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COAL-FIRED ELECTRIC GENERATING FACILITIES: IMPEDIMENTS UNDER FEDERAL ENVIRONMENTAL LEGISLATION

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I. INTRODUCTION

The increased use of coal is a key element in our nation's National Energy Plan. The electric utility industry is currently the United States' largest single coal consumer, and its ability to satisfy current and future fuel needs with coal will largely determine whether the nation's future energy requirements can be met. One of the most important constraints on coal-fired electric generating facilities is federal environmental legislation. Over the past decade, we have witnessed the enactment of various statutes designed to protect the quality of air, water, and land resources. These statutes, and their implementing regulations, have an enormous impact on all industrial activities, particularly the generation of electricity. This article will address how three environmental statutes, the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act, affect the construction of coal-fired powerplants.[1]

A. *National Coal Policy*

President Carter, in his National Energy Plan, has recognized the need to decrease our dependence on oil and natural gas, and has called for greater use of coal as an energy source.[2] Seeking to increase annual coal use to 1.2 billion tons by 1985, almost double the 1975 level,[3] he has proposed an oil and natural gas tax in addition to a ban on their use in new utility and industrial plants, and has recommended investment tax credits for coal production and combustion equipment.[4] The Powerplant and Industrial Fuel Use Act of 1978[5] is the most important legislation yet enacted to implement

1. These are certainly the three statutes that have the most direct and significant effect on utility operations. An additional environmental statute that impacts heavily on utility planning is the National Environmental Policy Act, 42 U.S.C. § 4331 (1976), which is beyond the scope of this article.

2. EXECUTIVE OFFICE OF THE PRESIDENT, ENERGY POLICY AND PLANNING, THE NATIONAL ENERGY PLAN, xii, xiv-xxi (1977).

3. Address by President Carter to a Joint Session of Congress, 13 WEEKLY COMP. OF PRES. DOC. 566, 567, 570 (Apr. 22, 1977). A number of observers have questioned whether the President's goal can be reached given existing constraints on the production and use of coal. *See* CONGRESSIONAL RESEARCH SERVICE FOR HOUSE COMM. ON INTERSTATE AND FOREIGN COMMERCE, 95TH CONG., 1ST SESS., PROJECT INDEPENDENCE: U.S. AND WORLD ENERGY OUTLOOK THROUGH 1990, at 31-34 (Comm. Print 1977); UNITED STATES GENERAL ACCOUNTING OFFICE, U.S. COAL DEVELOPMENT—PROMISES, UNCERTAINTIES (1977).

4. EXECUTIVE OFFICE OF THE PRESIDENT, ENERGY POLICY AND PLANNING, THE NATIONAL ENERGY PLAN 65-66 (1977).

5. Pub. L. No. 95-620, 92 Stat. 3289, 42 U.S.C.A. §§ 8301-8483 (West Supp. 1978). For

these proposals. The Act bans natural gas or petroleum as a primary energy source in any new electric powerplant, and requires that such plants be able to use coal or any other alternate fuel.[6] Moreover, new major fuel-burning installations that include a boiler may not use natural gas or petroleum as a primary energy source.[7] In addition, the Secretary of Energy is authorized to prohibit the use of these fuels in existing electric powerplants or other major fuel-burning installations when conversion to coal is economically and technically feasible.[8]

Extensive domestic coal reserves are available; of an estimated four trillion tons,[9] approximately 132-150 billion are recoverable under current economic conditions.[10] Only 42 billion tons, however, have a sulfur content low enough to comply with Environmental Protection Agency (EPA) standards.[11] These figures are subject to revision because of changes in the price and availability of alternate fuels, such as oil, natural gas, and uranium, modification of environmental controls on air emissions and effluent standards, and development of new methods for using coal including coal gasification or liquefaction.[12]

By conservative estimate, coal accounts for nearly 80 percent of the recoverable energy reserves in the United States, while petroleum and natural gas account for less than eight percent.[13] Yet, in 1976 domestic reserves of petroleum and natural gas provided over half of the energy consumed in this country.[14] Despite the availabil-

an overview of the Act's provisions, see Robertson, *The Powerplant and Industrial Fuel Use Act of 1978: Fuel Replacement,* 3 HARV. ENVT'L L. REV. 214 (1979).

6. Powerplant and Industrial Fuel Use Act of 1978, § 201, 42 U.S.C.A. § 8311 (West Supp. 1978). Other alternate fuels include shale oil, uranium, and geothermal energy. *Id.* § 103(a)(6)(A), 42 U.S.C.A. § 8302(a)(6)(A).

7. *Id.* § 202, 42 U.S.C.A. § 8312.

8. *Id.* §§ 301, 302, 42 U.S.C.A. §§ 8341, 8342.

9. Averitt, *Coal Resources of the United States, January 1, 1974,* U.S. GEOLOGICAL SURVEY BULL. 1412 (1975).

10. W. HELT, *Coal Resources Available for Power Generation,* in ILLINOIS COAL, PROCEEDINGS OF THE FOURTH ANNUAL ILLINOIS ENERGY CONFERENCE 31 (1976); NATIONAL PETROLEUM ADVISORY COUNCIL, U.S. ENERGY OUTLOOK COAL AVAILABILITY 22 (1973).

11. W. HELT, *Coal Reserves Available for Power Generation,* in ILLINOIS COAL, PROCEEDINGS OF THE FOURTH ANNUAL ILLINOIS ENERGY CONFERENCE 35 (1976).

12. *See Constraints on Coal Development: Hearing Before the Subcomm. on Energy and the Environment of the House Comm. on Interior and Insular Affairs,* 95th Cong., 1st Sess. 5 (1977) (statement of John F. O'Leary, Adm'r, Federal Energy Admin.).

13. NATIONAL COAL ASSOCIATION, COAL FACTS 1974-75 at 7 (1976).

14. EXECUTIVE OFFICE OF THE PRESIDENT, ENERGY POLICY AND PLANNING, THE NATIONAL ENERGY PLAN 16 (1977).

ity of coal, its use as an energy source in the United States has decreased. At the turn of the century coal supplied two-thirds of our energy needs, but by 1972, coal supplied only 17 percent of total energy needs.[15] Domestic supplies of petroleum and natural gas are clearly inadequate, creating a growing dependency on foreign oil. Over one-half of the oil used in the United States today is imported. Our continued reliance on imported oil is impossible for both economic and political reasons: the constant and rapid increase in the price of foreign oil undermines our economic stability and, potentially, our political stability as well.

B. *Electric Utility Industry's Use of Coal*

The electric utility industry is by far the United States' largest coal consumer. In 1945, utilities consumed 72 million tons, 13 percent of the United States' total annual coal production; by 1974, their annual coal consumption increased fivefold to 391 million tons constituting 70 percent of total coal production.[16] Their 1985 coal consumption is estimated to more than double as 241 new coal-fired generating plants are expected to come on line.[17] Yet, coal is decreasing as a percentage of utilities' fuel base. In 1945, 52 percent of the utilities' fuel base was coal and only four percent was oil or natural gas; in 1974, coal's share fell to 44 percent while the share of the other two fuels skyrocketed to 35 percent.[18]

This trend must be reversed. Application of the Powerplant and Industrial Fuel Use Act requires increased coal use in both new and existing plants, even without any increase in demand. Yet, increased demand is inevitable. In short, the utility industry of the future will have to use much more coal than at present; whether it can do so largely depends on the nature and application of environmental regulations.

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15. W. DUPREE & J. WEST, UNITED STATES ENERGY THROUGH THE YEAR 2000, at 43 (1972).

16. SENATE COMM. ON INTERIOR AND INSULAR AFFAIRS, FACTORS AFFECTING COAL SUBSTITUTION FOR OTHER FUELS IN ELECTRIC POWER PRODUCTION AND INDUSTRIAL USES, S. DOC. No. 94-17, 94th Cong., 1st Sess. 22-23 (1975).

17. *Coal Conversion Legislation: Hearings Before the Subcomm. on Energy Production and Supply of the Senate Comm. on Energy and Natural Resources*, 95th Cong., 2d Sess. 923, 951 (1977) (testimony of Carl Bagge, President, National Coal Ass'n).

18. SENATE COMM. ON INTERIOR AND INSULAR AFFAIRS, FACTORS AFFECTING COAL SUBSTITUTION FOR OTHER FUELS IN ELECTRIC POWER PRODUCTION AND INDUSTRIAL USES, S. DOC. No. 94-17, 94th Cong., 1st Sess. 22-23 (1975).

C. Coal Cycle: Combustion and Waste Generation

In discussing the use of coal, it is helpful to understand the component stages of the coal cycle: extraction, processing, transportation, combustion/conversion, and waste disposal.[19] Because each stage of the coal cycle affects the environment, all are subject to some environmental regulation. This article focuses on the last two stages, combustion/conversion and waste disposal: specifically, how the three federal environmental statutes regulating these stages, the Clean Air Act and the Clean Water Act for combustion/conversion, and the Resource Conservation and Recovery Act for waste disposal, may impede new coal-fired electric generating plant construction.

Coal is burned to produce heat. This heat generates steam, which in turn drives turbines that produce electricity.[20] The way in which coal is burned depends on (1) its characteristics, (2) the size of the burning facility, and (3) the applicable environmental regulations. Depending on where it is mined, coal can contain varying degrees of moisture, sulfur, ash, and trace elements. In its natural state, the coal has relatively "diluted" impurities, which become more concentrated with each successive step in the coal process.

Coal is most often burned in a pulverized coal-fired boiler furnace. Crushed coal is fed continuously into pulverizers that dry and grind it into a combustible "cloud." This cloud is blown into a huge furnace and burns at a flame temperature of at least 2,700 °F. The relatively cool furnace walls are heated by radiation and, in turn, boil surrounding water, generating steam. The steam is conveyed to the turbine where heat energy is converted into mechanical energy, which in turn is converted to electrical energy by the generator. During combustion, as the carbon in the coal is oxidized, by-products of the raw coal are released, some of which become ash—bottom ash, including slag, and fly ash. Fly ash, comprised of the oxides of sulfur, nitrogen, and carbon, as well as actual ash particles, is carried off by the boiler gases. To a lesser extent, trace organic elements, radionucleides, and hydrocarbons are also emitted. Many of these by-products are recaptured by emission-control devices, which often produce sludge for disposal. The large volume of coal burned by powerplants leaves massive amounts of bottom

19. McGinley & Sweet, *Acid Coal Mine Drainage*, 17 Duq. L. Rev. 67, 67 (1979).
20. For a detailed discussion of the coal combustion process see Office of Technology Assessment, United States Congress, The Direct Use of Coal 87 (1979).

ash as well.[21] Smaller amounts of other wastes result from processes designed to purify water and to maintain plant equipment.

D. *Environmental Impacts*

Disposal of the by-products of coal combustion affects air, water, and land. Air quality is affected by the release of sulfur, nitrogen, carbon oxides, and ash particles.[22] Coal combustion is a major source of sulfur emissions in the United States. Nitrogen oxides may be related to the formation of photochemical oxidants, which can be damaging to agriculture and forestry, and when transformed into nitrates, contribute to the so-called acid rain phenomenon. Because electrostatic precipitators are so efficient in removing large particles, only the fine particles pose environmental problems. In addition, these fine particulates can be transported great distances and can affect visibility by scattering light.

The impact on both water and land tends to be more geographically concentrated. Water quality is affected primarily by such powerplant operations as cooling tower blowdown, a discharge of concentrated salts, and water consumption. Water used in the cooling process may affect a river's assimilative capacity, impact ecosystems if water levels drop too low, and cause allocation problems where water is scarce. Improper land disposal of certain utility wastes, such as boiler blowdown, may cause the leaching of various chemicals into surface and ground waters.[23]

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21. It is estimated that in 1985 electric utilities will produce between 64 and 80 million tons of fly ash and between 25 and 31 million tons of bottom ash. By the year 2000, production of fly ash and bottom ash is expected to be 245 million tons annually. Scrubber sludge generation will increase from its 1985 level of 13-21 million tons to 23-30 million tons annually by the end of the century. Data compiled in Envirosphere Co., Fossil-Fuel Plant Background Information, Appendix 1, Tables D-5, D-6, D-10 (Mar. 16, 1979) (prepared for the Edison Elec. Inst., Utility Solid Waste Activities Group).

