

- Doc. Ex. 6366 -

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March 9, 2018

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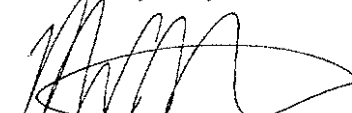
Re: Docket No. E-7, Sub 1146

Dear Ms. Jarvis:

Per the request in the rate hearing on March 5, 2018 in Docket No. E-7, Sub 1146, made by Commissioner Daniel G. Clodfelter for complete copies of documents excerpted as exhibits to pre-filed witness testimony, Sierra Club hereby submits a complete copy of the 1988 Report to Congress, Quarles Exhibit No. 3.

By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery. Please let me know if you have any questions or concerns.

Yours very truly,



Matthew D. Quinn

Attachment

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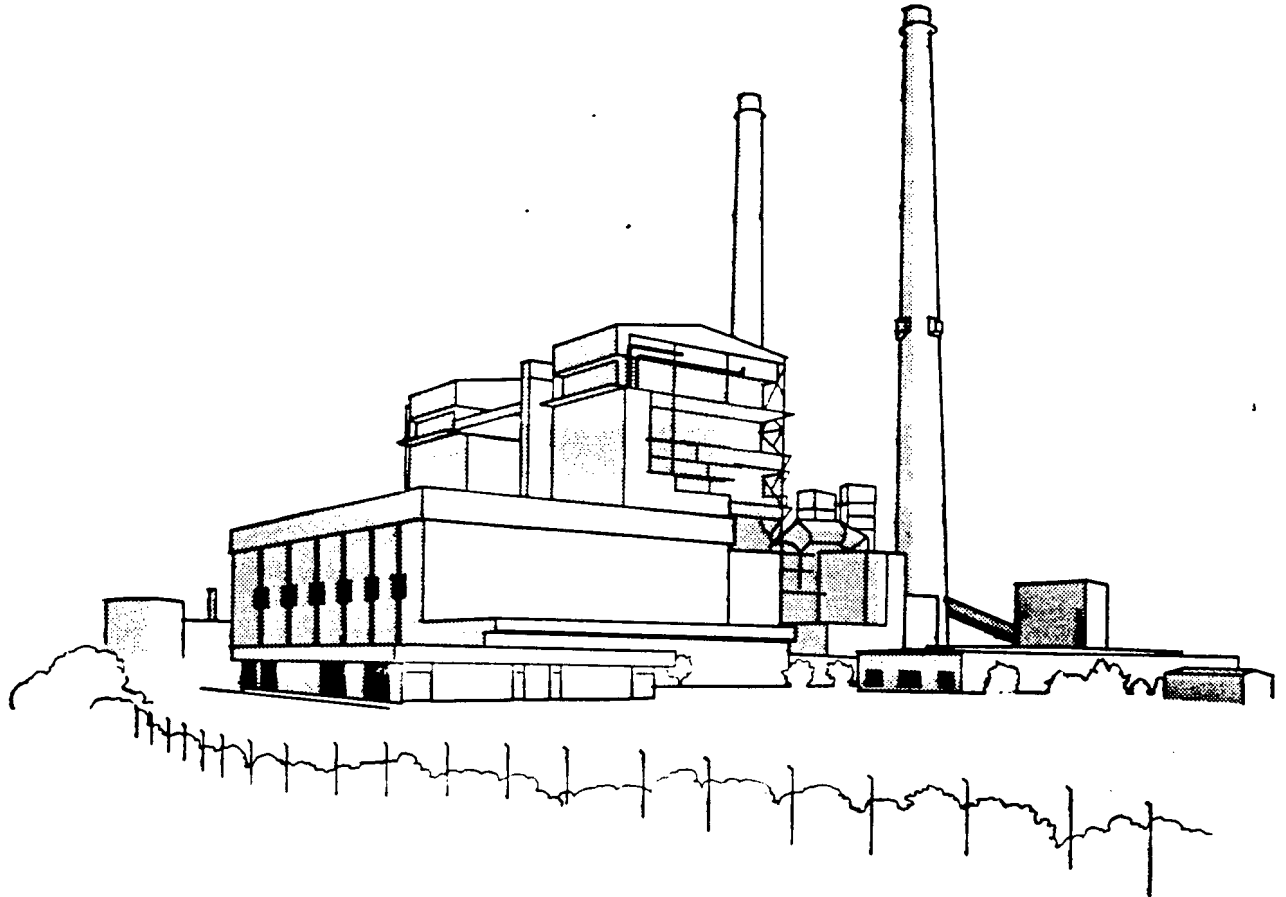
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Solid Waste



Report to Congress

Wastes from the Combustion of Coal by Electric Utility Power Plants



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- Doc. Ex. 6368 -

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable George Bush
President of the Senate
Washington, D.C. 20510

Dear Mr. President:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

A handwritten signature in black ink, appearing to read "Lee M. Thomas".

Lee M. Thomas

Enclosure

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Mar 09 2018

- Doc. Ex. 6369 -

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable James C. Wright
Speaker of the House
of Representatives
Washington, D.C. 20515

Dear Mr. Speaker:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

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Lee M. Thomas

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Mar 09 2018

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EXECUTIVE SUMMARY

The Environmental Protection Agency (EPA) has prepared this report on fossil fuel combustion wastes pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), as amended in 1980. These amendments to the Act added Section 8002(n), which directed the Administrator of EPA to

conduct a detailed and comprehensive study and submit a report on the adverse effects on human health and the environment, if any, of the disposal and utilization of fly ash waste, bottom ash waste, slag waste, flue gas emission control waste, and other by-product materials generated primarily from the combustion of coal or other fossil fuels.

Pending the completion of this study, fossil fuel combustion wastes were exempted from the hazardous waste requirements established under RCRA. Under Section 3001(b)(3)(A), EPA is prohibited from regulating these wastes until at least six months after this report is submitted to Congress.

If EPA determines that fossil fuel combustion wastes are hazardous under RCRA, and therefore subject to regulation under Subtitle C, EPA has some flexibility to promulgate regulations that take into account the unique characteristics of these wastes. Section 3004(x) states ...

If ... fly ash waste, bottom ash waste, slag waste and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels ... is subject to regulation under this subtitle, the Administrator is authorized to modify the requirements of subsections (c), (d), (e), (f), (g), (o) and (u) and section 3005(j) ... to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment.

This report examines only those wastes generated from the combustion of coal by the electric utility industry. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. EPA has deferred study of the disposal of wastes generated by the combustion of other fossil fuels and from coal combustion in industries other than the electric utility industry until a later date.

Coal-fired power plants produce substantial quantities of wastes. In 1984 about 69 million tons of ash and 16 million tons of flue gas desulfurization wastes were generated. Because of increasing reliance on coal for producing electricity, by the year 2000 the amount of ash waste is expected to increase by about 75 percent to about 120 million tons annually; production of FGD wastes is expected to triple to about 50 million tons annually.¹ In addition to the high-volume ash and flue gas desulfurization wastes, coal-fired power plants also generate several lower-volume waste streams as a result of equipment maintenance and cleaning activities.

About one-fifth of all waste generated at coal-fired electric utility power plants is currently reused; the remaining four-fifths are typically disposed in surface impoundments or landfills. The recycled wastes, usually fly ash, bottom ash, or boiler slag, have been used primarily as cement additives, high-volume road construction material, and blasting grit. There is some potential for increased use of these wastes in such applications. However, barring the

¹ It is possible that advances in coal combustion technology will alter the amount and types of coal-combustion wastes produced in the future. An analysis of these technological advances is beyond the scope of this report.

development of new utilization techniques, or major changes in combustion and environmental control technologies, the proportion of coal combustion wastes that are reused is unlikely to change significantly.

While utility waste management sites are currently exempt from RCRA hazardous waste requirements, they are subject to state and local level solid waste laws and regulations. There is substantial variation in the state-mandated disposal requirements.

Most utility waste management facilities were not designed to provide a high level of protection against leaching. Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination. Although most of the materials found in these wastes do not cause much concern (for example, over 95 percent of ash is composed of oxides of silicon, aluminum, iron, and calcium), small quantities of other constituents that could potentially damage human health and the environment may also be present. These constituents include arsenic, barium, cadmium, chromium, lead, mercury, and selenium. At certain concentrations, these elements have toxic effects.

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To assess the potential threat to health and the environment posed by these wastes and to document any specific damage cases, EPA, other agencies, and various private organizations sponsored several studies. The main research efforts cited in this Report to Congress are a 1985 study by Arthur D. Little, Inc. for EPA, which characterized the environmental effects of waste disposal at several utility disposal sites, and a series of reports submitted to the Agency in 1982 by the Utility Solid Waste Activities Group, the Edison Electric Institute, and the National Rural Electric Cooperative Association.

The findings of these various research efforts indicate that most coal combustion wastes do not exhibit any of the four hazardous characteristics defined in RCRA Subpart C. The results of a substantial number of extraction procedure tests were examined; these tests indicated that metals do not generally leach out of coal combustion wastes at levels classified as hazardous under RCRA. The only metals which were found in any ash or sludge samples at "hazardous" levels were cadmium and arsenic. For boiler cleaning wastes, chromium and lead were sometimes found at levels classified as hazardous under RCRA. This waste stream was also found to be corrosive in a number of samples. Results of EP Tests performed on co-disposed high and low volume wastes indicate, however, that boiler cleaning wastes do not exhibit hazardous characteristics when co-disposed with ash.

While most of the laboratory results indicated that coal combustion wastes do not possess RCRA hazardous characteristics, in some instances, data on actual field observations indicate that migration of potentially hazardous constituents from utility waste disposal sites has occurred. For example, observed

concentrations of contaminants found in ground water downgradient from the sites exceed the Primary Drinking Water Standards about 5 percent of the time.

Although the magnitude of the PDWS exceedances are typically not many times greater than the standard, a large number of disposal facilities report at least one PDWS exceedance at some time.

While a causal connection cannot always be made between the utility waste disposal site and the presence of contaminants at concentrations in excess of these standards, the available information indicates that some ground-water contamination from utility disposal sites is indeed occurring. The actual potential for exposure of human and ecological populations is likely to be limited, however, since ground water in the vicinity of utility waste disposal sites is not typically used for drinking water; the concentrations of contaminants in the ground water also tend to be diluted in nearby surface water bodies. These surface water bodies are typically used by electric utilities in the power plants for cooling and other purposes.

The electric utility industry currently spends about \$800 million annually to dispose of its coal-fired combustion wastes. Under current practices, costs for waste management at most basic facilities range from as little as \$2 per ton to as much as \$31 per ton. Mitigative measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up ground-water contamination. These mitigative measures, which are currently used at some utility waste disposal sites, may reduce the likelihood of ground-water contamination, but may also substantially increase disposal costs. For example,

the incremental cost of new waste disposal practices, excluding corrective action costs or higher recycling costs, could range up to \$70 per ton, or \$3.7 billion annually if all wastes were listed as hazardous. While substantial on a total cost basis, these increases would be unlikely to significantly affect the rate at which existing power plants consume coal. Due to the competitiveness of alternative fuels for electricity generation at future power plants, however, any increase in disposal costs could potentially slow the growth in electric utility coal consumption in future years. Moreover, if new disposal standards require corrective action measures as set forth in 40 CFR 264.100, the costs to utilities could be extremely high and could have a substantial effect on the utility industry.

Based on the findings from this Report to Congress, the Agency presents three preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D

authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA

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believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . .," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

CHAPTER ONE**INTRODUCTION**

This is the Environmental Protection Agency's Report to Congress on wastes from fossil fuel combustion, as required by section 8002(n) of the Resource Conservation and Recovery Act. It describes sources and quantities of utility waste, current utilization and disposal practices and alternatives to these practices, potential dangers to human health and the environment, and the costs of current and alternative waste management practices. This report is based on numerous literature reviews and contractor studies; EPA's RCRA Docket contains copies of the source materials that the Agency used in preparing this report.

1.1 Legislative History

Because Congress has amended the Resource Conservation and Recovery Act several times and EPA's regulatory program continues to evolve in response to these Congressional mandates and other additional information, a brief legislative and regulatory history is provided below.

The Resource Conservation and Recovery Act (RCRA, or the Act) of 1976 (Public Law 94-580) substantially amended the Solid Waste Disposal Act of 1965 and authorized the U.S. Environmental Protection Agency (EPA) to establish and enforce regulations concerning the identification, generation, transportation, and management of hazardous waste. These regulations would accomplish the Act's objectives of "...promote[ing] the protection of health and the environment ... and conserve[ing] valuable material and energy resources...."¹ RCRA comprises several subtitles, including Subtitle C-- Hazardous Waste

Management, and Subtitle D-- State or Regional Solid Waste Plans. The intent of the regulations promulgated under Subtitle C of the Act is that wastes identified as hazardous be properly managed from "cradle to grave," that is, from the time they are generated, during transport, throughout their use in various applications, and during disposal. As provided under RCRA Subtitle D, other wastes not considered hazardous as defined under Subtitle C are subject to State regulations.

On December 18, 1978, EPA proposed the first regulations to implement Subtitle C. In the course of preparing these regulations, EPA recognized that certain very large-volume wastes (e.g., wastes generated by utility power plants) could require special treatment:

... The Agency has very little information on the composition, characteristics, and the degree of hazard posed by these wastes, nor does the Agency yet have data on the effectiveness of current or potential waste management technologies or the technical or economic practicability of imposing the Subpart D standards [current RCRA section 3004--Standards applicable to owners and operators of hazardous waste treatment, storage, and disposal facilities] on facilities managing such waste.

The limited information the Agency does have indicates that such waste occurs in very large volumes, that the potential hazards posed by the waste are relatively low, and that the waste generally is not amenable to the control techniques developed in Subpart D.²

Thus, the Agency proposed a limited set of regulations for managing large-volume wastes, pending an additional rulemaking. Until that rulemaking was completed, EPA proposed exempting utility wastes from storage and disposal regulations.

On May 19, 1980, EPA promulgated the first regulations implementing Subtitle C of RCRA. By then, Congress was debating RCRA reauthorization, and both Houses had passed bills restricting EPA's ability to regulate utility wastes. Anticipating the enactment of legislation amending RCRA Section 3001, EPA excluded utility wastes from the promulgated regulations, writing in the preamble:

The United States Senate and House of Representatives have each recently passed a bill to reauthorize and amend RCRA (S.1156 and H.R.3994). Both bills contain amendments to Section 3001 which, if enacted, would repeal or temporarily suspend EPA's authority to regulate certain utility and energy development wastes as hazardous wastes under Subtitle C. These bills are now awaiting action by a conference committee. Because it appears likely that Congress will act before November 19, 1980 [the end of the six month comment period on the promulgated interim final regulations and the date on which they would take effect] to exempt these wastes, EPA has temporarily excluded them from this regulation (see section 261.4(b)). This exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted.³

In fact, Congress did act before November 19, 1980; the Solid Waste Disposal Act Amendments (Public Law 96-482) were passed in October 1980.

As anticipated, the amendments temporarily exempted from regulation fly ash waste, bottom ash waste, boiler slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. In section 8002(n), Congress directed EPA to produce a report on the kinds of waste generated by the combustion of coal and other fossil fuels, which would include an analysis of eight topics:

1. the source and volumes of such material generated per year;

1-4

2. present disposal and utilization practices;
3. potential danger, if any, to human health and the environment from the disposal and reuse of such material;
4. documented cases in which danger to human health or the environment from surface runoff or leachate has been proved;
5. alternatives to current disposal methods;
6. the costs of such alternatives;
7. the impact of those alternatives on the use of coal and other natural resources; and
8. the current and potential utilization of such materials.⁴

Finally, in section 3001(b)(3)(C), Congress directed that within six months after submitting this report, EPA must conduct public hearings and decide whether regulating the management of coal combustion wastes under Subtitle C is warranted. Once the decision is made, the Administrator must publish the Agency's regulatory determination in the Federal Register.

In a January 1981 letter,⁵ Gary Dietrich, then Associate Deputy Assistant Administrator for Solid Waste, provided an interpretation of RCRA regulations concerning the exemption from regulation of fossil fuel combustion waste.⁶ (This letter, as well as a February 18, 1981 memorandum that enclosed it as part of a mailing to EPA Regional Directors, is included as Appendix A.) The letter noted that the beneficial use of hazardous waste as a fuel was not subject to regulation, though it might well be subject to regulation in the future. This meant that utilities could burn as fuel a combination of

hazardous waste and coal, as long as more than 50 percent of the mixture was comprised of coal. The letter also addressed disposal, noting that wastes produced in conjunction with the burning of fossil fuels (e.g., cleaning and other maintenance-related wastes) may be exempt from Subtitle C regulations provided they are mixed and co-disposed or co-treated with fossil fuel wastes and provided "there is no evidence of any substantial environmental danger from these mixtures."⁷ The letter concluded:

...Pending the completion of [further study on the hazards posed by waste from coal-fired utility plants and the collection of relevant data from the utility industry], EPA will interpret 40 CFR 261.4(b)(4) to mean that the following solid wastes are not hazardous wastes:

- (a) Fly ash, bottom ash, boiler slag, and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, where coal makes up more than 50 percent of the mixture.
- (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, boiler cleaning solutions, boiler blowdown, demineralizer reagent, pyrites, and cooling tower blowdown.

In November 1984, Congress reauthorized RCRA by passing the Hazardous and Solid Waste Amendments (HSWA). These amendments restricted the land disposal

of certain hazardous wastes without treatment, established minimum technology requirements for landfills and surface impoundments, issued corrective action requirements for continuing releases at permitted facilities, and established interim status requirements for surface impoundments. Under this new legislation, EPA was granted some flexibility to promulgate regulations that take into consideration the unique characteristics of several types of large-volume wastes, including wastes generated by utility power plants. Specifically, if EPA determined that some or all of the wastes from fossil fuel combustion were subject to regulation under Subtitle C, EPA was empowered to modify the standards imposed by HSWA "...to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment."⁸

The HSWA Conference Report accompanying H.R. 2867 (which in its final amended form was passed by both Houses of Congress as Public Law 98-616) provides clarification:

This Amendment recognizes that even if some of the special study wastes [which include utility wastes as specified in Section 8002(n)] are determined to be hazardous it may not be necessary or appropriate because of their special characteristics and other factors, to subject such waste to the same requirements that are applicable to other hazardous wastes, and that protection of human health and the environment does not necessarily imply the uniform application of requirements developed for disposal of other hazardous wastes. The authority delegated to the Administrator under this section is both waste-specific and requirement-specific. The Administrator could also exercise the authority to modify requirements for different classes of wastes. Should these wastes become subject to the requirements of Section 3005(j), relating to the retrofit of surface impoundments, the Administrator could

modify such requirements so that they are not identical to the requirements that are applied to new surface impoundments containing such wastes. It is expected that before any of these wastes become subject to regulation under Subtitle C, the Administrator will determine whether the requirements of Section 3004(c), (d), (e), (f), (g), (o), and (u), and Section 3005(j) should be modified.⁹

1.2. Scope and Sources

This report addresses only the wastes generated by coal-fired electric utility power plants. Because this industry generates the vast majority of all fossil fuel combustion waste (nearly 90 percent),¹⁰ EPA decided to focus its study in this area. This study does not address oil- and gas-fired electric utility power plants or coal, oil and gas-fired industrial boilers.

A number of research projects were undertaken to provide data for this report. EPA sponsored a major study of current coal ash and flue gas desulfurization waste management practices at coal-fired electric utility power plants.¹¹ In this study comprehensive environmental monitoring was conducted, which included characterizing the wastes, soils, ground water, and surface water at six disposal sites. The contractor (Arthur D. Little, Inc.) evaluated the environmental effects of the disposal practices used at these six sites and, by inference, what effects may be present at other utility waste disposal sites. They also performed extensive engineering and cost evaluations of disposal practices at the six sites.

EPA also sponsored a separate study effort to develop information on the incidences of ground water contamination resulting from utility waste management practices.¹² In this study, contamination was defined as the presence of hazardous constituents at levels above primary drinking water

standards. The main source of information for this phase of the research was a review of case files at the state offices having responsibility for such matters.

In addition, the Agency also reviewed reports submitted by the Utility Solid Waste Activities Group (USWAG), the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association (NRECA).¹³ The reports present information on the sources, volumes, and physical and chemical characteristics of waste streams; ground-water monitoring results assembled from various utility plants; damage case information from various sources; costs of complying with hazardous waste regulations; and resource recovery opportunities using utility wastes.

EPA also has incorporated findings from several documents prepared by the Department of Energy (DOE) and the Electric Power Research Institute (EPRI).¹⁴ These reports examined the chemical composition of utility wastes, technologies for disposal and the costs associated with disposal, as well as results of leaching tests performed on utility wastes.

Finally, EPA gathered information from the Utility Data Institute's Power Statistics Database.¹⁵ This database contains information concerning the size of utility power plants, location of power plants, the types of disposal technologies employed by each power plant, and the amount of waste produced by site and by region. The information on location of power plants was combined with hydrogeologic, population, and ecological profiles of these locations to analyze the potential for exposure to coal combustion wastes.

1.3 Organization

The following chapters of this report address the eight issues (enumerated earlier in this chapter) as required by Section 8002(n) as they apply to coal-fired combustion wastes generated by electric utilities. Chapter Two of this report provides an overview of the U.S. electric utility industry. Chapter Three examines the amount and types of wastes that are generated. Chapter Four discusses current waste management and disposal practices used by the electric utility industry, as well as alternatives to these practices; a review of applicable State regulations is included in this chapter. Chapter Five reviews the potential and documented impact of these wastes on human health and the environment, and Chapter Six evaluates costs associated with current waste disposal practices and additional costs that could be incurred under a variety of alternative waste management practices. Finally, Chapter Seven summarizes the conclusions contained in the previous chapters and presents recommendations.

CHAPTER ONE

NOTES

- 1 Resource Conservation and Recovery Act of 1976 (RCRA), Section 1003(a).
- 2 Federal Register, Volume 43, No. 243, December 18, 1978, pp. 58991-58992.
- 3 Federal Register, Volume 45, No. 98, May 19, 1980, p. 33089.
- 4 RCRA, Section 8002(n).
- 5 Letter of January 13, 1981, from Gary N. Dietrich, Associate Deputy Assistant Administrator for Solid Waste, to Paul Elmer, Jr., Chairman of the Utility Solid Waste Activities Group.
- 6 See 40 CFR 261.4.
- 7 Gary N. Dietrich, January 13, 1981, op. cit.; for further information, see Congressional Record, February 20, 1980, p. H 1102, remarks of Congressman Bevill; also see remarks of Congressional Record, February 20, 1980, p. H 1104, remarks of Congressman Rahall.
- 8 RCRA, Section 3004(x)
- 9 H.R. Report 98-1133, pp. 93-94, October 3, 1984.
- 10 Most fossil fuel combustion wastes are generated from coal. For example, as indicated in Physical-Chemical Characteristics of Utility Solid Wastes (by Tetrattech, Inc. for EPRI, September 1983), only about one percent of utility wastes are generated from oil; the remaining 99 percent is largely attributable to coal-fired electricity production. Of the coal consumed in the U.S., electric utilities burn nearly 90 percent (excluding metallurgical coal, which is not burned but is instead converted into coke primarily for making steel).
- 11 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants. Prepared for EPA's Office of Research and Development, EPA Contract #68-02-3167; June 1985.
- 12 Franklin Associates, Ltd., Survey of Groundwater Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.
- 13 USWAG is an informal consortium of approximately 65 electric utility operating companies, EEI, and NRECA. The primary source used in the preparation of this report was Report and Technical Studies On The Disposal and Utilization of Fossil-Fuel Combustion By-Products, USWAG, EEI, and NRECA, October 26, 1982.

14 For example, see Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities; Prepared by Engineering-Science for DOE, DOE Contract Number DE-AC-01-79ET-13543, May 1983; Physical-Chemical Characteristics of Utility Solid Wastes, EPRI, September 1983; Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, Prepared by Western Research Institute, DOE Order Number DE-AP20-84LC00022, March 1984; and Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI, July 1984. More sources are included in the Bibliography.

15 Utility Data Institute's Power Statistics Database was developed under the auspices of the Edison Electric Institute to assist in their analysis of issues affecting the electric utility industry.

CHAPTER TWO
OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

This chapter provides a general overview of the U.S. electric utility industry. Section 2.1 summarizes electricity demand and discusses the overall structure of the electric utility industry. Section 2.2 focuses the discussion on the role that coal plays in generating electricity. Section 2.3 provides details of coal-fired electric generating technologies and the regional characteristics of coal-fired plants. The chapter concludes with a discussion in Section 2.4 of the waste streams that are produced during coal combustion.

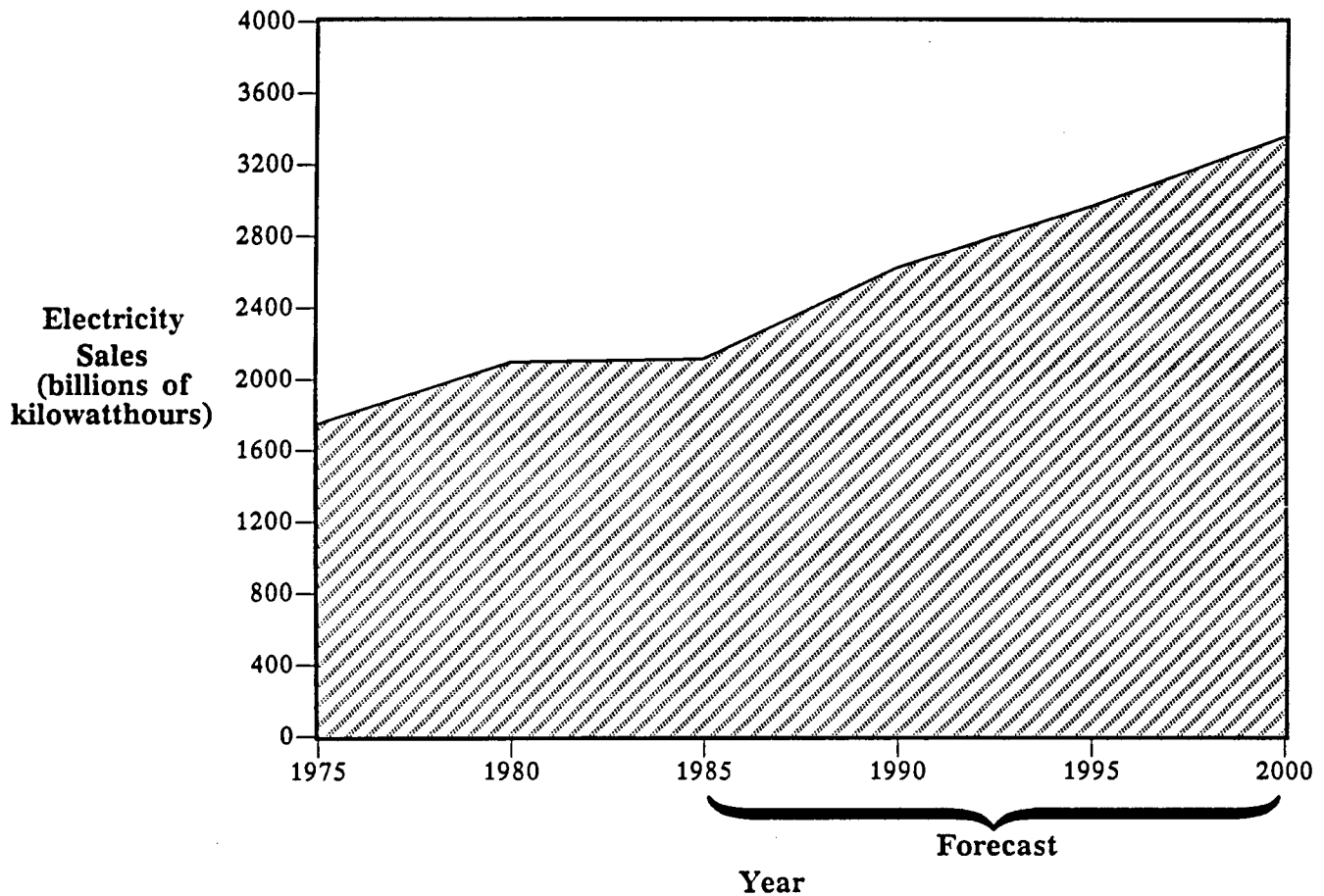
2.1 THE DEMAND FOR ELECTRICITY

The generation, transmission, and distribution of electricity is one of our nation's largest industries. With annual revenues in excess of \$140 billion and assets of about \$500 billion, the electric utility industry provides vital services to nearly every person in the U.S.¹

Total demand for electricity in the U.S. has increased substantially in recent decades and will likely continue to grow in coming years (see Exhibit 2-1). From the 1940's through the early 1970's, electricity demand grew at about 7 percent per year, doubling approximately every ten years. This growth slowed beginning with the 1973 OPEC oil embargo and subsequent changes in the energy markets such as fuel price increases, shifts in the economy to markets that require less electricity to meet their power needs, and energy conservation measures. Since 1973, growth in electricity demand has averaged

EXHIBIT 2-1

GROWTH IN ELECTRICITY DEMAND - 1975-2000



Sources: 1975-1985: Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (85/12), December 1985, p. 39.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

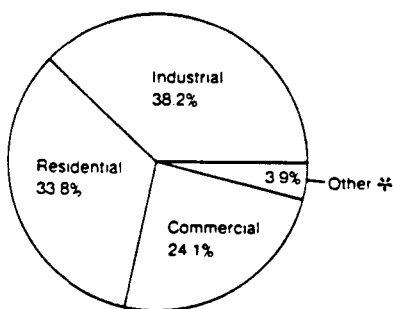
about three percent per year. Expectations are that electricity demand will continue to grow at an average rate of about 2 to 3 percent per year over the next several years.²

Every major segment of the U.S. economy relies on electricity to meet a portion of its energy needs. As shown in Exhibit 2-2, the demand for electricity is divided almost evenly between the industrial, commercial, and residential sectors. This demand for electricity has continued to increase over the last decade with total sales increasing from 1.7 million gigawatt-hours (Gwh) in 1975 to 2.3 million Gwh in 1985.³ As demand has increased, electricity sales patterns have remained relatively consistent. Industry continues to be the largest consuming sector, although industry's fraction of total sales has decreased by about 2.7 percent from 1975 to 1985, primarily due to an increased market share for the commercial sector (i.e., stores, office buildings, restaurants, etc.). Residential customers consume about one-third of all electricity for basic necessities such as lighting, heating, and electrical appliances.

Virtually every geographic area in the U.S. relies on electricity supplied by the electric utility industry. As shown in Exhibit 2-3, electricity demand is highest in the eastern half of the U.S., particularly in EPA Regions 3-6 (see Exhibit 2-4 for a map of these EPA Regions). This level of demand is not surprising considering that these areas are the most heavily industrialized and densely populated areas of the country.

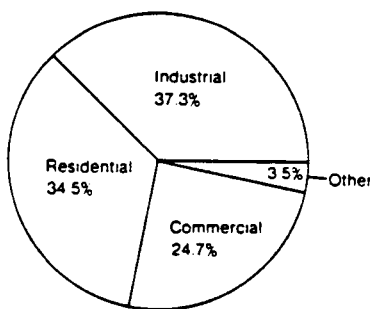
EXHIBIT 2-2
ELECTRICITY SALES BY YEAR AND CLASS OF SERVICE
(gigawatt-hours)

1975 SALES



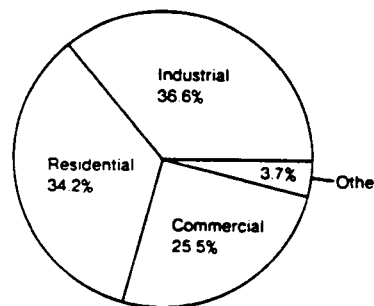
Total Sales = 1,733,024 kWh

1980 SALES



Total Sales = 2,126,094 kWh

1984 SALES



Total Sales = 2,285,532 kWh

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

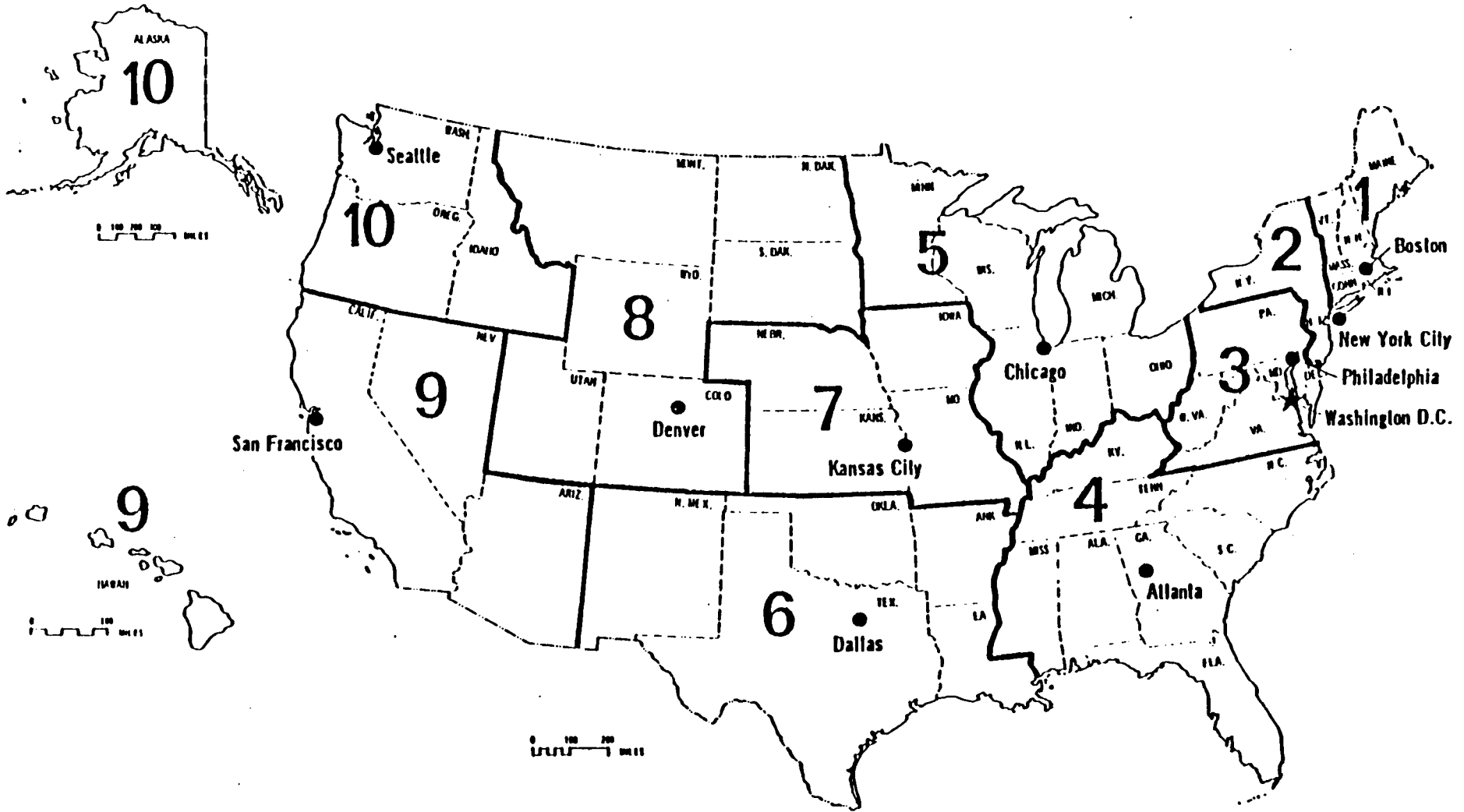
*Includes street lighting, other public authorities, railroads and interdepartmental transfers within utilities (i.e., use of electricity by the utility itself).

EXHIBIT 2-3
ELECTRICITY DEMAND by EPA REGION
1985

<u>EPA Region</u>	<u>Millions of Kilowatt Hours</u>	<u>Percent of Total</u>
1	86,397	3.8
2	164,780	7.2
3	230,055	10.1
4	483,248	21.2
5	428,873	18.8
6	340,198	14.8
7	112,076	4.9
8	72,458	3.2
9	227,006	10.0
10	135,716	6.0
	<hr/>	<hr/>
Total U.S.	2,280,585	100.0

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

EXHIBIT 2-4
EPA FEDERAL REGIONS



2-6

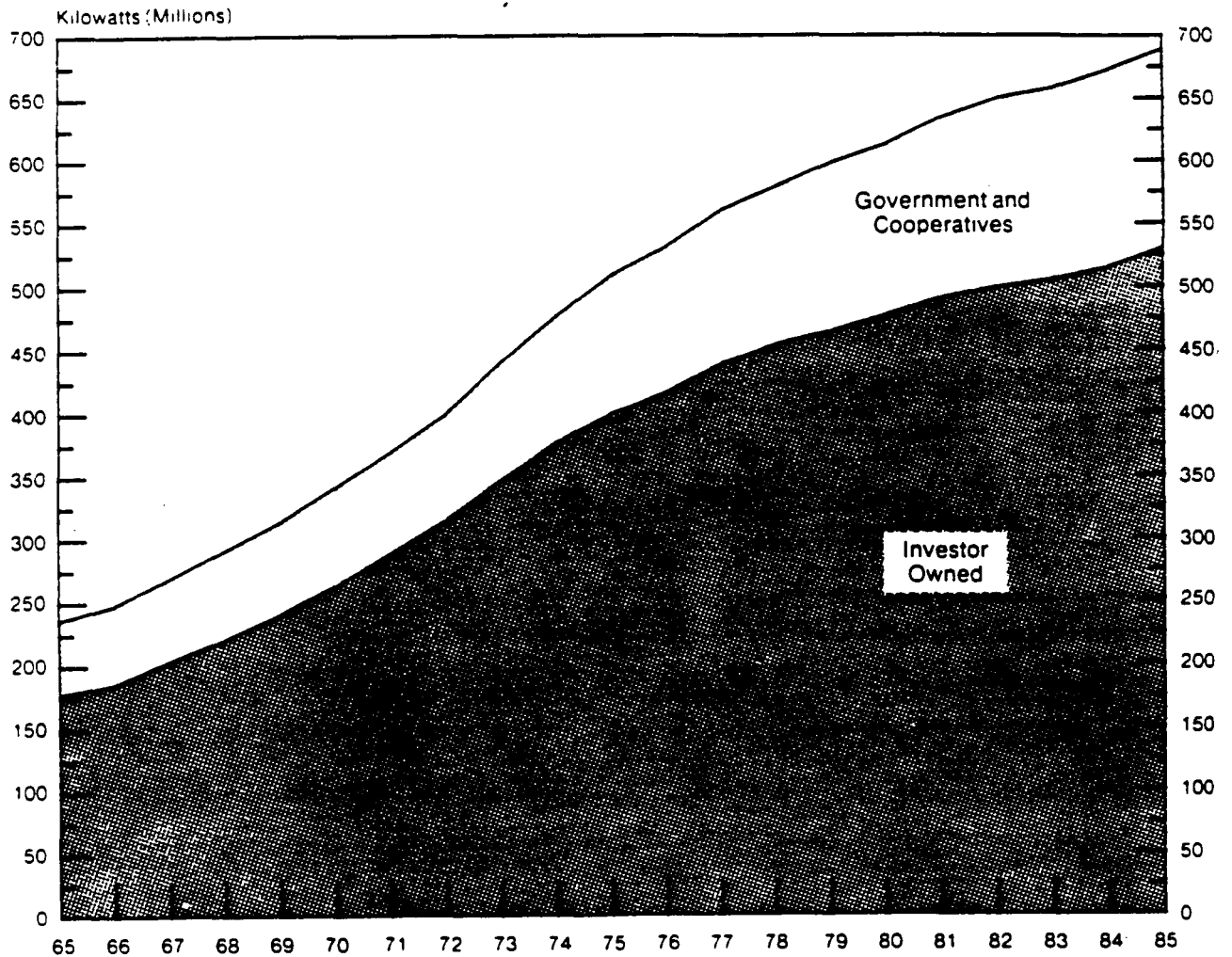
2.1.1 Structure of the U.S. Electric Utility Industry

The U.S. electric power industry is a combination of private, Federal, and public nonprofit organizations. The distribution of capacity, generation, revenue, and sales differs widely among these ownership groups since each group has different objectives, organizational characteristics, and financing methods. Private investor-owned utilities dominate the U.S. electric utility industry as shown in Exhibit 2-5. Investor-owned utilities have historically served large consolidated markets to take advantage of economies of scale. Federal, municipal, cooperative, and other publicly-owned utilities have generally served smaller markets where local governments or nonprofit organizations have had access to limited supplies of less expensive Federal power or to government-supplied capital for power plant construction. These circumstances have allowed municipal, cooperative, or other publicly-owned utilities to predominate in areas not traditionally served by investor-owned utilities.⁴ A brief discussion of each type of organization is provided below.

2.1.1.1 Investor-Owned Utilities

Investor-owned utilities account for about three-quarters of all U.S. electric utility generating capacity, generation, sales, and revenue. Investor-owned utilities are privately owned, profit-oriented businesses granted service monopolies in certain geographic areas. As franchised monopolies, they are obligated to provide service to all customers within their geographic area. In providing this service, investor-owned utilities are required to charge reasonable prices, to charge similar prices to similar

EXHIBIT 2-5
GENERATING CAPACITY IN THE UNITED STATES



Source: Edison Electric Institute, Statistical Yearbook for the Electric Utility Industry/1985, December 1986.

customers, and to give customers access to services under similar conditions.⁵ Investor-owned utilities operate in all states except Nebraska (which depends primarily on public power districts and rural electric cooperatives for electricity). In 1984, consumers paid an average of 6.5 cents per kilowatt-hour (kwh) for privately-produced power compared to the industry average from all ownership groups of 6.3 cents per kilowatt-hour (an average customer consumed 23,150 kwh in 1984).⁶

2.1.1.2 Federal Power

The U.S. Government is the second largest producer of electricity in the United States with roughly 10 percent of total U.S. generation and generating capacity. Consumers of Federal power paid the lowest rate among the different ownership groups -- only 3.5 cents per kwh on average in 1984, (compared to an industry average of 6.3 cents per kwh).⁷ Federal power production is designed to provide power at the lowest possible rate, with preference in the sale of electricity given to public entities and cooperatives.⁸ In this role the Federal Government is primarily a generator and wholesaler of electricity to other organizations, rather than a direct distributor to electricity consumers.⁹

2.1.1.3 Municipal Utilities

Municipal utilities are nonprofit local government agencies designed to serve their customers at the lowest possible cost. Most municipal utilities simply distribute power obtained from one of the other ownership groups (e.g., Federal facilities), although some larger ones also generate and transmit

power. Municipally-owned electric utilities rank third in the amount of installed capacity (5.5 percent of total generating capacity), but comprise the single most numerous ownership group (1,811 utilities in 1984).¹⁰ Average revenue per kwh sold in 1984 was 5.69 cents compared to an industry average of 6.3 cents per kwh. Municipal utilities are exempt from local, state, and Federal taxes and have access to less expensive capital via public financing and less expensive Federal power. As a result, municipal utilities can generally afford to charge less than investor-owned utilities for the power they produce.¹¹

2.1.1.4 Cooperatives

Rural electric cooperatives are owned by and provide electricity to their members and currently operate in 46 states. They have the lowest amount of installed capacity among all ownership categories (24.7 gigawatts in 1984 or less than 4 percent of all capacity).¹²

In 1984, average revenue for cooperatives from sales to consumers was 6.7 cents per kwh, the highest of all ownership types (the industry average was 6.3 cents per kwh). Large construction programs in the 1970's usually account for the high rates.¹³

2.1.1.5 Other Public Entities

There are a variety of other public organizations that provide electric power, including public power districts, state authorities, irrigation districts, and various other State organizations. These other public entities

operated a combined total of 32.8 gigawatts in 1984, or about 5 percent of all generating capacity in the U.S.¹⁴ The public power districts are concentrated in five states -- Nebraska, Washington, Oregon, Arizona, and California. The average price paid for electricity from all of these entities was 4.37 cents per kwh in 1984, compared to an industry average of 6.3 cents per kwh.¹⁵

2.1.2 Economic and Environmental Regulation of the Electric Utility Industry¹⁶

The electric utility industry is regulated by several different regulatory bodies at both the Federal and State levels. According to the U.S. Department of Energy: "The basic purpose of public utility regulation is to assure adequate service to all public utility patrons, without discrimination and at the lowest reasonable rates consistent with the interests both of the public and the electric utilities."¹⁷ This regulation involves both economic and environmental objectives. As natural monopolies, electric utilities are regulated to ensure that adequate, reliable supplies of electric power are available to the public at a reasonable cost. Additionally, since the operations of electric utilities can affect environmental quality, they are regulated to ensure the protection of the nation's air and water resources. This section briefly reviews the main regulatory bodies that affect the electric utility industry.

2.1.2.1 Federal Regulation

There are five major organizations at the Federal level that regulate some aspect of the electric utility industry -- the Federal Energy Regulatory Commission (FERC), the Economic Regulatory Administration (ERA), the

Securities and Exchange Commission (SEC), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA).

- The Federal Energy Regulatory Commission (FERC) oversees various aspects of the electric utility, natural gas, hydroelectric, and oil pipeline industries. FERC approves the rates and standards for wholesale interstate electricity sales between investor-owned utilities and other investor-owned utilities, municipals, or cooperatives (these sales are about 15 percent of total U.S. electricity sales).¹⁸ It determines whether these rates are reasonable and non-discriminatory. FERC also oversees utility mergers and the issuance of certain stock and debt securities, approves the rates of Federal Power Marketing Administrations, and administers agreements between utilities concerning electricity transmission.
- The Economic Regulatory Administration (ERA) has several responsibilities, including administering a program to ensure that all future power plants have the potential to burn coal, regulating international electricity transmission connections, and licensing exports of power.
- The Securities and Exchange Commission (SEC) is an independent regulatory agency established to regulate interstate transactions in corporate securities and stock exchanges. With respect to the electric utility industry, the SEC regulates the purchase and sale of securities, utility properties, and other assets.
- The Nuclear Regulatory Commission (NRC) is involved only in the regulation of nuclear facilities owned and operated by the utility industry. Its main responsibilities include licensing the construction and operation of nuclear facilities, licensing the possession, use, transportation, handling, and disposal of nuclear materials, licensing the export of nuclear reactors and the import and export of uranium and plutonium, and regulating activities affecting the protection of nuclear facilities and materials.

In addition to these regulatory bodies, the Environmental Protection Agency (EPA) is the main Federal regulatory authority for protecting the nation's air and water quality. As part of its overall authority, EPA sets limits on the level of air pollutants emitted from electric power plants and develops regulations to control discharges of specific water pollutants.

Throughout this Report to Congress key regulations that affect the electric utility industry are discussed. While EPA often takes the Federal lead when these regulations are developed, the Agency also works closely with the States since they often retain primary authority for implementing and enforcing standards (for example, see Section 4.1 on state regulation of coal combustion wastes).

2.1.2.2 State Regulation

States are also involved in the environmental and economic regulation of the electric utility industry. As mentioned above, the States often share regulatory authority with the various Federal organizations. For environmental regulation the States often have their own environmental protection agencies to implement and enforce State and Federal environmental regulations. For example, they are responsible for drafting State Implementation Plans (SIP) that must be approved by the U.S. EPA to attain National Ambient Air Quality Standards (NAAQS). Similarly, as will be discussed in greater detail in Chapter Four, the States have authority for implementing and enforcing regulations concerning the disposal of solid wastes under Subtitle D of RCRA. Environmental regulations for which the States exercise regulatory authority are discussed throughout this Report to Congress.

States are also very involved in the economic regulation of the electric utility industry. The primary goals of state economic regulation is usually to provide adequate nondiscriminatory service to electricity consumers at reasonable prices.¹⁹ This is usually accomplished by state regulatory

agencies such as public utility commissions. The amount of authority these state regulatory agencies have can differ widely from state to state. However, these agencies usually have the authority to approve electricity price levels and the rates of return allowed for utility stockholders. State regulators also approve the franchise under which the utility operates. Licensing for construction and operation and approval of the sites at which power plants will be built are also important functions of some state regulatory commissions. Other areas into which some commissions have entered to ensure that utility activities protect the public interest include setting rules about when competitive bids are required, promulgating company performance standards, deriving methods for allocating power during shortages, establishing billing and safety rules, and promoting conservation.²⁰

2.2 IMPORTANCE OF COAL TO ELECTRIC UTILITIES

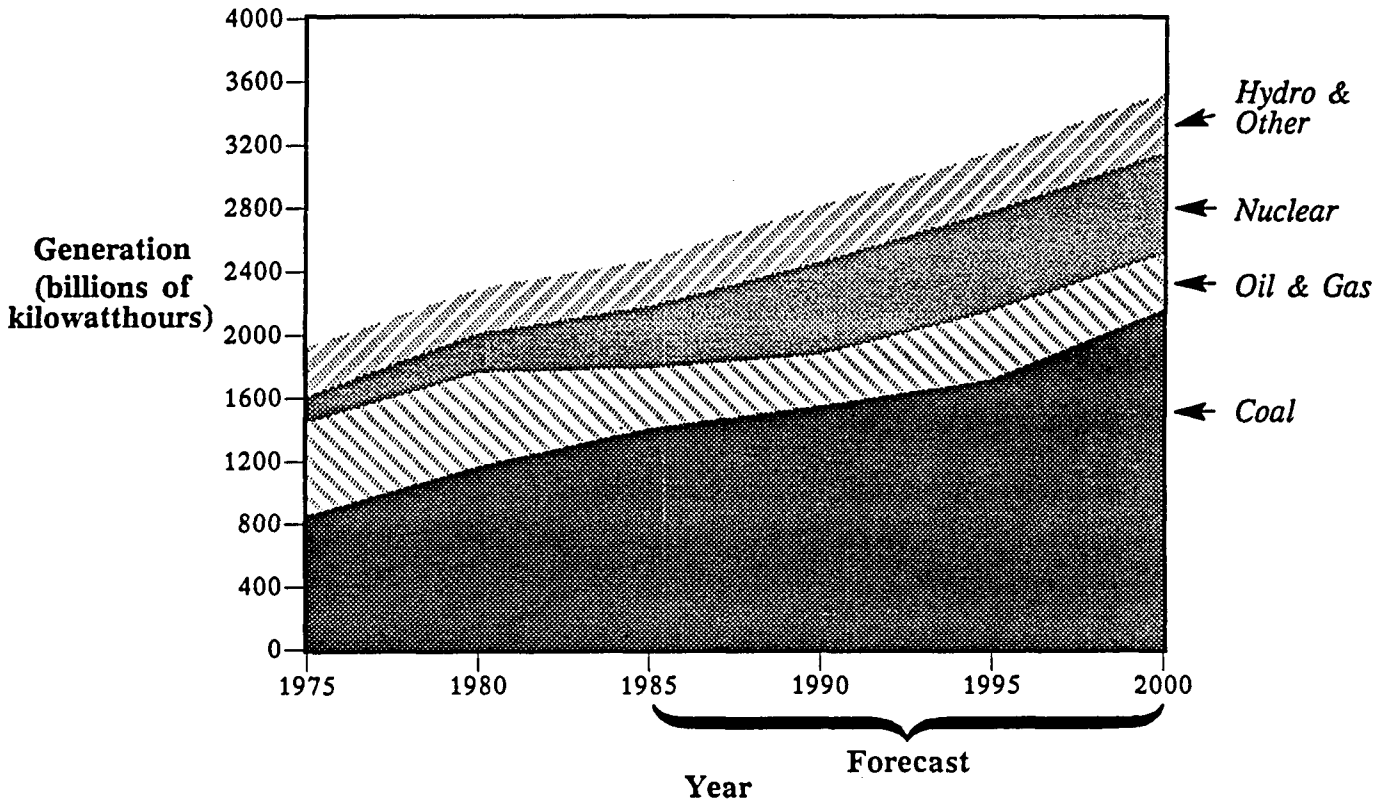
Electric utilities use many different technologies and energy sources to generate electricity. At present, as shown in Exhibit 2-6, over 70 percent of electricity in the U.S. is generated by the combustion of fossil fuels (coal, oil and natural gas); most of the remaining 30 percent is generated by hydroelectric plants and nuclear power plants. A small portion of electricity demand is satisfied by alternative sources such as geothermal energy, renewable resource technologies (e.g., wood, solar energy, wind), purchased power from industrial and commercial cogeneration (cogeneration is the simultaneous production of electricity and process steam; the electricity is typically used by the cogenerator or sold to another industry while the steam is used for various production processes), and power imports (primarily from Canada).

EXHIBIT 2-6

**ELECTRICITY GENERATION BY PRIMARY ENERGY SOURCE
1975-2000**

OFFICIAL COPY

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Source: 1975-1985: Energy Information Administration, Electric Power Monthly DOE/EIA-0226 (85/12), December 1985, p. 10.

1985-2000: ICF Incorporated, Analysis of 6 and 8 million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

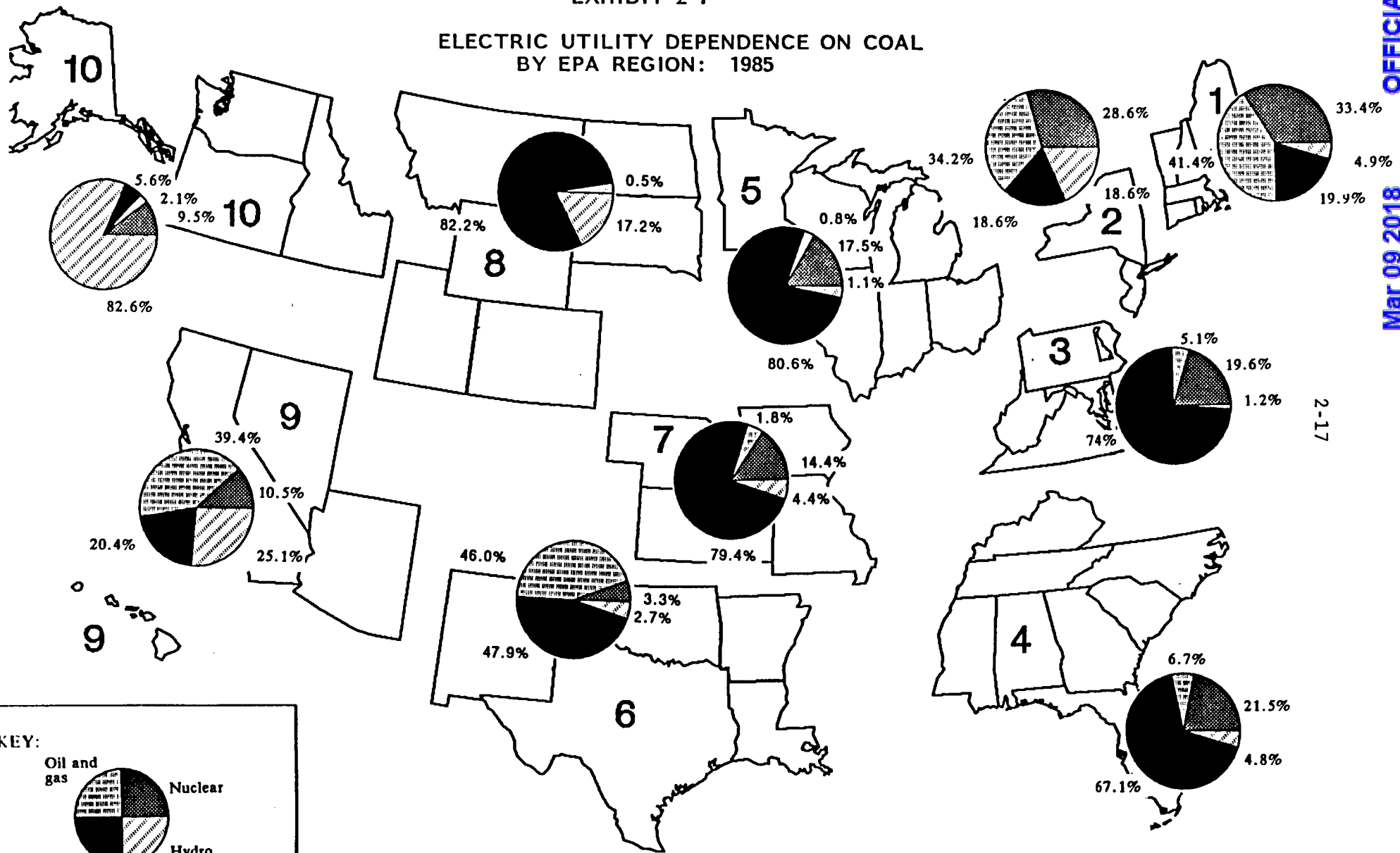
In 1984, coal accounted for more than half of all the electricity generated in the U.S.²¹ The portion of electricity generated from coal is expected to remain at about this level throughout the rest of the century since coal-fired generation is expected to remain economically attractive. The relative contribution to total generation made by other fossil fuels and by hydroelectric power will likely continue to decline, while the contribution made by nuclear power plants will likely increase for the next few years as several new units come on-line. However, the addition of nuclear plants beyond those now under construction will be minimal, leading to an eventual decline in nuclear's relative contribution. Cogeneration, power imports, and emerging technologies are expected to continue to grow, but their share of total generation will remain small. As a result, coal will continue to be the major fuel source for electricity generation.

The extent of the electric utility industry's dependence on coal varies geographically. Exhibit 2-7 shows that coal accounts for over three-quarters of electricity generation in some regions, but less than half in others. For example, in the far West and southern Plains states, the local availability of oil, gas, and hydroelectric power has limited regional dependence on coal. In many of the eastern regions, where coal is relatively more accessible and less costly than oil or gas, coal is significantly more dominant. Despite these regional variations, however, coal-fired electricity generation is an important source of electricity in most regions of the United States.

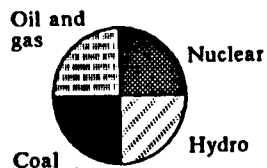
The use of coal by electric utilities has also made the coal and electric utility industries highly interdependent; not only does coal-fired electricity generation account for over half of the electricity produced in the U.S., but

EXHIBIT 2-7

ELECTRIC UTILITY DEPENDENCE ON COAL BY EPA REGION: 1985



KEY:



Percentages represent the proportion of the total electricity generated in the region by each type of fuel.

Source: Energy Information Administration, Electric Power Annual 1985, DOE/EIA-0348(85), pp.17-30.

the electric utility industry is the largest customer of the coal industry, purchasing approximately three-quarters of all coal mined, as shown in Exhibit 2-8. This interdependence has increased as electric utility coal consumption has grown from 406 million tons in 1975 to over 600 million tons in 1985.²² Moreover, electric utility coal consumption is expected to continue to increase to about 1 billion tons by the year 2000.

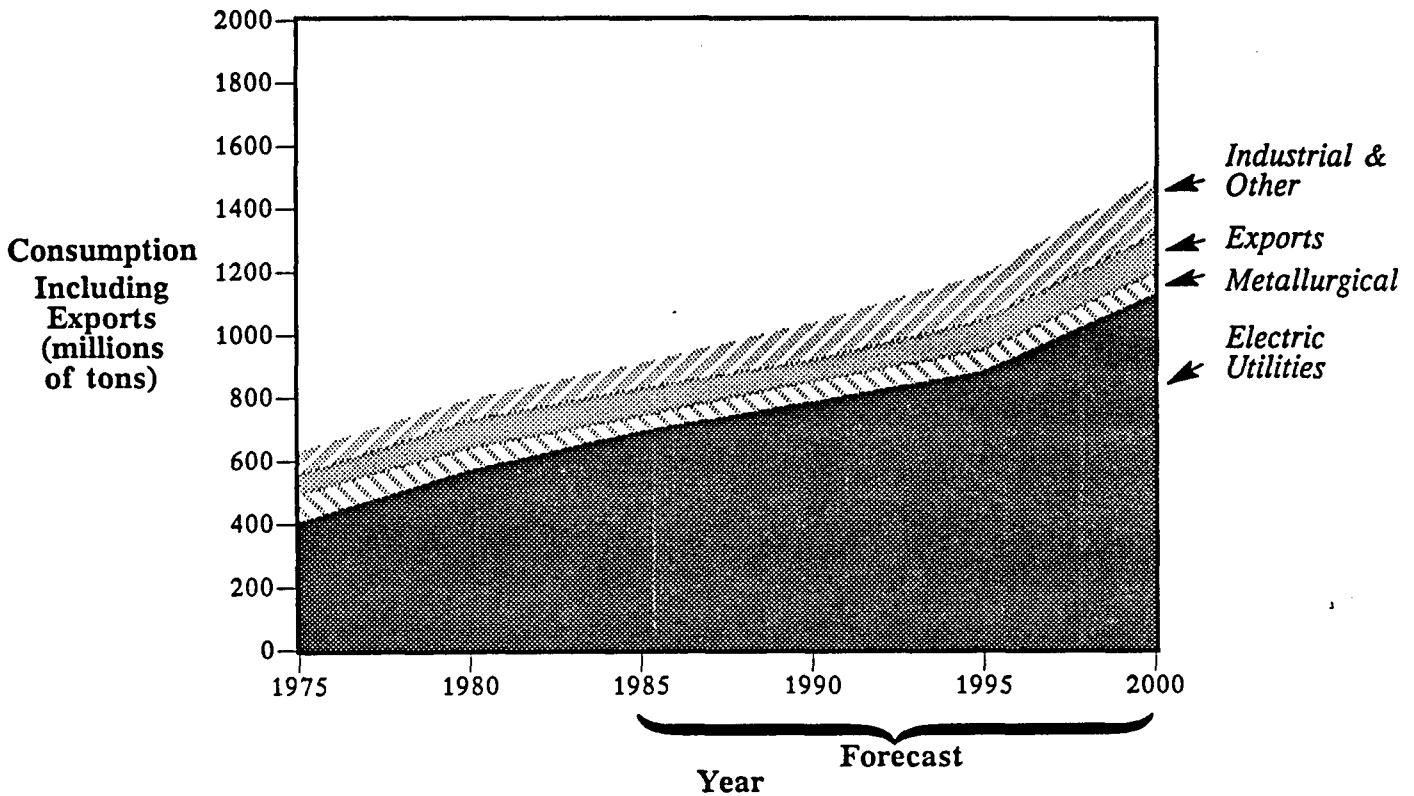
2.3 OVERVIEW OF COAL-FIRED POWER PLANTS

Coal-fired power plants can vary greatly in terms of their generating capacity and the type of boiler technology they employ which, in turn, can affect the amount and type of combustion wastes produced. This section discusses the geographic differences in the size of plants and generating units and describes the three main boiler types along with the regional importance of each.

2.3.1 Regional Characteristics of Coal-Fired Electric Generating Plants

Coal-fired power plants can range in size from less than 50 MW to larger than 3000 MW. In many cases, particularly at the larger power plants, one power plant site may be the location for more than one generating unit (a generating unit is usually one combination of a boiler, turbine, and generator for producing electricity). Exhibit 2-9 shows the number of coal-fired power plants and number of units in each EPA region and their average size in megawatts. On average, each power plant site is comprised of about three generating units. The average generating capacity of coal-fired power plants in the U.S. is approximately 584 MW, with an average unit size of 257 MW.

EXHIBIT 2-8
U.S COAL CONSUMPTION BY SECTOR
1975-2000



Sources: 1975-1985: Energy Information Administration, Annual Energy Review 1985, DOE/EIA-0384 (85), April 1985, pp. 167, 169.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

2-20

EXHIBIT 2-9

TOTAL NUMBER AND AVERAGE SIZE OF COAL-FIRED PLANTS AND UNITS

<u>EPA Region</u>	<u>Number of Plants</u>	<u>Average Size (MW)</u>	<u>Number of Units a/</u>	<u>Average Size a/ (MW)</u>
1	6	374	18	158
2	17	297	39	138
3	57	753	144	308
4	93	799	295	301
5	171	492	492	185
6	39	852	87	580
7	66	400	149	186
8	48	454	109	250
9	13	603	34	383
10	<u>4</u>	<u>479</u>	<u>11</u>	<u>382</u>
U.S. Total	514	584	1378	257

Source: Utility Data Institute Power Statistics Database.

a/ The total amount of generating capacity indicated by multiplying the number of units by their average size (e.g., 1378 units X 257 Mw = 354,146 Mw) is greater than the amount indicated by multiplying the number of power plants by their average (e.g., 514 plants X 584 Mw = 300,176 Mw) because the information in the UDI Power Statistics Database by generating units includes units planned, currently under construction, etc. while the information by power plants refers only to power plants currently operating.

Regional averages for power plant size range from 297 MW in Region 2 to 852 MW in Region 6. Unit sizes range from an average of 138 Mw in Region 2 to 580 Mw in Region 6. Individual power plants and units can be larger or smaller than these averages indicate.

The majority of coal-fired plants (60%) are smaller than 500 MW, while only about 4 percent of U.S. coal-fired power plants have a generating capacity exceeding 2000 MW. Exhibit 2-10 shows the distribution of coal-fired plant sizes across EPA regions.

2.3.2 Electricity Generating Technologies

The basic process by which electricity is produced with coal is shown in Exhibit 2-11. When coal is burned to produce electricity, there are three key components that are critical to the operation of the power plant: the boiler, turbine, and generator. As coal is fed into the boiler, it is burned in the boiler's furnace. In the boiler there are a series of water-filled pipes. As heat is released during combustion, the water is converted to steam until it reaches temperatures that can exceed 1000°F and pressures that approach 4000 pounds per square inch. This high pressure, high temperature steam is then injected into a turbine, causing the turbine blades to rotate. The turbine, in turn, is connected to a generator, so the mechanical energy available from the rotating turbine blades is transformed into electrical energy. The electricity produced by this process is distributed via transmission lines to residential, commercial, and industrial end-users who rely on the power to meet their electrical requirements. Although each step of this process is critical to the production of electricity, this study focuses on boilers only

2-22

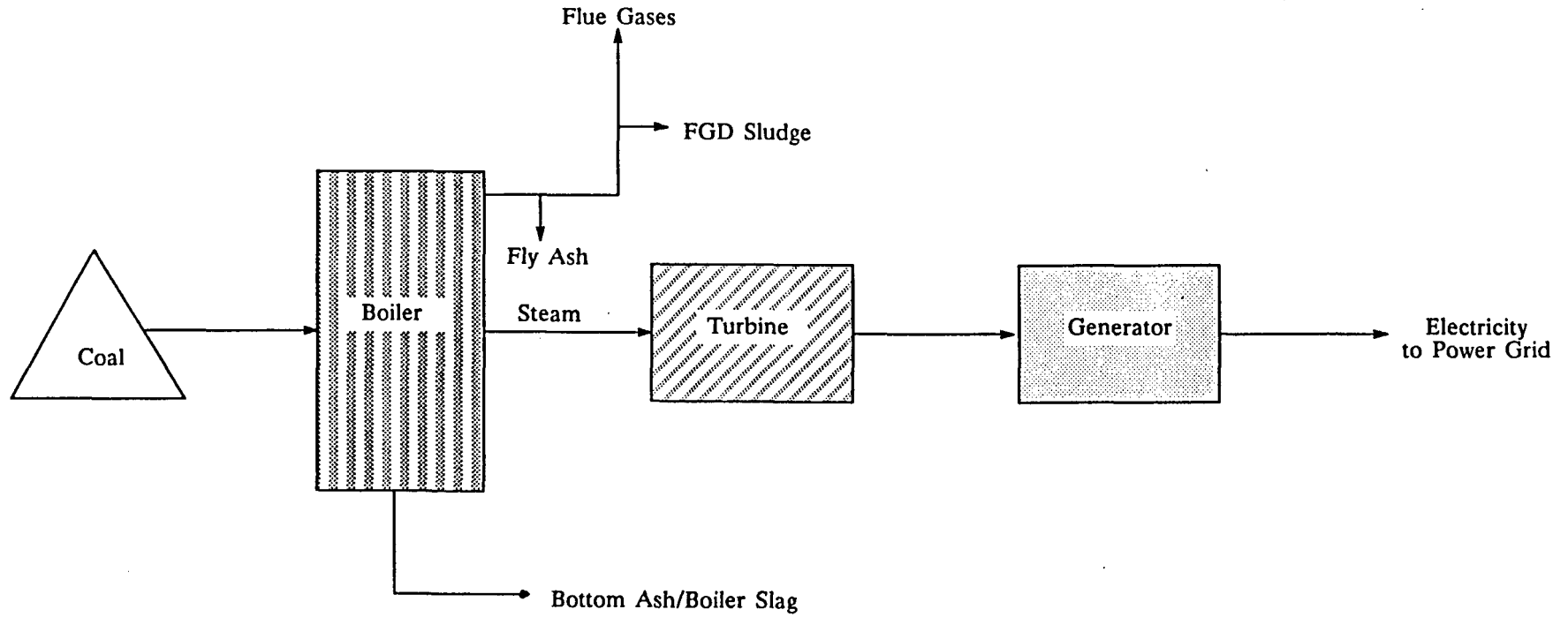
EXHIBIT 2-10

RANGE OF COAL-FIRED POWER PLANT SIZES
(number of plants)

EPA Region	Power Plant Size					Total
	<100 MW	101-500 MW	501-1000 MW	1001-2000 MW	≥2000 MW	
1	1	4	0	1	0	6
2	6	6	5	0	0	17
3	6	23	11	14	3	57
4	15	31	17	23	7	93
5	63	51	23	29	5	171
6	10	4	10	12	3	39
7	25	24	8	7	2	66
8	18	14	10	4	2	48
9	5	2	4	1	1	13
10	<u>2</u>	<u>0</u>	<u>1</u>	<u>1</u>	<u>0</u>	<u>4</u>
U.S. Total	151	159	89	92	23	514

Source: Utility Data Institute Power Statistics Database.

PROCESS FOR GENERATING ELECTRICITY AT COAL-FIRED POWER PLANTS



since it is in the boiler where the combustion wastes are produced as the coal is burned.

There are three main types of boilers: (1) pulverizers, (2) cyclones, and (3) stokers. As discussed below in greater detail, the key differences between these boiler types are operating size and the procedures used for handling and burning the coal. Pulverized coal boilers are so-named because the coal is finely pulverized prior to combustion; most utility boilers are this type. Cyclones have been used in past utility applications, but have not been built recently. They are called cyclones because of the cyclone-like vortex created by the coal particles in the furnace during combustion. Stoker boilers are usually used when smaller capacities are required (e.g., 20-30 MW) and burn coal in a variety of sizes.

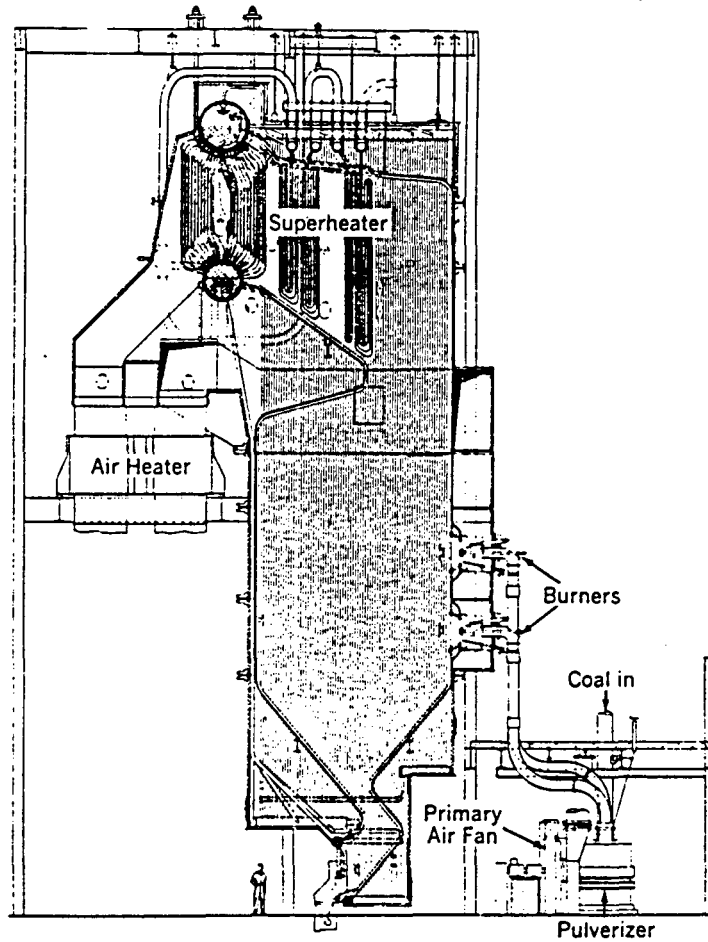
A brief description of each of these coal combustion technologies follows.²³

2.3.2.1 Pulverized-Coal Boiler

Exhibit 2-12 shows a typical pulverized-coal boiler setup. In a pulverized coal boiler, coal is ground to a fine size (about 200 mesh, which is powder-like) in a pulverizer or mill. The pulverized fuel is then carried to the burners by forced air injection and blown into the furnace, where it is burned in suspension. Much of the ash remaining after combustion remains airborne and is carried from the furnace by the flue gas stream (i.e., it becomes fly ash; see Chapter Three for a more detailed discussion of types of waste and how they are produced). Some ash is deposited on the furnace walls,

EXHIBIT 2-12

DIAGRAM OF A PULVERIZED COAL BOILER



Two-drum boiler direct-fired with pulverized coal.

Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY 1978.

where it agglomerates and may sinter or fuse. Ash that falls to the bottom of the furnace is removed via an ash hopper. Ash deposits and slagging are more of a problem in pulverized coal boilers than in stoker boilers.

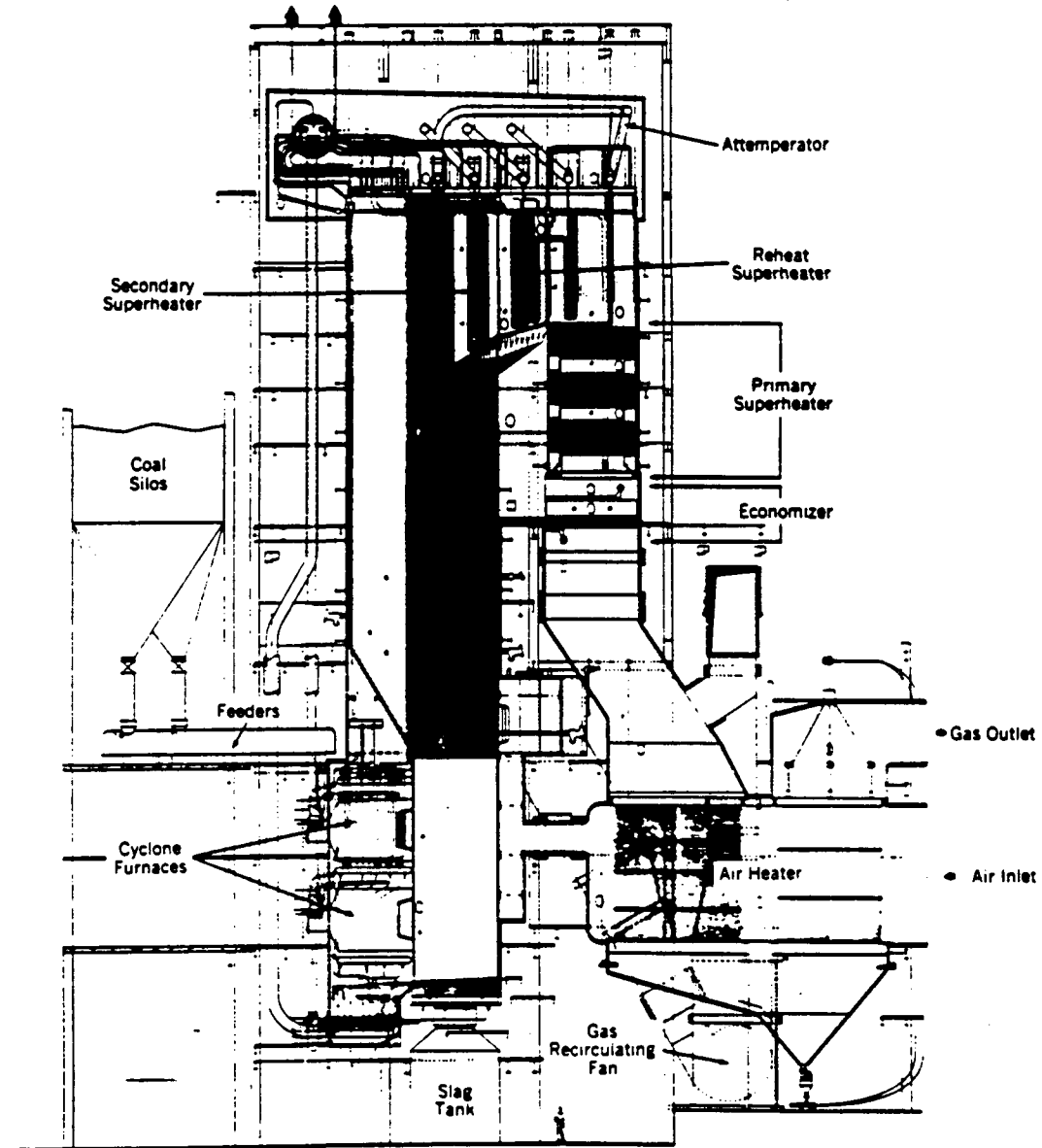
Most modern pulverized-coal boilers have dry-bottom furnaces; that is, the ash is intended to be removed as a dry solid before complete melting occurs. As a result, for dry-bottom boilers, the ash-fusion temperature (the melting point) of the coal must be high enough to prevent the ash from becoming a running slag (i.e., a liquid form). Wet-bottom, or slag-tap, pulverized-coal boilers are designed to remove the ash as a flowing slag. These boilers depend on lower ash-fusion temperature coals so that the ash will melt to form slag for easier removal.

2.3.2.2 Cyclones

The cyclone furnace consists of a water-cooled horizontal furnace in which crushed coal is fired and heat is released at high rates, as shown in Exhibit 2-13. The temperature inside the furnace may reach 3000°F, which is sufficient to melt the ash into a liquid slag that forms on the walls of the furnace. Air circulation within the furnace typically creates a cyclone-like vortex that not only helps the coal to burn in suspension but also causes many coal particles to impinge upon the slag-covered walls of the furnace. This tendency for coal particles to adhere to the walls of the cyclone boiler aids the combustion process because the coal particles will burn more thoroughly before reaching the bottom of the boiler. Most of the ash is retained in the slag layer, thus minimizing the amount of fly ash that is carried out of the boiler. The slag,

EXHIBIT 2-13

DIAGRAM OF A CYCLONE BOILER



Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY, 1978.

or melted ash particles, is typically removed at the bottom of the furnace.

The cyclone offers the advantage of being able to burn low ash-fusion coals that create problems when burned in most conventional pulverized-coal burners. The cyclone design also helps to minimize erosion and fouling problems in the boiler. The smaller amounts of fly ash created compared to other boiler types reduces the costs associated with particulate collection.

2.3.2.3 Stokers

Stokers are designed to mechanically feed coal uniformly onto a grate within a furnace. Because most of the combustion takes place in the fuel bed, not in suspension within the furnace, the heat release rate of this type of boiler is lower than it is for pulverizers or cyclones. As a result, stokers are generally designed for smaller-sized applications. In fact, this boiler type is used by many manufacturing industries, but has seen only limited use by electric utilities.

Stokers are classified by the method of feeding fuel to the furnace and by the type of grate. The three most important stoker types include:

- 1) the spreader stoker, the most popular type of overfeed stoker,
- 2) other overfeed stokers, such as the chain-grate, travelling-grate stoker, or the vibrating-grate stoker, and
- 3) the underfeed stoker.

The major features of each are summarized in Exhibit 2-14. An illustration of a spreader stoker is provided in Exhibit 2-15.

Use of the different boiler types varies by geographic region. As shown in Exhibit 2-16, about three-fourths of all boiler capacity in the U.S. uses pulverizers, with most of these dry-bottom pulverizers. Cyclones are the next most prevalent boiler type, representing only about 8 percent of all boilers. Stokers represent less than one-half of one percent of the total; due to their size limitations stokers are used primarily in other industrial applications for the production of steam.

Exhibit 2-17 shows the distribution of average capacity for each boiler type by EPA region. The range in average sizes is most pronounced in dry bottom boilers (127.8-610.0 MW), which reflects their substantial flexibility in terms of size and dominance in electric utility applications. Stokers tend to have the smallest capacities (an average of 14 MW nationwide), limiting their usefulness in utility applications compared to all of the other boiler types.

2.4 COAL CONSTITUENTS AND BY-PRODUCTS

Despite its attractiveness as a power plant fuel, coal has its drawbacks. As a solid fuel, coal is often more difficult and more costly to transport, store, and burn than oil or gas. Also, coal's many impurities require environmental control at various stages of the fuel cycle.

EXHIBIT 2-14

CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

<u>Stoker Type & Subclass</u>	<u>Typical Maximum Capacity Range (pph steam) a/</u>	<u>Burning Rate (Btu/hr/ft²) b/</u>	<u>Characteristics</u>
1. Spreader			
- Stationary and dumping grate	20,000-80,000	450,000	Capable of burning a wide range of coals, best ability to follow
- Travelling grate	100,000-400,000	750,000	fluctuating loads, high
- Vibrating grate	20,000-100,000	400,000	fly ash carry over, low load smoke.
2. Overfeed			
- Chain grate and travelling grate	20,000-100,000	600,000	Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
- Vibrating grate	30,000-150,000	400,000	Low maintenance, low fly ash carry over, capable of burning wide variety of weakly caking coals, smokeless operation over entire range.
3. Underfeed			
- Single or double retort	20,000-30,000	400,000	Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly ash carry over, suitable for continuous-load operation.
- Multiple retort			

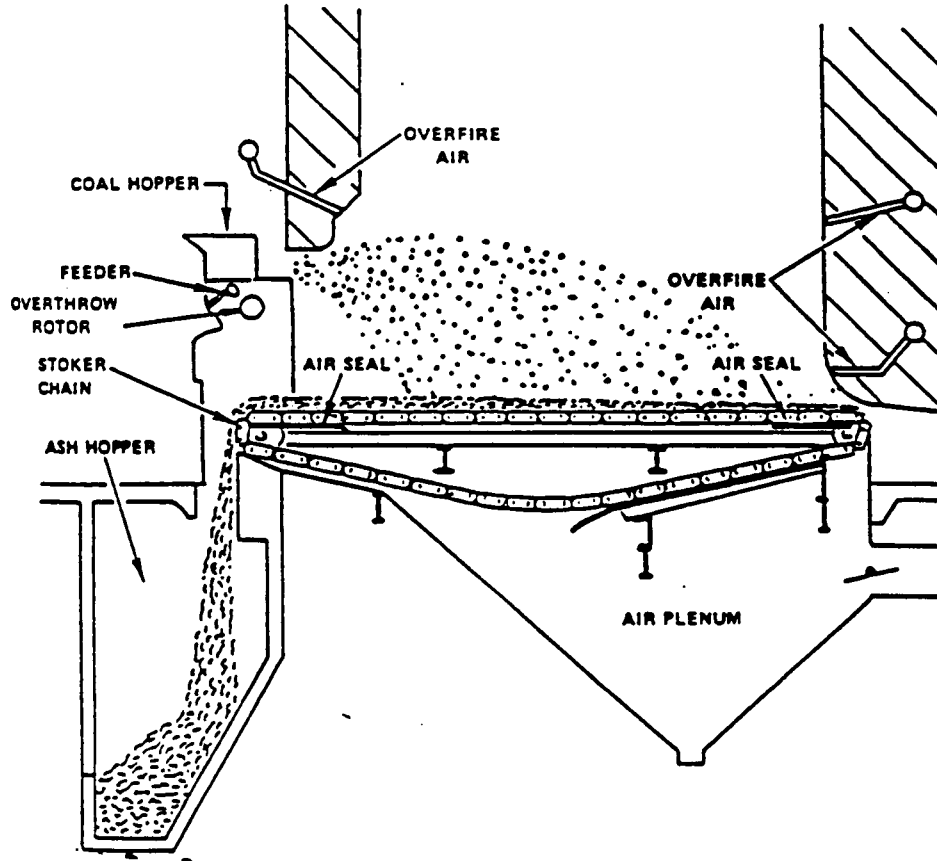
a/ pph = pounds steam/hr; 1 pph = 1000 Btu/hr.

b/ Maximum amount of Btus consumed per hour for each square foot of grate in the stoker.

Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

EXHIBIT 2-15

DIAGRAM OF A SPREADER STOKER



Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

EXHIBIT 2-16**TOTAL COAL BOILER CAPACITY BY EPA REGION
(%)**

<u>EPA Region</u>	<u>Pulverizers</u>		<u>Cyclone</u>	<u>Stoker</u>	<u>Other a/</u>	<u>Total</u>
	<u>Dry Bottom</u>	<u>Wet Bottom</u>				
1	69.2	11.3	16.7	0.0	2.8	100.0
2	60.6	19.4	5.0	2.7	12.2	100.0
3	87.6	0.3	2.8	0.0	9.2	100.0
4	71.6	5.3	5.2	0.1	17.7	100.0
5	70.4	4.9	14.0	0.5	10.1	100.0
6	48.6	12.5	0.0	0.0	38.9	100.0
7	58.3	3.5	19.2	1.0	18.0	100.0
8	60.3	5.4	10.6	1.1	22.5	100.0
9	77.5	0.0	0.0	0.0	22.5	100.0
10	<u>100.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>100.0</u>
U.S. Total	69.3	5.3	8.3	0.4	16.7	100.0

a/ Includes unknown, or other boiler types.

Source: ICF Coal and Utilities Information System Database.

EXHIBIT 2-17

AVERAGE COAL BOILER SIZE BY TYPE OF BOILER
AND BY EPA REGION
(MW)

<u>EPA Region</u>	<u>Pulverizers</u>		<u>Cyclone</u>	<u>Stoker</u>
	<u>Dry Bottom</u>	<u>Wet Bottom</u>		
1	210.2	102.7	228.0	N/A
2	127.8	137.7	143.5	39.0
3	297.6	136.0	195.3	N/A
4	249.3	147.4	342.6	14.6
5	185.0	117.0	222.6	11.2
6	522.7	489.0	N/A	N/A
7	162.5	148.3	243.2	12.3
8	234.2	141.7	322.8	17.9
9	388.3	N/A	N/A	N/A
10	<u>610.0</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>
U.S. Total	231.8	162.9	243.2	14.0

N/A - Not applicable.

Source: ICF Coal and Utilities Information System Database.

These impurities are typically referred to as "ash", whether the reference is to some of the constituents that compose the coal itself prior to combustion or the waste products that result from its combustion. Some coal ash is inherent to the coal seam, while other ash comes from non-coal strata near the coal seam which are intermixed during mining. The coal consumed by electric utilities is generally over 10 percent ash.²⁴ At current rates of coal consumption, about 70 million tons of ash pass through coal-fired power plants each year.²⁵

The ash generated at utility power plants is produced inside the boiler furnace from the inorganic components as the organic components of the coal combust. The types of ash produced can vary -- some ash is swept through the furnace with the hot flue gases to form fly ash, while some settles to the bottom of the boiler as bottom ash or slag. The amount of each type of ash produced depends upon the boiler configuration as described in Section 2.3 and the characteristics of the coal (see Chapter Three for further discussion of ash types).

Air quality regulations have long restricted the amount of fly ash that may be released through a power plant's stacks. Primarily through the use of electrostatic precipitators or bag houses, power plants collect fly ash particles, leaving the flue gases nearly particulate-free as they are emitted from the stack. As a result, the fly ash, bottom ash, and slag that is collected during and after combustion is approximately equal to the amount of ash in the coal prior to combustion.

For many power plants constructed since the 1970's, additional environmental controls also require that a portion of the sulfur oxides be removed from the flue gases. The dominant technology for removing sulfur oxides is known as flue gas desulfurization (FGD), in which alkaline agents, usually in liquid slurry form, are mixed with the flue gases to convert the sulfur into non-gaseous compounds. The resulting waste product is generally referred to as FGD sludge and can amount to 25 percent or more of the volume of coal consumed at a given plant.²⁶ In total, U.S. coal-fired power plants produce about 85 million tons of ash and FGD sludge per year. By the end of the century, this volume is expected to approximately double.

Exhibit 2-18 shows the number of coal-fired utility power plants and units that produce FGD wastes in each EPA region as of 1985. Regions 6, 8, and 9 have the highest proportion of both plants and units producing FGD wastes. For example, more than half of the coal-fired units in region 9 produce FGD wastes. The high proportion of FGD-producing plants in these regions is in part attributable to the fact that many of the coal-fired plants in these regions are relatively new and were required to incorporate scrubbers to meet air emission regulations.

Plants and units producing FGD waste represent a smaller percentage in other regions, primarily because these regions relied on coal-fired capacity for a major portion of their generation before units with FGD technology were installed. For example, the absolute number of both plants and units producing FGD waste is greatest in Region 4, reflecting this area's reliance on coal for generating electricity.

EXHIBIT 2-18

ELECTRIC UTILITY PRODUCTION OF FGD WASTES: 1985

<u>EPA Region</u>	<u># of Plants Producing FGD waste</u>	<u>Percent of Plants Producing FGD Wastes</u>	<u># of Units Producing FGD Wastes</u>	<u>Percent of Units Producing FGD Wastes</u>
1	0	0.0	0	0.0
2	3	17.6	3	7.9
3	5	8.8	13	9.4
4	11	12.0	26	9.8
5	10	5.8	16	3.6
6	8	20.5	23	35.9
7	6	9.1	11	7.9
8	9	18.8	25	29.4
9	3	23.1	12	57.1
10	<u>0</u>	<u>0.0</u>	<u>0</u>	<u>0.0</u>
Total U.S.	55	12.0	129	14.4

Source: Utility Data Institute Power Statistics Database.

Regions 1 and 10, at the other extreme, have no plants or units producing FGD wastes. These regions (New England and the Pacific Northwest) are not highly dependent upon coal and consequently, have relatively few coal-fired plants.

Numerous other types of wastes are produced during normal operation and maintenance at coal-fired power plants. These include, among others, boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. These wastes are usually small in volume relative to ash and FGD sludge, but because they may have higher concentrations of certain constituents that may cause environmental concern, they also require care in handling and disposal. All of these wastes are discussed in greater detail in Chapter Three.

CHAPTER TWO

NOTES

- 1 Edison Electric Institute, 1985 Statistical Yearbook.
- 2 Energy Information Administration, Annual Energy Outlook 1985, DOE/EIA-0383(85), p. 50.
- 3 A gigwatt-hour (Gwh) is one million kilowatt-hours; a kilowatt-hour is the amount of electricity generated by 1 kilowatt of electric generating capacity operating for one hour.
- 4 Energy Information Administration, Annual Outlook for U.S. Electric Power, DOE/EIA-0474(86), 1986.
- 5 Ibid.
- 6 Ibid.
- 7 Ibid.
- 8 Ibid.
- 9 Ibid.
- 10 Ibid.
- 11 Ibid.
- 12 Ibid.
- 13 Ibid.
- 14 Ibid.
- 15 Ibid.
- 16 The major portion of this discussion is taken from Annual Outlook for U.S. Electric Power, DOE/EIA, 1986. See this document for further information.
- 17 Ibid., page 5.
- 18 Ibid.
- 19 Ibid.
- 20 Ibid.
- 21 Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 24.

22 Energy Information Administration, Electric Power Monthly, DOE/EIA-0226(85/12), December 1985, p. 21.

23 For more detail, see Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, New York, 1981, pp. 378-431.

24 Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1984, DOE/EIA-0191(84), July 1985, p. 6.

25 American Coal Ash Association.

26 For example, a coal with 2 percent sulfur would produce approximately 80 pounds sulfur dioxide per ton of coal consumed. A limestone scrubber capturing 90 percent of the sulfur dioxide, assuming a stoichiometric ratio of 1.4 and a sludge moisture content of 50 percent, would produce almost 500 pounds of FGD sludge per ton of coal consumed. See Appendix B for a detailed discussion of the methodologies used to determine this calculation.

CHAPTER THREE**WASTES GENERATED FROM COAL-FIRED
ELECTRIC UTILITY POWER PLANTS**

As part of EPA's responsibility under Section 8002(n) of RCRA, Congress directed that the study of wastes from the combustion of fossil fuels should include an analysis of "the source and volumes of such material generated per year." In response to this directive, this chapter examines the physical and chemical characteristics of the types and quantities of wastes that are generated currently and likely to be generated in the future.

3.1 OVERVIEW OF ELECTRIC UTILITY WASTES

As discussed initially in Chapter Two, the noncombustible material that remains after coal is burned is called ash. The proportion of noncombustible material in coal is referred to as the ash content. There are four basic types of wastes that can be produced directly from coal combustion: fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) sludge. The smaller ash particles entrained by the flue (exhaust) gas are referred to as fly ash and are produced in varying degrees by all plants. Larger ash particles that settle on the bottom of the boiler will form either bottom ash (if the particles have never completely melted) or boiler slag (if the ash particles have melted), depending on the furnace design. Another waste product, called FGD sludge, is generated when some of the sulfur dioxide (formed when the sulfur present in the coal combines with oxygen during combustion) is removed from other flue gases. This removal process is required by the Clean Air Act Amendments of 1979, which revised the New Source

Performance Standards for any electric utility boiler constructed after September 1978. These plants are required to remove 90 percent of the sulfur dioxide, which is usually accomplished with a flue gas desulfurization (FGD, or scrubber) system. Because they are generated in very large quantities, these four waste materials -- fly ash, bottom ash, boiler slag, and FGD sludge -- are referred to by the industry as high-volume wastes. This term will be used throughout this study to be consistent with the terminology that is commonly used for these wastes.

Electric utility power plants also generate waste streams that the industry typically calls low-volume wastes, which are formed during equipment maintenance and water purification processes. Types of low-volume wastes generated by coal-fired power plants include boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. Because it is common industry terminology, the term "low-volume wastes" will be used throughout this report; however, some of these wastes (such as cooling tower blowdown) can be generated in substantial quantities, although generally in smaller quantities than high-volume wastes.

The remainder of this chapter describes each type of high-volume and low-volume waste stream, the various methods of collection used for each, the volumes produced, and the physical and chemical characteristics that determine the waste's behavior during disposal and its potential to leach.

3.2 HIGH-VOLUME WASTES

High-volume coal combustion utility wastes are those waste streams generated in the boiler furnace -- fly ash, bottom ash, and boiler slag -- and in the cleaning of coal combustion flue gas. The following sections describe the volumes and the physical and chemical characteristics of these high-volume waste streams.

3.2.1 Ash

The noncombustible waste material that remains after coal is burned is referred to as ash. Some noncombustible materials are characteristic of the coal itself, originating from the chemical elements in the plants from which the coal was formed. These materials generally account for no more than two percent of the ash content of the coal. Other noncombustible materials extraneous to the coal, such as minerals lodged in the coal seam during or after its geologic formation and rocks near the coal seam that are carried away with the coal during mining, are burned during the fuel combustion process along with the coal itself. These materials account for most of the ash content.

3.2.1.1 How Ash is Generated

The type of ash produced from a boiler is determined by the type of coal that is burned and the design of the boiler furnace. As discussed in Chapter Two, the major types of boilers used by electric utilities are wet-bottom pulverizers, dry-bottom pulverizers, cyclone-fired boilers, and stokers.

Pulverizers are the most widely used boilers in the electric utility industry because they can burn many different types of coal. Due to the very fine consistency of the coal after it is pulverized, the ash particles are easily carried out of the boiler along with the flue gases, resulting in a relatively large proportion of fly ash.

The amount of fly ash that accumulates in a pulverizer depends on whether it is dry-bottom or wet-bottom.¹ In dry-bottom pulverizers, which constitute the majority of electric utility boilers, ash particles in the coal generally do not melt during the combustion process because the ash fusion temperature (i.e., the melting point) is higher than the operating temperature in the boiler. In dry-bottom pulverizers, therefore, about 80 percent of the fine ash remains in the flue gas as fly ash. The remaining ash settles to the bottom of the boiler (hence the term bottom ash) where it is collected at a later time. In wet-bottom pulverizers, about 50 percent of the ash exits the boiler as fly ash, while the other 50 percent remains in the furnace. However, ash particles that remain in wet-bottom pulverizers become molten; this boiler slag remains in a molten state until it is drained from the boiler bottom.

Cyclone-fired boilers burn larger-sized coal particles than do pulverizers, since partial crushing is the only preparation required prior to injection into the furnace. The amount of fly ash that is generated in a cyclone boiler is less than that generated in a pulverizer because of the larger-sized coal particles and the design of the cyclone boiler. Because the air circulation within the boiler furnace is designed to create a cyclone-like

vortex, the coal particles have a tendency to contact the boiler walls. The operating temperature is high enough to melt the ash so that it adheres to the furnace walls as liquid slag. Excess slag continually drains to the bottom of the furnace, where it is removed for disposal. Only 20 to 30 percent of the ash formed in a cyclone boiler leaves the boiler as fly ash.

A few older and smaller power plants have stoker-type boilers, in which coal is burned on or immediately over a grate in the furnace. Stokers are designed to burn coals that do not contain too many small particles (fines), which can tend to smother the fire. Because there are fewer small particles, the amount of fly ash is reduced. For example, in a spreader stoker, the most common type of stoker boiler, the coal is uniformly fed over the fire in a manner that enables suspension burning of the finer pieces, while heavier pieces of coal fall onto the grate for further combustion. The large amount of coal that is burned on the grate reduces the amount of fly ash; the ash produced in a spreader stoker is generally about 50 percent fly ash and 50 percent bottom ash.

3.2.1.2 Methods of Ash Collection

As the flue gas leaves the boiler, it is passed through a mechanical ash collector to remove some of the fly ash particles. A mechanical ash collector operates by exerting centrifugal force on the fly ash particles, throwing them to the outside wall of the collector where they can be removed. These collectors are effective mainly for capturing the larger fly ash particles. To remove the smaller particles, the flue gas must then pass through some

other type of particulate control device, such as an electrostatic precipitator, a baghouse, or a wet scrubber.

The electrostatic precipitator (ESP) is the most common device for fine ash collection. ESPs operate by applying an electrical charge to the fly ash particles. In the presence of an intense electrical field, the charged particles are attracted to a grounded collection electrode. The collected dust is then discharged to a storage hopper by a process called rapping that dislodges the collected particles. ESPs are most efficient when coal with high sulfur content is used because the sulfur dioxide in the flue gas helps retain the electrical charge. When properly designed and maintained, an ESP is capable of collecting over 99 percent of the ash present in the flue gas.²

When coal with lower sulfur content is burned, baghouses (also called fabric filters) are often more appropriate to use as fly ash collection devices. If operated efficiently, they also can remove over 99 percent of the ash from the flue gas.³ In this system, the flue gas passes through a filter that traps the ash particles. The ash builds up on the filter, forming a filter cake. As this process continues, the ash collection efficiency tends to increase as it becomes more difficult for particles to pass through the filter material. Periodically, the cake is dislodged from the filters, which reduces efficiency until buildup occurs again.

Some power plants remove fly ash by the wet scrubbing method, in which liquids are used to collect the ash. In one method, the ash particles are removed from the flue gas stream by contacting them with a scrubbing liquid in a spray tower. This process forms an ash slurry, which is then discharged.

Alternatively, fly ash particles may be dislodged from the walls of the scrubber by a liquid flushing of the scrubber. Because the operation of a scrubber is very plant-specific, the collection efficiency of wet scrubbers varies, though wet scrubbers are generally not as efficient as ESPs and baghouses. The advantage of wet scrubbers, however, is that they can also be used simultaneously to collect sulfur oxides from the flue gas system.

Ash particles that do not escape as fly ash become bottom ash or boiler slag. In dry-bottom pulverizers and stokers, the temperatures are low enough to allow the molten ash to cool and reform into dry, solid ash particles, or bottom ash. In smaller boilers of this type, the ash falls onto a grate, which then is opened, allowing the ash to drop into a flat-bottom hopper. The large quantities of bottom ash produced in larger boilers often require hoppers with sloped sides for self-feeding. Some hoppers may contain water to quench the ash and to facilitate disposal.

In cyclone-fired boilers and wet-bottom pulverizers, the liquified ash particles that fall to the bottom of the boiler during combustion remain in a molten state and coalesce into large masses (called slag), which then drop onto the boiler floor. The slag is tapped into a water-filled hopper, or slag tank, which is periodically emptied and the slag disposed. Slag tanks for cyclone-fired boilers are similar to those used for pulverizers but have a higher relative capacity because a greater percentage of the ash in cyclones becomes boiler slag.

3.2.1.3 Quantities of Ash Generated

Nearly all of the noncombustible material in coal ends up as fly ash, bottom ash, or boiler slag. As mentioned earlier, the coal industry and the electric utility industry refer to this material as a coal's ash content. As a result, the volume of ash generated is directly related to the amount of coal consumed and the ash content of the coal. The ash content of coal will vary according to several factors, including coal-producing region, coal rank (i.e., bituminous, subbituminous, anthracite, or lignite), mine, seam, and production method. Although the proportion of ash in coal may range from 3 to 30 percent, the industry-wide average for electric utility power plants is 10.1 percent.⁴ Exhibit 3-1 shows the average ash content of coal that was delivered to coal-fired power plants in 1985 for some of the major coal-producing regions.

In 1984, electric utilities generated about 69 million tons of coal ash. Ash generation is expected to increase considerably, to about 120 million tons in the year 2000, an increase of about 72 percent over 1984 levels. This increase can primarily be attributed to the increase in the demand for coal by electric utilities. While there is some uncertainty over the amount of coal that will be consumed by electric utility power plants, coal-fired electricity generation is likely to increase significantly. For example, one estimate indicates that by the year 2000 electric utility power plants will burn over one billion tons of coal to meet 61 percent of total electricity demand,⁵ an increase of 70 percent over the 664 million tons consumed in 1984.⁶ Exhibit 3-2 shows historical and forecasted future ash generation by coal-fired electric power plants.

EXHIBIT 3-1

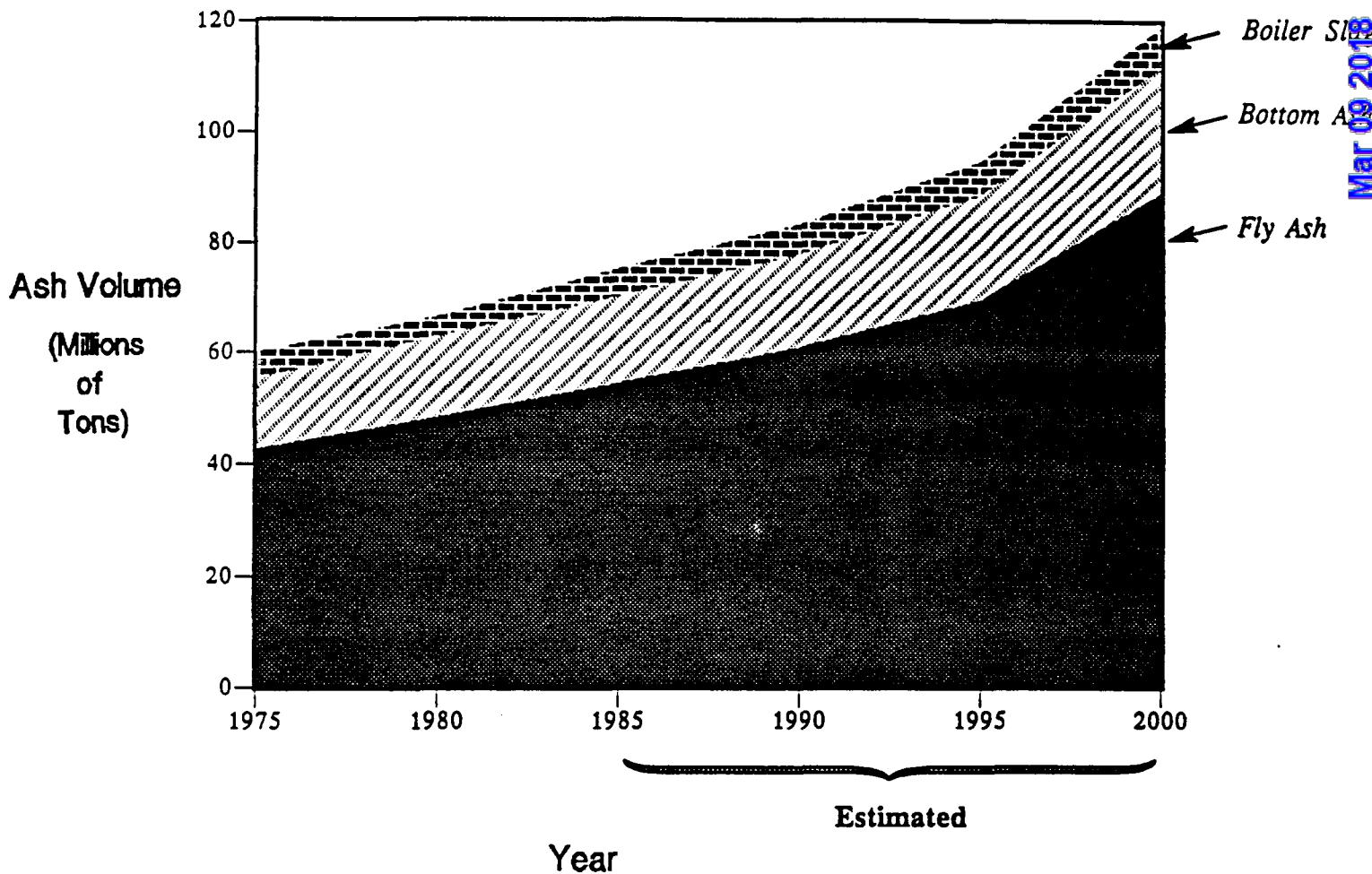
REPRESENTATIVE ASH CONTENTS BY PRODUCING
REGION AND COAL RANK: 1985

<u>Coal Rank and Region</u>	<u>Percent Ash</u>
<u>Anthracite</u>	
Northeastern Pennsylvania	29.4
<u>Bituminous</u>	
Western Pennsylvania	10.9
Northern West Virginia	10.4
Ohio	11.3
Eastern Kentucky	9.9
Alabama	12.2
Illinois	9.7
Colorado	6.2
Utah	9.4
Arizona	8.9
<u>Subbituminous</u>	
Wyoming	5.9
New Mexico	18.8
<u>Lignite</u>	
Texas	15.8
North Dakota	<u>9.0</u>
U.S. Average	10.1

Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(85), July 1986.

EXHIBIT 3-2

VOLUME OF ASH GENERATED BY COAL-FIRED
ELECTRIC UTILITY POWER PLANTS
1975 - 2000



Sources: 1975-1984: American Coal Ash Association.
1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

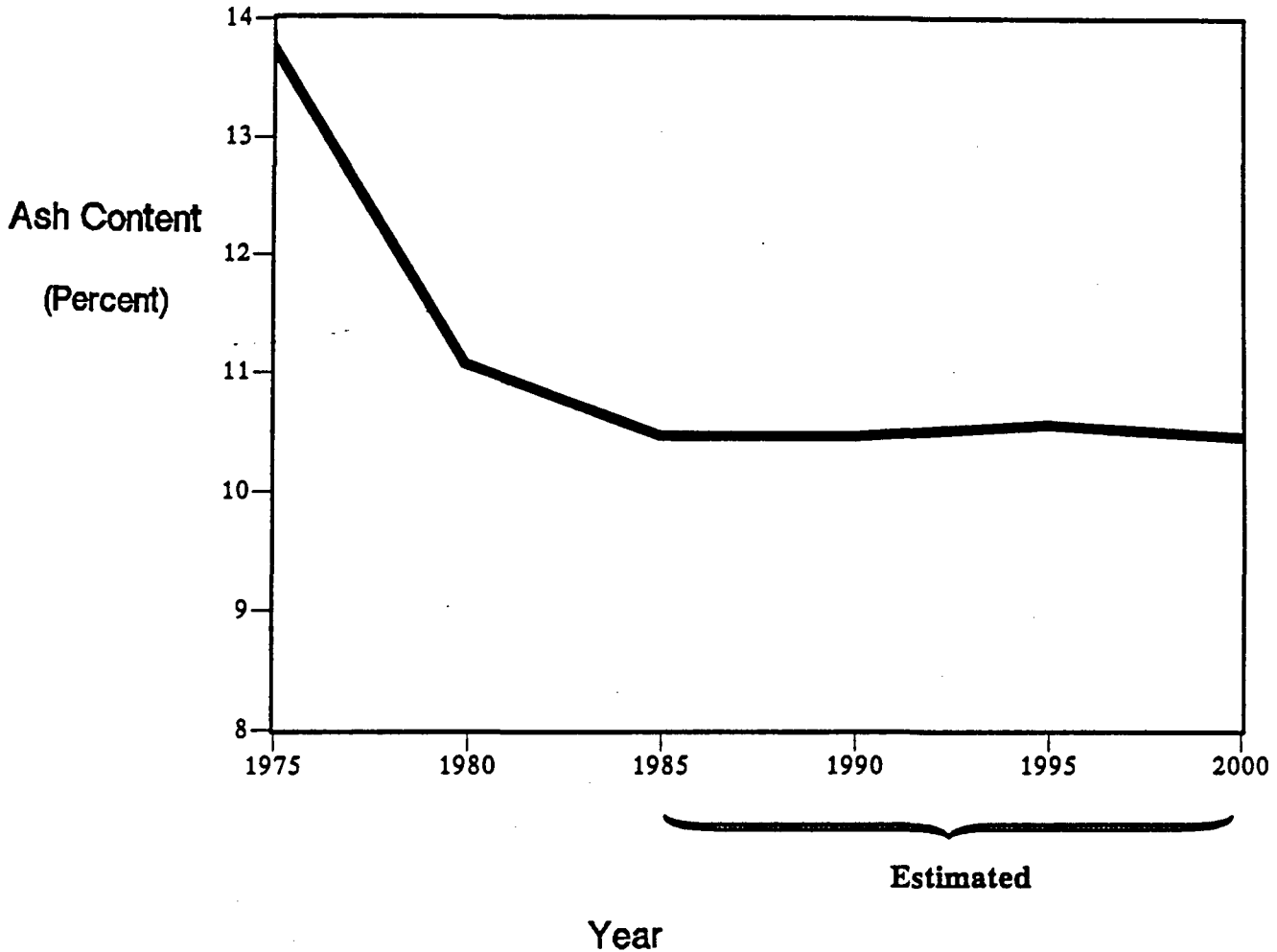
Mar 09 2018

The average ash content of coal burned by electric utilities has declined from about 14 percent to slightly more than 10 percent over the past decade (see Exhibit 3-3). To meet particulate emission standards and to lower certain operating and maintenance costs, more electric utilities are now choosing to burn coal with lower ash contents. Although some coals are naturally low in ash, producers and/or utilities can also reduce ash content by cleaning the coal.⁷ In some cases, cleaning can reduce ash content by as much as 50 to 70 percent. At present, utilities clean about 35 percent of all the coal they consume; most of the coal that is cleaned comes from eastern and midwestern underground bituminous coal-mining operations. Another reason for the increased use of coal with lower average ash content is the growth in Western coal production, particularly in the Powder River Basin area of Montana and Wyoming. These coals are naturally low in ash content, and little ash is extracted during the mining process.

The quantity of fly ash and bottom ash produced is likely to increase faster over time than the quantity of boiler slag because most new coal-fired plants will employ dry-bottom pulverizer boilers, which generate fly ash and bottom ash rather than boiler slag. Because dry-bottom pulverizers are capable of burning coal with a wide range of ash fusion temperatures,⁸ they are able to burn a greater variety of coals compared with cyclone boilers and wet-bottom pulverizers. Another advantage of dry-bottom pulverizers is that they produce less nitrogen oxide emissions than do other boiler types, which enables electric utilities to meet requirements for nitrogen oxide emissions control more easily.

EXHIBIT 3-3

**AVERAGE ASH CONTENT OF COAL BURNED
BY ELECTRIC UTILITY POWER PLANTS IN THE U.S.
1975 - 2000**



Source: 1975-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants.
1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

3.2.1.4 Physical Characteristics of Ash

The physical characteristics of coal combustion ash of interest are particle size and distribution, compaction behavior, permeability, and shear strength. Exhibit 3-4 provides representative ranges of values for these characteristics of fly ash, bottom ash, and boiler slag.

The greater the assortment of particle sizes in the material, the more it can be compacted to achieve greater density and shear strength and lower permeability. Generally, fly ash is similar in size to silt. Most fly ash particles are between 5 and 100 microns in diameter; within a single sample, the largest particles may be 200 times larger than the smallest particles.⁹ The size of bottom ash and boiler slag particles can range from that of fine sand to fine gravel, or about 0.1 to 10 millimeters.¹⁰

Compaction behavior refers to the amount of settling that takes place after disposal and the rate at which such settling occurs. Compressibility, density, and moisture content are factors affecting compaction behavior.¹¹ When compacted and dry, most fly ash and bottom ash behave very similarly to cohesive soil.

Permeability reflects the rate at which water will seep through the waste material in a given period of time and provides a good first estimate of the rate and quantity of leachate migration. A number of factors can influence the degree of permeability, such as the size and shape of the waste particles, the degree of compaction, and the viscosity of the water. Properly compacted fly ash often has low permeability, similar to that of clay, while the

EXHIBIT 3-4

**REPRESENTATIVE RANGES OF VALUES
FOR THE PHYSICAL CHARACTERISTICS OF
FLY ASH, BOTTOM ASH, AND BOILER SLAG**

	<u>Fly Ash</u>	<u>Bottom Ash/ Boiler Slag</u>
Particle Size (mm)	0.001-0.1	0.1-10
Compaction Behavior:		
Compressibility (%)	1.8	1.4
Dry Density (lbs/ft ³)	80-90	80-90
Permeability (cm/sec)	10 ⁻⁶ -10 ⁻⁴	10 ⁻³ -10 ⁻¹
Shear Strength		
Cohesion (psi)	0-170	0
Angle of Internal Friction (°)	25-45	25-45

Sources: For compressibility values, Arthur D. Little, Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Volume I, Prepared for U.S. Environmental Protection Agency, June 1985, p. 3-29. For other values, Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 3-3 - 3-8.

permeability of bottom ash is usually slightly higher. Boiler slag is higher still, having a permeability comparable to that of fine gravel.

Shear strength is an important determinant of the shape and structural stability of wastes disposed in landfills; a strong material (i.e., one with high shear strength) can form steep slopes and support heavy loads from above. Two indicators of shear strength are cohesion, a measure of the attraction between particles due to electrostatic forces, and the angle of internal friction, an indicator of the friction between particles. Dry, nonalkaline ash has no cohesion. Dry ash that is alkaline demonstrates some cohesion and, when compacted, increases in strength over time. The angle of internal friction associated with ash varies with the degree of compaction, although it is similar to that for clean, graded sand.

3.2.1.5 Chemical Characteristics of Ash

The chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very plant- and coal-specific.

In general, over 95 percent of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms. Magnesium, potassium, sodium, and titanium are also present to a lesser degree. Exhibit 3-5 shows the concentration of these major elements typically found in fly ash, bottom ash, and boiler slag.

Ash also contains many other elements in much smaller quantities. The types and proportions of these trace elements are highly variable and not

EXHIBIT 3-5

**LOW AND HIGH CONCENTRATIONS OF MAJOR CHEMICAL
CONSTITUENTS FOUND IN ASH GENERATED
BY COAL-FIRED POWER PLANTS
(parts per million)**

	<u>Fly Ash</u>		<u>Bottom Ash/Boiler Slag</u>	
	<u>Low</u>	<u>High</u>	<u>Low</u>	<u>High</u>
Aluminum	11,500	144,000	88,000	135,000
Calcium	5,400	177,100	8,400	50,600
Iron	7,800	289,000	27,000	203,000
Magnesium	4,900	60,800	4,500	32,500
Potassium	1,534	34,700	7,300	15,800
Silicon	196,000	271,000	180,000	273,000
Sodium	1,180	20,300	1,800	13,100
Titanium	400	15,900	3,300	7,210

Source: Utility Solid Waste Activities Group, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix A, Submitted to the U.S. Environmental Protection Agency, October 26, 1982, p. 31.

readily categorized. Concentrations for various trace elements in coal ash are shown in Exhibit 3-6, which indicates the potential range of values and median concentration for such trace elements for coals from different regions of the U.S. A summary of how the concentration of elements in ash varies according to coal source is shown in Exhibit 3-7. For example, Eastern and Midwestern coal ashes usually contain greater amounts of arsenic, selenium, chromium, and vanadium than do Western coal ashes, while Western coals have larger proportions of barium and strontium. Coal mining and cleaning techniques can reduce the amount of trace elements that are ultimately found in the ash after combustion. For example, in some cases, coal cleaning can remove more than half of the sulfur, arsenic, lead, manganese, mercury, and selenium that is contained in the coal prior to combustion.

The proportions of elements contained in fly ash, bottom ash, and boiler slag can vary. Exhibit 3-8 provides ranges and median values for element concentrations in different types of ash -- bottom ash and/or boiler slag, and fly ash. The concentrations of elements formed in fly ash are shown for two types -- the larger particles removed from the flue gas by mechanical collection and the smaller particles removed with an electrostatic precipitator or a baghouse (see Section 3.2.1.2 for more detail on methods of ash collection). For example, much higher quantities of arsenic, copper, and selenium are found in fly ash than are found in bottom ash or boiler slag. The distribution of elements among the different types of ash is largely determined by the firing temperature of the boiler relative to the coal's ash fusion temperature, which in turn affects the proportions of volatile elements that end up in fly ash and bottom ash. Some elements, such as sulfur, mercury, and chlorine, are almost completely volatilized and leave the boiler

EXHIBIT 3-6

ELEMENT CONCENTRATIONS IN ASH FROM THREE GEOGRAPHIC SOURCES
(milligrams per kilogram)*

Element	Eastern Coal		Midwestern Coal		Western Coal	
	Range	Median	Range	Median	Range	Median
Arsenic	2.0-279	75	0.50-179	54	1.3-129	18
Barium	52-2200	892	300-4300	905	300-5789	2700
Boron	10.0-580	121	10-1300	870	41.9-1040	311
Cadmium	0.10-8.24	1.59	0.50-18	2.6	0.10-14.3	1.01
Chromium	34-437	165	70-395	172	3.4-265	45
Cobalt	6.22-79	40.6	19-70	35.7	4.9-69	13.0
Copper	3.7-349	136	20-330	125	29-340	74.8
Fluorine	0.40-89	8.8	3.2-300	75	0.40-320	50.1
Lead	1.3-222	18.0	3.0-252	149	0.40-250	26.1
Manganese	79-430	190	194-700	410	56.7-769	194
Mercury	0.02-4.2	0.192	0.005-0.30	0.044	0.005-2.5	0.067
Molybdenum	0.84-51	15.0	7.0-70	43	1.4-100	12.0
Nickel	6.6-258	78	26-253	121	1.8-229	38.0
Selenium	0.36-19.0	8.05	0.08-19	7.0	0.13-19.0	4.1
Silver	0.25-8.0	0.695	0.10-1.20	0.39	0.040-6.0	0.26
Strontium	59-2901	801	30-2240	423	931-3855	2300
Thallium	7.0-28.0	25.0	2.0-42	16.0	0.10-3.50	1.06
Vanadium	110-551	269	100-570	270	11.9-340	94
Zinc	16-1420	163	20-2300	600	4.0-854	71

* Values shown are for all types of ash combined.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983.

EXHIBIT 3-7

EFFECT OF GEOGRAPHIC COAL SOURCE ON ASH ELEMENT CONCENTRATION

<u>Element</u>	<u>Concentration Pattern</u>
Arsenic	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	greater in eastern than in midwestern coal ash; greater still in western coal ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	greater in eastern than in western coal ash; greater still in midwestern coal ash

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-30.

EXHIBIT 3-8

ELEMENT CONCENTRATIONS IN THREE TYPES OF ASH
(milligrams per kilogram)

Element	Fly Ash					
	Bottom Ash/Boiler Slag		Mechanical Hopper Ash		Fine Fly Ash	
	Range	Median	Range	Median	Range	Median
Silver	0.1-.51	0.20	0.08-4.0	0.70	0.04-8.0	0.501
Arsenic	.50-168	4.45	3.3-160	25.2	2.3-279	56.7
Boron	41.9-513	161	205-714	258	10.0-1300	371
Barium	300-5789	1600	52-1152	872	110-5400	991
Cadmium	0.1-4.7	0.86	0.40-14.3	4.27	0.10-18.0	1.60
Cobalt	7.1-60.4	24	6.22-76.9	48.3	4.90-79.0	35.9
Chromium	3.4-350	120	83.3-305	172	3.6-437	136
Copper	3.7-250	68.1	42.0-326	130	33.0-349	116
Fluorine	2.5-104	50.0	2.50-83.3	41.8	0.40-320	29.0
Mercury	0.005-4.2	0.023	0.008-3.00	0.073	0.005-2.50	0.10
Manganese	56.7-769	297	123-430	191	24.5-750	250
Lead	0.4-90.6	7.1	5.2-101	13.0	3.10-252	66.5
Selenium	.08-14	0.601	0.13-11.8	5.52	0.60-19.0	9.97
Strontium	170-1800	800	396-2430	931	30.0-3855	775
Vanadium	12.0-377	141	100-377	251	11.9-570	248
Zinc	4.0-798	99.6	56.7-215	155	14.0-2300	210

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-24.

3-21

in the flue gas rather than remaining in the bottom ash or boiler slag. Some of these more volatile elements may condense on the surface of the fly ash particles as the flue gas cools.

3.2.2 FGD Sludge

Another waste stream often generated in large volumes by coal-fired utility power plants is FGD sludge, which is created when utilities remove sulfur oxides from the flue gases. Emissions of sulfur oxides in the flue gases are due to the oxidation of sulfur during coal combustion. State and Federal regulations require power plants to control the amount of sulfur oxides released through the stack. To meet the applicable requirements most power plants use coals whose inherent sulfur content is low. If the sulfur content is so low that additional sulfur dioxide removal is not needed, then FGD sludge is not produced.

Present requirements for all new coal-fired plants, however, not only limit the amount of sulfur oxides that can be emitted, but also mandate a percentage reduction in the amount of sulfur dioxide emissions.¹² This requirement will substantially increase the number of sulfur dioxide control systems in use. The primary method of sulfur dioxide control currently available is a flue gas desulfurization (FGD) system through which the flue gases pass before being emitted from the stack. The wastes produced by this system are called FGD (scrubber) sludge. Other methods of control include newer technologies such as fluidized bed combustion (FBC) and limestone injection multistage burners (LIMB).¹³ The technical and economic feasibility of the latter two technologies are currently under evaluation by private industry and the U.S.

Department of Energy. If these technologies do become more widely available, they also will produce substantial volumes of wastes.

3.2.2.1 Methods of FGD Sludge Collection

There are two major types of FGD (scrubber) systems. Non-recovery systems produce a waste material for disposal. Recovery systems produce recyclable by-products. Exhibit 3-9 illustrates the different types of FGD systems currently in use. Non-recovery systems, which account for 95 percent of the scrubber systems now in use by electric utilities, are further classified as wet or dry systems. In wet non-recovery scrubber systems, the flue gas contacts an aqueous solution of absorbents, thereby producing waste in a slurry form. The wastes generated by dry non-recovery systems contain no liquids.

Direct lime and limestone FGD systems are the most common wet non-recovery processes. With these systems, flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone in the form of a slurry. The slurry circulates between the contact chamber and a separate reaction tank, where the reagents are added. From the reaction tank, the slurry is fed to a thickening and dewatering device to be prepared for disposal. After dewatering, the resulting liquid is recycled back to the reaction tank and the sludge solids are removed for disposal. Under certain conditions, direct lime and limestone scrubbers have been able to remove over 95 percent of the sulfur dioxide in the flue gas.¹⁴

EXHIBIT 3-9

MAJOR TYPES OF FLUE GAS DESULFURIZATION SYSTEMS

Non-Recovery		Recovery	
Wet	Dry	Wet	Dry
Direct Lime	Spray Drying	Wellman-Lord	Alumina/Copper* Sorbent
Direct Limestone	Dry Sorbent Injection*	Magnesium Oxide	Activated Carbon* Sorbent
Alkaline Fly Ash			
Dual-Alkali			

*Systems are currently in development and testing phases, and are not as yet being used commercially.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-1 - 4-4.

A variation on the direct lime and limestone systems is the alkaline fly ash scrubber. Several western power plants that burn coal containing high-alkaline ash use these systems, which can improve sulfur dioxide removal. Rather than being collected by a separate upstream device (such as an ESP or baghouse), fly ash particles remain in the gas stream as it passes through the scrubber. In the scrubber, the alkaline fly ash, augmented with an alkaline lime/limestone slurry, acts to remove sulfur oxides. Alkaline fly ash scrubbers are not as efficient as direct lime and limestone systems, removing on average only about 40 percent of the sulfur dioxide.¹⁵

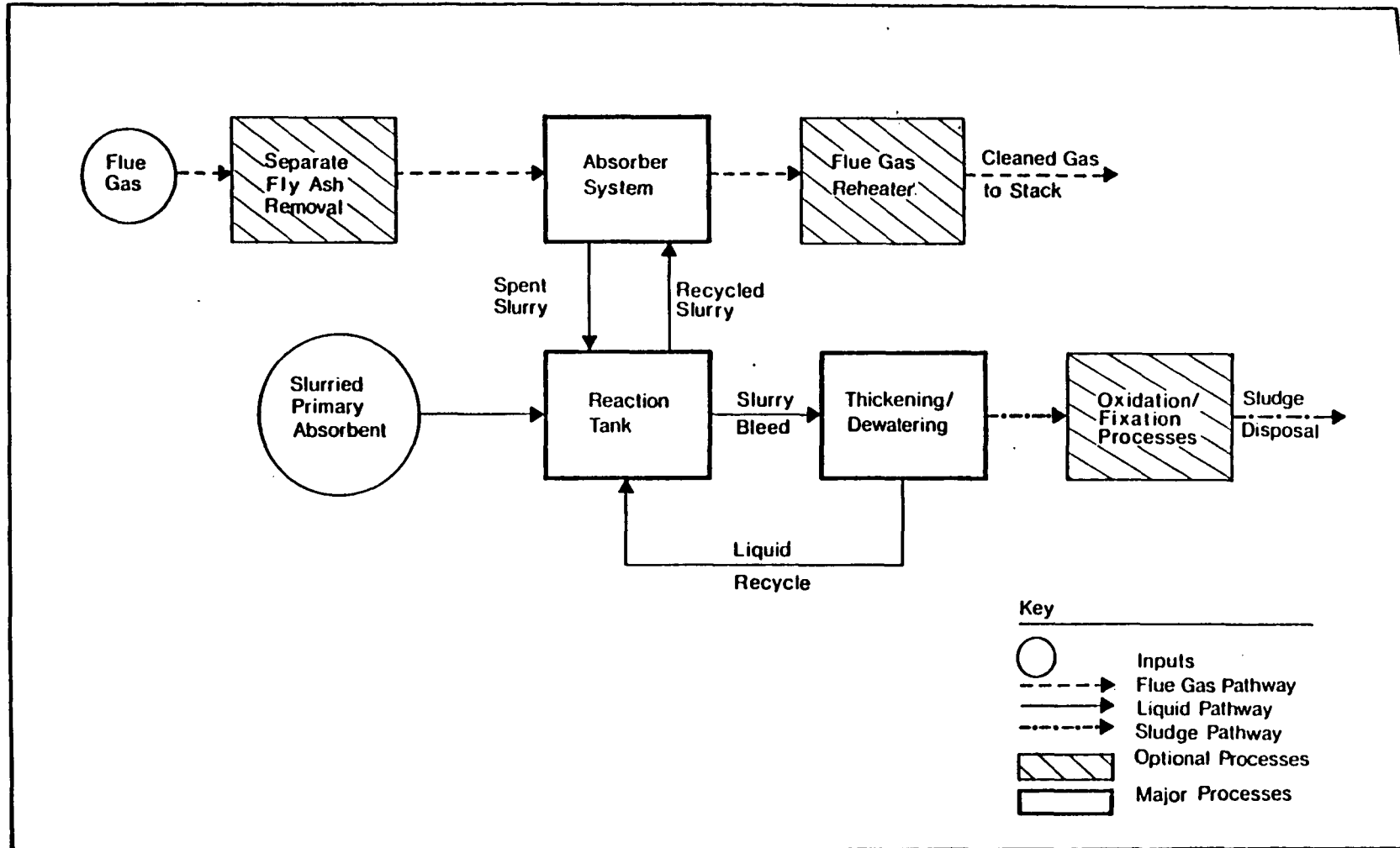
Another wet non-recovery system is the dual-alkali process. These scrubbers operate in much the same manner as the direct lime and limestone scrubbers. However, dual-alkali systems use a solution of sodium salts as the primary reagent to which lime is added for additional absorption. The soluble sodium salts are then recycled to the scrubber system and the insoluble portion of the slurry is left to settle so that it can be collected and disposed. Like direct lime and limestone systems, dual-alkali scrubbers remove up to 95 percent of the sulfur dioxide.¹⁶

Exhibit 3-10 presents a diagram of the operations of a wet FGD system. The flows shown for the flue gas, absorbent, slurry, and sludge are essentially the same for direct lime, direct limestone, alkaline fly ash, and dual-alkali systems.

At present, the two most popular methods of dry scrubbing under investigation are spray-drying and dry sorbent injection, although only the spray-drying process is now in commercial use at electric utility power plants.

EXHIBIT 3-10

FLOW DIAGRAM OF WET FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-3.

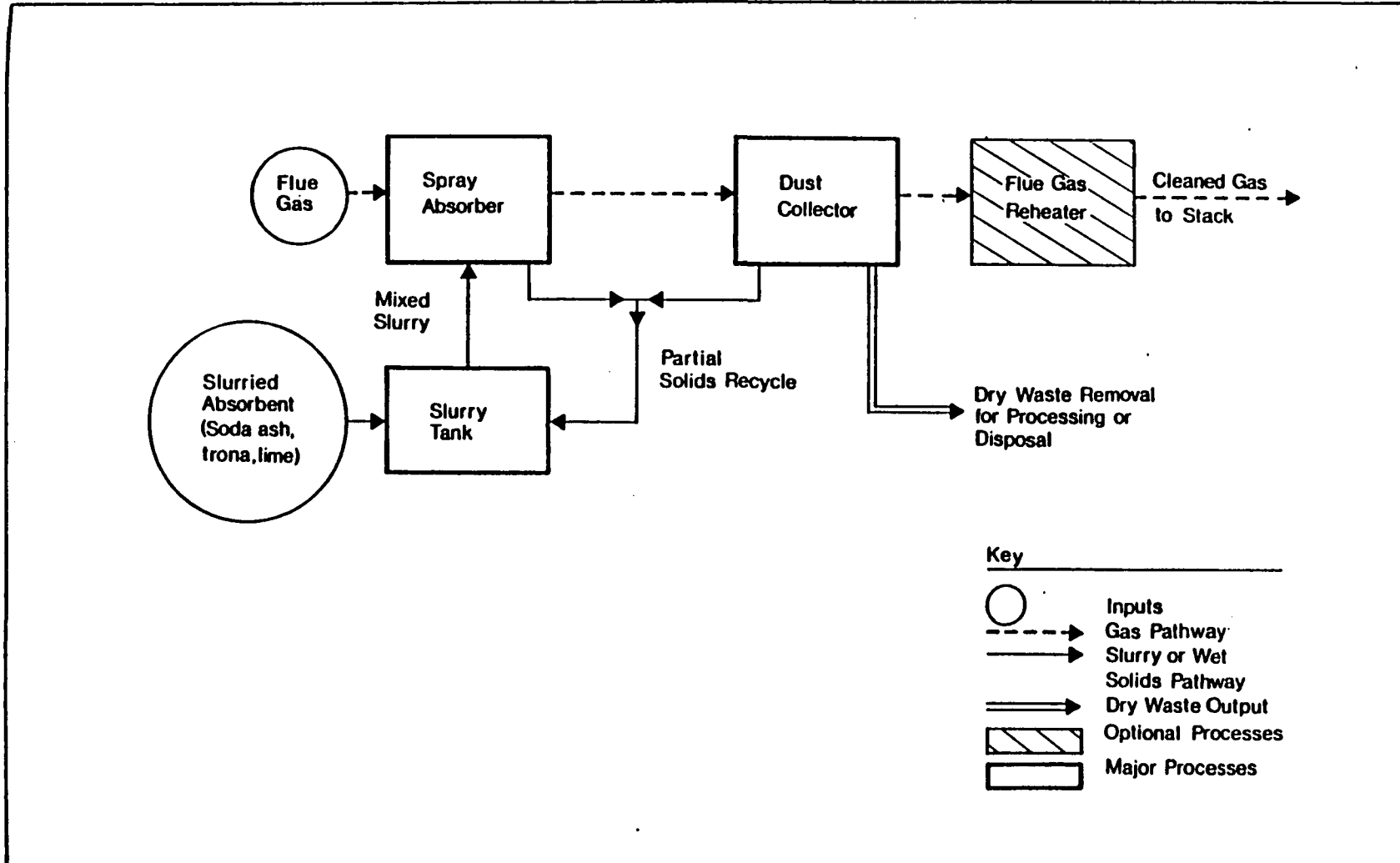
A flow diagram of a spray-drying system is presented in Exhibit 3-11. With this system, a fine spray of an alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water from the absorbent solution, leaving a dry powder. This powder is then collected downstream of the contact chamber by a particulate collector, usually a baghouse. Spray-drying typically removes about 70 percent of the sulfur dioxide from the flue gas.¹⁷ Because of the relatively low percentage reduction in sulfur dioxide achieved by spray-drying scrubbers compared with other scrubber technologies, this dry-scrubbing method is most commonly used for furnaces that burn lower sulfur coals.

Dry sorbent injection, illustrated schematically in Exhibit 3-12, is not yet used commercially by electric utilities, although one utility is designing a generating unit that will use this type of scrubber and which is due to begin operation by 1990.¹⁸ This system involves the injection of a powdered sorbent, either nacholite or trona, into the flue gas upstream of a baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse. The dry wastes, which form a filter cake, are then removed during normal filter cleaning.

Dry injection offers several advantages over traditional wet scrubbing and spray-drying techniques: the required equipment is smaller and less expensive, no water is needed, flue gas reheating is not necessary, and sulfur dioxide and fly ash are removed simultaneously. Potential drawbacks of this process are the limited geographic availability of the sorbents and problems associated with waste disposal. For example, the waste tends to be very water soluble,

EXHIBIT 3-11

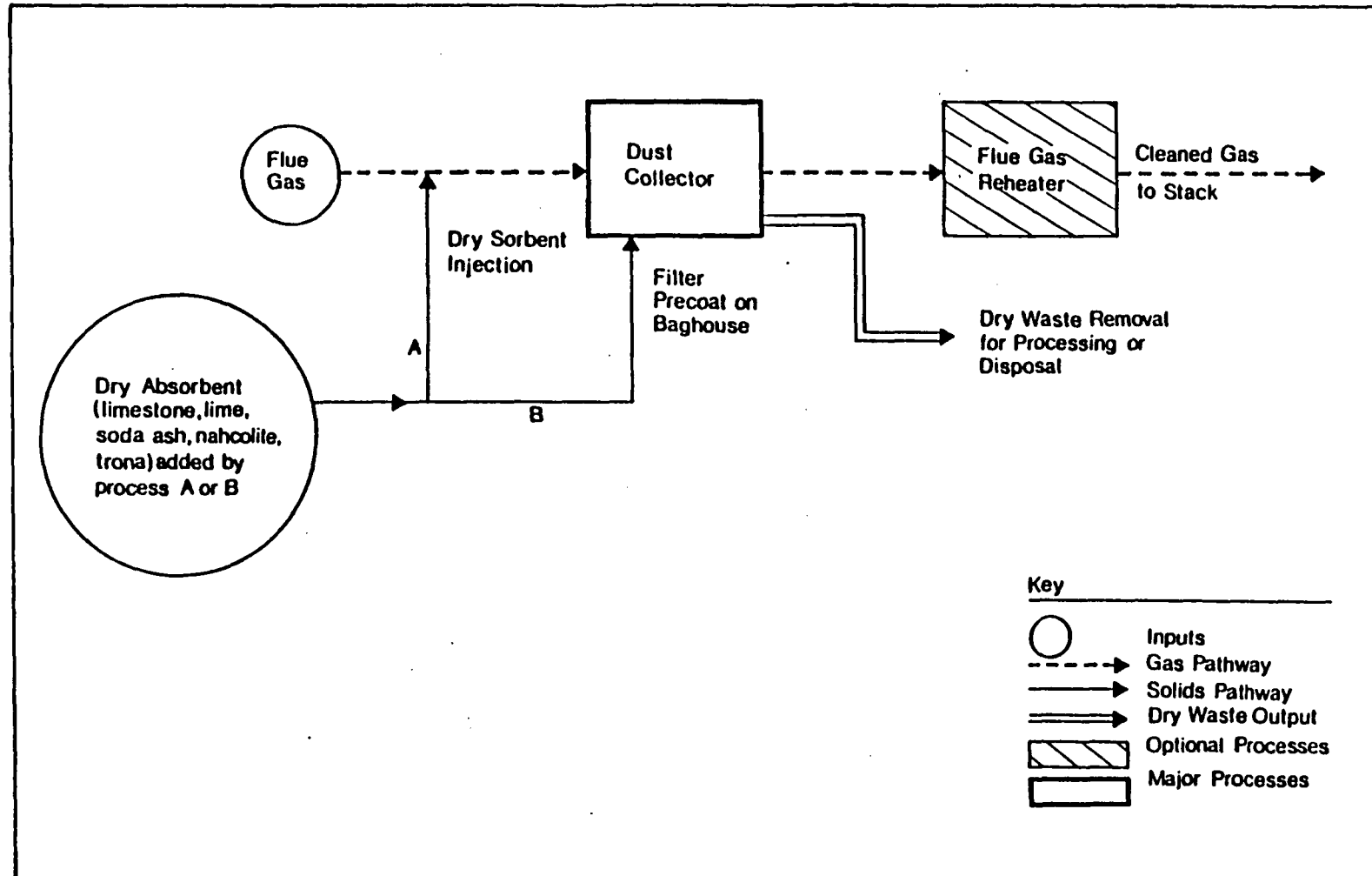
FLOW DIAGRAM OF SPRAY-DRYING FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-5.

EXHIBIT 3-12

FLOW DIAGRAM OF DRY INJECTION FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-6.

and could potentially affect ground-water quality. Also, dry injection is most effective when used for low-sulfur coals, achieving only 70 to 80 percent sulfur dioxide removal in most cases, compared with up to 95 percent removal by wet scrubbing systems.¹⁹

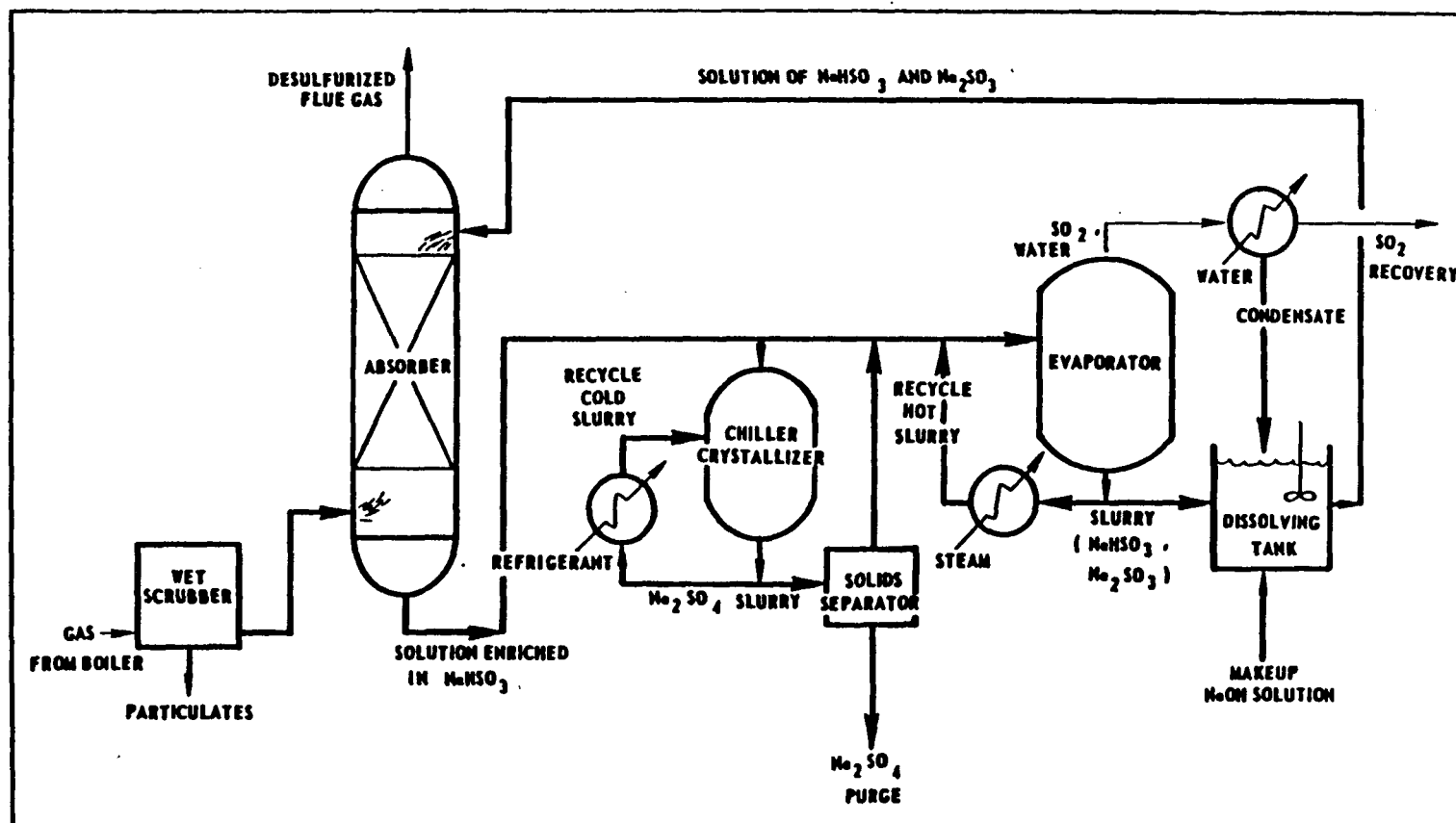
Recovery systems are designed to produce a salable by-product such as sulfur, sulfuric acid, or liquid sulfur dioxide; however, small amounts of waste are still produced. A prescrubber is usually required upstream of the main scrubber to filter out such contaminants as fly ash and chlorides. Secondary waste streams formed by the oxidation of the absorbent are sometimes present and, along with the prescrubber by-products, are the materials that need to be disposed. Two recovery FGD systems presently used commercially, the Wellman-Lord and Magnesium Oxide processes, are both based on wet scrubbing. Diagrams of these systems are shown in Exhibit 3-13. Other recovery systems, both wet and dry, have been developed, but are still in the testing phase.

3.2.2.2 Quantities of FGD Sludge Generated

There has been a large increase in the quantity of FGD sludge generated over the past decade, as shown in Exhibit 3-14. This increase is due to the more widespread use of scrubbers brought about by tightened state limits on sulfur dioxide emissions, the Federal New Source Performance Standards (NSPS) of the Clean Air Act of 1971, and the revisions to the NSPS in 1979. This trend will continue as new power plants are equipped with scrubbers as required under the NSPS. By the year 2000, scrubber capacity is likely to be several times greater than at present.

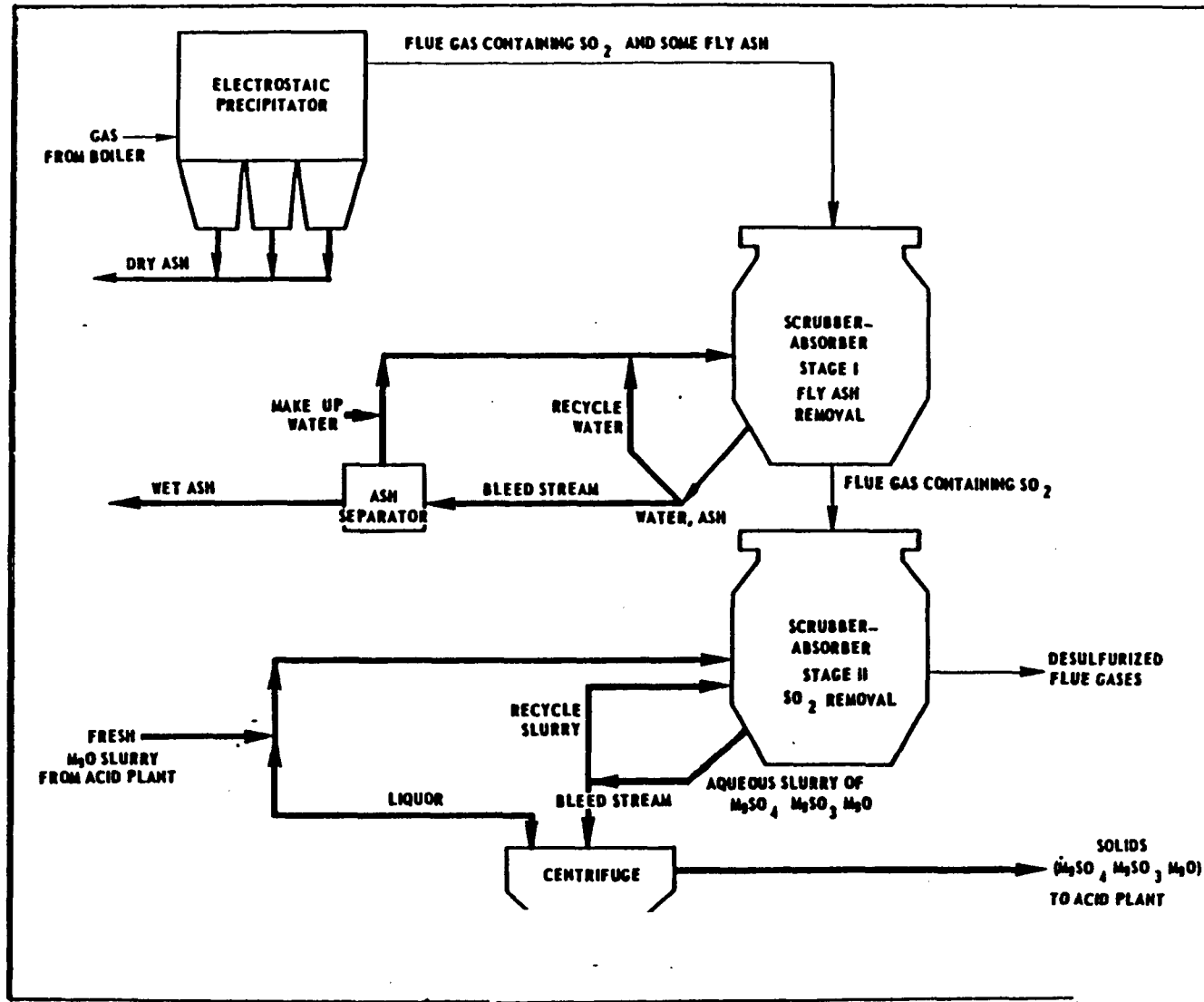
EXHIBIT 3-13
FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS

WELLMAN-LORD PROCESS



Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

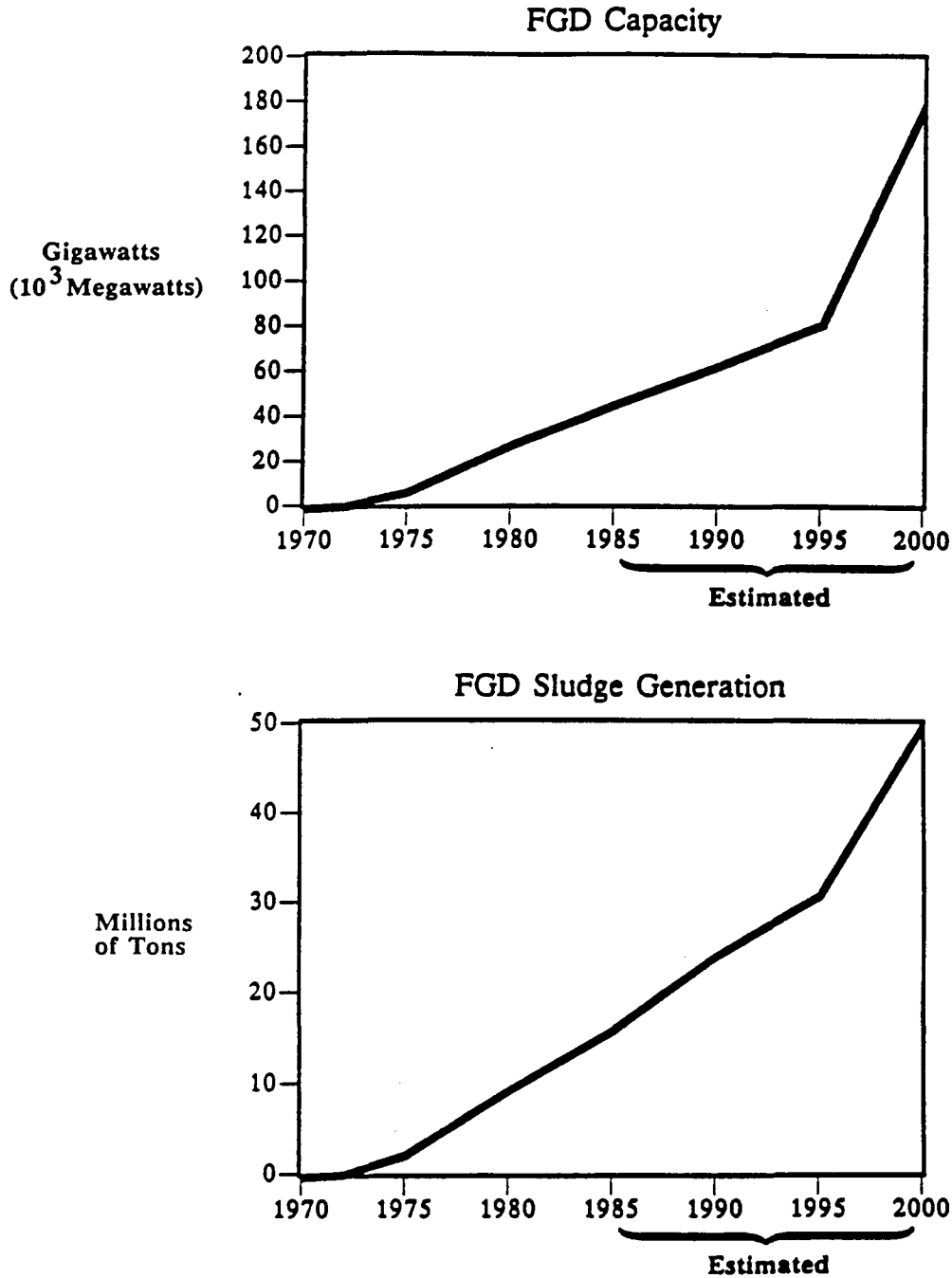
EXHIBIT 3-13 (Continued)
FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS
MAGNESIUM OXIDE PROCESS



Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

EXHIBIT 3-14

FGD CAPACITY AND FGD SLUDGE GENERATION
1970-2000



Source: 1970-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants, and Arthur D. Little, Inc., Full Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Vol. 1, June 1985.

1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

The dramatic increase in scrubber capacity has a direct effect on the amount of scrubber sludge produced. In 1984, about 16 million tons of scrubber sludge were generated. By 2000, the annual amount of sludge produced is estimated to be about 50 million tons, over three times the sludge generated at present.²⁰

All FGD sludge is comprised of spent reagent, which is made up of the chemicals that result from the reaction of the absorbent with the sulfur oxides in the flue gas, plus any unreacted portion of the absorbent. The sludge may also contain water and fly ash. Several factors determine how much spent reagent, water, and ash are present in the FGD sludge. These factors include the type of scrubber system used, the characteristics of the coal, and the sulfur dioxide emission limit that the power plant is required to meet by state or Federal law.

The type of FGD system is an important determinant of the amount of spent reagent, amount of water, and amount of ash present in the sludge. Reagents used in different systems vary as to their absorbent utilization, or "stoichiometry," which is the percentage of the reagent that reacts with the sulfur oxides. A lower percentage implies more reagent is needed to remove a given percentage of sulfur dioxide. Direct limestone systems have an average absorbent utilization of 80 percent, while the direct lime and dual-alkali processes both achieve higher utilization of 90 and 95 percent, respectively. This results in the generation of about six percent more sludge by direct limestone scrubbers compared to direct lime and dual-alkali processes.²¹

Wet systems, both non-recovery and recovery, employ aqueous solutions to remove the sulfur oxides from the flue gas. Dry FGD systems use no water for sulfur oxide removal, although dry FGD wastes may be mixed with water prior to disposal, which increases the volume of sludge. Because of their dependency on water, wet FGD systems generally produce larger volumes of wastes than do dry systems.

Wet FGD systems can also be used as fly ash removal devices. The amount of ash in the sludge depends on how much fly ash is generated by the boiler and whether any other particulate control device is upstream of the scrubber. In particular, alkaline fly ash scrubbers rely on the entrapment of ash to act as their primary absorbent, and therefore their sludge contains large amounts of ash. The collection of fly ash and wastes in a spray-drying system occurs simultaneously by a baghouse; therefore, the wastes from these systems also contain large proportions of ash. Recovery FGD systems often require prescrubbers to remove fly ash. Although recovery systems produce only about half the wastes of non-recovery systems, these wastes are predominantly made up of ash.

Specific characteristics of the coal can have a large effect on the quantity of sludge generated. For example, the higher the sulfur content, the more reagent that must be used to achieve a certain level of sulfur dioxide removal and, consequently, the more spent reagent in the sludge. The ash content of the coal affects the amount of ash caught up in the sludge. Just as using low-sulfur coal will reduce the amount of spent reagent, reducing the ash content prior to combustion will greatly reduce the amount of fly ash that is absorbed by wet scrubbers and thus the amount of sludge that must be disposed.

The amount by which a power plant must reduce sulfur dioxide emissions also affects the volume of sludge produced. To achieve a higher reduction, the amount of reagent used in the scrubber needs to be increased, which will, in turn, produce greater quantities of sludge.

3.2.2.3 Physical Characteristics of FGD Sludge

In general, the same physical properties important in determining the disposal behavior of ash are also important determinants of the disposal characteristics of FGD sludge. These physical characteristics -- particle size, compaction behavior, permeability, and shear strength -- vary considerably depending on the type of scrubber system and what (if any) preparation is done prior to disposal. Exhibit 3-15 presents representative ranges of values for these characteristics of FGD sludge.

Depending on the type of FGD system used, the particle size distribution of FGD sludge can vary substantially. For example, sludge from wet scrubbers tends to have a narrow range of particle sizes. The particles produced by dual-alkali systems are finer than those produced by direct lime or limestone scrubbers, while dry scrubbers generally produce sludge containing larger particles.

The density of FGD sludge depends directly on the method of handling. Wet sludge mixed with ash will have a higher density than untreated sludge, while chemical fixation increases the density even more.²² The density of the particles in dry sludge varies widely.

EXHIBIT 3-15

REPRESENTATIVE RANGES OF VALUES FOR THE
PHYSICAL CHARACTERISTICS OF FGD SLUDGE

	<u>Wet</u>	<u>Dry</u>
Particle Size (mm)	.001-.05	.002-.074
Density (g/cm ³)	0.9-1.7	Variable
Optimum Moisture Content (%)	16-43	0
Permeability (cm/sec)	10 ⁻⁶ -10 ⁻⁴	10 ⁻⁷ -10 ⁻⁶
Unconfined Compressive Strength (psi)	0-1600	41-2250

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-8 - 4-15.

The solids content of scrubber sludge is a function of many things, including whether the sludge is treated prior to disposal, the size of the particles in the sludge, the sulfur content of the coal, the amount of ash present in the sludge, and the desulfurization process used. The percentage of solids in untreated sludges usually ranges from 20 to 40 percent, although it can be as high as 60 percent.²³ Depending on the method of treatment used before disposal (if any), the percentage of solids could be much higher. In fact, some chemical fixation processes are designed to transform the sludge into a cement-like product.

The permeabilities of untreated FGD sludges from wet scrubber systems generally are very similar. Mixing the sludge with fly ash does not necessarily change the degree of permeability, although if fly ash acts as a fixative when added to the sludge, the mixed waste product will have a reduced permeability. Chemical fixation also can decrease permeability. Sludge from dry scrubber systems has low permeability relative to sludge from wet systems.

The shear strength of FGD sludge is referred to as "unconfined compressive strength," which reflects the load-bearing capacity of the sludge. The unconfined compressive strength of sludge is sensitive to the moisture content and age of the sludge. Untreated wet sludge has no compressive strength and is similar to toothpaste in this respect. Mixing with ash or lime increases compressive strength, as does chemical fixation. Also, as the treated sludge ages, its compressive strength becomes greater.

3.2.2.4 Chemical Characteristics of FGD Sludge

The major constituents found in wet FGD sludge are determined by the absorbent reagent used, the quantity of fly ash present, the sulfur content of the coal, and whether or not forced oxidation is used.

Most wet FGD systems operate by causing the sulfur dioxide in the flue gas to react with an absorbent reagent, such as lime or limestone, to form a calcium compound, such as calcium sulfite (CaSO_3), calcium sulfate or gypsum (CaSO_4), or calcium sulfite-sulfate ($\text{CaSO}_3 \cdot \text{CaSO}_4$), which can then be removed from the system in the sludge. The ratio of calcium sulfate to calcium sulfite is generally greater in sludge generated by direct limestone scrubber systems than in that produced by direct lime systems.

Dual-alkali scrubber systems differ slightly in that they use absorbent solutions containing sodium hydroxide (NaOH) or sodium sulfite (Na_2SO_3) as well as lime; sludges from these processes tend to have high levels of calcium sulfite and sodium salts. Because these compounds are highly soluble and apt to leach, they may pose problems as major components in a landfilled sludge.²⁴

Spray-drying scrubber systems produce particulates containing either sodium sulfate (Na_2SO_4) and sodium sulfite (Na_2SO_3) or calcium sulfate (CaSO_4) and calcium sulfite (CaSO_3), depending on whether the reagents are sodium- or calcium-based.

Exhibits 3-16 and 3-17 show the major chemical constituents found in sludge solids and sludge liquors. Oxides of calcium, silicon, magnesium, aluminum, iron, sodium, and potassium can be found in most FGD sludge. The presence of

EXHIBIT 3-16

**CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS
OF WET FGD SLUDGE SOLIDS BY SCRUBBER SYSTEM
AND SOURCE OF COAL *
(percent of total)**

	<u>Direct Lime</u>		<u>Direct Limestone</u>		<u>Dual-Alkali</u>		<u>Alkaline</u>
	<u>East</u>	<u>West</u>	<u>East</u>	<u>West</u>	<u>East</u>	<u>West</u>	<u>Fly Ash</u> <u>West</u>
Calcium Sulfate (CaSO ₄)	15-19	17-95	5-23	85	15-68	82	20
CaSO ₃ ·1/2 H ₂ O	13-69	2-11	17-50	8	13-68	1	15
Calcium Sulfite (CaSO ₃)	1-22	0-3	15-74	6	8-10	11	--
Sodium Sulfate (Na ₂ SO ₄ ·7H ₂ O)	--	--	--	--	4-7	4	--
Fly Ash	16-60	3-59	1-45	3	0-7	8	65

* Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., Bureau of Mine (BOM) Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 4-18.

EXHIBIT 3-17**CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS
OF WET FGD SLUDGE LIQUORS BY SCRUBBER SYSTEM
AND SOURCE OF COAL ^{a/}**

<u>Constituent</u> ^{b/}	<u>Direct Lime</u>	<u>Direct Limestone</u>		<u>Dual-Alkali</u>
	<u>East</u>	<u>East</u>	<u>West</u>	<u>East</u>
pH (units)	8-9.4	5.5-8.4	6.6-6.8	12.1
Total Dissolved Solids	2,800 - 10,260	5400	3300- 14,000	155,700
Chloride	1050-4900	1000	620-4200	4900-5600
Potassium	11-28	24	8-28	320-380
Sodium	36-137	12	370-2250	53,600-55,300
Calcium	660-2520	1600	390-770	7-12
Magnesium	24-420	53	3-9	0.1
Sulfate	800-4500	2500	1360-4000	80,000-84,000
Sulfite	0.9-2.7	160	1-3900	--

^{a/} Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., BOM Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

^{b/} All constituent concentrations, unless noted, in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-20.

these compounds results from the presence of fly ash in the sludge, and they are unreactive in FGD systems. In wet scrubbers that also serve as fly ash collection devices, more than 50 percent of the sludge solids may be ash. However, when an ESP or baghouse precedes the scrubber, ash may make up less than 10 percent of the sludge solids.²⁵

The calcium sulfate/calcium sulfite ratio of the sludge solids is important because sludge containing a greater proportion of sulfates has better disposal properties due to its lower solubility. This ratio is usually higher in systems scrubbing lower sulfur coals and in direct limestone systems. Many scrubber systems add a forced oxidation step to lower the calcium sulfite content of the sludge, thereby lowering its solubility.

The concentration of trace elements in FGD sludge reflects the levels of trace elements in the ash, the efficiency of the scrubber in capturing trace elements in the flue gas, and the trace elements present in the reagent and in the process makeup waters. Fly ash is the primary source of most of the trace elements found in scrubber sludge. Some elements, such as mercury and selenium, may be scrubbed directly from the flue gases and then captured in the scrubber sludge. Exhibit 3-18 illustrates the concentrations at which major trace elements are found in sludge from wet scrubber systems.

3.3 LOW-VOLUME WASTES

Low-volume utility wastes are those waste streams generated in the routine cleaning of plant equipment and in purifying of water used in the combustion process. The types and volumes of low-volume wastes vary among different power

EXHIBIT 3-18

CONCENTRATION OF TRACE ELEMENTS FOUND IN WET-FGD SLUDGES
(Solids and Liquors)

	<u>Sludge Solids</u> a/			<u>Sludge Liquors</u> b/		
	<u>Range</u>		<u>Median</u>	<u>Range</u>		<u>Median</u>
	<u>Low</u>	<u>High</u>		<u>Low</u>	<u>High</u>	
Arsenic	0.8	52.0	12	0.0004	0.1	0.03
Boron	42.0	530.0	14.0	2.1	76.0	14.9
Cadmium	0.1	25.0	10.6	0.002	0.1	0.02
Chromium	1.6	180.0	15.0	0.0002	0.3	0.02
Copper	6.0	340.0	17.5	0.0045	0.5	0.03
Fluoride	266.0	1017.0	625.0	0.2	63.0	2.3
Mercury	0.01	6.0	0.4	0.00006	0.1	0.005
Lead	0.2	290.0	2.4	0.005	0.5	0.03
Selenium	2.0	60.0	5.0	0.003	1.9	0.18

a/ Sludge solid concentrations in milligrams per kilogram.

b/ Sludge liquor concentrations in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-24.

plants, depending on plant-specific factors such as the size of the plant, the type of equipment, and the age of the equipment. Some low-volume wastes commonly produced are:

- boiler blowdown,
- coal pile runoff,
- cooling tower blowdown,
- demineralizer regenerants and rinses,
- metal and boiler cleaning wastes,
- pyrites, and
- sump effluents.

Estimates of the total amount of low-volume wastes generated each year by coal-fired power plants are not available. The frequency of generation and the quantities generated vary widely from power plant to power plant, depending on the maintenance requirements of the plant and operating conditions. Variations also occur within the same power plant, according to its maintenance schedule and operations. Exhibit 3-19 gives representative annual production figures for low-volume wastes generated by a typical power plant.

This section presents for each type of low-volume waste a brief description of how the waste is generated, typical quantities produced, and the physical and chemical composition of the waste.

3.3.1 Boiler Blowdown

Boiler systems can be either a once-through (supercritical) type or a

EXHIBIT 3-19

ANNUAL LOW-VOLUME WASTE GENERATION
AT A REPRESENTATIVE COAL-FIRED POWER PLANT *

<u>Type of Waste</u>	<u>Average Annual Production</u>
Boiler Blowdown	11 million gallons/year
Coal Pile Runoff	20 inches/year
Cooling Tower Blowdown	2.6 billion gallons/year
Demineralizer Regenerant	5 million gallons/year
Gas-side Boiler Cleaning	700,000 gallons/year
Water-Side Boiler Cleaning	180,000 gallons/year
Pyrites	65,000 tons/year

* Assuming a 500 megawatt power plant, operating at 70 percent capacity.

Sources: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979; Volume II: Water Management, EPA-600/7-80-012b, March 1980.

drum-type. In drum-type boiler systems, after steam passes through the turbines, it is converted back to water in the condenser and is recirculated through the boiler to produce steam again. In this process, impurities that become concentrated in the feedwater periodically must be purged from the system. This waste stream is known as boiler blowdown. A once-through system, however, maintains pressurized steam throughout the cycle, and thus does not require the recirculation of water. These boiler types, therefore, do not generate boiler blowdown.

Boiler blowdown is produced either in a continuous stream or intermittently during the day. The flow is adjusted in order to maintain the desired water quality in the boiler and is dependent on the quality of the feedwater and the size and condition of the boiler. The average blowdown rate for a 500 megawatt unit can range from 20 to 60 gallons per minute, or about 2 to 7 gallons per megawatt-hour.²⁶

Boiler blowdown is generally fairly alkaline with a low level of total dissolved solids. The waste stream usually contains certain chemical additives used to control scale and corrosion. Trace elements commonly found in boiler blowdown are copper, iron, and nickel. The components and characteristics of boiler blowdown are presented in Exhibit 3-20.

3.3.2 Coal Pile Runoff

Power plants typically maintain two types of coal storage piles in their coal yards: an active pile to supply their immediate needs and an inactive or long-term pile, which generally stores a 60- to 90-day supply of coal. Coal

3-46

EXHIBIT 3-20

CHARACTERISTICS OF BOILER BLOWDOWN

<u>Parameter</u>	<u>a/</u> <u>Range</u>	
	<u>Low</u>	<u>High</u>
pH (units)	8.3	12.0
Total Solids	125.0	1,407.0
Total Suspended Solids	2.7	31.0
Total Dissolved Solids	11.0	1,405.0
BOD5	10.8	11.7
COD	2.0	157.0
Hydroxide Alkalinity	10.0	100.0
Oil and Grease	1.0	14.8
Phosphate (total)	1.5	50.0
Ammonia	0.0	2.0
Cyanide (total)	0.005	0.014
Chromium (total)	0.02	b/
Chromium (Hexavalent)	0.005	0.009
Copper	0.02	0.2
Iron	0.03	1.4
Nickel	0.03	b/
Zinc	0.01	0.05

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

piles are usually 25-40 feet high and can cover an area of up to 75 acres, depending on the size and demands of the power plant.²⁷ Inactive coal piles are generally sealed with a tar spray to protect the coal against the weather; active piles are usually open and exposed. Coal pile runoff is formed when water comes into contact with the piles, whether from rainfall or snowfall, during spraying for dust control, or from underground streams that surface under the piles.

The quantity of coal pile runoff depends primarily on rainfall and, to a lesser extent, the permeability of the soil. It has been estimated that, on average, 73 percent of the total rainfall on coal piles becomes coal pile runoff.²⁸

The composition of coal pile runoff is influenced by the composition of the coal, the drainage patterns of the coal pile, and the amount of water that has seeped through. Bituminous coals generate runoff that is usually acidic, with the level of acidity depending on the availability of neutralizing materials in the coal, while subbituminous coals tend to produce neutral to alkaline runoff. Elements commonly found in high concentrations in coal pile runoff are copper, zinc, magnesium, aluminum, chloride, iron, sodium, and sulfate. Exhibit 3-21 displays ranges of concentrations for these and other characteristics.

3.3.3 Cooling Tower Blowdown

Power plants need cooling systems to dissipate the heat energy that remains after the production of electricity.²⁹ The two major types of cooling systems are once-through and recirculating. Cooling tower blowdown generally refers to

EXHIBIT 3-21

CHARACTERISTICS OF COAL PILE RUNOFF

Parameter	a/ Range	
	Low	High
pH (units)	2.1	9.3 b/
Acidity (as CaCO ₃)	300.0	7,100.0
Total Dissolved Solids	270.0	28,970.0
Total Suspended Solids	8.0	2,500.0
Aluminum	20.0	1,200.0
Ammonia	0.0	1.8
Arsenic	0.005	0.6
Beryllium	0.01	0.07
Cadmium	0.001	0.003
Chloride	3.6	481.0
Chromium	0.005	16.0
Cobalt	0.025	--
Copper	0.01	6.1
Iron	0.1	5,250.0
Magnesium	0.0	174.0
Manganese	0.9	180.0
Mercury	0.0002	0.007
Nickel	0.1	4.5
Nitrate	0.3	1.9
Phosphorus	0.2	1.2
Selenium	0.001	0.03
Sodium	160.0	1,260.0
Sulfate	130.0	20,000.0
Zinc	0.006	26.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All information, unless noted otherwise, is from EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

the water withdrawn from a recirculating cooling system to control the concentration of impurities in the cooling water; although once-through systems also discharge water from the cooling system, this discharge is not typically referred to as cooling tower blowdown. At present, about two-thirds of electric utility power plants use a once-through cooling system. This percentage may decrease, however, due to concern over water availability and potential environmental concern over thermal discharges; consequently, future plants may be built with recirculating systems that use cooling towers or cooling ponds.³⁰

Once-through cooling systems are primarily used by power plants located next to large bodies of water. After passing through the condenser, the cooling water is discharged, usually into a river, lake, or pond. The quantity discharged ranges from 26,000 to 93,000 gallons per megawatt-hour. For a 500 megawatt plant, this roughly equals 70-300 billion gallons per year.³¹ In most instances, the chemical composition of the water remains the same after passing through the condenser, but some changes may occur as the result of the formation of corrosion products or the addition of biocides.

