. Pursuant to this statutory directive, utilities other than QFs must obtain FERC approval to institute new rates or increase existing rates. 16 U.S.C. § 824d(d). The agency also possesses the power to investigate *sua sponte* or upon complaint, the justness and reasonableness of existing rates. 16 U.S.C. § 824(e)(a). Finally, the FERC has general rulemaking authority to carry out these responsibilities and has exercised it on numerous occasions.

tion, primarily through a series of decisions holding that sales by independent power projects to public utilities need not be based strictly upon cost-of-service principles applicable to public utilities.[73] The argument for this relaxed rate treatment is that the purchaser is not a captive customer, and therefore presumably would not pay an excessive or oppressive rate.[74]

Could the FERC, consistent with its pro-competitive policy, take action under the FPA to ensure that allowances are available to non-public utility generators? Probably. Will the FERC so act? Probably not. Acting under authority of the FPA,[75] the FERC could make explicit its view that the competition provided by non-public utility generators is in the public interest and, more specifically, helps to keep wholesale rates at the lowest level consistent with adequate supplies for the ultimate benefit of consumers. Since allowances will be necessary for non-public utility generators to operate, the hoarding of these allowances by utilities would be contrary to the public interest and subject to FERC regulation.[76]

The FERC would probably be hesitant to act to ensure the liquidity of allowances if only because the Amendments grant to the EPA primary responsibility at the federal level for creating and maintaining a competitive marketplace.[77] Further, state public utility commissions exercise jurisdiction over public utility planning and construction to meet the demand for electric power service.[78] Allowances probably will be classified by such com-

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73. *See supra* note 55.

74. *See* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations 32,456 at 32,109-114 (March 16, 1988).

75. 16 U.S.C. § 825(h) (Supp. 1990).

76. The amendments set up a scenario that is rife with antitrust implications: one set of competitors is granted possession and control of allowances, that another set of competitors needs to purchase in order to compete against them. Congress was cognizant of the anticompetitive potential inherent in this situation. *See* 1990 Amendment § 403(i). Accordingly, Congress provided some help in the form of auctions and EPA sales that would allow developers the option of purchasing a small number of allowances not owned by the utilities. *See* 1990 Amendment § 416. The vast majority of allowances, however, will be owned by public utilities and the way they utilize these allowances will determine who will build new power plants in the future.

Federal antitrust law applies to electric public utilities, and the regulation of their affairs by federal and state authorities does not, in itself, provide a shield against antitrust liability if electric public utilities engage in anticompetitive practices. *See* Otter Tail Power Co. v. U.S., 410 U.S. 366, 374-75 (1973). Nothing in the amendments changes this law. There are many antitrust precedents potentially available to non-public utility developers and a full treatment of them is beyond the scope of this article. A more practical consideration regarding this area is appropriate here.

Although it is not unlikely that a case may be brought by either a developer or the government under the antitrust statutes, and that a useful precedent may eventually emerge, as a practical matter antitrust enforcement probably will not serve as the primary tool for most non-public utility project developers. Many developers are relatively small business concerns for whom the prospect of challenging a public utility in court would be daunting. Further, most projects have a relatively small "widow of opportunity" during which they must be planned, financed, and constructed. The huge expense and protracted nature of antitrust proceedings would therefore not provide a suitable remedy. In the face of public utility obstinance, the fact that a cause of action could be brought in federal court under the antitrust statute is likely to be of nothing more than theoretical interest.

77. *See supra* text accompanying notes 65-76.

78. *See infra* text accompanying notes 82-88.

missions as an asset relevant to meeting public utilities' service requirements, and state regulators will therefore have a great deal to say about how allowances are utilized. Any FERC action on allowance availability could put it in conflict with state regulators.

FERC would be on firmer jurisdictional turf addressing the flow-through issue, but the problems that it will face are likely to be extraordinarily knotty. The question will be presented as to the justness and reasonableness of rates, including amounts for the purchase of allowances necessary to generate the power under the contract. FERC will be pressed to rule that non-public utility developers may recoup costs that are mandated by federal law from their public utility purchasers.

For non-public utility plants that are QFs, the flow-through issue would be framed in terms of avoided costs, the standard for public utility purchase prices under PURPA.[79] SO_2 allowance costs are avoided by a public utility that purchases power from a QF, as opposed to generating its own, or purchasing from another public utility.[80] The problem that arises is that the purchasing utility may have been the seller of allowances to the QF. If one purpose of the amendments is to give public utilities a profit incentive to create excess allowances,[81] requiring such utilities to finance purchases of allowances by QFs appears to undercut that incentive.