22. *See, e.g.*, National Institute of Envt'l Health Sciences, Committee on Health and Environmental Effects, Report on Increased Coal Utilization Report (1977), *reprinted in* 43 Fed. Reg. 2229 (Jan. 16, 1978); OFFICE OF TECHNOLOGY ASSESSMENT, UNITED STATES CONGRESS, THE DIRECT USE OF COAL 183-225 (1979); P. ERLICH, A. ERLICH & J. HOLDREN, ECOSCIENCE (1977).

23. No adverse environmental impact has been shown to result from the land disposal of high volume waste such as ash and sludge. In fact, a significant percentage of ash is reused for roadbeds, landfills, and construction materials. *The Need for a National Materials Policy: Hearings on S. 3560 Before the Panel on Materials Policy of the Subcomm. on Environmental Pollution of the Senate Comm. on Public Works*, 93d Cong., 2d Sess. 1304 (1974); Envirosphere Co., Report on Utility Solid Wastes as a Resource for Recovery and Utilization, *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Rules under Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976, Appendix 11, at 1-89 (Mar. 16, 1979).

E. Environmental Constraints and Planning Uncertainties

Environmental legislation significantly affects utility operations. Each of the statutes discussed in this article, however, was either enacted, or extensively amended, in recent years. The Clean Air and Clean Water Acts were substantially revised in 1977;[24] the Resource Conservation and Recovery Act,[25] the federal government's first substantive attempt to regulate solid wastes, was enacted in 1976. Many of the regulations implementing these statutes are not yet in place. Practical experience with final regulations is limited, and regulatory changes are continual. Accordingly, while we are beginning to understand how the statutes will affect the nation's ability to use more coal, only tentative answers are currently available. We can be fairly certain that these statutes will make powerplant siting more difficult, lengthen the licensing period, vastly increase capital and operating costs, and create greater uncertainty for long-term utility planning.

The process for planning a new coal-fired powerplant is lengthy, complex, and expensive. To appreciate some of the constraints that utilities face, other than those imposed by environmental regulations, a summary of a typical planning and construction schedule for a coal-fired generating plant[26] is useful.

The initial step, requiring six months and costing less than $100,000, is to determine whether a new facility is needed and what fuel will be used. The site selection program, which requires 18 months and $150,000-$500,000, is aimed at finding a preferred site and one to three alternatives. The next activities—detailed environmental evaluation of the sites, obtaining site access and options, and conceptual engineering—can be carried out simultaneously over a two year period and cost $2.3-$3.3 million plus the cost of the options on the land. The last preconstruction step is the year-long regulatory agency review of permits. Before construction can begin, five years have elapsed and up to $4 million have been spent.

24. *See* Clean Water Act of 1977, Pub. L. No. 95-217, 91 Stat. 1567, 33 U.S.C. §§ 1251-1376 (Supp. I 1977); Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685, 42 U.S.C. §§ 7401-7642 (Supp. I 1977).

25. Resource Conservation and Recovery Act of 1976, Pub. L. No. 94-580, 90 Stat. 2795, 42 U.S.C. §§ 6901-6987 (1976).

26. This account is adapted from a more detailed analysis which can be found in NUS Corp., Impact of Implementation of New PSD Regulations on Power Station Construction Schedules and Costs 4-5 to -9 (1978) (prepared for Edison Elec. Inst., Utility Air Regulatory Group).

The next steps are acquiring the land, completing engineering plans, and sending letters of intent to the manufacturers of the boiler, turbine generator, and other major equipment. Six months after the preconstruction permits are obtained, major equipment and fuel contracts are signed, and finally construction can begin. If coal is the selected fuel, the utility or a supplier may need to develop a mine; because this development may take at least seven years, it must begin *before* the powerplant permits are issued. The construction of the first unit begins 18-24 months after the permits are issued and is completed within six years; if a second unit is to be built at the same site, it will be completed approximately one year after the first unit. Thus, the time span from initial concept to completion of construction can run approximately 12 years, yet the time period may be increased by environmental requirements. Without question, capital outlay will be substantially increased.

F. Conflicts Between Environmental and Energy Objectives

As we review these statutes and the implementing regulations, an important issue should be kept in mind. This involves the natural tension between two worthy social objectives: environmental preservation and adequate energy supplies. The production of energy by any method has an impact on the environment. That impact can be minimized, perhaps almost eliminated; but the cost of doing so increases the cost of producing energy and the resulting price paid by the consumer. Inevitably there must be a trade-off; the greater the environmental preservation, the more society will pay for energy.

Who should decide where the line is to be drawn? This is not something that can or should be done alone by the regulated community, by EPA, or by environmentalists. Each group has an important role in presenting the most articulate argument for its viewpoint. After all the conflicting technical and economic data is considered, a value judgment must be made. In our society such judgments are made not by special interest groups or by bureaucrats, but by the people's representatives.

The environmental-energy argument is not static. As changes occur, we should ask ourselves: Do these statutes recognize that environmental and energy objectives are related yet conflicting, and require some kind of accommodation, balancing, and setting of priorities? Has Congress borne or shirked its responsibility for reconciling these conflicts? Has it given EPA too much control in balancing energy and environmental values? Have the rulemaking decisions made by EPA to date struck the proper balance?

In addition, one should consider the total regulatory system that EPA continues to develop. From statutory mandates that address a series of individual environmental problems, the Agency has fashioned powerful national controls over the siting not only of powerplants but of all major industrial activities. The cumulative effect of regulating air, water, and waste management is the creation of a national land-use planning program without congressional approval. Economic development is the key to growth, and EPA, by design or by accident, is determining where new industrial growth can occur.

Should patterns of economic growth be set by EPA? If so, should not the power to make such decisions be granted forthrightly and directly by Congress, and not occur *ad hoc* through the development of administrative rules to implement environmental statutes? As we review the environmental policies that have been set, we must keep in mind their influence on our future. Do they favor certain geographic areas of the country? Do they make center cities, suburbs, or rural areas less attractive? How will urban renewal, suburban sprawl, and preservation of prime agricultural land be affected? These issues are not addressed in this article. They will, however, become more and more urgent as the impacts of environmental regulation on both the regulated community and its customers become clearer.

II. Clean Air Act

The nation's efforts to improve ambient air quality substantially affect the use of coal by the electric utility industry. Environmental regulations designed to protect air quality may determine a utility's selection of fuel, and if coal is selected, whether eastern coal or lower sulfur western coal is burned. They will affect plant location. Ultimately, these regulations help to determine how much the utility will pay to burn coal and how much consumers will pay for electricity.

A. *Statutory and Regulatory Framework*

To understand how the Clean Air Act affects the use of coal, we must understand its general framework and implementing regulations. The Clean Air Amendments of 1970[27] directed EPA to establish national primary ambient air quality standards for various air pollutants.[28] The standards must be set at a level sufficient to protect public health, with an adequate margin of safety.[29] EPA and the states share the responsibility for attaining and maintaining the national standards through the State Implementation Plan (SIP).[30] If a state fails to adopt an approved plan, EPA is authorized to act in its stead.[31]

One mandatory element of a SIP is a preconstruction review of any proposed new stationary source that might prevent attaining or maintaining a national ambient air quality standard,[32] or for which a new source performance standard has been established.[33] Accordingly, the right to construct a coal-fired electric generating plant depends on whether it will meet the national standards, as well as the applicable new source performance standards.

Once EPA began issuing implementing regulations, it quickly became apparent that the statute did not provide guidance on a number of questions. Most importantly: (1) may new sources that meet the new source performance standards be constructed in nonattainment areas, that is, those areas in which one or more national ambient air quality standards are not being met? and, (2) can new development that diminishes existing air quality be permitted in those areas where the existing air quality exceeds that mandated by the national standards?

With some prodding from the courts and outside groups, EPA attempted to address these crucial issues. In a 1976 interpretive ruling, EPA announced what has become known as its emissions offset policy.[34] Briefly, the ruling required the owner whose proposed major stationary source will be located in a nonattainment area to (1) meet the lowest achievable emission rate; (2) obtain more than

27. Pub. L. No. 91-604, 84 Stat. 1676, 42 U.S.C. §§ 1857-1858a (1970) (amended 1977).

28. 42 U.S.C. § 1857c-4(a)(1)(1970) (current version at 42 U.S.C. § 7409(a)(1)(A) (Supp. I (1977)).

29. *Id.* § 1857c-4(b)(1) (current version at 42 U.S.C. § 7409(b)(1) (Supp. I 1977)).

30. *Id.* § 1857c-5 (current version at 42 U.S.C. § 7410 (Supp. I 1977)); *see* SENATE COMM. ON ENVIRONMENT AND PUBLIC WORKS, CLEAN AIR AMENDMENTS OF 1970, S. REP. No. 91-1196, 91st Cong., 2d Sess. 12 (1970).

31. 42 U.S.C. § 1857c-5(c)(1) (1970) (current version at 42 U.S.C. § 7410(c)(1) (Supp. I 1977)).

32. *Id.* § 1857c-5(a)(2)(D) (current version at 42 U.S.C. § 7410(a)(4) (Supp. I 1977)).

33. *Id.* § 1857c-5(a)(4) (current version at 42 U.S.C. § 7410(a)(4) (Supp. I 1977)).

34. 41 Fed. Reg. 55524 (Dec. 21, 1976).

offsetting emission reductions from existing sources; and (3) demonstrate that all of the owner's other sources in the area are in compliance or on an approved compliance schedule.[35] In nonattainment areas, industrial growth would be possible only if it contributed to the national ambient air quality standards.

In 1974, EPA issued final regulations for the prevention of significant deterioration (PSD).[36] This action followed a district court decision construing the Clean Air Act to mean that in areas where air quality is better than the national ambient air quality standards, it cannot be diminished to a level below the standards.[37] Again, this would make new development difficult in areas where air quality was better than the national standard.

In both cases, EPA's actions generated substantial criticism that led to further congressional involvement. This resulted in the Clean Air Act Amendments of 1977,[38] which generally supported the direction charted in the Agency's earlier regulations and interpretive ruling. These 1977 amendments and their implementing regulations significantly affect coal-fired powerplants. Three of their provisions will be discussed: prevention of significant deterioration, emissions offset policy in nonattainment areas, and new source performance standards (NSPS).

B. *Prevention of Significant Deterioration*

Congress followed and strengthened EPA's approach in the PSD area largely because it questioned whether the national ambient air quality standards sufficiently protected public health.[39] PSD areas have air quality superior to that mandated by the national ambient air quality standards.[40] Originally designated by Congress and subject to future redesignation by the states,[41] the areas are categorized as Class I, Class II, or Class III. A permitted

35. *Id.* at 55525.

36. 40 C.F.R. §§ 52.01, 52.21 (1977); 39 Fed. Reg. 42510 (Dec. 5, 1974).

37. Sierra Club v. Ruckelshaus, 344 F. Supp. 253, 255-57 (D.D.C.), *aff'd per curiam*, 4 E.R.C. 1815 (D.C. Cir. 1972), *aff'd per curiam by an equally divided court sub nom.* Fri v. Sierra Club, 412 U.S. 541 (1973).

38. Pub. L. No. 95-95, 91 Stat. 685, 42 U.S.C. §§ 7401-7642 (Supp. I 1977).

39. *See* HOUSE COMM. ON INTERSTATE AND FOREIGN COMMERCE, THE CLEAN AIR ACT AMENDMENTS OF 1977, H.R. REP. No. 95-294, 95th Cong., 1st Sess. 105-28, *reprinted in* [1977] U.S. CODE CONG. & AD. NEWS 1077, 1183-1206.

40. 42 U.S.C. § 7407(d)(1)(E) (Supp. I 1977).

41. *Id.* §§ 7472, 7474. Restrictions on the redesignation process do exist. *Id.* § 7474(a), (d).

increment of deterioration is assigned to each class, with the least permitted in Class I and the most in Class III.[42] The concentration of an air pollutant that exists on the "base date" is known as the "baseline concentration." The 1977 amendments establish a permitted increment of deterioration over the baseline concentrations,[43] but also require that the maximum allowable concentrations not exceed the national primary or secondary ambient air quality standard.[44] Thus, the maximum allowable concentration of a pollutant is the lesser of either the baseline concentration plus the increment or the national ambient air quality standard.