Recirculating cooling systems can use either cooling ponds or cooling towers. In a cooling pond system, water is drawn from a large body of water, such as a pond or canal. After it passes through the condenser to absorb waste heat, the water is recycled back into the pond or canal. Cooling tower systems operate by spraying the water through a cooling tower. About 80 percent of the waste heat contained in the water is then released through evaporation. The remainder of the water is recycled back through the cooling tower system. Cooling tower blowdown is a waste stream bled off to control the concentrations

of impurities and contaminants in the cooling system that could lead to scale formation in the condenser.³²

The cooling tower blowdown rate is adjusted to maintain water quality in the recirculating cooling system in order to prevent scale formation in the condenser. The quantity of blowdown generated is a function of the quality of the makeup water (the water added to the system to replace that which is lost by evaporation and blowdown), the condition of the cooling system, and the amount of water evaporated by the cooling tower. For a representative 500 megawatt unit, the blowdown rate varies between 2 and 30 cubic feet (15 to 225 gallons) per second.³³

The composition and quantity of cooling tower blowdown varies greatly from plant to plant. It generally reflects the characteristics of the makeup waters (e.g., fresh water versus brackish or saline water) and the chemicals added to prevent the growth of fungi, algae, and bacteria in the cooling towers and to prevent corrosion in the condensers. Some of these chemical additives are chlorine, chromate, zinc, phosphate, and silicate. Ranges of concentration for some of the characteristics and components of cooling tower blowdown are shown in Exhibit 3-22.

3.3.4 Demineralizer Regenerant and Rinses

A power plant must treat water prior to its use as makeup water. The use of demineralizers is the most common method of purification. During the demineralization process, which may entail several rinses, high-purity process water is provided for the boiler through an ion exchange process. The wastes

EXHIBIT 3-22

CHARACTERISTICS OF COOLING TOWER BLOWDOWN

Parameter	a/ Range	
	Low	High
Alkalinity (as CaCO ₃)	8.0	556.0
BOD	--	94.0
COD	--	436.0
Total Solids	750.0	32,678.0
Total Dissolved Solids	4.1	32,676.0
Total Suspended Solids	0.2	220.0
Ammonia (as N)	0.01	11.6
Nitrate (as N)	0.1	711.0
Phosphorus (as P)	0.1	17.7
Total Hardness (as CaCO ₃)	84.0	2,580.0
Sulfate	7.2	20,658.0
Chloride	5.0	16,300.0
Fluoride <u>b/</u>	0.3	33.0
Aluminum <u>b/</u>	1,100.0	1,700.0
Boron <u>b/</u>	0.5	1.0
Chromium (ug/l)	0.02	120.0
Copper (ug/l)	0.01	1,740.0
Iron (ug/l))	0.1	1,160.0
Lead (ug/l) <u>b/</u>	4.0	--
Magnesium (ug/l)	0.1	1,580.0
Manganese (ug/l) <u>b/</u>	24.0	220.0
Mercury (ug/l) <u>b/</u>	1.5	--
Nickel (ug/l)	0.03	150.0
Zinc (ug/l)	0.02	3,000.0
Oil & Grease	1.0	7.4
Phenols (ug/l)	--	72.0
Surfactants	0.2	--
Sodium	3.4	11,578.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

produced in this process can be either acidic or alkaline. When sulfuric acid is employed as the regenerant, calcium sulfate is precipitated in the waste stream. Exhibit 3-23 presents ranges for the components of demineralizer regenerants and rinses.

Regeneration of boiler makeup water by demineralizers is done on a batch basis. The frequency with which the process occurs depends on the quality of the incoming water, although for a 500 megawatt unit, regeneration usually occurs every one to four days. A single regeneration requires approximately 30,000 gallons of water, which amounts to about 3-10 million gallons per year.³⁴

3.3.5 Metal and Boiler Cleaning Wastes

This category of low-volume waste streams can be divided into two basic types: gas-side cleaning wastes and water-side cleaning wastes. Gas-side wastes are produced during maintenance of the gas-side of the boiler, which includes the air preheater, economizer, superheater, stack, and ancillary equipment. Residues from coal combustion (such as soot and fly ash), which build up on these surfaces, must be removed periodically -- usually with plain water containing no chemical additives.

Water-side wastes are produced during cleaning of the boiler tubes, the superheater, and the condenser, which are located on the water-side or steam-side of the boiler. The scale and corrosion products that build up on these boiler parts must be removed with cleaning solutions containing chemical additives.

EXHIBIT 3-23

CHARACTERISTICS OF
SPENT DEMINERALIZER REGENERANTS

Parameter	a/ Range	
	Low	High
Alkalinity (as CaCO ₃)	0.0	3,831.0
BOD	0.0	344.0
COD	0.0	440.0
Total Solids	284.0	36,237.0
Total Dissolved Solids	283.0	25,235.0
Total Suspended Solids	0.0	300.0 c/
Ammonia (as N)	0.0	435.0
Phosphorus (as P)	0.0	87.2
Turbidity (JTU)	2.5	100.0
Total Hardness (as CaCO ₃)	0.0	8,000.0
Sulfate	4.5	9,947.0
Chloride	0.0	20,500.0
Boron	0.0	0.1
Chromium	0.0	2,168.0
Copper (ug/l)	0.0	3,091.0
Iron (ug/l)	0.0	2,250.0
Lead (ug/l) b/	160.0	37,500.0
Magnesium (ug/l)	0.0	753.0
Manganese (ug/l)	0.0	3,100.0
Mercury (ug/l)	0.05	--
Nickel (ug/l)	0.0	560.0
Zinc (ug/l)	0.0	4,500.0
Oil & Grease b/	0.0	24.5
Phenols (ug/l)	0.0	303,000.0
Surfactants b/	1.7	--
Nitrate as N	0.0	118.0
Algicides b/	0.003	--
Sodium	4.9	30,000.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these components were limited.

c/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

The boiler and auxiliary equipment are cleaned intermittently, creating large quantities of wastes in a short time. Gas-side boiler cleaning is done approximately twice a year. The volume of the waste stream produced depends on the size of the boiler and the number of rinses. For a typical plant, gas-side cleanings can produce between 24,000 and 700,000 gallons of wastes. Water-side equipment is cleaned less frequently, approximately once every three years. As is true of gas-side cleaning, the volume of waste produced varies with the number of rinses. A representative 500 megawatt unit generates about 120,000-240,000 gallons of wastewater per treatment.³⁵

Because no chemicals are used, the composition of the waste streams associated with gas-side cleaning directly reflects the composition of the soot and fly ash residues and, therefore, of the coal that is burned. Exhibit 3-24 shows two reported values for components and characteristics of gas-side cleaning waste streams.

The particular solution used for the cleaning of the water-side of the boiler varies depending on the equipment being cleaned and the type of scale that needs to be removed. When the scale contains high levels of metallic copper, an alkaline solution that contains ammonium salts, an oxidizing agent such as potassium or sodium bromate or chlorate, and nitrates or nitrites is used. Exhibit 3-25 presents some of the major characteristics associated with these types of solutions and representative ranges of concentrations in which they are found.

For the removal of scale caused by water hardness, iron oxides, and copper oxide, an acid cleaning solution is needed. Usually hydrochloric acid acts as

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EXHIBIT 3-24

REPORTED CHARACTERISTICS OF GAS-SIDE CLEANING WASTES

<u>Parameter</u>	<u>Quantities Produced per Cleaning</u> <u>(in lbs. except as noted) a/</u>	
	<u>Source A</u>	<u>Source B</u>
Cleaning Frequency (cycles/yr)	2.0	8.0
Batch Volume (1000 gallons)	720.0	24.0
Alkalinity	0.0	6.0
COD	1,134.0	19.0
Total Solids	40,861.0	4,002.0
Total Dissolved Solids	35,127.0	3,002.0
Total Suspended Solids	3,823.0	119.1
Turbidity (JTU)	476.0	98.0
Hardness	35,409.0	791.4
Ammonia	1.5	0.4
Chloride	0.0	18.0
Chromium (total)	0.03	1.0
Copper	--	0.3
Iron	900.0	30.0
Lead	--	--
Magnesium	11,949.0	190.3
Nickel	30.0	--
Nitrate	14.7	0.7
Phosphorus	11.1	0.3
Sodium	0.0	9.0
Sulfate	11,949.0	299.4
Vanadium	--	--
Zinc	28.7	2.0

a/ Quantities produced are shown for two different reported values.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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EXHIBIT 3-25

CHARACTERISTICS OF SPENT WATER-SIDE
ALKALINE CLEANING WASTES

Parameter	a/ Range	
	Low	High
Alkalinity (as CaCO ₃)	20,200.0	25,700.0
NH ₃ -N	4,280.0	6,360.0
Kjeldahl-N	5,190.0	7,850.0
Nitrate-N	1.0	193.0
Oil & Grease	7.9	10.3
BOD ₅	5,820.0	8,060.0
COD	14,600.0	20,900.0
Total Suspended Solids	5,580.0	6,720.0
Total Dissolved Solids	10.0	400.0
TDS	22,100.0	32,300.0
Total Iron	180.0	10,800.0
Silica	1.0	40.0
Chromium	0.2	7.7 b/
Copper	8.0	1,912.0
Lead	0.004 b/	23.0 b/
Manganese	0.1	14.3
Nickel	2.5	130.0
Tin	2.0	20.7
Zinc	3.1	390.0
pH (units)	8.4 b/	10.3 b/

a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

the solvent in these solutions, although sulfuric, phosphoric, and nitric acids can also be used. Organic acids have been used increasingly as substitutes for hydrochloric acid because of their lower toxicity. For the removal of silica deposits, hydrofluoric acid or fluoride salts are added to the cleaning solution. Exhibit 3-26 presents the various characteristics of acid boiler cleaning solutions.

Alkaline chelating rinses and alkaline passivating rinses are often used to remove iron and copper compounds and silica and to neutralize any residual acidity left over from acid cleaning. These solutions may contain phosphates, chromates, nitrates, nitrites, ammonia, EDTA, citrates, gluconates, caustic soda, or soda ash. Exhibit 3-27 gives representative ranges for these components and others present in these rinses.

3.3.6 Pyrites

Pyrites are the solid mineral compounds, such as iron sulfides or other rock-like substances, present in raw coal. Most pyrites are generally separated out before coal is burned, usually at a preparation plant prior to shipment to the power plant. Smaller quantities of pyrites are often removed at the power plant just before the coal is pulverized. The size of the deposits depends on the method by which they are separated from the coal.

The volume of pyrites collected at a power plant depends on the amount and quality of the coal that is burned, which is determined by the source of the coal and the preparation process, as well as by the coal pulverization process.

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EXHIBIT 3-26

**CHARACTERISTICS OF SPENT WATER-SIDE
HYDROCHLORIC ACID CLEANING WASTES**

<u>Parameter</u>	<u>a/</u> <u>Range</u>	
	<u>Low</u>	<u>High</u>
pH (units)	0.5	3.3
Total Suspended Solids	8.0	2375.0
Silica	19.0	280.0
NH3-N	80.0	325.0
Nitrogen	1.0	870.0
Phosphorus	1.0	300.0
Sulfate	1.0	10.0
Aluminum	6.5	8.2
Arsenic	0.01	0.1
Barium	0.1	0.4
Beryllium	0.0	0.1
Cadmium	0.001	0.13 b/
Calcium	16.0	980.0
Chromium	0.005	16.8
Copper	2.2	960.0
Iron	1125.0	6470.0
Lead	0.01	5.2
Magnesium	5.7	8.8
Manganese	6.9	29.0
Mercury	0.0	0.002
Nickel	3.0	500.0
Potassium	1.4	2.3
Selenium	0.002	0.004
Silver	0.02	0.2 b/
Sodium	9.2	74.0
Tin	1.0	7.3
Zinc	0.9	840.0

a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

EXHIBIT 3-27

CHARACTERISTICS OF SPENT WATER-SIDE
ALKALINE PASSIVATING WASTES

Parameter	Range*	
	Low	High
pH (units)	9.2	10.0
Total Suspended Solids	13.0	45.0
NH3-N	15.0	232.0
Kjeldahl-N	97.0	351.0
Nitrite-N	7.0	12.9
BOD5	40.0	127.0
COD	98.0	543.0
TOC	16.0	23.0
Iron	7.5	28.0
Chromium	0.0	0.4
Copper	0.1	1.2

* All concentrations, unless noted, in milligrams per liter.

Source: EnviroSphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

The amount of pyrites to be disposed at a power plant can vary considerably, although coal typically contains up to 5 percent pyrites.³⁶ A 500 megawatt plant, depending on how often it operates and the quality of its coal, will generate, on average, between 30,000 and 100,000 tons of pyrites per year. The characteristics of pyrites and pyrite slurry transport water are shown in Exhibit 3-28.

3.3.7 Sump Effluents

Floor and yard drains collect waste streams from a variety of sources at power plants, such as rainfall, seepage from ground-water sources, leakage, small equipment cleaning operations, and process spills and leaks. As a result, the composition of drain effluents is highly variable. Depending on the particular circumstances at the power plant, these waste streams may contain coal dust, fly ash, oil, and detergents.

The frequency of sump effluent generation and quantities generated are very plant-specific. The more efficient a plant's operating procedures, the smaller this waste stream will be. Also, power plants located in dry areas of the country will have relatively small amounts of wastes collected in yard drains.

3.4 SUMMARY

In the process of generating electricity, coal-fired utility power plants produce a number of waste products. These wastes are produced in large quantities and have widely varying physical and chemical characteristics.

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EXHIBIT 3-28

CHARACTERISTICS OF PYRITES AND
PYRITE TRANSPORT WATER

<u>Parameter</u>	<u>Pyrite Slurry Water</u> ^{a/}	<u>Pyrites</u> ^{b/} <u>Solid Form</u>
Total Suspended Solids	1,700.0	--
Total Aluminum	93.3	--
Total Calcium	134.0	--
Total Iron	220.0	--
Total Magnesium	13.6	--
Sulfate	177.0	--
pH (units)	7.7	--
Arsenic	--	500-5000
Chromium	0.1	--
Copper	0.1	10-10,000
Lead	0.1	200-1000
Zinc	0.3	500-10,000
Manganese	--	10-5000
Selenium	--	10-100
Silica	212.0	--
Silver	--	10-50
Cobalt	--	100-5000
Nickel	--	10-1000
Vanadium	--	100-200

a/ All concentrations, unless noted, in milligrams per liter.

b/ All concentrations in parts per million.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

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- Coal-fired electric utility power plants produce three major forms of wastes:
 - 1) Ash, formed from the noncombustible material present in coal. There are three types of ash -- fly ash, bottom ash, and boiler slag;
 - 2) FGD sludge, produced by flue gas desulfurization systems designed to remove sulfur oxides from flue gas; and
 - 3) Low-volume wastes, generated primarily from equipment maintenance and cleaning operations.

- In 1984, about 69 million tons of ash and about 16 million tons of FGD sludge were produced by coal-fired electric utilities. By the year 2000, these wastes are expected to increase to about 120 million and 50 million tons, respectively.

- Several physical characteristics of utility waste determine the waste's behavior during disposal and the potential for leachate problems. These characteristics vary a great deal among the different types of ash and FGD sludge.

- The chemical constituents of ash and FGD sludge largely depend on the chemical components in the coal. Other chemical compounds present in FGD sludge, primarily calcium and sodium salts, are the result of the reactions between the absorbent reagent used and the sulfur oxides in the flue gas.

- Compared with ash and FGD sludge, low-volume wastes are generally produced in much smaller quantities. Many of these wastes contain various chemicals from the cleaning solutions used for power plant operations and maintenance; potentially-hazardous elements in these chemicals may be found at high concentrations in the low-volume waste.

CHAPTER THREE**NOTES**

¹ See Appendix B for a more in-depth discussion of boiler types and how the type of boiler affects the types of waste that are generated.

² Babcock & Wilcox, Steam: Its Generation and Use, New York: The Babcock & Wilcox Company, 1978, p. 18-3.

³ Ibid.

⁴ Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants-1985, DOE/EIA-0191(85), July 1986.

⁵ ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Pound Sulfur Dioxide Emission Reduction Cases, prepared for EPA, February 1986. There are many factors that can affect the amount of coal consumed, including electricity growth rates, oil and gas prices, types of technology available, etc. Nevertheless, utilities will continue to burn substantial amounts of coal in the foreseeable future.

⁶ Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 45.

⁷ There are presently over 500 coal cleaning plants in the U.S., the majority of which are operated by coal companies and located at the mouth of the mine. The type of cleaning method employed depends upon the size of the coal pieces to be cleaned, a factor that can be controlled at the cleaning plant.

The most widely used methods of coal cleaning are those that use specific gravity, relying on the principle that heavier particles (i.e., impurities) separate from lighter ones (i.e., coal) when settling in fluid. A common method of cleaning coarse coal pieces is to pulse currents of water through a bed of coal in a jig; impurities, such as shale and pyrite, sink, while the coal floats on top. The heavy, or dense, media process is used for cleaning coarse and intermediate-sized pieces. A mixture of water and ground magnetite, having a specific gravity between that of coal and its impurities, acts as a separating fluid. An inclined vibrating platform with diagonal grooves, known as a concentrating table, also is used to clean intermediate-sized coal pieces. Raw coal slurry is fed onto the high end of the table. As the slurry flows down, the vibrations separate the coal from the refuse, allowing the lighter coal to be carried along in the water, while the heavier impurities are trapped in the grooves.

Because of their small size, fine coal particles are very difficult to clean. Their recovery is important, however, because these particles can provide up to 25 percent of the energy derived from raw coal. A popular method of fine coal cleaning is froth flotation. The coal pieces are coated with oil and then agitated in a controlled mixture of water, air, and reagents until froth is formed on the surface. Bubbles tend to attach to the coal pieces, keeping them buoyant, while heavier particles such as pyrite, shale, and slate remain dispersed in the water. The coal can then be removed from the

surface. For more information, see Coal Preparation, 4th edition, Joseph Leonard, editor, American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., 1979.

⁸ Ash melts when heated to a sufficiently high temperature. The temperatures at which the ash changes forms -- e.g., melting from a cone shape to a spherical shape to a hemispherical shape to a flat layer -- are referred to as ash fusion temperatures.

⁹ Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 3-4. A micron is 0.001 millimeters.

¹⁰ Ibid.

¹¹ The compressibility of a material is measured as the ratio of its height at 50 psi to its original height at atmospheric pressure. The dry density, the ratio of weight to unit volume of the material containing no water, affects permeability and strength, which in turn determine the structural stability of a landfill and the extent of leachate mobility. The optimum moisture content is the moisture content, in percentage terms, at which the material attains its maximum density.

¹² In 1979 the New Source Performance Standards, part of the Clean Air Act of 1971, were revised. The new regulations required that all coal-fired electric utility units with capacity greater than 73 megawatts, whose construction commenced after September 18, 1978, would not only have to meet a 1.2 pound sulfur dioxide per million Btu emission limit, but would have to do so by a continuous system of emissions reduction. New power plants must reduce sulfur dioxide emissions between 70 and 90 percent, depending on the type of coal burned.

¹³ During fluidized bed combustion the sulfur oxides react with limestone or dolomite to form calcium sulfate. In LIMB technology, limestone is injected into the boiler, also forming calcium compounds.

¹⁴ Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, p. VII-15.

¹⁵ Ibid., p. VII-18.

¹⁶ Ibid., p. VII-23.

¹⁷ Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 4-4.

¹⁸ "Dry Capture of SO₂," EPRI Journal, March 1984, p. 21.

¹⁹ Ibid., p. 15.

- 20 ICF, op. cit. See Appendix B for a detailed explanation of how future FGD sludge estimates were derived.
- 21 U.S. Environmental Protection Agency, Controlling SO2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Volume I, EPA-600/7-78-044a, March 1978, p. 23.
- 22 See Chapter Four for a detailed discussion of the methods of sludge fixation.
- 23 Michael Baker, Jr., Inc., State-of-the-Art of FGD Sludge Fixation, prepared for Electric Power Research Institute, January 1978, p. 2-25.
- 24 Tetra Tech, Inc., op. cit., p. 4-17.
- 25 Ibid.
- 26 Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 26.
- 27 U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979: Volume II: Water Management, EPA-600/7-80-012b, March 1980, p. 3-146.
- 28 Ibid., p. 3-147.
- 29 Ibid., p. 3-16. About 35 to 40 percent of the total heat input of a power plant is converted to electricity, about 5 percent is lost in the stack gases, and the remaining 55 to 60 percent is rejected in the condenser.
- 30 Ibid., p. 3-17.
- 31 Ibid.
- 32 The term "cooling tower blowdown" refers to the waste waters produced by all recirculating cooling systems, whether they use a cooling pond or a cooling tower.
- 33 U.S. EPA, Waste and Water Management, p. 3-19.
- 34 Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 27.
- 35 Ibid., p. 27.
- 36 Ibid., p. 28. The term "pyrites" is used to refer to a variety of rock-like substances that may be found in raw coal; it does not just refer to pyritic sulfur that is found in all raw coal, although pyritic sulfur is typically part of the pyrites generated at a power plant.

CHAPTER FOUR**COAL COMBUSTION WASTE MANAGEMENT PRACTICES**

Under Section 8002(n) of RCRA, EPA is to analyze "present disposal and utilization practices" and "alternatives to current disposal methods." This chapter addresses these issues by first examining the various state regulations that affect coal combustion disposal since these regulations set the context for current practices. The following section describes coal combustion waste management practices. First, three commonly employed types of land management practices are described in detail. Next, this chapter describes additional measures currently employed by some utilities; more widespread use of these technologies could be employed as an alternative to current practices. Ocean disposal, an alternative that is in the research and development stage, is also addressed in this chapter. Finally, the extent of coal combustion waste recycling as an alternative to disposal is described.

4.1 STATE REGULATION OF COAL COMBUSTION WASTE DISPOSAL

Since coal combustion wastes are currently exempt from Federal hazardous waste regulation under RCRA, their regulation is primarily carried out under the authority of state hazardous and solid waste laws. State solid waste laws establish programs to provide for the safe management of non-hazardous solid wastes. If solid wastes are considered hazardous, state hazardous waste laws establish programs to provide for their safe management. To implement these laws, state health or environmental protection agencies promulgate solid and hazardous waste regulations. A 1983 report for the Utility Solid Waste Activities Group (USWAG) surveyed these regulations; the USWAG report provided

summaries of state regulations based on applicable state laws, regulations, and interviews with state environmental officials.¹ EPA updated the information provided in the USWAG summaries for the purposes of this report.

Exhibit 4-1 lists the disposal requirements promulgated under each state's solid waste (non-hazardous) regulations. (As will be discussed below, it is very rare for coal combustion wastes to be regulated as hazardous under state regulations.) The list of states is arranged in descending order according to each state's share of national coal-fired generating capacity (Column 1 of Exhibit 4-1). The information shown in the Exhibit is discussed in detail in Sections 4.1.1 and 4.1.2.

4.1.1 State Classification of Coal Combustion Wastes

Forty-three states have exempted coal combustion wastes from hazardous waste regulation.² As a result, in these states the state solid waste laws, which apply to non-hazardous wastes, regulate the disposal of these coal combustion wastes. Column 2 of Exhibit 4-1 shows that: (1) in seven states, coal combustion wastes are not exempt from hazardous waste regulation (indicated by an entry of CH), which means that they are tested to determine whether they will be regulated as solid or hazardous wastes; (2) in all but one of the remaining states wastes are regulated by solid waste regulations (indicated by an entry of SW); and (3) in the one remaining state, wastes are exempt from both the hazardous waste and solid waste regulations (indicated by an entry of EX).

EXHIBIT 4-1
STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
Texas	8.40%	SW	OFF SITE	NO	NO	NO	MAY	YES	YES
Indiana	6.44%	SW	ON & OFF SITE	NO	NO	NO	MAY	NO	NO
Kentucky	6.43%	CH	ON & OFF SITE	YES	MAY	YES	MAY	YES	NO
Ohio	6.02%	EX							
Pennsylvania	5.71%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Illinois	5.46%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	YES
West Virginia	3.87%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
North Carolina	3.41%	SW	ON & OFF SITE	YES	NO	NO	YES	YES	NO
Michigan	3.37%	SW	ON & OFF SITE	YES	NO	NO	YES	NO	NO
Georgia	3.35%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Florida	3.26%	SW	OFF SITE	YES	YES	YES	YES	YES	YES
Missouri	3.16%	SW	ON & OFF SITE	YES	NO	MAY	NO	YES	NO
Alabama	3.08%	SW	ON & OFF SITE	YES	MAY	NO	YES	YES	NO
Tennessee	2.54%	CH	ON & OFF SITE	YES	MAY	NO	MAY	YES	NO
Nevada	2.49%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
South Carolina	2.24%	SW	ON & OFF SITE	YES	NO	YES	NO	YES	NO
Wisconsin	2.19%	SW	ON & OFF SITE	YES	MAY	MAY	MAY	YES	YES
Louisiana	1.98%	SW	ON & OFF SITE	YES	YES	YES	YES	YES	YES
Colorado	1.97%	SW	OFF SITE	YES	YES	YES	YES	NO	NO
Iowa	1.83%	SW	OFF SITE	NO	NO	MAY	NO	NO	NO
Wyoming	1.82%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Kansas	1.69%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Arizona	1.67%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
New Mexico	1.58%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Utah	1.57%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Minnesota	1.54%	SW	ON & OFF SITE	YES	NO	MAY	YES	YES	NO
Arkansas	1.48%	SW	ON & OFF SITE	YES	NO	NO	NO	YES	YES
Maryland	1.48%	SW	OFF SITE	NO	NO	YES	YES	NO	NO
North Dakota	1.39%	SW	ON & OFF SITE	NO	NO	MAY	YES	YES	YES
Oklahoma	1.34%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
New York	1.24%	SW	ON & OFF SITE	YES	MAY	MAY	YES	YES	NO
Virginia	0.94%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Washington	0.93%	CH	OFF SITE	YES	YES	YES	YES	YES	NO
Nebraska	0.85%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO
Montana	0.74%	SW	OFF SITE	YES	NO	NO	NO	NO	NO
Mississippi	0.62%	SW	OFF SITE	NO	MAY	NO	NO	YES	NO
New Jersey	0.51%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
Massachusetts	0.41%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Oregon	0.31%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	YES
Delaware	0.27%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Maine	0.15%	CH	ON & OFF SITE	YES	YES	YES	MAY	YES	NO
South Dakota	0.13%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	NO

EXHIBIT 4-1 (continued)
STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
New Hampshire	0.12%	SW	ON & OFF SITE	NO	NO	NO	YES	NO	NO
Alaska	0.01%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	NO
California	0.00%	CH	ON & OFF SITE	YES	NO	YES	MAY	YES	YES
Connecticut	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Vermont	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Rhode Island	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	NO	NO
Hawaii	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Idaho	0.00%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO

NOTES

Column (1) Percent national coal-fired capacity: i.e., each state's share of total U.S. coal-fired generating capacity.

Column (2) Classification: SW - coal combustion waste is exempted from hazardous waste regulation and regulated as a solid waste.

CH - coal combustion waste is not exempted from hazardous waste regulation and is tested for hazardous characteristics (In practice, coal combustion wastes are rarely considered hazardous, therefore columns 3-8 reflect solid, not hazardous, waste regulations).

EX - coal combustion waste is exempted from both solid and hazardous waste regulation.

Column (3) Permits: Permits are required for off-site facilities only, or for both on-site and off-site facilities.

Columns (4), (5), (6), (7), (8), (9): YES - the disposal standard is imposed by state regulations.

NO - the disposal standard is not imposed by state regulations.

MAY - the regulation states that a case-by-case investigation will determine whether the disposal standard will be imposed.

Source: Wald, Harkrader & Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, prepared for the Utility Solid Waste Activities Group, September, 1983.

Of the seven states that do not exempt coal combustion wastes from hazardous waste regulation (indicated by a CH classification in Exhibit 4-1), California burns little coal to produce electricity. The hazardous waste regulations of the six remaining states -- Kentucky, Tennessee, New Jersey, Oklahoma, Maine, and Washington -- regard coal combustion wastes as "characteristic" waste; that is, the wastes are tested for Extraction Procedure (EP) toxicity (see Chapter Five for further discussion), and if the waste proves to be toxic, some or all sections of state hazardous waste regulations apply. In Kentucky, for example, hazardous waste standards concerning lining and leachate control are enforced for coal combustion wastes that are found to be toxic, but utilities are not required to participate in the hazardous waste management fund established to ensure the long-term viability of disposal facilities. Similarly, according to the hazardous waste regulations of Tennessee and Oklahoma, if a waste is determined to be toxic, strict analysis and monitoring requirements must be followed, but compliance with state hazardous waste design and operating standards is not required. Officials from these five states have indicated that it is very rare for a coal-burning utility's waste to be classified as hazardous.³ Therefore, state solid waste regulations, with only isolated exceptions, establish the standards applicable to most coal combustion waste disposal activities.

Although solid waste regulations in most states do not differentiate between coal combustion wastes and other solid wastes, solid waste regulations in three states make specific reference to coal combustion waste disposal:

- Ohio's solid waste regulations list "non-toxic fly ash ... and slag ... that are not harmful or inimical to public health" as wastes that are exempt from solid waste regulation. Ash is typically determined to be non-toxic, according to the USWAG report.
- Maine's solid waste regulations provide a separate, more stringent set of design and operating requirements for the disposal of coal combustion wastes. The requirements call for lining, leachate control, and ground-water monitoring at coal combustion waste sites. These standards do not apply to other solid waste disposal facilities.⁴
- Pennsylvania has established industry-specific waste disposal standards. Pennsylvania's regulations for coal combustion waste disposal exclude the leachate control systems and liner requirements that apply to general solid waste disposal facilities.

4.1.2 Requirements for Coal Combustion Waste Disposal

The solid waste regulations of every state require that off-site solid waste disposal facilities be permitted or have some form of official approval. In order to obtain a permit, the operator of a facility must meet the requirements that are outlined in the regulations. These regulations are listed in Exhibit 4-1 and described below:

- The regulations in 41 states require permits for both on-site and off-site facilities. Eight states' regulations explicitly exempt on-site disposal from the permit requirement (Ohio, which exempts coal combustion wastes from solid waste regulation, is not included among the eight states). Column 3 of Exhibit 4-1 shows whether a permit is required for the operation of on-site and off-site solid waste disposal facilities.⁵

- Site restrictions are included in the solid waste regulations of 30 states. Examples of site restrictions are prohibiting solid waste disposal facilities from violating local zoning laws, banning placement of a new facility in a 100-year floodplain, and prohibiting waste placement unless there is a minimum depth to ground water. Column 4, "site restrictions," shows whether a state's regulations include restrictions on a disposal facility's location.
- Five states' regulations (Florida, Louisiana, Colorado, Washington, and Maine) call for all solid waste facilities to have a clay or synthetic liner. In addition, six states' regulations (Kentucky, Alabama, Tennessee, Wisconsin, New York, and Mississippi) call for the state permitting authority to determine, on a case-by-case basis, whether a liner is required. Column 5, "liners," shows whether the state's regulations include a requirement for liners at solid waste disposal facilities.
- Leachate control systems are collection devices placed under wastes in landfills or impoundments to collect waste leachate. Regulations in 12 states call for leachate control systems in all solid waste disposal facilities; the regulations of an additional 8 states allow leachate control systems to be required on a case-by-case basis. Column 6, "leachate control systems," shows whether a state's regulations include a requirement for leachate control systems at solid waste disposal facilities.
- The solid waste regulations of 17 states call for ground-water monitoring systems at all solid waste disposal facilities. The regulations of an additional 11 states specify that ground-water monitoring may be required on a case-by-case basis. Column 7, "ground-water monitoring," shows whether a state's regulations include requirements for ground-water monitoring wells at solid waste disposal facilities.
- Twenty-six states have solid waste regulations that call for closure and post-closure care. Column 8, "closure conditions," shows whether a state's regulations include requirements for closure and post-closure care for disposal facilities that have ceased operating.

- Thirteen states have solid waste regulations that include a financial assurance requirement. Column 9, "financial assurance," shows whether a state's regulations include a requirement that a solid waste facility operator post a bond or participate in a waste management fund to ensure the long-term viability of safe disposal facilities.

The management of waste in surface impoundments, a common practice for coal-burning utility plants, is often only indirectly addressed by state solid waste regulations. Only six states -- Louisiana, Colorado, New York, Washington, Oregon, and New Hampshire -- have solid waste regulations that include requirements exclusively for surface impoundments. The solid waste regulations of Indiana, Tennessee, Kentucky, North Carolina, Georgia, and Missouri exclude surface impoundments and defer to state water laws for regulatory authority. The water regulations in these states do not include any design and operating requirements for surface impoundments. However, according to the USWAG report, the water agencies in Missouri do regulate the design and operation of impoundments -- requiring lining and ground-water monitoring. According to the same report, state water agencies in Pennsylvania also regulate the design and operation of surface impoundments.

The regulatory requirements discussed above refer to regulations explicitly promulgated by the states for waste disposal facilities. However, state solid and hazardous waste regulations generally allow state authorities a large degree of discretion in designing site-by-site disposal standards that are more strict than those specified in the solid waste regulations. Many states' regulations allow local governments to design their own waste disposal regulations, provided that the standards set forth in the state solid waste regulations are enforced. Interviews with several state environmental

officials and the summaries in the USWAG report indicate that in some states coal combustion utility wastes are regulated more stringently than what is required by the solid waste regulations. For example, the solid waste regulations in Texas have few design and operating requirements and exempt on-site disposal from the permit requirement. It is, however, the policy of the state environmental agency to provide guidelines for on-site facilities as well as off-site facilities, and to require ground-water monitoring. (For more information on individual state regulations, see Appendix C.)

4.1.3 Summary

The regulation of coal combustion waste is generally carried out under state solid, not hazardous, waste regulations. These solid waste regulations vary from state to state. Based on the requirements included under each state's solid waste regulations (as shown in Exhibit 4-1), it is difficult to generalize about the extent of state regulation of coal combustion wastes; some states have very stringent regulations and/or policies, such as those that impose design and operating standards and on-site and off-site permit requirements, whereas other states have few requirements or exempt on-site disposal from regulation. For a number of states, requirements are determined on a case-by-case basis. This allows the states to take climatic, geologic, and other site-specific characteristics into account for each waste management facility.

4.2 AVAILABLE WASTE MANAGEMENT METHODS AND CURRENT PRACTICES

There are a variety of methods available for managing coal combustion wastes. Wastes may be land managed in impoundments, landfills, mines, and quarries or may be reused for various purposes. This section describes types of land management of coal combustion wastes and their prevalence within the ten EPA-designated regions of the United States. The second part of the section reviews available waste management technology alternatives (such as lining, leachate collection, and pre-disposal treatment), and explores how these different technologies are currently used in different parts of the U.S. and how these technologies have changed over time. The third part of this section describes the potential for ocean disposal to be used to manage coal combustion wastes. The final section describes coal combustion waste recycling. The waste management methods discussed in this section apply to high-volume and low-volume utility waste streams since these wastes are often co-disposed in the same facility.⁶

4.2.1 Land Management of Coal Combustion Wastes

80 percent of coal combustion waste is treated, stored, and/or disposed by means of land management, with the remaining 20 percent recycled (see Section 4.2.4). This section describes three common methods of land management currently used for coal combustion wastes. It also presents data on use of these management methods geographically and how land management practices have changed over time.

4.2.1.1 Types of Coal Combustion Waste Land Management

Three types of utility waste land management facilities are commonly used today:⁷

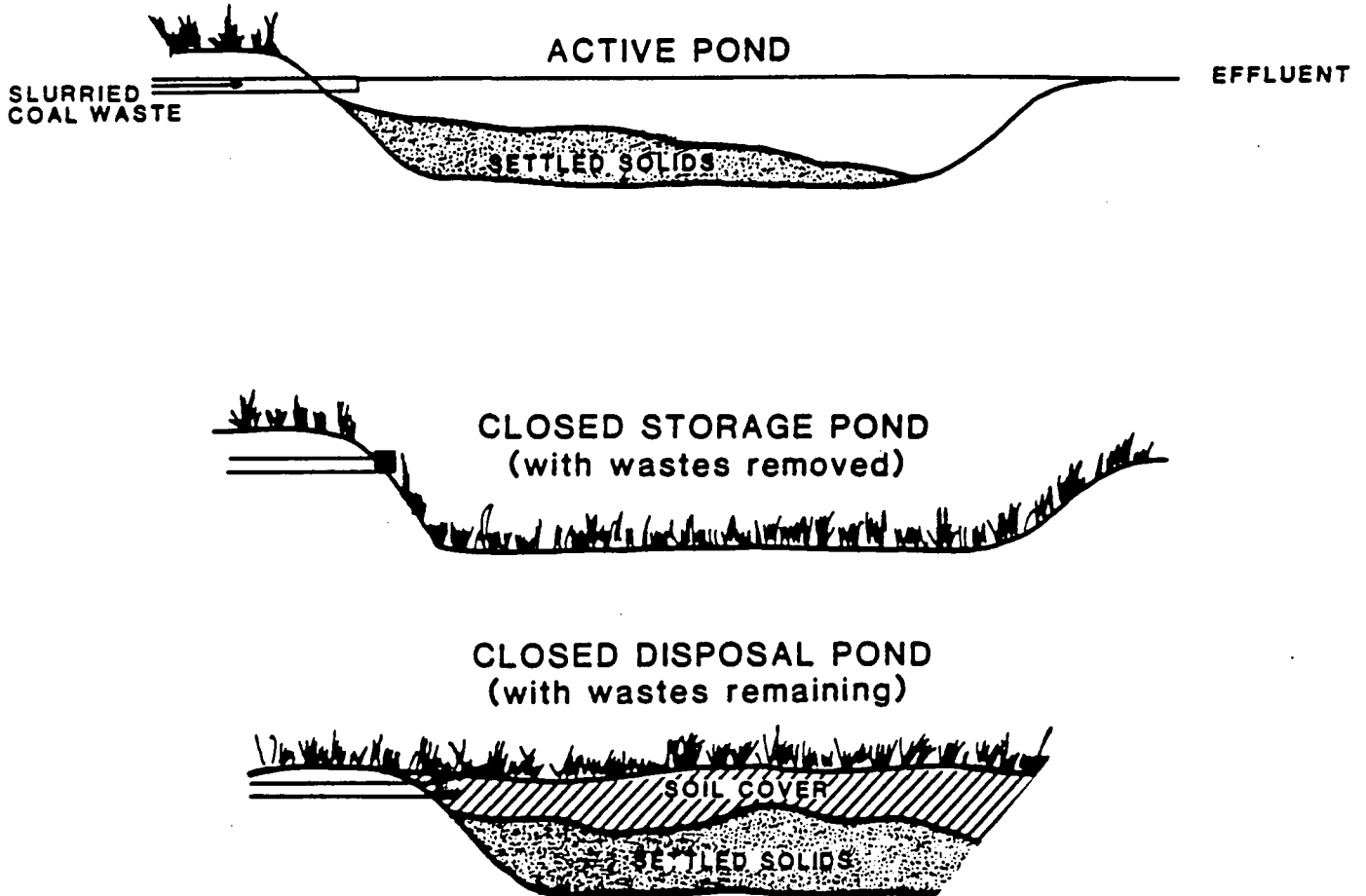
- **Surface Impoundments** -- often called wet ponds, in which coal combustion wastes are disposed as a slurry or sludge, allowing solids to settle and accumulate at the bottom of the pond.
- **Landfills** -- facilities used for disposing of dry or dewatered coal combustion wastes; landfills are typically managed like an earth-moving operation in which the wastes are disposed in the excavated area.
- **Mines and Quarries** -- abandoned pits in which wet or dry wastes are disposed.

Surface Impoundments

Surface impoundments are used to treat, store, and dispose of coal combustion wastes. Slurried coal ash and other wastes are introduced into the impoundment; the solids settle out and gradually accumulate at the bottom of the pond, leaving relatively clear water at the surface, which is often discharged to surface water. By using this method, certain types of waste treatment, such as neutralization of acids, can be accomplished concurrently with disposal. Exhibit 4-2 illustrates the different stages in the life of a typical impoundment.

Historically, wet ponding has been one of the most widely used disposal methods for coal ash and FGD wastes because it is simple and easily implemented. In 1983, about 80 percent of the waste management facilities used

EXHIBIT 4-2
TYPICAL SURFACE IMPOUNDMENT (POND) STAGES



by utilities employed some type of sedimentation treatment pond; most of these treatment ponds were used directly as final disposal impoundments (about 45 percent of all facilities; see section 4.2.1.2). The remainder of the impoundments were used only for treatment and temporary storage of waste, in part to comply with the National Pollutant Discharge Elimination System established in Section 402 of the Clean Water Act.⁸ In recent years, some state and local regulations concerning wet ponds have become more restrictive, requiring liners and ground-water monitoring at these facilities. These types of restrictions will tend to increase wet ponding costs, making it less attractive as a disposal option.⁹

Utilities may use a single pond or a series of ponds to facilitate the settling of solids. Chemicals or different wastes can be added at different points in the ponding system to produce desired chemical reactions, such as metals precipitation or neutralization. Fly ash, bottom ash, and FGD wastes are usually sluiced with water to the impoundments. The ash solids may be allowed to accumulate in a pond until it is full, or the pond may be drained and the solids dredged periodically and taken to an alternative disposal site, such as a landfill.

Pond designs vary widely depending upon local site conditions, the regulations that govern design of the impoundment, and whether bottom ash, fly ash, FGD wastes, or a combination of wastes are to be disposed and/or treated in the ponds. Because utility wastes are generated in large volumes, a pond's total surface area may cover up to several hundred acres, and the initial depth of a pond may be anywhere between 10 and 100 feet.¹⁰ The total

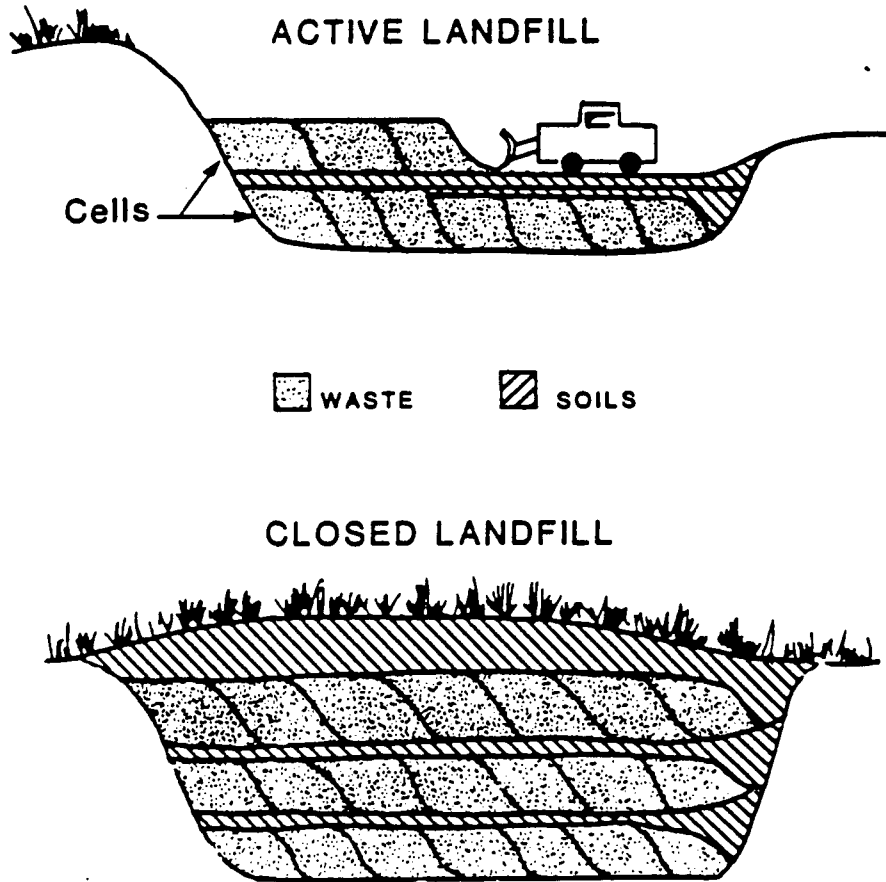
volume of an impoundment system depends on several factors, including the total quantity of ash to be disposed (both dry and slurried volumes), the liquid and solid retention times, the type and degree of treatment performed, and the desired quality of the discharge or effluent. The number of ponds in a system and the specific uses to which each is put can also influence the total volume required for wet ponding.

Landfills

Landfills are used to dispose of coal combustion wastes such as fly ash, bottom ash, and FGD sludges when they are produced or after they are dredged from surface impoundments that are used as interim treatment facilities. The typical design of a landfill during its active stage and after closure is depicted in Exhibit 4-3.

Landfills are constructed in a somewhat similar fashion to surface impoundments. Excavation is required in both cases, but may be ongoing throughout a landfill's active life because most large landfills are divided into sections, or cells, of which only one or two may be active at any given time. A landfill cell is defined as the area (up to several hundred square feet) over which waste is placed to a depth ranging from one to ten feet (industry practice refers to each layer of cells as a lift). Several lifts may be stacked atop one another in the landfill. A cell may be open for periods ranging from a day to a few weeks, after which it is usually covered with six inches to several feet of soil. The waste and soils are often sprinkled with water throughout the fill operation to mitigate potential dust problems.

EXHIBIT 4-3
DIAGRAMS OF ACTIVE AND CLOSED LANDFILLS



Excavation may be initiated in phases; for example, as one cell is filled, another is prepared for waste placement, while yet another is being excavated. Roads are built in to provide access for waste-hauling equipment as well as for the earth-moving and earth-compacting equipment that prepares the waste after it has been placed in the landfill cell. After a cell is filled, the access road frequently becomes part of the containment system as a wall separating one cell from the next.

Landfilling of coal ash and FGD sludges has increased over the past few years as the costs of wet ponding have increased (see section 4.2.1.2). Most electric utilities that use landfills currently dispose their high-volume wastes in Subtitle D (non-hazardous waste) landfills. Landfills in compliance with RCRA Subtitle C standards may be used occasionally for disposal of small quantities of hazardous waste.¹¹

Mine and Quarry Disposal

Some utilities use abandoned mines or quarries as ash and FGD sludge disposal sites. Abandoned mine disposal includes the use of mine shafts as well as strip-mined areas. Wastes disposed to abandoned mine shafts can be dumped into the shaft or carefully placed within the mine to fill the areas remaining after the coal or other material has been removed. Strip-mined areas may be filled like a landfill. Regulatory agencies may consider wastes disposed in this manner to pose less of a threat than the runoff and potential contamination from the abandoned mine itself.¹² In some cases, a chemical reaction between the waste and the mine runoff and leachate might actually

reduce the toxicity of the runoff (for example, an alkaline sludge could neutralize acid mine drainage). However, the likelihood of such a mitigative effect is very site-specific and would not necessarily occur uniformly throughout any given mine disposal site.

In a few cases, utility wastes, particularly acidic wastes, have been disposed in quarries. Limestone quarries are considered the best setting for this type of disposal because they provide a natural acid buffering capacity and the capacity for the metals present in the waste to be attenuated by chemically combining with materials in the quarry.¹³ Quarry disposal of wastes works well for lime or limestone slurry wastes, which harden to form a concrete-type floor at the bottom of the quarry, thereby plugging any potential leakage paths. The probability of achieving success with this method must be evaluated on a case-by-case basis prior to its use.

4.2.1.2 Prevalence of Various Land Management Methods

Use of the waste management methods described above can vary from plant to plant and, in some cases, among individual generating units at a single power plant. This section presents information on how these utility waste management methods are employed nationwide and within EPA regions. It also discusses how these utility waste management methods have changed over time. The emphasis is on surface impoundments and landfills because these two waste management methods are the most commonly-used utility waste management practices in the United States.

The information presented in this section was derived from the Edison Electric Institute Power Statistics Database, currently maintained by the Utility Data Institute. This database contains information on power plant characteristics for all electric utility generating plants in the U.S. These data include number of power plants, number of generating units at each power plant site, type of fuel, plant capacity, as well as other information. It also contains information on the type of waste management methods currently used by power plants throughout the country, including type of disposal facility and whether the wastes were disposed at the power plant or in off-site facilities. Because each generating unit at a power plant may have its own waste management practice, the database gives waste disposal information for all generating units.

Data were not available for all generating units in the database. When information is not available, the extent of data coverage is indicated. In some instances the number of generating units on which no information was available was quite high. Although EPA recognizes the possibility of some statistical bias due to lack of data on some generating units, this database is the most comprehensive source available on utility waste management practices. EPA has no reason to believe that such bias is serious enough to call into question conclusions drawn in this analysis.

Exhibit 4-4 displays, for each of the ten EPA regions of the U.S. (see Exhibit 2-4 for a map of these regions), the number of generating units whose waste is managed in surface impoundments, in landfills, or mines. The most

EXHIBIT 4-4**UTILITY WASTE MANAGEMENT FACILITIES BY EPA REGION**
(number of generating units) a/

<u>EPA Region</u>	<u>Surface Impoundments</u>	<u>Landfills</u>	<u>Minefills</u>	<u>Other/ Unknown</u>	<u>Total</u>
1	1	10	0	7	18
2	0	22	0	17	39
3	33	103	1	7	144
4	195	55	0	45	295
5	160	198	4	130	492
6	19	48	2	18	87
7	55	61	1	32	149
8	9	56	23	21	109
9	11	16	0	7	34
10	0	9	2	0	11
U.S. Total	483	578	33	284	1378

Source: Utility Data Institute Power Statistics Database

a/ The data are provided by generating unit because each generating unit at a power plant may have its own management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1,378 generating units located at 514 power plants.

common types of facilities used by the electric utility industry are surface impoundments and landfills:

- Landfills are the most common type of disposal facility used. Of the 1,094 generating units for which data were available (for 284 units, type of waste disposal method was unknown), 578 units (about 53 percent) used landfills for waste disposal. Landfills are used throughout the United States, with the largest number (over one-half of all landfills) located in the high coal-consuming, industrialized areas of the East and Midwest (Regions 3 and 5).
- Surface impoundments are also commonly used; approximately 44 percent of the generating units (483 out of 1,094) used this type of management facility. Of the 483 generating units that place wastes in surface impoundments, nearly 75 percent are located in Regions 4 and 5. (In the past, access to abundant, inexpensive supplies of water in these Regions often made it economical to use this management option.)
- Mine disposal is used for about three percent of all generating units (33 units out of 1,094). This disposal technique is used most frequently in the western U.S., particularly Region 8. Power plants in this area are often located at or near the coal mine that is supplying the plant. Since the coal mine is located nearby, disposal of waste in the mine is often economic.

When managing coal combustion wastes, electric utilities may treat, store, or dispose of the wastes at the power plant or at facilities located off-site. EPA could not determine from the data available how far the wastes are transported when managed off-site, although the cost of transporting the wastes would tend to encourage disposal near the power plant. A summary of industry practices is provided in Exhibit 4-5, which shows for each EPA region, by type of facility, whether the wastes are managed on-site or off-site.

EXHIBIT 4-5

**LOCATION OF UTILITY WASTE MANAGEMENT FACILITIES:
ON-SITE VERSUS OFF-SITE
(number of generating units)***

<u>EPA Region</u>	<u>On-Site</u>	<u>Off-Site</u>	<u>Unknown</u>	<u>Total</u>
1				
Surface Impoundments	1	0	0	1
Landfills	0	8	2	10
Other/Unknown	<u>0</u>	<u>0</u>	<u>7</u>	<u>7</u>
Total	1	8	9	18
2				
Surface Impoundments	0	0	0	0
Landfills	3	18	1	22
Other/Unknown	<u>0</u>	<u>0</u>	<u>17</u>	<u>17</u>
Total	3	18	18	39
3				
Surface Impoundments	25	3	5	33
Landfills	62	37	4	103
Other/Unknown	<u>0</u>	<u>1</u>	<u>7</u>	<u>8</u>
Total	87	41	16	144
4				
Surface Impoundments	186	4	5	195
Landfills	26	8	21	55
Other/Unknown	<u>0</u>	<u>0</u>	<u>45</u>	<u>45</u>
Total	212	12	71	295
5				
Surface Impoundments	141	5	14	160
Landfills	41	140	17	198
Other/Unknown	<u>0</u>	<u>6</u>	<u>128</u>	<u>134</u>
Total	182	151	159	492
6				
Surface Impoundments	18	0	1	19
Landfills	36	3	9	48
Other/Unknown	<u>0</u>	<u>6</u>	<u>14</u>	<u>20</u>
Total	54	9	24	87

4-22

EXHIBIT 4-5 (continued)**LOCATION OF UTILITY WASTE MANAGEMENT FACILITIES:
ON-SITE VERSUS OFF-SITE
(number of generating units)***

<u>EPA Region</u>	<u>On-Site</u>	<u>Off-Site</u>	<u>Unknown</u>	<u>Total</u>
7				
Surface Impoundments	42	0	13	55
Landfills	20	26	15	61
Other/Unknown	<u>7</u>	<u>1</u>	<u>25</u>	<u>33</u>
Total	69	27	53	149
8				
Surface Impoundments	6	2	1	9
Landfills	28	11	17	56
Other/Unknown	<u>2</u>	<u>23</u>	<u>19</u>	<u>44</u>
Total	36	36	37	109
9				
Surface Impoundments	9	2	0	11
Landfills	16	0	0	16
Other/Unknown	<u>0</u>	<u>0</u>	<u>7</u>	<u>7</u>
Total	25	2	7	34
10				
Surface Impoundments	0	0	0	0
Landfills	5	4	0	9
Other/Unknown	<u>0</u>	<u>2</u>	<u>0</u>	<u>2</u>
Total	5	6	0	11
Total U.S.				
Surface Impoundments	428	16	39	483
Landfills	237	255	86	578
Other/Unknown	<u>9</u>	<u>39</u>	<u>269</u>	<u>317</u>
Total	674	310	394	1378

* The data are provided by generating unit because each generating unit at a power plant may have its own management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1,378 generating units located at 514 power plants.

- Nearly 70 percent of all generating units in the U.S. manage their coal combustion wastes on-site (based on information for 984 units, 674 units dispose on-site). About two-thirds of the on-site facilities are surface impoundments; most of the other on-site facilities are landfills.
- Landfills are used for about 95 percent of all off-site disposal in the U.S. This is not surprising considering that surface impoundments are typically used when wastes are transported as a wet slurry; the cost of disposal could become prohibitive if a utility transported the slurry off-site.
- Coal combustion waste management practices also differ by region:
 - In the Northeast (Regions 1 and 2), where few coal-fired generating units are located, management tends to occur off-site in landfills.
 - The highest percentage of on-site management is found in the South (Region 4), where about 95 percent of all units manage their waste on-site (212 units, based on information from 224 units). On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant.
 - In the Rockies and northern Great Plains area (Region 8), most of the off-site disposal (23 of 36 units) occurs in mines that are generally adjacent to the power plant.

These trends in utility waste management methods have been changing in recent years, with a shift towards greater use of disposal in landfills located on-site. For example, for generating units built since 1975, nearly 65 percent currently dispose of coal combustion wastes in landfills, compared with just over 50 percent for units constructed before 1975. Similarly, over 80 percent of all units built since 1975 use

on-site management facilities, compared with just under 65 percent of all units built before 1975 that manage wastes on-site.

4.2.2 Alternative Waste Management Technologies

Section 4.2.1 described the types of land management facilities used by utilities and patterns of use. This section describes the additional technologies that utilities may employ at the facilities described above in order to reduce potential environmental risk associated with waste management. For example, some utilities use liner systems for impoundments and landfills, leachate collection systems, and ground-water monitoring systems to control and monitor waste constituent migration. Pre-treatment technologies, by altering physical and chemical properties, can also render wastes more amenable for certain disposal methods. This section also presents data on the prevalence of these various technologies. The alternative technologies discussed in this section, although not necessarily the same as technologies required for RCRA Subtitle C facilities, may be required by current state regulations (described in Section 4.1) and could be more widely used in the future to further mitigate potential environmental impacts at utility waste disposal sites not currently employing these technologies.

4.2.2.1 Installation of Liners

Until recently, most surface impoundments and landfills used for utility waste management have been simple, unlined systems. Lining is

becoming a more common practice, however, as concern over potential ground-water contamination from "leaky ponds" and, to a lesser extent, from landfills has increased. Some waste management facilities use one or more impermeable synthetic liners; some are lined with one or more layers of low-permeable clay¹⁴; and some use a combination of clay and synthetic liners.

Synthetic Liners

Several dozen manufacturers and distributors supply impermeable synthetic liners. The most common materials of construction for these liners include polyvinyl chloride (PVC) and high-density polyethylene (HDPE), although several other impermeable synthetics have also been used. Liners may be reinforced with fibers to increase strength and decrease the likelihood of punctures. The liners can be purchased in standard thicknesses that range from 10 mils to 100 mils,¹⁵ or can be made to order. Most liner installations will include protective geotextile fabric above and/or below the impermeable synthetic liner to minimize further the potential for puncture.

Preparation of the site prior to installation of a synthetic liner is similar to that which occurs before clay liner construction. However, more care must be taken to smooth out the surfaces to eliminate any peaks and cavities on the disposal facility floor that could cause a puncture of the liner material. Consequently, surface preparation costs are greater than those for clay liners. Excavation costs are usually less, however,

because the thinner synthetic liners allow shallower excavation (i.e., the additional excavation required to install a clay liner that is several feet thick can be avoided if a much thinner synthetic liner is installed).

The liner itself, which comes rolled or folded in large pieces, is laid in the field and sealed along the seams by heat or solvent fusion techniques; the seams may be field tested at spot checkpoints. The liner is usually covered with a foot or more of soil to protect it from puncture and to keep it in place during construction of the disposal facility. The edges of the liner at the tops of the dikes or landfill cell walls must be well secured to prevent the liner from pulling out and shifting due to the mass of the wastes placed in the impoundment or landfill. Some facilities are double lined and often contain a leachate collection system located in a soil or sand layer between the two liners.

Among the limitations to the use of synthetic liners is their susceptibility to tear and puncture. This is of particular concern in a single-lined impoundment because of the opportunity for liquids to seep through a single tear. Synthetic liners are also susceptible to degradation by certain waste materials. Acidic wastes, for example, can degrade some synthetic liner materials. As with clay liners, waste/liner compatibility testing should be performed to ensure that the disposed wastes will not weaken or permeate the liner. Additionally, because the seams of a synthetic liner are frequently weaker than the liner itself, they may pull apart under stress (e.g., large mass loadings or wave

action). Finally, dredging of synthetically-lined impoundments must be done cautiously, sometimes at very significant expense.

Synthetic liners, unlike clay liners (described below), are impermeable. Another advantage is the ease of repairing an exposed, damaged impoundment liner. A tear or puncture can be patched and seamed, and an impoundment put back into service, relatively quickly. (To repair subsurface damage, however, the impoundment must be wholly or partially drained.) Another advantage to using synthetic liners is that because of manufacturer quality control, a facility owner can be fairly certain that each liner sheet is as impermeable as the next. Clay is expensive to transport and in areas of the country where clay soils are scarce, a synthetic liner system may prove to be the less expensive option.

Clay Liners

The installation of a clay liner in a surface impoundment or landfill entails several steps. First, the site must be excavated or graded to a level below the design elevation of the facility floor. Many facilities take advantage of natural low areas or abandoned ponds to minimize excavation costs. The excavated earth can be used to build up the dike walls for the impoundment or to build containing berms within the landfill. Occasionally, soil must be brought to the construction site to raise the dikes to the design height.

Once the floor and dikes or berms have been prepared, the clay liner is laid in 6- to 9-inch lifts; its final thickness will be between 1 foot and 8 feet. Each lift is individually compacted before the next one is laid, thereby providing effective compaction and minimizing leakage potential. Field testing of the clay for permeability and other pertinent characteristics is sometimes performed during construction to provide quality assurance. Before the impoundment or landfill can be used, the liner is visually inspected for flaws; non-contaminated water may also be piped to the pond to assure that the liner is sufficiently impermeable.

One of the primary concerns about the use of clay liners is whether the entire clay liner meets thickness and permeability requirements. If weather conditions during liner construction are arid and hot, the liner may dry out and crack, causing localized areas of leakage. If conditions are wet or the clay is too moist, clay compaction may never be sufficient to achieve the necessary low permeability. The clays used as liner materials vary in the degree to which they are compatible with the wastes placed in the facility. Laboratory tests, in which the proposed liner material is exposed to the wastes intended for management, should be conducted for each facility to ensure that components of the waste material will not unduly alter the permeability of the clay used as liner material. If the chemical characteristics of the generated waste were to change over time, then the tests would need to be repeated to determine what effect the altered waste stream would have on the clay liner.

An advantage of clay liners is their potential for chemical, particularly cation, attenuation. The chemical structure of clay allows its use as an exchange site for metallic cations and other ions that might gradually seep out of the facility. Such exchange further reduces the opportunities for migration of waste constituents to the ground water. For facilities with fairly ready access to clays, the capital and construction costs associated with the use of a clay liner, even one that is several feet thick, may be substantially lower than those associated with the use of a synthetic liner.

Composite Liners

Many waste management facilities in industries currently subject to RCRA Subtitle C requirements are installing liner systems that combine both clay liner and synthetic liner technologies. Most commonly, an impoundment or landfill will be lined with 2-4 feet of impermeable clay, which is then prepared for placement of a synthetic liner. The synthetic liner may be covered with 1-2 feet of sand to serve as drainage for a leak detection system. Some facilities may then add another 1- to 2-foot layer of clay, which is again prepared for placement of the upper synthetic liner. In landfills, another leachate collection system is usually placed above this upper liner.

The composite synthetic/clay liner system offers a combination of advantages over single-material liners. A composite liner has some of the advantages provided by synthetic liners, such as factory quality control

and ease of repair (for the upper liner), as well as the advantage of clay's propensity for attenuating escaped ions. Furthermore, use of multiple-liner materials reduces the likelihood that waste material will leak into the ground water because of chemical incompatibility between a waste and a single liner material. In general, the more layers of impermeable liner material that are used, the more efficient containment of liquids will be, thus reducing the likelihood of a release of waste material.

The biggest drawback of the composite synthetic/clay liner system is the cost of installation. Utility waste landfills are very large (up to 100 acres or more), and a liner large enough to cover such a area could be very expensive. In areas where labor costs are high and clay is unavailable locally and must be transported long distances, these costs would be magnified.

Frequency of Liner Use

Some electric utilities have installed liners to retard the flow of leachate from the waste disposal facility to the surrounding area. Exhibit 4-6 shows the extent to which electric utilities are currently using this technology.

- About 25 percent of all generating units in the U.S. for which data were available (139 of 580 units) have installed some type of liner. There are no available data on the material used to construct these liners or if more than one liner has been installed at the disposal facility.

4-31

EXHIBIT 4-6

**INSTALLATION OF LINERS FOR LEACHATE CONTROL
AT UTILITY WASTE MANAGEMENT FACILITIES
(number of generating units)***

<u>EPA Region</u>	<u>Unlined</u>	<u>Lined</u>	<u>Unknown</u>	<u>Total</u>
1				
Surface Impoundments	0	0	1	1
Landfills	0	0	10	10
Other/Unknown	<u>0</u>	<u>0</u>	<u>7</u>	<u>7</u>
Total	0	0	18	18
2				
Surface Impoundments	0	0	0	0
Landfills	1	14	7	22
Other/Unknown	<u>0</u>	<u>0</u>	<u>17</u>	<u>17</u>
Total	1	14	24	39
3				
Surface Impoundments	17	2	14	33
Landfills	17	7	79	103
Other/Unknown	<u>0</u>	<u>0</u>	<u>8</u>	<u>8</u>
Total	34	9	101	144
4				
Surface Impoundments	153	3	39	195
Landfills	14	7	34	55
Other/Unknown	<u>0</u>	<u>0</u>	<u>45</u>	<u>45</u>
Total	167	10	118	295
5				
Surface Impoundments	90	20	50	160
Landfills	64	31	103	198
Other/Unknown	<u>0</u>	<u>4</u>	<u>130</u>	<u>134</u>
Total	154	55	283	492
6				
Surface Impoundments	7	7	5	19
Landfills	11	17	20	48
Other/Unknown	<u>0</u>	<u>0</u>	<u>20</u>	<u>20</u>
Total	18	24	45	87

EXHIBIT 4-6 (continued)

**INSTALLATION OF LINERS FOR LEACHATE CONTROL
AT UTILITY WASTE MANAGEMENT FACILITIES
(number of generating units)***

<u>EPA Region</u>	<u>Unlined</u>	<u>Lined</u>	<u>Unknown</u>	<u>Total</u>
7				
Surface Impoundments	30	4	21	55
Landfills	7	4	50	61
Other/Unknown	<u>6</u>	<u>0</u>	<u>27</u>	<u>33</u>
Total	43	8	98	149
8				
Surface Impoundments	4	0	5	9
Landfills	12	6	38	56
Other/Unknown	<u>0</u>	<u>0</u>	<u>44</u>	<u>44</u>
Total	16	6	87	109
9				
Surface Impoundments	2	9	0	11
Landfills	2	4	10	16
Other/Unknown	<u>0</u>	<u>0</u>	<u>7</u>	<u>7</u>
Total	4	13	17	34
10				
Surface Impoundments	0	0	0	0
Landfills	4	0	5	9
Other/Unknown	<u>0</u>	<u>0</u>	<u>2</u>	<u>2</u>
Total	4	0	7	11
Total U.S.				
Surface Impoundments	303	45	135	483
Landfills	132	90	356	578
Other/Unknown	<u>6</u>	<u>4</u>	<u>307</u>	<u>317</u>
Total	441	139	798	1378

* The data are provided by generating unit because each generating unit at a power plant may have its own waste management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1378 generating units located at 514 power plants.

- Based on the information available, landfills are more likely to be lined than surface impoundments. Of the 222 generating units that use landfills and that indicated whether the disposal facility was lined or not, about 40 percent (90 units) have lined disposal facilities. Only 13 percent of surface impoundments have liners installed (based on information from 348 of the 483 units).

The information in Exhibit 4-6 should be interpreted cautiously since data were available for only 42 percent of the population (580 units of 1,378 units). One of the reasons this information is unavailable is due to the number of electric utilities that dispose of coal combustion wastes off-site. In many of these cases, the utility does not know whether the off-site disposal facility is lined or not since the utility does not run the disposal operation.

Liner use has been increasing in recent years. Before 1975, less than 20 percent of all generating units managed their coal combustion wastes in lined facilities. For units constructed since 1975, however, this percentage has increased to over 40 percent. The proportion of lined management facilities is particularly high at generating units that produce FGD sludge; since 1975 about 60 percent of management facilities containing these wastes have been lined.

4.2.2.2 Leachate Collection and Ground-Water Monitoring

Any lined management facility may have a leachate collection system and any facility (lined or unlined) may be equipped with a ground-water monitoring system. Leachate collection systems are used to prevent the

migration of contamination from a landfill or impoundment. Both systems can be used to monitor the rate and extent of contaminant migration. The design and placement of ground-water monitoring and leachate collection systems should take into account the manner in which a landfill or impoundment might potentially interfere with natural ground-water flow and usage patterns.

In surface impoundments, the leachate collection system(s) can be placed below the entire liner system or it can be placed between any two liners. Leachate collection systems typically consist of a drainage media (coarse sand and/or gravel) and perforated pipes (called riser pipes) that slope toward a collection sump. The collected leachate is pumped out via these riser pipes to the surface for treatment and/or disposal. If the riser pipes through which the leachate is pumped perforate the synthetic or clay liner, tight seals are necessary to ensure that the leachate does not escape through the perforation.

In landfills, leachate control systems can be installed below all liners (this is usually called a pressure relief system), between liners (the inter-liner leachate control system), and/or above the upper liner. The floors of a landfill cell are designed to slope to the leachate collection sumps and are usually covered with a drainage media such as sand or gravel. Each leachate control system has its own collection sump, which is emptied through riser pipes so that the leachate can be treated or disposed appropriately. As with impoundment liner systems, riser pipes, if they pierce the liners, must be sealed to prevent leakage.

Ground-water monitoring wells are placed at strategic locations to facilitate early detection of any contaminants that escape the facility and migrate to the ground water. The design and placement of the monitoring wells is based on site-specific hydrogeological assessments, soil chemistry, specific regulatory directives, and other physical and chemical factors. Downgradient wells typically are used to monitor the extent of contamination arising from a facility, and upgradient "background" wells are installed to serve as controls.

Most newer utility waste management facilities have ground-water monitoring systems, and many also have leachate collection systems. In other industries, permitted facilities subject to Subtitle C regulations are required by law to have both ground-water monitoring and leachate collection systems.¹⁶ For utility waste disposal sites, it is estimated that about 15 percent of all facilities have leachate collection systems and about 35 percent have ground-water monitoring systems.¹⁷

4.2.2.3 Pre-disposal Treatment

Facilities employ a variety of waste treatment processes to alter the physical or chemical characteristics of wastes so that they will be compatible with the disposal method used. Treatment methods may also be employed to comply with the effluent limitations established under the Clean Water Act.

Sludge Dewatering

The most commonly used pre-disposal treatment process is sludge dewatering. This process is often necessary so that the sludge can be more easily handled and of a consistency suitable for landfill disposal. This procedure can also be used for any wet coal ash or combined coal ash/FGD sludge wastes. Most frequently, sludge dewatering is accomplished by sedimentation of the suspended solids in surface impoundments or, in some cases, in clarification tanks. This type of dewatering is carried out at 80 percent of the utilities.¹⁸

After the waste solids have had sufficient time to settle, the water layer is drawn off the tank or impoundment and is either discharged subject to National Pollutant Discharge Elimination System (NPDES) permits or recycled back to the plant as sluice or cooling water. The sludge layer containing the solid ash and other particles is allowed to accumulate for several months (or longer), and is finally dredged after the pond is drained. With this process, the solids content (initially between 5 and 15 percent by weight) can be increased to between 30 and 60 percent. The final solids content in the sludge is affected by the sedimentation impoundment or tank design, the initial solids content, the liquid and solids retention times, and the physical and chemical characteristics of the solid particles.

Even after dewatering, the settled sludges often have a mud-like consistency and still contain so much free liquid that they are

inappropriate for landfill disposal. In this case, the sludge may be further dewatered by natural or mechanical processes. In arid and semi-arid areas, the sludges may be retained in the impoundments until natural evaporation removes still more water. Sludges may also be placed on drying beds made of screens, sand, or other drainage media designed to allow water to percolate out by gravity, while the solids are retained. In mechanical sludge dewatering, belt or vacuum filters, filter presses, thermal dryers, or other processes are used. Ten percent of the utilities use some sort of filtration to dewater sludges.¹⁹ For high-volume sludges, however, mechanical dewatering equipment may be expensive and inconvenient to operate.

Reagent Addition

Most FGD sludges and some other wet sludges can be rendered less chemically reactive and/or more structurally stable by adding solidification, stabilization, or fixation reagents. This practice is not widespread; less than 10 percent of the utilities report using these processes.²⁰ Solidification agents, such as sawdust or soil, absorb the liquid in a sludge but do not chemically react with the sludge. Stabilization and fixation reagents chemically react with some portion of the sludge -- either the water, the dissolved solids, the particulate solids, or some combination of the three-- and, in some cases, may render potentially hazardous material non-hazardous as a result. All of these processes result in an increased volume of waste that contains less free water and is easier to handle than the original waste stream. An

additional benefit is an increase in the structural integrity (shear stress and load-bearing potential; see Chapter Three for discussion of these characteristics) of the waste material so that it may be placed in deeper disposal facilities and covered with more material.

Low-volume Waste Treatment

The major methods available for low-volume waste management and treatment include:

- co-disposal;
- contract disposal;
- evaporation;
- incineration;
- neutralization;
- physical/chemical treatment; and
- recycle/reuse.

The type of waste management method used most often depends on the type of low-volume waste stream. Exhibit 4-7 shows the treatment process commonly used for each low volume waste stream. Each of these treatment processes is discussed briefly below.

EXHIBIT 4-7

SUMMARY OF CURRENT HANDLING, TREATMENT AND
DISPOSAL OF LOW VOLUME WASTES

Low Volume Waste	Treatment	Predominant Disposal Method
Waterside Cleaning Waste	If organic chelating agents are used, this stream can be incinerated. If acids are used, the stream is often neutralized and precipitated with lime and flocculants.	<ol style="list-style-type: none"> 1. Co-disposal with high volume wastes in pond or landfill following treatment. 2. Disposal by paid contractor.
Fireside Cleaning Waste	Sometimes neutralized and precipitated. For coal-fired plants most often diverted to ash ponds without treatment. If metals content is high, chemical coagulation and settling is used.	<ol style="list-style-type: none"> 1. Co-disposal with high volume wastes in pond without treatment. 2. Ponding following treatment.
Air Preheater Cleaning Waste	Settling in ash pond; neutralized and coagulated if combined with other streams before treatment.	<ol style="list-style-type: none"> 1. Co-disposal in pond without treatment. 2. Ponding with treatment.
Coal Pile Runoff	Neutralized by diverting to alkaline ash pond. Fine coal material caught in perimeter ditch is often diverted back to coal pile.	<ol style="list-style-type: none"> 1. Co-disposal of sludge in landfill after treatment. 2. Co-disposal in ash pond.
Wastewater Treatment	Usually ponded with ash or as a separate waste. Sometimes solids co-disposed with bottom ash.	<ol style="list-style-type: none"> 1. Ponding 2. Landfilling
Make-up Water Treatment	usually co-disposed in ash pond.	<ol style="list-style-type: none"> 1. Co-disposal in pond.
Cooling Tower Basin Sludge	Very little survey or literature information; infrequent stream. Sludge comingled with wastewater treatment sludge.	<ol style="list-style-type: none"> 1. Landfilling

EXHIBIT 4-7 (Continued)**SUMMARY OF CURRENT HANDLING, TREATMENT AND
DISPOSAL OF LOW VOLUME WASTES**

Low Volume Waste	Treatment	Predominant Disposal Method
Demineralizer Regenerants	Equalized in tanks, then comingled into ash ponds.	1. Ponding
Pyrite Wastes	Disposed in landfills with bottom ash or diverted to ash pond	1. Ponding 2. Landfilling

Source: EPRI, Characterization of Utility Low-Volume Wastes, prepared by
Radian Corporation, Austin, Texas, May 1985.

-- Co-Disposal

Co-disposal of low-volume wastes with high-volume wastes into landfills and surface impoundments is commonly used in the utility industry. A January 1981 EPA letter (the Dietrich memorandum) currently allows co-disposal of low-volume wastes with high-volume wastes in landfills and surface impoundments.²¹ In a 1985 EPRI study on low-volume waste management, about three-fourths of the power plants interviewed co-disposed some low-volume wastes in a surface impoundment or landfill.²² The amount of treatment necessary before co-disposal varies with the waste stream. Solid wastes are typically disposed directly into the waste management facility. Liquid wastes are often routed to an interim treatment surface impoundment. Once in the surface impoundment, evaporation occurs and the remaining sludge is landfilled. If the liquid waste is chemically treated before ponding, heavy metals are often removed in a treatment facility; the treated liquid may then be reused or diverted to a surface impoundment while the residue from the treatment process is disposed in a landfill.

-- Contract Disposal

Many utilities hire outside contractors to treat and dispose of low-volume wastes. Contract disposal is most common for low-volume waste streams produced intermittently that are difficult to treat on-site. For example, hydrochloric acid boiler cleaning waste typically requires neutralization with high dosages of a caustic material. Construction of an on-site treatment system for this waste stream requires a large capital investment, although boiler cleaning wastes are produced only over a few hours once every two to five years. As a result, some

utilities (7 of 22 power plants surveyed in EPRI's 1985 study) employ outside contractors when boiler cleaning is required.²³ The treated boiler cleaning waste is then co-disposed on-site or disposed of off-site.

Contract disposal is also a common waste management practice for spent ion exchange resin. In EPRI's 1985 study, of five power plants responding, four plants hauled these wastes off-site while one power plant co-disposed the waste on-site.²⁴

-- Evaporation

Evaporation ponds are used to dispose of high concentration, low-volume liquid wastes. Prior to final disposal, liquid wastes are diverted to an evaporation pond, generally shallow ponds with a large surface area. The sludge remaining after most of the water evaporates is then dredged and disposed of in a landfill.

-- Incineration

Incineration of low-volume wastes includes injection into the boiler or mechanical evaporation. This method of disposal is most common with organic cleaning wastes (Ethylenediamide tetracetic acid (EDTA) or citrate waste). A 1987 EPRI study²⁵ examined the effect of incinerating EDTA and citrate wastes in a utility boiler. The findings showed that the additional metals contributed were minimal compared to the amount contributed by the coal.

Two of the twenty-two power plants interviewed in EPRI's 1985 study use this method of waste disposal.²⁶

-- Neutralization

Acidic or alkaline wastes can be treated with either strong bases or acids, respectively, to produce a near neutral stream. For example, wastewaters, demineralizer regenerant, and coal pile runoff must typically be within a pH range of 6.0 to 9.0 to meet Clean Water Act (CWA) and National Pollutant Discharge Elimination System (NPDES) limits. Neutralization can be used to achieve these levels. Similarly, hydrochloric acid boiler cleaning waste, which may have a pH below 2.0, can undergo neutralization to raise the pH above RCRA corrosivity guidelines (pH values between 2.0 and 12.5 are not considered corrosive under RCRA).²⁷

-- Other Physical/Chemical Treatment

Physical and/or chemical treatment systems can be used for reducing and removing dissolved and suspended contaminants from aqueous streams. The most prevalent treatments incorporate pH adjustment (i.e., addition of basic or acidic materials), precipitation (i.e., separating solids from solution or suspension), flocculation (i.e., aggregation of fine suspended particles), clarification (i.e., separating liquid and suspended solids) and filtration (i.e., trapping suspended solids). The continuous waste streams are treated to allowable levels. Boiler chemical cleaning and fireside cleaning wastes require higher reagent doses and occasionally additional

processing to meet Clean Water Act (CWA) and National Pollutant Discharge Elimination System (NPDES) discharge limits for metals. Ten of the 15 power plants questioned in EPRI's 1985 study route boiler cleaning wastes through physical and/or chemical treatment systems prior to discharge.²⁸

-- Reuse

Reuse is a common practice for many water-based low volume wastes, especially in water-limited regions of the country. For example, less contaminated streams (boiler blowdown, yard drains) can be used without treatment in cooling towers, ash handling systems, and flue gas desulfurization systems. Other wastes, such as boiler cleaning wastes and coal pile runoff, cannot easily be reused because they require extensive treatment prior to reuse. If a power plant does decide to treat these waste streams, the liquid portion of treated waste may be reused while the sludges produced during treatment are typically landfilled.

4.2.3 Ocean Disposal

Many different types of wastes, including industrial and municipal wastes, have been disposed at sea in the past, although the use of this method for disposing coal combustion wastes is only in the research and development phase. Typically, industrial and municipal wastes are shipped out to sea and disposed at any of several regulated dump sites, which are located anywhere from 20 miles to over 100 miles off the shore line. Another method of ocean disposal (seldom used, however) involves pumping or

gravity feeding wastes through a pipeline that feeds directly from the land-based waste generating site or dump site into the ocean. When the wastes reach the final oceanic disposal site, they either dissolve and disperse or form a manmade reef.

The 1972 Marine Protection Research and Sanctuaries Act (MPRSA), EPA regulations regarding ocean disposal,²⁹ and the London Dumping Convention currently regulate ocean dumping with respect to the solids content, metals content, and toxicity of wastes considered for this method of disposal.

4.2.4 Waste Utilization and Recovery of Various Waste By-Products

Although the majority of the waste generated by coal-fired electric utilities is land disposed, a substantial percentage is recovered and reused. From 1970 to 1980, an average of 18 percent of all coal ash generated annually was utilized;³⁰ from 1980 to 1985, the average coal ash utilization rate exceeded 22 percent, with utilization in 1985 over 27 percent of all coal ash produced.³¹ The amount of FGD sludge waste utilized is less than one percent of the total volume of FGD waste generated, although more efficient FGD sludge recovery and utilization processes currently being developed by the utility industry may increase this use. The combined utilization rate for all high-volume coal combustion wastes, i.e., fly ash, bottom ash, boiler slag, and FGD sludge, was about 21 percent in 1985.

The recovery processes are usually performed at the power plant. Use of the recycled waste may occur on-site or the recycled product may be sold for off-site use. Like any industrial product, the wastes to be recycled may be accumulated on-site prior to sale and delivery.

The recovery processes and the uses for waste by-products are numerous and quite varied:

- Bottom ash currently has the highest rate of utilization at 33 percent. It is used as blasting grit, road and construction fill material,³² for roofing granules, and has other miscellaneous uses.
- Fly ash utilization is substantial. About 17 percent of fly ash production is used for concrete admixture, cement additives, grouting, road and construction fill material, and for miscellaneous other uses.³³
- FGD wastes are not heavily utilized in the industry (less than 1 percent), but some utilities have the capacity to recover sulfur,³⁴ sulfuric acid, or other sulfur products from the waste.
- Some low-volume wastes (particularly solvents) that are segregated from the high-volume waste streams are potentially recoverable or available for other uses.
- Numerous other recovery processes and utilization techniques are currently in the research and development phase. At this time, however, the Agency is unaware of any advances in recovery processes that will significantly change the proportion of coal combustion wastes that are disposed.

Coal Ash

There are a variety of different options currently available for the utilization of fly ash, bottom ash, and boiler slag from coal-fired electric

utilities. All types of coal ash are appropriate for use as construction materials, as cement additives, and for several other uses. Coal ash utilization is primarily centered in the southeast and north central United States.³⁵

Most fly ash and some bottom ash exhibit pozzolanic (bonding) properties -- that is, the dried materials are cohesive and exhibit high shear strength and compressive load-bearing characteristics. These properties make ash an appropriate substitute for portland cement for many applications, including concrete production, standard cement production, and for special uses such as for the production of road base cement or even grouting.

Cement made with fly ash may be preferable to regular portland cement for some applications. One of the key benefits is the absence of heat release while the concrete or cement mixture cures; this absence of heat generation means that the design structural strength is more likely to be achieved. However, the use of fly ash and bottom ash as cement substitutes is limited because of the wide variability in ash composition, even in ash originating from the same coal supply or utility. The presence of metals in the ash can reduce the structural integrity of the final concrete by preventing the necessary chemical bonding. The presence of large quantities of sulfates or nitrates will also interfere with the pozzolanic properties. Because of this bonding interference, fly ash and bottom ash are thought to be able to replace no more than 20 percent of the cement used (or about 15 million tons of ash annually).³⁶ Improvements in utilization techniques may reduce the bonding interference and increase the reutilization potential of

fly ash; however, the Agency is unaware of technical advances at this time that will allow substantially greater utilization in cement applications.

Fly ash and bottom ash are also commonly used as high-volume fill for various construction materials. The pozzolanic properties of these materials facilitate soil stabilization, making them desirable as fill additives. Coal ash has been used as fill in asphalt, road bases, parking lots, housing developments, embankments, and to line on-site disposal facilities at the utilities. In the future, numerous other construction applications may use coal ash as fill, particularly if the ash is available at lower cost than standard fill materials. However, the use of ash as fill is limited somewhat because of the variability of the ash composition.

Bottom ash and boiler slag have been used as substitutes for sand in sand-blasting operations and road de-icing. Ash and slag particles are similar in size and density to sand particles. In areas where sand is costly to transport, these wastes can be economical substitutes. Ash is less corrosive than salt and could therefore be a preferable de-icing material, although in some municipalities the use of ash for de-icing has been prohibited due to public concern over aesthetics (e.g., ash residue on cars).

A variety of minor uses for fly ash and bottom ash have been considered, some of which have already been implemented at a small number of utilities. For example, bottom ash has been used for granular roofing material. Fly ash has been used by some facilities as a stabilization reagent for acidic

aqueous or semi-solid hazardous wastes: the high-pH fly ash reacts with other, low-pH waste to generate a neutral solution and to simultaneously precipitate dissolved metals as oxides and hydroxides. Because the fly ash exhibits pozzolanic properties, the ultimate waste product, when dried, often resembles concrete. The metals from the original waste stream are usually so strongly bound within the chemical structure of the final waste product that they will not leach out, even under acidic conditions.