B. State Authorities

Electric public utilities are under a legal obligation to provide electric power to all those who request it in their franchised service territory,[82] and have a concomitant duty to meet projected growth in demand by planning for and acquiring additional resources.[83] State laws and precedents impose these obligations and duties, and state regulatory commissions enforce them.[84]

Acquisition of new resources to meet growth in demand is perhaps the most difficult issue presently faced by public utilities, as evidenced by the unfortunate experience of the last two decades in which the industry was forced to write off billions of dollars invested in plant capacity that was either not needed or constructed over budget.[85]

In an effort to avoid repeating this experience, public utilities and regulators in most large states have adopted a policy of least-cost planning.[86] This is the notion that a public utility should consider a full range of options in

79. 18 C.F.R. § 292.304.

80. S. REP. NO. 228 at 303.

81. *See supra* text accompanying note 59.

82. *See* D. MUCHOW & W. MOGEL, ENERGY LAW AND TRANSACTIONS §§ 2.01 to 2.02(2)(b) (1990).

83. *See id.* § 2.01(2).

84. *Id.* § 4.01.

85. *Id.* § 4.02(b); *see* FERC Docket No. RM88-4-000, IV F.E.R.C. Statutes & Regulations ¶ 32,456 at 32,105, 106 (March 16, 1988).

86. *See* D. MURCHOW & W. MOGEL, *supra* note 82, at §§ 2.01, 4.02(3)(e)(1990).

planning for projected growth, as opposed to automatically building new plants, and should also pursue the most cost-effective option first.

To implement least-cost planning, many states have adopted competitive bidding programs,[87] which are in essence requests for proposals for new capacity. These proposals typically elicit bids from developers of non-public utility projects. The public utility compares the bids, evaluates them against the option of building its own capacity, and then chooses the overall best option. Clearly, the ability of competitive bidding to ferret out the best possible alternative of meeting increased demand is grounded upon attracting the widest possible universe of qualified bidders. This result will only occur if there are assurances that a proposed project can actually be financed, constructed and operated. This in turn depends upon the developer being assured of the necessary number of allowances and of the ability to flow the costs of such allowances through to the purchaser. A satisfactory solution to the allowance issue for non-public utility developers is a necessity if the least-cost planning strategy is to remain workable.

State regulators have ample regulatory power to resolve this issue. They possess plenary jurisdiction over the structure and activities of electric public utilities in order to fulfill their statutory responsibility to assure adequate, reliable and reasonably priced electric power service for consumers.[88] Strong arguments can be made that state commissions should invoke their authority to preserve the vitality of least-cost planning by guaranteeing that non-public utility projects that supply or bid to supply power for resale to consumers have access to allowances generated by regulated public utilities. Additionally, state commissions could establish a policy that the purchase cost of allowances is a legitimate and prudent expense and may be flowed through in rates to ultimate customers. The latter point would be complementary to a potential FERC policy providing that allowance purchase costs incurred by a QF project should be included in the rate paid by the public utility purchaser. As with a possible FERC policy, a state requirement allowing the cost of allowances to be flowed through appears to threaten the public utility's incentive to produce excess allowances.

How state commissions will treat allowances is, of course, an open question. It seems that some action along these lines is necessary to preserve for ratepayers the competitive benefits of a robust non-public utility power industry. To the extent state regulators are committed to this approach in meeting demand growth in their states, and indications are that their commitment is strong, it seems probable that they will act forcefully. Whether state action to ensure the availability of allowances for intra-state generators would necessarily foster the goals of the Amendments, however, is unclear. The actions of individual states might instead impair the fluidity of the allowance market as each state seeks to ensure a dependable supply of allowances for in-state projects.

87. *Id.* § 4.02(4)(b)(iii).
88. *See id.* § 4.01.

II. CONCLUSION

The emissions allowances purchase requirement for new power generating plants presents difficult issues that cut across the policies of different statutes, and fall, at least partly, within the jurisdiction of a number of expert federal and state agencies. Further complicating the task of making the allowance program work is the reality that the agencies possess mandates that may not be entirely consistent with one another, and that the agencies may lack the authority to make all the adjustments necessary to prevent the new acid deposition program from causing a dislocation in the financing of new QFs and IPPs. Fully defining and addressing issues raised by the allowance program should be a major priority of these agencies in order to prevent the enactment of the acid rain policy from becoming a de facto repeal of an emerging, and thus far successful, pro-competitive electric power policy.