To ensure compliance, the Act requires a PSD permit for the construction of any major emitting facility in a PSD area or in a nonattainment area that would significantly affect a PSD area.[45] Construction is not permitted if the proposed facility would exceed the maximum allowable concentrations.[46] Proposed coal-fired powerplants will have to undergo two types of review if subject to PSD regulations: (1) a technology review to determine what air pollution controls must be installed, and (2) an air quality review to assess the expected impact on the permitted increment and ambient standards. The applicant must use the best available control technology (BACT) as determined by EPA on a case-by-case basis;[47] in any event, no less than new source performance standards will be required. For coal-fired powerplants, this means that scrubbers must be used with both high and low sulfur coal. The idea is to optimize the consumption of the PSD air quality increments to maximize economic growth per unit of deterioration in air quality. The permit applicant is also responsible for extensive air quality monitoring and for analyzing the impacts.[48] Monitoring may be required for as long as one year,[49] and EPA has an additional year to act on a permit application;[50] thus, the permit process may take up to two years.

Acting in response to the 1977 amendments, EPA issued regula-

42. *Id.* §§ 7472-7474.

43. *Id.* § 7473(b).

44. *Id.* § 7473(b).

45. *Id.* § 7475(a). One of the 28 specified sources to which the PSD restrictions apply is "fossil-fuel fired steam electric plants of more than two hundred and fifty million British thermal units per hour heat input." *Id.* § 7479(1).

46. *Id.* § 7475(a)(3); 42 Fed. Reg. 57480 (Nov. 3, 1977).

47. 42 U.S.C. § 7475(a)(4) (Supp. I 1977).

48. *Id.* § 7475(e)(2).

49. *Id.* § 7475(e)(2).

50. *Id.* § 7475(c).

tions specifying minimum state implementation plan requirements for PSDs and comprehensive amendments to the old PSD regulations.[51] As a result of litigation by industry and environmental groups,[52] EPA has recently issued *proposed* amendments to its regulations for prevention of significant deterioration.[53] Much of the current debate focuses on EPA's definition of statutory terms; whether a new powerplant is treated as a major emitting facility and, therefore, subject to preconstruction review depends on the definition of "potential to emit."[54] Similarly, EPA's definitions of "baseline concentration" and "baseline date" determine how emissions are counted and how much growth can be supported.[55]

EPA has also proposed *de minimis* exemptions that could substantially reduce the effect of PSD regulations on the utility industry. First, there are *de minimis* emission levels or rates for specified pollutants.[56] The source is not subject to either type of PSD review if its pollutant emissions do not exceed the *de minimis* level. Second, there is a list of *de minimis* air pollutant impact levels.[57] The applicant is exempt from the air quality review if he can show that a pollutant's impact is no more than the *de minimis* level.

A final PSD provision warranting consideration required the EPA Administrator to issue by August 7, 1979, regulations to assure visi-

51. 43 Fed. Reg. 26380, 26388 (June 19, 1978).

52. *See* Alabama Power Co. v. Costle, No. 78-1006 (D.C. Cir. Dec. 14, 1979); 44 Fed. Reg. 51948 (Sept. 5, 1979).

53. 44 Fed. Reg. 51948 (Sept. 5, 1979).

54. EPA's definition of "potential to emit" as "the capability at maximum capacity to emit a pollutant in the absence of air pollution control equipment" found at 40 C.F.R. § 51.24(b)(3) (1978) was rejected by the District of Columbia Court of Appeals which said that EPA, interpreting the phrase "potential to emit," must take account of both the facility's maximum productive capacity and the "anticipated functioning of the air pollution control equipment designed into the facility." Alabama Power Co. v. Costle, No. 78-1006, slip op. at 26 (D.C. Cir. Dec. 14, 1979). Although the proposed definition will include only those pollutants emitted after application of air pollution control equipment, 44 Fed. Reg. 51948 (Sept. 5, 1979), EPA will not consider reductions that result from permit limitations on the source's hours of operations. By assuming that a source operates 24 hours per day, 365 days a year, EPA may subject various smaller electric utility industry facilities, such as combustion turbines, auxiliary boilers, small coal gasification units, combined cycle units, and certain auxiliary equipment at nuclear plants, to PSD review.

55. EPA's proposal to establish baseline dates for each Air Quality Control Region (AQCR) rather than the smaller section 107 subareas may create an administrative nightmare which would make it nearly impossible for an applicant to determine the baseline concentrations. 44 Fed. Reg. 51948-49 (Sept. 5, 1979) (proposed 40 C.F.R. § 51.24(b)(11)-(12)).

56. 44 Fed. Reg. 51937 (Sept. 5, 1979).

57. *Id.* at 51938.

bility protection.[58] A visibility impact review must be part of the PSD review whenever the proposed source would affect any Class I area.[59] If the federal land manager and federal officials responsible for a particular Class I area demonstrate that a proposed source will impair visibility or another air quality related value, the state may not issue a PSD permit even if the source would not have violated the Class I PSD increment. A report on visibility protection prepared by EPA concluded that there would be serious emission limitation and siting constraints for large powerplants, particularly in the West where a facility's zone of influence could extend nearly 250 miles.[60] Powerplants larger than 1000 megawatts (MW) may be unable to meet a five percent visual range reduction criterion even using BACT;[61] some may have to locate hundreds of miles from Class I areas to avoid impairing visibility.

The PSD regulations may have at least one of the following effects on a proposed new powerplant: a preferred site may be rejected; a site may be restricted to one plant; and levels for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates may be reduced.[62] Rejection of a site could mean a two to three year delay before an alternative is found.[63] Construction costs will escalate during the delay, and the plant's additional capacity will not be brought on line when originally scheduled. This may force the utility to buy power from other sources until the new plant is complete. If only one facility can be constructed at the site, rather than two, it will cause a one to three year delay and increase the costs of both facilities since they cannot share features such as a railroad spur line, water intake, coal handling system, and transmission lines.[64]

C. *Emissions Offset Policy in Nonattainment Areas*

In reviewing EPA's emissions offset policy, Congress was faced with the problem of how to improve air quality in areas with deficient air quality standards without causing severe economic disloca-

58. 42 U.S.C. § 7491(a)(4) (Supp. I 1977) (regulations not yet proposed).

59. *Id.* § 7475(d)(2)(C).

60. United States Environmental Protection Agency, Assessment of the Principal Technical Issues Related to Visibility Protection Under the Clean Air Act viii (1979).

61. *Id.* at 18.

62. *See* NUS Corp., Impact of Implementation of New PSD Regulations on Power Station Construction Schedules and Costs 6-2 (1978).

63. *See id.*

64. *See id.*

tion or stagnation. Congress made economic growth in nonattainment areas[65] contingent upon efforts by new or expanding industries to improve air quality. Clean air is viewed as a resource that must be managed; proper management will increase the number of industrial enterprises that can exist in an area without sacrificing air quality.[66]

The 1977 amendments left in place the existing EPA emissions offset policy until June 30, 1979,[67] at which time the statute's nonattainment plan went into effect. The statute's nonattainment restrictions apply only to major stationary sources and major modifications of existing sources.[68]

Nonattainment restrictions will also apply to proposed major stationary sources located in PSD areas if a nonattainment area will be significantly affected.[69] Of course, the air in a nonattainment area is polluted not only by major stationary sources, but also by commercial and residential development, as well as by minor stationary sources. These other sources are not subject to nonattainment restrictions, but should they cause a decrease in air quality, stricter regulation will be imposed on the major stationary sources.

A new major stationary source is subject to three basic requirements: meeting the lowest achievable emission rate (LAER), obtaining more than compensating emission offsets, and ensuring that the applicant's other sources are in compliance. LAER is either the most stringent emission limitation contained in any SIP or that achieved in practice, whichever is more stringent.[70] An owner has the opportunity to show that a SIP limitation is not achievable in practice.[71] However, if a limitation has been achieved in practice, yet the owner of the proposed facility cannot also achieve it, the facility may not be built.

Until the 1977 amendments, EPA's policy was to approach each proposed major stationary source case-by-case so that reductions in

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65. Nonattainment areas are those areas in which the national ambient air quality standard for any air pollutant is exceeded. 42 U.S.C. § 7501(2) (Supp. I 1977).

66. *See* 123 CONG. REC. 13697 (1977)(floor statement of Sen. Edmund S. Muskie).

67. Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 129(a)(1), 91 Stat. 745, 42 U.S.C. § 7502(a)(1) (Supp. I 1977).

68. 41 Fed. Reg. 55528 (Dec. 21, 1976). As defined by the statute a major stationary source is any source that "directly emits, or has the potential to emit, one hundred tons per year or more of any pollutant." 42 U.S.C. § 7602(j) (Supp. I 1977).

69. [1977] 8 ENVIR. REP. (BNA) 1109.

70. 42 U.S.C. § 7501(3) (Supp. I 1977).

71. *Id.*

existing emissions would compensate for new emissions.[72] Congress significantly modified this approach by permitting states to establish an allowance for growth.[73] New sources must either obtain offsets or use up part of the state's growth allowance. EPA retains the discretion to determine reasonable progress in light of the December 31, 1982 deadline for attaining national ambient air quality standards.[74] Finally, the owner of a proposed major stationary source must certify that all existing sources he owns or controls in the state comply with air pollution requirements or are on an approved timetable for compliance.[75]

EPA has subsequently issued a revised Emission Offset Interpretive Ruling to take into account the 1977 amendments,[76] although it did not address what has become one of the major issues in the emissions offset area: the "bubble" or alternative emission reduction concept.[77] In essence, this would permit plants to reduce emission control where costs are high in exchange for an equal increase in control where costs are lower. A facility with multiple process-related emission sources is treated as one entity. The applicant may propose to meet the *total* emission control requirements of the SIP for a given pollutant through a mix of controls other than that specified by the regulations. In this way industry may be able to reduce its pollution control costs without any increase in the emissions level.

The emissions offset policy as currently conceived will have a substantial impact on the siting of powerplants in areas with air quality below the national ambient standards. An applicant will have the burden of finding an offsetting reduction and paying for the controls both at his own facility and at the offsetting facility. The LAER is a stringent emission standard, one which will be more expensive to achieve than BACT.

72. 41 Fed. Reg. 55529 (Dec. 21, 1976).

73. 42 U.S.C. § 7502 (Supp. I 1977).

74. *Id.* § 7501(1).

75. *Id.* § 7503.

76. 44 Fed. Reg. 3274 (Jan. 16, 1979).

77. EPA has, however, proposed a policy statement that would encourage states to revise their SIP's to incorporate the bubble concept. 44 Fed. Reg. 3740 (Jan. 16, 1979). In response to a court ruling in *ASARCO v. EPA*, EPA has revoked the bubble concept as a means of determining what constitutes a modified source for the purpose of applying NSPS. ASARCO v. EPA, 578 F.2d 319, 329 (D.C. Cir. 1978); 45 Fed. Reg. 5616 (Jan. 23, 1980).

D. New Source Performance Standards

The 1970 Clean Air Act amendments required EPA to establish emission standards for new or substantially modified stationary sources.[78] The New Source Performance Standards (NSPS) were designed to prevent existing air quality problems from worsening or new ones from being created. Allowable emission rates were established for 19 categories of sources, and SIPs had to include a preconstruction review procedure for new sources to ensure the standards would be met.[79]

The 1977 Clean Air Act Amendments increased the number of source categories to 28 and tightened the basis on which EPA determines the allowable rate of emissions.[80] The sources must now use the best technological system of continuous emission reduction that has been adequately demonstrated.[81] Fossil fuel-fired sources including coal-fired powerplants are also subject to a percentage reduction limitation in emissions.[82] The 1977 amendments also require EPA to consider energy requirements, cost, and health and environmental impact other than air quality in determining which continuous emission reduction systems have been adequately demonstrated.[83] In calculating the percentage reduction requirements, the Administrator may give credit for mine-mouth and other precombustion fuel-cleaning processes.[84]

NSPS have been issued in final form for electric utility steam generating units.[85] EPA has set standards for limiting emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x), for new, modified, and reconstructed powerplants that can burn more than 250 million Btu's per hour of fossil fuel.[86] The SO_2 standards vary according to the type of fuel being burned; for powerplants burning other than anthracite or solid solvent refined coal, SO_2 emissions are limited to 1.2 lb/million Btu of heat input.[87] A 90 percent reduction in potential SO_2 emissions is required at all times; however, when emissions are less than .60 lb/million Btu heat

78. 42 U.S.C. § 1857c-6 (1970) (current version at 42 U.S.C. § 7411 (Supp. I 1977)).
79. *Id.* § 1857c-5(a)(4) (current version at 42 U.S.C. § 7410(a)(4) (Supp. I 1977)).
80. 42 U.S.C. § 7479 (Supp. I 1977).
81. *Id.* § 7411(a)(1)(C).
82. *Id.* § 7411(a)(1)(A)(ii).
83. *Id.* § 7411(a)(1).
84. *Id.* § 7411(a)(1).
85. 44 Fed. Reg. 33580 (June 11, 1979).
86. *Id.* at 33580-81.
87. *Id.* at 33614 (proposed 40 C.F.R. § 60.43a(a)(1)).

input, only a 70 percent reduction in potential emissions is required.[88] This means that whether high or low sulfur coal is being burned, 90 percent of potential SO_2 emissions must be captured by the control technology.