Because fly ash has some of the same physical characteristics as a silty clay, fly ash may be used as an additive to clay liners for waste management facilities, particularly for impoundments. Fly ash is cohesive and fairly impermeable when properly compacted, and mixes well with some of the clays used in impoundment liners. However, because chemical composition of fly ash is variable, its utilization as liner material may be limited. If methods are improved to be sure that minimum permeability and shear strength requirements could be maintained over time, then the use of fly ash as an impoundment liner material may increase.

Fly ash has been used occasionally as a soil conditioner to increase the pH of acidic soils, thereby enhancing crop growth. Fly ash can also contribute minerals to the soil. However, soil conditioners in common use today, mostly agricultural limestones, are so inexpensive and easy to obtain that it would be difficult to penetrate this market with a fly ash product.

There are few processes currently available for recovery of materials from coal ash. One facility has had some commercial success at producing

magnetite from fly ash.³⁷ Magnetite recovered from fly ash actually contains a higher percentage of magnetics than does natural magnetite, making it a more efficient coal cleaning agent. This particular technology shows some promise of expanding; other processes, mostly for metals recovery, are in the development stage. Recovery processes for alumina and titanium are at an advanced stage of development. However, while both these technologies have been proven feasible, neither is currently economically competitive with ore-processing technologies. Another potential metal recovery process, dubbed the DAL process and still in the research stage, involves a series of relatively simple operations that can be performed with commercially available process equipment to recover various metals from fly ash. Theoretically, this process could show a substantial return on investment soon after the recovery facility began operating.³⁸

There is little information available to the Agency on the environmental effects of utilization of coal combustion wastes. For many applications, such as the use of coal ash in cement and concrete products, it would appear that any adverse environmental impacts would be minimal. To the extent that coal combustion wastes can be recycled in an environmentally acceptable manner, utilization would help to reduce the amount of waste disposed. The Agency is very interested in reducing the amount of waste that needs to be disposed by the utility industry; however, barring major breakthroughs in recycling techniques, it appears the potential for significantly increasing the amount of waste utilization may be limited.³⁹ Given current utilization techniques, the Agency expects that the major portion of coal combustion wastes will continue to be land disposed.

FGD Wastes

The prospects for utilization of FGD sludge are less promising than those for ash utilization. FGD sludge is not structurally stable or strong enough to serve as a construction material, nor does it show the pozzolanic properties required for a cement substitute. Current research in the field of FGD sludge utilization is focusing on a dry scrubber method in which reagents will be used to precipitate the FGD waste streams as dry gypsum powder. Gypsum is sold for use in wallboard; however, there is currently a glut on the market, and in any case, other sources of gypsum may be preferred because the gypsum produced from FGD is often of lesser quality. Some researchers are making an effort to find a reagent that will precipitate a dry powder which, when mixed with water, will exhibit pozzolanic properties and will harden to a concrete-like material. No testing has been done, however, as the research is still in the conceptual stage.

Although by-product utilization of FGD sludges comprises less than one percent of total sludge production, a much greater percentage of FGD by-products may be recoverable in the very near future since two full-scale recovery processes and one test-scale recovery process for FGD by-products are currently under development. Of the two full-scale processes, the Wellman-Lord process recovers both sulfuric acid and elemental sulfur from the waste stream, while the magnesium oxide scrubber process recovers only sulfuric acid.⁴⁰ The citrate scrubbing process, currently in the testing phase, recovers elemental sulfur. FGD recovery processes currently in the

research stage will be used to recover elemental sulfur, sulfuric acid, and gypsum from the FGD process, and should be available for full-scale use within the next decade.⁴¹ All recovery processes for FGD wastes generate both a by-product stream and a waste stream that must be disposed.

Low-Volume Utility Wastes

EPA currently assumes that most low-volume utility wastes are co-disposed with the high-volume wastes or, in some instances, burned in the boiler at the power plant, although little data exist that accurately describe industry-wide practices on low-volume waste disposal.⁴² Since co-disposal is a common industry practice, low-volume wastes do not have specific processes associated with their recovery or utilization. Although this practice of co-disposal (or burning) may continue into the future, certain waste streams, such as spent cleaning solvents, might be recovered by distilling and collecting the solvents at high temperature, which would leave a low-volume residue to be disposed. The recovered solvent could then be reused on-site as a cleaning solvent or sold to another facility. If an organic solvent were contaminated in such a way that contaminant removal were difficult or impossible, the contaminated solvent could be burned. For low-volume waste streams burned in the boiler, these wastes could be transported to an off-site facility that would burn them as fuel. If low-volume wastes were considered hazardous, regulations might restrict the burning of these wastes, potentially making this option infeasible.⁴³

Other recovery schemes for individual low-volume waste streams may be developed if these streams are segregated from the high-volume wastes. At this time, however, few recovery processes and utilization techniques have been considered separately for low-volume utility wastes.

Recycled Effluent

Approximately 25 percent of the utilities that utilize surface impoundments recycle some of their pond effluent back to the plant.⁴⁴ If the recycled effluent is used as sluice water, the system pH may increase to values well above 10. The recycled effluent may also be used as cooling water prior to ultimate discharge. Although effluent recycling is not a waste recovery or utilization technique, it can affect the chemical characteristics of the solid wastes that may come into contact with the recycled water.

4.3 SUMMARY

Coal combustion waste management practices by electric utilities vary widely across the industry. State regulation, regional factors such as land availability and water availability, and age of the power plant all have an effect on the type of waste management practices that are employed. Alternative practices, such as ground-water monitoring and leachate collection, are used by some utilities, and in some states are mandated by regulation. A significant portion of coal combustion by-products are recovered and utilized for various purposes.

- All but one state regulates the disposal of coal combustion wastes under their hazardous or solid waste disposal regulations. One state exempts these wastes from regulation.
- State solid waste regulations applicable to coal combustion wastes vary widely across the country. Generally, solid waste regulations require that disposal facilities have permits; location restrictions and standards related to liners, leachate control, and ground-water monitoring are applied on a case-by-case basis.
- Currently, about 80 percent of all coal-fired power plant wastes are land managed; the remaining 20 percent are recycled or recovered. The most common types of disposal facilities used by utilities generating coal-fired wastes are surface impoundments, landfills, and abandoned mines.
- Currently, about 25 percent of utility treatment, storage, and disposal facilities that receive combustion waste are lined. About 15 percent of all facilities have leachate collection systems, and 35 percent have ground-water monitoring.
- Newer facilities are more likely to be lined, have leachate collection systems, and ground-water monitoring systems. More than 40 percent of all generating units constructed since 1975 use lined disposal facilities.
- About 20 percent of all high-volume combustion wastes, particularly fly ash and bottom ash, are recycled, primarily as cement additives, high-volume road construction material, or blasting grit.
- About 99 percent of FGD wastes are currently disposed; however, recovery of sulfur and sulfur products from FGD wastes is a developing and promising technology.

CHAPTER 4

NOTES

¹ Wald, Harkrader & Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, for the Utility Solid Waste Activities Group (USWAG), 1983.

² States have probably followed U.S. EPA's lead in exempting coal combusting wastes. Many states' regulations explicitly refer to 40 CFR 261.4, or use the clause's exact wording.

³ The following State officials were interviewed: Brett Bettes, Solid Waste Division, Washington Department of Ecology, January 6, 1987; Ken Raymond, Industrial and Solid Waste Division, Oklahoma Department of Health, December 31, 1986; Dwight Hinch, Division of Waste Management, Tennessee Department of Health, December 31, 1986; Shelby Jett, Division of Waste Management, Kentucky Department of Environmental Protection, January 6, 1987; Vincent Nikle, Assistant Liaison's Office, New Jersey Department of Environmental Protection, December 17, 1986.

⁴ According to Maine's Solid Waste Management Regulations: "More Stringent Criteria for Large-Scale Disposal of Oil, Coal and Incinerator Ash: Because of the concentration of heavy metals in residues from the combustion of municipal solid waste or the combustion of oil or coal, including bottom ash and fly ash, disposal of such ashes when they occur in amounts that exceed a total accumulation of 20 cubic yards of coal ash ... per week over any one-month period shall be confined to a secure landfill. For the purposes of these rules, a secure landfill shall mean a landfill with a liner and a leachate management system." (Maine's Solid Waste Management Regulations, Chapter 401.2.3.).

⁵ The exhibit assumes that both on-site and off-site permits are required unless the regulations explicitly state otherwise.

⁶ See Chapter One for discussion of the regulation of low-volume utility waste streams.

⁷ Waste piling, a method occasionally employed by utilities, is not discussed in this report. Waste piles are mounds of ash placed on the ground and covered with soil.

⁸ U.S. Department of Energy, Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities, Volume II. 1983.

⁹ See Chapter 6 for a discussion of disposal costs.

¹⁰ Haller, W.A., J.E. Harwood, S.T. Mayne, and A. Gnilka, "Ash Basin Equivalency Demonstration (for treatment of boiler cleaning wastes containing heavy metals)," Duke Power Company, 1976.

11 EnviroSphere Company, Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI Report EA-3681, 1982.

12 Ibid.

13 Ibid.

14 A low-permeable clay is one that has been determined in laboratory testing to have a permeability coefficient, K , of 10^{-7} cm/sec or less.

15 There are one thousand mils per inch.

16 See 40 CFR 264.

17 Engineering-Science, Background Data on Utility Fossil Fuel-fired Facilities, prepared for USDOE, Office of Fossil Energy, 1983.

18 Ibid.

19 Ibid.

20 EPRI Journal, 1985, op. cit.

21 EPRI, Manual for Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

22 EPRI, Characterization of Utility Low-Volume Wastes, prepared by Radian Corporation, Austin, Texas, May 1985.

23 Ibid.

24 Ibid.

25 EPRI, 1987.

26 EPRI, 1985.

27 EPRI, 1987.

28 EPRI, 1985.

29 40 CFR 228, Criteria for the Management of Ocean Disposal Sites for Ocean Dumping.

30 Envirosphere Company, "Economic Analysis of Impact of RCRA on Coal Combustion By-Products Utilization" in Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix G, prepared for Utility Solid Waste Activities Group (USWAG), October 1982.

31 Information compiled by the American Coal Ash Association on 1985 ash utilization, August 1, 1986.

32 EPRI Journal. 1985. op. cit.

33 Ibid.

34 Ibid.

35 USWAG, 1982.

36 EPRI Journal. 1985. op. cit.

37 USWAG. 1982. op. cit.

38 Ibid.

39 For example, see comments by Garry Jablonski, section manager of ash utilization for the American Electric Power Company, "Coal Ash Market Report," Vol. 1, No. 9, July 15, 1987.

40 EPRI, State-of-the-Art of FGD Sludge Fixation, 1978.

41 Ibid.

42 Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated At Fossil Fuel Electric Generating Stations, prepared for USWAG and Edison Electric Institute, August 1981.

43 The economics of burning these wastes would depend on the applicable regulations. Regulations concerning the burning of hazardous wastes are currently being developed and are scheduled for final promulgation in mid-1987.

44 U.S. Department of Energy. 1983. Op. cit.

CHAPTER FIVE
POTENTIAL DANGERS TO HUMAN HEALTH AND THE ENVIRONMENT

Under Section 8002(n) of RCRA, EPA is to analyze the "potential danger, if any, to human health and the environment from the disposal and reuse" of coal combustion wastes and "documented cases in which danger to human health or the environment from surface runoff or leachate has been proved." This chapter examines potential and documented dangers to human health and the environment caused by wastes generated from the combustion of coal at electric utility power plants.

As described in Chapter One, special large volume wastes, including coal combustion wastes, are to be treated differently under RCRA than other industrial wastes. Due to the extremely large volume of coal combustion waste and the expectation of relatively low risk from its disposal, Congress directed EPA to evaluate all the factors in 8002(n) of RCRA in determining whether Subtitle C regulation is warranted. The danger from coal combustion waste management is only one of the factors EPA must consider. In order to provide a starting point for evaluating the potential danger from coal combustion waste management, this chapter begins by providing the reader with background information on the characteristics that an industrial solid waste must exhibit to be considered hazardous under RCRA, and then looks at which of these characteristics apply to coal combustion wastes. The next section analyzes several studies that monitored ground-water and surface-water concentrations in and around coal combustion waste disposal sites and documented the number of times that drinking water standards were exceeded. The third section of this

chapter reviews studies that compiled and evaluated reported incidences of contamination to ground water and surface water due to the disposal of coal combustion wastes. Finally, the fourth section analyzes the factors affecting the exposure of humans, animals, and plants to contaminants from coal combustion waste by examining environmental setting and population data for a random sample of 100 coal-fired utility power plants.

5.1 RCRA SUBTITLE C HAZARDOUS WASTE CHARACTERISTICS AND LISTING CRITERIA

Under RCRA, solid wastes are classified as hazardous if they exhibit characteristics of ignitibility, corrosivity, reactivity, and/or EP toxicity as defined by RCRA or if they are listed as hazardous by the Administrator.

- Ignitibility refers to the tendency of a substance to catch fire. A liquid waste is ignitable if it has a flash point less than 60°C, as determined by EPA-specified test protocols. A non-liquid waste is ignitable if, under standard temperature and pressure, it is capable of causing a persistent, hazardous fire through friction, absorption of moisture, or spontaneous chemical change.¹
- Corrosivity of waste is determined by measuring the waste's pH, the value used to express relative acidity or alkalinity. A pH value of 7.0 is neutral; substances with a pH less than 7.0 are acidic, while those with a pH greater than 7.0 are alkaline. A waste is corrosive, and therefore hazardous, if it is aqueous and has a pH less than or equal to 2.0 or greater than or equal to 12.5.² A waste is also corrosive if it is liquid and corrodes steel at a rate greater than 6.35 mm per year. The pH measurements and the corrosion rate must be determined using EPA-approved methods.³
- Reactivity refers to the stability of a substance. Wastes that are highly reactive and extremely unstable tend to react violently or explode. A waste is reactive if it undergoes violent physical change without detonating, if it reacts violently with water, if it forms a potentially explosive or toxic mixture with

water, or if it is capable of detonating or exploding at standard temperature and pressure.⁴

- Extraction Procedure (EP) Toxicity is determined from a laboratory procedure designed to simulate leaching from a disposal site under actual disposal conditions.⁵ Concentrations in the effluent from this test are compared with the Primary Drinking Water Standards (PDWS) of eight constituent metals to determine whether a waste is hazardous. A waste is EP toxic if it produces a leachate using an EPA-approved procedure that has concentrations of contaminants that are 100 times the PDWS.⁶

Wastes are also regulated as hazardous wastes under Subtitle C if the Administrator lists them in 40 CFR 261.31-261.33. The Administrator may list wastes using several criteria:

- if they are ignitable, corrosive, reactive, or EP toxic as described above.
- if they have been found to be fatal to humans in low doses, or, in the absence of data on human toxicity, fatal to animals in laboratory tests (these wastes are designated Acute Hazardous Wastes).⁷
- if they contain any of the toxic constituents listed in Appendix VIII of 40 CFR 261, unless the Administrator, after considering the factors contained in 40 CFR 261.11(a)(3), concludes that "the waste is not capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed." The factors that the Administrator may consider include the toxicity of the constituent, the concentration of the constituent in the waste, the potential for degradation, the degree of bioaccumulation to be expected from the constituent, and the quantities of the waste generated. These wastes are designated Toxic Wastes.⁸

Determining whether coal combustion wastes show any of the hazardous characteristics is important in analyzing potential danger to human health and the environment. In general, most coal combustion wastes, such as ash and FGD sludge, are not ignitable. Reactivity is also generally not a characteristic

of concern for coal combustion wastes. The chemical and physical characteristics of most coal combustion wastes identified in Chapter Three indicate that these wastes are very stable and will likely not react with other substances in their disposal area. The remainder of this section will analyze data on coal combustion wastes to see if these wastes exhibit the characteristics of corrosivity and/or EP toxicity.

5.1.1 Corrosivity of Coal Combustion Wastes

Under current RCRA regulations, only liquid wastes can be considered corrosive. Coal combustion ash, therefore, could not by itself be considered corrosive, even if it generates a corrosive leachate.

For wastes that are aqueous, a waste is corrosive if its pH is less than or equal to 2.0 or greater than or equal to 12.5. Available data indicate that the pH values of most waste streams of coal-fired power plants do not fall within these ranges; in fact, the only wastes that may be classified as corrosive according to the above definition are water-side, hydrochloric acid-based cleaning wastes, which have had measured pH as low as 0.5 (see Exhibit 3-26). In an EPRI report on low volume wastes (see section 5.1.2) three samples of hydrochloric acid-based boiler cleaning waste all had pH levels less than 2. However, these wastes are often neutralized before disposal. Several other waste streams have pH levels which fall very near the corrosive ranges. Most of these are also low volume wastes. Boiler blowdown has measured pH as high as 12, with a range of 8.3-12 (see Exhibit 3-20), and coal pile runoff has measured pH as low as 2.1, with a range of 2.1-6.6 (see Exhibit 3-21). Sludge from dual-alkali FGD processes using eastern coal is a high volume waste with

measured pH of approximately 12.1 (see Exhibit 3-17). Chapter Three contains a complete description of these wastes.

Several studies of coal combustion waste streams surveyed in this chapter indicate that the alkalinity or acidity of coal combustion wastes, while not necessarily falling in the RCRA corrosive ranges, may occasionally reach levels of potential concern. For example, pH readings of waste fluids taken during a study by Arthur D. Little were as high as 11.4 (see Section 5.2.1). Three case studies described in Appendix D (a study of 12 Tennessee Valley Authority power plants, an individual study at the Bull Run Power Plant, and a study of the Savannah River Project) showed pH readings of waste fluids at 2.0, 3.5, and 2.9, respectively. Section 5.3.1 describes a documented case in which highly alkaline coal combustion waste (pH 12.0) caused substantial harm to aquatic life after it accidentally spilled into Virginia's Clinch River in 1967.

5.1.2 Extraction Procedure (EP) Toxicity of Coal Combustion Wastes

Current RCRA regulations (40 CFR 261.24) specify that if a leachate extracted using an EPA-approved extraction procedure contains any of the metals shown in Exhibit 5-1 at concentrations equal to or greater than the given limit, the waste is classified as EP toxic and, unless otherwise exempted, will be subject to Subtitle C regulation.⁹ The concentrations shown in Exhibit 5-1 are 100 times the current Primary Drinking Water Standards (PDWS) established by the Safe Drinking Water Act for those constituents.

Waste extraction tests are used to predict the type and concentration of constituents that may leach from a waste disposal site under field conditions.

EXHIBIT 5-1**MAXIMUM CONCENTRATION OF CONTAMINANTS FOR
CHARACTERISTIC OF EP TOXICITY**

<u>Contaminant</u>	<u>Level</u>
Arsenic	5.0 mg/1
Barium	100.0 mg/1
Cadmium	1.0 mg/1
Chromium	5.0 mg/1
Lead	5.0 mg/1
Mercury	0.2 mg/1
Selenium	1.0 mg/1
Silver	5.0 mg/1

Source: 40 CFR 261.24, January 16, 1987.

Most extraction tests are conducted by mixing or washing a waste sample with a water-based solution of a specified composition for a specified length of time. The resulting leachate solution is then separated from the solids and tested for constituent concentrations.

5.1.2.1 Types of Extraction Procedures

Several different types of waste extraction procedures are described in detail below. Although under current regulations only the Extraction Procedure (EP) toxicity test is used to determine whether a waste is EP toxic, EPA has recently proposed a new procedure, the Toxic Characteristic Leaching Procedure (TCLP), to replace the EP test (see Federal Register, Volume 51, No. 114, June 13, 1986, p. 21648). Furthermore, in the period since EPA has promulgated the Extraction Procedure (EP) toxicity test, many people have alleged that the EP provides an inappropriate measure of leaching under field conditions. For these reasons, EPA has reviewed the results of other extraction procedure tests as well as the EP. To the extent that the results of these other procedures on coal combustion wastes are generally consistent with the EP results, the debate over whether the EP test is appropriate or not is moot. Three of the extraction tests described below (EP, TCLP, and ASTM) are batch leaching tests. Batch tests are conducted by placing a waste sample in a water-based solution for a specified period of time. The fourth procedure, the column test, passes a solution through the waste.

- The procedure for the standard EPA extraction test, the Extraction Procedure (EP) toxicity test,¹⁰ requires obtaining a waste sample of at least 100 grams and then separating the liquids from the solids. The solid portion is placed in a container along with 16 times its weight in deionized water, and continually agitated at 20-40°C. Throughout the test, the pH of the batch

mixture is monitored. If the solution remains above pH 5.0, acetic acid is added to maintain a pH of 5.0. If the solution is less than pH 5.0, no acetic acid is added. If the pH of the batch solution is not below 5.2 after the initial 24-hour agitation period, the pH is adjusted to 5.0 ± 0.2 at the beginning of each hour during an additional 4 hour agitation period. After agitation, the leachate solution is then separated from the solid portion, and the liquid extracted from the original waste sample is added to the leachate solution. These combined liquids are then tested for constituent concentrations.

- Toxic Characteristic Leaching Procedure (TCLP), which EPA has proposed as a replacement for the EP,¹¹ uses a different leaching solution depending on the nature of the waste being tested. For wastes of low alkalinity, a pH 5.0 acetic acid/sodium acetate buffer is used for extraction. If the waste is more alkaline, a normal acetic acid solution is used. Unlike the EP toxicity test, the TCLP can be used for volatile waste constituents.
- The American Society for Testing and Materials (ASTM) developed the ASTM A procedure, which requires 48-hour agitation of a 1:4 mixture of waste to distilled deionized water. Another test, ASTM B, involves the extraction of waste constituents in a buffered acetic acid solution of pH 4.5.¹² ASTM D, similar to ASTM A, involves the 48-hour agitation of a 350-gram sample with 1400 milliliters of deionized distilled water, and the filtering of the aqueous phase, after agitation, with a 0.45 micron filter.
- Unlike the batch testing methods described above, the column test is conducted by passing a solution through the waste. This test process simulates the migration of leachate and ground water through waste, but still cannot duplicate field conditions perfectly. Because there is no standard column test procedure, column tests are described individually in the studies reviewed in the next section of this chapter.

The results of various studies (conducted with the above-mentioned extraction tests) on the leaching of constituents from coal combustion wastes are discussed below.

5.1.2.2 Results of Extraction Tests

Tetra Tech Study

In 1983 Tetra Tech conducted a literature review for the Electric Power Research Institute (EPRI) and reported results from a number of leachate extraction studies.¹³ An examination of the results of various leaching tests (EP toxicity test, ASTM A, and ASTM B) on coal ash and flue gas desulfurization (FGD) sludge revealed that results differed by waste type and were ultimately dependent upon the source of the fuel (see Exhibit 5-2) and the mechanics of combustion. The study results were presented separately for ash and FGD sludge.

Results of the batch leaching tests (EP, ASTM A, and ASTM B) reported in the studies reviewed by Tetra Tech were presented as averages of the element concentrations found in numerous runs of one type of extraction test. Ranges of the concentrations were sometimes presented as well. Depending on the laboratory that ran the test, EP, ASTM A, and ASTM B batch leaching tests were run on as few as 3 and as many as 62 samples.

Tetra Tech reviewed 457 EP tests on various types of ash. Results from these EP tests show a geometric mean concentration for selenium equal to its PDWS. Geometric mean concentrations for the other 7 metals were below their respective PDWS. The maximum concentrations were 4 times the PDWS for silver, 29 times for arsenic, 8 times for barium, 140 times for cadmium, 14 times for chromium, 4 times for mercury, 5 times for lead, and 17 times for selenium.

Tetra Tech also reported results from 202 ASTM A tests on ash. Selenium was

EXHIBIT 5-2**EFFECT OF GEOGRAPHIC COAL SOURCE
ON ELEMENT CONCENTRATION IN ASH**

<u>Element</u>	<u>Geographic Variation</u>
Arsenic	low in western coal ash; difference in concentration between eastern coal and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; difference in concentration between eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	highest in western ash; lowest in midwestern ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	highest in midwestern ash; lowest in western ash

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

the only constituent with a geometric mean concentration greater than the PDWS, at a level approximately 2 times the PDWS. The maximum concentrations were less than the PDWS for silver and mercury. For the other elements, the maximum concentrations from the ASTM-A procedure were 7 times PDWS for arsenic, 4 times for barium, 1.3 times for cadmium, 10 times for chromium, 5 times for lead, and 48 times for selenium.

Cadmium was the only constituent in fly ash leachate extracted using the EP for which there was a maximum concentration over 100 times the PDWS (and therefore above the EP toxicity level). The EP produced a leachate that had a maximum cadmium concentration 140 times the PDWS. However, the average cadmium concentration for the 62 EP samples was only half the PDWS. Tetra Tech did not report the percentage of samples whose cadmium concentration exceeded 100 times the PDWS. In general, the more acidic or alkaline the leaching solution, the higher the concentrations of leached constituents. Tetra Tech concluded that the geometric mean concentrations from the EP and ASTM-A tests were similar. The results of the EP and ASTM-A tests are presented in Exhibit 5-3.

Tetra Tech also reviewed data from a number of column tests on coal ash. The test results did not show any concentrations greater than 100 times the PDWS for any element tested. One test was conducted during a two-year period using a continuous-flow method to produce leachate from fly ash. In another test, fly ash and bottom ash were packed separately in glass columns, each of which was leached for 27 days with 200 milliliters per day of either distilled water, dilute base, or dilute acid. For a third test, fly ash and bottom ash were packed in water-saturated glass columns. At one-week intervals, the columns were flushed from below at a moderate rate for two hours. This test was

EXHIBIT 5-3

RESULTS OF TETRA TECH EXTRACTION TESTS ON COAL COMBUSTION ASH

Constituent	Primary Drinking Water Standard (mg/l)	EP Test Results			ASTM A Test Results		
		Range	Geometric Mean	Maximum Exceedance	Range	Geometric Mean	Maximum Exceedance
Arsenic	.05	<.004- 1.46 mg/l	.012 mg/l	29 X PDWS	<.0005-0.37 mg/l	.0072 mg/l	7 X PDWS
Barium	1.0	.003- 7.6 mg/l	0.222 mg/l	8 X PDWS	.0004-3.8 mg/l	0.208 mg/l	4 X PDWS
Cadmium	.01	.0001- 1.4 mg/l	.0047 mg/l	140 X PDWS	.0001-.013 mg/l	.00039 mg/l	1.3 X PDWS
Chromium	.05	.001- 0.68 mg/l	.036 mg/l	14 X PDWS	.0005-0.5 mg/l	.047 mg/l	10 X PDWS
Lead	.05	<.0001-0.25 mg/l	.005 mg/l	5 X PDWS	<.0001-0.25 mg/l	.0025 mg/l	5 X PDWS
Mercury	.002	<.0001- .007 mg/l	.00042 mg/l	4 X PDWS	<.0001-.0012 mg/l	.00027 mg/l	0.6 X PDWS
Selenium	.01	<.0001-0.17 mg/l	.01 mg/l	17 X PDWS	.0005-0.48 mg/l	.019 mg/l	48 X PDWS
Silver	.05	<.0001-0.20 mg/l	.00064 mg/l	4 X PDWS	<.0001-.03 mg/l	.0007 mg/l	0.6 X PDWS

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

intended to simulate the intermittent wetting to which some ash disposal sites are subject.

Partly because flue gas desulfurization (FGD) technologies have only achieved widespread commercial usage in recent years, FGD sludge has not been as thoroughly characterized as coal ash. However, the Tetra Tech study reported the results of tests performed on sludges from a number of scrubber processes, including the lime/limestone/alkaline fly ash process, the dual alkali/sodium carbonate process (both these processes produce "lime sludge" and are the main technologies currently in use), and the spray drying process (this process produces calcium-based dry scrubber sludge and may be used more extensively in the future).

Results from EP tests on calcium-based dry scrubber sludge showed a maximum concentration of cadmium that was 150 times the PDWS, above the EP toxic level. Arsenic and selenium were also analyzed using the EP test; the maximum arsenic concentration was 32 times the PDWS and the maximum for selenium was 1.8 times the PDWS. No other constituents were tested for this waste stream. (Results from the EP studies on calcium-based dry scrubber sludge were not averaged but reported as ranges - the number of tests performed was not given).

Tetra Tech also presented results of EP tests on lime sludge. These tests measured concentrations of all EP toxicity constituents, and none were found to be at EP toxic levels.

Tetra Tech also reported on column tests performed on FGD sludge. In one column test, calcium-based dry scrubber sludge was leached with deionized water

for 11 months. In another, various proportions of fly ash, wet calcium sulfate (i.e., gypsum), calcium sulfite precipitate, and calcium oxide (lime) were mixed, cured for 500 days, and leached with deionized water that was forced through the waste columns. The leaching test results (reported in a manner similar to that for reporting results of coal ash leaching studies) indicated, on the basis of an unreported number of tests, that PDWS constituents in lime sludge and calcium-based dry scrubber sludge leached at concentrations that exceeded their PDWS by multiples of less than 5 for silver, 32 for arsenic, 2 for barium, 30 for chromium, 10 for lead, and 15 for selenium; the concentration of mercury found in sludge leachate matched its PDWS. No constituents were at concentrations above 100 times the PDWS.

In summary, none of the coal ash or FGD sludge leaching studies reviewed by Tetra Tech showed constituent concentrations greater than 100 times the PDWS, with the exception of cadmium from calcium-based dry scrubber FGD sludge and from coal ash. Both results were from EP toxicity procedure tests. The behavior of these wastes primarily depended on the source of the fuel and the mechanics of combustion. Tetra Tech concluded that there were gaps in the characterization of these wastes that made definitive conclusions difficult to reach.

Department of Energy Study

The Department of Energy (DOE) conducted a compilation study of leaching test results, Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project,¹⁴ for the purpose of generating a data base on the

leaching characteristics of coals and their combustion wastes. The EP test was compared to a water leach test developed by ASTM (this test later became ASTM D) and evaluated to determine the precision of the EP toxicity method when applied to coal wastes. In their summary of the collected data, DOE reported that for six of the analyzed constituents there were no significant differences between the testing results derived from the two methods. The results of 2492 separate extraction tests for the eight PDWS constituent metals (arsenic, barium, cadmium, chromium, lead, mercury, selenium and silver) indicated that none of the metals leached at concentrations that exceeded the PDWS by 50 times, and most leached at concentrations less than 10 times the PDWS. This was true for both the EP test and the ASTM test.

Arthur D. Little Study

EPA sponsored a study by Arthur D. Little, Inc. (see Section 5.2.1) which included EP Toxicity tests on 20 fly ash samples from 16 power plants and 3 FGD waste samples from 3 power plants.¹⁵ The names of the plants from which the samples were taken were not revealed because Arthur D. Little did not consider the single "grab" samples obtained for testing to be representative. The EP test results showed no EP toxic levels in the extracted leachates of any samples. Silver and mercury concentrations were below the reported detection limits of .001 mg/l and .002 mg/l, respectively, for all samples. Lead was detected in only three out of seventeen samples. Other PDWS constituents (arsenic, cadmium, chromium, selenium, and barium) were detected, but all were found at concentrations less than 100 times the PDWS. In contrast to the Tetra Tech study reported above, leachates extracted from FGD samples had concentrations of PDWS constituents that tended to be lower than the

concentrations in leachates extracted from fly ash samples, whereas the Tetra Tech report indicated that, in general, higher concentrations of PDWS constituents were leached from FGD sludges than from coal ash. This discrepancy may be due to variations in the wastes themselves, which, in turn, are due to differences among coals derived from different sources. Results of the Arthur D. Little study are presented in Exhibit 5-4.

Battelle Pacific Northwest Study

In another study for the Electric Power Research Institute (EPRI), Battelle Pacific Northwest reviewed data developed during a round-robin study that compared results from three laboratories performing both the EP and TCLP tests.¹⁶ Battelle Northwest compared the two extraction procedures by looking at the ratio of the mean TCLP concentrations to the mean EP concentrations for each element. These ratios fell within the range of 0.8 to 1.2 about 60 percent of the time. Only 15 percent of the ratios exceeded 2.0. In 83 percent of the comparisons, the TCLP test leachate contained greater concentrations of the PDWS constituents than the EP test leachate.¹⁷

Battelle compared the maximum mean concentration of each compound (taken from the pool of averaged results for each constituent from both EP and TCLP testing of all the waste samples) with the corresponding PDWS. This comparison indicated that for both the EP and the TCLP procedures, concentrations of silver, barium, and mercury were less than the established PDWS for those metals, whereas the concentration of arsenic was 21 times the PDWS; cadmium, 25 times; chromium, 13 times; lead, 4 times; and selenium, 14 times.

EXHIBIT 5-4

RESULTS OF ARTHUR D. LITTLE TESTING SHOWING THE
RANGE OF CONCENTRATION OF METALS IN EP EXTRACTS a/

Metal	Average Values		(A) Overall Range Observed (mg/l)		(B) Primary Drinking Water Standards	Ratio of Observed Range to PDWS (A/B)	
	Fly Ash	FGD Waste	Fly Ash	FGD Waste		Fly Ash	FGD Waste
	Arsenic	.08	0.20	0.002-.410	0.002-0.065	.05 mg/l	0.04-8.2
Barium	.34	.18	0.1-0.7	0.15-0.23	1.0 mg/l	0.1-0.7	0.15-0.23
Cadmium	.03	.01	0.002-0.193	0.002-0.020	0.01 mg/l	0.2-19.3	0.2-2
Chromium (CrVI) <u>b/</u>	.16	.02	0.008-0.930	.011-0.026	0.05 mg/l	0.16-18.6 <u>c/</u>	0.22-0.52
Lead	.01	.01	0.003-0.036	0.005	0.05 mg/l	0.06 to 0.72	0.1
Mercury	<.002	<.002	<0.002	<0.002	0.002 mg/l	<1	<1
Selenium	.05	.020	.002-0.340	0.008-0.049	0.01 mg/l	0.2 to 34	0.8-4.9
Silver	<.001	<.001	<0.001	<0.001	0.05 mg/l	<0.02	<0.02

a/ Ranges are shown for fly ash and FGD samples; comparisons are made to the Primary Drinking Water Standards.

b/ The Arthur D. Little study tested the concentration of Cr(VI), an ion of chromium.

c/ Since total chromium values are measured by the graphite furnace atomic absorption analysis method, these are upper limits for the Cr(VI) values.

Source: Arthur D. Little, Inc., Full-Scale Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared for the Air and Energy Research Laboratory of the U.S. Environmental Protection Agency, for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

University of Alberta Study

The University of Alberta conducted a study for EPRI that involved passing a water-based solution through a series of columns with increasing ash concentrations.¹⁸ The study results indicate that while some constituent metals were initially released or mobilized from the wastes using this method, these same constituents were attenuated in columns further along in the series. Boron, selenium, and arsenic were initially mobilized, but only boron remained mobilized to a significant extent. Arsenic and selenium interacted in successive columns such that the movement of arsenic and selenium through the system was retarded.

In addition to studying the test leachates, the University of Alberta researchers studied the fly ash itself to determine the processes that affect the migration of metal constituents. The study results indicated that some constituents are not uniformly distributed within the fly ash particles. The fly ash particles typically consist of an interior "glass" matrix covered by a relatively reactive and soluble exterior coating. The study found that arsenic and selenium were concentrated almost exclusively in the coating of the fly ash particles and thus were readily leached; the barium concentration was split evenly between the interior and exterior of the particles; about 75 percent of the cadmium and chromium were concentrated in the interior glass matrix; and almost all the lead was concentrated in the interior glass matrix and was, therefore, not readily mobilized.

The study attributed the uneven concentration of constituents in the fly ash particles to the vaporization of relatively volatile constituents during

combustion, followed by the condensation of these constituents on the exterior of fly ash particles entrained in the flue gas. However, this study reported that lead was contained within the interior glass matrix of the fly ash particles, while the Tetra Tech study discussed earlier reported that lead was volatile and thus likely to be found on the surface of fly ash particles. Both studies reported that arsenic and selenium were found on the surface of the fly ash particles. The University of Alberta concluded that the physical and chemical characteristics of the fly ash were determined by both the chemical composition of the coal from which it came and the mechanics of fly ash formation during combustion.

The difference between the University of Alberta study and the standard leaching test studies is that the mobility of constituents was observed under a variety of conditions. A number of waste concentrations could be tested in the columns to imitate specific field conditions. (Single column extractions also possess such flexibility, but to a lesser degree.) The University of Alberta study simulated landfill conditions by allowing the laboratory leachate solution to continually change as it migrated through multiple waste columns, whereas in batch extraction tests the laboratory leachate solution is allowed to come into contact with only one ash sample.

Battelle Chemical Characterization Study

Battelle Pacific Northwest Laboratories recently completed a study for EPRI on chemical characteristics of fly ash, bottom ash, and FGD sludge.¹⁹ As part of this study, Battelle performed a comparison of the EP Toxicity Test and the TCLP test. While most of the results of the two procedures were consistent,

differences were observed with acidic samples. One acidic fly ash EP sample had both arsenic and chromium above RCRA limits. Another acidic fly ash sample also exhibited elevated levels of arsenic and chromium, but not at levels exceeding RCRA limits. The study found, however, that the two samples showed considerably less leachability for arsenic and chromium with the TCLP, while other elements tested showed similar results from the two testing procedures. The study concluded that the difference between the two types of tests resulted from the acidic character of the samples.

Radian Corporation Study

The Radian Corporation conducted two studies for EPRI that involved testing various low-volume waste streams. In the first of these studies (published in May 1985),²⁰ Radian Corporation collected thirty-two samples on eight types of low volume wastes. These samples were tested using the EP toxicity test as well as some other testing procedures. The results of the EP toxicity test showed that the only waste stream Radian tested that exceeded the EP toxicity limits in the 1985 Radian study was untreated boiler chemical cleaning waste. Exhibit 5-5 presents the results for three samples of untreated boiler cleaning wastes. All three samples had elevated levels of chromium and cadmium, including exceedances of EP toxicity limits, and two samples of boiler cleaning wastes had elevated concentrations of lead, including an exceedance of EP limits. This study also performed EP tests on boiler cleaning wastes after neutralization in a plant treatment system. As shown in Exhibit 5-5, the two samples of treated boiler cleaning waste did not exceed EP toxicity limits for any metals.

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EXHIBIT 5-5

**EP TOXICITY ANALYSIS FOR UNTREATED
AND TREATED BOILER CHEMICAL CLEANING WASTES a/
(concentrations in mg/l)**

Untreated Boiler Cleaning Waste Type

<u>Metals</u>	<u>Maximum Allowable EP Toxicity Limits</u>	<u>Ammoniated EDTA with Inhibitor</u>	<u>Oxidizer</u>	<u>Hydrochloric Acid</u>
Silver	5.0	0.002 <u>b/</u>	0.002 <u>b/</u>	0.007
Barium	100.0	0.76	0.67	0.91
Cadmium	1.0	<u>3.0</u>	<u>3.0</u>	0.64
Chromium	5.0	4.7	4.7	<u>20.0</u>
Arsenic	5.0	0.006	0.002 <u>b/</u>	0.051
Mercury	0.2	0.0002 <u>b/</u>	0.0002 <u>b/</u>	0.0042
Lead	5.0	3.6	<u>5.6</u>	0.002 <u>b/</u>
Selenium	1.0	0.002 <u>b/</u>	0.002 <u>b/</u>	0.003 <u>b/</u>

Treated Boiler Cleaning Waste Type

<u>Metals</u>	<u>Maximum Allowable EP Toxicity Limits</u>	<u>HCl+ Inhibitor, Chelant</u>	<u>Hydrochloric Acid</u>
Silver	5.0	0.042	0.033
Barium	100.0	0.40	0.25
Cadmium	1.0	0.002 <u>b/</u>	0.012
Chromium	5.0	0.001 <u>b/</u>	0.099
Arsenic	5.0	0.002 <u>b/</u>	0.002 <u>b/</u>
Mercury	0.2	0.0002 <u>b/</u>	0.0002 <u>b/</u>
Lead	5.0	0.002 <u>b/</u>	0.002 <u>b/</u>
Selenium	1.0	0.002 <u>b/</u>	0.002 <u>b/</u>

a/ All underlined values exceed maximum allowable limits under current RCRA regulations for hazardous wastes.

b/ Values shown are detection limits. Actual values could be less than, but no greater than, the indicated value.

Source: Electric Power Research Institute, Characterization of Utility Low-Volume Wastes, Radian Corporation, May 1985.

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In Radian Corporation's second study of low-volume wastes (published in July 1987),²¹ they collected additional data on certain low-volume waste streams that the first study indicated might have high concentrations of metals. As shown in Exhibit 5-6, eight of twenty-one samples of low-volume liquid wastes from coal-fired plants were found to exceed EP toxicity limits. For boiler chemical cleaning wastes, 7 of 10 samples exceeded EP toxicity limits for at least one constituent. Six of the boiler chemical cleaning waste exceedances were for chromium and the remaining exceedance was for lead. One wastewater brine sample out of five tested samples exceeded the EP limits for selenium. There were no reported EP exceedances for waterside rinses or coal pile runoff.

Radian Corporation also conducted EP Toxicity tests on low-volume waste sludges. None of the three samples from coal-fired power plants were considered EP Toxic, including a boiler chemical cleaning waste sludge. For the two wastewater pond sludges, the study compared the EP and TCLP testing procedures. Results of the EP and TCLP tests are shown in Exhibit 5-7. The two extraction procedures produced nearly identical concentrations of metals in their extracts.

As in their first study, the Radian Corporation also sampled low-volume wastes that had been treated. This study found significant reductions in concentrations of chromium, copper, iron, nickel and zinc after hydrochloric acid boiler cleaning waste was neutralized.

The study also examined the treatment effectiveness of co-disposal of low-volume wastes with high-volume wastes. Results of EP toxicity tests on co-disposal mixtures found that co-disposal significantly reduced concentrations of contaminants in the co-disposed mixture. Results of the EP tests are

EXHIBIT 5-6

EP TOXICITY TEST RESULTS FOR LIQUID LOW-VOLUME WASTES
(mg/l)

ELEMENT	EP Toxicity Limit	Boiler Cleaning Waste			Waterside Rinses			Coal Pile Runoff			Wastewater Brines		
		# of Tests	Range	Mean	# of Tests	Range	Mean	# of Tests	Range	Mean	# of Tests	Range	Mean
Arsenic	5.0	10	.002-0.36	0.112	3	0.01-0.018	0.014	3	0.002-0.006	0.003	5	0.019-0.52	0.194
Barium	100.0	10	0.022-2.6	0.629	3	0.005-0.097	0.064	3	0.04-0.078	0.054	5	0.1-0.18	0.134
Cadmium	1.0	10	0.002-0.21	0.181	3	0.002-0.04	0.015	3	0.001-0.004	0.002	5	0.002-0.04	0.019
Chromium	5.0	10	0.02- <u>35</u>	<u>8.467</u> 1/	3	0.028-0.77	0.303	3	0.005-0.005	0.005	5	0.005-0.31	0.148
Lead	5.0	10	0.008- <u>23</u>	2.603 2/	3	0.002-0.46	0.181	3	0.002-0.08	0.032	5	0.002-0.002	0.002
Mercury	0.2	10	.0002-0.0039	0.001	3	0.0002-0.0002	0.0002	3	0.0002-0.0003	0.0003	5	0.0002-0.025	0.005
Selenium	1.0	10	.002-.002	0.002	3	0.002-0.002	0.002	3	0.002-0.002	0.002	5	0.002- <u>1.5</u>	0.314 4/
Silver	5.0	10	.001-0.2	0.065	3	0.002-0.02	0.011	3	0.012-0.0023	0.002	5	0.002-0.03	0.013
ph (units)	2<ph<12.5	8	<u>1.01</u> -10.8	5.6 3/	2	9.3-9.4	9.35	3	3.1-9.3	6.9	4	4.6-4.9	4.75

1/ 6 of 10 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

2/ 1 of 10 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

3/ 3 of 8 tests were outside RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

4/ 1 of the 5 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

NOTE: Boiler Cleaning Wastes include EDTA, Hydrochloric Acid, Bromate, Citric Acid, and Hydroxyacetic/formic acid..

Waterside Rinses are wastes resulting from washing the boiler and other plant equipment.

Wastewater Brines are produced during treatment of water-based low volume wastes.

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

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EXHIBIT 5-7

COMPARISON OF EP AND TCLP EXTRACTIONS FOR
LOW-VOLUME SLUDGE DREDGED FROM WASTEWATER PONDS
(mg/l)

<u>ELEMENT</u>	<u>RCRA Limit</u>	<u># of Tests</u>	<u>EP Test</u>		<u>TCLP Test</u>	
			<u>Range</u>	<u>Mean</u>	<u>Range</u>	<u>Mean</u>
Arsenic	5.0	2	0.002-0.015	0.0085	0.004-0.016	0.010
Barium	100.0	2	0.045-0.12	0.0825	0.07-0.089	0.080
Cadmium	1.0	2	0.002-0.002	0.002	0.002-0.002	0.002
Chromium	5.0	2	0.01-0.011	0.0105	0.018-0.023	0.021
Lead	5.0	2	0.002-0.006	0.004	0.002-0.16	0.081
Mercury	0.2	2	.0002-0.0002	0.0002	0.0002-0.0002	0.0002
Selenium	1.0	2	.003-0.0003	0.003	0.003-0.03	0.017
Silver	5.0	2	0.002-0.004	0.003	0.009-0.012	0.011

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

presented in Exhibit 5-8 for co-disposal with fly ash from three geographic areas.

5.1.2.3 Summary of Extraction Test Results

In conclusion, the results of these studies indicate that coal combustion utility wastes may leach several elements, including PDWS constituents. While a variety of extraction procedures were used in these studies, and questions have been raised about the applicability of certain testing methods to coal combustion wastes (which are generally disposed on-site in monofills), all of the extraction procedures used in the studies (EP, TCLP, ASTM, and column) produced average concentrations of constituents that were below the EP toxic level for all waste streams except untreated boiler cleaning waste. In the 1987 Radian Corporation study, untreated boiler cleaning wastes had a mean concentration 169 times the PDWS for chromium using the EP Toxicity test.

For the high-volume waste streams, cadmium, arsenic, and chromium were the only elements for which a maximum concentration was found that was over 100 times the PDWS. Arsenic and chromium were above EP toxicity limits based on EP tests for one acidic fly ash sample in the Battelle chemical characterization study. These were the only exceedances based on 23 samples. Cadmium was found at a concentration 150 times the PDWS in calcium-based dry scrubber sludge leachate and at a concentration 140 times the PDWS in some coal ash leachate as reported in the Tetra Tech study; these leachates were extracted using the EP test method. For both types of waste, however, the exceedances represented the maximum concentrations; all averages of cadmium concentration levels were below 100 times the PDWS. In fact, the geometric mean of cadmium in coal ash

EXHIBIT 5-8

EP TOXICITY TEST RESULTS OF LOW VOLUME
WASTES BEFORE AND AFTER CO-DISPOSAL*
(mg/L)

Midwestern Bituminous Coal Fly Ash

ELEMENT	RCRA Limit	Fly Ash Waste	EDTA Waste	EDTA Waste	Citrate Waste	Citrate Waste	General Wastewater	Wastewater
				Co-disposed With Ash		Co-disposed With Ash		Co-disposed With Ash
Arsenic	5.0	0.006	0.006	0.026	0.21	0.037	0.003	0.031
Barium	100.0	0.006	0.76	0.23	1.6	0.006	1.2	0.17
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.02
Chromium	5.0	0.01	4.7	0.01	3.9	0.01	0.11	0.01
Lead	5.0	0.002	3.6	0.008	0.002	0.002	0.002	0.002
Mercury	0.2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.028	0.002	0.006	0.003	0.002	0.003	0.002
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

Southeastern Bituminous Coal Fly Ash

ELEMENT	RCRA Limit	Fly Ash Waste	EDTA Waste	EDTA Waste	Citrate Waste	Citrate Waste	General Wastewater	Wastewater
				Co-disposed With Ash		Co-disposed With Ash		Co-disposed With Ash
Arsenic	5.0	0.037	0.006	0.036	0.21	N/A	0.003	0.042
Barium	100.0	N/A	0.76	0.33	1.6	0.006	1.2	0.47
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.085
Chromium	5.0	0.036	4.7	0.01	3.9	0.15	0.11	0.01
Lead	5.0	0.002	3.6	0.002	0.002	0.004	0.002	0.023
Mercury	0.2	0.0002	0.0002	0.0003	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.003	0.002	0.015	0.003	0.082	0.003	0.003
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

EXHIBIT 5-8 (Continued)

EP TOXICITY TEST RESULTS OF LOW VOLUME
WASTES BEFORE AND AFTER CODISPOSAL
(mg/L)

Western Subbituminous Coal Fly Ash

<u>ELEMENT</u>	<u>RCRA</u> <u>Limit</u>	<u>Fly Ash Waste</u>	<u>EDTA</u> <u>Waste</u>	<u>EDTA Waste</u> <u>Co-disposed</u> <u>With Ash</u>	<u>Citrate</u> <u>Waste</u>	<u>Citrate Waste</u> <u>Co-disposed</u> <u>With Ash</u>	<u>General</u> <u>Wastewater</u>	<u>Wastewater</u> <u>Co-disposed</u> <u>With Ash</u>
Arsenic	5.0	0.006	0.006	0.08	0.21	0.45	0.003	0.005
Barium	100.0	0.94	0.76	0.7	1.6	0.43	1.2	0.8
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.02
Chromium	5.0	0.01	4.7	0.01	3.9	0.01	0.11	0.01
Lead	5.0	0.002	3.6	0.041	0.002	0.002	0.002	0.002
Mercury	0.2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.034	0.002	0.026	0.003	0.031	0.003	0.003
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

*All underlined values indicate an exceedance of the current RCRA limit for hazardous wastes.

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

leachates in the Tetra Tech study was just under 0.5 of the PDWS.

For the low-volume waste streams, the only exceedance of EP toxicity limits for wastes other than boiler cleaning waste was one wastewater brine sample that had selenium at 150 times the PDWS. The mean concentration of selenium in the wastewater brine samples was below EP toxicity limits. While untreated boiler cleaning wastes had exceedances of EP toxicity limits for chromium and lead, as noted above, EP toxicity tests on neutralized boiler cleaning wastes and on boiler cleaning wastes co-disposed with fly ash showed no exceedances of EP limits.

5.2 EFFECTIVENESS OF WASTE CONTAINMENT AT UTILITY DISPOSAL SITES

Coal combustion wastes contain trace elements that at certain levels could pose a potential danger to human health and the environment if they migrate from the disposal area. The extraction procedure tests described in Section 5.1.2 indicate that these trace elements may leach out of disposed wastes, although rarely at concentrations greater than 100 times the PDWS. This section of the report analyzes studies of ground-water and surface-water quality at and around utility disposal sites to ascertain whether potentially hazardous constituents that leach out of the waste migrate into surrounding ground water or surface water. The studies discussed in this section use as a measure of water quality the concentration of Primary Drinking Water Standards (PDWS) and Secondary Drinking Water Standards (SDWS) constituents in the water around utility waste disposal sites. Primary and Secondary Drinking Water Standards were established in the Safe Drinking Water Act. Primary Drinking Water Standards establish concentration limits for toxic constituents. Secondary Drinking Water Standards

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are based on aesthetic characteristics such as taste, color, and odor. Exhibit 5-9 shows the current PDWS and SDWS. If ground water and surface water downgradient from waste disposal sites have concentrations of constituents in excess of PDWS or SDWS, and upgradient concentrations are below the standards or are lower than the downgradient concentrations, the coal combustion waste could be one of the sources contributing to ground water or surface water contamination.

EPA has conducted a number of studies on the quality of ground water in the immediate vicinity of utility disposal sites. Arthur D. Little performed extensive ground-water monitoring at six utility disposal sites. In a second study, Franklin Associates compiled data from state records on ground-water quality in the vicinity of 66 utility disposal sites. This section also reviews and evaluates a study conducted by Envirosphere for USWAG on available data on ground-water quality at 23 electric utility sites to evaluate whether and to what extent occurrences of ground-water contamination have resulted from the disposal of coal combustion wastes.

5.2.1 ADL Study of Waste Disposal at Coal-Fired Power Plants

Arthur D. Little, Inc. (ADL), conducted a three-year study for EPA's Office of Research and Development to assess the environmental effects and engineering costs associated with coal ash and flue gas desulfurization waste disposal practices at six coal-fired power plants.²² Appendix E contains a detailed discussion of the study, including how the six sampled sites were selected, the study approach, and results for each site. A summary of the six sites is presented below:

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EXHIBIT 5-9**PRIMARY DRINKING WATER STANDARDS**

<u>Contaminant</u>	<u>Concentration (mg/l)</u>
Arsenic	0.05
Barium	1.0
Cadmium	0.01
Chromium	0.05
Fluoride	4.0
Lead	0.05
Mercury	0.002
Nitrate (as N)	10.0
Selenium	0.01
Silver	0.05

SECONDARY DRINKING WATER STANDARDS

<u>Contaminant</u>	<u>Level</u>
Chloride	250 mg/l
Color	15 color units
Copper	1.0 mg/l
Corrosivity	Noncorrosive
Foaming Agents	0.5 mg/l
Iron	0.3 mg/l
Manganese	0.05 mg/l
Odor	3 Threshold odor number
pH	6.5 - 8.5
Sulfate	250 mg/l
Total Dissolved Solids	500 mg/l
Zinc	5.0 mg/l

Source: 40 CFR 141 and 143, September 1, 1986.

- The Allen Plant in North Carolina disposed of a mixture of fly ash and bottom ash in two unlined disposal ponds, one closed and one in active use. Intermittent waste streams, such as boiler wastes and coal pile runoff, were also disposed in the ponds. While concentrations of trace elements in downgradient ground water were higher than upgradient concentrations, exceedances of the Primary Drinking Water Standards were not found. Elevated concentrations of arsenic (up to 31 times the PDWS) were found in fluids within the active ash pond. Attenuation tests indicated that the arsenic concentrations would be chemically attenuated by iron and manganese in the soils beneath and surrounding the site. Ground-water contamination, particularly from arsenic, could have resulted if these attenuative soils had not been present. Secondary Drinking Water Standards were exceeded in both the upgradient and downgradient ground water for manganese and in the downgradient ground water for iron. This was attributed to high concentrations of these elements present in the soils of the site. Steady-state conditions have probably not been achieved at the Allen site; increases in downgradient ground-water concentrations of non-attenuated contaminants may be expected in the future.
- The Elrama Plant in western Pennsylvania disposed a fixated FGD sludge-fly ash mixture, along with small volumes of bottom ash and sludge from coal pile runoff treatment ponds, in an abandoned coal-mining area 12 miles from the plant. Part of the landfill is underlain by acid-producing spoils from the strip mining of coal. Cadmium was found in concentrations exceeding the Primary Drinking Water Standard by as much as 20 times in downgradient ground water; the highest concentration was found in the well closest to the landfill. There were no upgradient exceedances for cadmium. Steady-state conditions did not appear to have been achieved at the site, so that effects of leachate from the landfill may be expected to increase with time. Secondary Drinking Water Standards (for pH, manganese, sulfate, and iron) were exceeded at the site in both upgradient and downgradient ground water. These exceedances probably occurred because of characteristics of the disposal area and because ground water was already contaminated from acid mine drainage. Test results indicated that any constituent migration from the landfill did not measurably affect the water quality of the nearby Youghiogheny River.

Arsenic was repeatedly detected at levels three to five times the Primary Drinking Water Standard in pond liquors, but appeared to be attenuated by soils at the site. This suggests the possibility that similar wastes

at other sites could leach arsenic at higher levels if arsenic were not attenuated by surrounding soils or diluted before reaching drinking water.

The results discussed above indicate that the fixated FGD/fly ash wastes have been, and will continue to be, a source of contamination at the site. Because exceedances for many contaminants were probably due to concurrent contamination from acid mine drainage, leachate from coal combustion waste may have only a small incremental impact on water quality.

- The Dave Johnston plant in Wyoming is located in an arid region with little ground-water recharge. The plant is the oldest of the six sites, and burns low-sulfur western coal. There are a number of disposal areas at the site; the ADL study investigated two unlined fly ash landfills, one active and one closed. Exceedances of the Primary Drinking Water Standards for cadmium (up to 3 times the PDWS) were found in ground water upgradient and downgradient of the site. Cadmium was found at elevated concentrations in pond liquors and ground water beneath the wastes. Exceedances of Secondary Drinking Water Standards for manganese and sulfate were also observed in downgradient and upgradient ground water. These two contaminants and boron were found in elevated concentrations in ground water beneath the waste and in pond liquors. No samples were analyzed for the presence of arsenic in the pond liquors. Chemical attenuation by soils at the site was found to be low for trace metals such as arsenic. Interpretations of the sampling results were difficult to make because other potential contamination sources exist, such as other waste disposal areas at the site (the location and ages of which are uncertain) and contaminants naturally occurring in the soil, which is highly mineralized around the Johnston site; and uncertainties with regard to what degree leachate from the two landfills had reached the downgradient wells. Contamination from the site could possibly increase until steady-state concentrations are reached.
- The Sherburne County Plant in central Minnesota disposed of fly ash and FGD waste in one clay-lined pond and bottom ash in an adjacent clay-lined pond. Exceedances of the Primary Drinking Water Standards were observed in both upgradient and downgradient ground water for cadmium (up to 2 times the PDWS for both) and for nitrate, and in downgradient ground water for chromium (up to 1.2 times the PDWS). Pond liquors were found to exhibit high concentrations of several constituents, including cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride, nitrate, lead (up to 28 times the PDWS), and selenium (up to 25 times the PDWS). While the pond

liquors exhibited high concentrations of contaminants, leachate from these wastes did not appear to have migrated into and mixed with ground water to a great extent. Ground-water samples collected at the site seemed to indicate that a few constituents (sulfate and boron) had migrated from the wastes, but not at levels exceeding SDWS. The clay liner appeared to have significantly reduced the rate of release of leachate from the disposal ponds, precluding the development of elevated trace metal concentrations at downgradient wells. Over time, downgradient wells will likely show increased levels of contamination, since steady-state conditions had not been achieved between leachate from the landfill and the ground water. Without the clay liner, the leachate seepage rate would probably have been much greater. Since the surrounding soils may not chemically attenuate selenium, this contaminant might cause PDWS exceedances once steady-state concentrations in ground water are reached.

- The Powerton Plant disposed fly ash, bottom ash, and slag in an older landfill approximately one mile south of the site. In a newer portion of the landfill, disposal operations consisted of disposing intermixed fly ash and slag. The newer landfill and part of the older one are underlain by a liner consisting of ash and lime. The downgradient ground-water wells exhibited levels of cadmium up to three times the Primary Drinking Water Standard and, in one sample, lead at four times the PDWS. An upgradient well, located on the border of the landfill wastes, exhibited a concentration of cadmium at the level of the Primary Drinking Water Standard. Secondary Drinking Water Standards for iron, manganese, and sulfate were exceeded in downgradient wells, and for manganese in an upgradient well (but at a level of exceedance lower than the downgradient measurements). These results indicate that leaching and migration of ash wastes had occurred at the site, but it was difficult to determine the effect the leachate had, or will have, on ground-water quality. Dilution and chemical attenuation may have prevented the buildup at downgradient locations of significant concentrations of trace metals such as arsenic and selenium. The degree to which Lost Creek, a nearby downgradient stream, was diluting waste constituents that reach it may be significant.
- The Lansing Smith plant in southern Florida disposed a mixture of fly ash and bottom ash in an unlined disposal pond located in a coastal area. Concentrations greater than the Primary Drinking Water Standards were observed for cadmium (up to five times the PDWS), chromium (up to four times the PDWS), and fluoride in the downgradient ground water at the site and, with the possible exception

of fluoride, appeared to be due largely to the leaching of the ponded ash wastes. Exceedances of Secondary Drinking Water Standards for sulfate, chloride, manganese, and iron were also observed in downgradient ground water. However, most of these contaminants are seawater-related and their reported concentrations appeared to be influenced by the use of seawater in plant operations and infiltration of estuarine (saline) water at the site. The leachate generated migrates to a shallow, unused, tidal aquifer. These results indicate that ash disposal at this site appears to have had a measurable impact on ground-water quality. Health risks at this particular site, however, were probably minimal since the ground water and surface water were not used as a source of drinking water.

5.2.1.1 Ground-water Sampling

Exhibits 5-10 and 5-11 summarize the results of the ADL ground-water quality data at the six disposal sites for constituents with established Primary and Secondary Drinking Water Standards, respectively. As can be seen from Exhibit 5-10:

- One site had no exceedances of PDWS constituents, either upgradient or downgradient.
- One site had PDWS exceedances for cadmium only, with the same maximum PDWS exceedance upgradient and downgradient.
- One site had downgradient PDWS exceedances for cadmium, chromium, and nitrate, but for cadmium and nitrate the upgradient exceedances were at least as large as the downgradient exceedances. There were no upgradient exceedances of chromium; the one downgradient exceedance was 1.2 times PDWS.
- The three remaining sites had downgradient PDWS exceedances for cadmium that were more frequent and larger than upgradient exceedances. The largest downgradient exceedance for cadmium at any of the six sites was 20 times the PDWS.
- There were no upgradient chromium exceedances and only three exceedances out of 94 downgradient observations. Two of the downgradient exceedances were 1.2 times the PDWS and one was 4 times the PDWS. These three exceedances were at three different sites.

EXHIBIT 5-10

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER
QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
PDWS		1/		1/		1/		1/		1/		1/	
		Downgradient (11 wells)	Upgradient (1 well)	Downgradient (5 wells)	Upgradient (1 well)	Downgradient (3 wells)	Upgradient (2 wells)						
2/ Drinking	Water	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	
Contam.	Standard	Exceed./ Total	Max./ Exceed.	Exceed./ Total	Max./ Exceed.	Exceed./ Total	Max./ Exceed.	Exceed./ Total	Max./ Exceed.	Exceed./ Total	Max./ Exceed.	Exceed./ Total	Max./ Exceed.
Arsenic (liq.)	0.05	0/12	0/2	0/1	0/2	0/2	0/3						
Barium	1	0/31	0/3	0/19	0/4	0/9	0/6						
Cadmium	0.01	0/31	0/3	3/19	20	0/4	6/9	3	3/6	3			
Chromium (Cr VI)	0.05	0/31	0/3	1/19	1.2	0/4	0/9	0/6					
Fluoride	4.0	0/34	0/4	0/21	0/4	0/12	0/8						
Lead	0.05	0/31	0/3	0/19	0/4	0/9	0/6						
Mercury	0.002	0/0	0/0	0/0	0/0	0/0	0/0						
Nitrate 5/	45	0/34	0/4	0/20	0/4	0/12	0/8						
Selenium (liq.)	0.1	0/5	0/2	0/1	0/2	0/2	0/3						
Silver	0.05	0/31	0/3	0/19	0/4	0/9	0/9						

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-10 (Continued)**SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER
QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES**

Units = ppm		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
PDWS		1/		1/		1/		1/		1/		1/	
		Downgradient (3 wells)	Upgradient (2 wells)	Downgradient (3 wells)	Upgradient (1 well)	Downgradient (5 wells)	Upgradient (3 wells)						
2/ Drinking	Water	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	
Contam.	Standard	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.
Arsenic (liq.)	0.05	0/3		0/3		0/8		0/2		0/5		0/4	
Barium	1	0/12		0/8		0/9		0/4		0/14		0/6	
Cadmium	0.01	2/12	2	2/8	2	8/9	3	2/4	1	10/14	5	2/6	2
Chromium (Cr VI)	0.05	1/12	1.2	0/8		0/9		0/4		1/14	4	0/6	
Fluoride	4.0	0/12		0/8		0/9		0/4		5/14	13.5	0/6	
Lead	0.05	0/12		0/8		1/9	4	0/4		0/14		0/6	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	2/12	1.1	2/8	27	0/9		2/4	1.1	0/0		0/0	
Selenium (liq.)	0.1	0/3		0/3		0/8		0/2		0/5		0/4	
Silver	0.05	0/12		0/8		0/9		0/4		0/14		0/6	

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-11

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY
DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
SDWS		1/		1/		1/		1/		1/		1/	
		Downgradient (11 wells)	Upgradient (1 well)	Downgradient (5 wells)	Upgradient (1 well)	Downgradient (3 wells)	Upgradient (2 wells)						
2/ Drinking	Water	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	
Contam.	Standard	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.
Chloride	250	0/34		0/4		0/21		0/4		0/12		0/8	
Copper	1	0/31		0/3		0/19		0/4		0/9		0/6	
Iron	0.3	7/31	82	0/3		0/19		1/4	1.8	0/9		0/6	
Manganese	0.05	19/31	102	1/3	1.4	19/19	456	4/4	197	1/9	3.2	1/6	4.6
Sulfate	250	0/34		0/3		9/19	4.7	3/4	1.5	12/12	5.8	4/8	5.1
Zinc	5	0/31		0/3		0/19		0/4		0/9		0/6	
pH Lab 5/	<=6.5	10/10	4.7	1/1	5.9	0/0		0/0		0/0		0/0	
	>=8.5	0/10		0/1		0/0		0/0		0/0		0/0	
pH Field 5/	<=6.5	21/28	4.4	2/3	6.2	9/14	5.2	2/2	4.5	0/9		0/6	
	>=8.5	0/28		0/3		0/14		0/2		0/9		0/6	

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

EXHIBIT 5-11 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY
DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
SDWS		1/		1/		1/		1/		1/		1/	
		Downgradient (3 wells)	Upgradient (2 wells)	Downgradient (3 wells)	Upgradient (1 well)	Downgradient (5 wells)	Upgradient (3 wells)	Downgradient (3 wells)	Upgradient (3 wells)				
2/ Drinking	Water	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/
Contam.	Standard	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.
Chloride	250	0/12	0/8	0/9	0/4	14/14	22.4	0/6					
Copper	1	0/12	0/8	0/9	0/4	0/14		0/6					
Iron	0.3	0/12	1/8 1.9	4/9 42	0/4	14/14	118	6/6	37				
Manganese	0.05	2/12 22	1/8 1.4	9/9 194	2/4 11	13/14	17.2	2/6	1.4				
Sulfate	250	0/12	0/8	6/9 2.7	0/4	8/14	8.4	0/6					
Zinc	5	0/12	0/8	0/9	0/4	0/14		0/6					
pH Lab 5/	<=6.5	0/0	0/0	0/0	0/0	4/6	4.4	1/2	6.5				
	>=8.5	0/0	0/0	0/0	0/0	0/6		0/2					
pH Field 5/	<=6.5	0/8	0/6	1/9 6	0/3	10/13	2.9	4/6	6				
	>=8.5	0/8	0/6	0/9	0/3	0/13		0/6					

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

- One site had downgradient PDWS exceedances for fluoride in 5 of 14 samples. The maximum exceedance was 13.5 times the PDWS. There were no upgradient PDWS exceedances for fluoride at any of the six sites.
- There were no lead exceedances upgradient and only one PDWS exceedance out of 94 downgradient observations at 4 times the PDWS.
- The contaminants of most concern at the six sites appear to be cadmium and, to a lesser extent, chromium. For both of these contaminants, three sites had exceedances of the PDWS in downgradient ground water at levels higher than were found in upgradient ground water.

For constituents for which there are Secondary Drinking Water Standards, exceedances in downgradient ground water generally were higher than levels observed in upgradient wells. Results are shown in Exhibit 5-11.

5.2.1.2 Surface Water Sampling

Exhibit 5-12 summarizes the results of surface-water quality data obtained by ADL at background, peripheral, and downstream locations at three of the study sites -- Elrama, Powerton, and Lansing Smith -- for constituents with established Primary and Secondary Drinking Water Standards. Examination of these results for PDWS constituents indicates that:

- At the Lansing Smith site, downgradient and peripheral surface water samples showed cadmium concentrations up to 5 times the PDWS, chromium concentrations up to 1.2 times the PDWS, and fluoride concentrations up to 20 times the PDWS. No upgradient samples were collected at the Lansing Smith site.
- Exceedances were found for cadmium (up to 2 times the PDWS) and nitrate (up to 1.2 times the PDWS) in both upgradient and downgradient surface water at the Powerton site. The exceedances were similar in upgradient and downgradient samples both in terms of the proportion of samples in which exceedances were found and the magnitude of the exceedances.

EXHIBIT 5-12

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA
ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
PDWS		1/		1/		1/		1/		1/		1/			
		Downgradient (4 stations)	Upgradient (1 station)	Downgradient (1 station)	Upgradient (3 stations)	Downgradient (6 stations)	Peripheral (3 stations)	Downgradient (2 stations)	Downgradient (2 stations)						
2/ Drinking	Water	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/		
Contam.	Standard	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.		
Arsenic (liq.)	0.05	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Barium	1	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Cadmium	0.01	0/7		0/3		2/3	2	5/8	2	10/13	5	4/8	4	5/5	4
Chromium (Cr VI)	0.05	0/7		0/3		0/3		0/8		0/13		0/8		1/5	1.2
Fluoride	4.0	0/7		0/3		0/3		0/8		5/13	6.5	2/8	2	2/5	20
Lead	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	0/7		0/3		1/3	1.1	3/7	1.2	0/0		0/0		0/0	
Selenium (liq.)	0.1	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Silver	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	

1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may become contaminated by lateral dispersion of waste constituents.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-12 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA
ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm	New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
	1/		1/		1/		1/		1/		1/			
SDWS	Downgradient (4 stations)		Upgradient (1 station)		Downgradient (1 station)		Upgradient (3 stations)		Downgradient (6 stations)		Peripheral (3 stations) Downgradient (2 stations)			
2/ Drinking Water Standard	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/	3/ 4/		
Contam.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.	Exceed./ Total	Max. Exceed.		
Chloride	250	0/7	0/3	0/3	0/3	0/8	13/13	11.9	5/8	10	5/5	58		
Copper	1	0/7	0/3	0/3	0/3	0/8	0/13		0/8		0/5			
Iron	0.3	0/7	0/3	0/3	0/3	0/8	11/13	370	6/8	34	0/5			
Manganese	0.05	7/7	7.4	3/3	4.2	2/3	2.2	2/8	1	11/13	64	6/8	4.8	0/5
Sulfate	250	0/7	0/3	0/3	0/3	0/8	12/13	7.5	4/8	3.4	5/5	9.9		
Zinc	5	0/7	0/3	0/3	0/3	0/8	0/13		0/8		0/5			
pH Lab 5/	<=6.5	0/0	0/0	0/0	0/0	0/0	5/6	3.3	2/3	3.8	0/1			
	>=8.5	0/0	0/0	0/0	0/0	0/0	0/6		0/3		0/1			
pH Field 5/	<=6.5	4/7	6.1	2/3	6	0/3	0/8		5/10	4.1	4/7	3.4	0/5	
	>=8.5	0/7	0/3	1/3	8.5	2/8	8.5	0/10	0/7		0/5			

- 1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may become contaminated by lateral dispersion of waste constituents.
- 2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.
- 3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.
- 4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 5/ As indicated in footnote 10, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

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- No exceedances of PDWS were found upgradient or downgradient at the Elrama site, although there had been downgradient exceedances at Elrama in ground water for cadmium and chromium.

5.2.1.3 Waste Fluid Sampling

In addition to ground-water monitoring, waste fluid samples were collected from the waste ponds at the Allen, Sherburne County, and Lansing Smith sites, and from dry fly ash landfills at the Dave Johnston site. Water from within and beneath FGD sludge and fly ash waste mixtures were collected from the Elrama landfill. No waste fluid samples were obtained at the Powerton site. Key observations are presented below.

- Arsenic was present in the waste fluids at elevated concentrations (up to 31 times the Primary Drinking Water Standard) at two of the five sites sampled. At these sites (Allen and Elrama), arsenic may be attenuated by soils at the site; attenuation tests indicate the soils had a moderate to high attenuation capacity, and no exceedances for arsenic were observed in ground water at the sites. The Dave Johnston site was the only disposal area where soils were found to have low attenuation capacities for arsenic; however, there are no data pertaining to waste fluids at this site, and exceedances for arsenic in the ground water were not observed. These results indicate that, depending on the coal source, arsenic may occur at elevated concentrations in waste fluids, but can be attenuated by soils within and surrounding a coal combustion waste disposal site. If the soils at a disposal site have low attenuation capacities for arsenic, this element may be of concern with regard to ground water and surface water contamination.
- Cadmium is present at elevated concentrations (up to 30 times the Primary Drinking Water Standard) in the waste fluids at all five sites. At Powerton, although no waste fluid samples were taken, ground-water samples obtained from directly beneath the wastes also exhibited elevated concentrations of cadmium. These results support the conclusion that elevated concentrations of cadmium observed in downgradient ground water may be attributable to coal combustion wastes.

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- Chromium is present at elevated concentrations (up to 21 times the Primary Drinking Water Standard) in the waste fluids at two of the five sites. At these sites, higher chromium concentrations were found in downgradient ground water than were found in upgradient ground water. These observations suggest that ground-water contamination by chromium at these two study sites may be attributable to the coal combustion wastes. At a third site at which downgradient exceedances of chromium in ground water were observed, waste fluid samples were mixed with ground water occurring beneath the wastes during collection, which may account for lower waste fluid concentrations at this site.
- Other constituents that were found at elevated concentrations within the waste fluids include fluoride at all five sites (up to 10 times the PDWS); lead at one of five sites (up to 28 times the PDWS); nitrate at one of five sites (up to 7 times the PDWS); and selenium at one of four sites (up to 25 times the PDWS).
- Constituents for which Secondary Drinking Water Standards are established were found at the following elevated concentrations: chloride at three of five sites (up to 61 times the SDWS); iron at two of five sites (up to 221 times the SDWS); manganese at four of five sites (up to 466 times the SDWS); and sulfate at four of five sites (up to 42 times the SDWS). Exceedances of pH standards were found in the waste fluids at two of three sites tested. At these two sites, both acidic (as low as pH 5.9) and alkaline (as high as pH 11) conditions were found to exist. Average pH values measured in these waste fluids indicated that they were generally alkaline.
- Results of waste fluid sampling at the Sherburne County site showed exceedances of Primary Drinking Water Standards for cadmium (up to 30 times PDWS); chromium (up to 16 times the PDWS); fluoride (up to 13 times the PDWS); lead (up to 28 times the PDWS); nitrates (up to 6.9 times the PDWS); and selenium (up to 25 times the PDWS). Measurements also showed maximum exceedances of Secondary Drinking Water Standards for chloride (up to 1.9 times the SDWS); iron (up to 6.1 times the SDWS); manganese (up to 316 times the SDWS); and sulfate (up to 42 times the SDWS). This was the only site where disposal areas or ponds were completely lined. The clay liner appeared to have reduced the release of leachate, thereby concentrating waste constituents.

Results from waste fluid studies conducted by other organizations are described in Appendix D.

5.2.1.4 Summary

Results from the Arthur D. Little study suggest that under the waste management procedures used by the facilities studied, some coal combustion waste leachate was migrating into ground water beneath and downgradient from disposal sites. Five sites had concentrations of cadmium in downgradient ground water that exceeded the PDWS. Two of these five had maximum upgradient exceedances at the same level as the maximum downgradient exceedance, and two of the sites had upgradient concentrations that were equal to or above the PDWS, although the maximum concentration was less than the downgradient concentrations. One of the five sites had upgradient measurements of cadmium that were below the PDWS. Exceedances of chromium were detected in a few ground-water samples downgradient of three sites; there were no chromium concentrations above the PDWS in the upgradient ground water of any site. There were no detected exceedances of arsenic, barium, mercury, selenium, or silver in the ground water or surface water at any of the six sites. In total, approximately 5 percent of the downgradient observations exceeded the PDWS.

5.2.2 Franklin Associates Survey of State Ground-Water Data

EPA commissioned Franklin Associates to gather data from state regulatory agencies on the quality of ground water at or near coal-fired electric utility fly ash disposal sites.²³ The objective of this survey was to determine the level of ground-water contamination in the vicinity of disposal sites. However,

according to the Franklin Associates report: "No attempt was made to determine what monitoring wells might be up gradient, or what wells might be down gradient, or even as to whether specific ash disposal sites were in fact contributing specific pollutants."

Franklin Associates contacted 44 states in which coal-fired facilities were located; of these 44 states, 13 provided data. The data base that was developed included data from more than 4700 well samples taken from 66 sites.

Analysis of these samples revealed 1129 exceedances of the PDWS out of more than 15,000 observations, as shown in Exhibit 5-13. Ninety-two percent of the exceedances were less than ten times the PDWS; eight of the exceedances were 100 times greater than the PDWS.

There were 5952 exceedances of the SDWS out of nearly 20,000 observations as shown in Exhibit 5-14. These secondary standards were exceeded more frequently than the primary standards, and exceedances were usually greater. For example, about 77 percent of the SDWS exceedances were less than 10 times the standard (compared with 92 percent for PDWS exceedances), whereas 4 percent of the exceedances were greater than 100 times the SDWS (compared with less than one percent for PDWS exceedances).

Since this study did not compare upgradient and downgradient concentrations, it is not possible to determine whether occurrences of contamination at particular sites are the result of utility waste disposal practices or background levels of contaminants.

EXHIBIT 5-13

SUMMARY OF PDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

<u>Constituent</u>	<u>Total Observations</u>	<u>Number of Observations Exceeding PDWS By</u>			<u>Highest Exceedance (X PDWS)</u>
		<u>1 X</u>	<u>10 X</u>	<u>100 X</u>	
Arsenic	1995	94	0	0	9.8
Barium	1353	108	9	0	44.0
Cadmium	1733	126	16	1	531.0
Chromium	1863	92	5	0	50.2
Fluoride	995	28	3	0	19.3
Lead	1722	243	20	1	182.0
Mercury	1282	30	8	5	500.0
Nitrate	1432	204	0	0	7.3
Selenium	2453	196	30	1	100.0
Silver	<u>530</u>	<u>8</u>	<u>0</u>	<u>0</u>	8.0
TOTAL	15,358	1129	81	8	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

EXHIBIT 5-14

SUMMARY OF SDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

Constituent	Total Observations	Number of Observations Exceeding SDWS By			Highest Exceedance (X SDWS)
		1 X	10 X	100 X	
Chloride	2921	109	14	0	42.0
Copper	650	1	0	0	1.2
Iron	3140	1942	862	149	4,000.0
Manganese	1673	1050	467	80	2,400.0
pH	4107	843	-	-	-
Sulfate	4378	1059	13	0	23.2
TDS	1925	920	24	0	28.7
Zinc	<u>1175</u>	<u>28</u>	<u>4</u>	<u>0</u>	46.0
TOTAL	19,969	5952	1384	229	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

5.2.3 Envirosphere Ground-Water Survey

In response to the temporary exemption of utility wastes from regulation under Subtitle C of RCRA, the Utility Solid Waste Activities Group (USWAG) commissioned Envirosphere, Inc., to review information available from electric utilities on the quality of ground water at utility waste disposal sites.²⁴ Envirosphere solicited information from 98 utilities on the number and type of constituents they monitored, the frequency with which measurements were taken, and the period of time for which they had collected ground-water monitoring data. Ninety-six of the contacted utilities responded to the request for information. From these 96 utilities, Envirosphere selected for further study those that appeared to have adequate data on ground-water quality. These utilities were contacted and asked to provide their available data for use in Envirosphere's study. The participating utilities (the exact number of utilities was not provided) forwarded the requested information to Envirosphere on the 28 disposal facilities they operated. The utilities chose to withdraw three of the 28 disposal sites from the study subsequent to the analysis of the data, leaving 25 disposal sites in the data pool.

In order to analyze the data, Envirosphere paired the measurements taken at upgradient and downgradient wells at approximately the same time and in the same aquifer.²⁵ These data were then compared to the applicable drinking water standards to determine whether the standards had been exceeded. Two disposal sites were then eliminated from further consideration because no upgradient wells could be identified. The remaining 23 disposal sites produced a total of 9,528 paired measurements of upgradient and downgradient ground-water concentrations.

Exhibit 5-15 summarizes the information from the EnviroSphere data base for those cases where the Primary Drinking Water Standards (PDWS) were exceeded by the downgradient measurement. The most obvious indication that a waste facility is contributing to a PDWS exceedance is a measurement indicating downgradient values higher than the PDWS and upgradient values lower than the PDWS. According to EnviroSphere's report, about 1.7 percent of the data fell into this category.²⁶ For those cases in which both the upgradient and downgradient values were exceeded, EnviroSphere argued that it was difficult to attribute the exceedances to the disposal facility without further site-specific analysis. About 5 percent of the measurements fell into this category, with 60 percent of these indicating upgradient values equal to or greater than the downgradient values.

Maximum concentrations of several substances significantly exceeded the PDWS in downgradient wells: arsenic, 560 times the PDWS; lead, 480 times the PDWS; mercury, 235 times the PDWS, and selenium, 100 times the PDWS. These values must be compared to the maximum upgradient reading since some of the contamination may be unrelated to the disposal facility. As shown in Exhibit 5-15, the downgradient concentration was sometimes higher than the upgradient value even when the upgradient value exceeded the PDWS. However, exceedances of the magnitudes shown in Exhibit 5-15 comprised a small fraction of the total measurements in the EnviroSphere data base.

The EnviroSphere data also included information regarding exceedances of the Secondary Drinking Water Standards (SDWS). A summary of these data is shown in Exhibit 5-16. The data indicate that in 8.2 percent of the cases the

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EXHIBIT 5-15

SUMMARY OF PDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

Constituent	Total Observations	Downgradient Observations <u>a/</u> Exceeding PDWS When:				Maximum Downgradient Observation (X PDWS)	
		Upgradient Does Not Exceed		Upgradient Exceeds			
		Number	%	Number	%		
Arsenic	588	7	1	0	0	560	(192)
Barium	298	0	0	0	0	1	(3)
Cadmium	571	59	10	9	2	6	(1)
Chromium	658	20	3	10	2	20	(76)
Lead	639	29	5	67	10	480	(220)
Mercury	575	8	1	2	<u>c/</u>	235	(9)
Selenium	489	5	1	34	7	100	(100)
Silver	<u>261</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	1	(0.2)
TOTAL	4079	128	3 <u>d/</u>	122	3 <u>d/</u>		

a/ EnviroSphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the PDWS, classification depended on whether the upgradient value also exceeded the PDWS. Both categories of measurements are shown here, although EnviroSphere focused primarily on pairs of measurements in which the downgradient value exceeded the PDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the EnviroSphere data base. The corresponding paired upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ Less than 0.5 percent.

d/ These percentages apply to the total number of observations. EnviroSphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: EnviroSphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

EXHIBIT 5-16**SUMMARY OF SDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA**

Constituent	Total Observations	Downgradient Observations <u>a/</u> Exceeding SDWS When:				Maximum Downgradient Observation (X SDWS) <u>b/</u>
		Upgradient Does Not Exceed		Upgradient Exceeds		
		Number	%	Number	%	
Chloride	502	4	1	7	1	22 (5)
Copper	452	9	2	0	0	2 (0.02)
Iron	964	60	6	376	39	3458 (2)
Manganese	487	157	32	143	29	474 (5)
Sulfate	1028	289	28	57	6	32 (8)
Total Dissolved Solids	908	159	18	292	32	31 (2)
Zinc	<u>387</u>	<u>3</u>	<u>1</u>	<u>3</u>	<u>1</u>	1 (0.1)
TOTAL	4728	681	14 <u>c/</u>	875	19 <u>c/</u>	

a/ EnviroSphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the SDWS, classification depended on whether the upgradient value also exceeded the SDWS. Both categories of measurements are shown here, although EnviroSphere focused primarily on pairs of measurements in which the downgradient value exceeded the SDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the EnviroSphere data base. The corresponding (paired) upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ These percentages apply to the total number of observations. EnviroSphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: EnviroSphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

downgradient value exceeded the SDWS while the upgradient value did not. In some cases the exceedances were substantially greater than the SDWS; e.g., the maximum observation for iron was 3458 times greater than the SDWS and manganese was 474 times greater.

In summary, the EnviroSphere ground-water data show that Primary and Secondary Drinking Water Standards were exceeded in ground water downgradient from utility waste disposal facilities. However, the percentage of cases in which constituent concentrations in downgradient wells exceeded the standards when those in upgradient wells did not was small. There are limitations in the data, due in part to the way in which they were collected (e.g., only data from those utilities that voluntarily submitted data are included in the report). There is also a limited amount of information regarding the extent to which site-specific factors, such as environmental setting characteristics or other possible sources of contamination, could have had an effect on ground-water contamination.

5.2.4 Summary

The studies described in this section demonstrate that downgradient ground-water and surface-water concentrations exceeded the PDWS and SDWS for a few constituents. In some of these downgradient exceedances, corresponding upgradient exceedances also occurred, suggesting that the contamination was not necessarily caused by the waste disposal sites. For cases in which the downgradient ground water had constituent concentrations higher than the corresponding upgradient concentrations, the PDWS exceeded most often were those for cadmium, chromium, lead, and to a lesser extent, arsenic.

Some PDWS exceedances were quite high, e.g., up to 560 times for arsenic and 480 times for lead (see Exhibit 5-15). However, the frequency of PDWS exceedances for downgradient ground water and surface water is rather low. For example, 3.7 percent of the EnviroSphere data had downgradient ground-water concentrations of PDWS higher than those measured in upgradient wells. Three of the six Arthur D. Little sites had downgradient ground water with concentrations of constituents that were both above the PDWS and above corresponding upgradient concentrations. Although the Arthur D. Little pond liquor data show high concentrations of PDWS and SDWS constituents, in most cases the constituents appeared to be contained within the disposal area or attenuated in the surrounding soils. This is particularly true for the case of arsenic, which was detected in the waste fluids at a level 31 times the PDWS, but was not found at elevated levels in ground water or surface water. There were no exceedances of arsenic, barium, mercury, selenium, or silver in downgradient ground water at any of the six Arthur D. Little sites. The EnviroSphere study detected no exceedances of barium or silver.

5.3 EVIDENCE OF DAMAGE

This section examines documented cases in which danger to human health or the environment from surface runoff or leachate from the disposal of coal combustion wastes has been proved. The first part of this section reviews two major studies conducted for the Utility Solid Waste Activities Group (USWAG): a 1979 EnviroSphere, Inc., study and a 1982 Dames and Moore study. To supplement these two major studies, in 1987 EPA conducted a literature review of all readily-available sources, which revealed only two additional case studies on proven damages occurring in 1980 and 1981. The Agency has not identified any

proven damage cases in the last seven years; however, no attempt was made to compile a complete census of current damage cases by conducting extensive field studies.

As with all damage cases, it is not always clear whether damages could occur under current management practices or whether they are attributable to practices no longer used. As described in Chapter Four, there has been an increased tendency in recent years for utilities to utilize mitigative technologies, including a shift to greater use of landfills rather than surface impoundments and an increased use of liners.

5.3.1 Envirosphere Case Study Analysis

The Utility Solid Waste Activities Group (USWAG) and the Edison Electric Institute (EEI) commissioned the Envirosphere Company in 1979 to investigate and document available information on the nature and extent of the impact of utility solid waste disposal on public health, welfare, and the environment.²⁷ To conduct this analysis, Envirosphere reviewed various reports, including EPA's damage incident files, environmental monitoring studies at utility disposal sites, and other research and studies as available; they contacted state regulatory agencies to determine what information was available in state files.

From its review of the available data, Envirosphere found few documented cases where utility solid waste disposal had potentially adverse environmental effects. They identified nine cases from EPA's damage incident files that appeared to show damage to the environment. Envirosphere reviewed data from environmental monitoring studies at the utility disposal sites and other

available research, and noted that the information available on the potential impacts of utility waste disposal was inconclusive. Some data indicated "... that elevated levels of some chemical parameters have occurred at locations downgradient of some utility solid waste disposal sites." EnviroSphere concluded, however, that it was not clear to what extent these impacts could be attributed to utility solid waste disposal practices.

Some of the specific cases from EnviroSphere's sources are summarized below:

- Texas, 1977. A clay liner was improperly installed in a 14.3 acre disposal pond for metal cleaning solutions. The liner dried and cracked before wastes were introduced into the facility. After the pond was put in service, ground-water monitoring wells detected contaminant migration. Levels of selenium and chromium occasionally exceeded the PDWS for these elements, and several SDWS were exceeded. The pond was taken out of service, the liner was saturated with water, and the pond was put back into operation.
- Indiana, 1977. EnviroSphere found that leaching from two large, unlined ash disposal ponds was contributing to ground-water contamination. Arsenic and lead were found in downgradient ground water at concentrations about two times the PDWS, while concentrations of selenium were about four times the PDWS.
- Pennsylvania, 1975. A private waste handler illegally disposed fly ash in a marsh located in a tidal wetland area. Visual inspections by the state indicated marsh contamination due to fly ash leachate. When ordered to stop the dumping and clean up the site, the handler declared bankruptcy, and the ash remained in the marsh. Detailed analysis of any potential impacts has not been conducted.
- Connecticut, 1971. A municipal landfill, which was located in a marsh, accepted many substances, including large quantities of fly ash. Surveys revealed numerous SDWS contaminants, some of which appeared to be related to the ash. The site, considered unsuitable for disposal of solid waste, was closed and turned into a state park.
- Virginia, 1967. A dike surrounding a fly ash settling lagoon collapsed, and 130 million gallons of caustic solution (pH 12.0) were released into the Clinch River.

Large numbers of fish were killed over a distance extending 90 miles from the spill site. Surveys conducted 10 days after the spill showed dramatic reductions in bottom dwelling fish food organisms for 77 miles below the release site. Virtually all such organisms were eliminated for a distance of 3 to 4 miles. The waste was eventually diluted, dispersed, and neutralized by natural physical/chemical processes. Two years after the spill, however, the river had not fully recovered.

5.3.2 Dames & Moore Study of Environmental Impacts

Dames & Moore, in a study for USWAG, conducted a survey of existing data and literature to document instances in which danger to human health and the environment was found to have occurred because of the disposal of coal combustion wastes.²⁸ Dames & Moore established criteria by which to evaluate whether a given record of a contamination incident could be considered "documented" evidence proving danger to health or the environment: 1) the report must exist in the public record; 2) the case must involve high-volume (utility) wastes; 3) information must exist to permit determination of possible health or environmental risks; and 4) the possible risks may have been caused by leachate migration or runoff from utility disposal sites.

The danger to health and the environment was examined by accounting for the types, concentrations, and locations of constituents shown to be present that could have harmful effects. In addition, Dames & Moore considered both the potential for public access to utility waste constituents and any observed effects on the population or environment. The three major data sources providing information reviewed in this study were computer data bases used to search for publicly available references; Federal Government agencies such as

EPA, U.S. Geological Survey, and the Tennessee Valley Authority; and 12 state environmental, natural resource, health or geological agencies.

Using information from these sources, Dames & Moore identified seven cases that presented a potential danger to human health and the environment. Six of the seven cases involved potential impacts from ground water and one case involved surface water. Dames & Moore concluded that none of these cases represented a "documented" case of such danger. However, Dames & Moore eliminated several sites from the documented category because they believed sufficient data from the sites were unavailable or did not meet the selection criteria described above. Dames & Moore evaluated in detail the seven sites at which there existed a potential for adverse environmental and health effects. Their findings are summarized below.

- Chisman Creek Disposal Site, York County, Virginia. The Chisman Creek disposal area was an inactive site with four separate fly ash disposal pits on both sides of Chisman Creek. An electric utility hired a private contractor to transport and dispose of fly ash and bottom ash from petroleum coke (a residual product of the oil distillation process) and coal combustion. The site was active from the late 1950's to 1974. In 1980, nearby residential drinking water wells became green from contamination of vanadium and selenium and could no longer be used. The site is currently on the CERCLA (Superfund) National Priorities List. A minimum of 38 domestic wells and 7 monitoring wells near the four disposal sites were sampled over time. Two off-site domestic wells located 200 feet from the disposal area had elevated concentrations of vanadium, selenium, and sulfate. One of these two wells was sampled four times. Three of the four measurements exceeded the PDWS for selenium up to 2 times. Another domestic well contained 0.11 mg/l of vanadium. (EPA has not established concentration limits for vanadium.) At both wells, sulfate concentrations exceeded the SDWS. In addition, samples from six of the seven monitoring wells exhibited increased concentrations of sulfates. The highest concentrations of selenium and vanadium that were observed in monitoring well samples were 0.03 (3 times

the PDWS) and 30 mg/l, respectively. The high concentrations of selenium and vanadium were noticed in monitoring wells that were drilled directly through the disposal pits.

The Virginia State Water Control Board (SWCB) conducted the initial study at this site. The SWCB concluded that the quality of ground water immediately beneath and down-gradient from the site had been affected. Moreover, the SWCB stated that the water in the two domestic wells had elevated concentrations of selenium and vanadium because of the disposal of the fly ash. Dames & Moore was critical of the conclusions reached by the SWCB because of what they termed "significant data gaps." Dames & Moore cited a lack of background water quality information and a general lack of information on the well installation, sample collection procedures, and other possible sources of contamination, such as the York County landfill which is adjacent to one of the ash disposal areas. The two contaminated off-site domestic wells identified by the SWCB, however, were over 2,000 feet from the county landfill but within a couple of hundred feet from the ash disposal areas. Additionally, monitoring wells located between the landfill and the affected domestic wells did not register the same elevated concentrations of selenium. Residents in the area no longer rely on ground water for their drinking water.

- Pierce Site, Wallingford, Connecticut. Coal fly ash had been deposited at the Pierce Site since 1953. In 1978, the United States Geological Survey (U.S.G.S.) collected ground-water quality data from three on-site wells - one upgradient and two downgradient. The U.S.G.S. took samples from the wells on three days over a period of two months. One sample from one downgradient well showed a concentration of chromium that exceeded the PDWS by a multiple of 1.6. Concentrations of cadmium, manganese, zinc, and sulfate were higher in the downgradient wells than in the upgradient well.

According to Dames & Moore, there were not enough data at this site to state conclusively whether or not the ground water had been adversely affected by the fly ash pit. To determine potential damage to ground water quality, Dames & Moore stated that EPA recommends a minimum of three downgradient wells and one upgradient well. In this case, there were only two downgradient wells. Three samples over a period of two months were not considered sufficient because naturally occurring temporal changes in the area were believed to render comparisons invalid.

The Pierce disposal site is situated on a deposit of thick, stratified sediments composed of particles that

range in size from clay to coarse sand. The disposal site is located within a few hundred feet of the Quinnipiac River, and the ground water flows from the site to the river, which diluted contaminants in the ground water. Although there are residences within a few blocks of the power plant, they do not use local ground water for drinking supplies.

- Michigan City Site, Michigan City, Indiana. The Michigan City site, situated on the shore of Lake Michigan, contained two fly ash disposal ponds. Ground-water flow at the site was towards Lake Michigan, facilitated by the porous sand that underlies the site. Twenty-one monitoring wells were installed at this site. Two of these were placed upgradient from the site outside the site boundaries; the remaining 19 wells were established within the boundaries of the facility and downgradient from the disposal areas.

Monitoring of the wells (which took place periodically over a one-year period) indicated that trace metals migrated from the disposal sites and that certain constituents had elevated ground-water concentrations. Arsenic and lead were observed in concentrations that exceeded their PDWS. Seven samples collected from three downgradient monitoring wells had arsenic concentrations that exceeded the standard -- up to 100 times the PDWS. All of the samples taken from the upgradient off-site monitoring wells contained arsenic at concentrations below the PDWS. Five of the downgradient monitoring wells contained lead concentrations which exceeded the PDWS, with the highest exceedance 7 times the PDWS. Three samples from the two upgradient monitoring wells also had lead concentrations in excess of the standard, with the highest exceedance 3 times the PDWS.

Dames & Moore concluded that effects on ground water appeared to be limited to areas within the facility boundaries because of attenuation mechanisms operative at the site -- absorption, dilution, precipitation, and a steel slurry wall installed between the disposal site and Lake Michigan. However, no downgradient monitoring wells were situated off-site. Based on the locations of the waste disposal sites and the monitoring wells, it appears that the ash ponds are responsible for arsenic concentration above the PDWS in the ground water within the site boundaries. Because high lead concentrations were observed in some of the upgradient background wells, it is impossible to state with certainty that the high lead concentrations in the ground water are attributable to the disposal sites. Dames and Moore noted that nearby residents do not use the ground water for their water supply.

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- Bailly Site, Dune Acres, Indiana. The Bailly site is located near the Indiana National Lakeshore on Lake Michigan in a highly industrialized area. Fly ash at this site has been slurried to interim settling ponds, which are periodically drained. The drained ash is then disposed in an on-site pit. Two aquifer units, designated Unit 1 and Unit 3, underlie the site. Unit 1 contains fine-to-medium sand and some gravel, while Unit 3 is composed of sand with overlying layers of varying amounts of sand, clay and gravel.

Ground-water samples from Unit 1 were collected from an upgradient well and from several wells downgradient from the ash settling ponds. Samples from Unit 3 were collected upgradient and from one well downgradient from the ash ponds. These wells were sampled at five-week intervals between September 1976 and May 1978.

In samples from Unit 1, arsenic, cadmium, fluoride, and lead occasionally exceeded the PDWS. Upgradient concentrations of arsenic never exceeded the PDWS, whereas the maximum downgradient concentration for arsenic was 4.6 times the PDWS. Downgradient on-site concentrations of cadmium exceeded the PDWS at one well by 25 times, while the maximum upgradient concentration of cadmium exceeded the PDWS by 22 times. One downgradient well measurement indicated lead concentrations that exceeded PDWS by 1.26 times.

All of the above-mentioned exceedances were observed in Unit 1. None of the samples from Unit 3 contained constituents at concentrations that exceeded the PDWS.

Aluminum, boron, iron, manganese, molybdenum, nickel, strontium, and zinc all increased in concentration downgradient from the disposal areas, though not in levels exceeding the SDWS.

Leachate from the ash disposal ponds is the most probable contributor to the increased concentrations of arsenic and lead observed in the aquifer samples taken from the on-site wells. Cadmium was the only constituent whose downgradient off-site concentration was observed to exceed the PDWS. However, because elevated cadmium concentrations were also found in samples taken from the background well, the elevated concentrations of cadmium may not have been caused by the leachate from the coal ash. Dames and Moore noted that ground water at this site flows away from the nearest residential area.

- Zullinger Quarry Fly Ash Disposal Site, Franklin County, Pennsylvania. The Zullinger quarry was situated in a limestone formation in south-central Pennsylvania. The

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quarry was excavated to 40 feet below the water table. Fly ash was deposited in the quarry from 1973 to 1980 with no attempt to dewater the quarry prior to placement of the fly ash.

The site operator, consultants, and the Pennsylvania Department of Environmental Resources (DER) have been independently involved in water quality investigations at the site. Initially, six monitoring wells were established onsite. Later, several existing off-site domestic wells were added to the sampling program. Two of the monitoring wells were installed upgradient to provide background constituent concentrations. The other monitoring wells, and the domestic wells in the sampling program, were downgradient from the fly ash deposited in the quarry.

Lead was found to exceed its PDWS by up to eight times in eight out of over 100 samples. Six of these eight exceedances occurred in two on-site monitoring wells, while the seventh (2.6 times PDWS) was found in an off-site domestic well. Another exceedance (1.5 times PDWS) was found in the background well.

Several constituents for which there are secondary drinking water standards were found in elevated concentrations downgradient from the ash disposal site. Sulfate concentrations increased dramatically during the first few years of quarry filling, then began to sharply decline in 1976 when the fly ash had filled the quarry. From 1976 until deactivation of the disposal site in 1980, the fly ash was deposited above the water table. Zinc and iron were also found in elevated concentrations. Elevated levels of sulfate, zinc, and iron are probably attributable to leachate from the fly ash, as are the lead levels in excess of the PDWS. Most of the trace metals appear to be attenuated onsite by the limestone formation.

- Conesville Site, Conesville, Ohio. Various types of coal combustion waste had been deposited at the Conesville site in central Ohio. The monitoring program at the Conesville site was established to determine the ability of an FGD sludge fixation process (Poz-O-Tec, a solid material produced by mixing FGD sludge with fly ash and lime) to stabilize and thus immobilize potential contaminants. The stabilized FGD sludge has been deposited next to a fly ash pond. Permeable sand and gravel underlie the Muskingum River flood plain on which the Conesville site is located.

A total of 34 monitoring wells were installed at the Conesville site. Two of the wells were situated upgradient from the disposal area to provide the

necessary background water quality data. Two sets of water quality data were taken, the first between February 27 and April 12, 1979, and the second between December 4, 1979, and July 10, 1980.

Some samples from the first set of data contained constituents at concentrations that exceeded the PDWS. Lead concentrations exceeded the PDWS in two on-site wells by up to 3 times and three off-site wells by up to 2 times. The concentration of mercury found in one sample from an on-site well exceeded the PDWS by 1.4 times; however, this exceedance could not be attributed to the fly ash. One of the fourteen background measurements had the highest observed concentration of selenium, 6 times the PDWS. Thus, selenium appears to be leaching from indigenous sediments rather than from the FGD waste and fly ash deposited at the site. The first set of data also showed the SDWS constituents of calcium, magnesium, total dissolved solids, sulfate, and iron, had increased in those wells located on the site property and just across the property boundaries.

Measurements taken between December 1979 and July 1980 showed increases in calcium, magnesium, total dissolved solids, and sulfate relative to those measurements taken in the first data collection period. Concentrations in excess of the PDWS were found for selenium (several wells), arsenic (one sample), cadmium (four samples), and chromium (five samples). Two of the chromium exceedances were found in on-site wells, while three occurred in off-site wells, with concentrations ranging up to 16 times the PDWS on-site and 2 times the PDWS off-site. Background wells also had elevated levels of selenium. The single arsenic exceedance (2.4 times the PDWS) and all of the cadmium exceedances (up to 12 times the PDWS) were detected in on-site wells. In contrast to the first round of sampling, lead was not detected in concentrations greater than the PDWS. The only constituents that appear to be migrating offsite are lead and chromium. Based on the data collected, it appears there may be a temporal variation in the water quality at this site. Dames and Moore noted that the town of Conesville is downgradient from the site but on the other side of the river, which would tend to mitigate potential adverse impacts.

- Hunts Brook Watershed, Montville-Waterford, Connecticut
The electric utility hired a private contractor to transport and dispose of fly ash in three separate sites (Chesterfield-Oakdale, Moxley Hill, and Linda Sites) along three different tributaries to Hunts Brook. Disposal of fly ash in this area began in the mid 1960's and ended in 1969. The surface-water quality studies that took place in this area focused on pH, iron,

sulfate, and total dissolved solids (TDS). No analyses were performed for any of the PDWS constituents. Upstream surface water samples were compared to downstream samples to determine if the surface water quality had been degraded at any of the sites.

At the Chesterfield-Oakdale site, concentrations of iron in the surface water increased from less than the SDWS to more than 100 times the SDWS between the upstream and downstream sampling points. Sulfate concentrations increased by over an order of magnitude, from 20 to 299 mg/l, (at 299 mg/l, still only 1.2 times the SDWS) between the upstream and downstream sampling positions, while TDS increased from less than the SDWS to 44 times the SDWS. At another sampling point approximately 1.2 miles downstream from the site, the measured parameters had all returned to levels close to the upstream values.

At the Moxley Hill Site, the pH and iron concentrations remained relatively constant between the upstream and downstream sampling points; median sulfate values increased, although not to levels exceeding the SDWS. The elevated concentrations of sulfate and TDS had been significantly attenuated at another point three-quarters of a mile downstream.

At the Linda Site, no upstream data were collected. It is therefore impossible to quantify the potential effects of fly ash deposition on the water quality.

5.3.3 Other Case Studies of the Environmental Impact of Coal Combustion By-Product Waste Disposal

This section presents a review of two independent case studies of ground-water contamination at utility disposal sites.

Cedarsauk Site, Southeastern Wisconsin

The Cedarsauk site is a fly ash landfill in southeastern Wisconsin. At the time of this study,²⁹ fly ash had been deposited at the site into an abandoned sand and gravel pit over a period of eight years. Part of the pit is in direct contact with an aquifer composed mainly of sand and gravel with some clay. This upper aquifer is approximately 15 to 20 meters thick with a permeability of 10^{-3}

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to 10^{-2} cm/sec. Soluble carbon aqueous material comprises about 35 percent of the aquifer. The upper sandy aquifer overlies another aquifer consisting of fractured dolomite-bedrock.

A water quality study of the area was undertaken in 1975. This study eventually included 35 monitoring wells and seven surface-water sampling sites. Twenty of the wells were placed upgradient of the site to provide background water quality information, while the remaining wells were positioned downgradient. Sampling was performed on a monthly basis. Most of the ground-water flow beneath the site surfaced in a marsh directly east of the ash disposal area.

The monitoring results showed that downgradient ground water had SDWS exceedances. Background levels of total dissolved solids (TDS) were below 500 mg/l, while the levels in the ground water downgradient from the disposal site exceeded 800 mg/l, or 1.6 times the SDWS. After eight years of disposal, the contaminant plume appeared to stabilize approximately 200 meters downgradient from the ash disposal site. The stabilization of the constituent plume appeared to be due to dilution and the ability of the materials in the aquifer to attenuate contaminants. Only iron, manganese, and zinc were found in detectable quantities in the downgradient off-site wells.

The maximum detected iron concentration was more than 33 times the SDWS, while the maximum manganese concentration reached 30 times the SDWS. Neither iron nor zinc could be detected 200 meters downgradient from the disposal site. Another contributor to ground-water contamination at this site was sulfate. Background concentrations of sulfate varied between 20 and 30 mg/l (well below

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the SDWS), while the concentrations of sulfate in the contaminant plume achieved levels approximately 3.4 times the SDWS. Other trace metals for which analyses were performed, such as copper, molybdenum, nickel, lead, and titanium, were not detected.

As the leachate contacted the sediments in the aquifer, it was neutralized from an initial pH value of 4.5 to around neutral pH levels (i.e., about 7.0). This change in pH probably caused the precipitation of many of the trace metals and other constituents in the leachate. In addition, adsorption reactions between the clay in the sediments and the constituents probably attenuated the leachate concentrations of many of the potential contaminants observed in the leachate.

Center Mine, Center, North Dakota

Fly ash at this site had been deposited in a mine pit and between mine ash piles. A study was conducted to determine the potential effects of FGD and fly ash disposal on ground water quality at the surface mining site.³⁰ This investigation used field monitoring and laboratory column leaching experiments in conjunction with geochemical computations. By collecting both field and laboratory data, the investigators hoped to test the applicability of laboratory column experiments to field situations. Roughly 150 wells were placed both in the vicinity of the waste disposal sites and in unaffected areas.

Ground-water concentrations were generally within drinking water standards in the background wells. However, selected constituents were higher than the drinking water standards. For instance, sulfate concentrations tended to exceed

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the SDWS by a factor of 2 to 4. The maximum iron concentration was 4.3 times the SDWS. Manganese concentrations were all above the SDWS, varying from 0.06 to 2.75 mg/l, or 1.2 to 55 times the SDWS.

Samples collected from wells located adjacent to the FGD waste site indicated that none of the PDWS constituents exceeded the standards. For the SDWS constituents, molybdenum concentrations fluctuated between 0.070 and 4.850 mg/l, and sulfate concentrations reached a high of 9,521 mg/l, or 38 times the SDWS. (EPA has not established maximum concentration levels for molybdenum.)

Ground water in areas that appear to be affected by leachate from the fly ash disposal sites had sulfate concentrations ranging from 21.7 to 211 times the SDWS. Higher values were obtained immediately below recent deposits of fly ash, while lower values were observed at older sites or at greater distances from the disposal area. Arsenic and selenium concentrations in the ground water were as high as 0.613 mg/l (12 times the PDWS) and 0.8 mg/l (80 times the PDWS), respectively. The highest arsenic and selenium concentrations were associated with higher pH values. Ground-water pH values for samples in the area of the fly ash ranged from 6.95 to 12.1. (The Secondary Drinking Water Standard for pH is 6.5 to 8.5). Iron and manganese concentrations were also high in samples taken from around the fly ash disposal site. The maximum concentration of iron was 8.6 times the SDWS; the maximum concentration of manganese was 130 times the SDWS.

Leachates from the fly ash of western coals are often characterized by a high pH that tends to cause many potentially harmful constituents to be released. The pH-dependent solubility of many trace elements, as apparently

observed at this site, demonstrates the importance of neutral pH values that are conducive to contaminant attenuation.

5.3.4 Summary

The studies reviewed in this section indicate that constituents from coal-combustion waste disposal sites have been detected in both on-site and off-site ground and surface water. However, those constituents that did exceed the drinking water standards seldom exceeded these standards by more than ten times. Moreover, the total number of exceedances is quite small compared to the total number of monitoring wells and samples gathered. The contaminant exceedances that do occur appear to be correlated to some extent with acidic or alkaline pH levels. At fly ash disposal sites, pH values between 2 and 12 have been measured. High and low pH values can contribute to metal solubility in ground water.

There are two documented cases of coal combustion waste disposal sites causing significant harm to the environment. Drinking water wells around the Chisman Creek fly ash disposal site in Virginia (which was closed in 1974) were contaminated with high concentrations of vanadium and selenium. Concentrations of these elements at this site were also due to petroleum coke waste (a product of oil combustion, not coal combustion). The site has been placed on the CERCLA National Priority List. In 1967, a dike failed at a utility waste disposal site on the banks of the Clinch River in Virginia, causing waste to spill into the river. This accident caused substantial damage to the biotic life in the river.

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**5.4. FACTORS AFFECTING EXPOSURE AND RISK AT COAL
COMBUSTION WASTE SITES**

The previous sections analyzed the constituents of coal combustion waste leachates and the quality of the ground water and surface water surrounding disposal sites. However, this is only part of determining the potential dangers that the wastes pose to human health and the environment. Exposure potential, the degree to which populations could be expected to be exposed to potentially harmful constituents, must also be analyzed. Exposure potential is determined by a variety of factors. Hydrogeologic characteristics of a site will affect the migration potential of waste constituents. Proximity of sites to drinking water sources and to surface-water bodies will determine potential for exposure to populations using the water sources.

In order to address this issue of exposure, EPA collected a wide variety of data on a random sample of 100 coal-fired utility plants around the country. The sample was taken from the Utility Data Institute Power Statistics Database, which contains information on every coal-fired electric utility plant in the country. Most plants dispose of their waste on-site, and in these cases information was collected on the plant location given by the data base. If the plant disposed off-site, data were collected on that off-site location. EPA assumed that off-site disposal took place at the nearest municipal landfill, unless additional information indicated otherwise. Characteristics such as depth to ground water, hydraulic conductivity, distance to surface water, location of private and public drinking water systems, type of surrounding natural ecosystems, and location of human population were obtained from a wide variety of sources. This simple aggregation of the individual factors affecting exposure at coal combustion waste sites provides a qualitative perspective on

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the potential risk that coal combustion waste sites pose, and is presented in Sections 5.4.1-5.4.3. Appendix F displays the data for each coal combustion waste site in the random sample.

5.4.1 Environmental Characteristics of Coal Combustion Waste Sites

Environmental characteristics of coal combustion utility waste sites will have a significant effect on the potential for the waste constituents to travel and reach receptor populations. Key environmental characteristics are:

- Distance to surface water - The distance between a coal combustion waste disposal site and the nearest surface water body. Proximity to surface water would decrease the possible health effects of ground-water contamination due to the fact that there would be fewer opportunities for drinking water intakes before the ground water reached the surface water body; once the plume reached the surface water, contamination would be diluted. However, proximity to surface water would possibly increase danger to aquatic life because less dilution of the contaminant plume would occur before the plume reached the surface water body.
- Flow of surface water - A high surface water flow will increase the dilution rate of coal combustion constituents that may enter the surface water, thereby reducing concentrations in the surface water.
- Depth to ground water - The distance from ground level to the water table. A larger depth to ground water will increase the time it takes for waste leachates to reach the aquifer; it also allows more dispersion of the leachate before it reaches the aquifer so that once the leachate reached the aquifer, concentrations of metals would be decreased.
- Hydraulic conductivity - This factor is an indication of the rate at which water travels through the aquifer. A high hydraulic conductivity indicates that constituents will travel quickly through the ground water and possibly more readily reach drinking water wells, although high conductivity also indicates a more rapid dilution of constituent concentration.

- Net recharge - This factor is a measure of net precipitation of a site after evapotranspiration and estimated runoff is subtracted. Recharge is calculated in order to determine the amount of rainfall annually absorbed by the soil. A high net recharge indicates a short period of time for contaminants to travel through the ground to the aquifer, but will also indicate a higher potential for dilution.
- Ground-water hardness - This factor is a measure of the parts per million (ppm) of calcium carbonate (CaCO₃) in the aquifer. Ground water with over 240 ppm of CaCO₃ is typically treated when used as a public drinking water supply. This treatment of the hard ground water has an indirect mitigative effect on exposure because treatment of the ground water will tend to remove contamination from other sources.

To conduct this exposure analysis, environmental data on the 100 randomly selected coal combustion waste sites were gathered using a number of sources. These data were then aggregated in order to present an overview of the environmental characteristics that contribute to exposure. The data collected on the sample of coal combustion waste sites were compared to information presented in a study by Envirosphere for the Electric Power Research Institute.³¹ The Envirosphere report gave detailed information on the hydrogeologic settings of 450 operating utility plants. The information provided by the exposure analysis on the sample of 100 plants corresponded fairly closely with the settings described in the Envirosphere report.

The following sections summarize the data that were collected and the relationship of the various characteristics to potential exposure.

5.4.1.1 Distance to Surface Water and Surface-Water Flow

The proximity of a waste site to surface water affects exposure potential in several ways. If the site is very near a surface-water body, there is less

opportunity for humans to use contaminated ground water as a source of drinking water. However, sites that are close to surface water can more easily contaminate the surface-water body, although waste constituents will be more quickly diluted if the flow of the surface water is high.

Distance to the nearest surface-water body, e.g., creek, river, lake, or swamp, was determined from measurements obtained using United States Geologic Survey (U.S.G.S.) maps. The sample of coal combustion waste sites was located on 7-1/2 or 15 minute maps, and the distance between the site and nearest surface water body was calculated.

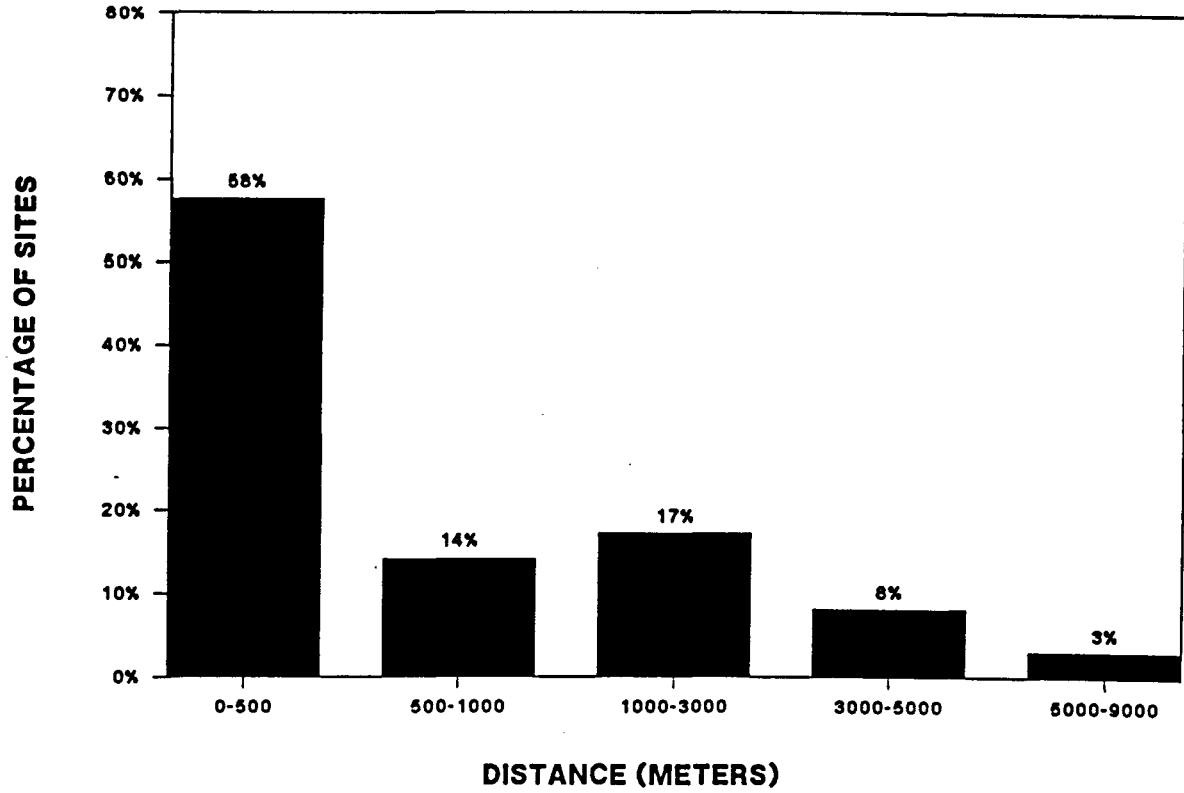
When the boundaries of the plant or waste site were marked on the maps, the reference point was the downgradient boundary of the site. If the boundaries were not marked, the latitude and longitude points for the sites provided by the Utility Data Institute Power Statistics Database were used.

The average distance from the sample of coal-burning waste sites to surface-water body is 1279 meters. Distances range from 10 to 18,000 meters. Over 50 percent of the disposal sites are within 500 meters of surface water; more than 70 percent are within 1,000 meters of surface water. Exhibit 5-17 provides the number and percentage of sites within specified distances of surface water.

Since most sites are located somewhat near surface-water bodies, the potential for human exposure to contaminated ground water seems to be low. The proximity of the sites to surface water could, however, pose a threat to aquatic life and to humans using the surface water if contaminants are entering

EXHIBIT 5-17

DISTANCE OF COAL COMBUSTION WASTE SITES TO SURFACE WATER



SOURCE: ICF Inc, based on USGS data

the surface water. The concentration in surface water will be less, however, if the surface-water body close to the site has a high flow.

Flow data on surface-water bodies near the sample of 100 sites were obtained from U.S.G.S. data. Flow is expressed in terms of cubic feet per second (cfs), and given for minimum and maximum average flow for one-month periods. In order to obtain a conservative estimate of exposure (i.e., one that does not understate exposure) this report used estimates for the month with the minimum monthly flow. The results are presented in Exhibit 5-18.

Exhibit 5-18 shows that 19 percent of the sites have a flow of zero. A zero flow generally indicates that the body of water is a lake, swamp, or marsh that does not have any continual flow of water, although this category could include a seasonal stream. For surface-water bodies with zero flow, dilution of potential contamination would occur because of the volume of water in the surface-water body, but there would not be any additional dilution as water flowed away from the source of contamination. Forty-one percent of the surface-water bodies have a flow of 1-1000 cubic feet per second, 21 percent have a flow of 1,000-10,000 cfs, and 18 percent have a flow of over 10,000 cfs.

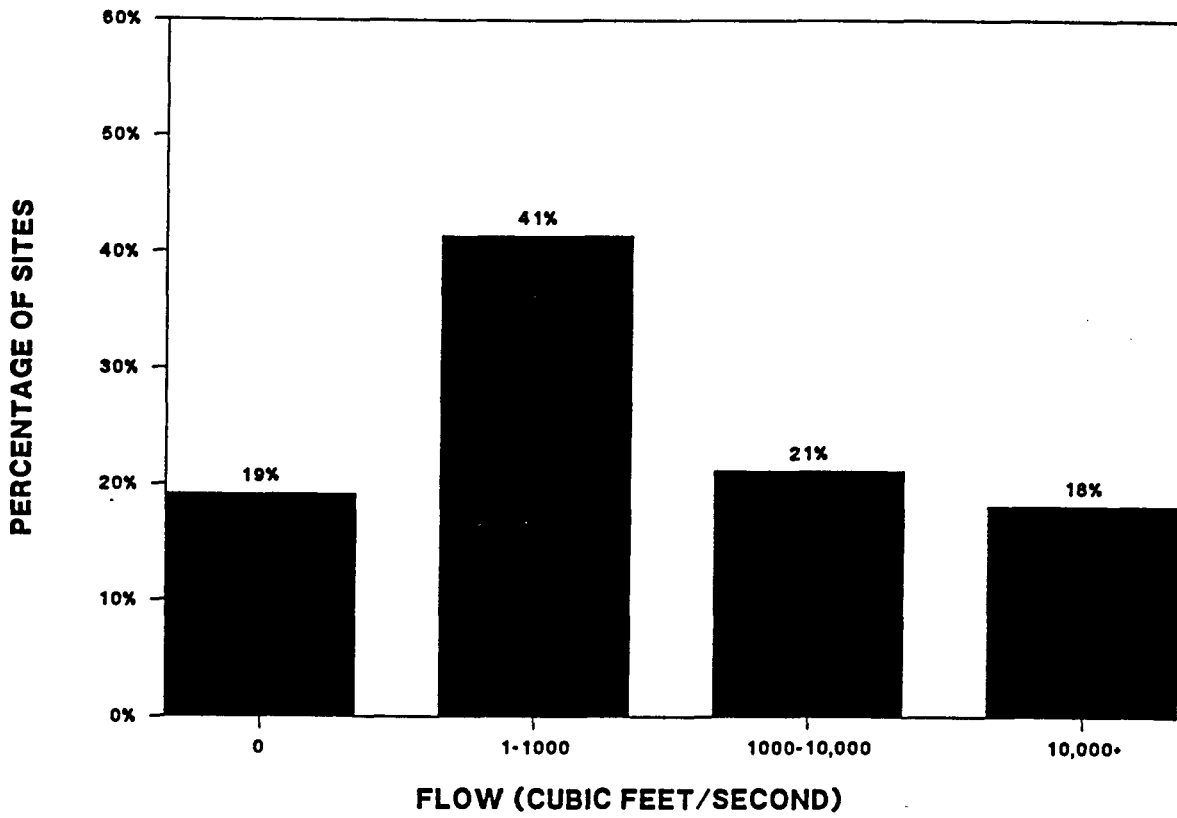
5.4.1.2 Hydrogeologic Measurements

The hydrogeologic measurements of depth to ground water, hydraulic conductivity, and net recharge were determined through the use of information provided by the DRASTIC system. The DRASTIC system, developed by the National Well Water Association, categorizes aquifers on the basis of geographic region and subregion. Each site was located on a 7 1/2 or 15 minute U.S.G.S. map that

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EXHIBIT 5-18

FLOW OF NEAREST SURFACE-WATER BODY



SOURCE: ICF Inc, based on USGS data

was then compared with a map on which the 11 major DRASTIC regions had been outlined. The topography and geology of the sites, which were determined from looking at the U.S.G.S. maps, were assessed in order to further classify the sites into DRASTIC subregions. Subregions are defined by hydrogeologic characteristics and vary in size from a few acres to hundreds of square miles. Measurements for depth to ground water, hydraulic conductivity, and net recharge of the sites were taken largely from A Standardized System for Evaluating Ground-water Pollution Potential Using Hydrogeologic Settings, by the National Well Water Association, which presents a range of values for each of these hydrogeologic properties for each subregion.³² The ranges were compared with characteristics that could be observed by studying U.S.G.S. maps, and, when necessary, they were modified accordingly.

Depth to Ground Water

A small depth to ground water indicates a higher potential for waste constituents to reach the ground water at harmful concentrations than if the distance to ground water were greater, thereby increasing the chance of ground-water contamination. Depth to ground water was generally based on DRASTIC region and subregion, but was modified when the topography or site characteristics indicated a depth different from that provided by the DRASTIC system. For example, if the DRASTIC subregion indicated that there was a high depth to ground water range, but a particular site was located very near a surface-water body, the Agency used a smaller depth to ground water than the DRASTIC range indicated.

Exhibit 5-19 provides the number and percentage of sites within each range of depth to ground water. Depth to ground water is calculated in feet and based on 10 ranges. In over 80 percent of the sites depth to ground water is less than 30 feet, indicating a reasonably high potential that leachate from the disposal site would reach the ground water.

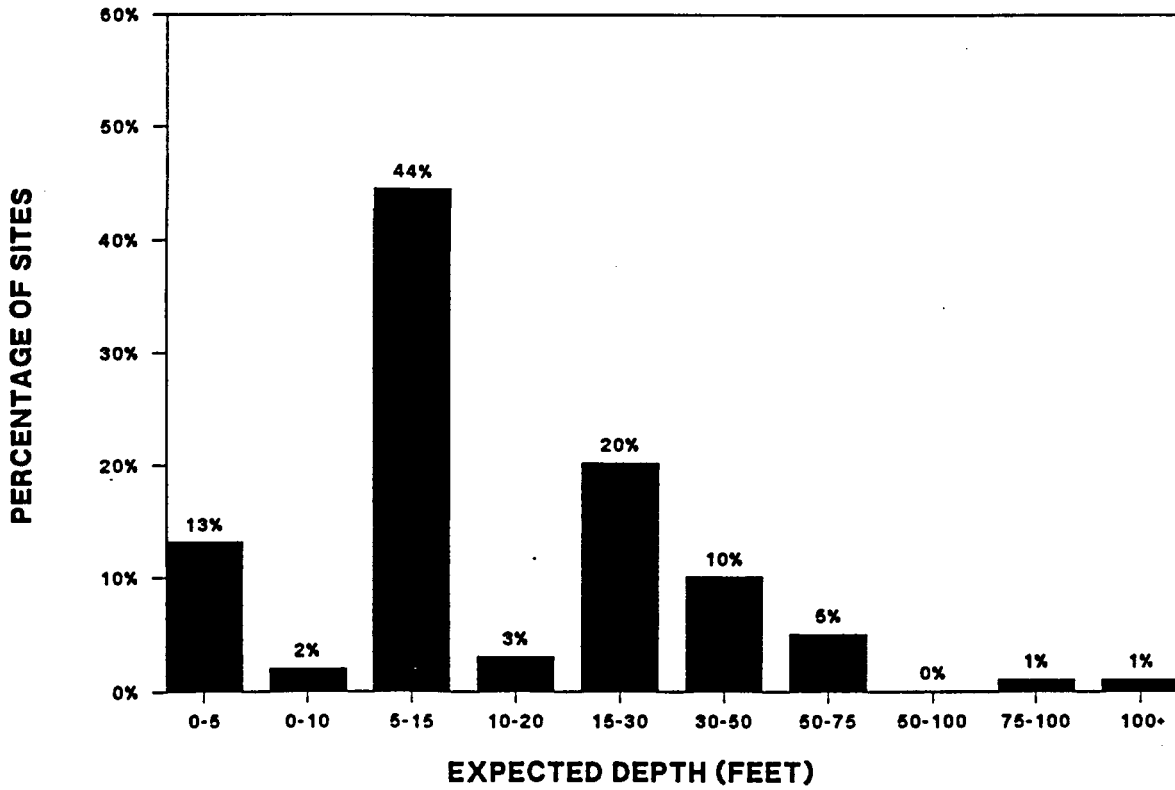
Hydraulic Conductivity

Hydraulic conductivity is an indication of the ease with which a constituent may be transported through the ground water. Conductivity is also based on the site's DRASTIC region and subregion, and is measured in gallons per day per square foot and grouped into six ranges.

Hydraulic conductivity is one of the factors used to calculate ground-water velocity, or volumetric flow of the water table. Velocity has a direct bearing on the degree to which leachate constituents are diluted once they reach the ground water and travel to a point of exposure (i.e., human drinking water source). High ground-water conductivity signifies high velocity and therefore a high dilution potential.

Exhibit 5-20 provides the number and percentage of sites falling into each hydraulic conductivity range. Thirty-three percent of the sites show a hydraulic conductivity of 700-1,000 gallons per day per square foot; 27 percent have a conductivity of 1,000-2,000 gallons per day per square foot. There is a wide spread of conductivity values -- indicating hydrogeologic diversity among sites.

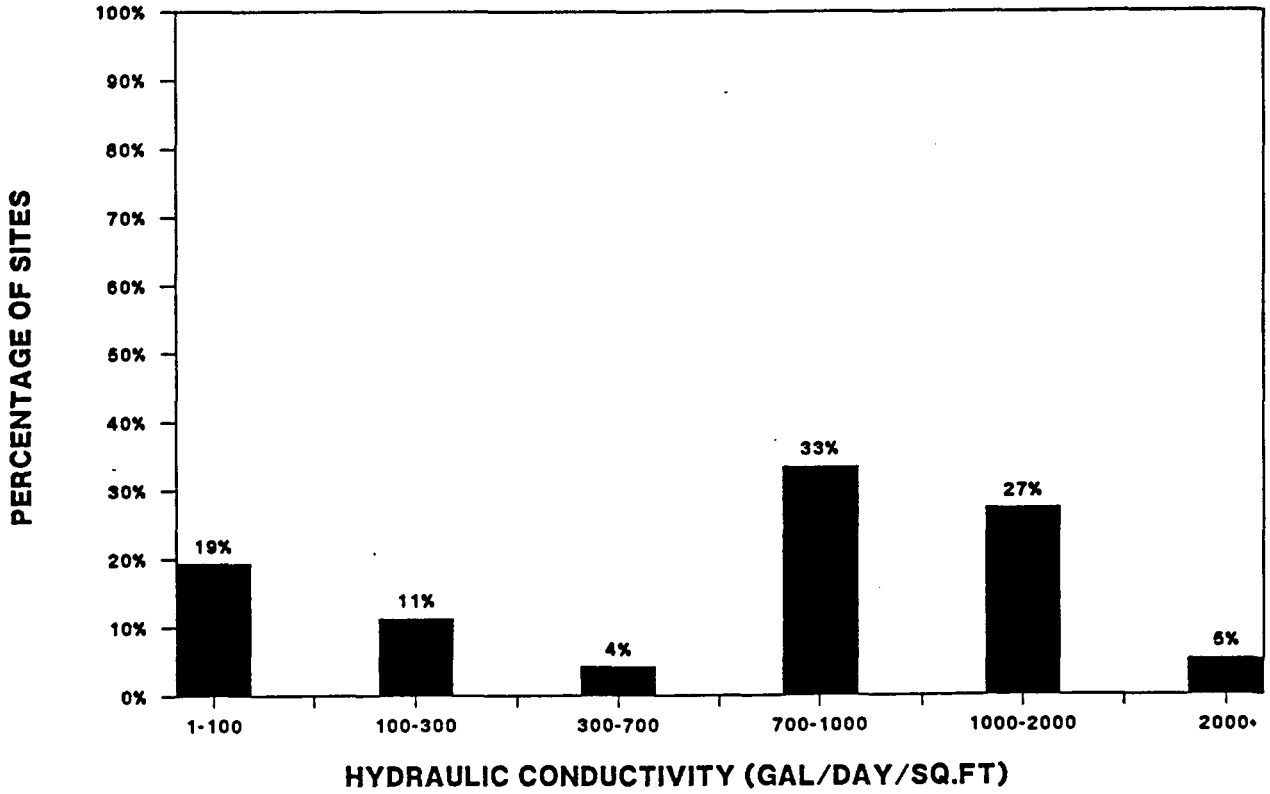
EXHIBIT 5-19
DEPTH TO GROUND WATER
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC

EXHIBIT 5-20

HYDRAULIC CONDUCTIVITY
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC data

While ground-water velocity gives an indication of how fast contamination may travel in the ground water, contaminants do not move at the same velocity as the ground water. This is because of basic interactions between contaminants and soil that retard the movement of the contaminants. There are three different mechanisms that affect the retardation of contaminant movement -- exchange on soil particle sites (ion exchange), adsorption onto soil particle surfaces, and precipitation. The exchange and adsorption mechanisms will retard the movement of contaminants but will not eliminate the movement of all contaminants due to limited soil attenuation capacity.

As with the diversity among sites in terms of hydraulic conductivity and ground-water velocity, the various attenuation mechanisms differ among sites. To determine the attenuation potential at a site requires detailed data inputs on water chemistry on a site-specific basis.

Net Recharge

Net recharge indicates how much water is annually absorbed into the ground. It is measured by subtracting evapotranspiration (the amount of rainfall that evaporates and transpires from plant surfaces) and estimated runoff from total precipitation at a site. It affects exposure potential in a number of ways. Low recharge will result in smaller volumes of more concentrated leachate, but if the aquifer is deep and/or has a high velocity, it will quickly dilute the leachate. High recharge produces more leachate, but may also indicate that the area has higher ground-water flow.

Exhibit 5-21 shows the number and percentage of sites that fall into each range. Recharge is measured in inches and is grouped into five ranges. Although a wide variety of net recharge ranges is represented by the sample, the recharge of sites generally falls into the higher ranges of 4-7 inches, 7-10 inches, and over 10 inches. For example, more than 80 percent of the sites have a net recharge of over 4 inches and over 50 percent have a recharge of over 7 inches. This implies that leachate constituents will be more quickly carried to the water table but the higher recharge rate will also result in greater dilution of the leachate.

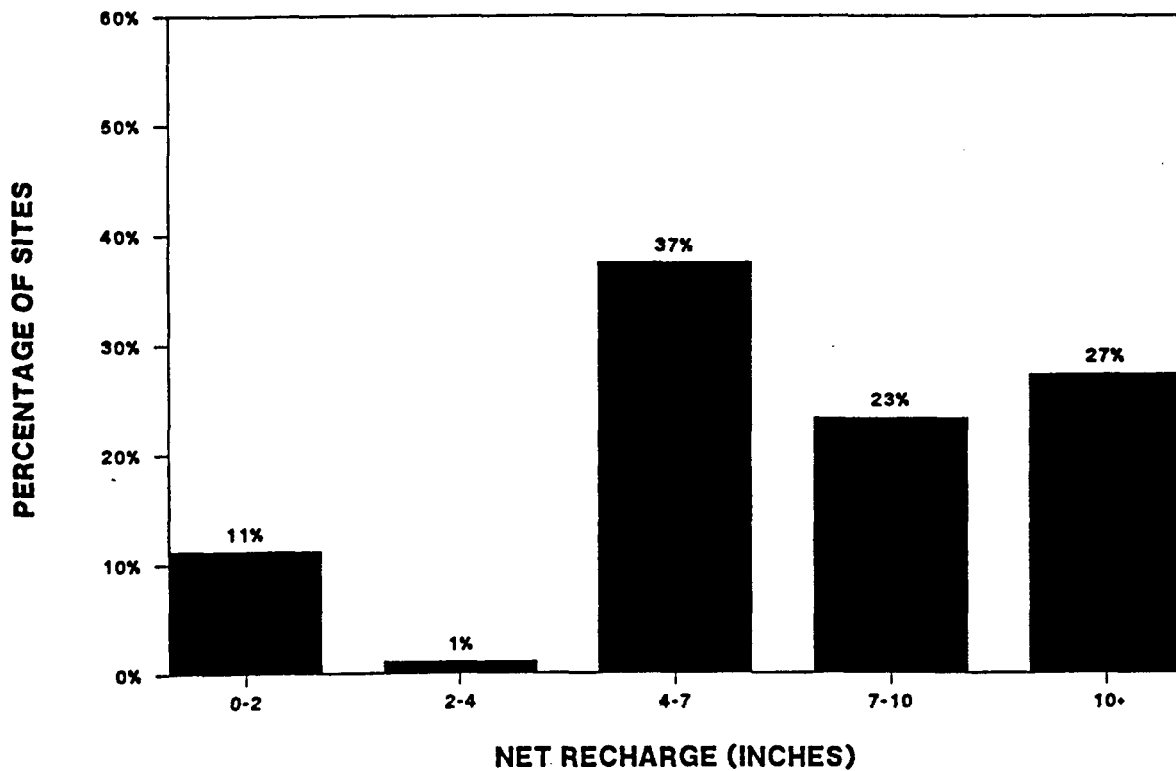
Ground-water Hardness

The hardness of the ground water near coal combustion waste sites will have an effect on potential exposure through drinking water since excessive hardness is typically treated in a public drinking water system. Treatment would lessen the exposure potential to humans from contaminants in the ground water from other sources (such as coal combustion wastes). Measurements for ground-water hardness were obtained by locating the sites on maps provided in Ground-water Contamination in the United States (Pye, Patrick, and Quarles).³³

As shown in Exhibit 5-22, ground-water hardness is measured in parts per million (ppm) of calcium carbonate (CaCO₃) and grouped into five ranges. Ground water with a hardness of over 240 ppm of calcium carbonate is typically treated if used in a public drinking water system. In this sample, 45 percent of the sites show ground-water hardness in this range. Ground water with a hardness of 180-240 ppm of calcium carbonate may also be treated, although

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EXHIBIT 5-21
NET RECHARGE
AT COAL COMBUSTION WASTE SITES

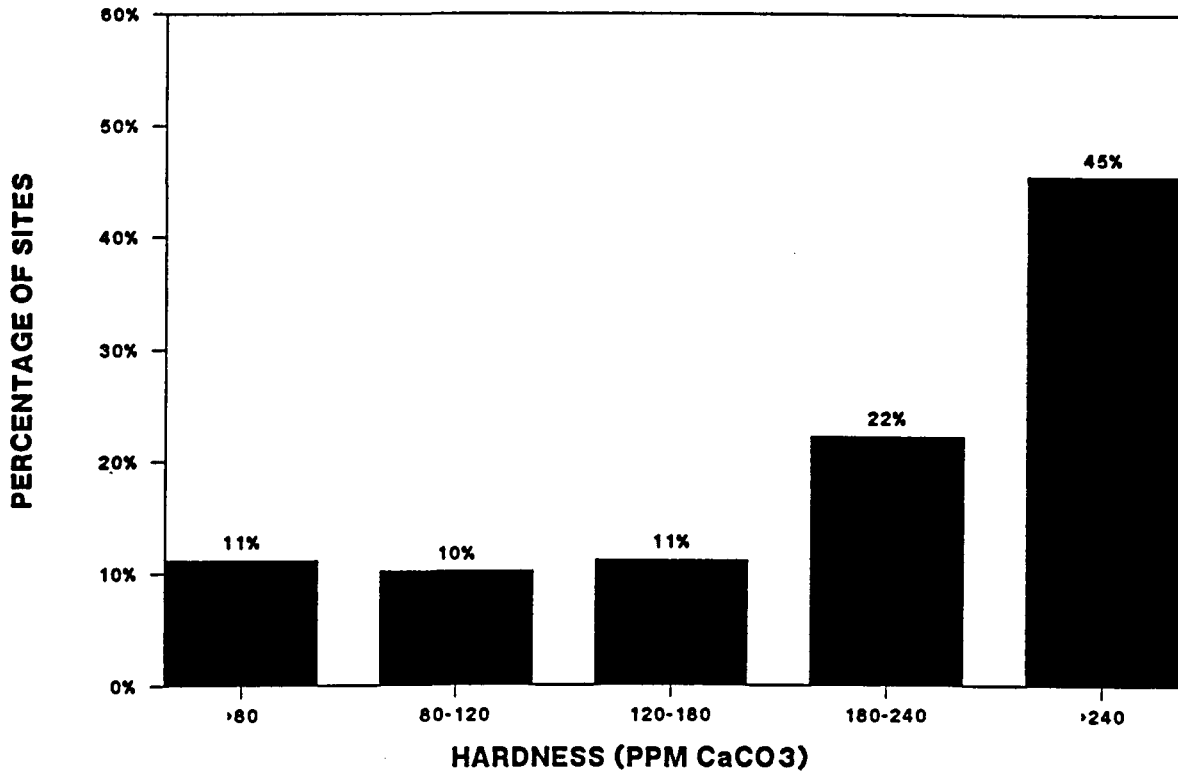


SOURCE: ICF Inc, based on DRASTIC

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EXHIBIT 5-22

**GROUND-WATER HARDNESS
AT COAL COMBUSTION WASTE SITES**



SOURCE: ICF Inc, based on Pye, et al, Groundwater Contamination In U.S.

treatment is much less likely. An additional 22 percent fall in the 180-240 ppm range.

The high levels of calcium carbonate found in the ground water near coal combustion waste disposal sites suggest that if a drinking water supply is in the vicinity, the water would often require treatment before being used. Therefore, contamination that might exist in the drinking water from other sources would be mitigated due to the treatment process since trace constituents tend to be removed during the treatment process.

5.4.2 Population Characteristics of Coal Combustion Waste Sites

Environmental characteristics, such as distance and flow of surface water and hydrogeologic measurements, are only one part of the analysis of exposure potential. Opportunities for human exposure to coal combustion waste constituents depend in part on the proximity of coal combustion waste disposal sites to human populations and to human drinking water supplies. Census data (1980) provide information about the number of people living within specified distances from the coal combustion waste sites. This information is obtained through the CENBAT program, part of the Graphic Exposure Modeling System developed by EPA's Office of Solid Waste. The Federal Reporting Data System (FRDS) data base, developed by EPA's Office of Drinking Water, provides estimates of the number of public water supply systems and the size of the populations using them.

5.4.2.1 Proximity of Sites to Human Populations

CENBAT provides information on the number of people living within specified distances around designated locations. The sites were defined by latitude and longitude coordinates. Populations were analyzed for areas within 1-, 2-, 3-, 4-, and 5-kilometer radii of the waste disposal sites.

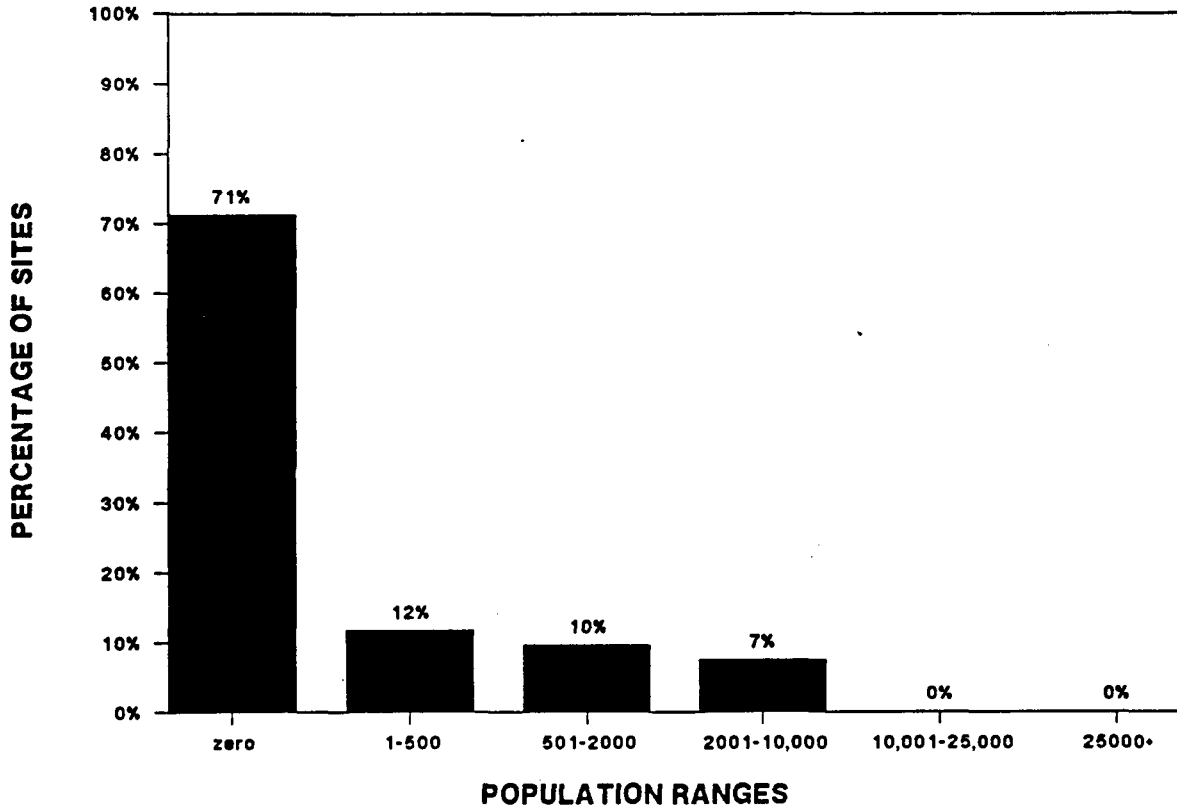
Exhibit 5-23 shows the distribution of population within one kilometer of the waste disposal sites. The CENBAT results show that most sites, 71 percent, do not have any population within a one-kilometer radius. Overall, the population range within a one-kilometer radius is 0 - 3708 people, with an average of 359 people.

Exhibit 5-24 shows the population characteristics for the sample of coal combustion waste sites at a three-kilometer radius. When the search distance is increased to three kilometers, the percentage of sites that have no people within a three-kilometer radius decreases to 32 percent. Average population within three kilometers is 3,737, and the range is 0 - 35,633 people. There is a large degree of diversity of populations at this distance. For example, while 32 percent of the sites have zero population, the same percentage has populations over 2,000.

Exhibit 5-25 shows the distribution of populations within a five-kilometer radius. Only 10 percent of the sites do not have any population living within this distance. The average population is 12,128 people, with a range from 0 to 123,160. The diversity among coal combustion waste disposal sites is even more apparent at this distance. While 20 percent of the sites have populations

EXHIBIT 5-23

POPULATIONS WITHIN ONE KILOMETER OF WASTE SITES

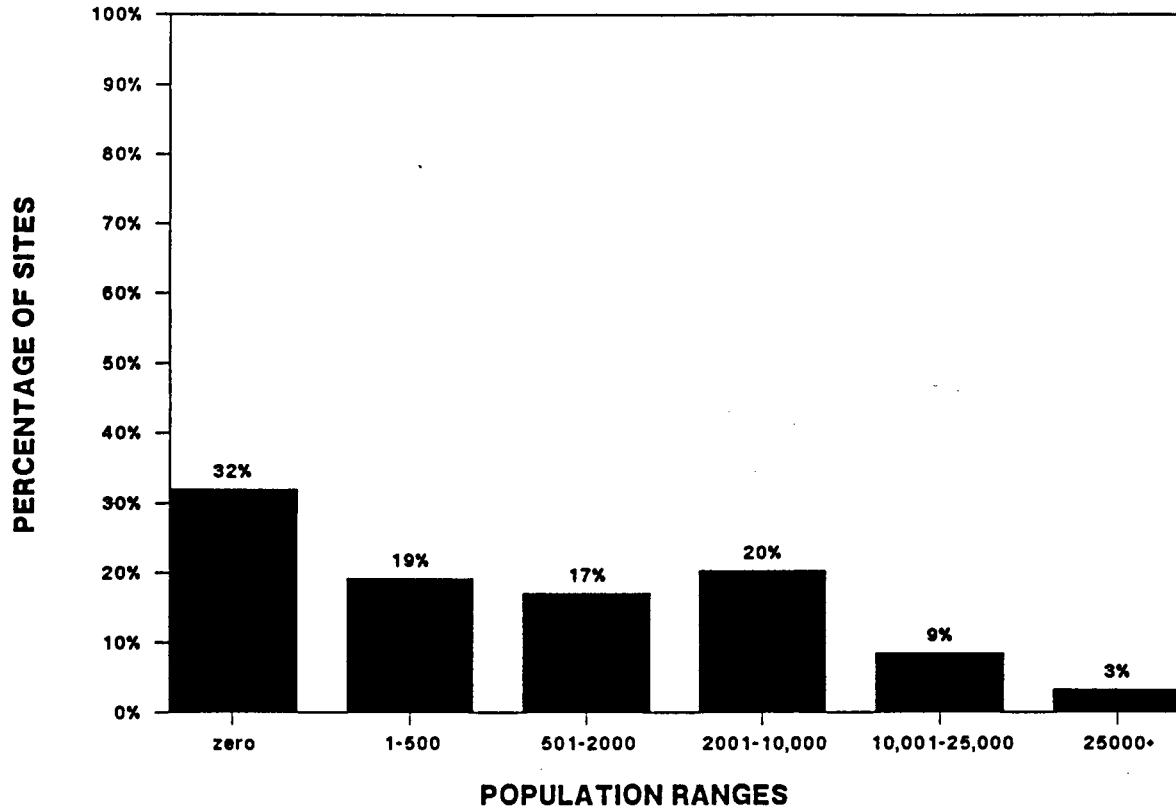


SOURCE: ICF Inc, based on CENBAT data

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EXHIBIT 5-24

POPULATIONS WITHIN THREE KILOMETERS OF WASTE SITES

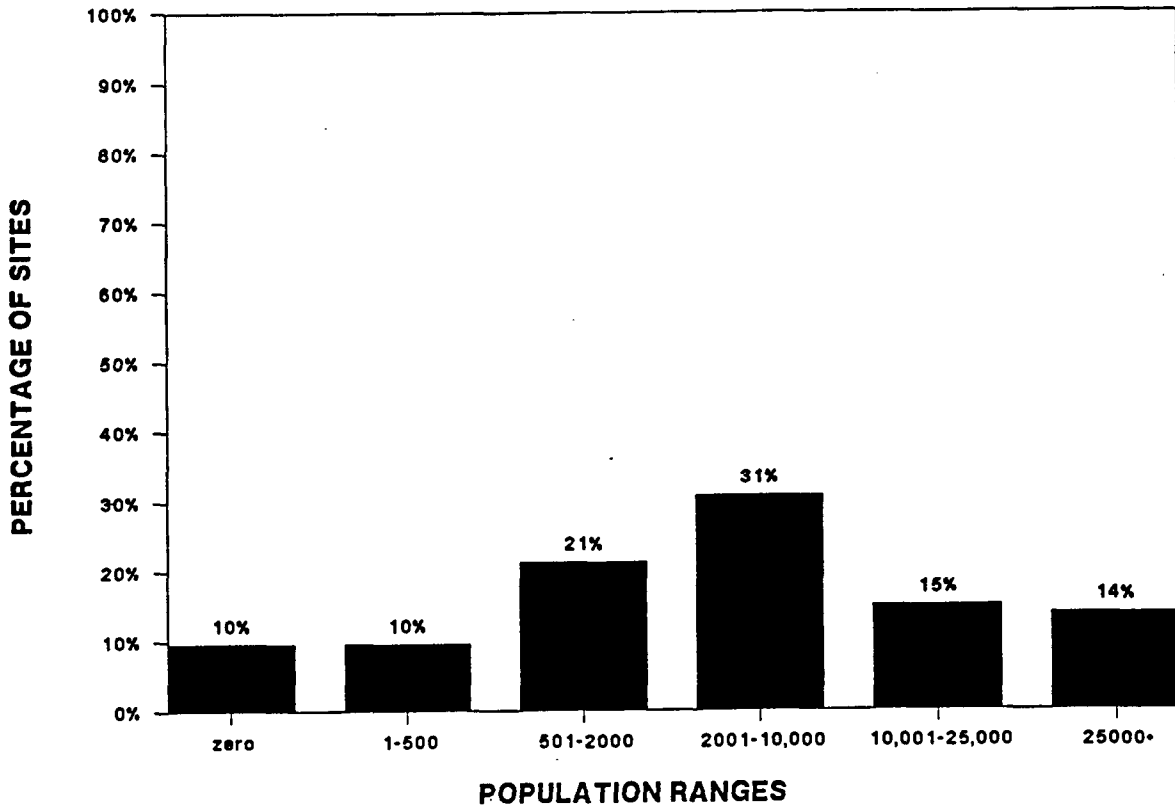


SOURCE: ICF Inc., based on CENBAT data

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EXHIBIT 5-25

POPULATIONS WITHIN FIVE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT

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within a five-kilometer radius of fewer than 500 persons, 29 percent have populations over 10,000.

The CENBAT results indicate that density increases on average with distance from the disposal site. Many waste sites appear to be located on the outskirts of populated areas, with fairly low population immediately adjacent to the site, but with significant populations within a five-kilometer radius.

5.4.2.2 Proximity of Sites to Public Drinking Water Systems

If coal combustion waste sites are close to public drinking water systems, there may be potential for human exposure through drinking water supplies. The location of public water supplies was determined through the use of the Federal Reporting Data System (FRDS), developed by EPA's Office of Drinking Water.

The FRDS data base provides the number of public water supply systems located within specified distances from a site and the populations using the systems. It should be noted that the FRDS data base locates water systems based on the centroid of the zip code of the mailing address of each utility and that the actual location of the intake or well may be different. This can cause some inaccuracy in the calculation of the distance and location of public drinking water supplies in relation to the waste site. In order to remedy potential inaccuracies and omissions, the locations of public water systems that appeared on topographical maps but were not reported by FRDS are also recorded.

Exhibit 5-26 shows the population served by public water systems located in the downgradient plume from the sites and within a five-kilometer radius. The exhibit also shows how many sites have no public water systems within a five-kilometer radius. Sixty-six percent of the sites have no public water systems within a five-kilometer radius. Fifteen percent of coal combustion sites have public water systems located within a five-kilometer distance and had systems which served over 5,000 people, and 19 percent have public water systems that serve fewer than 5,000 people.

The population data indicate that while there are often quite large populations in the vicinity of coal combustion waste sites, only 34 percent of the sites have public drinking water systems downgradient from the site.

5.4.3 Ecologic Characteristics of Coal Combustion Waste Sites

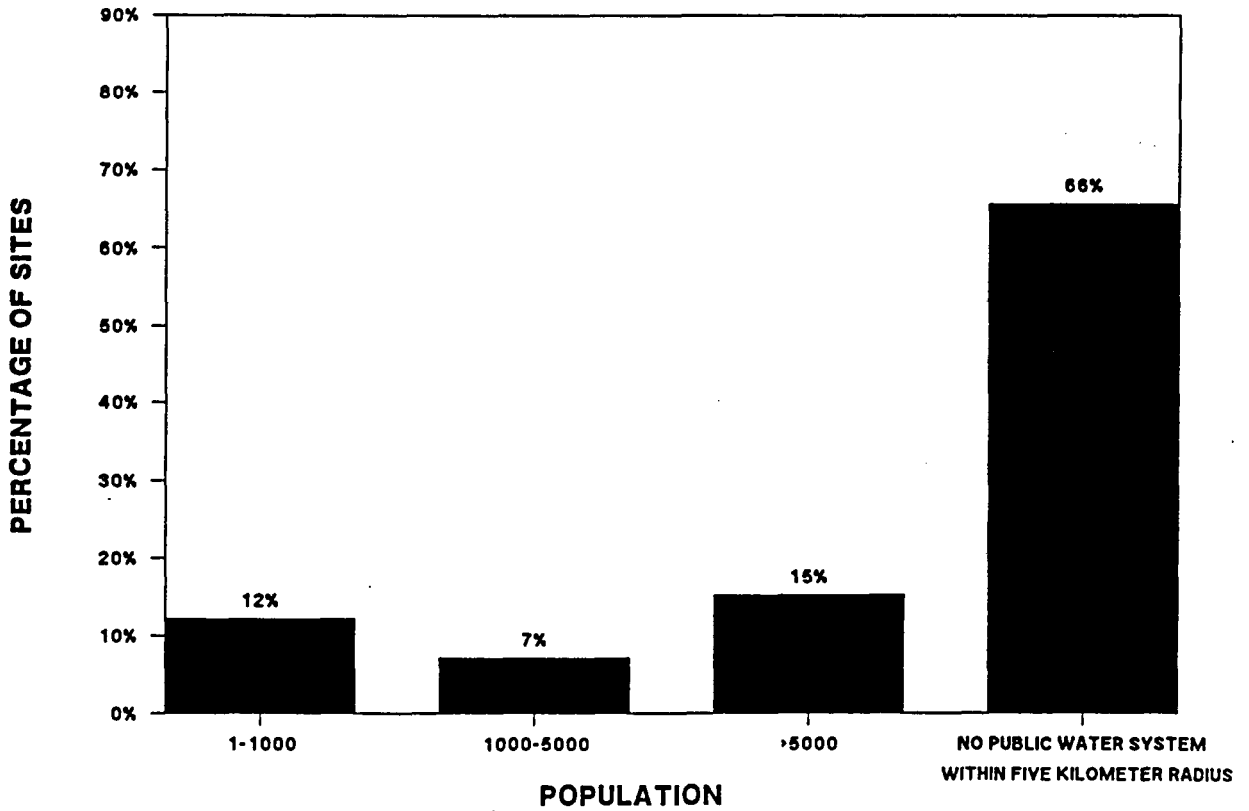
Ecological data on endangered, threatened, or unique plants and animals is available through state Heritage Programs. The Nature Conservancy established the Heritage Programs, which now usually function as offices of state governments. The Heritage Programs develop and maintain data bases that describe jeopardized species and rare ecosystems within each state. It should be noted that there can be substantial variation in the completeness of data available from different states; some state Heritage Programs are fairly new, and basic data collection is still in its preliminary stages.

While it may not currently be possible to quantitatively model risk to ecosystems from coal combustion waste, the information provided by the Heritage Programs can indicate whether there are any jeopardized species near a specific

5-90

EXHIBIT 5-26

POPULATIONS SERVED BY PUBLIC WATER SYSTEMS NEAR WASTE SITES



SOURCE: ICF, based on FRDS data

waste site. If potentially hazardous constituents of coal combustion waste do migrate and produce environmental contamination, it could affect species and natural communities that are particularly vulnerable, thereby lessening ecosystem diversity.

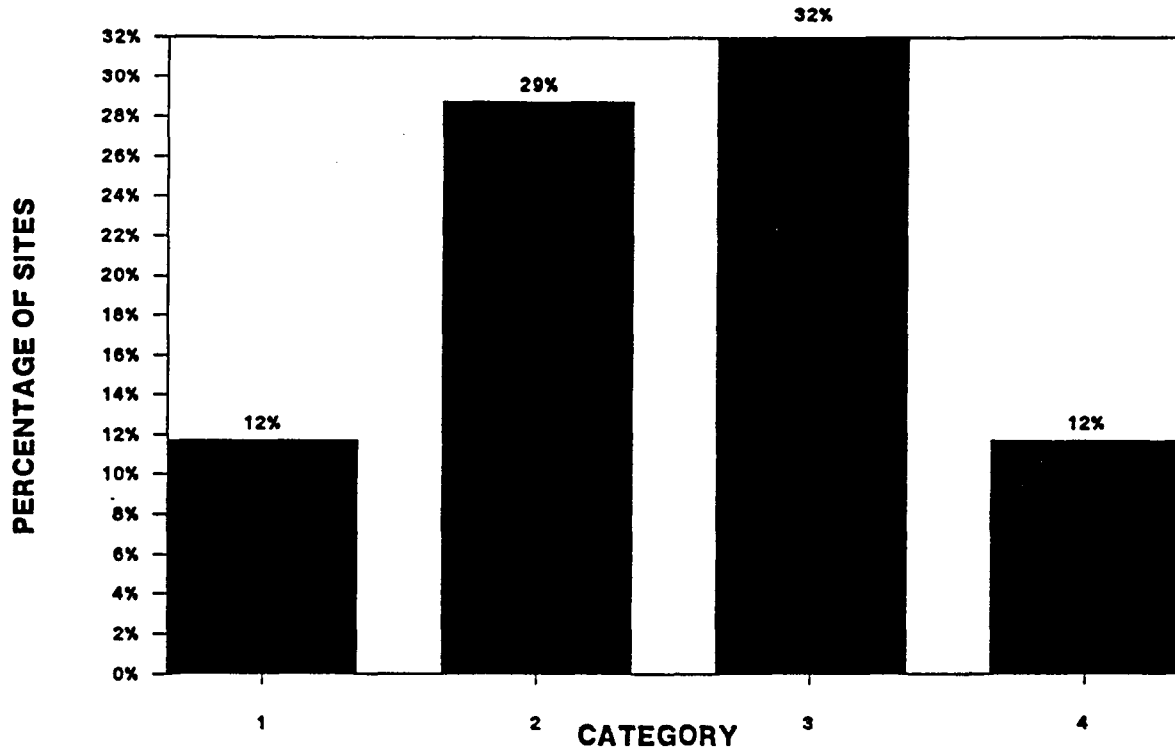
EPA provided Heritage Program staff with latitudes and longitudes for the sampled sites in states that had such programs. Using these coordinates, the Heritage Program staff performed a search of their data bases for rare or endangered species within a five-kilometer radius from the site.

The sample sites were grouped into four categories based on the results obtained from the Heritage Program. Category 1 includes sites having Federally designated threatened or endangered species within the five-kilometer radius. Category 2 includes sites that have no Federally designated threatened or endangered species within the five-kilometer distance, but which do contain species or natural communities designated by state Heritage Offices as critically endangered in that state. Category 3 contains sites for which there are species or natural communities of concern in the area. For sites in Category 4, there is no record of the existence of species of concern in the five-kilometer area.

Information was available on 85 of the 100 coal combustion waste sites in the sample. Exhibit 5-27 presents the breakdown of sites according to the categories described above. Twelve percent of the sites fall into Category 1, 29 percent in Category 2; 32 percent in Category 3; and 12 percent in Category 4 (no information was available for 15 percent).

EXHIBIT 5-27

ECOLOGICAL STATUS OF WASTE SITES



Category 1 : Federally designated plants or animals within a five km. radius
Category 2: Species of priority state concern within five km. radius
Category 3: species of concern to state environmental offices
Category 4: no data on ecosystem surrounding the site

SOURCE: ICF inc., based on State Heritage Data

Given the high percentage of sites that have rare plant and animal communities within a five-kilometer radius supplies, and the proximity discussed earlier of waste disposal sites to surface-water bodies (which provide animals with drinking water), there could be a high potential for species exposure to coal combustion constituents.

5.4.4 Multivariate Analysis

The previous sections of this exposure analysis presented independent analyses of the population, environmental, and ecological characteristics of coal combustion waste sites. This section examines a number of these factors simultaneously in order to determine interactions that affect the overall potential for exposure from coal combustion waste sites.

As mentioned previously, only 34 percent of coal combustion waste sites (based on a random sample of 100 sites) have public drinking water systems in the downgradient plume within 5 kilometers of the waste site. Some of these public drinking water systems may use ground water that is currently treated before it is used as drinking water, indicating that human populations are unlikely to be directly exposed to any water that may be contaminated from coal combustion waste constituents. As discussed earlier, one reason for treating the water is ground-water hardness. Ground water that has a hardness greater than 240 ppm CaCO₃ is likely to be treated if it is used as a drinking water source. Of the 34 percent of the sites in the sample that have public water systems in the downgradient plume within 5 kilometers of the waste site, just under one-half of these sites have ground water with a hardness over 240 ppm CaCO₃. These results show that the potential for human exposure through

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drinking water is likely to be less than the proximity to public drinking water systems (FRDS data) indicates. Of all the sites sampled, only 18 percent have public drinking water systems within 5 kilometers and ground water under 240 ppm CaCO₃.³⁴

The potential for human exposure through drinking water can be further evaluated by comparing the FRDS and ground-water quality characteristics with the hydrogeologic factors of net recharge and depth to ground water. Sites with a net recharge greater than 7 inches and a depth to ground water of fifteen feet or less are more likely to develop ground-water contamination due to waste leaching since water has a greater likelihood of contacting the coal combustion wastes. Of the 18 percent of the sites that have public water supplies and ground-water hardness below 240 ppm CaCO₃, two-thirds have a net recharge greater than 7 inches as well as a depth to ground water of 15 feet or less. Therefore, only 12 percent of the sites in the sample (18 percent x 2/3) have ground water that is likely to be used without treatment and hydrogeologic characteristics that indicate high potential for leachate migration.

This multivariate analysis of the factors affecting exposure at coal combustion waste sites illustrates the limited potential for human health risk through drinking water. Only 34 percent of the sites have public water systems within five kilometers and many of these public water systems are likely to treat the ground water due to hardness.

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5.5 SUMMARY

This chapter has reviewed available information on the potential for coal-fired combustion wastes from electric utility power plants to affect human health and the environment. First, data on the potential corrosivity and EP toxicity of utility wastes was reviewed. After determining that coal combustion leachate sometimes contains hazardous constituents at levels above drinking water standards, the potential for this leachate to migrate from waste disposal sites was examined. Results of ground-water monitoring in several studies were interpreted and a number of compilations of "documented" damage cases were evaluated. After describing instances in which trace elements in coal combustion leachate have migrated from waste disposal sites, the potential effect of these migrations was examined. A sample of 100 utility waste disposal sites was selected, and these sites were evaluated in terms of population, environmental, and ecological characteristics to assess the potential for leachate migration and exposure of human and ecological populations.

Based on these data and analyses, several observations relating to potential dangers to human health and the environment can be made:

- If the current exemption from Subtitle C regulation were lifted for coal combustion wastes and these wastes were required to be tested for corrosivity or EP toxicity, most current waste volumes and waste streams would not be subject to hazardous waste regulation. The only waste stream which has had corrosive results is boiler cleaning waste. (Since coal ash is not aqueous, it cannot be corrosive.) For the other waste streams, available data indicate that while some of these waste streams could have high or low pH levels, they are not likely to fall under the RCRA definition of corrosive waste.

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Similarly, while a few high-volume waste samples did exceed the EP toxicity limits for cadmium, chromium, and arsenic, this was limited to a few waste streams and represented only a small fraction of the samples for these waste streams (the chromium and arsenic exceedances were from only one fly ash sample). Available data on low-volume wastes showed that the only waste stream with significant RCRA exceedances was boiler cleaning waste, which had exceedances for chromium and lead. Wastewater brines were shown to exceed the RCRA standard for selenium in one sample. Results of EP tests on co-disposed wastes indicate that boiler cleaning wastes may not possess hazardous characteristics when co-disposed with ash. Results for all other waste streams and all other constituents were below EP toxicity limits.

- Results available from ground-water monitoring studies and documented cases of ground-water or surface-water contamination show some migration of PDWS constituents from utility waste disposal sites. In the most comprehensive and systematic of these studies, the Arthur D. Little survey of six utility sites, evidence of constituent migration downstream from the waste sites was conclusive only for cadmium. The EnviroSphere ground-water study showed that only 3.7 percent of the samples showed downgradient concentrations of PDWS constituents that were higher than the concentrations of upgradient constituents (indicating that some contaminants are migrating from the site). This tends to support the results of the waste extraction tests. For the one utility disposal site on the National Priorities List, a site currently inactive since it was closed in 1974, the major ground-water contaminants were vanadium and selenium. However, this site differs from some other sites for which ground-water quality data are available in that wastes are from both coal and petroleum coke combustion.
- Although coal combustion waste leachate has the potential to migrate from the disposal area, the actual potential for exposure of human and ecological populations is likely to be limited. Because utility plants need a source of water to operate, most of the disposal sites are located quite close to surface water. Fifty eight percent of the 100 sample sites were within 500 meters of surface water. It is not common for drinking water wells to be located between the disposal site and the nearest downgradient surface water body. The effect of this proximity to surface water is that only 34 percent of the sampled sites had drinking

water intakes within five kilometers. Furthermore, the flow of the surface water will tend to dilute the concentrations of trace metals to levels that satisfy drinking water standards.

- Simultaneously examining the environmental and population characteristics of coal combustion waste sites shows even less potential for exposure to human populations. 12 percent of the sites in the sample have public water systems within five kilometers of the site where the ground water may not be treated (i.e., ground-water hardness below 240 ppm CaCO₃) and hydrogeologic characteristics that indicate high potential for leachate migration.

CHAPTER 5

NOTES

- 1 See 40 CFR 261.21.
- 2 See 40 CFR 261.22. In using pH to determine corrosivity, EPA explained that "wastes exhibiting low or high pH can cause harm to human tissue, promote the migration of toxic contaminants from other wastes, and harm aquatic life."
- 3 These methods are set forth in 40 CFR 260.21 and 260.22.
- 4 See 40 CFR 261.23.
- 5 See 40 CFR 261.24.
- 6 See 40 CFR Part 261, Appendix II. These procedures for testing and the limits allowed for determining whether a waste is hazardous or not are currently under review.
- 7 A waste would be considered hazardous if it has been shown to have an oral LD 50 toxicity to rats of less than 50 mg/kg, an inhalation LC toxicity to rats of less than 2 mg/l, or a dermal LD 50 toxicity to rabbits of less than 2000 mg/kg.
- 8 See 40 CFR 261.11.
- 9 See CFR 40 Section 261.24. RCRA also establishes EP toxicity limits for six pesticides.
- 10 See CFR 40 Section 261, Appendix II.
- 11 Federal Register, Volume 51, No. 114, Friday, June 13, 1986, p. 21648.
- 12 Since the completion of the ASTM B tests discussed in this section, ASTM has dropped this extraction test (EPRI 1983).
- 13 Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.
- 14 Jackson, L. and Moore, F., Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, prepared for the U.S. Department of Energy, Office of Fossil Energy, DOE/LC/00022-1599 (DE84009266), March 1984.