The utility industry and the Department of Energy (DOE) advocated a sliding scale approach that would have established a lower percentage reduction for those plants using low sulfur coal.[89] DOE argued that its proposal would reduce SO_2 emissions almost as much as EPA's full control approach but at a savings of $10-$12 billion through 1995.[90] Furthermore, DOE's approach would reduce oil consumption by 185,000 barrels daily, while not affecting the West's share of the eastern coal market.[91]

Under the previous NSPS, annual costs for pollution control in 1990 were estimated to be $4.45 billion, which increases to $6.14 billion under the utility proposal and $7.72 billion under EPA's final standards.[92] Between 1977 and 2020, it is estimated the EPA proposal will add $27.5 billion to air pollution control costs over what they would be under the utility standard.[93] Yet for all these expenditures, SO_2 emissions will be only 11.3 percent less than what they would have been with the prior NSPS.[94] While the industry faces an increase of more than $900 per ton for removing SO_2, research suggests that the benefits of removing SO_2 from plant emissions

88. *Id.* at 33614 (proposed 40 C.F.R. § 60.43a(a)(1), (2)).

89. For contrasting viewpoints on whether the Clean Air Act permits or requires a sliding scale approach see Badger, *New Source Standard for Power Plants I: Consider the Costs,* 3 HARV. ENVT'L L. REV. 48, 52 (1979) and Ayres and Doniger, *New Source Standard for Power Plants II: Consider the Law,* 3 HARV. ENVT'L L. REV. 63, 76 (1979).

90. Letter from John F. O'Leary, Deputy Secretary, DOE, to Douglas Costle, Administrator, EPA (Dec. 15, 1978), Enclosure B—Comparison of Sliding Scale and Full Control Alternatives.

91. *Id.* at Enclosure B.

92. National Economic Research Assoc., Comments on The Economic Impacts of EPA's Sept. 19, 1978 Proposed Revision to New Source Performance Standards for Electric Utility Steam Generating Units 5 (Dec. 15, 1978) (prepared for Edison Elec. Inst., Utility Air Regulatory Group) [hereinafter cited as Comments on NSPS Revisions].

93. Comments on NSPS Revisions, *supra* note 92, at 5. The increase over pollution control costs under pre-1979 NSPS is $57 billion by the year 2020; this translates to a per household increase of $406. Comments on NSPS Revisions, *supra* note 92, at 5-6.

94. Comments on NSPS Revisions, *supra* 92, at 5-6. Compare the EPA reduction with a 7.3 percent decrease under the Utility Air Regulatory Group (UARG) proposal and a 9.8 percent decrease under the DOE proposal. The costs per ton of SO_2 removed will escalate tremendously under any of the three proposals. From a pre-1979 per ton cost of $158, the per ton cost will skyrocket to $1063 under the EPA NSPS. Comments on NSPS Revisions, *supra* note 92, at 7.

amount to only approximately $200 per ton.[95]

The recently set NSPS will also significantly increase the sludge disposal problem. While the utility industry and DOE sliding scale approaches would have increased annual sludge production by approximately two million tons, EPA's NSPS will result in a 12.86 million ton annual increase.[96] Each proposal will, however, decrease the amount of ash produced. If ash and sludge are classified as hazardous under the Resource Conservation and Recovery Act, and assuming a disposal cost of $20 per ton, a highly conservative estimate, EPA's NSPS would increase utilities' waste disposal costs by nearly $150 million annually over what they would have been under the utility industry proposal.[97]

The effect of the NSPS changes is to force utilities to meet the NSPS by using technological controls, such as precombustion treatment of the coal or use of a scrubber, rather than alternative fuels such as oil or low-sulfur coal. To comply with the new emission restrictions, utilities have only one option in the immediate future: use of flue gas desulfurization (FGD) systems ("scrubbers"). There are, however, serious questions about the reliability of FGD systems.[98] In any event, use of these systems will mean less efficient and more costly generation of electricity. For example, an estimated 10-15 percent of a plant's capital cost will go to the FGD system.[99]

The new standards for particulates and nitrogen oxides are less controversial. The standard for particulate matter limits emissions when coal is burned to .03 lb/million Btu heat input and requires a 99 percent reduction in uncontrolled emissions.[100] Most utilities use

95. NATIONAL ACADEMY OF SCIENCES, NATIONAL ACADEMY OF ENGINEERING, NATIONAL RESEARCH COUNCIL, AND STAFF OF SENATE COMM. ON ENERGY AND NATURAL RESOURCES FOR SENATE COMM. ON PUBLIC WORKS, 94TH CONG., 1ST SESS., AIR QUALITY AND STATIONARY SOURCE EMISSION CONTROL 628-29 (Comm. Print 1975).

96. Comments on NSPS Revisions, *supra* note 92, at 11.

97. Comments on NSPS Revisions, *supra* note 92, at 11.

98. One consultant who has studied the issue concluded that: "FGD systems whose performance characteristics are consistent with the performance characteristics of the FGD system data base and which achieve the 92% mean SO_2 removal set forth in September 19, 1978 Subpart Da proposal will not be able to comply consistently with the 90% SO_2 removal, 30 day rolling average required." Entropy Environmentalists, Inc., A Statistical Evaluation of the EPA FGD System Data Base Included in the Subpart Da NSPS Docket 7 (1979) (prepared for Edison Elec. Inst., Utility Air Regulatory Group).

99. *See* OFFICE OF TECHNOLOGY ASSESSMENT, UNITED STATES CONGRESS, THE DIRECT USE OF COAL 172 (1979).

100. 44 Fed. Reg. 33614 (June 11, 1979) (proposed 40 C.F.R. § 60.42a(a)).

electrostatic precipitators (ESPs) to limit particulate matter emissions. An alternative that may become more common, particularly when low-sulfur coal is being burned, is the use of fabric filter baghouses.

The standard for NO_x, when subbituminous coal is being burned, is .50 lb/million Btu heat input, and 65 percent of potential emissions must be controlled.[101] Compliance with the emission limit will assure compliance with the percentage reduction requirements.[102] Control techniques involve combustion modifications, although various degrees of nitrogen can be removed by precombustion fuel-cleaning technologies.

The new NO_x limitations may cause adverse side effects on utility equipment, such as boiler corrosion, severe slagging, or reduced efficiency, and affect the release of other pollutants.[103] Furthermore, when EPA concluded additional compliance costs would be low, it failed to consider the cost of additional research and development, corrosion damages, reduced operating efficiency, and design changes that manufacturers switching to tangential boilers will have to make.[104]

E. Summary

The Clean Air Act has a significant effect on the construction and operation of coal-fired powerplants. A proposed plant in a clean air area must incorporate the best available control technology (BACT); even this, however, may not be enough if the area's allowable increment of deterioration has already been consumed—then, the plant could not be built. There are similar constraints in nonattainment areas where EPA's efforts are aimed at improving low quality air. A plant's cost will increase in order to obtain emissions offsets and to satisfy the lowest achievable emission rate (LAER) standard. Once again these restrictions may require a plant site to be relocated because the applicant may not find a source of offsets or may not be able to achieve the LAER technology. Finally, the NSPS will greatly increase the cost of controlling emissions, par-

101. *Id.* at 33615 (proposed 40 C.F.R. § 60.44(a)).

102. *Id.* at 33586.

103. *See* KVB (A Research-Cottrell Co.), Evaluation of the Proposed NSPS for NO_x Emissions From Coal Fired Utility Boilers 10 (1979) (prepared for Edison Elec. Inst., Utility Air Regulatory Group).

104. *Id.* at 11.

ticularly SO_2, at the expense of reduced operating capacity and efficiency.

III. Resource Conservation and Recovery Act of 1976

The Resource Conservation and Recovery Act of 1976[105] (RCRA) was enacted to close a loophole—the unregulated land disposal of discarded materials—that remained after passage of federal legislation regulating air and water pollution.[106] RCRA was designed to prevent direct environmental damage by regulating the land disposal of both hazardous and nonhazardous wastes. Since coal-burning utilities generate massive amounts of by-products, principally fly ash, bottom ash, and scrubber sludge, that must be disposed of, RCRA will have an important impact on their operations.

A. *Statutory and Regulatory Framework*

The statute creates separate schemes for the control of hazardous and nonhazardous wastes. Hazardous wastes are those substances that may (1) cause or significantly contribute to an increase in either mortality or serious illness or (2) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of.[107] All other discarded materials are nonhazardous wastes. States have final authority for deciding how, or indeed whether, to manage nonhazardous wastes, and if a state's plan satisfies federal guidelines, the state is eligible for federal technical and financial assistance.[108]

The federal government plays a larger role in regulating hazardous wastes. The Act directs EPA to establish, within 18 months of the Act's passage, which deadline has long since passed, criteria for identifying and listing hazardous wastes, as well as standards for generators and transporters of such wastes, and for owners or operators of treatment, storage, and disposal facilities (TSDFs). The Act also called for EPA to establish a full-fledged permit system.[109] States are authorized to administer their own hazardous waste pro-

105. Pub. L. No. 94-580, 90 Stat. 2796, 42 U.S.C. §§ 6901-6987 (1976).

106. House Comm. on Interstate and Foreign Commerce, Resource Conservation and Recovery Act of 1976, H.R. Rep. No. 94-1491, 94th Cong., 2d Sess. 6, *reprinted in* [1976] U.S. Code Cong. & Ad. News 6238, 6238-39.

107. 42 U.S.C. § 6903(5) (1976).

108. Id. § 6947(b).

109. *Id.* §§ 6921-6925.

grams if they adopt an EPA-approved plan.[110]

The Agency has commenced the rulemaking process for both nonhazardous and hazardous wastes. It has issued final regulations establishing guidelines for state solid (i.e., nonhazardous) waste management plans,[111] which include definitions of sanitary landfills, a permissible management technique, and open dumps, which are prohibited.[112] The sanitary landfill criteria consist principally of general performance standards but include a few specific operational techniques designed to protect human health and the environment.

EPA's Subtitle C program,[113] which will regulate hazardous wastes, is still in proposed form, and will probably be substantially modified before it becomes final. In their current form, these Subtitle C regulations would establish a pervasive "cradle-to-grave" management control system for any waste that could be potentially hazardous to human health or the environment.