- 15 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared for the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency for the Office of Solid Waste, EPA-600-7-85-028, June 1985.
- 16 Mason, B.J., and Carlile, D.W., draft report of Round Robin Evaluation for Selected Elements and Anionic Species from TCLP and EP Extractions, prepared by Battelle Pacific Northwest Laboratories, for the Electric Power Research Institute, EPRI EA-4740, April 25, 1986.
- 17 Battelle's test varied from standard TCLP procedure by allowing 14 days, rather than the normal 7, for the completion of the test.
- 18 Electric Power Research Institute, "Mobilization and Attenuation of Trace Elements in an Artificially Weathered Fly Ash," prepared by the University of Alberta, Edmonton, Canada, EPRI EA-4747, August 1986.
- 19 Battelle Pacific Northwest Laboratories, Chemical Characterization of Fossil Fuel Combustion Wastes, prepared for the Electric Power Research Institute, September 1987.
- 20 Radian Corporation, Characterization of Utility Low-Volume Wastes, prepared for the Electric Power Research Institute, May 1985.
- 21 Radian Corporation, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared for the Electric Power Research Institute, July 1987.
- 22 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared by the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency, for the Office of Solid Waste, EPA-600-7-85-028, June 1985.
- 23 Franklin Associates, Ltd., Survey of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.
- 24 Envirosphere Company, "Report on the Ground Water Data Base Assembled by the Utility Solid Waste Activities Group," in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil Fuel By-Products, October 26, 1982, Appendix C.
- 25 It is not necessarily true that measurements taken from upgradient and downgradient wells at approximately the same time yield comparable measurements. In fact, due to migration time, there will be a lag between the time of comparable upgradient and downgradient measurements.

- 26 EnviroSphere Company, Op. cit., p. 38. These percentage numbers do not correspond precisely to the data in Exhibit 5-11 because EnviroSphere normalized the data it received from the utilities so that each facility would be weighted evenly (i.e., a facility with many more measurements would not be weighted excessively). EnviroSphere reports that 1.7 percent of the normalized data had upgradient measurements lower than the PDWS and the downgradient higher than the PDWS; 5 percent of the data indicated that both values exceeded the standard.
- 27 EnviroSphere Company, Environmental Effects of Utility Solid Waste Disposal, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, July 1979.
- 28 Dames & Moore, "Review of Existing Literature & Published Data to Determine if Proven Documented Cases of Danger to Human Health and the Environment Exist as a Result of Disposal of Fossil Fuel Combustion Wastes", in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix B.
- 29 Cherkauer, D. S. "The Effect of Fly Ash Disposal on a Shallow Ground-Water System." Ground Water, Vol. 18, No. 6, pp. 544-550, 1980.
- 30 Groenewold, G. H., and B. W. Rehm. "Applicability of Column Leaching Data to the Design of Fly Ash and FGD Waste Disposal Sites in Surface-Mined Areas." In Proceedings of the Low-Rank Coal Technology Development Workshop, comp. Energy Resources Company, Inc., DOE/ET/17086-1932, CONF-8106235; Washington, D.C., U.S. Department of Energy, Technical Information Center, pp. 3-79 - 3-95, 1981.
- 31 EnviroSphere Company, Environmental Settings and Solid-Residues Disposal in the Electric Utility Industry; prepared for the Electric Power Research Institute, August 1984.
- 32 Linda Aller, Truman Bennet, Jay H. Laher, Rebecca J. Betty, A Standardized System for Evaluating Ground Water Pollution Potential Using Hydrologic Settings, prepared by the National Well Water Association for U.S. EPA Office of Research and Development, Ada, OK, May 1985. EPA 600-285-018.
- 33 Veronica T. Pye, Ruth Patrick, John Quarles, Ground Water Contamination in the United States, Philadelphia: University of Pennsylvania Press, 1983.
- 34 Ground water over 180 ppm CaCO₃ may also be treated. Of the 34 percent of the sites in the sample that have public water systems in the plume downgradient from the site within 5 kilometers, 73 percent have ground water with a hardness over 180 ppm CaCO₃. Therefore, only 9 percent of the sites in the sample have both public water systems within 5 kilometers and ground water under 180 ppm CaCO₃. Since many public water systems may not treat water in the range of 180-240 ppm CaCO₃, the discussion in the report focuses only on ground water in excess of 240 ppm CaCO₃. This is a conservative assumption since the water may be treated, either by the public authority or the private homeowner. In all cases, the extent of exposure through private wells would have to be evaluated on a site-by-site basis.

CHAPTER SIX
ECONOMIC COSTS AND IMPACTS

Section 8002(n) of RCRA requires that EPA's study of coal combustion wastes examine "alternatives to current disposal methods," "the costs of such alternatives," "the impact of those alternatives on the use of coal and other natural resources" and "the current and potential utilization of such materials." In response to these directives this chapter examines the potential costs to electric utilities if coal-fired combustion waste disposal practices are regulated differently than they are currently.

The first section of this chapter (Section 6.1) examines the costs incurred by electric utilities using current disposal methods for coal combustion wastes.¹ Section 6.2 follows with a discussion of the costs that could be incurred if coal combustion wastes were regulated differently than they are today. These costs include the costs of implementing alternative waste management practices and the costs of additional administrative responsibilities that would be incurred. Section 6.3 examines how new regulations might affect the cost of utilizing coal combustion wastes in various by-product applications. The last section of this chapter (Section 6.4) considers how energy use patterns in the electric utility industry might change if alternative waste management practices that significantly affect the cost of generating electricity with coal were imposed.

6.1 WASTE DISPOSAL COSTS ASSOCIATED WITH CURRENT DISPOSAL METHODS

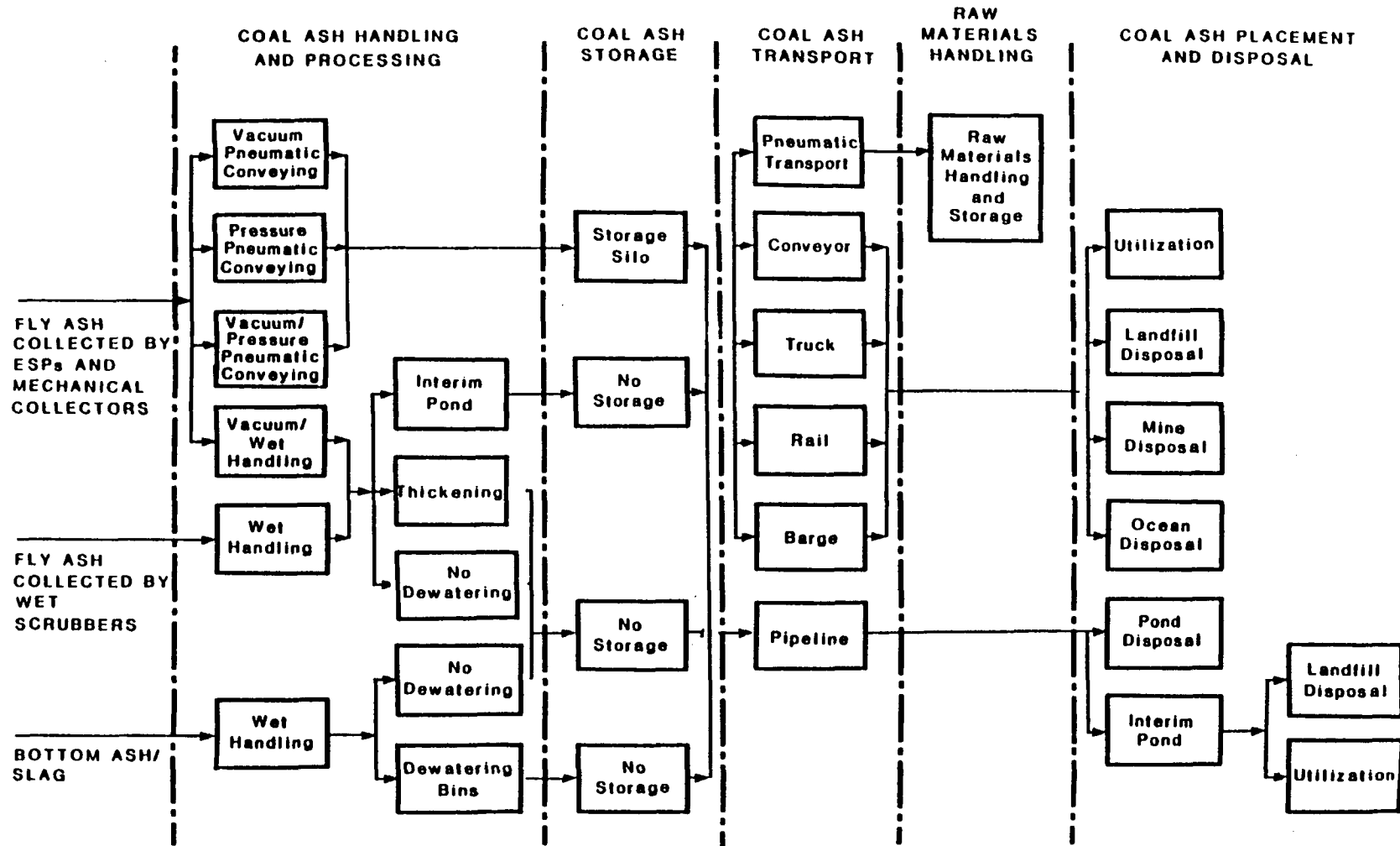
The management of utility wastes comprises a series of activities -- from initial waste collection to disposal. These current waste management activities can be classified into five basic components:²

1. **Waste Handling and Processing.** This is the initial phase of the disposal process, involving collection of the various waste products after they have been generated and initial treatment of the wastes to prepare them for final disposal.
2. **Interim Waste Storage at the Plant.** Some waste products that are dry when produced, such as fly ash or flue gas desulfurization (FGD) wastes from dry scrubbers, often require interim storage prior to final disposal.
3. **Raw Materials Handling and Storage.** Some disposal processes involve stabilization or chemical fixation of the waste to prepare it for disposal. The raw materials used for this phase, including additives such as lime, Calcilox, and basic fly ash, often require special handling and storage facilities.
4. **Waste Transport to a Disposal Facility.** Environmentally sound disposal requires careful transportation of the waste to the disposal site. Many modes of transportation can be used, including trucks, railroads, barges, pipelines, and conveyor systems.
5. **Waste Placement and Disposal.** This is the final stage of the waste disposal chain. It involves placing the waste in a suitable waste management facility (usually a surface impoundment or landfill) and all activities required after the facility is closed. Alternatively, the final disposition of a waste product may entail utilization of the waste in various applications (such as cement production or sandblasting operations).

Exhibit 6-1 presents a schematic illustration of the current waste management and disposal options for coal ash; Exhibit 6-2 illustrates the options available for FGD wastes. The waste management costs discussed in this

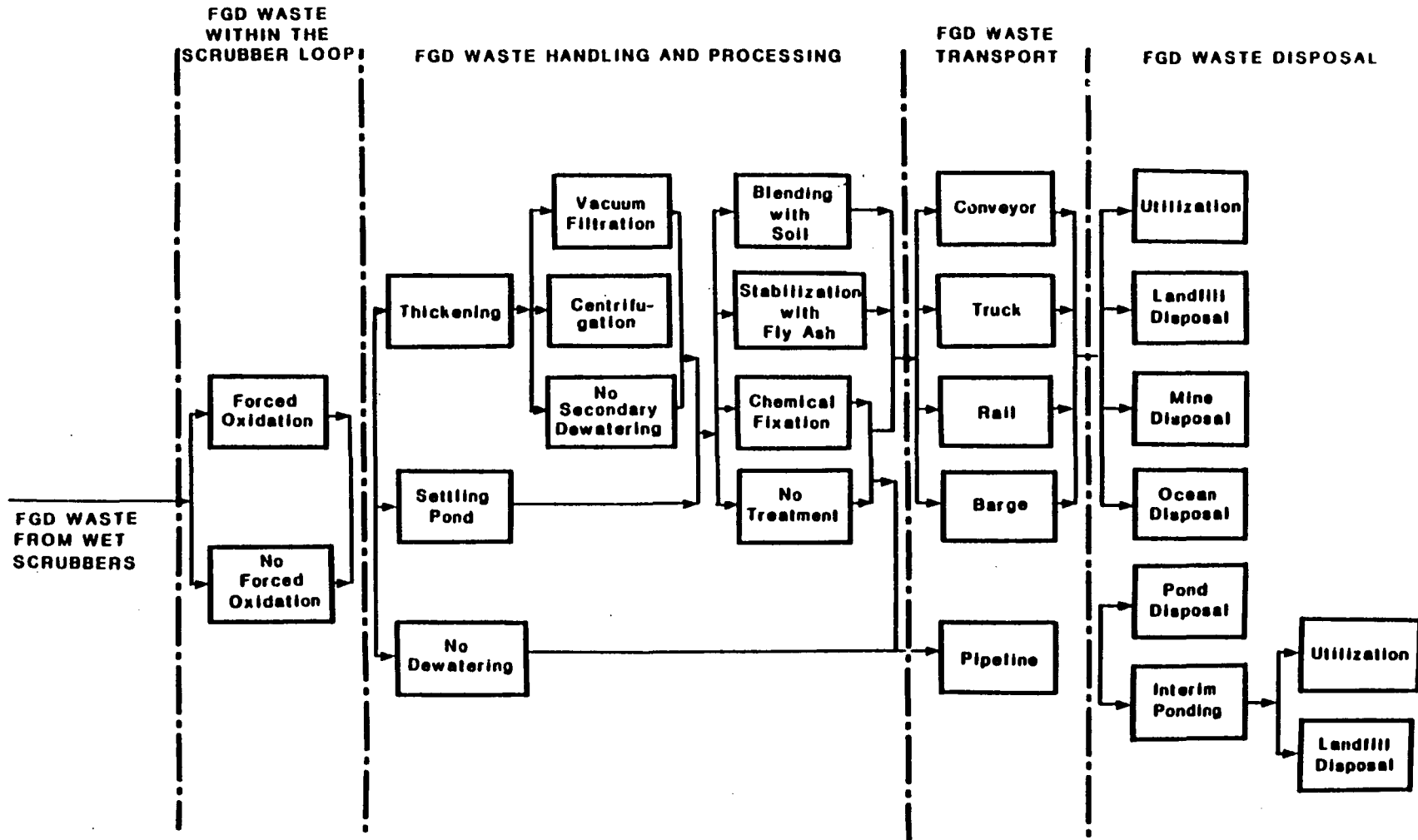
Exhibit 6-1

Overview of Waste Handling and Disposal Options for Coal Ash



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

Exhibit 6-2 Overview of Waste Handling and Disposal Options for FGD Waste



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

chapter are those associated with the last component of waste management (i.e., waste placement and disposal). These are the costs associated with actual construction of the waste management facility and placement of the wastes into the facility. If current practices for managing coal-fired wastes from electric utilities are altered, it is this final stage in waste management that would probably be most affected. However, as will be explored later in this chapter, some regulatory alternatives may affect other aspects of waste management.

6.1.1 Costs of Waste Placement and Disposal

The wastes from coal-fired combustion at electric utility power plants are often mixed together in the same waste management facility, typically a surface impoundment or landfill. Although surface impoundments were once the preferred method, and are still widely used, landfiling has become the more common practice because less land is required, and it is usually more environmentally sound (because of the lower water requirements, reduced leaching problems, etc.).

The costs of waste disposal can vary substantially. Exhibit 6-3 shows representative capital costs associated with constructing surface impoundments and landfills for coal-fired electric utility wastes. Exhibit 6-4 shows total costs (i.e., annualized capital costs plus operation and maintenance expenses).³ Costs are shown for power plants that range in size from 100 to 3000 megawatts (Mw); power plants that fall outside of this range may incur

EXHIBIT 6-3**RANGES OF AVERAGE CAPITAL COSTS ASSOCIATED WITH
COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL
(4th quarter 1986 dollars per kilowatt)**

Type of Waste	Size of Power Plant			
	100 MW	500 MW	1000 MW	3000 MW
<u>Landfills</u>				
Fly Ash	9-14	4-7	3-5	2-3
Bottom Ash	2- 5	2-3	1-2	1-1.3
FGD Waste	6-13	4-7	3-6	2-4
<u>Surface Impoundments</u>				
Fly Ash	27-50	15-27	13-23	10-18
Bottom Ash	10-20	6-11	5- 9	3- 6
FGD Waste	14-30	10-19	9-17	7-14

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

EXHIBIT 6-4

**RANGES OF AVERAGE TOTAL COSTS FOR COAL-FIRED ELECTRIC
UTILITY WASTE DISPOSAL
(4th quarter 1986 dollars per ton)***

Type of Waste	Size of Power Plant			
	100 MW	500 MW	1000 MW	3000 MW
<u>Landfills</u>				
Fly Ash	9-18	6-11	5-9	2-6
Bottom Ash	10-16	5-9	4-8	2-6
FGD Waste	4-10	4-7	3-6	2-4
<u>Surface Impoundments</u>				
Fly Ash	17-31	9-17	8-14	5-8
Bottom Ash	11-26	8-15	7-13	5-8
FGD Waste	8-17	7-13	6-10	5-7

* Dollar per ton estimates are based on the amount of waste produced each year. For purposes of this illustration, a power plant is assumed to generate annually 308 tons of fly ash per megawatt (MW), 77 tons of bottom ash per MW, and 264 tons of FGD waste per MW. Amounts will vary depending on coal quality, FGD technology, and boiler type, among other factors.

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

different waste management costs. Both capital costs and total costs are shown for unlined facilities without ground-water monitoring or leachate control systems. The major factors affecting the cost of waste management are discussed below.

The amount of capital costs for a waste management facility can be attributed primarily to three factors: site preparation, excavation, and construction of containment structures.⁴ Capital costs can be substantially reduced if the amount of earthwork can be minimized. Capital costs for surface impoundments, for example, increase significantly if dike construction or excavation is required. However, if existing site features can be used, such as valleys or abandoned pits, capital costs will be lower. Similarly, capital costs for landfills that require little excavation are lower than for those sites requiring extensive earthwork.

As Exhibit 6-3 illustrates, landfills are far less capital intensive than surface impoundments. For example, capital costs for fly ash placement in a surface impoundment at a 500 MW power plant would range from approximately \$15 to \$27 per kilowatt.⁵ In contrast, capital costs for landfills range from about \$4 to \$7 per kilowatt. Landfills tend to cost less than impoundments primarily because the area required for a given amount of waste is less, and neither dikes nor piping and pumping systems are necessary.

Annual costs for landfills (see Exhibit 6-4) also tend to be less than those for surface impoundments primarily because landfills tend to be far less capital intensive. For example, costs for fly ash management at a 500 MW power plant range from about \$9 to \$17 per ton when the wastes are placed in surface

impoundments, while the comparable range at a landfill is about \$6 to \$11 per ton. Similarly, the cost for bottom ash disposal at an impoundment for a 500 MW power plant ranges from \$8 to \$15 per ton, while the costs to dispose in a landfill range from about \$5 to \$9 per ton.

Other factors that affect the cost of utility waste disposal include

- **Size of the Power Plant.** Because larger power plants consume more coal than smaller facilities, they generate more waste material. However, more efficient operating procedures allow a larger disposal site to realize economies of scale not available at smaller sites; thus, the cost per ton of waste disposed is typically less.
- **Rate of Operation.** The number of hours that a coal-fired power plant operates varies from plant to plant, ranging from fewer than 3,500 hours per year to more than 6,500 hours. As operating levels increase, the amount of waste generated will increase as more coal is burned to meet the higher generation load.
- **Type of Coal.** The quantity of ash produced is proportional to the ash content of the coal, which ranges from 5 to 20 percent on average. Also, the grade of coal and boiler design will affect the relative proportions of fly ash and bottom ash (see Chapter Three for a discussion of the impact of boiler design on types and amount of wastes generated).
- **FGD Equipment.** Because of the additional materials used in flue gas desulfurization, a power plant that uses this process to remove sulfur dioxide generates substantially more waste than does a power plant with no sulfur dioxide controls. The amount of waste generated also varies from one FGD operation to the next, primarily because of differences in sulfur content among the various coals and, to a lesser extent, because of the type of FGD process employed.

For the few power plants currently disposing their waste in mines or quarries, this disposal method has been economic because of convenient access to the disposal site. Since much of the excavation normally required at a disposal

site has already been performed as a result of the mining or quarrying operation, waste disposal costs can be quite competitive with costs associated with more traditional methods of disposal. The cost of disposing in mines or quarries for power plants that do not have easy access to the mine or quarry could quickly become prohibitive due to the costs of arranging for disposal at a remote site and of transporting the waste. Costs are also affected by whether or not the mine or quarry is still operating, whether the mining was surface or underground, and the amount of additional preparation required to dispose of the wastes, among other factors.

The costs of ocean disposal are not well known because there has been limited experience with this disposal method. Ocean disposal has been considered for unconsolidated waste (i.e., waste material that has not been physically or chemically altered prior to disposal)⁶ and for more stabilized forms of waste, such as blocks for artificial reef construction;⁷ however, this method has been attempted only for projects such as artificial reef construction, and then only on a trial basis. The most critical factors that would affect the magnitude of costs for ocean disposal are the availability of ash-handling facilities to load ocean-going vessels, the ability to gain easy access to the necessary waterways, and the physical characteristics of the wastes intended for disposal.

Because neither ocean disposal nor mine or quarry disposal is likely to be used on a widespread basis, they have been discussed here only briefly; see Chapter Four for a more detailed discussion of these two disposal options.

6.1.2 Costs Associated with Lined Disposal Facilities

The waste management costs presented above for surface impoundments and landfills do not include the cost of natural or synthetic liners to control the flow of leachate from the disposal area. Traditionally, most waste management sites, both surface impoundments and landfills, have not been lined to retard leaching, although this practice has become more widespread in recent years (see Chapter Four for a detailed discussion of liners). Currently, about 25 percent of all coal combustion waste management sites employ some type of liner system. Most liners are made of clay, synthetic materials, or stabilized utility waste.

Clay is used as a liner material because it is not very permeable, although its permeability will vary depending on the nature of the clay and the degree of compaction. Because clay is expensive to transport, the costs of the various clays used for liner material are directly related to the local availability of the clay. The installed cost of clay liners can range from \$4.45 to \$15.75 per cubic yard.⁸ For a liner 36-inches thick, (liner thicknesses do vary), this results in a cost range of \$21,000 to \$75,000 per acre, or about \$0.70 to \$2.55 per ton of waste disposed in a landfill and \$2.25 to \$8.20 per ton for waste placed in an impoundment for a 500 MW power plant.⁹

Synthetic liner materials come in two basic varieties--exposable and unexposable. The membranes of exposable liners are resistant to degradation from exposure to the elements even if the liner is left uncovered. The membranes of unexposable liners will not function properly if the liner is exposed. Costs for installing exposable liners range from \$43,000 to \$113,000 per acre, or \$1.45 to \$3.85 per ton of waste disposed in landfills and from

\$4.70 to \$12.35 per ton of waste placed in surface impoundments.¹⁰ Costs to install unexposable liners range from \$59,000 to \$123,000 per acre, or \$2.00 to \$4.15 per ton of waste disposed in landfills and \$6.45 to \$13.45 per ton placed in impoundments.¹¹ The ranges of costs are due primarily to differences in the cost of the material, differences in liner thickness, and allowances for various site-specific costs.

Stabilized utility waste, made from combinations of various ash wastes (such as fly ash or bottom ash), FGD waste, and lime, may be used as liner material when the required materials are available at the plant site. At an installed cost of about \$13.70 per cubic yard, liners ranging from 3 feet to 5 feet in thickness can be constructed for \$66,000 to \$110,000 per acre,¹² which corresponds to total capital costs of \$3.0-\$5.0 million at a landfill, or about \$2.25 to \$3.75 per ton of disposed waste from a 500 Mw power plant. Total capital costs at impoundments would be \$9.6-\$16.0 million, or \$7.20-\$12.00 per ton of waste managed.¹³

6.2 COSTS OF ALTERNATIVE DISPOSAL OPTIONS

As described above, coal-fired utility wastes are currently exempt from RCRA Subtitle C waste management requirements. In the interim, coal combustion wastes are regulated under state statutes and regulations (see Chapter Four). If these wastes are subject to Subtitle C regulation, the incremental costs will depend on the regulatory option(s) ultimately selected. Section 6.2.1 outlines the major regulatory alternatives and discusses the flexibility allowed EPA under RCRA to promulgate regulations that account for the special nature of coal combustion wastes. Section 6.2.2 presents cost estimates for individual

Subtitle C disposal requirements, and Section 6.2.3 presents cost estimates for three regulatory scenarios if coal combustion wastes are regulated under Subtitle C.

6.2.1 Regulatory Alternatives under Subtitle C

As described in Chapter Five, there are two ways in which coal combustion wastes could be identified as hazardous and thus subject to requirements outlined in Part 264 of RCRA: the characteristic procedure and the listing procedure.

- **Regulation As Characteristic Waste.** Unless otherwise exempted, solid wastes are hazardous under RCRA if they display any of four characteristics: ignitability, corrosivity, reactivity, or EP toxicity. Coal combustion wastes are unlikely to be ignitable or reactive, but could be corrosive (for aqueous wastes) or EP toxic. Subtitle C regulations would apply only to those waste streams that exhibited any of the hazardous characteristics. As discussed in Chapter Five, it is likely that only a small percentage of all waste generated would be hazardous. However, since some low volume wastes may be corrosive, this could have an impact on utilities that currently co-dispose high- and low-volume wastes. In these cases, the utility could either stop co-disposing or the landfill would have to conform to Subtitle C standards. In the case of surface impoundments, it might still be possible to co-dispose high- and low-volume wastes if the disposal impoundment met the requirements for a neutralization surface impoundment as set forth in 47 FR 1254, January 11, 1982.
- **Regulation as Listed Waste.** In addition to regulation under Subtitle C as characteristic waste, the Administrator may list a waste as hazardous under RCRA if it meets any of the three criteria contained in 40 CFR 261.11: (1) the waste exhibits any of the four characteristics described above; (2) it has been found to be fatal to humans in low doses or is otherwise measured as acutely hazardous; or (3) it contains any of the toxic constituents listed in Appendix VIII of Part 261. The Administrator does not have to list a

waste that contains any of the toxic constituents listed in Appendix VIII if the Agency concludes that "the waste is not capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed". The Administrator could decide to list as hazardous all coal combustion waste streams or only selected ones.

If Subtitle C regulation is warranted for coal combustion wastes, all the requirements for hazardous waste treatment, storage, disposal, and recycling facilities in 40 CFR 264 could be applied to the wastes from coal-fired power plants. Since coal combustion waste is mainly managed in surface impoundments and landfills, the requirements of Subparts A-H, K, and N would apply. In general, the required activities include the following:

- **General Facility Standards.** Facilities must apply for an identification number, prepare required notices when necessary, perform general waste analysis, secure the disposal facility to prevent unauthorized entry, comply with general inspection requirements, provide personnel training, and observe location standards (these include a provision that facilities located in a 100-year flood plain must be designed, constructed, operated, and maintained to prevent washout of any hazardous waste by a 100-year flood). (40 CFR 264 Subpart B)
- **Preparedness and Prevention.** Hazardous waste facility operators must design and operate facilities to minimize the possibility of fire or explosion, equip the facility with emergency equipment, test and maintain the equipment, and provide EPA and other government officials access to communications or alarm systems. (40 CFR 264 Subpart C)
- **Contingency Plan and Emergency Procedures.** The facility operators must have a contingency plan to minimize hazards to human health or the environment in the event of fire or explosion. (40 CFR 264 Subpart D)

- **Manifest System, Recordkeeping, and Reporting.** Hazardous waste facility operators must maintain a manifest system, keep a written operating record, and prepare a biennial report. (40 CFR 264 Subpart E)
- **Ground-water Protection.** Unless a waste management facility meets certain standards,¹⁴ a Subtitle C facility is required to comply with requirements to detect, characterize, and respond to releases from solid waste management units at the facility. These requirements include ground-water monitoring and corrective action as necessary to protect human health and the environment. (40 CFR 264 Subpart F)
- **Closure and Post-closure.** Subtitle C facilities must comply with closure and post-closure performance standards to minimize the risk of hazardous constituents escaping into the environment. (40 CFR 264 Subpart G)
- **Financial Requirements.** Subtitle C facilities must establish a financial assurance plan for closure of the facility and for post-closure care. Possible methods of financial assurance include a closure trust fund, surety bonds, closure letter of credit, closure insurance,¹⁵ or financial test and corporate guarantee. (40 CFR 264 Subpart H)
- **Design and Operating Requirements.** Unless granted an exemption, new surface impoundments or landfills or new units at existing impoundments or landfills must install two or more liners and a leachate collection system between the liners. (40 CFR 264 Subparts K and H)

In recognition of the special nature of coal combustion wastes, Congress afforded EPA some flexibility in designing regulations for coal combustion wastes if they are subject to regulation under Subtitle C. This flexibility allows EPA to exempt electric utilities from some regulations imposed on owners and operators of hazardous waste treatment, storage, and disposal facilities by the Hazardous and Solid Waste Amendments of 1984. Specifically, section 3004(x) of RCRA allows the Administrator to modify the following requirements when promulgating regulations for utility waste.

- Section 3004 (c) prohibits the placement of uncontained liquids in landfills;
- Section 3004 (d) prohibits the land disposal of specified wastes;¹⁶
- Section 3004 (e) prohibits the land disposal of solvents and dioxins;
- Section 3004 (f) mandates a determination regarding disposal of specified wastes into deep injection wells;
- Section 3004 (g) mandates determinations on continued land disposal of all listed hazardous wastes;
- Section 3004 (o) lists minimum technical requirements for design and operation of landfills and surface impoundments, which specify the installation of two or more liners, a leachate collection system, and ground-water monitoring;
- Section 3004 (u) requires the Administrator to promulgate standards for facilities that burn hazardous waste as fuel; and
- Section 3005 (j) provides that interim-status surface impoundments must also meet minimum technical requirements specified in section 3004 (o).

In addition to the flexibility afforded by 3004 (x), it is possible for EPA to modify any of the standards applicable to waste treatment and disposal facilities if lesser standards are protective of human health and the environment. Section 3004 (a) states "... The Administrator shall promulgate regulations establishing such performance standards, applicable to owners and operators of facilities for the treatment, storage, or disposal of hazardous waste identified or listed under this subtitle, as may be necessary to protect human health and the environment."

There remains substantial uncertainty, however, about the extent to which, in practice, the statutory language of Subtitle C would provide sufficient flexibility to design a waste management program appropriate for high-volume,

low-toxicity coal combustion wastes. EPA may also consider waste management requirements, as needed, under the current Subtitle D provisions for solid wastes, or may seek appropriate additional authorities.

6.2.2 Cost Estimates for Individual RCRA Subtitle C Disposal Standards

If EPA determines that Subtitle C regulation is warranted for coal combustion wastes, there is a wide range of regulatory options that could be undertaken. Required activities could consist of some, all, or variations of the requirements listed in 40 CFR Subparts B-H (and described briefly in Section 6.2.1). This section presents estimates for the costs that would be associated with compliance with individual Subtitle C requirements.

6.2.2.1 General Facility Standards; Preparedness and Prevention; Contingency Plan and Emergency Procedures; and Manifest System

Subparts B through E in Part 264 of the RCRA regulations list general requirements for such activities as preparing written notices and plans for submission to EPA; conducting waste analyses; providing security at the disposal site; and recordkeeping and reporting. Many of these activities would be undertaken during the permitting process, which is set forth in Part 270 of RCRA.

The Part B application must contain the technical information listed in Part 264 B through E. The cost to the electric utility industry to prepare a Part B permit application was estimated in a study done for the Utility Solid Waste Activities Group (USWAG), which calculated that the total cost of submitting

Part B permit analyses would be \$721,000 per plant, or about \$0.55 per ton of waste disposed.¹⁷ The industry cost, if all power plants filed Part B applications, would be about \$370 million, or about \$54 million in annualized costs.

Location standards are also specified under Subpart B of Part 264 of RCRA. One such standard is for facilities located in a 100-year flood plain. Part 246.16(b) requires protective measures to prevent washout from flooding.

USWAG estimated the costs for protecting waste disposal facilities located within a 100-year flood plain to be about \$740 per acre for surface impoundments and about \$1,100 per acre for landfills on an annualized basis.¹⁸ This corresponds to waste management costs of approximately \$0.55 per ton of waste at surface impoundments and \$0.25 per ton at landfills.¹⁹ Industry-wide costs for flood protection at all impoundments are estimated to be about \$92 million for capital expenditures (about \$13 million in annualized costs); costs for flood protection at all landfills would be about \$146 million for capital expenditures (about \$20 million in annualized costs).²⁰

6.2.2.2 Ground-water Protection

Subpart F of 40 CFR Part 264 lists requirements for ground-water monitoring systems. The costs of installing and maintaining an acceptable ground-water monitoring program are dependent on the number of monitoring wells required and the frequency of testing. The study conducted by Arthur D. Little for EPA estimated that capital costs for installing six monitoring wells at a facility would range from \$18,000 to \$25,000.²¹ At a sampling frequency of four times

per year, annual operating and maintenance costs would be \$10,000 to \$14,500. Total ground-water monitoring costs would range from \$0.06 to \$0.10 per ton of managed waste. In another study conducted for USWAG by EnviroSphere, which used different well configurations and cost parameters, somewhat higher costs (\$0.10-\$0.12 per ton of waste managed) were estimated.²²

It is not known how many coal-fired power plants currently have adequate ground-water monitoring systems in place. To estimate industry-wide costs, EPA has conservatively assumed that all power plants would be required to install new ground-water monitoring systems. Using the costs developed in the Arthur D. Little study, EPA calculated that total capital costs would be about \$9.3 to \$12.8 million. Total annualized costs would range from \$6.5 to \$9.3 million.

6.2.2.3 Corrective Action

Subpart F of 40 CFR Part 264 also lists requirements for corrective action. A variety of actions may be undertaken to correct ground-water contamination problems caused by a hazardous waste disposal facility. The facility owner or operator would need to conduct a site-specific investigation to ascertain the potential degree of contamination and the appropriate response that would be most effective in remedying the situation. Types of remedial responses that might be required would be placing a cap (made of either a clay or synthetic material) on the disposal unit, counter-pumping the ground water to retard contaminant migration, excavating the disposal area and removing the wastes to a Subtitle C landfill, or installing an impermeable curtain around the disposal area to prevent ground-water flow into or out of the disposal area. As one example of the potential magnitude of corrective action costs, this section

evaluates the cost to excavate the existing disposal areas and transfer the wastes to RCRA Subtitle C-approved facilities.

EPA developed the following formula to calculate total excavation costs for Subtitle C units, (including closure of the existing site and removal of the wastes to a Subtitle C facility):

$$\text{Cost} = [(\text{Surface Area} \times \$45) + (\text{Volume} \times \$187)] \times 2.16$$

where the surface area is measured in square meters, and volume is measured in cubic meters.²³

For a power plant of average size (500 MW), it has been assumed that a 45-acre landfill would be required, or about 182,000 square meters, with a capacity of approximately 5 million cubic meters. Based on the cost equation listed above, costs for excavation and waste transfer for a landfill site would be about \$2.0 billion.²⁴ For surface impoundments, the appropriate parameters are 145 acres, or about 587,000 square meters, and a volume of about 5 million cubic meters, which works out to about \$2.1 billion for the same type of corrective action. If this type of corrective action were required at all power plants, compliance costs for the industry would be enormous. At a cost of about \$2 billion per plant, industry-wide costs would exceed one trillion dollars.

6.2.2.4 Closure and Post-closure

Subpart G of 40 CFR 264 specifies general closure and post-closure requirements for Subtitle C facilities and 40 CFR 264(K) and (N) list specific

requirements for closure and post-closure care of surface impoundments and landfills, respectively. These requirements, as applied to coal combustion wastes, would require the dewatering of ash ponds, installation of a suitable cover liner made of synthetic materials, application of topsoil to support vegetation, seeding and fertilizing, installation of security fencing, and long-term ground-water monitoring. USWAG estimates that capital costs for closing a waste management facility range from \$39,000 to \$128,000 per acre for surface impoundments and from \$55,000 to \$137,000 per acre for landfills.²⁵ Once the facility is closed, additional costs would be incurred for post-closure care -- about \$1,050 per acre annually.²⁶ Total annual costs for closure of a surface impoundment would range from about \$1.0 to \$2.8 million for a typical 500 Mw power plant, or \$5.00 to \$14.75 per ton of waste managed. For a landfill, total annual costs would range from \$0.4 to \$0.9 million, or \$2.10 to \$4.90 per ton.²⁷

An owner or operator that chooses to close a facility in the event that coal combustion wastes are brought under Subtitle C regulation would not necessarily have to follow the closure and post-closure requirements for hazardous waste facilities listed in 40 CFR Part 264. If regulations are proposed, there would be some period of time before final regulations take effect.²⁸ If the disposal facility is closed during this interim period, the closure standards that would apply would be those required under state regulations, not Subtitle C regulations.

A facility that closes after the new regulations take effect, however, is subject to Subtitle C closure and post-closure requirements. The USWAG study provides an estimate of the total costs of closing all existing coal combustion

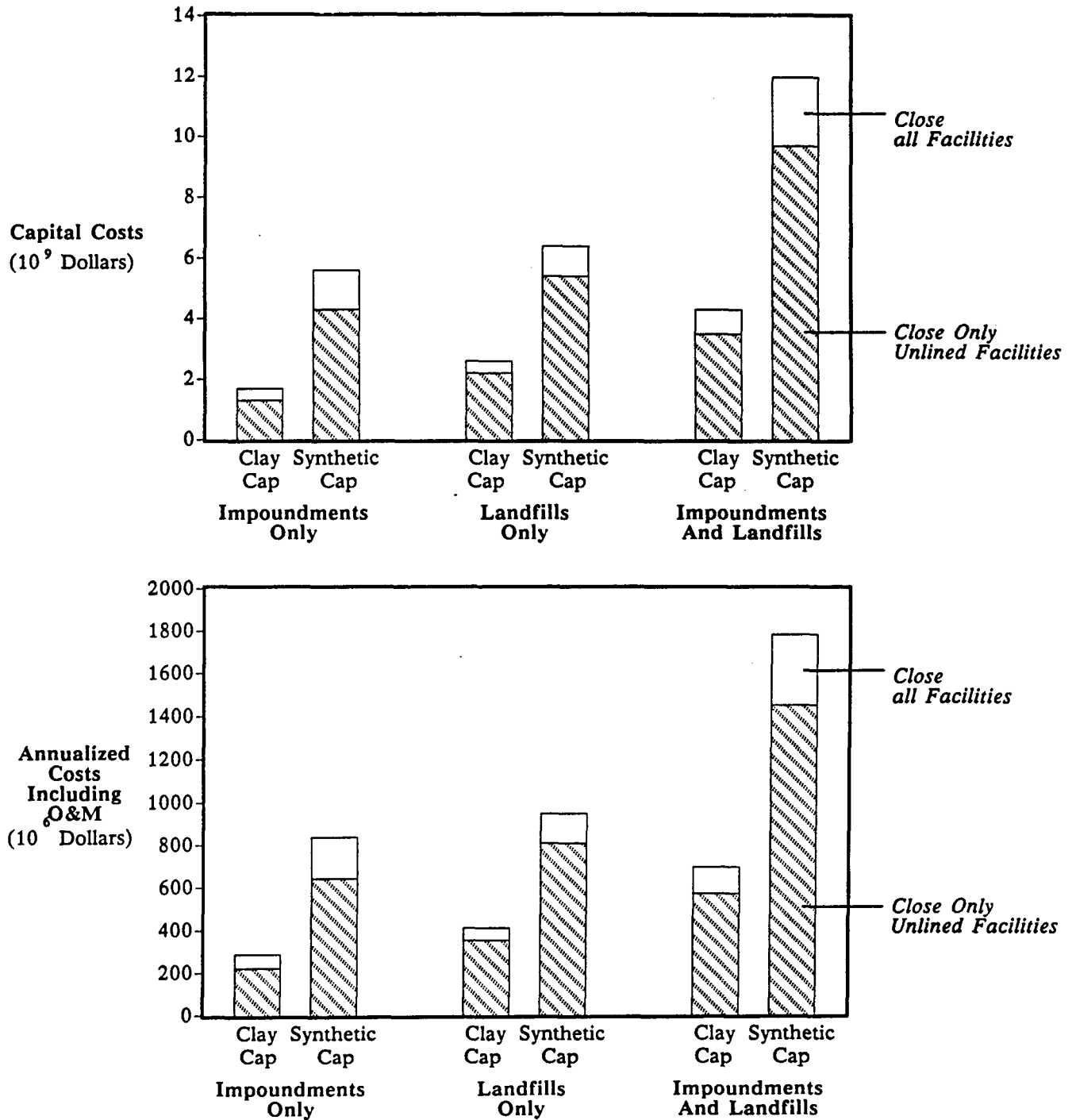
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waste disposal facilities and of the costs of closing only unlined facilities (See Exhibit 6-5). Total capital costs required to close all unlined landfills and impoundments would range from \$3.5 billion for clay-capped facilities to \$9.7 billion for synthetic-capped facilities. If all facilities closed under Subtitle C regulation, total capital costs would be about \$4.3 billion for clay-capped closure and \$12.0 billion for synthetic-capped closure.²⁹ Total annualized costs to close only unlined facilities would range from about \$575 million for closure with clay caps to about \$1.5 billion for synthetic caps. If all current waste management facilities were closed, annualized costs would be about \$700 million for clay caps to \$1.8 billion for synthetic caps.

6.2.2.5 Financial Responsibility

Subpart H of 40 CFR 264 sets forth requirements for financial responsibility for closure and post-closure care of hazardous waste facilities. A facility owner may use several different financial mechanisms to demonstrate financial responsibility, including purchasing a letter of credit, posting a surety bond, establishing a trust fund, purchasing an insurance policy, providing a corporate guarantee, or passing a financial test. Financial responsibility could be required for closure/post-closure costs or corrective action costs. The magnitude of the costs can vary considerably depending on the financial mechanism that is used and the type of activity for which financial assurance is required. For example, costs to provide a corporate guarantee or pass a financial test may be on the order of a few hundred dollars per facility; on the other hand, annual costs to obtain a letter of credit or to establish a trust fund are often based on some percentage (e.g., one to two percent) of the total

EXHIBIT 6-5
SUMMARY OF COSTS TO CLOSE
EXISTING WASTE DISPOSAL FACILITIES



Source: EnviroSphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal," in USWAG, *Report on the Costs of Utility Ash and FGD Waste Disposal*, Appendix F Part 2, October 19, 1982.

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costs of the closure/post-closure or corrective action activity to be undertaken.³⁰

6.2.2.6 Design and Operating Requirements for Landfills and Surface Impoundments

The level of effort required to come into compliance with Subtitle C design and operating requirements will depend on many site-specific considerations. In some cases, it may be possible to seal off the portion of the existing disposal site that has been in use and upgrade the remaining portion by installing a liner. In other situations the required changes may be sufficiently different from existing disposal practices that the most cost-effective action may be to open an entirely new disposal facility.

Given the variety of site-specific situations that may arise, and given the regulatory flexibility EPA has in designing coal combustion waste management standards, it is not feasible to estimate how many utility waste management facilities may be affected or what type of waste management measures may be required without conducting site-specific investigations. Nevertheless, to indicate the approximate magnitude of costs that may be involved for different waste management practices, the costs for three management options -- single-lined landfills, single-lined surface impoundments, and double-lined surface impoundments -- are presented below.

Landfills

As noted earlier, single clay liners can be installed in a landfill for

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about \$0.70 to \$2.55 per ton of disposed waste and single synthetic liners for about \$1.45 to \$4.15 per ton of disposed waste. The costs presented in Exhibit 6-4 indicate that waste disposal costs at a representative 500 Mw power plant with no flue gas desulfurization equipment would average about \$5 to \$11 per ton of disposed waste for a landfill operation. Adding a single clay liner to the landfill would increase total costs to \$5.70 to \$13.55 per ton of disposed waste; adding a single synthetic liner would increase costs to \$6.45 to \$15.15 per ton of disposed waste.

These estimates appear to be similar in magnitude, although somewhat lower than costs estimated in another study of utility waste disposal costs conducted for the Utility Solid Waste Activities Group (USWAG) by Econometric Research, Inc. That study estimated that total costs for complying with requirements related to the construction, operation, and maintenance of a single-lined landfill would range from about \$15 to \$24 per ton of waste, depending on the type of liner.³¹

The study for USWAG also analyzed the total costs to the electric utility industry if all power plants currently using landfills were required to construct new landfills with single liners. For this scenario, USWAG assumed that existing facilities, even if lined, would have to be replaced to comply with new requirements. Total capital costs for this alternative would range from \$2.6 billion for landfills with one synthetic liner to \$4.0 billion for landfills with a single clay liner.³² Estimated annualized costs were about \$400 million for installing a single synthetic liner at all landfills and about \$600 million for installing a single clay liner.³³

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Surface Impoundments

The costs presented in Exhibit 6-4 for unlined surface impoundments indicated that waste managed at a representative 500 Mw power plant with no FGD waste production would cost about \$8 to \$17 per ton of waste. Using the cost estimates for liners noted earlier (see Section 6.1.2), adding a single clay liner would increase total management costs to about \$10.25-\$25.20 per ton of waste, and adding a synthetic liner would increase costs to \$12.70-\$30.45 per ton of waste.

These cost estimates for single-lined impoundments appear to be reasonably consistent with other estimates. Studies for USWAG indicated that management costs for impoundments with a single synthetic liner were about \$19 per ton of waste and \$30 per ton of waste for impoundments with a single clay liner.³⁴

The USWAG report also estimated the total costs to the electric utility industry to construct new impoundments with single liners (i.e., all power plants currently using surface impoundments would be required to construct new facilities to meet disposal requirements even if the current impoundment is already lined). For this alternative total capital costs would range from \$5.8 billion for impoundments with single synthetic liners to \$9.5 billion for impoundments with single clay liners.³⁵ Annualized costs would range from \$850 million for single synthetic liners at all impoundments to \$1.4 billion for single clay liners.³⁶

The study for USWAG also estimated management costs for surface impoundments with two different types of double liners -- a double synthetic liner (each with

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a 30 mil thickness) and a double liner system consisting of one synthetic liner (30 mil) and a clay liner (36 inches). Total management costs for double-lined surface impoundments would range from about \$29 per ton of waste for a site with two synthetic liners to \$36 per ton of waste for a site with one synthetic liner and one clay liner.³⁷

Industry-wide costs were also estimated for the installation of new double-lined surface impoundments at all power plants currently using surface impoundments. Total capital costs for installing a double-lined impoundment ranged from \$9.3 billion for a double synthetic liner to \$11.6 billion for one clay and one synthetic liner.³⁸ Total annualized costs were estimated at \$1.4 billion for all impoundments with a double synthetic liner and \$1.7 billion for all impoundments with one clay liner and one synthetic liner. A summary of the costs for the various types of lined disposal facilities discussed herein is presented in Exhibit 6-6.

6.2.2.7 Summary of Costs for Various Waste Management Alternatives

Exhibit 6-7 summarizes the costs to the electric utility industry of each of the waste management options previously discussed. The exhibit presents cost estimates for the total amount of capital required for each waste management standard and for the total amount of annualized costs (i.e., annual capital, operation, and maintenance costs) that would be incurred in order to comply with each requirement if coal-fired combustion wastes were regulated as hazardous wastes.

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EXHIBIT 6-6**SUMMARY OF COSTS FOR DIFFERENT TYPES
OF LINED WASTE MANAGEMENT FACILITIES**

	<u>Cost per ton</u>	<u>Total Annual Costs for the industry ^{a/} (millions of dollars)</u>
<u>Landfills</u>		
Basic Practice--Unlined	\$ 5.00-\$11.00	N.A.
Single Clay Liner	\$ 5.70-\$13.55	600
Single Synthetic Liner	\$ 6.45-\$15.15	400
<u>Surface Impoundments</u>		
Basic Practice--Unlined	\$ 8.00-\$17.00	N.A.
Single Clay Liner	\$10.25-\$25.20	1,380
Single Synthetic Liner	\$12.70-\$30.45	865
Double Synthetic Liners	\$29.00	1,360
Double Liners:		
1 Synthetic and 1 Clay	\$36.00	1,680

a/ Total annual costs refer to annualized costs that capture capital, operation, and maintenance expenses. Since these costs were calculated by assuming that the utility industry would have to construct new facilities to comply with hypothetical alternative regulations, these costs are in addition to the current management costs incurred by the industry.

Source: Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal." In USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982.

Preparation of Part B Permit

Construction of New Disposal
Facilities

Landfills

- Single clay liner
- Single synthetic liner 2.6

Surface Impoundments

- Single clay liner 9.5 1400
- Single synthetic liner 5.8 850
- Double liner
- clay/synthetic 11.6 1700
- two synthetic 9.3 1400

Closure of Existing Disposal
Facilities

Only Unlined Facilities Close

- Clay cap 3.5 575
- Synthetic cap 9.7 1500

All Facilities Close

- Clay cap 4.3 700
- Synthetic cap 12.0 1800

Installation of Leachate
Collection Systems

1.2 460

Provisions for Flood Protection

- Landfills 0.15 20
- Impoundments 0.09 13

Ground-water Monitoring Systems

0.009-0.013 6-9

Excavate Existing Facilities,

Removing Waste to Subtitle C Facilities 1028.0 a/ NA

a/ Costs shown are for capital, operation, and maintenance costs for the entire industry since the amount of capital required was not readily available.

A combination of compliance alternatives could occur (e.g., closing existing disposal facilities and constructing new facilities with leachate collection and ground-water monitoring systems). The actual cost to the electric utility industry for complying with RCRA Subtitle C requirements would depend on the regulatory actions taken by the Agency if the temporary exemption under Section 3001 of RCRA is removed. Three possible regulatory scenarios are discussed in the following section.

6.2.3 Potential Costs to the Industry of RCRA Subtitle C Waste Management

Section 6.2.2 presented cost estimates for individual regulatory requirements that could be imposed on utilities if EPA determines that Subtitle C regulation is warranted for coal combustion wastes. In this section, three possible regulatory scenarios are examined to quantify the range of incremental costs that could result from various regulatory options. In the first scenario, the incremental costs of regulating a portion of low volume wastes under Subtitle C are presented. The second scenario assumes that all coal combustion waste would be subject to Subtitle C requirements. The third scenario assumes that high volume coal combustion wastes would be tested for RCRA hazardous characteristics and that a small portion of the waste would be classified as Subtitle C characteristic waste. For all three regulatory scenarios, costs are shown only for bringing all existing power plants into compliance with the assumed RCRA Subtitle C management regulations.

Low Volume Waste Scenario

This scenario evaluates the costs to the utility industry if some low volume waste streams are classified as hazardous wastes under Subtitle C. As discussed in Chapter Three, some of these wastes can exhibit hazardous characteristics such as corrosivity. The information available to EPA at this time does not permit the Agency to quantify the amount of low volume wastes that may exhibit hazardous characteristics. In this scenario, EPA has assumed that all water-side boiler cleaning wastes are regulated as hazardous wastes since these waste streams may exhibit corrosive characteristics. These waste streams are assumed to be hazardous to provide an approximate estimate of the costs to the industry if some low volume wastes display RCRA hazardous characteristics. That is, both high-volume and low-volume wastes could be tested for RCRA hazardous characteristics, but only a small portion of the low-volume wastes (as represented by all water-side boiler cleaning wastes) would need to be treated as hazardous.

As shown in Exhibit 3-19, a representative power plant generates about 180,000 gallons per year of water-side boiler cleaning wastes. The cost to dispose of these wastes as hazardous liquids can vary depending on waste stream variability, regional differences in disposal costs, and quantity to be disposed, among other factors.³⁹ For purposes of this analysis, an incremental cost of \$2 per gallon (including transportation) has been assumed based on a 1985 survey of hazardous waste management prices.⁴⁰ With 180,000 gallons generated per year at a representative power plant, annual disposal costs would be about \$360,000 per power plant. Since there are 514 power plants in the U.S., annual disposal costs to the utility industry would be about \$185 million.

Full Subtitle C Regulation Scenario

If EPA lists high volume coal combustion waste streams in 40 CFR 261.31-261.33, all utilities will be affected. Utilities would be required to manage all coal combustion wastes in Subtitle C permitted facilities. To estimate the incremental costs to the industry of this regulatory scenario, the Agency assumed that all utilities would close existing facilities and open new waste management facilities that complied with Subtitle C standards. This scenario assumes that the costs of managing wastes off-site will equal the costs of managing wastes on-site and that existing facilities would be closed in the six months before Subtitle C regulation took effect, thereby avoiding Subtitle C closure and post-closure requirements.

Under existing state regulations, a clay cap is assumed to be adequate to close existing waste management facilities. The total annual costs of closing all existing facilities with a clay cap would be \$700 million. For the new facilities, EPA assumed utilities would prepare a Part B permit application, construct new landfills and surface impoundments with clay/synthetic double liners, install leachate collection systems, make provisions for flood protection, and install ground-water monitoring systems. To determine incremental costs for the industry, EPA assumed that the current proportions of waste management facilities that were landfills and surface impoundments would remain unchanged under Subtitle C regulation. As summarized in Exhibit 6-7, total annual costs of the new Subtitle C facilities would be \$54 million for Part B permit applications, \$725 million for new double lined landfills,⁴¹ \$1700 million for new double lined surface impoundments, \$460 million for leachate

collection systems, \$33 million for flood protection, and \$9 million for ground-water monitoring. Total incremental costs for this regulatory scenario would be \$3.7 billion annually.⁴²

High Volume Characteristic Waste Scenario

If coal combustion wastes were not exempt from RCRA Subtitle C regulation, utilities would have to test high-volume and low-volume coal combustion wastes for RCRA hazardous characteristics. Based on the RCRA characteristic results in Chapter Five, it appears that only a small portion of coal combustion wastes possess the hazardous characteristics of EP Toxicity or corrosivity. For purposes of this scenario, the Agency assumed that five percent of the wastes generated by utilities would need to be disposed in Subtitle C permitted facilities. The Agency does not have sufficient information to know exactly the amount of coal combustion waste that would exhibit RCRA hazardous characteristics. EPA believes that coal combustion wastes generally would not fail the RCRA hazardous characteristic tests. Based on limited information presented in Chapter Five that indicate about five percent of all ground-water observations at utility sites exceed the Primary Drinking Water Standards, the Agency assumed that five percent of all wastes would require Subtitle C treatment. The total annual cost to the industry if utilities close existing facilities and construct new double lined facilities for five percent of all coal combustion wastes would be \$185 million.

6.3 IMPACT OF REGULATORY ALTERNATIVES ON UTILIZATION OF COAL COMBUSTION WASTES

As discussed in Chapter Four, coal-fired utility wastes have been used in a

variety of applications by electric utilities and other industries to replace other types of material. The use of utility wastes as a replacement for other materials has reduced the amount of wastes utilities have had to dispose, while correspondingly reducing the resource requirements of other industries that have managed to find a productive use for the waste material.

In the event that some or all of these wastes were declared hazardous, it is possible that the amount of by-product utilization of coal-fired utility wastes would decline as a result of increased costs for their use and the potential for outright prohibition of their use in some applications. On the other hand, it is possible that certain forms of utilization (e.g., the use of fly ash in cement) may be deemed environmentally acceptable practices if the wastes would be unlikely to pose an environmental threat when used for such purposes. Since costs for other forms of disposal may increase, utilization may also increase. However, for discussion purposes, this section assumes that designation as a hazardous waste would tend to discourage by-product utilization.

The costs that would be incurred as a result of environmental concerns over the utilization of coal-fired utility wastes would depend on the regulatory requirements that would have to be followed to use the wastes. The more stringent the additional regulatory burden imposed, the greater the impact on by-product utilization due to the higher costs of using the wastes.

In the USWAG study referenced above, the potential range of costs associated with reduced use of coal combustion by-products was also evaluated. Three different regulatory scenarios were analyzed.⁴³

- The transportation of coal-fired utility wastes is regulated as hazardous waste transportation under Subtitle C of RCRA; use or disposal of the wastes would not be regulated.
- All activities associated with reuse of coal combustion by-products is regulated, and the regulations affect both the transporter and owner/operator of a Subtitle C hazardous waste management facility.
- Reuse of coal combustion by-products is prohibited.

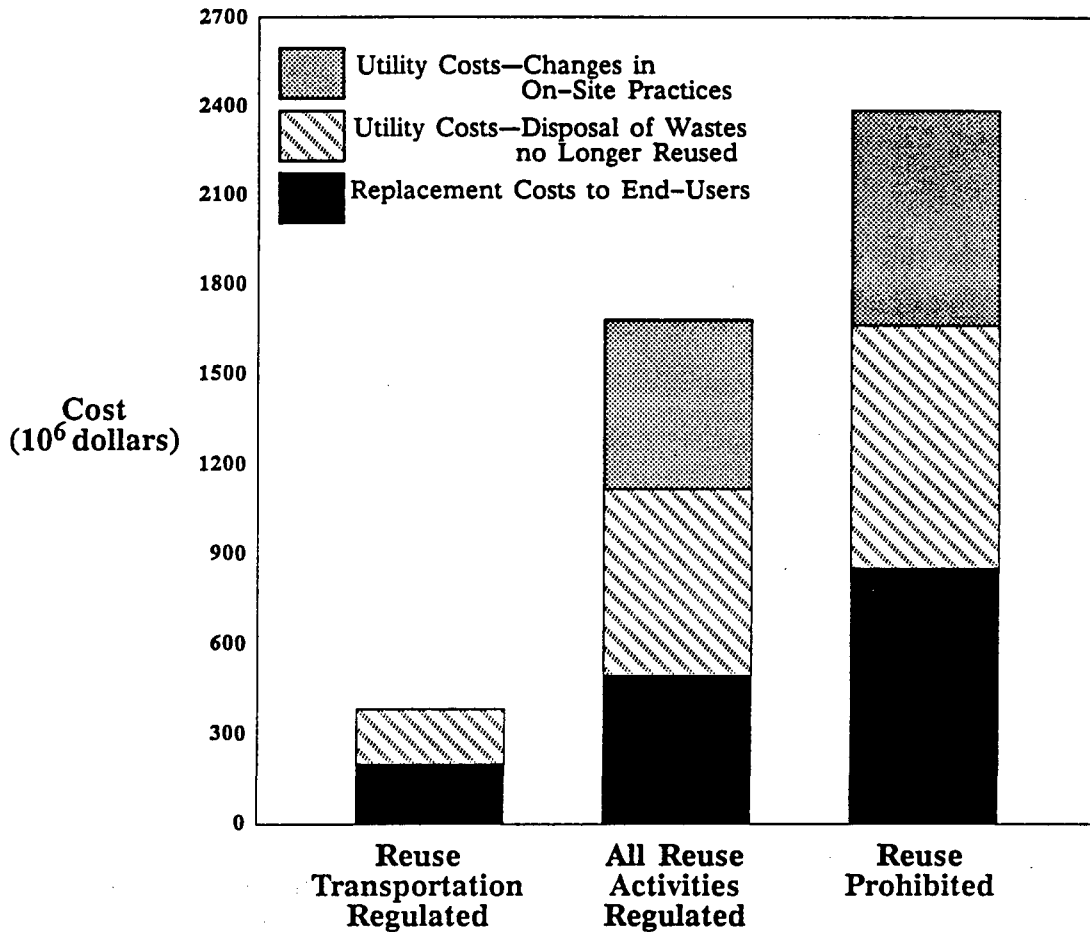
There would be three types of costs incurred under these regulatory scenarios: (1) replacement costs to the end-users who would no longer find it economic to utilize the coal combustion by-products, (2) costs to utilities to dispose of wastes no longer reused by other industries, and (3) additional costs to the utility industry for replacement and disposal of wastes that could no longer be used on-site. A summary of the costs associated with each scenario is provided in Exhibit 6-8.⁴⁴

If the transportation of coal combustion by-products were subject to increased regulation under Subtitle C, the USWAG report estimated that the use of these by-products would decline by nearly 40 percent, increasing overall disposal volumes by about 8 percent.⁴⁵ The industries that would be affected the most would be the roofing granules industry (conventional roofing granules would replace bottom ash and boiler slag at a cost of about \$115 million in annual costs) and the concrete industry (portland cement would replace fly ash at a cost of about \$40 million in annual costs).⁴⁶

If all activities pertaining to reuse of coal combustion wastes were subject to Subtitle C regulations, utilization of coal combustion

EXHIBIT 6-8

Summary of Economic Impacts on By-Product Utilization under Different RCRA Regulatory Scenarios*



* All costs are annualized based on impacts estimated from 1984-2000.

Source: USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix G, October 26, 1982

by-products was estimated to decline by about 75 percent, increasing overall disposal volumes by about 14 percent.⁴⁷ The greatest impact would be on the concrete industry, which would spend about \$270 million annually to replace fly ash with portland cement.⁴⁸

If all reuse of coal combustion by-products were prohibited, industries using these by-products would have to find suitable replacements; total disposal volumes would increase by nearly 20 percent.⁴⁹ The largest impacts would be on the asphalt industry, which would be forced to replace ash with asphalt at a cost of approximately \$250 million annually, and the concrete industry, which would replace fly ash with portland cement at a cost of about \$270 million annually.⁵⁰

6.4 ECONOMIC IMPACTS OF ALTERNATIVE WASTE DISPOSAL OPTIONS

Since many alternative disposal practices discussed in this chapter could impose additional costs on the electric utility industry, this section evaluates the effect that these increased costs might have on electricity generation costs and U.S. coal consumption. This study employs three measures to determine the potential economic impact of alternative disposal practices:

1. Average increase in electricity generation costs at existing coal-fired power plants,
2. Average increase in electricity generation costs at coal-fired power plants yet to be constructed, and
3. Impact on the electric utility industry's consumption of coal.

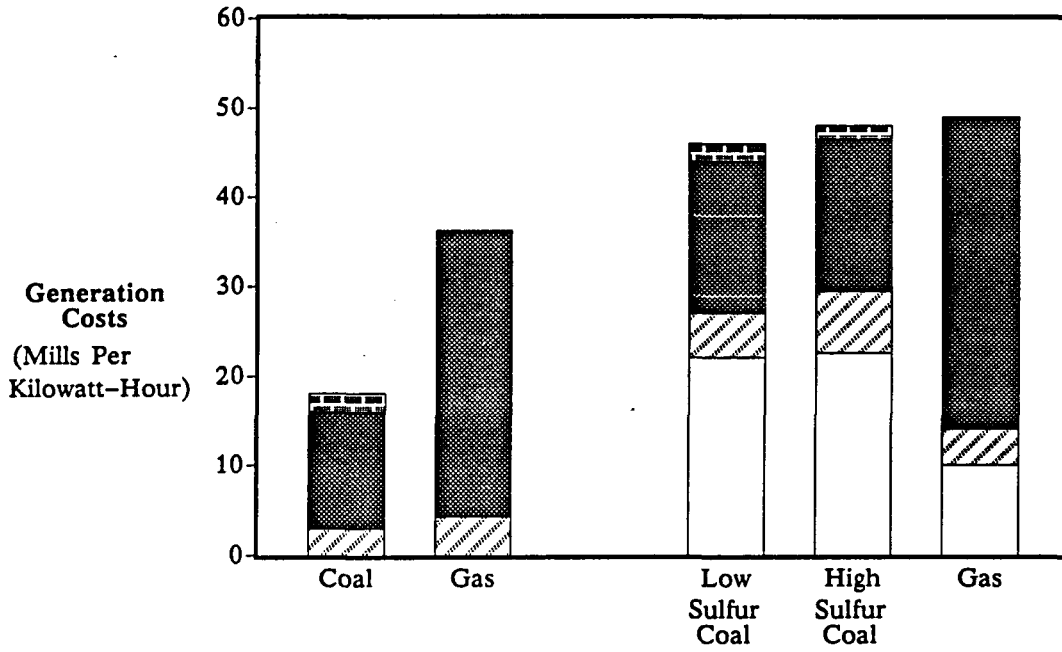
Exhibit 6-9 summarizes the cost of generating electricity at both existing and yet-to-be-constructed power plants (see Appendix G for a detailed discussion of the assumptions used to determine these generation costs).⁵¹ Disposal costs average about 3-5 percent of total generation costs at existing coal-fired power plants, but only about 1-3 percent at future power plants. Although the actual costs of disposal at existing and future power plants are similar, the percentages are different because total generation costs at future power plants are higher than generation costs at existing power plants (resulting in a lower overall percentage for disposal costs at future power plants). Total generation costs are higher at future power plants because they include capital, operation and maintenance, and fuel costs, while the generation costs for existing power plants include operation and maintenance and fuel costs only.⁵² Based on the cost assumptions used to develop Exhibit 6-9, coal-fired electricity generation at both new and future baseload⁵³ power plants is less expensive than generation with natural gas.⁵⁴

The economic impacts likely to result from the use of alternative coal-fired utility waste disposal practices will depend upon several factors, including which disposal options are required, how much the cost of coal-fired electricity generation changes, and whether these changes affect the relative competitiveness between coal and other fuels. To indicate the potential magnitude of these impacts, Exhibit 6-10 summarizes the potential cost impacts on electricity generation rates due to the alternative waste disposal options discussed earlier in this chapter.

As indicated in Exhibit 6-10, some alternative disposal options could





EXHIBIT 6-9

**IMPACT OF CURRENT WASTE DISPOSAL COSTS
ON TOTAL ELECTRICITY GENERATION COSTS***



Existing Power Plant

Future Power Plant

-  Disposal Cost
-  Fuel
-  Operation and Maintenance
-  Capital

* Generation costs are based on typical 500 Mw power plant in the midwest operating at 70 percent utilization rate. Regional costs will vary depending on fuel price and availability, among other factors.

Source: Generation cost estimates are from ICF Incorporated. Waste disposal costs are taken from Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*. June 1985.

EXHIBIT 6-10

IMPACT OF ALTERNATIVE DISPOSAL OPTIONS ON ELECTRICITY GENERATION COSTS

Option	Incremental Cost (\$/ton of disposed waste)	Impact On Generation Costs		
		a/ mills/kilowatt-hour	% of Total Generation Costs Existing Plant Future Plant	
Part B Permit	\$0.55	0.03	0.2	0.1
<u>Existing Landfills b/</u>				
Single Clay Liner	\$0.70-\$2.55	0.04-0.16	0.2-0.9	0.1-0.3
Single Synthetic Liner	\$1.45-\$4.15	0.09-0.26	0.5-1.4	0.2-0.6
<u>Existing Surface Impoundments</u>				
Single Clay Liner	\$2.25-\$8.20	0.14-0.51	0.8-2.8	0.3-1.1
Single Synthetic Liner	\$4.70-\$13.45	0.30-0.84	1.7-4.7	0.6-1.8
<u>New Landfills</u>				
Single Clay Liner	\$ 5.70-\$12.55	0.36-0.79	2.0-4.4	0.8-1.7
Single Synthetic Liner	\$ 6.45-\$15.15	0.40-0.95	2.2-5.3	0.9-2.0
<u>New Surface Impoundments</u>				
Single Clay Liner	\$10.25-\$25.20	0.64-1.58	3.6-8.8	1.4-3.4
Single Synthetic Liner	\$12.70-\$30.45	0.80-1.91	4.4-10.6	1.7-4.1
Double Synthetic Liner	\$29.00	1.82	10.1	3.9
Double Synthetic/ Clay Liner	\$36.00	2.26	12.6	4.8
Site Closure	\$2.10-\$14.75	0.13-0.93	0.7-5.2	0.3-2.0
Leachate Control	\$4.70	0.30	1.7	0.6
Flood Protection	\$0.25-\$0.55	0.02-0.03	0.1-0.2	ε/
Ground-water Monitoring	\$0.06-\$0.10	0.004-0.006	ε/	ε/
Utilization				
Transportation				
Regulated	\$3.00	0.19	1.1	0.4
All Activities				
Regulated	\$13.20	0.83	4.6	1.8
Reuse Prohibited	\$18.75	1.18	6.6	2.5

a/ Based on a representative 500 Mw plant operating at a 70 percent utilization rate. Costs are incremental costs only; that is, cost impact of new disposal facilities is only that portion of costs in excess of current disposal costs (see Exhibit 6-4 for these costs). A mill is one-tenth of a cent (\$0.001).

b/ Costs for existing waste disposal facilities refer only to the cost of liner installation. Costs for new waste disposal facilities refer to all the costs for site construction and liner installation.

ε/ Less than 0.1 percent.

increase electricity generation costs at existing power plants by several percent. In some cases the cost impact could be substantial if several options were combined as part of an integrated waste management strategy. For example, if new waste management regulations led to closure of the current disposal site and the construction of a new lined facility with a leachate control system, flood protection, and ground-water monitoring system, coal-fired generation costs at existing coal-fired power plants could increase by nearly 20 percent (roughly 3.5 mills/kilowatt-hour).

Generation cost increases of this magnitude have the potential to reduce coal consumption at existing coal-fired power plants if these cost increases make it more expensive to generate electricity with coal than with other fuels. A utility decides how much electricity to generate at any existing power plant primarily by comparing the operation and maintenance costs (including fuel) associated with generating electricity at all of its power plants. Power plants with the lowest generation costs will be operated first. Generally, it is less expensive to generate electricity with coal than with other fuels such as oil or gas, but oil-fired electricity generation can be competitive with coal when the price of oil is approximately \$10-\$15 per barrel.⁵⁵ However, whether and to what degree electric utilities would shift away from the use of coal would depend on several factors, including the relative price of coal compared with the price of other fuels, the magnitude of the increase in generation costs if disposal practices were altered, and the overall efficiency of competing power plants.

For power plants yet to be constructed, the impact of higher disposal costs on coal consumption could be more substantial, with possible generation cost

increases approaching 8-10 percent if several options are combined. Generation cost increases of this magnitude could have a substantial effect on the amount of coal consumed at future power plants since many utilities may decide not to build coal-fired power plants. Although currently coal-fired electricity generation may be a more economic option than oil-fired or gas-fired generation at plants yet to be constructed, this situation could change if more expensive disposal practices were required for coal combustion wastes. This is because the higher capital costs of coal-fired electricity generation, compared with oil- or gas-fired generation, reduces the overall cost differential between the use of coal and the use of oil or gas at future power plants (compared to the cost differential between coal and oil or gas at existing power plants). As a result, coal is more likely to be replaced by alternative fuels at future power plants than it is at existing power plants.

In fact, since oil prices dropped below \$20 per barrel in early 1986, many utilities have been seriously evaluating the feasibility of building oil- or gas-fired generating capacity in lieu of coal-fired units. As a result, in some instances even an increase of a few percent in coal-fired generation costs could be sufficient to tip the balance in favor of using natural gas or oil to fuel power plants that have not yet been constructed. If increased disposal costs do promote such competition, growth in future U.S. consumption of coal would probably decline. The exact magnitude of this decrease in future coal consumption would depend on many factors, including the type of new waste disposal practices adopted and the price of alternative fuels in different regions of the country. An in-depth analysis of the potential impact of alternative waste management scenarios on electric utility generation practices and investment decisions and, as a result, the level of coal consumption, is

beyond the scope of this Report to Congress. However, EPA intends to seek more information and analysis on the issue of economic impacts through the public hearing process and through its own additional investigations. As required by law EPA will conduct the appropriate regulatory impact analyses, including the economic impact analysis, during the six month public review period following submission of this report to Congress if it is determined that current utility waste management practices for coal-fired combustion wastes are inadequate and additional regulations are warranted.

6.5 SUMMARY

The cost to manage coal combustion waste in basic waste management facilities currently ranges from as little as \$2 to as much as \$31 per ton. The wide range in management costs is primarily due to differences in (1) the type of facility, (2) the size of the facility and (3) the characteristics of the waste.

- Some facilities currently incur additional costs because they have undertaken additional safeguards against leaching, including liner installation, leachate collection and treatment, and ground-water monitoring.
- Management costs at surface impoundments tend to be greater than those at landfills because of the higher costs of site preparation at impoundments.
- The size of larger waste disposal facilities allows them to operate more efficiently, which tends to reduce the cost per ton of waste management.
- Fly ash is typically more expensive to manage than bottom ash or FGD waste because of additional requirements for collection, handling, and treatment prior to disposal.

- If additional regulations are promulgated requiring electric utilities to alter the current methods by which they manage coal-fired wastes, additional costs may be incurred by the industry as it complies with the new requirements.
- The most common practice for controlling leaching at a waste management site is installation of a liner prior to placement of the waste. Liners are usually made of low permeable clay or a synthetic material and can be installed in one or more layers. The cost of installing a liner ranges from \$0.70 to \$8.20 per ton of waste for clay liners and \$1.45 to \$13.45 per ton for synthetic liners. Total disposal costs for single-lined landfills range from about \$6 to \$15 per ton of waste, while costs for single-lined surface impoundments range from \$10 to \$30 per ton. Industry-wide costs to construct and install lined management facilities could range from \$0.4 to \$1.7 billion on an annualized basis, depending on type of facility, type of liner material, and number of liners installed.
- Installation of leachate collection systems to control potential environmental problems that might result from substances leaching from a waste management site could cost about \$4 to \$5 per ton of waste. Total costs to the utility industry to install leachate collection systems could be \$1.2 billion in capital costs, or about \$460 million in annualized costs.
- The cost of installing a ground-water monitoring system to detect the presence and concentration of various waste constituents in the ground water surrounding a waste management facility is generally less than \$0.25 per ton of waste. Total capital requirements to the industry would likely range from \$9 to \$13 million, with annual costs of \$6 to \$9 million.
- If coal combustion wastes were regulated under Subtitle C of RCRA, costs to the utility industry could approach \$3.7 billion annually if all wastes were listed as hazardous. Costs would be substantially lower than \$3.7 billion annually if coal combustion wastes were tested for hazardous characteristics since only a small portion of coal combustion wastes would be likely to fail the RCRA hazardous characteristic tests. These costs to comply with Subtitle C do not include corrective action costs or the higher costs that may be associated with recycling coal combustion wastes; these costs to the utility industry could be very high.

- New waste management practices could increase the cost of generating electricity at existing coal-fired power plants by nearly 20 percent in some cases. Although coal is generally the preferred boiler fuel at existing power plants, an increase of this magnitude could cause a decline in the amount of coal consumed at these power plants if alternative fuel prices were reasonably competitive.
- If new management practices are required at future power plants, the increase in generation costs is unlikely to exceed 10 percent. Although on a percentage basis this increase would be less than the percentage increase possible at existing power plants, the choice of fuels at future power plants is much more competitive (due to the capital costs that must be included in the costs of a future power plant). In some instances this could lead to a decrease in coal consumption if the use of alternative fuels is found to be more cost effective since many utilities may decide not to build coal-fired power plants.

7 In one study, the cost of building and operating an artificial reef construction system was estimated to be about \$50 per ton, roughly double the amount estimated by the study authors for more conventional waste disposal. In those situations where space constraints or other factors would substantially increase the costs for conventional disposal, ocean disposal through reef construction was seen as an economically viable option. See J.H. Parker, P.M.J. Woodhead, and I.W. Dued all, "A Constructive Disposal Option for Coal Wastes -- Artificial Reefs," in Proceedings of the Second Conference on Management of Municipal, Hazardous, and Coal Wastes, S. Sengupta (Ed.), September 1984, p. 134.

8 Arthur D. Little, p. 6-132. "Installed cost" of a liner (expressed in terms of cost per ton of disposed waste) refers to the increase in the cost of disposing of one ton of waste as a result of adding a liner to an unlined landfill or surface impoundment.

9 Ibid. The costs in the Arthur D. Little report were presented for an 18-inch clay liner. Costs were doubled to approximate the costs for installing a 36-inch clay liner, which is currently a more common practice. The dollar per ton estimate was derived by multiplying total capital costs by a 14.5 percent capital recovery factor to determine annual capital charges. Assuming that a 500 Mw power plant has a 45 acre landfill disposal site, total capital charges would range from \$945,000 to \$3.4 million, or about \$140,000 to \$490,000 in annualized charges. Assuming that a 500 Mw power plant would need a 145-acre wet surface impoundment, total costs would range from \$3.0 to \$10.9 million, or \$440,000 to \$1.6 million in annualized costs. These annualized charges were then divided by the amount of waste produced annually by a 500 Mw power plant with no FGD process, (i.e., 192,500 tons) to determine the dollar per ton cost. This approach is used throughout the report to calculate dollar per ton estimates. See Appendix G for more detail on this methodology.

10 Ibid. For landfills, total installed costs would range from \$1.9 to \$5.1 million per plant, assuming a 45-acre disposal site. Annual costs would range from about \$280,000 to \$740,000. Based on 192,500 tons of waste, the cost is \$1.45-\$3.85 per ton. For ponds (i.e., impoundments), total installed costs would be \$6.2-\$16.4 million, or \$900,000-\$2.4 million annualized. On a dollar per ton basis, this range is \$4.70-\$12.35.

11 Ibid. For landfills total installed costs would range from \$2.7-\$5.5 million, or about \$385,000-\$800,000 in annual costs per ton. This corresponds to \$2.00-\$4.15 per ton. Total installed costs for ponding operations are \$8.6-\$17.8 million, or \$1.2-\$2.6 million annualized. This corresponds to \$6.45-\$13.45 per ton.

12 Ibid.

13 Total capital costs for landfills of \$3.0 to \$5.0 million correspond to annual charges of about \$430,000 to \$720,000. Assuming 192,500 tons of waste, the per ton cost is \$2.25 to \$3.75. Using the same approach to derive disposal costs at a 145-acre lined impoundment yields \$7.20 to \$12.00 per ton.

14 A waste management unit is not subject to regulation under Section 264.1 if the Regional Administrator finds that the unit (1) is an engineered structure, (2) does not receive or contain liquid waste or waste containing free liquids, (3) was designed and is operated in such a way to exclude liquids, precipitation, and other run-on and run-off (4) has both inner and outer layers of containment enclosing the waste, (5) has a leak detection system built into each containment layer, (6) will have continuing operation and maintenance of these leak detection systems during its active life and throughout the closure and post-closure care periods, and (7) is constructed in such a way that, to a reasonable degree of certainty, hazardous constituents will not migrate beyond the outer containment layer prior to the end of the post-closure care period. (40 CFR 264.90(b)(vii).

15 See 40 CFR 246.143.

16 These specified wastes are liquid hazardous wastes that have a pH less than or equal to 2.0 and/or (1) free cyanides at concentrations greater than or equal to 1,000 mg/l, (2) arsenic and/or arsenical compounds at concentrations greater than or equal to 500 mg/l, (3) cadmium and/or cadmium compounds at concentrations greater than or equal to 100 mg/l, (4) chromium and/or chromium compounds at concentrations greater than or equal to 500 mg/l (5) lead and/or lead compounds at concentrations greater than or equal to 500 mg/l, (6) nickel and/or nickel compounds at concentrations greater than or equal to 134 mg/l, (7) mercury and/or mercury compounds at concentrations greater than or equal to 20 mg/l, (8) selenium and/or selenium compounds at concentrations greater than or equal to 100 mg/l, (9) thallium and/or thallium compounds at concentrations greater than or equal to 130 mg/l, (10) polychlorinated biphenyls at concentrations greater than or equal to 50 mg/l, (11) halogenated organic compounds at concentrations greater than or equal to 1,000 mg/kg.

17 EnviroSphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal", in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982, p. 21, Appendix F, part 2. Dollar per ton estimates were determined by calculating annual costs (\$721,000 x 14.5 percent capital recovery factor = \$104,500). The capital recovery factor was applied to all costs since a breakdown of different types of costs required for a Part B permit was not available.

18 Ibid, p. 18.

19 Assuming a 145-acre impoundment site, costs would be about \$107,000. On a per ton basis, this corresponds to about \$0.55. For a 45-acre landfill with costs of \$1100 per acre, total costs would be about \$50,000, for a per ton cost of \$0.25.

20 EnviroSphere, in USWAG, Appendix F, Part 2, p. 27, 32.

21 Arthur D. Little, p. 6-133. On an annualized basis, capital costs would range from about \$2,650 to \$3,550.

22 EnviroSphere Company, in USWAG, Appendix F, Part 2, p. 37. EnviroSphere estimated that about four wells, one upgradient from the site and three downgradient, would be required for each 100 acre disposal site (or about six wells for a site of 145 acres) at a capital cost of approximately \$6,000 per well. Total capital costs for six wells would be \$36,000, which is about \$5,200 on an annualized basis. It was assumed that the wells would be sampled quarterly the first year, then semi-annually thereafter. The operation and maintenance costs would average about \$2,500 to \$3,000 per well, for facility costs (assuming six wells) of \$15,000 to \$18,000 per year. Total annualized costs, therefore, would range from \$20,200 to \$23,200, or \$0.10 to \$0.12 per ton of waste disposed.

23 For a more complete discussion, see ICF Incorporated, Liner Location Risk and Cost Analysis Model, Draft Phase II Report, Appendix F-2, Office of Solid Waste, U.S. Environmental Protection Agency, March 1987.

24 The cost equation on which this cost estimate is based was developed for typical RCRA Subtitle C landfills. Since these facilities tend to be much smaller than the size of utility disposal areas, extrapolating the cost equation for larger sizes may introduce some errors. Nevertheless, these cost estimates do indicate the approximate magnitude of corrective action costs that would likely be incurred.

25 Econometric Research, "The Economic Costs of Potential RCRA Regulations Applied to Existing Coal-Fired Electric Utility Boilers," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, p. 15, Appendix F, part 1.

26 Ibid, p. 15.

27 Ibid, p. 18. On a per acre basis, total annual costs range from \$6,700 to \$19,600 for surface impoundments and \$9,000 to \$21,000 for landfills. For a 145-acre impoundment, this corresponds to \$1.0 to \$2.8 million in total annual costs, or \$5.00 to \$14.75 per ton of waste. For landfills the per ton cost would be \$2.10 to \$4.90 based on total annual costs of \$0.4 to \$0.9 million.

28 See Administrative Procedure Act, U.S. Code 5 Sec. part 551.

29 Ibid, see pages 26 and 31 of the Econometric report for all closure costs.

30 For further discussion of the potential magnitude of these costs, see ICF Incorporated, Flexible Regulatory and Enforcement Policies for Corrective Action, prepared for U.S. Environmental Protection Agency, September 12, 1985.

31 Econometric Research, in USWAG, Appendix F, Part 1, p. 15. Econometric Research used capital costs for disposal of about \$5.20 per ton of waste produced over a 20-year life of the facility for synthetic liners and about \$8.10 per ton for clay liners, plus about \$0.06 per ton per year for operation and maintenance costs. Total initial capital outlays would then be \$104 per ton (\$5.20 per ton times 20 years) for synthetic liners, or about \$15.08 per ton on an annualized basis, and \$162 per ton (\$8.10 per ton times 20 years) for clay liners, or \$23.49 per ton on an annualized basis. With the addition of

the \$0.06 per ton for operation and maintenance costs, total costs would range from \$15.14 per ton for synthetic liners and \$23.55 per ton for clay liners for each ton of waste produced annually.

32 Ibid., p. 27. Total capital costs for existing power plants were assumed to be \$2.1 billion for single synthetic liners and \$3.2 billion for single clay liners. Since these cost estimates were based on a universe of 412 power plants, costs were adjusted upward by 514/412 to approximate total industry costs for the number of power plants estimated at the time of this study -- 514 power plants. This adjustment was made for all industry-wide costs cited from the USWAG report.

33 Ibid., p. 32.

34 Ibid., p. 18. Econometric Research, Inc., calculated that disposal costs for an impoundment with a single synthetic liner were about \$0.95 per ton of waste over the life of the facility and about \$1.50 per ton of waste for clay-lined impoundments. For a plant generating 192,500 tons each year for 20 years (or 3.85 million tons), that corresponds to 3.85 million tons x \$0.95 per ton = \$3.7 million for an impoundment with a single synthetic liner (or about \$19 per ton based on \$3.7 million divided by 192,500 tons of waste annually) and 3.85 million tons x \$1.50 per ton = \$5.8 million for an impoundment with a single clay liner (or about \$30 for each ton of waste disposed in a year).

35 Ibid., p. 26. The costs in the USWAG report were adjusted by 514/412 to account for the 514 power plants estimated at the time of this study compared to the 412 power plants assumed in the USWAG report.

36 Ibid. p. 31.

37 Ibid., p. 18. The double synthetic liner disposal system averages about \$1.45 per ton over the life of the facility and a system with one synthetic liner and one clay liner costs about \$1.80 per ton. At 3.85 million tons of waste over a 20 year facility life, that is \$5.6 million for a double synthetic liner (or about \$29 for each ton disposed in a year). For a combination synthetic/clay liner system, 3.85 million tons x \$1.80 per ton = \$6.9 million (or about \$36 per ton).

38 Ibid., p. 26.

39 ICF Incorporated, 1985 Survey of Selected Firms In The Commercial Hazardous Waste Management Industry, Prepared for U.S. Environmental Protection Agency, November 6, 1986.

40 Ibid.

41 To develop a cost estimate for landfills constructed with clay/synthetic double liners, the ratio of the cost of single clay and synthetic liners at landfills in Exhibit 6-7 to the cost of single clay and synthetic liners at surface impoundments was multiplied by the cost of clay/synthetic liners at surface impoundments.

42 The costs to close and cap existing facilities have been included in this estimate, while corrective action costs have not been included. Although closure costs will be incurred eventually by the industry, in most cases they would not be incurred for many years to come. To be conservative, EPA has included closure costs as part of potential RCRA Subtitle C compliance costs.