Proposed regulations under section 3001 of RCRA define hazardous wastes in two ways: by listing specific wastes and waste-producing processes considered hazardous, and by establishing hazardous characteristics for all nonlisted wastes.[114] The proposed section 3002 regulations apply to generators of hazardous waste, and establish a manifest system to track the waste from point of disposition until its ultimate disposal.[115] The proposed section 3003 regulations cover transporters of hazardous wastes.[116] Under section 3004, proposed regulations establish the level of human health and environmental protection that the owner/operator of a TSDF must provide.[117] In addition, certain specified low risk wastes occurring in large volume, while still within the "hazardous" classification, are proposed to be designated as "special waste" subject to less pervasive regulation.[118] This special waste category is particularly important to electric utilities because it includes fly ash, bottom ash, and scrubber sludge.[119] Until more information about this class of wastes is available, and detailed management regulations can be issued,

110. *Id.* § 6926.
111. 44 Fed. Reg. 45066 (July 31, 1979).
112. 44 Fed. Reg. 53438 (Sept. 13, 1979).
113. 42 U.S.C. §§ 6921-6931 (1976).
114. 43 Fed. Reg. 58949 (Dec. 18, 1978).
115. *Id.* at 58969, 58972.
116. 43 Fed. Reg. 18506 (Apr. 28, 1978).
117. 43 Fed. Reg. 58982 (Dec. 18, 1978).
118. *Id.* at 58991, 59015 (proposed 40 C.F.R. § 250.46).
119. *Id.* at 59015 (proposed 40 C.F.R. § 250.46-2).

each type of special waste will be subject only to selected section 3004 standards. Proposed section 3005 regulations establish EPA permit-granting procedures for TSDFs, and regulations under section 3006 outline requirements for approved state hazardous waste plans.[120]

Although these regulatory proposals are still being revised and refined, it is not too early to suggest that EPA's expansive approach will create an administrative monster that will not respond to Congress' real concern: to regulate those wastes that may harm human health and the environment. EPA's apparent plan is to classify as hazardous substances wastes that pose a *theoretical,* rather than actual or probable, threat to human health or the environment.[121] Certain of the proposed tests to determine whether a waste is hazardous, the toxicity protocol is a prime example, would measure risks in an imaginary disposal environment disregarding the probability of harm.[122] By expanding the definition of hazardous wastes, EPA increases the number of wastes controlled under Subtitle C, and, in turn, subjects thousands of additional generators, transporters, and disposers to Subtitle C burdens regardless of the actual risk

120. 44 Fed. Reg. 34244 (June 14, 1979).

121. Congressional intent to regulate only those wastes posing an actual or probable threat to health or the environment is evidenced by the statutory definition of hazardous waste: a substance that may "(A) cause or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or (B) pose a substantial present or potential hazard to human health or the environment *when improperly treated, stored, transported, or disposed of, or otherwise managed."* 42 U.S.C. § 6903(5) (1976) (emphasis added). This conclusion is buttressed by the legislative history of RCRA, including testimony by EPA itself. *See, e.g.,* HOUSE COMM. ON INTERSTATE AND FOREIGN COMMERCE, RESOURCE CONSERVATION AND RECOVERY ACT OF 1976, H.R. REP. No. 94-1491, 94th Cong., 2d Sess. 6, *reprinted in* [1976] U.S. CODE CONG. & AD. NEWS 6238, 6238-39; *The Need for a National Materials Policy: Hearings Before the Panel on Materials Policy of the Subcomm. on Environmental Pollution of the Senate Comm. on Public Works,* 93d Cong., 2d Sess. 1141 (1974) (statement of John Quarles, EPA Deputy Adm'r); *Hearings on H.R. 13176 Before the House Subcomm. on Public Health and Environment of the House Comm. on Interstate and Foreign Commerce,* 93d Cong., 2d Sess. 156 (1974) (statement of Russell Train, EPA Adm'r).

122. EPA's own background studies condemn its proposed approach because standardized leaching tests are suitable only for an initial screening function. Any definitive determination of hazardousness can be made only after an evaluation of the individual waste's particular disposal environment and exposure pathways. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, BACKGROUND STUDY ON THE DEVELOPMENT OF A STANDARD LEACHING TEST 127 (1979) (EPA-600/2-79-109); UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, COMPARISON OF THREE WASTE LEACHING TESTS 20 (1979) (EPA-600/2-79-071). *See generally* UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, COMPILATION AND EVALUATION OF LEACHING TEST METHODS (1978) (EPA-600/2-78-095).

posed by a particular waste.[123]

It is yet unclear which by-products of coal combustion will be deemed hazardous. Indeed, various elements of coal combustion residue may fall in each category, and residue will certainly vary in its composition depending on the characteristics of the coal being burned. In any event, it is necessary to examine each management scheme to determine how RCRA will affect the solid waste management practices of coal-fired generating plants.

B. *Nonhazardous Wastes*

Nonhazardous wastes will be subject to state-regulated solid waste management plans that must incorporate the EPA-issued guidelines if a state is to receive federal aid. Any approved state plan must ban open dumping.[124]

Rather than defining open dumping directly, EPA has established criteria for classifying solid waste disposal facilities and practices.[125] If a facility complies with these criteria, it is a sanitary landfill; if not, it is an open dump.[126] To qualify as a sanitary landfill, the facility must be shown to meet criteria established in the following areas:[127] (1) floodplains; (2) endangered species; (3) surface water; (4) groundwater; (5) application of solid waste to land used for food-chain crop production; (6) disease; (7) air; and (8) safety.

EPA broadly defines "facility" to include "any land and appurtenances thereto used for the disposal of solid wastes."[128] The Agency specifically rejected suggestions that utility waste disposal facilities be exempted from coverage.[129] Accordingly, states with EPA-approved solid waste management plans must ensure that utilities' nonhazardous waste disposal sites meet these criteria, or the sites will be considered open dumps to be closed or upgraded.

EPA's decision to rely on performance standards rather than detailed design and operating requirements may be both a benefit and a problem for utilities. Although the performance standards are

123. EPA estimates that 270,000 waste generating facilities and 10,000 transporters will be regulated under the Subtitle C program. Of that number, 30,000 will have to obtain a permit as an owner or operator of a treatment, storage, or disposal facility. 43 Fed. Reg. 58946 (Dec. 18, 1978).

124. 42 U.S.C. § 6945 (1976).

125. 44 Fed. Reg. 53438 (Sept. 13, 1979).

126. *Id.* at 53461 (proposed 40 C.F.R. § 257.2).

127. *Id.* at 53461 (proposed 40 C.F.R. § 257.3).

128. *Id.* at 53461 (proposed 40 C.F.R. § 257.2).

129. *Id.* at 53440-41.

flexible for each site, a utility cannot be certain if a proposed facility will actually meet EPA standards.

The floodplain criteria have great potential impact on utilities' solid waste management practices. Because large quantities of water are needed, many powerplants are constructed near rivers and, consequently, are located within the 100-year floodplain. To minimize the transport of wastes, disposal facilities are often sited adjacent to the plants. EPA has stated, however, that it "is generally desirable to locate disposal facilities outside of floodplains,"[130] and that facilities or practices in floodplains must not: (1) restrict the flow of the base flood; (2) reduce the temporary water storage capacity of the floodplain; or (3) permit a washout of solid waste.[131] Although less stringent than the originally proposed criteria, these may be very costly for a utility that must demonstrate (with sophisticated engineering and hydrological analysis) that each facility proposed in the 100-year floodplain will not pose a hazard to human life, wildlife, or land or water resources.

If a utility, in order to meet the floodplain criteria, is forced to locate its disposal site away from the generating facility, it would be required to transport the waste from point of generation to point of disposal. A conveyor system is one possibility; a four-mile conveyor system for a 500 MW plant would add $2.5 million in capital costs and $250,000 in annual operating costs.[132] A rail line in excess of five miles would add capital costs of $300,000 per mile and annual operating costs of $175,000 for a 500 MW plant.[133]

The criteria for groundwater protection set forth in the new rules will also be troublesome. EPA has selected the National Interim Primary Drinking Water Standards as maximum contaminant levels for groundwater, and has designated the solid waste boundary as the site for monitoring compliance with these standards.[134] Since RCRA requires that EPA integrate and coordinate RCRA regulations with other federal environmental statutes,[135] including the

130. *See id.* at 53442.

131. *Id.* at 53461 (proposed 40 C.F.R. § 257.3-1(a)).

132. Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations 22-23, *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Rules Under Sections 3001, 3002, 3003 and 3004 of the Resource Conservation and Recovery Act of 1976 (Mar. 16, 1979) [hereinafter cited as Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations].

133. Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at 22-23.

134. 44 Fed. Reg. 53462 (Sept. 13, 1979) (proposed 40 C.F.R. § 257.3-4(c)(2), (c)(5)).

135. *See* 42 U.S.C. § 6905 (1976).

Safe Drinking Water Act, the Agency's decision to apply the primary drinking water standards is probably defensible. Its choice of a monitoring location is more problematic. Its stated reasons for selecting the solid waste boundary as the monitoring location have surface appeal: (1) monitoring under the solid waste facility itself risks creating a direct conduit for leachate from the solid waste into the aquifer; and (2) monitoring at the property boundary would risk delaying detection of groundwater contamination until after the damage is done, and such a distance would also risk contamination of future drinking water sources between the solid waste facility and the property boundary.[136] Selection of the solid waste boundary, however, fails to take into account attenuation or dilution of leachate which inevitably will occur between the solid waste facility and the affected groundwater, or within the groundwater itself. The effect of this failure could, unless the rule is changed, be to classify as open dumps many facilities that have no environmental impact on aquifers but which, because of their locations, would either have to be closed or upgraded at significant expense.

C. *Hazardous Wastes*

Any utility waste classified as hazardous will be subject to hazardous waste regulations under Subtitle C. As presently proposed, high-volume utility waste—ash, slag, and sludge—would be deemed "special" waste subject to only some of the Subtitle C requirements. Should these requirements be applied in full, however, they would significantly affect the siting and design of powerplants and waste disposal facilities, utility waste management practices, and capital and operating costs. Application only of the "special" waste proposal would somewhat soften the regulatory impacts, but would by no means eliminate them.

Under EPA's scheme, the manner in which a generator is regulated depends on where it sends its waste: to an on-site or off-site, in-state or out-of-state, owned or not-owned disposal facility.[137] In general, off-site facilities not owned by the generator and out-of-state facilities owned by the generator are subject to more stringent regulation. EPA has defined "on-site" to mean "on the same or geographically contiguous property."[138] Utility disposal sites may be

136. *See* 44 Fed. Reg. 53448 (Sept. 13, 1979).

137. 43 Fed. Reg. 58975 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.20(c)(1)).

138. *Id.* at 58976 (proposed 40 C.F.R. § 250.21(b)(18)). Two pieces of property that are

located away from the powerplant, because disposal activities are not compatible with land use close to the plant. Furthermore, RCRA's own proposed Subtitle C siting restrictions, especially those for wetlands and floodplains, may cause more utility disposal facilities to locate off-site. To the extent that off-site disposal is required by final Subtitle C regulations, burdens on utilities will increase.[139]

The manifest requirement imposed on generators applies only for an off-site facility. A manifest, including information such as the quantity of each hazardous waste being transported, must accompany each shipment[140] creating a significant administrative and paperwork burden. It has been estimated that this requirement would increase annual operating costs at a typical 515 MW powerplant by $241,000.[141] Given the homogenous nature of high-volume utility wastes and their acknowledged lack of hazardousness, the manifest requirement seems a needless—and expensive—exercise.

Proposed section 3002 regulations would permit generators to hold hazardous wastes on-site for up to 90 days without regulation as a treatment, storage, and disposal facility under section 3004. However, if the waste is held for a longer period, all requirements for a treatment, storage, and disposal facility, including the permit requirement, would apply.[142] Utilities frequently store waste materials more than 90 days; economy, weather, and availability of transportation, as well as plans for reuse, determine how long wastes are kept on-site. Requiring utilities to obtain a permit and meet the management standards for hazardous waste TSDFs would add significant cost to the disposal process.

Another troubling possibility raised in the preamble to the proposed section 3002 regulations is that EPA will hold a generator liable for the entire transportation, treatment, and disposal process even if the generator subcontracts these activities.[143] Apart from

geographically contiguous and divided by a right of way are considered a single site. *Id.* at 58976.

139. *See generally* Radian Corp., Study of Non-Hazardous Wastes from Coal-Fired Electric Utilities (Dec. 15, 1978). Nearly 93 percent of all bottom ash and fly ash generated by the 54 coal-fired plants being studied were disposed of within five miles of the plant where generated. *Id.* at 114-15. The cost of transporting the massive volumes of utility waste makes it imperative that disposal facilities be located as close as possible to powerplants. See notes 132, 133 *supra* and accompanying text.

140. 43 Fed. Reg. 58977 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.22).

141. Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at 27-29.

142. 43 Fed. Reg. 58976 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.20(c)(2)).

143. *See id.* at 58971, 58975.

legal difficulties, this approach could discourage generators from contracting with third parties who intend to reuse the hazardous waste, and could impede development of a responsible service industry to manage hazardous wastes. In addition, this far-ranging liability will increase utilities' insurance costs.

If utility wastes are deemed hazardous, transporters of these wastes will also be subject to Subtitle C regulation. Proposed section 3003 regulations discuss procedures for recordkeeping, transporting hazardous waste, complying with the manifest system, delivering the hazardous waste to a designated facility, spills, and placarding/marking of vehicles.[144]

In addition, the Hazardous Materials Transportation Act authorizes the Department of Transportation (DOT) to regulate the transportation of hazardous wastes.[145] Although the efforts of EPA and DOT are intended to be compatible and not duplicative,[146] transporters may find themselves subject to both regulatory schemes and enforcement actions by two agencies—a potentially confusing situation. Because EPA will probably modify its transporter regulations to reflect the DOT Hazardous Materials Regulations,[147] one of DOT's proposed requirements—a prohibition on the use of open-top vehicles for transporting hazardous wastes—warrants comment here.[148] Open trucks are often used to transport utility ash and sludge; a flat prohibition would require the acquisition of fleets of tank trucks or other enclosed vehicles at enormous expense.

The last group of hazardous waste regulations, under section 3004 of the statute, will govern the activities of owners or operators of hazardous waste treatment, storage, and disposal facilities (TSDFs). In addition to specific operational requirements, proposed section 3004 regulations include overriding human health and environmental performance standards[149] that would allow an EPA or state permit issuer to establish more stringent design and operating criteria if it believed the stated requirement would not adequately protect human health and the environment.[150] Although EPA em-

144. 43 Fed. Reg. 18506 (Apr. 28, 1978).
145. 49 U.S.C. § 1804 (1976).
146. 43 Fed. Reg. 18507-08 (Apr. 28, 1978).
147. *Id.* at 18506.
148. 43 Fed. Reg. 22633-34 (May 25, 1978) (proposed 49 C.F.R. § 173.510(a)(5)).
149. 43 Fed. Reg. 58999 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.42).
150. *Id.* at 58983.

phasizes that these standards are only for unusual situations,[151] their existence makes any analysis of RCRA's impact on utility solid waste management practices uncertain; even if the regulatory design and operating standards are met, a utility may have to satisfy more onerous criteria at greater cost.

The general facility standards—the operational requirements—will regulate site selection, security, contingency and emergency planning, personnel training, manifest and records systems, visual inspections, closure and postclosure procedures, and financial requirements for owners/operators.[152] Each requirement will affect current solid waste management practices and increase capital and operating costs.[153]

Of the general facility standards, the site selection criteria and the groundwater monitoring requirements are most problematic. The proposed regulations would affect disposal facilities located in an active fault zone, a 500-year floodplain, a recharge zone of a sole source aquifer, and a wetland.[154] If EPA's sweeping definitions of floodplain and wetlands remain part of the final regulations, massive dislocations of waste disposal facilities may occur.[155] The Edison Electric Institute has estimated that (1) nearly one-quarter of existing coal-fired powerplants are located in a 500-year floodplain, (2) 14 percent are located in wetlands, and (3) an additional 13

151. *Id.* at 58983.

152. *Id.* at 58999-59007 (proposed 40 C.F.R. § 250.43).

153. For example, the proposed section 250.43-2(a) requirement that a six-foot fence surround the entire solid waste facility would increase capital costs by an average of $82,000 and operating costs by $91,100 annually. Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at 25-27; *see* 43 Fed. Reg. 58999-59007 (Dec. 18, 1978). Since the proposed section requires controlled access to facilities, payroll accounts for 24 hour security guards constitute the majority of the annual operating cost. *See* Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at 25-27. The leachate monitoring requirement of proposed section 250.43-8 would increase capital costs by $10,000-$20,000 depending on the site's natural geological conditions. Envirosphere Co., Economic Impact of RCRA Subtitle C Requirements in the Absence of Special "Utility Waste" Provisions 22-23, *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Rules Under Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976 (Mar. 16, 1979); *see* 43 Fed. Reg. 58999-59007 (Dec. 18, 1978). Annual operating costs after the first year would be $6,000-$10,000 and would continue for the life of the plant and through the 20-year post-closure period. Envirosphere Co., Economic Impact of RCRA Subtitle C Requirements in the Absence of Special "Utility Waste" Provisions 22-23 (1979), *reprinted in* Edison Elec. Inst. Utility Solid Waste Activities Group, Comments on Proposed Rules Under Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976 (Mar. 16, 1979).

154. 43 Fed. Reg. 59000 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.43-1).

155. See notes 147, 148 *supra* and accompanying text.

percent of these plants are located in both a wetlands and floodplain.[156] Recharge areas for sole source aquifers probably include large areas of the country; requiring impervious liners for disposal facilities in these areas would be exorbitantly expensive, particularly where natural clay is not locally available.

The proposed regulations would require the owner/operator of either a landfill or surface impoundment to operate a groundwater monitoring system[157] and, in addition, to detail the number, design, and location of the monitoring wells.[158] It is estimated these regulations would result in a capital cost of $66,000 per site and annual operating costs of $9,100.[159]

The proposed regulations covering treatment and disposal require that (1) surface impoundments be designed, located, constructed, and operated to prevent both direct contact with navigable water[160] and discharges into groundwater or navigable water,[161] and that (2) surface impoundment dikes must prevent discharge of waste in either a horizontal or vertical direction.[162] Together these requirements mandate total containment of wastes within the impoundment. In addition to the uncertain technical feasibility of ensuring zero discharge, this requirement will impose huge costs; depending on the site's geologic conditions, between $31 million and $55 million[163] for a surface impoundment for a *single* 500 MW powerplant generating 31,000 tons of bottom ash per year and 105,000 tons of fly ash per year.

Finally, RCRA regulations will affect the reuse of utility by-products. Congress clearly favors resource recovery and reuse,[164] and

156. Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Rules Under Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976, at 197 (Mar. 16, 1979).

157. 43 Fed. Reg. 59005 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.43-8).

158. *Id.* at 59005 (proposed 40 C.F.R. § 250.43-8(a)).

159. Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at 30-32.

160. 43 Fed. Reg. 59011 (Dec. 18, 1978) (proposed 40 C.F.R. § 250.45-3(a)(1)).

161. *Id.* at 59011-12 (proposed 40 C.F.R. § 250.45-3(c)(1)).

162. *Id.* at 59012 (proposed 40 C.F.R. § 250.45-3(c)(8)).

163. Envirosphere Co., Economic Impact of RCRA Subtitle C Requirements in the Absence of Special "Utility Waste" Provisions 19-20 (1979), *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Rules Under Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976 (Mar. 16, 1979).

164. 42 U.S.C. § 6902(7) (1976). Both the Department of Interior's Bureau of Mines and the Department of Transportation's Federal Highway Administration testified to the reuse potential of large volume electric utility by-products. *The Need for a National Materials Policy: Hearings on S. 3560 Before the Panel on Materials Policy of the Subcomm. on Envi-*

the value of utility by-products, particularly powerplant ash and slag, is uncontested. In 1978, nearly 25 percent of fly ash, bottom ash, and boiler slag produced was reused[165] in such applications as a raw material in cement, brick and block construction, highway construction, and land reclamation.[166] Scrubber sludge, although a newer product, can be used in gypsum wallboard, cement, highway construction, and for land recovery.[167] If these materials come in contact with the environment, however, EPA proposes to regulate them as hazardous wastes. Such an approach is likely to end the reuse of those by-products classified as hazardous, thereby turning an asset into a problem. First, labelling a material as hazardous will discourage most people from using it, regardless of how low the resultant level of risk. Second, the management requirements may interfere with established commercial practice for using the by-product. Finally, reuses of utility by-products are marginally economical and must be offered in highly competitive markets; imposing a substantial layer of regulatory control will certainly send re-users elsewhere.

D. Special Wastes

Special wastes, including high-volume utility waste deemed hazardous, will be subject only to some portions of the full hazardous waste regulations. As presently proposed, the principal impacts of the special waste rules will be on site selection, groundwater monitoring, and utility by-product reuse. Preliminary calculations of these impacts show that capital and operating costs for *existing and planned* powerplants would increase by:

—$1 billion, if the special wastes standards are imposed for three years;

—$1.7 billion, if imposed for five years;

—$20.3 billion, if imposed through the year 2000.[168]

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ronmental Pollution of the Senate Comm. on Public Works, 93d Cong., 2d Sess. 1152-54, 1303-75 (1974).

165. Figures compiled by the National Ash Association and the Edison Electric Institute.

166. For an in-depth discussion of the potential reuses of utility by-products, see Envirosphere Co., Report on Utility Solid Wastes as a Resource for Recovery and Utilization (1979), *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976 at 1-89 (Mar. 16, 1979).

167. *Id.* at 94-103.

168. These conclusions are drawn from reports prepared for the Utility Solid Waste Activities Group of the Edison Electric Institute. *See* Envirosphere Co., Critique of the Draft

A 1979 Department of Energy interim report suggests how great RCRA's impact will be and how important the determination of a hazardous or nonhazardous classification will be for utility wastes.[169] DOE's consultant has estimated that if nonhazardous waste regulations are applied to utility waste, the utility industry's current disposal costs of $3.56 per ton would rise to $19.45 per ton.[170] But if utility wastes are classified as hazardous, disposal costs would skyrocket to $56.48 per ton.[171] It is the consumer who must ultimately bear, through higher utility bills, whatever cost increases result from RCRA.

E. *Summary*

The Resource Conservation and Recovery Act will have important ramifications for utility waste management practices. Because states retain ultimate authority for regulating nonhazardous wastes, the impact of RCRA in this context will vary widely. If federal guidelines for acceptable landfill practices are satisfied, the costs of managing these nonhazardous wastes will increase greatly. Hazardous and special waste provisions will make the siting of utility waste disposal facilities much more difficult. Utilities will have to sacrifice otherwise prime sites or incur the additional costs of operating an off-site disposal facility. The detailed requirements that apply to generators, transporters, and TSDF owner/operators will affect the way utilities handle, store, ship, and treat coal by-products. This means an operational impact requiring changes in management practices, additional paperwork, and an increase in waste management costs. Finally, the regulations will reduce the reuse potential of coal by-products.

IV. CLEAN WATER ACT

The impact of the Clean Water Act is more limited, in a sense, than either the Clean Air Act or RCRA, which with their imple-

Economic Impact Analysis on Subtitle C of the Resource Conservation and Recovery Act of 1976 (1979), *reprinted in* Edison Elec. Inst., Utility Solid Waste Activities Group, Comments on Proposed Sections 3001, 3002, 3003, and 3004 of the Resource Conservation and Recovery Act of 1976 Appendix 6, 9-16 (Mar. 16, 1979); Gilbert/Commonwealth, Economic Impact of Interim RCRA Regulations, *supra* note 132, at Appendix 3, 37-38.

169. UNITED STATES DEP'T OF ENERGY, EVALUATION OF THE IMPACTS OF THE PROPOSED REGULATIONS TO IMPLEMENT THE RESOURCE CONSERVATION AND RECOVERY ACT ON COAL-FIRED ELECTRIC GENERATING FACILITIES, INTERIM REPORT II-3 (1979).

170. *Id.* at VI-5 to -8.

171. *Id.* at VI-5 to -8.

menting regulations pose severe constraints on the siting of coal-fired generating plants. Those constraints are beyond the control of the party wishing to construct a powerplant. For example, if the air pollution in a PSD area is at maximum levels allowable because of other industry, the powerplant cannot be built even if its own emissions are strictly controlled. Similarly, in a nonattainment area, the party proposing new construction must obtain offsets from existing sources. Under RCRA, it will be impossible, or prohibitively expensive, to locate a waste treatment facility in certain terrain. Of course, both statutes will also affect a powerplant's operational procedures, as well as increasing capital and operating expenses.

The Clean Water Act does not pose the same kind of siting problems; its requirements are not likely to prevent the construction of a powerplant on a particular site. Utilities can satisfy the Act's effluent limitations and water quality standards by adjusting plant operations and constructing water pollution control facilities, although at significant additional costs.