43 EnviroSphere Company, "Economic Analysis of Impact of RCRA On Coal Combustion By-Products Utilization." In USWAG, Report and Technical Studies On the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix G.

44 EnviroSphere Company, in USWAG, Appendix G. The costs in Exhibit 6-8 are based on estimated impacts between 1984 and 2000 and adjusted by a capital recovery factor of 14.5 percent to annualize the costs (total capital requirements were not identified). It was estimated that about 203 million tons of coal combustion by-products would be used over this period, with a similar amount used on-site by the utilities. That is, the costs assume that the amount of by-products utilized would have increased over time.

45 Ibid., p. 89. Total ash generation in 2000 was assumed to be 169.5 million tons, with about 27.3 million tons utilized and therefore, 142.2 million tons destined for disposal areas. Utilization was estimated to decline about 11.5 million tons, so the total amount of waste to be disposed would increase to 153.7 million tons.

46 Ibid.

47 Ibid., p. 91. Total utilization was assumed to decline by about 20.3 million tons in 2000. Therefore, the total amount of waste disposed would increase from 142.2 million tons to 162.5 million tons.

48 Ibid.

49 Total utilization was assumed to be 27.3 million tons in 2000, thereby increasing total disposal volume from 142.2 million tons to 169.5 million tons.

50 EnviroSphere Company, in USWAG, Appendix G, p. 93.

51 To estimate the potential impact of alternative disposal practices on electricity generation costs, the first step was to calculate the approximate portion of generation costs due to current basic disposal practices. Current basic disposal practices for coal-fired utility wastes were assumed to be disposal in either an unlined pond or landfill, although other practices are sometimes followed. Generation costs for a typical coal- and gas-fired power plant are shown to indicate the relative competitiveness of these two fuels when current disposal practices for coal-fired utility wastes are followed. See Appendix G for a detailed discussion of the assumptions used to determine these generation costs.

52 Capital costs are not included in the cost estimates for existing power plants because these are "sunk" costs, i.e., they have already been spent. As a result, the percentage impact on total generation costs at existing power plants is larger because the cost base is smaller compared to future power plants.

53 Baseload refers to power plants that are operated as much as possible to maximize the amount of electricity these plants can generate. For this analysis a baseload power plant is assumed to operate 70 percent of the time.

54 The generation costs in Exhibit 6-9 are intended to be representative of typical power plants. However, the actual cost of generation and the relative competitiveness between coal and gas depends on many factors, including plant size, utilization rate, and delivered fuel cost.

55 This price range is only intended to illustrate the approximate range at which oil becomes competitive with coal at existing power plants. The actual level at which coal might begin to lose market share depends on many factors, including relative price differentials, fuel availability, gas prices vis-a-vis oil prices, types of power plants (i.e., overall plant efficiency), etc.

CHAPTER SEVEN**CONCLUSIONS AND RECOMMENDATIONS**

This chapter concludes the Environmental Protection Agency's Report to Congress on fossil fuel combustion wastes. Pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), the Report addresses the nature and volumes of coal combustion wastes, the environmental and human health effects of the disposal of coal combustion wastes, present disposal and utilization practices, and the costs and economic impacts of employing alternative disposal and utilization techniques. A statement of the scope of the report and a summary of the report's findings are presented below, followed by the Agency's recommendations.

7.1 SCOPE OF REPORT

As discussed in Chapter One, this Report to Congress covers the generation of coal-fired combustion wastes by the electric utility industry. Other fossil fuel combustion wastes not discussed in this report include coal, oil and gas combustion wastes from other industries and oil and gas combustion wastes from electric utilities. Overall, coal combustion by electric utilities accounts for approximately 90 percent of all fossil fuel combustion wastes that are produced. Moreover, this percentage is likely to increase in the future since coal consumption by the electric utility industry is expected to increase substantially while coal use by other sectors remains relatively constant. Electric utility coal consumption will grow as new coal-fired power

plants are constructed to meet increasing electricity requirements in the United States.

7.2 SUMMARY OF REPORT

The Agency's conclusions from the information presented in this report are summarized under seven major groupings paralleling the organization of the report: 1) Location and Characteristics of Coal-Fired Power Plants, 2) Waste Quantities and Characteristics, 3) Waste Management Practices, 4) Potential Hazardous Characteristics, 5) Evidence of Environmental Transport of Potentially Hazardous Constituents, 6) Evidence of Damage, and 7) Potential Costs of Regulation.

7.2.1 Location and Characteristics of Coal-Fired Power Plants

1. There are about 500 power plant sites in the United States that consume coal to generate electricity. Each power plant may be the location for more than one generating unit; at these 500 power plants there are nearly 1400 generating units.
2. The size of coal-fired power plants can vary greatly. The size of a power plant is typically measured by the number of megawatts (Mw) of generating capacity. Coal-fired power plants can range in size from less than 50 Mw to larger than 3000 Mw.

3. Coal-fired power plants are located throughout the United States. Coal is used to generate electricity in every EPA region; almost every state has some coal-fired generating capacity.

4. More coal-fired power plants will be built as the demand for electricity increases. Coal is a fuel often used by the electric utility industry to generate power. This reliance on coal is unlikely to change for many years to come in the absence of greatly increased costs for coal-fired electricity.

5. Coal-fired power plants are located in areas of widely-varying population density. Some power plants are located in remote rural areas, whereas others are located in urban environments. They are usually, although not always, located at least a couple of kilometers from major population concentrations. In general they are located near a major body of surface water such as a lake, river, or stream.

7.2.2. Waste Quantities and Characteristics

1. The amount of wastes generated annually by coal-fired power plants is large by any standard. About 84 million tons of high-volume wastes -- fly ash, bottom ash, boiler slag, and FGD sludge -- are generated annually. The total amount of low-volume wastes generated from equipment maintenance and cleaning operations is not known precisely, but is also substantial.

2. Quantities of waste produced will increase significantly as more electricity is generated by coal. The amount of high-volume wastes produced annually could double by the year 2000. In particular, the amount of FGD sludge produced will triple (to about 50 million tons) as newly-constructed power plants install FGD equipment to remove sulfur dioxide from the flue gases.
3. Coal combustion wastes are a common by-product from the generation of electricity. The noncombustible materials are present in the coal as a result of geologic processes and mining techniques. Given current technologies for generating electricity, wastes from coal combustion will continue to be produced in significant quantities.
4. High-volume coal combustion wastes do contain elements that in sufficient concentrations can pose a potential danger to human health and the environment. Most elements in coal are not hazardous. However, trace elements typically found in coal become concentrated as a result of the combustion process. Certain elements known to pose health risks can be found in the wastes at hazardous levels.
5. Although most low-volume wastes do not appear to be hazardous, there are some waste streams from cleaning that could potentially be hazardous. The waste streams of most concern are water-side boiler cleaning solutions, which may be corrosive or toxic. Because the amount and type of low-volume wastes produced can vary substantially from one power plant to the next, not as much is known about low-volume wastes compared to high-volume wastes.

7.2.3 Waste Management Practices

1. Most coal combustion wastes are typically disposed in landfills or surface impoundments, with recent trends toward increased reliance on landfills. Although some disposal does occur off-site, most wastes are disposed on-site; it is likely that most power plants built in the future will dispose on-site in a landfill.
2. Typical industry practice is to co-dispose low-volume wastes with high-volume wastes or, in some instances, to burn the low-volume wastes in the utility boiler. There are many other types of waste management practices that are also used to alter the physical and chemical characteristics of low-volume wastes prior to disposal. These practices vary widely from plant to plant. There are no reliable data sources that accurately describe the types of low-volume disposal practices used at each power plant.
3. The potential for increased waste utilization as a solution to waste management in the utility industry appears to be limited. About 21 percent of all high-volume wastes are currently recycled; some opportunities appear to exist to increase utilization, but not in a major way.
4. Coal combustion wastes are typically regulated under state solid waste laws, which treat these wastes as non-hazardous materials. The

extent of state regulation can vary significantly from one state to another.

5. Many waste management practices applied to hazardous waste in other industries, such as liners, have only seen limited use for coal combustion waste management. In recent years, some of these practices, including liners and leachate collection systems, have become more common. There is an increasing tendency to manage coal combustion wastes by disposing on-site (at the power plant) in landfills.
6. There are few major innovations under development that would lead to major changes in waste management practices.

7.2.4 Potential Hazardous Characteristics

1. The RCRA hazardous characteristics of most concern are corrosivity and EP toxicity. Coal combustion wastes are generally not ignitable or reactive.
2. Most waste streams would not be considered corrosive under RCRA definitions. Only aqueous wastes, which most coal combustion wastes are not, are considered corrosive under RCRA. There are some aqueous coal combustion waste streams that are very near corrosive levels, particularly low volume wastes such as boiler blowdown or coal pile runoff. In some instances, boiler cleaning wastes may be corrosive, particularly those that are hydrochloric acid-based.

3. Coal combustion wastes generally are not EP toxic, although there are some exceptions. It is rare for coal combustion wastes to fail the EP test (or the TCLP test developed more recently). Extract concentrations in excess of 100 times the Primary Drinking Water Standards have been found only for the elements cadmium, chromium, and arsenic from some FGD sludges and coal ash samples, although these levels are quite rare -- average levels are substantially below 100 times the PDWS.

4. There are insufficient data to determine a priori which waste streams at a power plant will exhibit RCRA hazardous characteristics.

Accurate determinations could only be made if site-specific analyses were conducted.

7.2.5 Evidence of Environmental Transport of Potentially Hazardous Constituents.

1. Migration of potentially hazardous constituents has occurred from coal combustion waste sites. From the limited data available, exceedances of the Primary Drinking Water Standards have been observed in the ground water for several elements, including cadmium, chromium, lead, selenium, and arsenic.

2. Ground-water contamination does not appear to be widespread. Only a few percent of all ground-water quality observations indicate that a PDWS exceedance has occurred, although many utility waste management

sites at which ground-water monitoring has been done have had at least one exceedance. However, the observed contamination may not necessarily be chronic since sites at which exceedances have been noted do not consistently register in excess of the PDWS.

3. When ground-water contamination does occur, the magnitude of the exceedance is generally not large. Most PDWS exceedances tend to be no more than 10 or 20 times the PDWS, although a few observations greater than 100 times the PDWS have been noted.
4. Human populations are generally not directly exposed to the groundwater in the vicinity of utility coal combustion waste management sites. Public drinking water intakes are usually at least a few kilometers away. Also, most power plants are located near surface water bodies that dilute the concentration of any elements found in the ground water.
5. Because high-volume and low-volume waste streams are often co-disposed, it cannot be determined if one specific waste stream was the source of contamination.
6. The ground-water quality information on which this evidence is based is limited. Data were only available from a small number of utility waste management sites; no comprehensive database on ground-water contamination potentially attributable to coal combustion wastes exists.

7.2.6 Evidence of Damage

1. There are few cases considered to be documented evidence of damage from coal combustion wastes. Among these cases there is some dispute whether any observed damage can be attributed to the utility waste management facility.
2. Damage cases are dominated by chronic incidents (seepage, periodic runoff) as opposed to catastrophic incidents (sudden releases, spills), although one documented damage case was due to structural failure of a surface impoundment.
3. Documented damage typically involves physical or chemical degradation of ground water or surface water, including fish kills or reduction in biota, but seldom involves direct effects on human health because the water is not consumed for drinking water purposes. Much of the damage has occurred in the immediate vicinity of the waste management site; drinking water intakes are generally far enough away such that any contaminated water is not being directly used for human consumption.

7.2.7 Potential Costs of Regulation

1. If additional regulations are promulgated for utility waste management, the total costs incurred by the industry could vary considerably depending on the extent of the additional regulations.

For example, total annual costs to install and operate ground-water monitoring systems would be unlikely to exceed \$10 million. On the other hand, total annual costs for the industry could approach \$5 billion if all existing facilities were capped and closed and new facilities were constructed with liners, leachate collection systems, flood protection, and ground-water monitoring. (Corrective action costs, such as excavating all existing facilities for removal of the wastes to RCRA Subtitle C facilities, are not included in this estimate; such costs would be extremely high.)

2. Regulation of utility coal combustion wastes under full RCRA Subtitle C requirements could halt all recycling of coal combustion wastes if recycling was also subject to Subtitle C requirements. Total costs to the industry could approach \$2.4 billion annually. If recycled wastes were not subject to Subtitle C disposal requirements, it is possible the amount of recycling could increase as the utility industry increased waste utilization to avoid full Subtitle C disposal costs.

3. The costs to the utility industry for full RCRA Subtitle C compliance could decrease the amount of coal consumed in coal-fired power plants. The costs of generating electricity with coal could increase by several percent (depending on the extent of additional regulations), making it economic to generate electricity with other fuels. These impacts could be felt in two ways: 1) lower coal consumption at existing power plants and 2) construction of fewer coal-fired power plants in the future.

7.3 RECOMMENDATIONS

Based on the findings from this Report to Congress, this section presents the Agency's preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider

whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period.

The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes.

The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third. EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From

the information available to the Agency at this time, current waste

utilization practices appear to be done in an environmentally safe manner.

The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . .," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

GLOSSARY

acidity - the amount of free carbon dioxide, mineral acids and salts (especially sulfates or iron and aluminum) which hydrolyze to give hydrogen ions in water and is reported as milli-equivalents per liter of acid, or ppm acidity as calcium carbonate, or pH the measure of hydrogen ions concentration. Indicated by a pH of less than 7.

administrator - the Administrator of the United States Environmental Protection Agency, or his/her designee.

alkaline cleaning solution wastes - water-side cleaning waste resulting from the removal of high copper content scale from the utility boiler.

alkaline passivating waste - water-side cleaning waste resulting from the removal of iron and copper compounds and silica to neutralize acidity after acid cleaning.

alkalinity - the amount of carbonates, bicarbonates, hydroxides and silicates or phosphates in the water and is reported as grains per gallon, pH, or ppm of carbonate. Indicated by a pH of greater than 7.

alkaline fly ash scrubber - a flue gas desulfurization system in which flue gas reacts with alkaline fly ash that is augmented with a lime/limestone slurry.

anthracite - a high ASTM ranked coal with dry fixed carbon 92% or more and less than 98%; and dry volatile matter 8% or less and more than 2% on a mineral-matter-free basis.

aquifer - a water-bearing bed or structure of permeable rock, sand, or gravel capable of yielding quantities of water to wells or springs.

ash - the incombustible solid matter in fuel.

ash fusion - the temperatures at which a cone of coal or coke ash exhibits certain melting characteristics.

attenuation - a process that slows the migration of constituents through the ground.

baghouse - an air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags usually made of glass fibers.

base load - base load is the term applied to that portion of a station or boiler load that is practically constant for long periods.

batch test - a laboratory leachate test in which the waste sample is placed in, rather than washed with, leachate solution.

bituminous coal - ASTM coal classification by rank on a mineral/matter-free basis and with bed moisture only.

low volatile: dry fixed carbon 78% or more and less than 86%; and dry volatile matter 22% or more and less than 14%.

medium volatile: dry fixed carbon 69% or more and less than 78%; and dry volatile matter 22% or more and less than 31%.

high volatile (A): dry fixed carbon less than 69% and dry volatile matter more than 31% - Btu value equal to or greater than 14,000 moist, mineral-matter-free basis.

high volatile (B): Btu value 13,000 or more and less than 14,000 moist, mineral-matter-free basis.

high volatile (C): Btu value 11,000 or more and less than 13,000 moist, mineral-matter-free basis commonly agglomerating, or 8,300

to 11,500 Btu agglomerating.

blower - the fan used to force air through a pulverizer or to force primary air through an oil or gas burner register.

boiler - a closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof, under pressure or vacuum by the application of heat.

boiler blowdown - removal of a portion of boiler water for the purpose of reducing solid concentration or discharging sludge.

boiler cleaning waste - waste resulting from the cleaning of coal combustion utility boilers. Boiler cleaning wastes are either water/side or gas-side cleaning wastes.

boiler slag - melted and fused particles of ash that collect on the bottom of the boiler.

boiler water - a term used to define a representative sample of the boiler circulating water. The sample is obtained after the generated steam has been separated and before the incoming feedwater or added chemical becomes mixed with it so that its composition is affected.

bottom ash - large ash particles that settle on the bottom of the boiler.

British Thermal Unit (Btu) - the mean British Thermal Unit is 1/180 of the heat required to raise the temperature of 1 pound of water from 32°F to 212°F at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise 1 pound of water 1 degree F.

capacity factor - the total output over a period of time divided by the product of the boiler capacity and the time period.

CERCLA - The Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as Superfund.

cell - a section of a landfill, or the size of that section. Usually only a few cells of a landfill are open to accept waste at a time.

chain grate stoker - a stoker which has a moving endless chain as a grate surface, onto which coal is fed directly from a hopper.

coal pile runoff - surface runoff from a plant's coal pile.

cogeneration - the production of steam (or hot water) and electricity for use by multiple users generated from a single source.

column test - a leachate extraction procedure that involves passing a solution through the waste material to remove soluble constituents.

contingency plan - a document setting out an organized, planned, and coordinated course of action to be followed in case of a fire or explosion or a release of hazardous waste constituents into the environment.

cooling tower blowdown - water withdrawn from the cooling system in order to control the concentration of impurities in the cooling water.

cyclone furnace - specialty furnace for high intensity heat release. So named because of its swirling gas and fuel flows.

demineralizer regeneration and rinses waste - a low volume wastewater generated from the treatment of water to be used at the plant.

direct lime flue gas desulfurization - see lime/limestone FGD process.

direct limestone flue gas desulfurization - see lime/limestone FGD process.

disposal - the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water such that any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

dry-bottom furnace - a pulverized-fuel furnace in which ash particles are deposited on the furnace bottom in a dry, non-adherent condition.

dry scrubber - an FGD system for which sulfur dioxide is collected by a solid medium; the final product is totally dry, typically a fine powder.

dry sorbent injection - an FGD system in the research and development stage for which a powdered sorbent is injected into the flue gas before it enters the baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse.

dual alkali fly ash scrubber - a flue gas desulfurization system similar to the lime/limestone process, except that the primary reagent is a solution of sodium salts and lime.

effluent - a waste liquid in its natural state or partially or completely treated that discharges in to the environment from a manufacturing or treatment process.

electrostatic precipitator - an air pollution control device that imparts an electrical charge to particles in a gas stream causing them to collect on an electrode.

evapotranspiration - the combined process of evaporation and transpiration.

fabric filter - a cloth device that catches dust and particles from industrial or utility emissions.

flash point - the lowest temperature at which vapors above a volatile combustible substance ignite in air when exposed to flame.

flue gas - the gaseous products of combustion in the flue to the stack.

flue gas desulfurization (FGD) sludge - waste that is generated by the removal of some of the sulfur compounds from the flue gas after combustion.

fly ash - suspended ash particles carried in the flue gas.

furnace - the combustion chamber of a boiler.

gas-side cleaning waste - waste produced during the removal of residues (usually fly ash and soot) from the gas-side of the boiler (air preheater, economizer, superheater, stack, and ancillary equipment).

ground water - water found underground in porous rock strata and soils.

ground water monitoring well - a well used to obtain ground-water samples for water-quality analysis.

hazardous waste - a solid waste, or combination of solid wastes, which, because of its quantity, concentration, or physical, chemical, or infectious characteristics, may (1) cause, or significantly contribute to, an increase in serious irreversible, or incapacitating reversible illness; or (2) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of, or otherwise managed.

hard water - Water that contains sufficient dissolved calcium and magnesium to cause a carbonate scale to form when the water is boiled or to prevent the sudsing of soap in the water.

high volume waste - fly ash, bottom ash, boiler slag, and flue gas desulfurization sludge.

hydraulic conductivity - the quantity of water that will flow through a unit cross-sectional area of a porous material per unit of time.

hydrochloric acid cleaning waste - wastes from the cleaning of scale caused by water hardness, iron oxides, and copper.

land disposal - the placement of wastes in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave.

landfill - a disposal facility or part of a facility where hazardous waste is placed in or on land and which is not a land treatment facility, a surface impoundment or injection well.

leachate - the liquid resulting from water percolating through, and dissolving materials in, waste.

leachate extraction test - a laboratory procedure used to predict the type and concentration of constituents that will leach out of waste material.

leachate collection, removal, and treatment systems - mitigative measures used to prevent the leachate from building up above the liner.

lift - the depth of a cell in a landfill.

lignite - a coal of lowest ASTM ranking with calorific value limits on a moist, mineral-matter-free basis less than 8,300 Btu.

lime - calcium oxide (CaCO_3), a chemical used in some FGD systems.

limestone - calcium carbonate (CaOH_2), a chemical used in some FGD systems.

lime/limestone FGD process - form of wet non-recovery flue gas desulfurization system in which flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone to form a slurry which is dewatered and disposed.

liner - a mitigative measure used to prevent ground-water contamination in which synthetic, natural clay, or bentonite materials that are compatible with the wastes are used to seal the bottom or surface impoundments and landfills.

low volume waste - wastes generated during equipment maintenance and water purification processes. Low volume wastes include boiler cleaning solutions, boiler blowdown, demineralizer regenerant, pyrites, cooling tower blowdown.

mechanical stoker - a device consisting of mechanically operated fuel feeding mechanism and a grate, and is used for the propose of feeding solid fuel into a furnace, and to distribute it over a grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal or discharge of refuse.

net recharge - the amount of precipitation absorbed annually into the soil.

off-site - geographically noncontiguous property, or contiguous property that is not owned by the same person. The opposite of on-site.

on-site - the same or geographically contiguous property which may be divided by public or private right(s)-of-ways, provided the entrance and exit between the properties is at across-roads, intersection, and access is by crossing as opposed to going along the right(s)-of-way. Noncontiguous properties owned by the same person but connected by a right-of-way which the person controls and to which the public does not have access, is also considered on-site property.

Part A - the first part of the two part application that must be submitted by a TSD facility to receive a permit. It contains general facility information.

Part B - the second part of the two part application that includes detailed and highly technical information concerning the TSD in question. There is no standard form for the Part B, instead the facility must submit information based on the regulatory requirements.

particulates - fine liquid or solid particles such as dust, smoke, mist, fumes, or smog, found in the air or emissions.

permeability (1) - the ability of a geologic formation to transmit ground water or other fluids through pores and cracks.

permeability (2) - the rate at which water will seep through waste material.

petroleum coke - solid carbaceous residue remaining in oil refining stills after distillation process.

pH - a measure of the acidity or alkalinity of a material, liquid or solid. pH is represented on a scales of 0 to 14 with 7 being neutral state, 0 most acidic and 14 most alkaline.

plume - a body of ground water originating from a specific source and influenced by such factors as the local ground-water flow pattern and character of the aquifer.

pond liquors - waste fluid extracted from a surface impoundment or landfill.

pozzolanic - forming strong, slow-hardening cement-like substance when mixed with lime or other hardening material.

PDWS - Primary Drinking Water Standards established by the Safe Drinking Water Act.

pulverizer - a machine which reduces a solid fuel to a fineness suitable for burning in suspension.

pyrites - solid mineral deposits of raw coal that are separated from the coal before burning.

reagent - a substance that takes part in one or more chemical reactions or biological processes and is used to detect other substances.

recharge - the replenishment of ground water by infiltration of precipitation through the soil.

RCRA - Resource Conservation and Recovery Act, as amended (Pub. L. 94-580). The legislation under which EPA regulates solid and hazardous waste.

RCRA Subtitle C Characteristics - criteria used to determine if an unlisted waste is a hazardous waste under Subtitle C of RCRA.

- **corrosivity** - a solid waste is considered corrosive if it is aqueous and has a pH less than or equal to 2 or greater than or equal to 12.5 or if it is a liquid and corrodes steel at a rate greater than 6.35 mm per year at a test temperature of 55°C.

- **EP toxicity** - a solid waste exhibits the characteristic of EP (extraction procedure) toxicity if, after extraction by a prescribed EPA method, it yields a metal concentration 100 times the acceptable concentration limits set forth in EPA's primary drinking water standards.

- **ignitability** - a solid waste exhibits the characteristic of ignitability if it is a liquid with a flashpoint below 60°C or a non-liquid capable of causing fires at standard temperature and pressure.

- **reactivity** - a waste is considered reactive if it reacts violently, forms potentially explosive mixtures, or generates toxic fumes when mixed with water, or if it is normally unstable and undergoes violent change without deteriorating.

SDWS - Secondary Drinking Water Standards established by the Safe Drinking Water Act.

settling lagoon - surface impoundment.

shear strength - the resistance offered by a material subjected to a compressive stress created when two contiguous parts of the material are forced in opposite parallel directions.

slag - molten or fused solid matter.

sludge - a soft water-formed sedimentary deposit that is mud-like in its consistency.

slurry - a mixture of insoluble matter in a fluid.

solid waste - As defined by RCRA, the term "solid waste" means any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities,

but does not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to permits under the Clean Water Act, or special nuclear or byproduct material as defined by the Atomic Energy Act of 1954.

spray drying process - a flue gas desulfurization system in which a fine spray of alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water in the solution, leaving a dry powder, which is collected by a particulate collector.

stabilization - making resistant to physical or chemical changes by treatment.

steady state - an adjective that implies that a system is in a stable dynamic state in which inputs balance outputs.

stoker - see mechanical stoker.

storage - the holding of waste for a temporary period, at the end of which the hazardous waste is treated, disposed of, or stored elsewhere.

subbituminous coal - An intermediate rank coal between lignite and bituminous with more carbon and less moisture than lignite.

sump effluent - waste from sumps that collect floor and equipment drains.

surface impoundment - a facility which is a natural topographic depression, artificial excavation, or diked area formed primarily of earthen materials (although it may be lined with artificial materials), which is designed to hold an accumulation of liquid wastes or wastes containing free liquids.

surface water - water that rests on the surface of the rocky crust of the earth.

traveling grate stoker - a stoker similar to a chain grate stoker except that the grate is separate from but is supported on and driven by chains.

trace element - An element that appears in a naturally-occurring concentration of less than 1 percent.

treatment - any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of a waste so as to neutralize it, recover it, make it safer to transport, store or dispose of, or amenable for recovery, storage, or volume reduction.

TSD facility - waste treatment, storage, or disposal facility.

utility boiler - a boiler which produces steam primarily for the production of electricity in the utility industry.

volatile - A volatile substance is one which tends to vaporize at a relatively low temperature.

water-side cleaning waste - waste produced during the removal of scale and corrosion products from the water side of the boiler (i.e., the piping systems containing the steam or hot water).

wet bottom furnace - a pulverized fuel fired furnace in which the ash particles are deposited and retained on the floor thereof and molten ash is removed by tapping either continuously or intermittently. (also called a slag tap furnace)

wet scrubber - a device utilizing a liquid, designed to separate particulate matter or gaseous contaminants from a gas stream by one or more mechanisms such as absorption, condensation, diffusion, inertial impaction.

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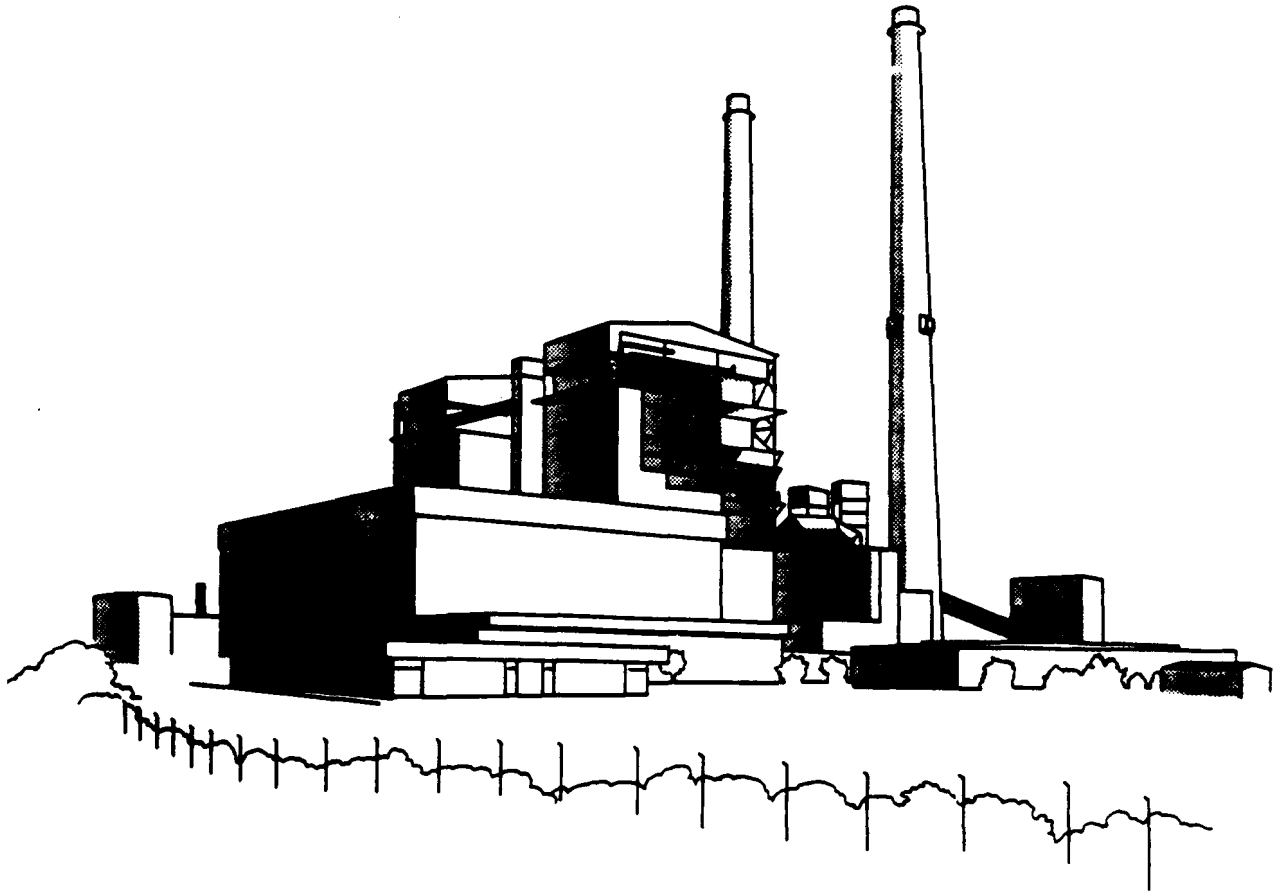
Solid Waste



Report to Congress

Appendices

Wastes from the Combustion of Coal by Electric Utility Power Plants



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Mar 09 2018





UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D C 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable George Bush
President of the Senate
Washington, D.C. 20510

Dear Mr. President:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

A handwritten signature in black ink, appearing to read "Lee M. Thomas".

Lee M. Thomas

Enclosure



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable James C. Wright
Speaker of the House
of Representatives
Washington, D.C. 20515

Dear Mr. Speaker:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

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A handwritten signature in black ink, appearing to read "Lee M. Thomas".

Lee M. Thomas

Enclosure

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JAN 13 1981

OFFICE OF WATER
AND WASTE MANAGEMENT

Mr. Paul Emler, Jr.
Chairman
Utility Solid Waste Activities
Group
Suite 700
1111 Nineteenth Street, N.W.
Washington, D.C. 20036

Dear Mr. Emler:

This is a response to your letter of October 10, 1980 to Administrator Costle, regarding the recent Solid Waste Disposal Act Amendments of 1980 and their relation to the electric utility industry. In your letter and its accompanying document, you discussed the specific amendments which address fossil fuel combustion wastes, and suggested interpretive language which EPA should adopt in carrying out the mandate of the amendments. You requested a meeting with our staff to make us more fully aware of the solid waste management practices of the electric utility industry, and to discuss the effect of the amendments on the utility solid waste study which EPA is currently conducting.

I appreciated the opportunity to meet with you, in your capacity as chairman of the Utility Solid Waste Activities Group (USWAG), on November 21 to discuss your concerns. I am taking this occasion to share with you the most recent EPA thinking on the exclusion from our hazardous waste management regulations of waste generated by the combustion of fossil fuels, and to confirm certain agreements which were reached during our meeting. The language contained in this letter should provide you and your constituents with an adequate interpretation of the fossil fuel combustion waste exclusion in Section 261.4(b)(4) of our regulations. This letter is also being circulated to appropriate Agency personnel, such as our Regional Directors of Enforcement, for their information and use. We intend to issue in the Federal Register an official Regulations Interpretation Memorandum reflecting the policies articulated in this letter.

In our May 19, 1980 hazardous waste management regulations, we published an exclusion from Subtitle C regulation for those fossil fuel combustion wastes which were the subject of then pending Congressional amendments. The language of that exclusion in §261.4(b)(4) of our May 19 regulations is identical to pertinent language of Section 7 of the Solid Waste Disposal Act

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regulations. We clearly explained in the preamble to Part 261 of our May 19 regulations that we fully intend to eventually regulate the use and recycling of hazardous wastes and, in doing so, would probably, in most cases, develop special requirements that provide adequate protection of human health and the environment without unwarranted discouragement of resource conservation. Consequently, although the burning of hazardous waste as a fuel (a beneficial use assuming that the waste has a positive fuel value) is not now subject to our regulations (except as noted above) it may well be subject to our regulation in the future.

Our second concern with combustion of fuel mixtures is the one at focus in this interpretation. It must first be noted that we do not intend for §261.6 to provide an exemption from regulation for combustion wastes resulting from the burning of hazardous wastes in combination with fossil fuels; it only provides an exemption for the actual burning of hazardous wastes for recovery of fuel value. Thus, if these combustion wastes are exempted from our regulation, such exemption must be found through interpretation of §261.4(b)(4). Secondly, we note that although the pertinent language in Section 7 of the Solid Waste Disposal Act Amendments of 1980 and the related legislative history on this matter speak of allowing the burning of alternative fuel without precisely defining or delineating the types of alternative fuel, the only examples of alternative fuels used in the legislative history are refuse derived fuels. Therefore, a literal reading of the legislative history might enable us to interpret the exclusion to include combustion wastes resulting from the burning of fossil fuels and other fuels, including hazardous wastes. However, since each of these legislative comments was made in the context of refuse derived fuels or other non-hazardous alternate fuels, we do not believe the Congressional intent compels us to make such an interpretation if we have reason to believe that such combustion wastes are hazardous.

Presently, we have little data on whether or to what extent combustion wastes are "contaminated" by the burning of fossil fuel/hazardous waste mixtures. The data we do have (e.g., burning of waste oils) suggests that the hazardous waste could contribute toxic heavy metal contaminants to such combustion wastes. When coal is the primary fuel, the amount of resulting contamination is probably in amounts that are not significantly different than the metals that would be contributed by the fossil fuel component of the fuel mixture. This may not be the case with oil and gas, where huge volumes of waste are not available to provide a dilution effect. We suspect that the other hazardous constituents of the hazardous wastes that typically would be burned as a fuel are either thermally destroyed or are emitted in the flue gas (and therefore are part of our first concern as discussed above). If

these data and this presumption are true, then combustion wastes resulting from the burning of coal/hazardous waste mixtures should not be significantly different in composition than combustion wastes generated by the burning of coal alone. Because the Congress has seen fit to exclude the latter wastes from Subtitle C, pending more study, we feel compelled to provide the same exclusion to the former wastes.

Accordingly, we will interpret the exclusion of §261.4(b)(4) to include fly ash, bottom ash, boiler slag and flue gas emission control wastes generated in the combustion of coal/hazardous waste mixtures provided that coal makes up more than 50 percent of the fuel mixture.

We offer this interpretation with great reluctance and with the clear understanding it is subject to change, if and when data indicate that combustion wastes are significantly contaminated by the burning of hazardous wastes as fuel. We also offer this interpretation with the understanding, as discussed at our meeting of November 21, that the utility industry will work with us over the next several months to improve our data on this matter. We believe it is essential that we make a more informed judgement and possible reconsideration of our interpretation of the exclusion as soon as possible and before completion of our longer-term study of utility waste which is proceeding. Accordingly, we would like you to provide to us all available data on the following questions by August 1, 1981:

1. What types of hazardous wastes are commonly burned as fuels in utility boilers? In what quantity? In what ratio to fossil fuels? How often? What is their BTU content?
2. Does the burning of these wastes contribute hazardous constituents (see Appendix VIII of Part 261 of our regulations) to any of the combustion wastes? If so, what constituents, and in what amounts? How does the composition of combustion wastes change when hazardous wastes are burned?

Co-disposal and Co-treatment

The second issue raised in your letter was whether the exclusion extends to wastes produced in conjunction with the burning of fossil fuels which are co-disposed or co-treated with fly ash, bottom ash, boiler slag and flue gas emission control wastes. As examples of such wastes, you specifically mention boiler cleaning solutions, boiler blowdown, demineralizer regenerant, pyrites, cooling tower blowdown, or any "wastes of power plant origin whose co-treatment with fly ash, bottom ash, slag and flue gas emission control sludges is regulated under State-or-EPA-sanctioned management or treatment plans."

The legislative history on this matter clearly indicates that the Congress intended that these other wastes be exempted from Subtitle C regulation provided that they are mixed with and co-disposed or co-treated with the combustion wastes and further provided that "there is no evidence of any substantial environmental danger from these mixtures." (See Congressional Record, February 20, 1980, p. H 1102, remarks of Congressman Bevill; also see remarks of Congressman Rahall, Congressional Record, February 20, 1980, p. H1104.)

We have very little data on the composition, character and quantity of these other associated wastes (those cited above), but the data we do have suggest that they are generated in small quantities relative to combustion wastes, at least when coal is the fuel, and that they primarily contain the same heavy metal contaminants as the combustion wastes, although they may have a significantly different pH than the combustion wastes. These limited data therefore suggest that, when these other wastes are mixed with and co-disposed or co-treated with the much larger quantities of combustion wastes, their composition and character are "masked" by the composition and character of the combustion wastes; that is, they do not significantly alter the hazardous character, if any, of the combustion wastes.

Given this information base and given the absence of definitive information indicating that these other wastes do pose a "substantial danger" to human health or the environment, we believe it is appropriate, in the light of Congressional intent, to interpret the §261.4(b)(4) exclusion to include other wastes that are generated in conjunction with the burning of fossil fuels and mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag and flue gas emission control wastes.

We offer this interpretation with some reluctance because it is made in the absence of definitive information about the hazardous properties of these other wastes or their mixtures with combustion wastes. We therefore believe it is imperative that we proceed to collect all available data on this matter within the next several months and reconsider this interpretation when these data are assessed. Toward that end and consistent with the discussion at our meeting of November 21, we are asking that you assist us in collecting these data. Specifically, we ask that you collect and submit by August 1, 1981, any available data on the following questions:

1. What are the "other" wastes which are commonly mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag or flue gas emission control wastes? What are their physical (e.g., sludge or liquid) and chemical properties? Are they hazardous wastes in accordance with Part 261?

2. What are the co-disposal or co-treatment methods employed?
3. How often are these wastes generated? In what quantities are they generated? Are they commonly treated in any way before being co-disposed?
4. Does the industry possess any data on the environmental effects of co-disposing of these wastes? Groundwater monitoring data? What are the results?

The interpretation on other associated wastes provided in this letter is limited to wastes that are generated in conjunction with the burning of fossil fuels. We do not intend to exempt hazardous wastes that are generated by activities that are not directly associated with fossil fuel combustion, steam generation or water cooling processes. Thus, for example, the §261.4(b)(4) exclusion does not cover pesticides or herbicide wastes; spent solvents, waste oils or other wastes that might be generated in construction or maintenance activities typically carried out at utility and industrial plants; or any of the commercial chemicals listed in §261.33 which are discarded or intended to be discarded and therefore are hazardous wastes. Further, the exclusion does not cover any of the hazardous wastes listed in §§261.31 or 261.32 of our regulations. None of these listed wastes were mentioned in your letter or our discussions.

The interpretation on other wastes is also limited to wastes that traditionally have been and which actually are mixed with and co-disposed or co-treated with combustion wastes. If any of these other wastes (e.g., boiler cleaning solutions, boiler blowdown, demineralizer regenerant, pyrites and cooling tower blowdown) are segregated and disposed of or treated separately from combustion wastes and they are hazardous wastes, they are not covered by the exclusion. In the same vein, the exclusion does not cover other wastes where there are no combustion wastes (or relatively small amounts of combustion wastes) with which they might be mixed and co-disposed or co-treated--a situation which might prevail where natural gas or oil is the principal fossil fuel being used. Therefore, this interpretation of the exclusion applies only where coal is the primary fuel. We feel this is a legitimate interpretation of Congressional intent, wherein the argument of little potential environmental hazard, primarily due to the dilution factor, is clearly based upon co-disposal or co-treatment with the huge volumes of wastes generated during coal combustion.

EPA Utility Waste Study

The groups of questions raised above bring us to the final subject which you address concerning the study of utility solid waste management which EPA is conducting. We agree that the study, as currently being conducted, does not focus on the matters discussed in this letter. We would, however, like to address these matters and include them in our report to Congress, to the extent possible. To accomplish this, we plan to meet in the very near future with our contractor, Arthur D. Little, Inc., to discuss what studies may need to be carried out in addition to their currently planned activities under the contract. The inputs of your organization could be quite useful in this effort. It may be impossible, however, to modify our present study to include a detailed investigation of all of the issues discussed above.

Notwithstanding, we would like to address the matters discussed in this letter within a shorter time frame--during the next six months. Based on our meeting of November 21, it is my understanding that the utility industry, working closely with EPA, is willing to develop data on the questions put forth above. We agreed that, as a first step, USWAG will prepare a study outline designed to obtain these data. EPA staff and industry representatives designated by your organization will then mutually review the information needs. The data collection effort will then follow. Finally, data and analyses will be presented to EPA for review. This will enable us to reconsider the interpretation provided in this letter and make any changes deemed necessary. Therefore, I would appreciate it if you would designate a technical representative as USWAG's contact person for this coordinated data collection effort.

In the meantime, and pending completion of this effort, EPA will interpret 40 CFR §261.4(b)(4) to mean that the following solid wastes are not hazardous wastes:

- (a) Fly ash, bottom ash, boiler slag and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, up to a 50 percent mixture of such other fuels.
- (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, the following wastes:

- (1) boiler cleaning solutions,
- (2) boiler blowdown,
- (3) demineralizer regenerant,
- (4) pyrites, and
- (5) cooling tower blowdown.

I am hopeful that our future research activities together will prove fruitful and that these issues can be rapidly resolved. I have designated Ms. Penelope Hansen of my staff as the EPA point of contact for this effort. You may reach her at (202) 755-9206.

Sincerely yours,

Gary N. Dietrich
Associate Deputy Assistant Administrator
for Solid Waste



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

DATE:

SUBJECT: EPA Regulation of Utility Waste

FROM: Steffen W. Plehn, Deputy Assistant Administrator for Solid Waste (WH-562)

R. Sarah Compton, Deputy Assistant Administrator for Water Enforcement (EN-335)

TO: Regional Directors --
Air and Hazardous Materials Division
Enforcement Division
Surveillance and Analysis Division
Offices of Regional Counsel (see list)
Director, National Enforcement Investigations Center

Attached is a copy of a letter which provides interpretation of EPA's regulation of solid wastes from fossil fuel combustion. This letter, addressed to Mr. Paul Emler of the Utility Solid Waste Activities Group on January 13, 1981, interprets the language contained in §261.4(b)(4) of the May 19, 1980 regulations for Hazardous Waste Management, implementing Subtitle C of the Resource Conservation and Recovery Act of 1976 (RCRA).

In those regulations, we published an exclusion from Subtitle C regulation for those fossil fuel combustion wastes which were the subject of then pending Congressional amendments. The language of the exclusion in §261.4(b)(4) is identical to pertinent language of Section 7 of the Solid Waste Disposal Act Amendments of 1980 (P.L. 96-482) which was enacted on October 21, 1980 and which mandates that exclusion. Specifically the exclusion language of our regulations provides that the following solid wastes are not hazardous wastes:

"Fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels."

In the January 13 letter, EPA interpreted this exclusion language to mean that the following solid wastes are not hazardous wastes:

- (a) Fly ash, bottom ash, boiler slag and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, up to a 50 percent mixture of such other fuels.
- (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, the following wastes:

- (1) boiler cleaning solutions,
- (2) boiler blowdown,
- (3) demineralizer regenerant,
- (4) pyrites, and
- (5) cooling tower blowdown.

This exclusion from hazardous waste regulation applies only until such time as EPA studies the environmental effects of disposal of these wastes and makes a determination as to how they should be managed. The utility industry will be assisting EPA in the collection of such information. In the meantime, utility waste is regulated as a solid waste, subject to RCRA Subtitle D criteria.

After receipt of information from the utility industry, our current interpretation of the fossil fuel combustion waste deferral may be revised. In the meantime, however, the guidance provided to Mr. Emler represents EPA's position on this issue. I urge each of you to study carefully the details of and rationale behind the guidance, and make the appropriate persons on your staff aware of it. If you have any questions on this issue or on the letter itself, please contact John Heffelfinger, in the Office of Solid Waste, at (202) 755-9206.

Attachment

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**METHODOLOGY FOR ESTIMATING VOLUME OF
ASH AND FGD SLUDGE GENERATION**

The estimates of future ash and FGD sludge generation presented in Chapter Three were derived based on assumptions regarding future coal consumption, the amount of coal-fired capacity, the types of boilers in service, and environmental regulations. Estimates were derived for 1985, 1990, 1995, and 2000. This appendix explains the key assumptions and methodology used to develop the estimates of future ash and FGD sludge generation. The major source used to develop these estimates was Analysis of 6 and 8 Million Ton and 30 year/NSPS and 30 Year/1.2 lb Sulfur Dioxide Emission Reduction Cases (prepared by ICF Incorporated for EPA, February 1986).¹

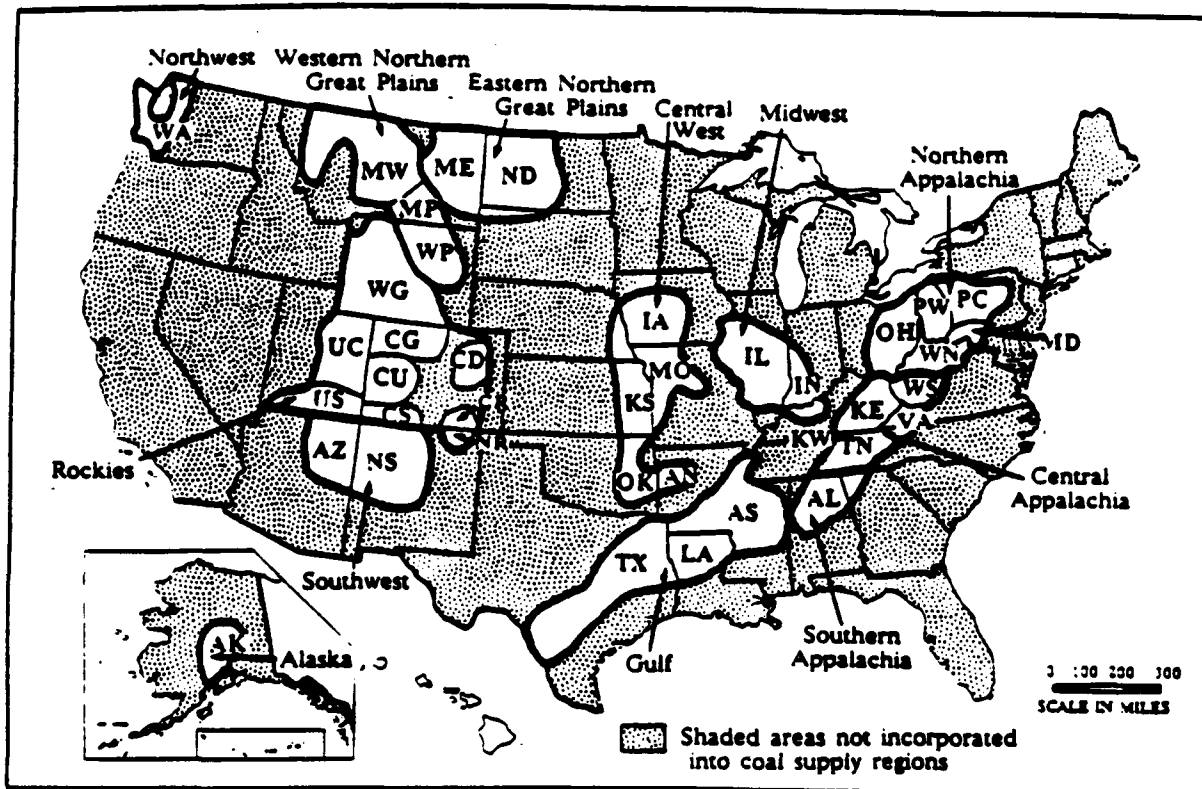
B.1 ASH

The first step in developing estimates of the volume of ash generated by coal-fired utilities was to determine for each coal-producing region in the U.S. (see Exhibit B-1) an average ash content of coal (on an as-shipped basis), specified by rank, heat content, and volatility level. These average ash contents are shown in Exhibit B-2. Next, these average values were multiplied by the quantity of coal expected to be shipped from each coal-producing region, using the following formula:

$$\begin{aligned} & \text{Ash Content of Coal (\%)} \times \text{Amount of Coal (Million Tons)} \\ & \quad = \text{Amount of Ash (Million Tons)} \end{aligned}$$

EXHIBIT B-1

COAL-PRODUCING REGIONS OF THE UNITED STATES



Northern Appalachia
 Pennsylvania, Central (PC)
 Pennsylvania, West (PW)
 Ohio (OH)
 Maryland (MD)
 West Virginia, North (WN)

Central Appalachia
 West Virginia, South (WS)
 Virginia (VA)
 Kentucky, East (KE)
 Tennessee (TN)

Southern Appalachia
 Alabama (AL)

Midwest
 Illinois (IL)
 Indiana (IN)
 Kentucky, West (KW)

Central West
 Iowa (IA)
 Missouri (MO)
 Kansas (KS)
 Arkansas, North (AN)
 Oklahoma (OK)

Gulf
 Texas (TX)
 Louisiana (LA)
 Arkansas South/Mississippi (AS)

Eastern Northern Great Plains
 North Dakota (ND)
 Montana, East (ME)

Western Northern Great Plains
 Montana, Powder River (MP)
 Montana, West (MW)
 Wyoming, Powder River (WP)

Rockies
 Wyoming, Green River (WG)
 Colorado, Green River (CG)
 Colorado, Denver (CD)
 Colorado, Raton (CR)
 Colorado, Uinta (CU)
 Colorado, San Juan (CS)
 Utah, Central (UC)
 Utah, South (US)
 New Mexico, Raton (NR)

Southwest
 New Mexico, San Juan (NS)
 Arizona (AZ)

Northwest
 Washington (WA)

Alaska
 Alaska (AK)

Imports
 Imports (IM)

EXHIBIT B-2

AVERAGE ASH CONTENT OF COAL
(percent)

Coal-Producing Region	Bituminous				Subbituminous	Lignite
	Low and Medium <u>1/</u> Volatility	High Volatility <u>1/</u>				
		10,500- 11,500 Btu/lb	11,500- 14,000 Btu/lb	14,000- Over 14,000 Btu/lb		
Central Pennsylvania	12.0	12.0	12.0	12.0		
Western Pennsylvania	7.0		12.0	12.0		
Ohio			12.0	12.0		
Maryland	12.0					
Northern West Virginia	7.0		12.0	12.0		
Southern West Virginia	12.0		12.0	12.0		
Virginia	12.0		12.0	12.0		
Eastern Kentucky			12.0	12.0		
Tennessee			12.0	12.0		
Alabama	12.6		12.6	12.6		
Illinois			10.3	10.3		
Indiana			10.4			
Western Kentucky			12.0			
Iowa		10.0	10.0			
Missouri			12.0	12.0		
Kansas			14.0	12.7		
Northern Arkansas	12.0					
Oklahoma	12.4	12.4	12.4			
Texas						15.3
Louisiana						12.0
Southern Arkansas						14.0
North Dakota						9.1
Eastern Montana					6.9	8.0
Montana, Powder River					6.9	
Western Montana		13.0	13.0			
Wyoming, Powder River					6.0	
Wyoming, Green River		10.0	10.0		10.0	

EXHIBIT B-2

AVERAGE ASH CONTENT OF COAL
(percent)

Coal-Producing Region	Volatility	Bituminous ^{▲▲}			Subbituminous	Lignite
		High Volatility	1/			
		10,500- 11,500 Btu/lb	11,500- 14,000 Btu/lb	Over 14,000 Btu/lb		
Colorado, Green River		10.0	10.0			
Colorado, Denver					18.0	18.0
Colorado, Raton			10.0	10.0		
Colorado, Uinta	8.0		8.0	8.0		
Colorado, San Juan			10.0	10.0		
Central Utah			8.0	8.0		
Southern Utah		12.0	9.0			
New Mexico, Raton			13.1	13.1		
New Mexico, San Juan		18.3			18.3	
Arizona			10.0			
Washington					16.0	
Alaska					9.0	

1/ Volatility Content, as measured on a dry, mineral-matter-free basis.

Low : 14.0-21.9 percent volatile matter
 Medium : 22.0-30.9 percent volatile matter
 High : Over 31.0 percent volatile matter

Source: See Attachment B-1 for the major assumptions used to develop these average ash contents. These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

The results represent the quantities of ash received by electric utility power plants throughout the United States. It was assumed that the total quantity of ash received by utilities would not burn; therefore, the amount of ash generated is equal to the amount received. Exhibit B-3 presents estimates by state of the total amount of ash that will be generated by electric utilities between 1985 and 2000 and the average ash content of the total quantity of coal received by the utilities in each state.

To determine quantities of each type of ash that would be generated, the amount of ash produced by each type of electric utility boiler was calculated. This was determined by apportioning the total quantity of ash generated according to the capacity of each boiler type (as a fraction of total capacity of coal-fired utilities in the U.S.). In Exhibit B-4 total electric utility capacity is described by boiler type. The majority of future coal-fired power plants are expected to use dry-bottom pulverizers, which can burn a greater variety of coals than other boilers. Therefore, it is assumed that the capacity assigned to the "unknown" category in Exhibit B-4 is additional dry-bottom pulverizer capacity.

Once the amount of ash generated by each type of boiler was determined, the quantities of the different types of ash formed could be estimated. Each major boiler type (dry-bottom pulverizers, wet-bottom pulverizers, cyclones, and stokers) produces different proportions of fly ash, bottom ash, or boiler slag, depending on the design of the boiler and operating conditions. The percentage of ash generated as fly ash, bottom ash, and boiler slag by each type of boiler is presented in Exhibit B-5. These percentages were used to determine the amount of each ash type generated by the four types of boilers,

EXHIBIT B-3

TOTAL AMOUNT OF ASH GENERATED BY ELECTRIC UTILITY POWER PLANTS -- 1985 to 2000^{a/}

State	1985		1990		1995		2000	
	Million Tons	% Ash	Million Tons	% Ash	Million Tons	% Ash	Million Tons	% Ash
Maine/Vermont/New Hampshire	0.2	12.0	0.1	12.0	0.2	12.0	0.4	11.6
Massachusetts/Connecticut/Rhode Island	0.5	12.0	0.9	12.0	0.9	12.0	0.9	12.0
New York	0.8	11.2	0.9	10.5	1.6	11.5	1.5	10.2
Pennsylvania	5.0	12.4	5.1	12.3	5.1	12.4	4.9	12.4
New Jersey	0.4	12.0	0.4	12.0	0.6	12.0	1.0	12.0
Maryland/Delaware/District of Columbia	1.0	9.7	0.9	10.4	1.2	10.3	2.0	10.0
Virginia	0.9	12.0	1.0	12.0	1.2	11.7	2.7	11.8
West Virginia	3.2	11.2	3.8	11.2	3.5	11.3	3.7	11.5
North Carolina/South Carolina	3.9	12.0	3.8	12.0	4.1	12.0	4.8	12.0
Georgia	3.0	11.6	3.4	11.7	3.8	11.8	4.3	11.9
Florida	2.0	11.8	2.5	11.8	3.1	11.8	5.0	11.9
Ohio	6.0	11.8	6.0	11.8	6.3	11.9	7.8	10.9
Michigan	3.2	10.6	3.3	10.2	3.4	10.3	3.4	10.3
Illinois	3.1	9.0	2.8	8.8	3.1	8.9	3.3	8.3
Indiana	4.1	9.8	4.6	9.9	4.8	9.7	4.9	9.7
Wisconsin	1.4	8.2	1.6	7.6	1.7	7.6	1.6	7.8
Kentucky	2.6	12.0	3.9	12.0	4.1	12.0	4.0	12.0
Tennessee	3.4	11.6	3.3	11.4	3.0	11.3	4.6	11.5
Alabama	1.6	12.6	1.9	12.5	2.2	12.4	2.0	12.4
Mississippi	0.5	10.7	0.5	10.7	0.6	10.5	0.6	11.1
Minnesota	0.8	7.0	0.9	7.0	1.1	7.1	1.1	7.1
North Dakota/South Dakota	1.8	9.1	2.1	9.1	2.1	9.1	3.3	8.3
Iowa	1.3	7.4	1.3	7.5	1.3	7.5	1.2	7.5
Missouri	2.7	10.3	2.8	10.4	3.0	9.6	3.6	8.5
Kansas/Nebraska	1.5	7.1	1.6	7.2	1.6	7.2	1.7	7.1
Arkansas	0.8	6.0	0.7	6.0	0.8	6.0	0.8	6.0
Oklahoma	0.9	6.0	1.1	6.0	1.1	6.0	1.8	6.0
Louisiana	0.6	6.0	1.0	7.8	1.0	7.6	2.0	9.1
Texas	8.2	12.5	10.0	12.8	15.7	13.6	23.9	13.3
Montana	0.4	6.9	0.6	6.9	0.6	6.9	0.8	6.9
Wyoming	1.5	7.8	1.5	7.8	1.9	7.3	2.1	7.1
Colorado	1.3	8.3	1.3	8.3	1.4	8.2	1.8	7.7
New Mexico	2.8	18.1	2.6	17.8	2.9	17.0	3.2	16.2
Utah	0.5	8.3	0.9	8.2	1.3	8.1	1.5	8.1
Arizona	1.7	12.6	2.2	14.1	2.1	13.0	2.3	11.9
Nevada	0.8	9.7	0.8	9.7	1.0	9.8	1.0	9.9
Washington/Oregon	0.8	13.9	0.8	14.0	1.0	13.8	1.9	9.5
California	b/	8.0	b/	8.0	0.1	9.0	0.3	9.8
Total U.S.c/	75.0	10.5	83.1	10.5	94.5	10.6	119.1	10.5

a/ For each year, the numbers in the left column indicate the amount of ash generated by coal fired electric utility power plants in the indicated state(s); the numbers in the right column are the average percentages of ash content in the coal received by utilities in the indicated state(s).

b/ Amount of ash is less than 0.1 million tons.

c/ Totals may not add due to independent rounding

Source: See Attachment B-1 for the major assumptions used to develop these estimates. These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

EXHIBIT B-4

**ELECTRIC GENERATING CAPACITY
OF COAL-FIRED UTILITIES BY BOILER TYPE a/
(gigawatts)**

	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Wet-Bottom Pulverizers	15.2	15.2	15.2	15.0
Dry-Bottom Pulverizers	199.1	198.9	198.7	198.1
Cyclones	23.8	23.8	23.7	23.7
Stokers	1.1	1.1	1.1	1.1
Unknown <u>b/</u>	<u>30.1</u>	<u>54.4</u>	<u>68.4</u>	<u>140.9</u>
TOTAL	269.3	293.4	306.9	378.8

a/ A gigawatt equal 1,000 megawatts.

b/ Plants yet to be constructed are assumed to have primarily dry-bottom pulverizer boilers.

Source: See Attachment B-1 for the major assumptions used to develop these estimates. These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

EXHIBIT B-5**PERCENTAGE OF EACH TYPE OF ASH
GENERATED BY EACH BOILER TYPE**

	<u>Fly Ash</u>	<u>Bottom Ash</u>	<u>Boiler Slag</u>
Wet-Bottom Pulverizers	50%	--	50%
Dry-Bottom Pulverizers	80%	20%	--
Cyclones	25%	--	75%
Stokers	50%	50%	--

Source: Babcock & Wilcox, Steam: Its Generation and Use, New York: The Babcock & Wilcox Company, 1978, pp. 15-7 - 15-8.

and then these amounts were aggregated to determine total ash generation by the electric utility industry in 1985, 1990, 1995, and 2000.

Some minor variances were noted between these estimates and historical trends in ash generation as reported by the American Coal Ash Association. Some adjustments were made in the distribution among ash types (but not the total quantities) so that forecasted quantities were more consistent with historical trends. The ash production forecasts, as well as historical data for 1980 to 1984, are presented in Exhibit B-6.

B.2 FGD SLUDGE

Because the sludge produced by flue gas desulfurization systems can vary a great deal in composition, consistency, and water/solids content, several simplifying assumptions were made to arrive at values for future FGD sludge generation.

- Wet scrubbers were assumed to be of the direct limestone type, producing a waste composed of unreacted reagent (limestone) and reacted reagent (gypsum). Dry scrubbers use lime as a reagent and were assumed to produce a waste composed of 25 percent gypsum and 75 percent $\text{CaSO}_3 \cdot 1/2(\text{H}_2\text{O})$.
- The stoichiometry for wet scrubbers is 1.4, while that for dry scrubbers is 1.86.
- The proportion of dry solids in sludge from wet scrubbers is 50 percent²; in sludge from dry scrubbers it is 100 percent.
- The purity of the reagents (limestone for wet scrubbers and lime for dry scrubbers) was assumed to be 95 percent.

EXHIBIT B-6

ASH GENERATION BY ELECTRIC UTILITY POWER PLANTS
(millions of tons)

	<u>Fly Ash</u>	<u>Bottom Ash</u>	<u>Boiler Slag</u>	<u>Total</u>
<u>Historical</u>				
1980	48.3	14.5	3.6	66.4
1981	50.2	12.9	5.2	68.3
1982	47.9	13.1	4.4	65.4
1983	47.2	12.7	3.9	63.8
1984	51.3	13.6	4.2	69.1
<u>Estimated</u>				
1985	54.4	15.7	4.9	75.0
1990	60.8	16.9	5.4	83.1
1995	69.4	19.1	6.0	94.5
2000	89.0	22.9	7.2	119.1

Source: 1980-1984: American Coal Ash Association

1985-2000: See Attachment B-1 for the major assumptions used to develop these estimates. These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

Sludge factors for wet and dry scrubbers, in pounds of sludge generated per pound of sulfur dioxide removed, were derived by applying the assumptions noted in the following equation:

$$\begin{aligned} & \left(\frac{\text{lbs. sludge}}{\text{lbs. SO}_2 \text{ removed}} \right) = \frac{\text{Molar Weight of Reacted By-Product and Waste}^3}{\text{Molar Weight of SO}_2^5} + \frac{\text{Molar Weight of Reagent Including Waste}^4}{\text{Percent Dry Solids}} \times (\text{Stoichiometry}) \end{aligned}$$

For wet scrubbers this factor equals 6.90, and for dry scrubbers the factor can be 3.14 or 3.08, depending on the percent of sulfur dioxide that is required to be removed (either 90% or 70% was assumed, depending on which level of sulfur removal was most consistent with the Revised New Source Performance Standard for sulfur dioxide from utility boilers).

Based on the expected sulfur content and total quantity of coal consumed by electric utilities, future federal and state sulfur dioxide regulations, and the amount of scrubber capacity forecasted to be in operation in future years, amounts of sulfur dioxide removed were estimated on a state basis. The sludge factors explained above were then applied to the quantities of sulfur dioxide removed to arrive at total FGD sludge generation. Exhibit B-7 presents historical and future FGD capacity and FGD sludge generation for the U.S.

EXHIBIT B-7**FGD CAPACITY AND FGD SLUDGE GENERATION**

	<u>FGD Capacity</u> <u>(10³ megawatts)</u>	<u>FGD Sludge Production</u> <u>(millions of tons)</u>
<u>Historical</u>		
1970	--	--
1972	0.7	0.2
1975	6.7	2.3
1980	27.4	9.5
<u>Estimated</u>		
1985	45.2	16.0
1990	62.4	24.1
1995	80.7	30.9
2000	179.3	50.3

Sources: 1970-1980: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants - 1980, DOE/EIA-0191(80), and Arthur D. Little, Inc., Full Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Volume I, June 1985.

1985-2000: See Attachment B-1 for the major assumptions used to develop these estimates. These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

ATTACHMENT B-1

**MAJOR ASSUMPTIONS USED IN THE DERIVATION
OF FUTURE ASH AND FGD SLUDGE GENERATION ESTIMATES ⁶**

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASH AND FGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value	Comments	
<u>Global Energy and Economic Conditions</u>			
● GNP (% Per Year Real Growth)	1983-1985	= 5.0	GNP growth is forecasted to be higher during the current recovery and then slow to a 3 percent average per annum growth rate by 1990.
	1986-1990	= 3.5	
	1991-1995	= 3.0	
	1996-2000	= 3.0	
	2001-2010	= 3.0	
● World Oil Prices (mid-1985 \$/bbl)	1985	= 28.10	ICP forecasts assume that oil prices will remain constant in nominal terms through 1985 because of near-term market conditions. Prices are assumed to recover somewhat by 1990, with 2.5-3.0 percent increases per year in real terms thereafter.
	1990	= 29.20	
	1995	= 34.10	
	2000	= 38.90	
	2010	= 49.80	
● Natural Gas Prices and Availability	1985 deregulation is assumed		
<u>Electric Utility Energy Demand</u>			
● Electricity Growth Rate (% Per Year)	1980-1984	= 2.2	
	1984-1985	= 2.4	
	1986-1990	= 2.5	
	1991-1995	= 2.5	
	1996-2000	= 2.5	
	2001-2010	= 2.5	
● Nuclear Capacity (Gw)	1985	= 67	Capacity estimates through 2000 reflect most recent announcements, postponements, and delays of currently planned power plants. Nuclear capacity in 2010 reflects an assumed upturn in nuclear capacity additions after 2000, which more than offset the forecasted retirement of 27 gigawatts of nuclear power plant capacity expected between 2001 and 2010.
	1990	= 105	
	1995	= 108	
	2000	= 109	
	2010	= 120	

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASH AND PGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value	Comments	
● Nuclear Capacity Factors (%)	1985	= 60	Improvement in the availability of nuclear units is expected as recent regulatory and technical problems resulting primarily from the Three-Mile Island experience are resolved.
	1990	= 64	
	1995	= 67	
	2000	= 67	
	2010	= 67	
● Substitution of Coal for Oil and Gas (Gw)	Reconversion capacity (1982-1995)	= 11.3	Reconversions and accelerated replacement are limited by institutional (e.g., state utility commissions) and financial (e.g., bond and equity markets) constraints. Latest estimates reflect expected delays and cancellations. Capital surcharges, which vary by CEUM region, are imposed on accelerated replacements to reflect these constraints.
● Utility Capital Costs (1980 \$/kw)	Coal	= 717- 851	Capital costs include 10 percent real escalation from 1980 to 1985. Nuclear capital cost estimates have been increased about 35 percent above previous EPRI estimates, reflecting (1) significantly longer construction and lead times, (2) more safety requirements for future plants, and (3) additional escalation in materials, equipment and labor costs. Nuclear capital cost estimates correspond to recent DOE estimates. Other power plant cost estimates are based on EPRI figures.
	Nuclear	= 1375-1561	
	Turbine	= 219- 251	
	Scrubbers, Dry	= 79- 91	
	Scrubbers, Wet	= 163- 189	
● Capital Cost Surcharges (1980 \$/kw)	1985-1990:	500-2000 (varies by region)	Capital cost surcharges are imposed on new capacity builds to limit economic replacements. Surcharges reflect regulatory, financial, and institutional constraints to capital investment.
	1995-2000:	500 for WO, CN, CS 750 for all others	
	2010:	0	
● Power plant Lifetime (Years)	Coal Steam	- 60	Power plant units are assumed to retire based on the assumed number of years after their initial date of commercial operation <u>except</u> for announced retirements. Coal power plants are refurbished after 30 years for \$200/kw (early-1985 \$). This is assumed to extend their useful lifetime from 45 to 60 years. Reconversions are assumed to retire 30 years after their reconversion date.
	Oil/Gas Steam	- 45	
	Nuclear	- 35	
	Oil/Gas Turbine	- 20	

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASH AND PGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value	Comments
● Coal Power plant Heat Rates Over Time	0.25% per year increase over current levels, After refurbishment improves heat rates are improved (decreased) by five percent from previous forecasts levels.	Based on empirical studies and engineering assessments of heat rate deterioration over time and the effects of power plant refurbishment.
● Minimum Turndown Rates	Coal - 35% Oil/Gas Steam - 20%	Coal and oil/gas steam units must operate at or above minimum load during the week. Minimum load levels assumed herein are based on various empirical studies of operating practice and constraints.
● Canadian Imports of Electricity (BKWH transmitted)	1985 = 45 1990 = 69 1995 = 89.9 2000 = 86.8 2010 = 96.9	Imports reflect current contracts and announced plans.
Financial Parameters		
● Inflation Rate (% Per Year)	1984 = 3.8 1985 = 4.0 1986-2010 = 5.0	Latest forecasts anticipate a small increase in average annual inflation rates.
● Real Discount Rate (% Per Year)	Coal Mine = 6.00 Utility = 4.27	
● Real Capital Charge Rates (%)	Coal/Nuclear/Combined Cycle 9.0 Pollution-Control--New 9.0 Pollution-Control--Retrofit 6.5 Combustion Turbine 10.5	The retrofit pollution-control capital charge rate is lower than the new pollution-control rate because of the rapid tax write-off provision available to retrofits only. Use of industrial revenue bond financing was not assumed.
● Book Life (years)	Coal/Nuclear/Combined Cycle 30 Combustion Turbine 20 Pollution Control-Retrofit 30 Pollution Control-New 30	Longer book life for pollution-control equipment assumed in the previous EPA base is the major reason for lower real capital charge rates for this equipment.

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASH AND FGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value	Comments	
● Tax Depreciation Life (years)	5	Tax depreciation based on Accelerated Cost Recovery System (ACRS) under Economic Recovery Tax Act of 1981.	
Retrofit Pollution Control	15		
Others			
● Input Year Dollars	early 1980		
● Output Year Dollars	early 1985		
● Escalation Input to Output Dollars	1.34		
<u>Real Cost Escalation Parameters</u>			
● Coal Transportation Rates (% Total Real Escalation)	<u>Rail</u>		Growing competition will hold down the marginal rail rates to levels below current average rail rates. Truck and barge rates are assumed to escalate in real terms to account for long-term fuel price increases.
	1981 - 1985	= -5.0	
	1986 - 2000	= 0.0	
	<u>Truck and Barge</u>		
	1981 - 1985	= 5.0	
	1986 - 2000	= 0.0	
<u>Coal Mining Productivity</u>			
● Mining Costs (% Annual Real Escalation)	Capital	= 1.0	
	Labor	= 1.0 in 1984; 2.0/3 yrs. thereafter	
	Materials	= 0.0	
● Mining Productivity Base Level (1985) (% of Standard)	UMWA	= 80	
	Non-UMWA	= 95	
	Mixed	= 90	
% Annualized Productivity Increase (1985-95)	Surface	= 1.0	
	Deep-Continuous		
	Mine	= 1.0	
	Deep-Longwall	= 2.0	
● Utility Power plant Capital Costs (% Total Real Escalation)	1980-1985	= 10.0	Expected real escalation in nuclear plant costs is higher and is incorporated in base nuclear cost estimates.
	1985-2000	= 0.0	

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASE AND FGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value	Comments	
<u>Other Governmental Regulations</u>			
● Federal Leasing Policy	Enough	Federal leasing is assumed to be sufficient to avoid artificially driving up market prices.	
● Air Pollution Regulations	Most recent federal and state rules.	Sulfur dioxide emission limits assumed to be tightened in New York and Wisconsin over the next ten years in light of recent state legislation aimed at responding to acid rain and/or ambient air quality concerns. Certain variances are assumed to expire and revisions are assumed to occur. No other changes assumed beyond current emission limitations.	
<u>Non-Utility Coal Demand</u>			
● Industrial/Retail Coal Use (10 ⁶ tons)	1985	= 82	Reflects recent forecasts of industrial boiler coal demand combined with forecast of the kiln and residential/commercial coal markets. Low oil prices and increased reliance on waste products and conservation are expected to dampen near-term coal demand.
	1990	= 109	
	1995	= 135	
	2000	= 170	
	2010	= 220	
● Steam Coal Exports (10 ⁶ tons)	1985	= 28	Reflects low growth in worldwide electricity demand and less market share going to U.S. producers, particularly in 1985 and 1990. Reduction in longer-term demands concentrated mainly in the Pacific Rim.
	1990	= 25	
	1995	= 48	
	2000	= 69	
	2010	= 120	
● Metallurgical Coal Use (10 ⁶ tons) -- Export	1985	= 53	Reflects sluggish growth expected in world markets.
	1990	= 49	
	1995	= 53	
	2000	= 61	
	2010	= 65	
-- Domestic	1985	= 54	Continuing trends in steel substitution limit forecasted domestic metallurgical coal use through most of the 1980's. Steel's recovery from the present slump is not yet complete by 1985.
	1990	= 61	
	1995	= 62	
	2000	= 62	
	2010	= 62	

MAJOR ASSUMPTIONS USED IN THE DERIVATION OF FUTURE ASH AND FGD SLUDGE GENERATION ESTIMATES

Critical Parameter	Value		Comments
● Synthetics (Coal Input in 10 ⁶ tons) (Million Tons)	1985	= 4	Outlook for coal-based projects continues to be unfavorable. Some slippage seen in on-line dates of major near-term projects. Great Plains Gasification Project assumed to stay on schedule.
	1990	= 8	
	1995	= 8	
	2000	= 8	
	2010	= 8	

APPENDIX B

NOTES

- ¹ For more detail regarding assumptions, see Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, February 1986, prepared by ICF Incorporated for the Environmental Protection Agency. The major assumptions concerning future energy demand, economic conditions, and government regulations used to derive the estimates in the ICF study are presented in Attachment B-1 to this Appendix.
- ² Arthur D. Little, Inc., Full Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June 1985.
- ³ The reacted by-product generated by wet scrubbers has a molar weight of 179; that generated by dry scrubbers has a molar weight of 146.3.
- ⁴ The molar weight of limestone (the reagent used in wet scrubbers), including 5 percent waste, is 105.3. The molar weight of lime (the reagent assumed used in dry scrubbers), including 5 percent waste, is 59.
- ⁵ The molar weight of sulfur dioxide (SO₂) is 64.064.
- ⁶ These assumptions were used in the analysis summarized in Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, prepared by ICF Incorporated for the Environmental Protection Agency, February 1986.

**REGULATION OF COAL COMBUSTION WASTE DISPOSAL
IN SEVENTEEN HIGH COAL-BURNING STATES**

This appendix contains a state-by-state description of coal combustion waste disposal regulation. The 17 states whose regulations are described below are the highest coal-burning states in the country -- together they account for over 70 percent of the nation's coal-fired electric capacity. This appendix supplements the description of state regulation found in Chapter 4 and serves as a companion document to the table shown in Exhibit 4-1.

Texas

Coal combustion wastes are regulated under Texas' Industrial Waste Management Regulations. The regulations cover two types of waste, referred to as Class I and Class II wastes, although they do not give any information about how a particular waste stream would be classified. Class I wastes are controlled to a greater extent than are Class II wastes; ground-water monitoring is required at Class I waste facilities. The regulations include no additional design or operating requirements for either type of waste. A permit is required for off-site disposal; on-site disposal requires notification only.

The report conducted for USWAG by Wald, Harkrader, and Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion By-Products, gives information on additional requirements in Texas: "For both on-site and off-site disposal, the Department performs a site-specific technical review based on written guidelines that recommend installation of soil-based liners, ground-water monitoring and vegetative cover. Surface impoundments containing wet fly ash should be scrutinized for excess leachate

head." A follow-up interview with a Texas environmental official gave the same information. According to the interview, a new plant's waste is given temporary Class I classification until the plant proves that the waste is non-hazardous. (The official could not recall any instance of a plant's failing to do so.) Although permits are not required for on-site disposal, plants follow site-specific guidelines issued by the Department when disposing of wastes on-site.

Texas' Industrial Waste Regulations include impoundments in the definition of an industrial waste facility, but do not give separate guidelines. According to the USWAG report and the Texas official, they are subject to the same requirements as are landfills, and regulated by both state water authorities, which govern discharges to surface water, and by state solid waste authorities.

Indiana

Coal combustion wastes are regulated under Indiana's Solid Waste Rules. According to these rules, permits are required for on-site and off-site disposal, and ground-water monitoring may be required. According to the USWAG survey, "both on-site and off-site facilities ... are subject to the sanitary landfill permit requirements, including ground-water monitoring, a periodic cover, and a two-foot final cover." A state environmental official stated during a follow-up interview that ground-water monitoring and other design and operating standards are required on a case-by-case basis, based on the geology of the site and on the results of a chemical testing of the waste.

The USWAG survey does not address Indiana's regulation of impoundments. The regulations only specifically apply to sanitary landfills -- impoundments are not mentioned. An Indiana environmental official states that impoundments are regulated only by the state's NPDES program, which does not specify design or operating requirements.

Kentucky

Under Kentucky's hazardous waste regulations, coal combustion wastes are "special wastes." If a waste fails an EP toxicity test, its disposal will be regulated as a hazardous waste, and be subject to RCRA Subtitle C-type design and operating requirements. Otherwise, the disposal is regulated under Kentucky's solid waste rules. Kentucky's solid waste regulations require leachate control systems; according to the USWAG survey liners are also required. Ground-water monitoring requirements are implemented on a case-by-case basis.

Kentucky's solid waste regulations are for "solid waste disposal facilities," and do not explicitly exclude or include impoundments. According to an interview with a Kentucky solid waste official, if the impoundment is part of a treatment process that discharges to surface water, it must have an NPDES permit. These permits do not specify design or operating requirements. If the impoundment no longer discharges to surface water, solid waste regulations apply.

Ohio

Ohio's hazardous waste regulations exempt coal combustion waste from regulation. The solid waste regulations also exclude "non-toxic fly ash." No criteria are given in the regulations for determining toxicity. According to the USWAG survey and a follow-up interview with an Ohio environmental official, the ash is given an EP toxicity test to determine whether it will be subject to Ohio's solid waste regulations. Almost all ash passes the test, and is therefore exempt from all regulation.

Ohio's solid waste regulations specifically exempt "pond or lagoon operations." Such operations are regulated under Ohio's water regulations, which do not specify design or operating requirements.

Pennsylvania

Pennsylvania has designed regulations specifically for the disposal of coal combustion waste. These regulations specify that chemical and geologic analysis must be performed at the disposal site; and that ground-water monitoring may be required on a case-by-case basis. However, the lining and leachate collection systems that are required for other solid waste disposal facilities are not required for coal combustion waste disposal sites.

According to the USWAG report, "fly ash ponds are regulated by permit under the Clean Streams Law of Pennsylvania; the permit requires NPDES testing and design standards, which include ground-water monitoring and leachate control."

Illinois

Coal combustion wastes are governed by Illinois' solid waste regulations. The regulations state that a permit is required for solid waste disposal facilities. Although the regulations do not distinguish between on-site and off-site disposal, a state environmental official interviewed for this report stated that on-site facilities are exempted from the permit requirement.

Although the regulations do not explicitly require liners, ground-water monitoring, or leachate collection, an Illinois representative indicated that these standards are often required for coal combustion waste disposal on a case-by-case basis.

The solid waste regulations only list regulatory requirements for landfills -- impoundments are not addressed. An agency representative stated that impoundments are regulated by Illinois' NPDES program, which requires ground-water monitoring.

West Virginia

Coal combustion wastes are regulated by West Virginia's solid waste regulations, which require permits for disposal. The regulations contain only cover and closure requirements, although the USWAG survey, citing interviews with environmental officials, gives more information: "All disposal sites must meet leachate, waste confinement, and aesthetic standards. There are specific

requirements concerning ground-water monitoring and final cover."

Michigan

Michigan's solid waste regulations call for on-site and off-site landfills to be permitted and to have ground-water monitoring systems. A Michigan official and information in the USWAG survey both confirmed this.

North Carolina

According to North Carolina's solid waste regulations, on-site and off-site landfills must have permits. In order to receive permits, the landfills must have a ground-water monitoring system. This information is confirmed by the USWAG report.

The Solid Waste regulations explicitly exclude impoundments, and leave their regulation to North Carolina's water regulations. The official water regulations regulate only discharge from impoundments, and do not contain any design or operating requirements, such as lining or ground-water monitoring, for surface impoundments.

Georgia

Georgia's solid waste regulations require permits for off-site and on-site disposal. No mandatory design or operating requirements, such as ground-water monitoring, liners, or leachate collection, are listed. According to a Georgia environmental official, design and operating standards are applied on an

case-by-case basis.

Only landfills are addressed in Georgia's solid waste regulations. According to a Georgia environmental official, surface impoundments are regulated by the state water regulations, which cover only discharge to surface water, and do not have requirements for ground-water monitoring or liners.

Florida

Florida's solid waste regulations require that off-site disposal facilities be permitted and have liners, leachate collection, and ground-water monitoring systems. On-site facilities do not need permits. The regulations have been changed significantly since 1983, when the USWAG report was written. The regulations apply only to sanitary landfills -- impoundments are not specifically mentioned.

Missouri

The regulation of coal combustion utility wastes are handled primarily under Missouri's solid waste regulations. According to the regulations, leachate collection systems are required on a case-by-case basis.

The solid waste regulations exempt lagoon operations that have permits from the Clean Water Commission. The Missouri Water Quality Standards do not specify any design or operation requirements for impoundments; the USWAG survey, however, states: "Permits from the Clean Water Commission impose specific requirements on ground-water quality." A follow-up interview with a

Missouri water official confirmed the information derived from the USWAG report.

Alabama

Alabama's Solid Waste Regulations require permits for off-site and on-site disposal. According to the USWAG survey, off-site disposal requires additional permission from local health authorities. The regulations require ground-water monitoring and an artificial lining on a case-by-case basis.

Tennessee

Under Tennessee's hazardous waste rules, "fly ash ... [is a] hazardous waste which [is] exempt from certain regulations." The hazardous waste regulations that apply to coal combustion by-products are for the testing of waste. An official from Tennessee indicated that the testing requirement gives the state waste agency information with which to design suitable disposal requirements for coal combustion wastes. Tennessee's solid waste rules govern the design and operation of coal combustion waste disposal facilities. Tennessee's solid waste regulations allow liners and ground-water monitoring to be required on a case-by-case basis.

Like most state solid waste regulations, Tennessee's regulations are unclear about the regulation of on-site facilities. Due to legal challenges, on-site solid waste facilities in Tennessee are not currently being regulated. Tennessee's solid waste regulations only explicitly list requirements for

sanitary landfills. Surface impoundments are not specifically addressed, although according to a Tennessee Valley Authority official, surface impoundments are regulated under NPDES permitting until the pond is full; once the impoundment no longer discharges to surface water, state solid waste regulations apply.

Nevada

Nevada's solid waste regulations pertain only to landfills, and specify only siting restrictions, cover, and layering requirements; ground-water monitoring, lining, and leachate collection are not required. According to the USWAG report, in practice, more stringent requirements are enforced: "The Department now requires a liner or its functional equivalent and groundwater monitoring." Nevada's solid waste regulations require municipalities and districts to devise a waste management system, and local authorities may adopt more stringent regulations than currently mandated by state law.

The solid waste regulations of Nevada appear to address only landfills; impoundments are not explicitly mentioned.

South Carolina

South Carolina regulates the disposal of coal combustion waste under its solid waste regulations. Disposal facilities must have permits, and minimal design and operating standards (cover, grade, siting) are imposed. The regulations require that facilities be designed by state-permitted engineers.

Impoundments are addressed in South Carolina's industrial solid waste disposal regulations: "Disposal of waste sludges and slurries shall be done with special consideration of air and water pollution, and the health and safety of employees ... [and] case-by-case provisions [are made]." No specific requirements are listed.

Wisconsin

In Wisconsin, coal combustion wastes are regulated under the state's solid waste regulations, which require solid waste disposal facilities to be licensed. Ground-water and leachate monitoring may be required on a case-by-case basis. Impoundments are included in Wisconsin's definition of a solid waste disposal site.

**SOURCES FOR APPENDIX C
(By State)**

Texas

Texas Industrial Waste Management Regulations. Interview with Richard Anderson, Industrial Solid Waste Section, Texas Department of Health, January 2, 1987. Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, prepared by Wald, Harkrader & Ross for the Utility Solid Waste Activities Group (USWAG), pp. 62-63.