It is useful to understand the effect of coal as a powerplant fuel on the quality of surface waters. The major environmental impacts are thermal discharges and consumption of water in the combustion process, and the subsequent release of chemical effluents. These effects can be traced to a steam-electric generating plant's dissipation of approximately 60 percent of the heat produced by coal combustion.[172] This waste heat is dissipated through the condensor cooling system, requiring large volumes of water. It is for this reason that powerplants are usually located on or near a water body.

There are two types of condensor cooling systems: open- and closed-cycle. In an open-cycle system, water is withdrawn from a natural water body, absorbs excess process heat, and is discharged back into the natural body. The return water, of course, reenters at a much higher temperature; its heat is diffused through both flow and current movements and surface heat transfer. In a closed-cycle system, instead of discharging cooling water into a natural water body, heat is extracted from cooling water that is then recirculated within the plant. Heat is removed by cooling towers, evaporative

172. The laws of thermodynamics place inherent limitations on the efficiency of the steam-electric cycle; only 32-40 percent of the heat extracted from the combustion of the fuel can be converted into electricity. *Implementation of the Federal Water Pollution Control Act: Hearings Before the Subcomm. on Investigations and Review of the Senate Comm. on Public Works and Transportation*, 95th Cong., 1st Sess. 93 (1977) [hereinafter cited as *Implementation of FWPCA*].

spray systems, or cooling ponds or lakes. This process avoids the thermal discharge problem but creates two others: (1) the evaporative systems require massive amounts of water, and (2) the recirculating water must constantly be replaced with fresh water because the process continually increases its mineral content. The replaced water, called blowdown, is high in mineral content and is discharged into surface waters.

These activities may affect the environment in these ways:

1. Entrainment—Aquatic organisms and fish eggs contained in the cooling water are destroyed;
2. Impingement—Fish and shellfish may be killed on the cooling water intake screens;
3. Flow modifications—The reduced flow affects the stream's ability to dilute downstream discharges, and water-dependent ecosystems may be degraded;
4. Thermal discharges—The discharge of heat alters species behavior and composition;
5. Chemical discharges—Such effluents may kill or alter reproductive functions;
6. Stratification changes—Eutrophication may result and eliminate species' habitats.[173]

The Clean Water Act seeks to prevent these effects.

A. Statutory and Regulatory Framework

Before 1972, the federal government's effort to protect water quality was limited to two statutes: the Rivers and Harbors Act of 1899[174] and the Federal Water Pollution Control Act of 1948.[175] The former prevented the discharge of refuse into the nation's navigable waters; the latter established water quality standards designed to maintain the quality of a stream for its designated use. In 1972, the Federal Water Pollution Control Act[176] established a new regulatory scheme that used effluent limitations to establish maximum discharge levels that could be made more stringent through the use of water quality standards.[177] Congress sought a level of water quality

173. *Implementation of FWPCA, supra* note 172, at 429; *see* OFFICE OF TECHNOLOGY ASSESSMENT, UNITED STATES CONGRESS, THE DIRECT USE OF COAL 237-40 (1979).

174. Ch. 425, 30 Stat. 1151 (current version at 33 U.S.C. §§ 401-467e (1976)).

175. Pub. L. No. 80-845, 62 Stat. 1155 (current version at 33 U.S.C. §§ 1251-1376 (1976)).

176. Pub. L. No. 92-500, 86 Stat. 816 (1972), 33 U.S.C. §§ 1251-1376 (1976).

177. Federal Water Pollution Control Act, 33 U.S.C. §§ 1311, 1313 (1976).

that, by mid-1983, would have protected fish, shellfish, and wildlife and provided for recreation.[178] By 1985, there was to be no discharge of pollutants into navigable waters.[179] To enforce this prohibition, section 402 established the National Pollutant Discharge Elimination System (NPDES), authorizing EPA, or a state with an approved program, to issue discharge permits for industrial and municipal polluters.[180] The permit conditions were to require discharges to meet effluent limitations established under section 301(b).

The effluent limitations were to be based on two levels of effluent reduction. By July 1, 1977, industrial dischargers were to have employed the "best practicable control technology currently available" (BPT).[181] By July 1, 1983, industrial dischargers were to meet effluent limitations by applying the "best available technology economically achievable" (BAT).[182] The Act also outlined the factors for EPA to consider in determining BPT or BAT. For BPT-based effluent limitations, the Act specified a cost/benefit analysis;[183] for BAT limitations, however, the Act did not require a cost-benefit analysis;[184] therefore, BAT limitations are potentially more stringent.

The 1972 Act also created the National Commission on Water Quality and authorized a study of the impact of achieving or not achieving the 1983 no discharge objective.[185] The Senate Committee on Environment and Public Works, on the basis of the Commission's report and its own hearings, found that although there was no need for a change in the basic structure of the 1972 Act,[186] the Act's implementation had been "uneven, often contrary to congressional intent, and, frequently more the result of judicial order than administrative initiative."[187] Therefore, the Committee recommended amendments that would serve as a mid-course correction without abandoning the 1972 Act's overall thrust and objectives.

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178. *Id.* § 1251(a)(2).
179. *Id.* § 1251(a)(1).
180. *Id.* § 1342.
181. *Id.* § 1311(b)(1)(A).
182. *Id.* § 1311(b)(2)(A).
183. *Id.* § 1314(b)(1)(B).
184. *Id.* § 1314(b)(2)(B).
185. *Id.* § 1325.
186. SENATE COMM. ON ENVIRONMENT AND PUBLIC WORKS, CLEAN WATER ACT OF 1977, S. REP. No. 95-370, 95th Cong., 1st Sess. 2, *reprinted in* [1977] U. S. CODE CONG. & AD. NEWS 4326, 4328.
187. *Id.* at 1, *reprinted in* [1977] U.S. CODE CONG. & AD. NEWS 4326, 4327.

The 1977 amendments[188] provided for limited exceptions to the 1977 BPT deadline for both industrial[189] and municipal[190] dischargers. More significantly, it extended the 1983 BAT deadline. Both the date for compliance, and the level of pollution control technology on which effluent limitations will be based, depend on the category of pollutant involved. For conventional pollutants, industrial dischargers will have to meet a new standard by July 1, 1984: application of "best conventional pollutant control technology" (BCT).[191] This limitation should fall between the previously established BPT and previously required BAT-based limitations.[192] For currently listed toxic pollutants, the BAT deadline is now July 1, 1984.[193] Industry will be given three years to comply with effluent limitations for toxic pollutants listed in the future.[194] Finally, for nonconventional pollutants, those pollutants not identified as either toxic or conventional, a BAT-based effluent limitation must be met within three years of its establishment, but not later than July 1, 1987.[195]

Nonconventional pollutants are a new category, and it is not clear what is included. By a process of elimination, thermal discharges and all nonsewage pollutants that are not defined as toxic may be considered nonconventional. The BAT limitations may be waived only for nonconventional pollutants. A discharger of a nonconventional pollutant will be allowed to meet BPT rather than BAT requirements if he shows that the modification (1) will not place an additional burden on another discharger; (2) will not impair water quality; and (3) will not create an unacceptable risk to human health or the environment.[196] Thermal discharge waivers are allowed but on a slightly different basis.[197]

The Act is now known as the Clean Water Act and consists of five titles, two of which are of particular interest: title III, dealing with

188. Clean Water Act of 1977, Pub. L. No. 95-217, 91 Stat. 1566 (amending chapter 26 of 33 U.S.C. (1976)).

189. *See* 33 U.S.C. § 1319(a)(5)(B) (Supp. I 1977).

190. *Id.* § 1311(i)(1).

191. *Id.* § 1311(b)(2)(E).

192. *See* Recent Development, *Highlights of the Clean Water Act of 1977*, 8 ENV. L. 869, 874-75 (1978).

193. 33 U.S.C. § 1311(b)(2)(C) (Supp. I 1977).

194. *Id.* § 1311(b)(2)(D).

195. *Id.* § 1311(b)(2)(F).

196. *Id.* § 1311(g)(1).

197. *Id.* § 1326(a) (1976).

standards and enforcement,[198] and title IV, providing for a permit system.[199] The provisions that will be addressed in detail here are effluent limitations, water quality standards, thermal discharges, new source performance standards, and the NPDES.

B. *Effluent Limitations and Water Quality Standards*

Effluent limitations are the primary means for protecting water quality. Established by EPA, they limit "quantities, rates, and concentrations of chemical, physical, biological, and other constituents which are discharged from point sources into navigable waters."[200] An electric powerplant is one example of a point source, and regulations establishing effluent limitations for steam-electric power generating units have been issued.[201] The limitations, expressed as the amount of a substance that may be discharged per volume of waste flow, are based on the level of technology specified by the Act, best practicable control technology currently available (BPT), best conventional pollution control technology (BCT), or best available technology economically achievable (BAT). BPT was to be applied by all point sources by July 1, 1977.[202] Conventional pollutants must meet BCT by mid-1984.[203] The stricter effluent limitations represented by BAT will be mandated by mid-1984 for toxic pollutants with possible extensions until 1987.[204] The Act sets out in some detail what EPA must consider in setting effluent limitations for each standard, for example, the age of equipment and facilities involved, the process employed, control techniques, engineering aspects, and nonwater quality environmental impact, including energy requirements.[205] For BPT, EPA must also consider the cost of the control technology compared to its effluent reduction benefits, which means this is a generally less restrictive standard.[206]

Current effluent limitations for steam-electric power generating units cover pollutants such as pH factor, PCBs, oil and grease, copper, iron, chlorine, zinc, and chromium.[207] These wastes are car-

198. *Id.* §§ 1311-1328 (1976 & Supp. I 1977).
199. *Id.* §§ 1341-1345.
200. *Id.* § 1362(11) (1976).
201. *See* 40 C.F.R. Part 423 (1979).
202. 33 U.S.C. § 1311(b)(1)(A) (1976).
203. 33 U.S.C. § 1311(b)(2)(E) (Supp. I 1977).
204. *Id.* § 1311(b)(2).
205. 33 U.S.C. § 1314(b)(1)(B), (b)(2)(B) (1976 & Supp. I 1977).
206. 33 U.S.C. § 1314(b)(1)(B) (1976).
207. 40 C.F.R. Part 423 (1979).

ried by once-through cooling water, ash transport water, metal cleaning wastes, boiler blowdown, and cooling tower blowdown. For all pollutants except corrosion-inhibiting materials, the current limitations are the same for BPT and BAT. These limitations affect nearly every powerplant and require the construction of pH control facilities and settling basins at an aggregate cost that runs into the billions. Yet, the Clean Water Act does not pose the very real siting constraints that exist under the Clean Air Act and RCRA; furthermore, effluent limitations apply uniformly throughout the country. Generally, a utility can meet the Act's requirements by constructing water pollution control facilities or by modifying operational procedures. If the BAT effluent limitations are tightened, a likely possibility, the impact could be much more severe. For example, proposed effluent limitations for chlorine pose serious operational difficulties for condensors and cooling towers which, in turn, jeopardize the reliability of the plant's power production. The proposal could cost utilities, and ultimately their customers, up to $20 billion.

Effluent limitations[208] based on BPT and BAT apply to existing sources. The dischargers subject to these regulations will usually have to modify existing plant facilities. Achieving controls through retrofitting is more expensive than achieving them through original design and construction of the plant. Accordingly, the Act authorizes EPA to establish more stringent standards for new sources. The standards for new sources are based on the "best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants."[209]

One category of sources for which the Act directs the Administrator to establish new source performance standards is steam-electric powerplants.[210] The regulations already issued, however, set effluent limitations that are no more stringent than those applicable to existing sources.[211] When EPA reviews, and in all likelihood strengthens, the new source performance standards for powerplants, the Clean Water Act's impact on utilities could be more severe.

Water quality standards can be thought of as a holdover from the

208. Determined in part, by age and condition of equipment.

209. 33 U.S.C. § 1316(a) (1976).

210. *See id.* § 1316(b)(1)(A).

211. *Compare* 40 C.F.R. § 423.15 (1979) (standards of performance for new sources) *with id.* § 423.12 (effluent limitation guidelines using BPT) *and id.* § 423.13 (effluent limitation guidelines using BAT).

days when federal efforts focused on maintaining a stream's quality for a designated use rather than regulating effluents at the point of discharge. Despite the desire to adopt an effluent regulating approach, Congress has preserved the right of states to establish water quality standards, which establish the level of effluent discharge that could be assimilated by a body of water without deterioration for a designated use.[212] State standards furnish a higher level of protection than effluent limitations which only set maximum discharge levels. States that had not adopted water quality standards by 1972 were given six additional months before EPA was authorized to act for them.[213]

A state's plan must identify those bodies of water for which enforcement of federal effluent limitations will not ensure protection of shellfish, fish, and wildlife.[214] For those waters, the state must establish total maximum daily loads for pollutants and thermal discharges that will provide the necessary level of protection.[215] It should be noted that these standards are based not on economic or technical feasibility but solely on a scientific judgment of the maximum amount of a pollutant that marine life can tolerate without suffering damage. As a result, the water quality standards could regulate powerplant discharges much more stringently than do the effluent limitations. Additionally, water quality standards may vary from state to state; thus siting constraints will vary according to the severity of standards imposed by a state.

C. *Thermal Discharges*

Along with issuing BAT effluent limitations, EPA established an effluent limitation guideline prohibiting the discharge of any heat from the main condensors of a powerplant.[216] As a result of a

212. 33 U.S.C. § 1313(a)(2) (1976).

213. *Id.* § 1313(a)(3), (b)(1).

214. *Id.* § 1313(d)(1)(B). See 40 C.F.R. Part 131 (1979) for EPA guidelines on the preparation of state water quality management plans.

215. 33 U.S.C. § 1313(d)(1)(C), (D) (1976).

216. 40 C.F.R. § 423.13(1) (1979). Existing plants need not adhere to this standard under exceptions to the general limitation which include:

1. Blowdown from recirculated cooling water systems, provided the temperature of the discharge does not exceed the lowest temperature of recirculating cooling water prior to the addition of the make-up water;
2. Where land owned before March 4, 1974, is not sufficient for mechanical draft cooling towers and no alternate recirculating cooling system is practicable; and
3. Where the FAA concludes the cooling tower plume would cause a substantial hazard

legal challenge, this limitation has been remanded for further agency action.[217] Therefore, there are currently no thermal discharge limitations. Despite uncertainty over what the regulations will include, many utilities continue to build costly cooling towers which the industry does not favor, apparently anticipating regulations similar to the ones mandated.

Cooling towers, either natural or mechanical draft, are the most commonly used evaporative closed-cycle cooling system. Natural draft cooling towers are huge concrete structures, 350-550 feet in diameter and 300-600 feet high. Mechanical draft cooling towers consist of a series of 40 by 70 foot modules, in 300-foot rows that are spaced 400-600 feet apart. In 1977 testimony before a House Subcommittee, a utility official estimated that the cost of cooling towers for new plants was $16-$21 per kilowatt (kw) capacity representing six percent of total plant cost.[218] The average capital cost of retrofitting mechanical draft cooling towers on an existing plant has been estimated at $28 per kw capacity.[219] If cooling towers are required for all new powerplants, it would mean an additional $16.3 billion in capital costs for the utilities by 1990.[220] Finally, closed-cycle cooling reduces a powerplant's efficiency and capacity in two ways: (1) more fuel must be burned to operate the cooling systems; and (2) the resultant higher back pressures reduce turbine capacity. The result is that two percent more fuel must be burned and three percent more capacity must be built to supply the same amount of electricity.[221]

When thermal effluent limitations are finally established, their impact on utilities will still be uncertain. The 1972 Act provides for an exception to any thermal standard if the discharger can show that EPA's limitation is "more stringent than necessary to assure the pro[t]ection and propagation of a balanced, indigenous popula-

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to commercial aviation and no alternate recirculating cooling system is practicable. *Id.* § 423.13(1)(1)-(6). New powerplants are subject to the same standard and can only take advantage of a narrower range of exceptions. *Id.* § 423.15(1).

217. Appalachian Power Co. v. Train, 545 F.2d 1351, 1378 (4th Cir. 1976).

218. *Implementation of FWPCA, supra* note 172, at 100.

219. *See Implementation of FWPCA, supra* note 172, at 100.

220. *See Implementation of FWPCA, supra* note 172, at 100. EPA estimated the proposed thermal discharge limitations would impose capital requirements of $23.2 billion by 1983, result in consumption of an additional 33 million tons of coal, and impose a loss of 14,700 MW of generating capacity. *Implementation of FWPCA, supra* note 172, at 118. The Agency said the actual penalties would be less due to section 1326(2).

221. *Implementation of FWPCA, supra* note 172, at 100.

tion of shellfish, fish, and wildlife."[222] EPA has established a procedure for determining alternative effluent limitations.[223] Three types of demonstrations may be required depending on the plant's location and whether it is new or existing. For an existing plant, the owner may show that the thermal discharge has caused no appreciable harm or that the requested alternate limitations will eliminate the prior harm.[224] The owner of an existing or new plant may show that despite the thermal discharge, representative important species will be protected.[225] Finally the owner may submit biological, engineering, or other data to show there will be sufficient protection of shellfish, fish, and wildlife.[226]

A 1977 Edison Electric Institute survey revealed that 67 demonstrations under the section 1326(a)[227] mechanism had cost $29,500,000,[228] and projected that future demonstrations would cost $39 million for section 1326(a) and $31.6 million for section 1326(b).[229] Since EPA expects 50 percent of all new powerplants to receive an exemption,[230] it would seem more realistic if the assumption were reversed, that is, less stringent standards unless need for greater protection is shown.

D. *Permit Programs: NPDES*

The National Pollutant Discharge Elimination System (NPDES) is the mechanism for regulating effluent limitations and water quality standards.[231] Any discharge of a pollutant into navigable waters of the United States without a NPDES permit is unlaw-

222. 33 U.S.C. § 1326(a) (1976).

223. 40 C.F.R. Part 122 (1979). These regulations were unsuccessfully challenged. *See* Appalachian Power Co. v. Train, 545 F.2d 1351, 1372 (4th Cir. 1976). However, the regulations implementing section 1326(b), BAT for cooling water intake structures, were remanded because of EPA's failure to comply with the Administrative Procedure Act. Appalachian Power Co. v. Train, 566 F.2d 451, 457 (4th Cir. 1977).

224. 40 C.F.R. § 122.9(b)(1) (1979).

225. *Id.* § 122.9(b)(2).

226. *Id.* § 122.9(b)(3).

227. 33 U.S.C. § 1326(a) (1976) (modification to thermal discharge limitations).

228. *See Implementation of FWPCA, supra* note 172, at 114.

229. *See Implementation of FWPCA,* supra note 172, at 114. *See generally* 33 U.S.C. § 1326(b) (1976).

230. *See Implementation of FWPCA, supra* note 172, at 118. The Senate Committee on Environment and Public Works expressed its disapproval with the way EPA has transformed section 1326(a) from a limited exception into a gaping loophole. SENATE COMM. ON ENVIRONMENT AND PUBLIC WORKS, CLEAN WATER ACT OF 1977, S. REP. No. 95-370, 95th Cong., 1st Sess. 7-8, *reprinted in* [1977] U.S. CODE CONG. & AD. NEWS 4326, 4333-34.

231. 33 U.S.C. § 1342 (1976 & Supp. I 1977).

ful.[232] A permit for a period of up to five years is obtained from EPA[233] or from the state if it has adopted an NPDES permit program approved by EPA.[234] In addition to limiting the amount of a pollutant that may be discharged, the permit establishes deadlines for satisfying limitations and standards, as well as interim deadlines for submitting plans, beginning construction, and the other steps in installing pollution control facilities.[235] It may also require the permit holder to install monitoring equipment, sample effluents, maintain records, and provide information to public agencies.[236] Best management practices that have been established under the Act's authority may also be imposed as a requirement for a NPDES permit.

The operation of the NPDES permit program will be affected by EPA's proposed consolidated permit procedures.[237] These proposed rules are modeled on existing NPDES procedures. However, as proposed, they make possible the consolidation of applications and processing of permits under all the following programs: NPDES permits under the Clean Water Act, permits under RCRA, underground injection control permits under the Safe Drinking Water Act, and PSD permits under the Clean Air Act.[238] While there are benefits in utilizing consolidated procedures, there are also risks of excessive delay. Further, EPA might condition the issuance of a permit under one program on compliance under another permit program. These effects would be inconsistent with both the letter and spirit of the statutes involved, and permit applicants must guard against them.

E. *Summary*

The Clean Water Act significantly affects powerplant operations and electricity generating costs. Effluent limitations and water quality standards on pollutants, including thermal discharges, necessitate construction of expensive pollution control facilities. Be-

232. 33 U.S.C. § 1311(a) (1976).

233. 40 C.F.R. §§ 124.44, 125.23 (1979).

234. *See* 40 C.F.R. Part 124, Subpart G (1979); *id.* § 125.27.

235. 40 C.F.R. Part 125, Subpart B (1979).

236. State programs are authorized under section 402(b) of the Act. *See* 33 U.S.C. § 1342(b) (1976 & Supp. I 1977). EPA has promulgated regulations establishing the elements of a state permit program required to obtain federal approval. *See* 40 C.F.R. Part 124 (1979).

237. 44 Fed. Reg. 34244, 34346, 34393 (June 14, 1979).

238. *Id.*

cause of the Act's projected zero discharge standard, costs to utilities must be weighed against benefits derived by society. In the authors' view, the Act may have adopted unnecessarily strict standards. Although on its face the Clean Water Act, unlike the Clean Air Act and RCRA, will rarely stop a powerplant from being built, it may effectively do that by making plant construction prohibitively expensive.

V. Conclusion

Some tentative answers can be offered to the questions raised in the Introduction. Considering the combined effects of these three acts, particularly the Clean Air Act and RCRA, it is clear that EPA is involved in land-use planning on a large scale. The location of major new industrial activities will depend largely on an area's air quality and the availability of suitable waste disposal sites, with varying effects in each region. Industrial development will become much less likely in or near areas with superior air quality, in areas with air quality below national standards, in floodplains and high water table areas. Yet, it is not apparent that Congress intended to implement a national land-use and economic development control program when it enacted these statutes. Congress must examine what has happened and decide whether this is a necessary or desirable result of its efforts to protect air, water, and land resources.

Even more needy of further congressional examination is the balancing of environmental and energy objectives. Clearly, these regulatory efforts are increasing the cost of electricity far beyond what we might expect from normal inflationary impacts. We question whether EPA is the proper federal entity to be weighing the costs and benefits of environmental regulations. Yet, balanced consideration of these matters is essential. The need for balance was articulately explained by Alfred Kahn, when he was a Chairman of the New York State Public Service Commission, in testimony on the implementation of federal water quality laws:

> Energy is obviously an economic good. It is costly to supply, and the more we have of it, the less we can have of other economic goods. The same is true of environmental preservation. Like all other economic goods, we cannot have unlimited quantities of environmental preservation except at unlimited costs. We can no more have an absolute prohibition of all injury to the environment than we can have unlimited consumption of bread, medical care, or travel. Each involves an economic cost, a sacrifice of alternatives.

In the case of environmental protection and cheap energy, the competition is direct. Both are important. There is no way of asserting logically that either is absolutely more important than the other.

. . . .

The only possible question for public policy, then, must be: How much pollution, or its opposite, how much environmental protection are the proper or the optimum amounts, given the fact that both of them involve economic costs and, therefore, the sacrifice of other values? Or how much energy, considering that the more we have of it, the less we can have of other things?

The only rational way of making these choices is to compare the additional cost of having more of any of these things with the additional benefits.

This means, for example, comparing the incremental costs of progressively reducing sulfur dioxide emissons with the additional benefits of doing so; or, to put it the other way, comparing the incremental costs that such pollution imposes on society with the incremental sacrifices that would be entailed in reducing that pollution—and obviously continue to incur the costs as long as the additional costs are less than the additional benefits, and ceasing to incur the additional costs or the cost of eliminating pollution at that point at which the additional costs involve greater sacrifice of other things—of health, of education, of police protection—than the benefits.[239]

An equitable balancing will occur when Congress assumes a greater role in implementation of environmental legislation. Special interest groups of every persuasion will inevitably, and appropriately, take part in any balancing process, but that process should occur in the political arena, with full participation by elected representatives, rather than in an administrative setting where the agency's very reason for existence precludes any real balancing.

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239. *Implementation of FWPCA, supra* note 172, at 10-11.