Indiana

Indiana Solid Waste Management Permit Regulations. Interview with George Oliver, Land Pollution Control Division, State Board of Health, January 2, 1987. USWAG Survey, p. 20.

Kentucky

Kentucky Waste Management Regulations. Interview with Shelby Jett, Natural Resources and Environmental Protection Cabinet, Department of Environmental Protection, January 6, 1987. USWAG Survey, p. 24.

Ohio

Ohio Solid Waste Disposal Regulations. Interview with Tina Redman, Office of Land Pollution Control, Ohio Environmental Protection Agency, January 2, 1987. USWAG Survey, pp. 51-52.

Pennsylvania

Pennsylvania Solid Waste Regulations. Interview with Ron Hassinger, Bureau of Solid Waste Management, Department of Environmental Resources, January 2, 1987. USWAG Survey, p. 55.

Illinois

Illinois Solid Waste Regulations. Interview with Harry Chapel, Division of Land and Noise Pollution Control, Environmental Protection Agency, January 5, 1987. USWAG Survey, p. 18.

West Virginia

West Virginia Solid Waste Regulations. USWAG Survey, p. 69.

Michigan

Michigan Solid Waste Management Regulations. Interview with Karen Kligman, Resource Recovery Division, Department of Natural Resources, January 6, 1987. USWAG Survey, p. 32.

North Carolina

North Carolina Solid Waste Management Regulations. USWAG Survey, p. 49.

Georgia

Georgia solid Waste Management Rules. Interview with Burt Langley, Land Protection Branch, Division of Environmental Protection, Department of Natural Resources, January 2, 1987. USWAG Survey, p. 15.

Florida

Florida Resource Recovery and Management Regulations.

Missouri

Missouri Solid Waste Rules and Regulations. Missouri Water Quality Standards. Interviews with Suzanne Renard, Missouri Waste Management Program, and with Bob Hengtes, Missouri Clean Water Commission, January 23, 1987. USWAG Survey, p. 36.

Alabama

Solid Waste Management Regulations. USWAG Survey, p. 1.

Tennessee

Tennessee Hazardous Waste Management Rules. Tennessee Solid Waste Regulations. Interview with Dwight Hinch, Regulations and Legislative Office, December 31, 1986. USWAG Survey, p. 61.

Nevada

Nevada Solid Waste Management Regulations. USWAG Survey, p. 41.

South Carolina

South Carolina Industrial Solid Waste Disposal Site Regulations, South Carolina Guidelines for Waste Disposal Permits. USWAG Survey, p. 58.

Wisconsin

Wisconsin Solid Waste Management Regulations. USWAG Survey, p. 70.

WASTE FLUID STUDIES

This appendix presents the results of studies on the waste fluids in coal combustion waste landfills and impoundments. Waste fluids are not ingested, but the constituents in the waste fluids have the potential to affect the quality of surrounding ground water or surface water. These studies are also useful for illustrating some of the characteristics of coal combustion wastes.

Tennessee Valley Authority Power Plants

A report by R.J. Ruane and others summarized Tennessee Valley Authority (TVA) research on wet ash disposal and wet limestone scrubber-sludge.¹ The study on ash disposal involved 12 TVA coal-fired plants, including a description of the effects of ash disposal at a typical 1000-MW plant, which produces approximately 700 tons of fly and bottom ash per day. The ash is either disposed of in a dry form or sluiced to the ash containment ponds. The wet limestone scrubber-sludge examined in the study was from a 550-MW plant at the Widows Creek Steam Plant.

Several constituents in subsurface leachates from the ash ponds exceeded the primary and secondary drinking water standards. Constituents found in concentrations that exceeded the primary or secondary criteria included cadmium, chromium, iron, manganese, lead, sulfate, pH, and TDS. Some of the ash pond leachates were quite acidic with measured pH values as low as 2.0.

The operation of the wet limestone scrubber and the transfer of scrubber

blowdown to the ash ponds caused statistically significant increases in the concentrations of calcium, magnesium, chloride, sulfate, selenium, TDS and conductivity in the ash pond discharges.

In addition to monitoring ash pond effluents, the TVA also conducted toxicity studies on ash pond effluents from four distinct waste disposal sites. The toxicity studies were performed in the spring and fall. The fall studies showed no significant effects on the tested species (Daphnia pulex and Pimephales promelas) while the spring studies revealed significant effects on the survival and reproduction of Daphnia pulex.

In summary, several of the fly ash leachates had constituent concentrations that exceeded drinking water standards. These constituents included cadmium, chromium, iron, manganese, and lead. Higher concentrations of potential contaminants were associated with extreme pH values. Some of the fly ash leachates had pH values as low as 2.0. Some of the fly ash effluents demonstrated the potential to affect the biological environment.

Turner Study of Arsenic in Coal Ash Leachate

R.R. Turner (1981) collected ash disposal pond effluents at 12 coal-fired utilities and pond influent samples at three utilities.² At one of the sites, two wells were drilled into an older ash basin and used to collect interstitial water from the middle and bottom of the basin. All samples collected, including influents, effluents, and well samples, were analyzed for total dissolved arsenic (TDA) and for arsenic (III).

The effluents from the ponds located at the 11 largest utilities had TDA measurements ranging from 0.5 to 130 $\mu\text{g}/\text{l}$. The arsenic (III) to TDA ratio was always 0.40 or smaller at these 11 plants. Arsenic concentrations in the pond at the smallest of the 12 plants were between 116 and 460 $\mu\text{g}/\text{l}$ in the pond influent and varied from 118 to 150 $\mu\text{g}/\text{l}$ in the pond effluent. The interstitial fluid drawn from the wells located in the middle and bottom of the older fly ash disposal site had arsenic concentrations that reached 550 $\mu\text{g}/\text{l}$ in the middle well and 1590 $\mu\text{g}/\text{l}$ in the well placed at the bottom of the fly ash. Arsenic (V), the less toxic state of arsenic, was the predominant arsenic species in all of these samples.

There was a wide variability in arsenic concentrations in all of the samples collected from the field as well as in the effluents from column leaching studies that were conducted concurrently with the field studies. This demonstrates the inherent variability of the fly ashes and the environments in which they are located, and thus the difficulty of trying to determine generic conditions for fly ash disposal. Arsenic (V) concentrations appeared to be controlled either by adsorption onto amorphous iron oxyhydroxides in the neutral to slightly acidic pH range or by slightly soluble metal arsenates. Mechanisms controlling arsenic (III) concentrations were not determined by this study.

The study results suggest that the use of iron oxyhydroxides in limiting the migration of trace elements may be beneficial at selected sites.

Savannah River Project, Aiken, South Carolina

In a series of papers, Cherry, Guthrie, and co-workers studied the drainage system for an ash basin serving a coal-fired power plant at the Savannah River Project in Aiken, South Carolina.³ To provide data for these papers, surface water samples were collected from the influent to and effluent from several large ash basins. Also, samples were taken at several points within the drainage system downstream from the ash disposal ponds. These samples were analyzed to determine the concentrations of constituents.

Plants, invertebrates, and vertebrates were also monitored. These studies took place over a period of more than eight years from mid-1973 to January 1982. During this time, selected water quality parameters were monitored on a monthly, bimonthly, or quarterly basis. By studying the various sinks for the constituents in the effluents from the ash disposal ponds, conclusions were reached as to the dissipation mode of constituents in the surface waters of the drainage system. Differences in constituent concentrations accumulated in the various components of the system were tested by a two-tailed analysis of variance.

The biotic components of the drainage system tended to contain higher concentrations of potentially toxic constituents (titanium, manganese, copper, chromium, zinc, arsenic, selenium, cobalt, cadmium, and mercury) than the surface water components inhabited by the biota. The highest concentrations of constituents occurred in the benthic sediments; the settling of sediments represented the mechanism for the greatest removal of constituents from the

system. Certain constituents, calcium and zinc, were concentrated in invertebrates and fish at a higher level than that found in the sediments. Two constituents, cadmium and selenium, were present in the effluents from the ash ponds in concentrations that exceeded the primary drinking water standards. Though concentrated by invertebrates, the invertebrate concentration of these constituents did not exceed the concentration found in the sediments. At near neutral pH values (pH 6.5), mean concentrations of arsenic, cadmium, chromium, copper, selenium, and zinc in the effluent drainage system were higher than either the maximum and/or 24 hour average allowable for these parameters in the U.S. EPA Water Quality Criteria.⁷ The mean elemental concentrations of four of these constituents (cadmium, chromium, copper, and zinc) were from one to two orders of magnitude higher than the allowable 24 hour average.

When the ash disposal system was properly managed, there appeared to be a minimal effect on the aquatic system. However, when an ash pond overflowed into the effluent drainage system without adequate time for settling of the sediments to occur, major impacts upon the effluent drainage system were observed. Heavy sediment concentrations and low pH conditions (the extreme effluent pH observed was 3.5) caused by the overflow resulted in severe reductions of most invertebrate fauna. The invertebrate population densities eventually returned to pre-overflow levels when the problem was corrected. The bioconcentration of potentially toxic constituents will, undoubtedly, have an effect on the biota. It is impossible to ascertain the effect of constituent accumulation from the ash ponds, however, because the constituent concentrations prior to initiation of this study are not known. Several trace

metals have concentrations in ash pond effluents that exceed the primary drinking water standards.

Bull Run Steam Plant, Oak Ridge, Tennessee

In cooperation with personnel from the TVA, Coutant and others⁴ investigated the chemistry and biological hazard of seepage from an ash pond at the TVA's 900-MW Bull Run Steam Plant near Oak Ridge, Tennessee. Ash from the Bull Run Steam Plant is slurried to three ash ponds connected in a series. The ash stream consists of fly ash, bottom ash and pieces of pyrite that were separated from coal prior to combustion. The three ponds act as settling ponds to allow ash particles to drop out of solution. At the end of the third pond is a weir over which effluent flows into the Clinch River. Monitoring at the discharge weir has been regularly conducted since 1967. During this time, analyses have been performed for a variety of constituents including alkalinity, conductivity, TDS, calcium, magnesium, chloride, sodium, total iron, total manganese, sulfate, and silicon dioxide.

In addition to the flow through the ash ponds and over the weir, there is another flow that was previously uncharacterized. This flow was in a drainage ditch that ran parallel to one of the ash ponds. The drainage ditch ends at a culvert that flows into the Clinch River. The sediments at the bottom of the drainage ditch, the water in the ditch and vegetation that had blown into the ditch were all colored a reddish hue. The objective of this study was both to characterize and understand the mechanism responsible for the reddish hue and to check for biological hazard by exposing fish to the drainage discharge at

its confluence with the Clinch River. Samples were taken so as to follow the flow in the drainage ditch from its uppermost point to its point of discharge at the river.

The reddish precipitate contained over 40 percent iron and was determined, by x-ray diffraction, to be mainly FeOOH . The formation of the precipitate was consistent with the chemical data which revealed that iron concentrations in the drainage liquor continuously decreased along the flow path. Total dissolved iron concentration was 927 mg/l at the beginning of the ditch, and fell to 320 mg/l by the time the liquor reached the culvert that discharged into the Clinch River. Concomitant with the drop in total dissolved iron, ferrous iron concentrations fell and ferric iron concentrations rose along the same flow path. Most of the iron leaving the ash ponds went through the drainage ditch and not over the weir at the end of the ash ponds. The liquor in the ditch became more acidic as flow progressed towards the Clinch River. Initial pH values in the flow were 3.2, while the pH fell to 2.9 at the culvert. The total iron discharged from the ditch per unit time was approximately 44 times the iron discharged over the weir, even though the volume of the flow over the weir was roughly 20 times the flow in the ditch.

As might be expected, the discharge from the ditch posed a biological hazard. All fish placed in the ditch at the entrance to the culvert or in the Clinch River at the culvert discharge point died within three days. A control group of fish, placed in an unaffected part of the Clinch River, survived during the time frame of the experiment (2 weeks).

Liquor in the drainage ditch from the ash pond leachate poses a biological threat. This threat is limited because of dilution by the significantly greater flow of the Clinch River. The acidification encountered in this study probably is a result of the oxidation of the pyritic ore that was discharged to the ash ponds. Oxidation of pyrite produces hydronium and sulfate ions. Lower pH values, besides posing a threat to the environment because of the acidity, can mobilize many trace constituents found in the ash. Analyses were not performed for trace constituents in this study.

APPENDIX D

NOTES

- 1 Ruane, R.J., J.D. Milligan, R.C. Young, T.Y.J. Chu and H. Olem. "Aquatic Effects of Wet Ash Disposal and Wet Limestone Scrubber Systems." In International Conference on Coal Fired Power Plants and the Aquatic Environment. Supplement to Proceedings. CONF-8208123, Hoersholm, Denmark, Water Quality Institute, pp. 669-673, 1982.
- 2 Turner, R.R. "Oxidation State of Arsenic in Coal Ash Leachate." Environmental Science Technology, Vol. 15, No. 9, pp. 1062-1066, 1981.
- 3 Cherry, D.S., and R.K. Guthrie. "Mode of Elemental Dissipation from Ash Basin Effluent." Water, Air, Soil, Pollution, Vol. 9, pp. 403-412, 1978.

Cherry, D.S., R.K. Guthrie, E.M. Davis and R.S. Harvey. "Coal Ash Basin Effects (Particulates, Metals, Acidic pH) upon Aquatic Biota: An Eight-Year Evaluation." Water Resource Bulletin, Vol. 20, No. 4, pp. 535-544, 1984.
- 4 Coutant, C.C., C.S. Wasserman, M.S. Chung, D.B. Rubin and M. Manning. "Chemistry and Biological Hazard of a Coal Ash Seepage Stream." Journal of Water Pollution Control Federation, Vol. 50, pp. 747-753, 1978.

**ARTHUR D. LITTLE STUDY OF
WASTE DISPOSAL AT COAL-FIRED POWER PLANTS**

Arthur D. Little, Inc. (ADL) conducted a 3-year study for EPA's Office of Research and Development on coal ash and flue gas desulfurization waste disposal practices at coal-fired power plants. The study involved characterizing wastes generated at coal-fired power plants and gathering data to assess the environmental effects and engineering costs associated with the disposal of combustion wastes.

Results of the study were intended to be used: (1) as a technical basis to help EPA determine the degree, if any, to which disposal of these wastes should be managed to protect human health and the environment; and (2) to provide useful information on environmentally sound disposal of coal ash and FGD wastes to utility planners and state and local permitting officials.

To accomplish these goals, in-depth evaluations of six waste disposal sites around the country were undertaken. The study approach is discussed below.

E.1 SITE SELECTION PROCESS

To characterize the different types of waste generated at coal-fired utility power plants, individual assessments of impacts were conducted at specific waste disposal sites. Only six sites were actually investigated, although the original intent of the study was to examine a larger number of utility disposal sites. The process by which these six sites were selected is briefly discussed below.

The 48 contiguous states were divided into 14 physiographic regions,¹ and coal-fired power plants for which data² was available were identified in each of these regions.³ Sites were then screened to identify those for which a reasonable assessment of data obtained from one year of environmental monitoring would be possible. Screening criteria were based on engineering/technology-related, hydrologic, and other site-selection factors (e.g., site age, generating capacity, technological or hydrogeologic complexity, waste types generated, disposal methods, site location, etc.)⁴

As a result of this process about 26 "candidate sites" were chosen. The "candidate sites" were then subjected to further evaluation to assess their suitability. This included:

- contact with the facility to determine its willingness and ability to cooperate in the study.
- a visit to the power plant and disposal sites; and
- review of the available data on the hydrogeologic and environmental setting of the area and site.

On the basis of these evaluations, a final number of six sites were selected. These six sites were the Dave Johnston Plant in Wyoming, the Sherburne County Plant in Minnesota, the Powerton Plant in Illinois, the Elrama Plant in Pennsylvania, the Allen Plant in North Carolina, and the Smith Plant in Florida. Factors that were considered to be important in the selection of each site for of the study are discussed in subsequent sections.

E.2 SITE INFORMATION

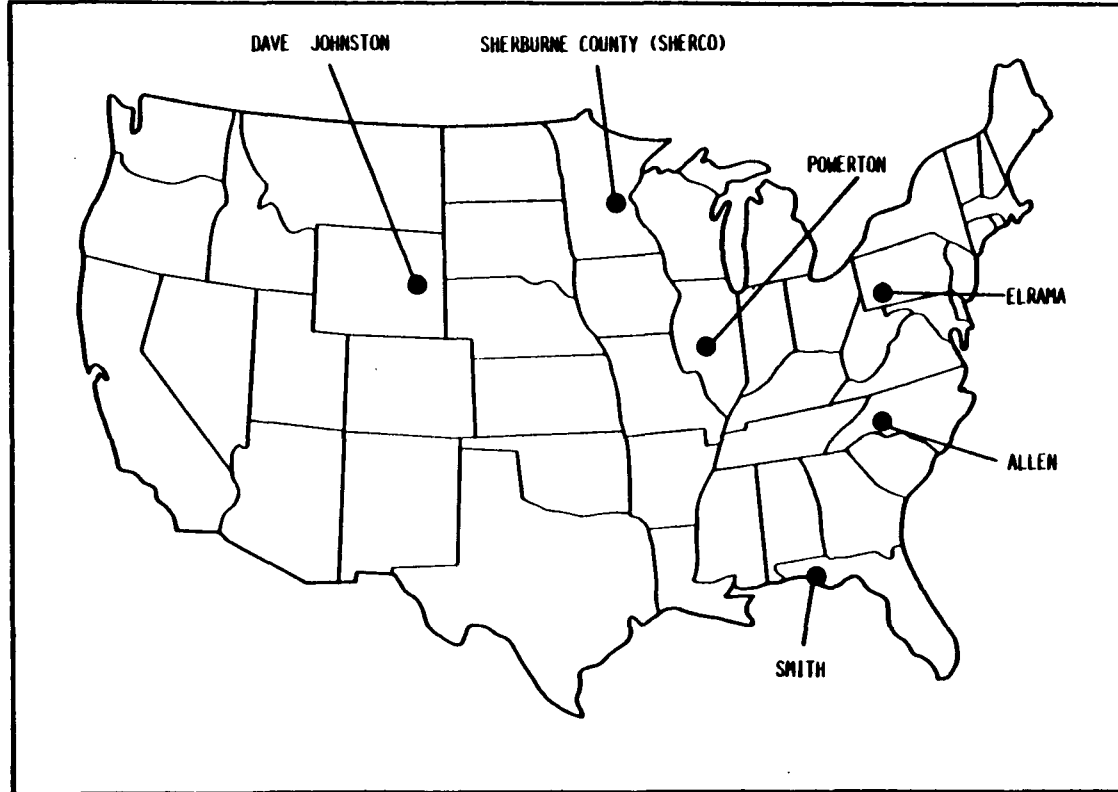
Exhibit E-1 shows the general locations of the six sites of the ADL study. Exhibit E-2 provides information from each site, including generating capacity, operating dates, and waste type and disposal method.

E.3 STUDY APPROACH

Investigations carried out at the six sites included physical and chemical sampling of the wastes, soils, ground water, and surface water at the site, subsurface explorations utilizing boring and wells, soil and rock classification and mapping, and water balance studies. Results were used to make individual environmental assessments of each site (i.e., assessing the effects of waste disposal on ground-water and surface-water quality). Findings from the six sites were also used to try to make generic projections of industry-wide implications of coal ash and FGD Waste Disposal.

The six sites are discussed individually in the following sections, E.4-E.9. A brief description is given of each site's disposal activities, hydrogeology, and reasons for its selection by ADL for study. Also presented are the results of testing done at the site and discussion of these results. An analysis of the testing results at the six sites for QA/QC is presented in Section E.10. A summary of findings at each site and a discussion of conclusions that can be drawn from the ADL study in regard to the environmental impacts that may occur due to waste disposal practices at coal-fired power plants is presented in Chapter 5.

EXHIBIT E-1
LOCATIONS OF SITES SELECTED FOR ADL STUDY



Source: Tetra Tech, Incorporated, Groundwater Data Analyses at Utility Waste Disposal Sites. This report evaluated the A.D. Little data for the Electric Power Research Institute.

Source: Arthur D. Little 1985.

EXHIBIT E-2
INFORMATION ON SITES OF ADL STUDY

Plant	Utility	Location		Capacity (MW)		Startup Date (mo/yr)		Waste Site Under Study		High Priority Issues Under Study		
		State	County	Nameplate Generating	FGD Unit On	Plant	FGD	Waste Type	Disposal Method	Ground-water Quality	Surface-water Quality	Potentially Mitigative Practice
Allen	Duke Power	NC	Gaston	1155	-	-/57	-	Combined fly and bottom Ash	Pond (UL)	x	x	x
Elrama	Duquesne Light	PA	Washington	510	510	6/52	10/75	Stabilized FGD waste Combined fly and bottom ash	Landfill (UL; offsite) Landfill (UL)	x	x	x
Dave Johnston	Pacific Power & Light	WY	Converse	750	-	-/57	-	Fly Ash	Landfill (UL)	x	-	x
Sherburne County	Northern States Power	MN	Sherburne	1458	1458	5/76	5/76	Fly ash/FGD	Pond (AL)	x	-	x
Powerton	Commonwealth Edison	IL	Tazewell	1786	-	-/72	-	Combined fly and bottom ash	landfill (AL)	x	x	x
Smith	Gulf Power	FL	Bay	340	-	6/65	-	Combined fly and bottom ash	Pond (UL)	x	x	x

Notes:

^aUL - Unlined
AL - Artificially Lined

^bDisposal site operated by Conversion Systems, Inc.

E.4 ALLEN PLANT

Plant Allen of Duke Power Company is located in Gaston County, North Carolina, four miles southeast of the town of Belmont. The plant began operations in 1957. The plant site is adjacent to the west bank of Lake Wylie, an impoundment that is part of the Catawba River Development. At the time of the study, there were five units at the plant. Electrostatic precipitators were added to all units between 1965 and 1970. The Appalachian bituminous coal used for fuel had about one percent sulfur and 12 to 15 percent ash.

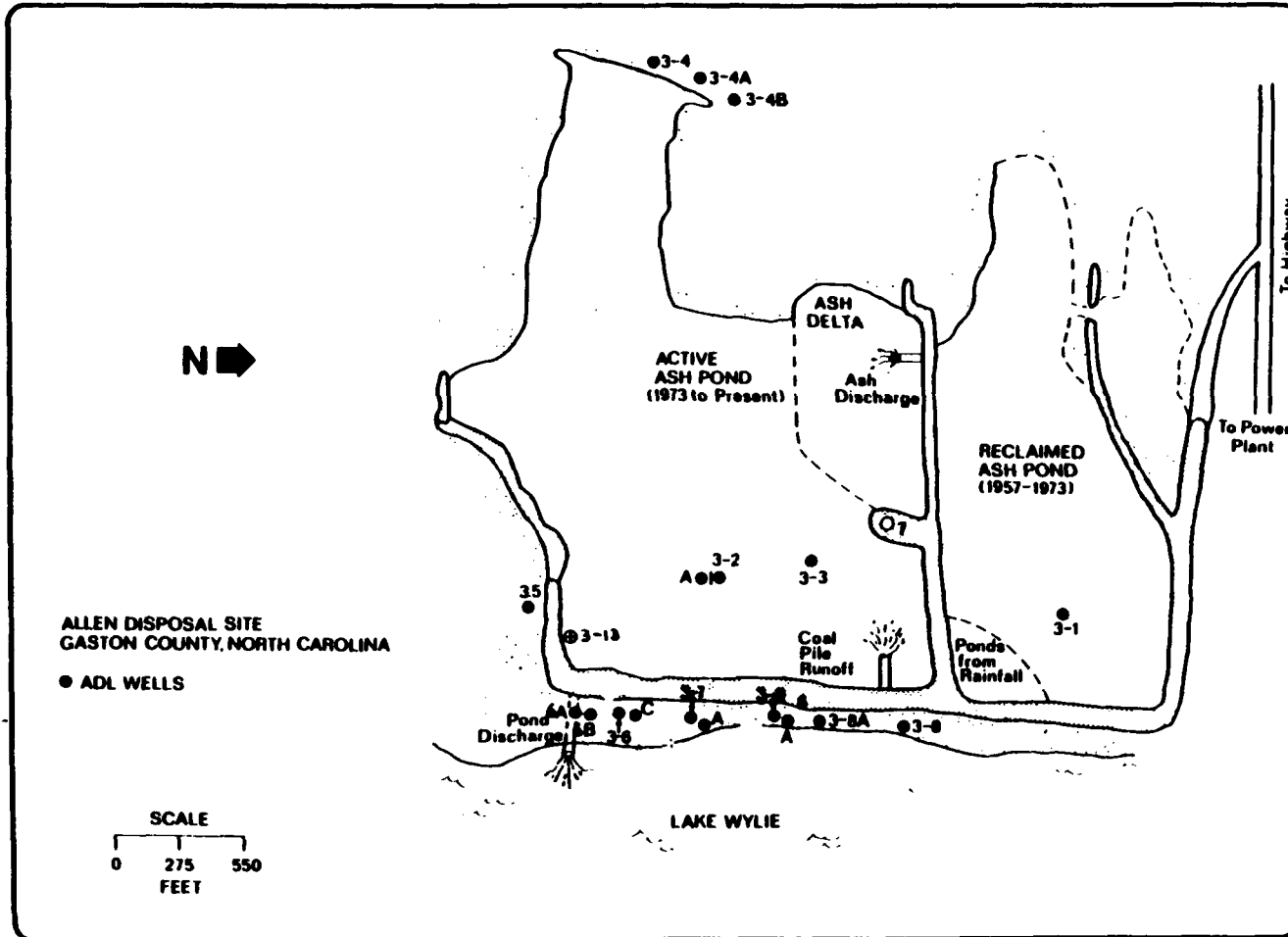
The coal ash disposal site at the Allen Plant consisted of two separate, major units (Exhibit E-3). One unit was the operating or active ash pond, 146 acres in size, which was unlined and dates back to 1973. Combined fly ash and bottom ash were wet-sluiced to the pond (using waters from Lake Wylie). In addition, the pond received two types of low-volume wastes: surface runoff from the power plant (including coal pile runoff) and boiler cleaning wastes. Significant amounts of copper, nickel, and zinc were added to the disposal pond during boiler cleaning events. The liquid supernatant from the pond was discharged untreated into Lake Wylie.⁵

A second retired ash disposal pond was located immediately north of and adjacent to the active pond. This 127 acre facility was used from 1957 to 1973 for disposal of fly ash and bottom ash. Part of this pond had been graded, covered with soil, and seeded.

The igneous bedrock at the site slopes toward the lake and has been intruded with permeable dikes and sills. These dikes and sills tended to create

EXHIBIT E-3 DISPOSAL PONDS AND SAMPLING LOCATIONS AT ALLEN SITE

Source: Tetra Tech 1985.



drainage paths. Overlying the bedrock was a thick soil layer formed from the underlying bedrock. This "residual" soil layer ranged from 10 to more than 40 feet in thickness at the site, and was composed chiefly of sand and silt. Beneath some portions of the site, there were alluvial deposits filled with loose and permeable material.

The Allen site received an average of 43 inches of precipitation a year. The net ground-water recharge from precipitation was about 12 inches per year. In addition, a large amount of ash sluice water entered the pond (approximately 30 times as much water as the total direct precipitation on the active pond). There were indications that plant discharges into the disposal ponds had created ground-water mounding in their immediate vicinity and had saturated the vadose zone. The residual soil and alluvium comprised the aquifer in the vicinity of the Allen site. Upgradient from the pond, the water table was approximately 30 feet beneath the land surface. Immediately downgradient, it was continuous with the surface of Lake Wylie. Local surface and ground-water flow was easterly towards Lake Wylie.

Factors that were considered to be important in the selection of the combined fly ash/bottom ash disposal operation at the Allen Plant for study included the following:

- The site was located in the Piedmont Region, which contained significant coal-fired generating capacity;
- The practice of pond disposal of combined fly ash and bottom ash was the most common disposal practice for these wastes in the United States and virtually the only disposal practice in the Piedmont Region;

- The environmental conditions (the amount of precipitation and the mix of residual and alluvial soils) were considered typical of many other locations in the eastern half of the U.S. and are particularly representative of the Piedmont Region; and
- Co-disposal of intermittent, contaminant-rich waste streams (i.e., boiler cleaning wastes and coal pile run-off) in ash ponds occurred at Allen Plant and was also widely practiced at other utility sites.

E.4.1 Sampling Approach

Samples of wastes and soils were collected for physical and chemical testing. Samples of ground water, waste fluids (or liquors), and ash pond discharge samples were collected for chemical testing. A series of attenuation tests were executed using ash pond liquors and local site soils.

ADL installed 18 monitoring wells at the site, of which four were drilled close together but to different depths. Three wells were intended to be background (upgradient) ground-water wells, however, two (Wells 3-4 and 3-4A) were inundated more than once when the pond elevation rose. Thus only one well yielded representative background ground-water data (Well 3-4B). One downgradient ground-water well (Well 3-5) was drilled on the south side of the active pond dike. The other 10 downgradient ground-water wells were located between the active pond and Lake Wylie. Seven of these downgradient wells were drilled into the residual soils (Wells 3-5, 3-6, 3-6C, 3-7A, 3-8, 3-9, and 3-9A), one was drilled into alluvium (Well 3-6A), and two were drilled into what is identified as "fill" (it is unclear what this material is). Four of the downgradient wells were considered to be "representative" of the site -- Wells 3-6, 3-9, 3-7A, and 3-8.

One monitoring well was located within the retired ash pond (3-1) and appears to have sampled waters in and under the older waste. Three monitoring wells were drilled within the active ash pond. One sampled fluids within the ash solids (pond liquors, Well 3-2A), one sampled water within the alluvium under the ash and within the ash (Well 3-2), and one sampled water in the residual soils under the ash and within the ash (Well 3-3). Fluids from the ash pond that are discharged into Lake Wylie were also examined (Well 3-13).

Locations of site wells are shown on Exhibit E-3. Wells were sampled for contaminant concentrations on three dates. The values of and trends in sampling and analysis results for the site, and comparison of ground-water concentrations with relevant EPA standards for drinking water are discussed below.

E.4.2 Results

Exhibit E-4 presents the results of chemical sampling at the Allen site. This includes samples from the downgradient and upgradient ground-water wells, samples from wells placed within the wastes to collect interstitial waters or fluids, and water samples obtained from materials beneath the wastes.

Waste Solids. Fly ash and bottom ash wastes in the abandoned pond were found to be segregated due to different discharge locations. The bottom ash was found to have a greater permeability than the finer fly ash. No distinct zones of fly ash and bottom ash were found in the active pond. A range in permeability of 2×10^{-4} cm/sec to 4×10^{-3} cm/sec was found.

EXHIBIT E-4

CHEMICAL SAMPLING RESULTS FOR ALLEN SITE

ALLEN SITE
(no Surface Water data)

Units = ppm		Ground water						Water In and Under Waste						Waste					
PCMS	Drinking Water Standard	1/ Total Downgradient (11 wells)			2/ "Representative" Downgrad. (4 wells)			3/ Upgradient (1 well)			4/ Water Under Active Pond (2 wells)			5/ Water Under Retired Pond (1 well)			6/ Pond Liquors (8 stations)		
		Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	7/ Samples	8/ Ave. Conc.	9/ Max. Exceed.
Arsenic (liq.)	0.05	12	0		7	0		2	0		4	0		2	2	1.1	5	0.55	30.5
Barium	1	31	0		12	0		3	0		6	2	1.3	3	0		7	0.23	
Cadmium 11/	0.01	31	0		12	0		3	0		6	0		3	0		1	0.053	5.3
Chromium (Cr VI)	0.05	31	0		12	0		3	0		6	0		3	0		4	0.014	
Fluoride	4.0	34	0		14	0		4	0		7	0		3	0		7	0.79	
Lead	0.05	31	0		12	0		3	0		6	0		3	0				12/
Mercury	0.002	0			0			0			0			0			NS		
Nitrate 13/	45	34	0		14	0		4	0		7	0		3	0		8	1.4	
Selenium (liq.)	0.01	5	0		4	0		2	0		2	0		1	0		3	0.0047	
Silver	0.05	31	0		12	0		3	0		6	0		3	0		0		

SDMS																			
Chloride	250	34	0		14	0		4	0		7	0		3	0		8	9	
Copper	1	31	0		12	0		3	0		6	0		3	0		4	0.026	
Iron	0.3	31	7	82	12	3	48	3	0		6	3	89.7	3	0		7	0.02	
Manganese	0.05	31	19	102	12	5	54	3	1	1.4	6	6	280	3	0		7	0.1	
Sulfate	250	34	0		14	0		3	0		7	0		3	0		8	137	
Zinc	5	31	0		12	0		3	0		6	0		3	0		1	0.03	
pH Lab 14/	<=6.5	10	10	4.7	4	4	6.1	1	1	5.9	2	2	6.3	1	0		NS		12/
	>=8.5	10	0		4	0		1	0		2	0		1	1	10.2	NS		12/
pH Field 14/	<=6.5	28	21	4.4	10	4	5.9	3	2	6.2	6	2	6.4	3	0		NS		12/
	>=8.5	28	0		10	0		3	0		6	0		3	3	11.4	NS		12/

EXHIBIT E-4 (Continued)
CHEMICAL SAMPLING RESULTS FOR ALLEN SITE

- 1/ Wells 3-5 (this well is somewhat peripheral to pond), 3-6, 3-6C, 3-7A, 3-8, 3-9, 3-9A, 3-6A, 3-6B, 3-8A, and 3-7.
- 2/ Wells 3-9, 3-7A, 3-6, and 3-8. These wells were chosen by ARL as being representative of the downgradient groundwater.
- 3/ Well 3-4B.
- 4/ Wells 3-2 (all.) and 3-3 (res.). The fluids collected at these wells are from beneath the active ash pond.
- 5/ Well 3-1. The fluids from this well are from beneath the retired ash pond.
- 6/ Stations 3-2 (16-18 ft), 3-2 (20-22 ft), 3-2 (24-26 ft), 3-2 (38-40 ft), 3-2A (24.5-26.4 ft), 3-3 (10-12 ft), 3-3 (22-24 ft), and 3-3 (24-26 ft). These "pond liquors" are fluids collected from within the landfilled wastes.
- 7/ The number of samples with reported concentrations above the drinking water standard.
- 8/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 9/ The number of "pond liquor" samples with reported concentrations above the reported detection limits. An entry of "0" indicates that no sample had a detectable contaminant concentration, not that no samples were taken (see footnote 13).
- 10/ Ave. Conc. is the average of the reported concentrations of all "pond liquor" samples taken that showed a contaminant concentration above the detection limit. The reported pH measurements of the "pond liquors" are also averaged.
- 11/ Where the reported detection limit for cadmium was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For some water samples collected from total and "representative" downgradient groundwater, upgradient groundwater, and under the active and retired ash ponds, the reported detection limit of 0.1 was greater than the PDMS for cadmium.
- 12/ The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPWQS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 13/ NS = not sampled.
- 14/ As indicated in footnote B, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

Waste Fluids. Results from fluid samples collected from wells implanted within the waste indicate that these fluids or pond liquors, when compared to Primary Drinking Water Standards, exhibit elevated concentrations of arsenic (up to 31 times the PDWS) and chromium (up to 2 times the PDWS). Although waste fluids are not directly ingested, comparison to the drinking water standards are shown to indicate the potential for contamination at the site.

Observed levels of arsenic in the pond liquors were up to 31 times the PDWS. Although interpretations to EP (extraction procedure) test results cannot be readily made, it should be noted that the results of EPA Extraction Procedure (EP) tests on waste samples from this site indicated much lower levels (about two orders of magnitude) of arsenic than the elevated concentrations of arsenic measured in waters from within the ash.

Water samples obtained from in and under the closed ash pond exhibited a slight exceedance of the PDWS for arsenic. The pH of these samples (as high as 11.4) indicated alkalinity. Water samples obtained from in and under the active ash pond exhibited a slight exceedance of the PDWS for barium (1.4 times the PDWS). These samples also exhibited elevated concentrations of iron (up to 90 times the SDWS), elevated concentrations of manganese (up to 280 times the PDWS), and slight acidity (pH as low as 6.3).

Ground water. Estimates were made of seepage velocities at the site. Results from these calculations appeared to indicate that there had been enough time for waste leachate constituents in the eastern (downgradient) portion of the disposal pond to have reached downgradient wells and Lake Wylie.

No exceedances of Primary Drinking Water Standards were found in the ground water of the downgradient wells or the ground water of the upgradient wells. Secondary Drinking Water Standards were found to be exceeded in the downgradient ground water for iron (up to 82 times the SDWS) and manganese (up to 102 times the SDWS). These contaminants were not observed in the pond liquor samples, but were the same as those observed in water samples collected in and under the wastes of the active pond. Downgradient ground water was found to be slightly acidic (pH as low as 4.4). Secondary Drinking Water Standards were also found to be exceeded in the upgradient ground water for manganese (up to 1.4 times the SDWS). The pH also indicated slight acidity (pH as low as 5.9) in the upgradient ground water.

Surface Water. No surface water samples were collected at this site.

Attenuation Tests. The results of attenuation tests with pond liquor solutions and site soils indicated that the local soil attenuation capacity for arsenic was very high (10 micrograms/gram of soil). It appears likely that arsenic was chemically attenuated by iron and/or manganese oxides which were found to be present in high levels in the soils under and around the ash pond. The degree of attenuation was also determined to be high for selenium. The estimated chemical attenuation of strontium and sulfate was found to be moderate.

Ash Pond Discharge. Ash pond discharges are discharged directly into Lake Wylie. Results from sampling are presented in Exhibit E-5. Arsenic was found to exceed the PDWS (up to 1.25 times the PDWS) in the discharge samples and manganese was found to exceed the SDWS (up to 1.8 times the SDWS). These

EXHIBIT E-5

ASH POND DISCHARGE RESULTS FOR ALLEN SITE

ALLEN SITE

(Direct ash pond discharge into Lake Wylie)

Units = ppm		Lake Wylie Discharge		
POMS	Drinking Water Standard	Discharge (1 station)		1/
		Total Samples	Exceed. Samples	2/ 3/
Contam.				Max. Exceed.
Arsenic (liq.)	0.05	1	1	1.2
Barium	1	2	0	
Cadmium	0.01	2	0	
Chromium (Cr VI)	0.05	2	0	
Fluoride	4.0	2	0	
Lead	0.05	2	0	
Mercury	0.002	0		
Nitrate 4/	45	2	0	
Selenium (liq.)	0.01	1	0	
Silver	0.05	2	0	
SOMS				
Chloride	250	2	0	
Copper	1	2	0	
Iron	0.3	2	0	
Manganese	0.05	2	1	1.8
Sulfate	250	2	0	
Zinc	5	2	0	
pH Lab 5/	<=6.5	0		
	>=8.5	0		
pH Field 5/	<=6.5	2	0	
	>=8.5	2	1	8.9

1/ Station 3-13.

2/ The number of samples with reported concentrations above the drinking water standard.

3/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

4/ The POMS for nitrate measured as N is 10 ppm.

5/ As indicated in footnote 3, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

samples were also found to be alkaline and in exceedance of Secondary Drinking Water Standard for pH (pH up to 8.9).

E.4.3. Discussion and Conclusions

At all ground-water sampling locations at the Plant Allen site, levels of contaminants did not exceed Primary Drinking Water Standards. Some exceedances of Secondary Drinking Water Standards were noted, including iron at downgradient wells and manganese at downgradient and upgradient wells. Samples at both upgradient and downgradient ground-water wells were also found to be slightly to moderately acidic, with a seeming increase in acidity in downgradient well samples. In fluids obtained from the pond wastes (pond liquors), highly elevated concentration levels of arsenic were detected.

It is not clear to what extent migration of waste leachate to downgradient ground water had occurred. Examination of concentrations for ash solutes such as sulfate, boron, chloride, calcium, magnesium, strontium, and sodium in upgradient versus downgradient wells and in pond liquors indicated that these constituents are present in higher concentrations in pond liquors and in ground-water wells downgradient from both active and retired ponds than in upgradient or background ground water. Consequently, this indicates that some leaching and migration of ash wastes had occurred to the extent that solutes have reached the downgradient wells. At the time of the study, no serious degradation of water quality due to ash leaching had occurred. Whether this has changed or may change in future years is discussed below.

The surrounding soils in the immediate vicinity of the ponds appeared to

have been able to attenuate the contaminants arsenic and boron, thereby limiting their downgradient movement. The results of the attenuation tests were evaluated along with the water balance, geological profile, mass balance and physical testing data to estimate the potential for long-term leaching of arsenic from the ash ponds to Lake Wylie. It was estimated that the attenuation capacity of the surrounding soils would be sufficient to prevent passage of arsenic leachate with concentrations in exceedance of drinking water standards into Lake Wylie for longer than the estimated 15 year operating life of the active pond.

As mentioned previously, it was likely that at the time of the study only leachate generated in the downgradient (eastern) portions of the ash ponds had begun to reach downgradient ground-water well locations, and that leachate from the upgradient (western) portions had not yet reached downgradient ground-water wells. This suggests that the downgradient ground water had not yet reached steady state conditions (or concentrations) with respect to the movement and admixing of leachate generated by the ponds, since steady state conditions (i.e., all potential flow paths carrying leachate) would not be achieved until the whole pond contributes leachate to downgradient locations. This means that concentrations of contaminants present in leachate of the waste (pond liquors) could be expected to increase in downgradient ground water over the next several years. While a precise estimate of future ground-water quality at the site cannot be made, steady state concentrations may range between existing concentrations and concentrations typical of ash leachate.

Since Primary Drinking Water Standards contaminants appeared to be either attenuated by soil at the site or were not present at elevated concentrations in

the pond liquors, ground-water degradation by these constituents may not be expected in the future. If arsenic had not been attenuated by soils at the site, future concentrations of arsenic in downgradient ground water could have been as high as 31 times the Primary Drinking Water Standard (the concentration in pond liquors). Additionally, since the Secondary Drinking Water Standard's contaminants were not observed to exceed standards in either the pond liquors or the downgradient wells, significant degradation of the ground-water quality due to future increases in downgradient concentrations (incremental leachate impacts) of these contaminants would not be expected.

It has been suggested that the lack of elevated concentrations observed in the ash pond liquors of elements added to wastes from boiler cleaning wastes (copper, nickel, zinc) was due to their precipitation upon mixing with pond liquors.

In summary, Allen Plant in North Carolina disposed of a mixture of fly ash and bottom ash in two unlined disposal ponds, one retired and one in active use. Intermittent waste streams, such as boiler wastes and coal pile runoff, were also disposed of in the ponds. While comparisons of concentrations of waste-related constituents in upgradient and downgradient ground water and in waste fluids indicated that leachate migration had occurred, exceedances of the Primary Drinking Water Standards were not found to occur in ground-water samples (i.e., no significant degradation of ground-water quality). Elevated concentrations of arsenic (up to 31 times the PDWS) were found in fluids within the active ash pond. Attenuation tests indicated that these concentrations of arsenic were chemically attenuated by iron and manganese in the soils beneath and surrounding the site. Ground-water contamination, particularly from arsenic, could have resulted if these attenuating soils had not been present.

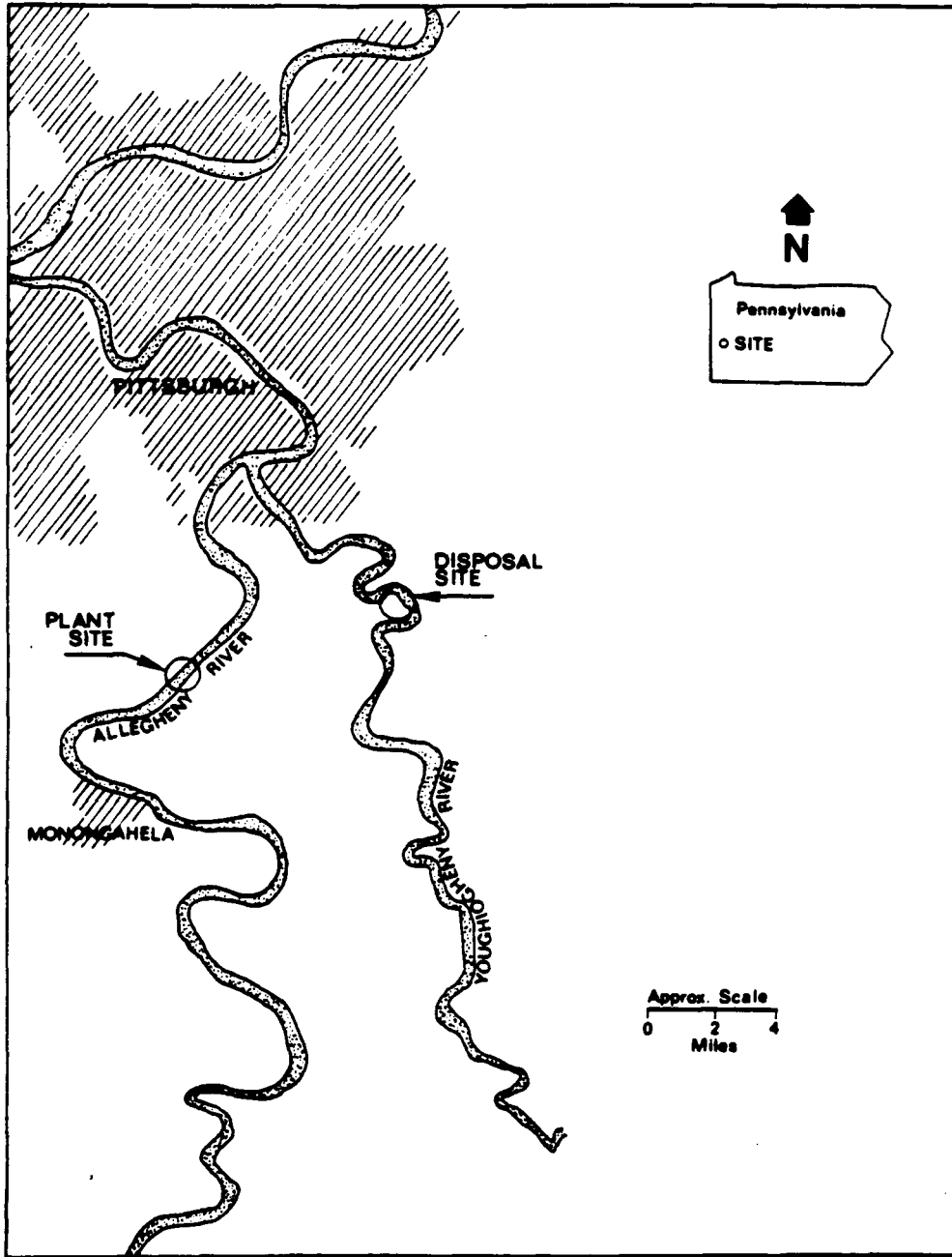
Secondary Drinking Water Standards were found to be exceeded in both the upgradient and downgradient ground water for manganese and in the downgradient ground water for iron. This was attributed to high concentrations of these elements present in the soils of the site. ADL calculations of seepage velocities at the site suggested that it was possible that steady-state conditions had not been achieved. Increases in downgradient ground-water concentrations of non-attenuated waste leachate species may be expected in the future.

E.5 ELRAMA PLANT

The Elrama Power Plant is located in Washington County, Pennsylvania, approximately 20 miles south of Pittsburgh. At the time of the ADL study, it had four units and burned Appalachian coal having 2-2.5 percent sulfur and 19 percent ash. Waste disposal methods consisted of wet sluicing bottom ash and occasionally fly ash to an on-site interim pond. The dewatered contents of the pond were subsequently excavated and removed to a landfill disposal site. In 1975, limestone scrubbers were added to remove sulfur dioxide from the flue gas. The FGD scrubber sludge was mixed with dry fly ash and lime to form Poz-O-Tec⁶ at a processing facility on the power plant site. This fixation step was a proprietary process. The fixated sludge was then trucked approximately 12 miles east to the disposal site, in Elizabeth Township, Allegheny County, where it was placed in a landfill. The plant and disposal site locations are shown in Exhibit E-6. Disposal of scrubbing wastes at the disposal site began in 1979.

EXHIBIT E-6

LOCATION OF THE ELRAMA POWER PLANT AND DISPOSAL SITE



Source: Tetra Tech

Bottom ash and sludge from a coal pile runoff treatment pond were also disposed at the landfill. At the time of the study, approximately 1500 tons of waste were placed in the facility each day.

The disposal site was on a hillside overlooking the Youghiogheny River in Allegheny County, Pennsylvania. The area of the fill at the time of sampling was 22 acres. The waste was being disposed on top of coal strip-mine spoils, and was implanted in a series of terraced lifts. At completion, the outer part of each Poz-O-Tec lift was covered with about 2 feet of soil and seeded. A vertical profile through the disposal site is shown in Exhibit E-7. Unlined sedimentation ponds at the foot of the landfill collected surface runoff from the waste fill. The westernmost pond had an overflow discharge to the river.

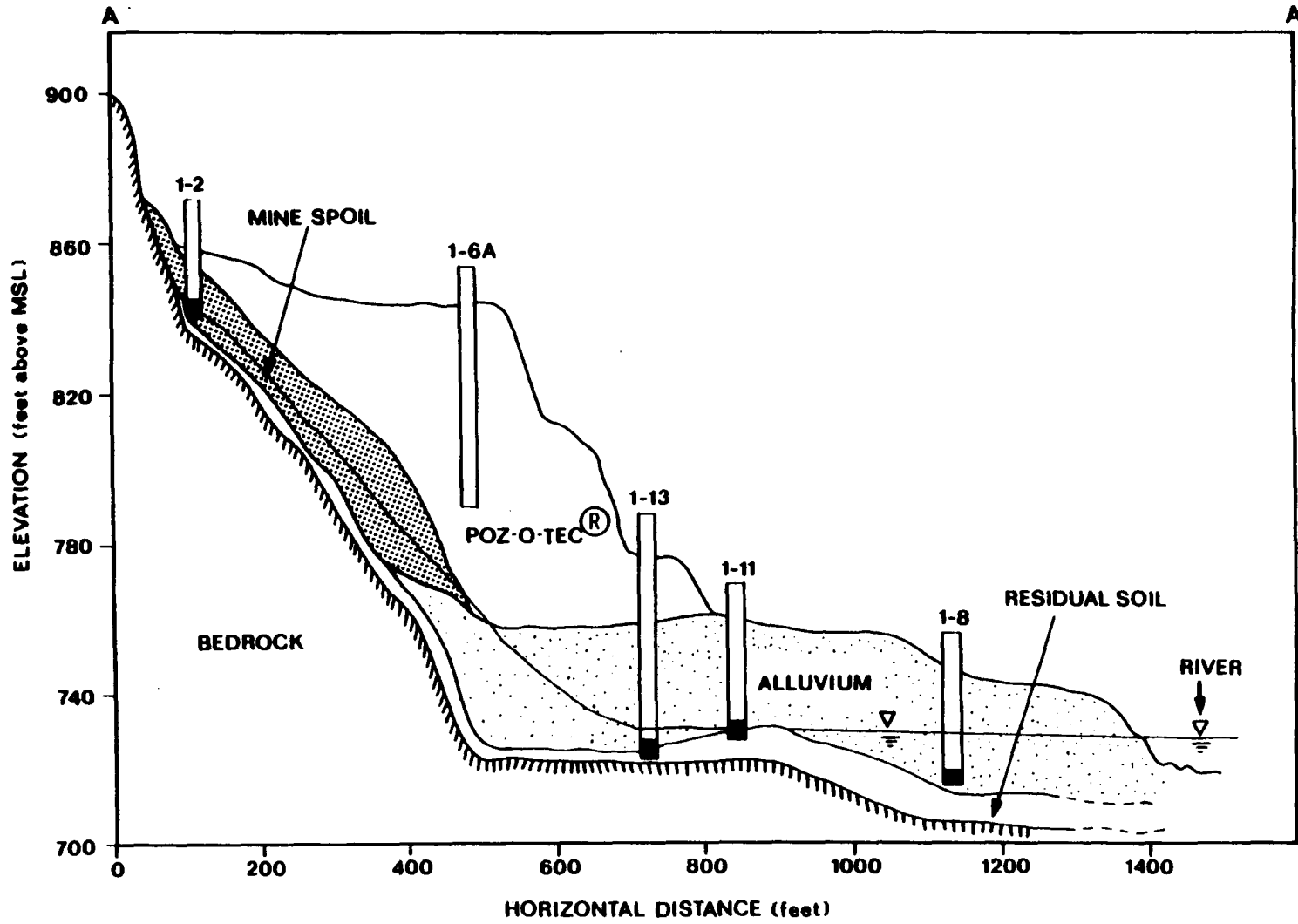
The bench that the landfill was located on was created by mining of the Pittsburgh coal seam. Beneath this bench, the sedimentary bedrock was overlain by floodplain deposits of aluminum (silts and sands) up to 40 feet thick. Under much of the waste, the bedrock was covered by a five to ten feet thick layer of soil and weathered rock ("residual soil"). In the westernmost part of the landfill, mine spoil materials left from previous strip coal mining operations underlay the Poz-O-Tec wastes. The spoil material was an unconsolidated mix of soil, coal wastes, and bedrock fragments. Leachate from the mine spoils was noted by the site operators as being acidic.

The average annual precipitation at the Elrama site was 38 inches. The water table at the Elrama site sloped steeply from southeast to northwest,

EXHIBIT E-7

VERTICAL PROFILE THROUGH LANDFILLED WASTES
AT ELRAMA DISPOSAL SITE
(FROM THE SOUTHEAST TO THE NORTHWEST)

Source: Tetra Tech

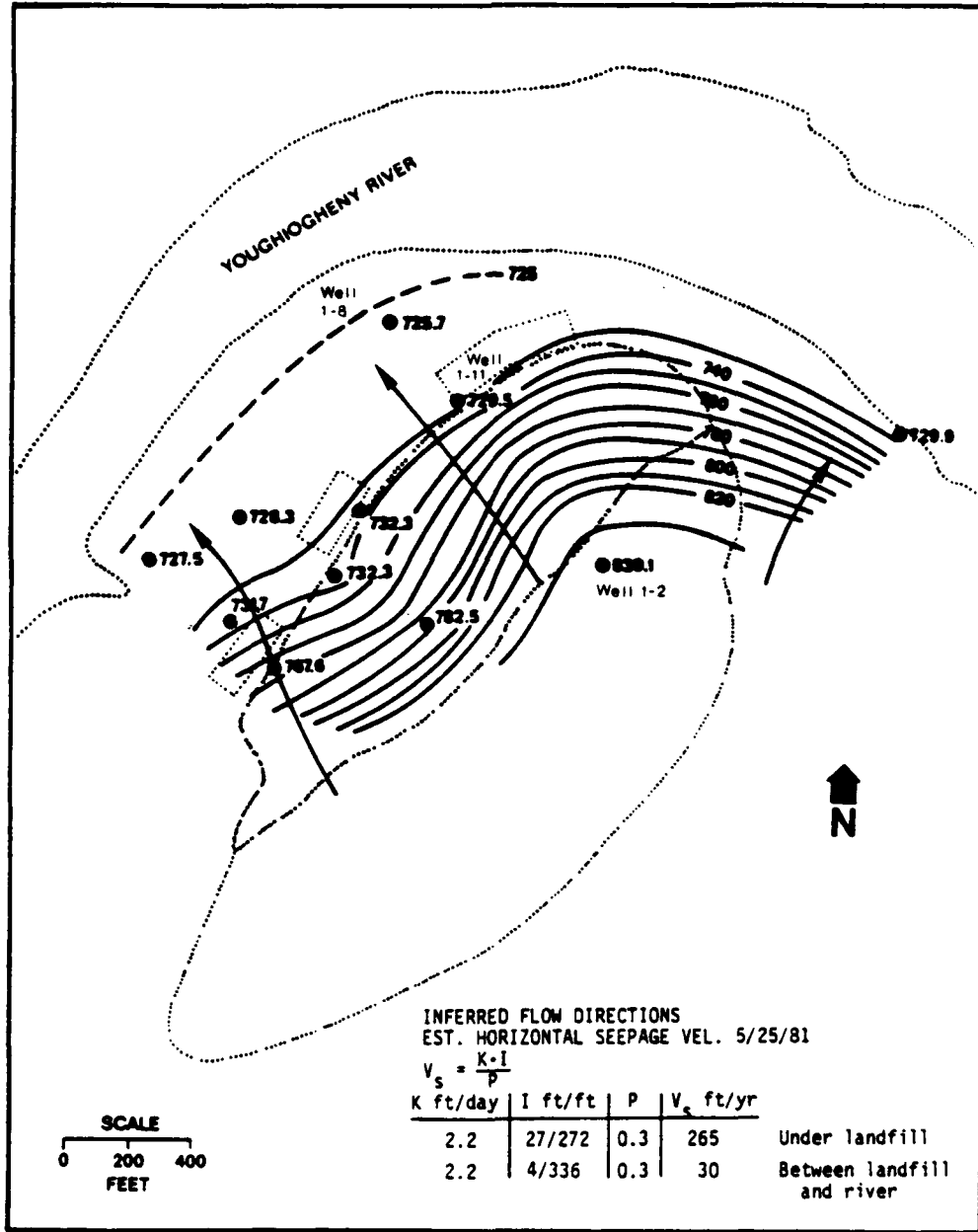


roughly parallel to the ground surface. Most of the mine spoil material was saturated during the period of the ADL study. The saturated zone extended up into the lower portions of the Poz-O-Tec fill. Ground-water levels varied considerably with the site topography, being relatively deep in the bedrock at the higher site elevations and varying from 20 to 30 feet below ground surface in the low lying alluvial deposits. All surface and ground-water flow was northwesterly to the adjacent Youghiogheny River (Exhibit E-8).

Factors that were considered important in the selection for study of the fixated FGD waste landfill operation at the Elrama disposal site included:

- Fixated FGD waste landfilling was available for study at very few sites in 1980; however, this disposal option was planned for many other locations in the United States. The type of fixation practiced at Elrama was based on controlled mixing of FGD combustion waste from a thick slurry to a highly alkaline, soil-like material. This process makes landfill disposal a practical alternative to pond disposal.
- Landfill disposal of FGD wastes in abandoned strip mines was also a growing practice at the time of the study. The Elrama landfill site occupied an abandoned coal mining area that exhibited acid mine drainage. This situation represented an opportunity to fill a significant data gap on highly alkaline waste disposal in a typical acid mine drainage setting.
- Climatic conditions (average rainfall, temperature range and typical frost penetration) was considered representative of the Appalachian Region.
- There was generally good ground-water flow expected in this setting.
- Alluvium underlying the disposal area was anticipated to provide a good monitoring medium.

EXHIBIT E-8
GROUND-WATER FLOW DIRECTIONS AT ELRAMA
DISPOSAL SITE



Source: Tetra Tech 1985.

- The landfill was in close proximity to surface water (Youghiogheny River), although it was separated from the river by runoff collection ponds.

E.5.1 Sampling Approach

Samples of wastes and soils were collected for physical and chemical testing. Samples of ground water, waste fluids (or liquors), and surface water samples were collected for chemical testing. A series of attenuation tests were performed using local site soils and pond liquor solutions (spiked with trace elements).

Sixteen monitoring wells and three lysimeters were installed at the site. One upgradient ground-water well (Well 1-14) was installed in the alluvial floodplain for background monitoring purposes, and one upgradient ground-water well (Well 1-2) was installed within the mine spoil debris. Following site development and the sampling visit, fixated FGD waste was disposed adjacent to and upgradient of well 1-2. Five downgradient observation wells (1-11, 1-8, 1-10, 1-4, and 1-5) were installed in the alluvial flood plain deposits of the Youghiogheny River. Observation wells (1-6, 1-13, 1-12, 1-15, 1-9, 1-3, 1-6A and 1-15A) and lysimeters (1-6, 1-13A, and 1-12A) were installed in the lower benches of the compacted waste fill to sample waters from beneath and within the wastes. The lysimeters were installed in the unsaturated vadose zone beneath the waste fill deposit to provide interstitial water samples which had not been in contact with any mine spoil leachate. In addition, surface water samples were collected from five sampling stations in Youghiogheny River -- four downgradient (downstream) and one upgradient.

Locations of site wells and surface water sampling locations are shown on Exhibit E-9. Sampling at the site was conducted on three occasions.

E.5.2 Results

Exhibit E-10 presents the results of chemical sampling at the Elrama site. This includes samples from the downgradient and upgradient ground-water wells, samples from the well and lysimeters implanted within the waste to collect interstitial fluids, water samples obtained from beneath the waste, and surface water samples. Results are discussed below.

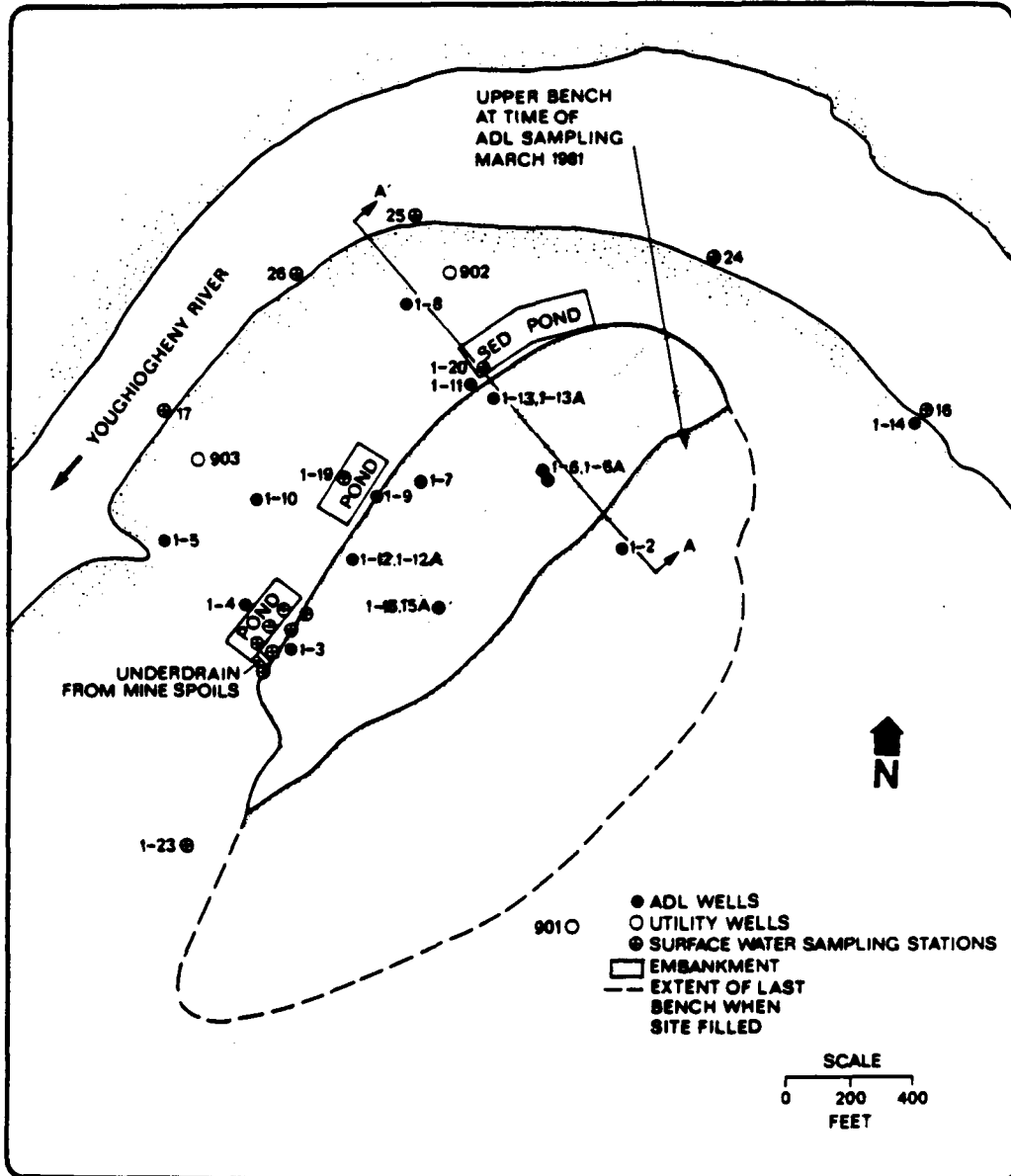
Waste solids. Fly ash and bottom ash were found to occur in layers within the waste. Coefficients of permeability ranged from 7×10^{-6} cm/sec to 1×10^{-3} cm/sec.

All three wastes disposed at the site, fixated (with lime and fly ash) FGD waste, bottom ash, and mine spoil, were chemically analyzed. Calcium was found to be present at much greater levels in the fixated waste than in the mine spoil. Sulfate and aluminum concentrations were found to be high in the mine spoil and the FGD waste. However, sulfate was noticeably higher in the FGD waste. Arsenic was detected at significantly higher concentrations in the FGD waste than in the other materials. Additionally, the FGD waste was found to be highly alkaline and the mine spoil acidic.

Fluids In and Beneath Waste. Fluid samples collected from the on-site waste may represent leachate from these wastes, so that examination of

EXHIBIT E-9

SAMPLING LOCATIONS AT ELRAMA DISPOSAL SITE



Source: Tetra Tech 1985.

EXHIBIT E-10

CHEMICAL SAMPLING DATA FOR ELRAMA DISPOSAL SITE

ELRAMA SITE
(no Pond Liquor data)

Contam.	Units = ppm PONS	Ground water			In and Under Waste						Surface Water (Youghiogheny River)								
		1/			2/			3/			4/			5/			6/		
		Downgradient (5 wells)			Upgradient (1 well)			Water In and Under Waste (11 wells)			Water in Mine Spoils (1 well)			Downgradient (4 stations)			Upgradient (1 station)		
Drinking Water Standard	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	
Arsenic (liq.)	0.05	1	0		2	0		13	2	5.3	2	0		1	0		1	0	
Barium	1	19	0		4	0		33	0		4	0		7	0		3	0	
Cadmium 9/	0.01	19	3	20	4	0		33	9	20	4	2	20	7	0		3	0	
Chromium (Cr VI)	0.05	19	1	1.2	4	0		33	0		4	1	1.6	7	0		3	0	
Fluoride	4.0	21	0		4	0		32	0		4	0		7	0		3	0	
Lead	0.05	19	0		4	0		33	0		4	0		7	0		3	0	
Mercury	0.002	0			0			0			0			0			0		
Nitrate 10/	45	20	0		4	0		32	0		3	0		7	0		3	0	
Selenium (liq.)	0.01	1	0		2	0		13	0		2	0		1	0		1	0	
Silver	0.05	19	0		4	0		33	0		4	0		7	0		3	0	
SDMS																			
Chloride	250	21	0		4	0		31	11	2.3	4	0		7	0		3	0	
Copper	1	19	0		4	0		33	0		4	0		7	0		3	0	
Iron	0.3	19	0		4	1	1.8	33	7	221	4	3	570	7	0		3	0	
Manganese	0.05	19	19	456	4	4	197	33	22	466	4	4	680	7	7	7.4	3	3	4.2
Sulfate	250	19	9	4.7	4	3	1.5	33	33	8.1	4	4	9.3	7	0		3	0	
Zinc	5	19	0		4	0		33	0		4	0		7	0		3	0	
pH Lab 11/	<=6.5	0			0			0			0			0			0		
	>=8.5	0			0			0			0			0			0		
pH Field 11/	<=6.5	14	9	5.2	2	2	4.5	17	10	5.9	3	2	5.1	7	4	6.1	3	2	6
	>=8.5	14	0		2	0		17	3	9.9	3	0		7	0		3	0	

- Doc. Ex. 6829 -
EXHIBIT E-10 (Continued)

CHEMICAL SAMPLING DATA FOR ELRAMA DISPOSAL SITE

- 1/ Wells 1-1f, 1-B (29 ft), 1-B (40 ft), 1-10 (36 ft), 1-10 (37 ft), 1-4 (8 ft), 1-4 (28 ft), 1-4 (41 ft), and 1-5.
- 2/ Well 1-14.
- 3/ Wells 1-3, 1-15A, 1-13A, 1-12A, 1-7, 1-6 (50 ft), 1-6 (52 ft), 1-6 (55 ft), 1-13, 1-12, 1-15, 1-9, 1-6A (52 ft), and 1-6A (50-55 ft). Lysimeters were used at wells 1-13A, 1-7, and 1-12A for sample collection.
- 4/ Well 1-2.
- 5/ Stations 1-17, 1-24, 1-25, 1-26.
- 6/ Station 1-16.
- 7/ The number of samples with reported concentrations above the drinking water standard.
- 8/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 9/ Where the reported detection limit for cadmium was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For some water samples collected from downgradient and upgradient groundwater, the reported detection limit of 0.1 was greater than the PDWS for cadmium.
- 10/ The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPDWS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 11/ As indicated in footnote 7, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

results from chemical analysis of these samples can yield information on the potential for ground-water contamination.

Waters collected from materials beneath and within the wastes (utilizing monitoring wells and lysimeters) exhibited an exceedance of the Primary Drinking Water Standards for arsenic (up to 5 times the PDWS), cadmium (up to 20 times the PDWS). Exceedances of Secondary Drinking Water Standards were noted for chloride (up to 2 times the SDWS), iron (up to 221 times the SWDS), manganese (up to 466 times the SDWS), and sulfate (up to 8 times the SDWS). Exceedances were also noted for pH (as low as 5.9 and as high as 9.9).

Waters collected from within mine spoil debris beneath the waste exhibited exceedances of the Primary Drinking Water Standards for cadmium (up to 20 times the PDWS) and chromium (up to 2 times the PDWS). These samples exhibited exceedances of the Secondary Drinking Water Standards for iron (up to 570 times the SDWS), manganese (up to 680 times the SDWS), and sulfate (up to 9 times the SDWS). Values for pH indicated acidity (as low as 5.1).

The fluids collected from within and beneath the waste are not ingested; comparison to drinking water standards were done to indicate the potential for contamination at the site.

Ground water. Because of runoff transport, contaminants were expected to migrate from the wastes to the downgradient alluvium and eventually to the river relatively quickly by the runoff and seepage directed to the ponds and subsequent recharge to the alluvium. Ground-water travel times from the landfill to downgradient well locations were uncertain, but appeared to range

from one to five years for near downgradient locations and from five to ten years for far downgradient locations. Travel time from the runoff collection ponds to far downgradient locations were in the one to five year range. Thus it would appear that there had been enough time for constituents in waste leachate to have reached downgradient wells and the Youghiogheny River. However, there had also probably been ample time and opportunity for acid drainage from earlier mining operations to have infiltrated the site's ground water. Because the fixated waste had been at the site for only about 2 years at the time of sampling, solutes in leachate from the waste may not have reached wells furthest downgradient.

Primary Drinking Water Standards were found to be exceeded in the ground water of the downgradient wells for cadmium (up to 20 times the PDWS) and for chromium (up to 1.2 times the PDWS). There were no upgradient exceedances in ground water of the Primary Drinking Water Standards.

Secondary Drinking Water Standards were found to be exceeded in the downgradient ground-water wells for manganese (up to 456 times the SDWS) and sulfate (up to 5 times the SDWS). Exceedances for these contaminants were also found in upgradient ground water -- manganese at up to 197 times the SDWS and sulfate at up to 1.5 times the SDWS. Additionally, iron was found to exceed the Secondary Drinking Water Standards (1.8 times the SDWS) in the upgradient well. Both the upgradient and downgradient ground-water wells were found to exhibit pH's below the lower limit (6.5) for Secondary Drinking Water Standards. The pH of the upgradient samples were found to be as low as 4.5, and those of the downgradient samples as low as 5.2.

Surface Water. Primary Drinking Water Standards were not found to be exceeded for any contaminants in both the upgradient and downgradient surface water (river) samples. Secondary Drinking Water Standards were found to be exceeded for manganese in both the downgradient (7 times the SDWS) and upgradient (4 times the SDWS) surface water samples. Both the downgradient and upgradient surface water samples exhibited pH values below the lower limit of Secondary Drinking Water Standards (as low as 6.0).

Attenuation Tests. Attenuation tests using various pond liquor solutions and the soils obtained from the Elrama site indicated that these soils generally had moderate capacities to attenuate trace metals.

E.5.3 Discussion and Conclusions

Cadmium (up to 20 times) and chromium (up to 1.2 times) were found to exceed the Primary Drinking Water Standards in downgradient ground water. Manganese and sulfate were observed to exceed Secondary Drinking Water Standards in downgradient and upgradient ground water. Exceedances for iron were also observed in upgradient ground water. Elevated concentrations of arsenic, cadmium, chromium, and fluoride were observed in waters obtained from within and beneath the landfilled FGD wastes. Chloride, iron, manganese, and sulfate were observed at elevated concentrations in waters in and under the waste.

These results and their implications to FGD waste disposal and ground water quality at the Elrama disposal site are difficult to interpret due to the coal mining activities that had taken place -- and subsequent acid mine drainage

that was occurring -- at the site. Interpretations of the results that can be made are discussed below.

Based on sampling results, differences in concentrations between background or upgradient ground water, mine spoil leachate and FGD waste leachate, were observed to occur. Background waters were typically neutral or acidic or alkaline (alkalinity up to 5 meq/l), and had low to moderate levels of iron and manganese and low levels of total salts. Mine spoil leachate was neutral to acidic and had high levels of iron and manganese relative to background concentrations. Samples taken from fluids within the Poz-O-Tec FGD waste were found to be different from both of these two types of samples. It was neutral to alkaline, high in dissolved solids (or solutes), but low in iron and manganese, and arsenic and selenium were found to be concentrated in interstitial waters. Boron mean levels were higher in both types of waste interstitial waters than in the background samples.

All wells at the site, except the lysimeters screened in the FGD wastes, were potentially affected by both leachate from the FGD wastes and from the mine spoil. Both water quality and the water table configuration indicated that the upgradient background well (1-14) was influenced by mine spoil leachate or coal seam seepage. High pH (7.9 to 9.9) characterized ground water samples directly associated with the alkaline fixated FGD waste. As mentioned previously, neutral to low pH (4.5) characterized the background ground-water samples. Low pH was also found to characterize some of the downgradient ground-water samples. For both the background (upgradient) and downgradient samples this was very likely the result of acid mine drainage in the area. The western portion of the site exhibited the highest downgradient solute

concentrations. This observation was consistent with the higher permeabilities measured in the area, plus the fact that the disposal area of FGD wastes and mine spoils was closer to the downgradient wells here than in areas to the north.

The high levels of arsenic observed within the interstitial water or leachate of the FGD waste were not observed in downgradient ground water. Thus, it appeared that arsenic was being attenuated by the surrounding soils. High levels of arsenic were not evident in waters attributable to mine spoil leachate.

Iron and manganese concentrations were elevated at many locations. The iron concentration was especially high in ground-water samples affected by FGD-related wastes, while manganese levels seemed highest in samples more affected by mine drainage. Nonetheless, even the least contaminated ground-water samples showed levels of these constituents that exceeded the Secondary Drinking Water Standards. This may suggest that the concentrations of these constituents were characteristically high in ground water in the area, and both mining and FGD wastes are likely contributing to incremental elevations.

Concentrations of some major FGD waste constituents (e.g., sulfates) appeared generally elevated at this site, prior to its use for utility waste disposal, as a result of acid mine drainage. This is illustrated by the similar concentrations evident in lysimeters and wells downgradient of the landfill and within ground water downgradient of mine drainage.

The data did not indicate a measurable effect of the landfill on the water

quality of the Youghiogheny River. Surface water results indicated that the river was diluting migrating leachate.

The trends in contaminant concentrations over the sampling period indicated that ground water at several downgradient locations had not yet reached steady-state concentration and was only beginning to be affected by the landfill. The effects can be expected to increase over time. Even in the future, there may be little basis for qualitative distinction between the ground water affected by the fixated FGD waste and acid mine drainage at the site, and the influence of projected steady-state ground-water concentrations for many contaminants may be small in magnitude in an already contaminated situation. However, results from sampling at the Elrama site indicated that the FGD wastes had been, and may have continued to be, a source of contamination for some constituents at the site. This may be especially true for the observed cadmium contamination, since the source for this trace metal was probably less likely to be the mine spoils (overburden) than the utility wastes.

In summary, the Elrama Plant in Western Pennsylvania disposed of fixated FGD sludge-fly ash mixture (known as Poz-O-Tec) along with small volumes of bottom ash and sludge from coal pile runoff treatment ponds, in an abandoned coal-mining area twelve miles from the plant. Part of the landfill was underlain by acid-producing spoils from the strip mining of coal. Cadmium was found to exceed the Primary Drinking Water Standards in downgradient ground water by as much as 20 times, especially in the well closest to the landfill. Steady-state conditions did not appear to have been achieved at the site, so that effects of leachate from the landfill may have increased with time.

Certain Secondary Drinking Water Standards (for pH, manganese, sulfate, and iron) were found to be exceeded in both upgradient and downgradient ground water at the site. These exceedances probably occurred because of characteristics of the disposal area and because ground water was already contaminated from acid mine drainage. Results did not indicate a measurable effect by the landfill on the water quality of the Youghiogheny River.

Among the trace metal species, arsenic, in water collected from the waste deposit, was often detected at levels three to five times the Primary Drinking Water Standards, but appeared to be attenuated by site soils. Arsenic could be of concern if it were not attenuated by surrounding soils or diluted before reaching drinking water.

Results from sampling at the Elrama disposal site indicated that the fixated FGD wastes had been a contamination source at the site. Due to the contamination of the water by acid mine drainage, the FGD leachate may have had a small incremental impact on water quality.

E.6 DAVE JOHNSTON PLANT

The Dave Johnston Power Plant of Pacific Power and Light Company is located approximately 30 miles east of Casper, Wyoming. The plant and its ash disposal facility are located on the north bank of the North Platte River. The plant has been in operation since 1959. At the time of the study, the subbituminous coal burned was from the Powder River Basin of Wyoming and had about 0.45 percent sulfur and 9 to 11 percent ash. Three of the generating units were equipped with electrostatic precipitators, and fly ash from these units was transported

in dry form to several landfills. The fourth unit had a wet ash scrubber, and fly ash from it was disposed in ponds north of the power plant.

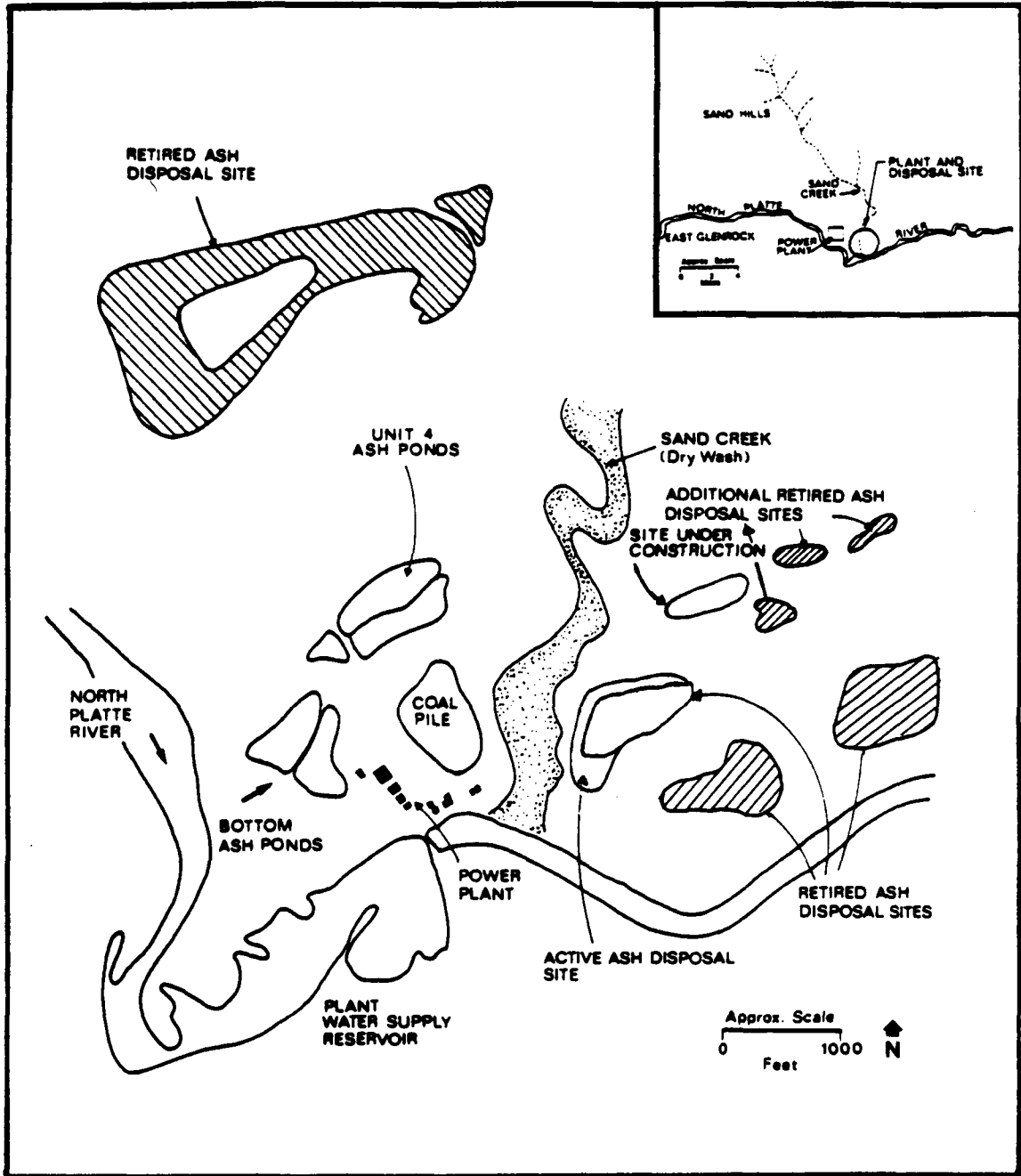
There were a number of disposal areas at this site (Exhibit E-11). The ADL study only investigated a site east of Sand Creek. Two major ash disposal areas, reflecting different times and methods of placement, were assessed. One was the existing and operational dry fly ash disposal site and municipal landfill. The other, to the southeast, was an unlined, abandoned, and reclaimed ash disposal site. The operational fly ash disposal area was excavated into the natural sand deposits. No liner was placed in the excavation which was in close proximity to the ground-water table. There were several other closed ash landfills at this site, which were estimated to be 10 to 20 years old.

The Dave Johnston Plant was selected for study primarily because it provided the opportunity to evaluate landfill disposal of dry fly ash. Other factors that were considered to be in the selection and evaluation of the landfilling operations at the Dave Johnston Plant included the following:

- The environmental setting combined significant net evaporation with a flood-plain location that would be expected to illustrate contaminant migration in identifiable patterns, while exemplifying arid western conditions.
- Active and inactive landfills were available for study in the selected portion of the site. These landfills have been developed over about a 20-year period.

EXHIBIT E-11

LOCATION OF DISPOSAL AREAS AT DAVE JOHNSTON SITE



Source: Tetra Tech 1985.

- The disposal operation was considered to be representative of existing and future operations at many western locations. At the active landfill studied, dry fly ash was disposed of along with small amounts of miscellaneous plant trash, a practice characteristic of western plants.

The environmental assessment carried out at this plant focused on the effect of fly ash landfill disposal on downgradient ground-water quality in an arid floodplain environment.

The Dave Johnston site was located in an arid area. The mean annual precipitation in the site vicinity was only 12 inches. The majority of the precipitation was lost through evaporation. Nearly all recharge to the ground-water system occurred during spring runoff. The area was underlain by bedrock of shales with interbedded sandstones and thin coal units. The bedrock was overlain by sand and gravel river terrace deposits and alluvial sediments. Sand dunes were common throughout the site area. Ground water was found within the site area in two different and separate hydrogeological environments -- in a deeper bedrock aquifer and in the near-surface unconsolidated fluvial deposits. The ground water flowed generally southeast across the active disposal site and south under the retired landfill (see Exhibit E-12) towards the adjacent North Platte River. At the closed landfill, located to the southeast of the active landfill, the distance between the base of the ash and the water table was about 10 feet. The active landfill was excavated to within a foot or less of the water table.

E.6.1 Sampling Approach

Samples of wastes and soils were collected for physical and chemical testing. Samples of ground water and fluids from within the waste (pond liquors) and beneath the waste were collected for chemical testing.

Twelve monitoring wells were installed at the site. Their locations are shown in Exhibit E-13. Two were installed to sample upgradient ground water (7-5 and 7-11), three were installed to sample ground water peripheral to the disposal areas, three were installed to sample downgradient ground water (7-4, 7-6, and 7-9), and one was installed to sample ground water between the active and inactive ash landfills (7-12). One monitoring well was emplaced in each of the ash landfills to sample water from beneath these wastes (7-2 and 7-3) and one was emplaced within the active ash landfill to sample interstitial waste fluids (pond liquors -- 7-2A).

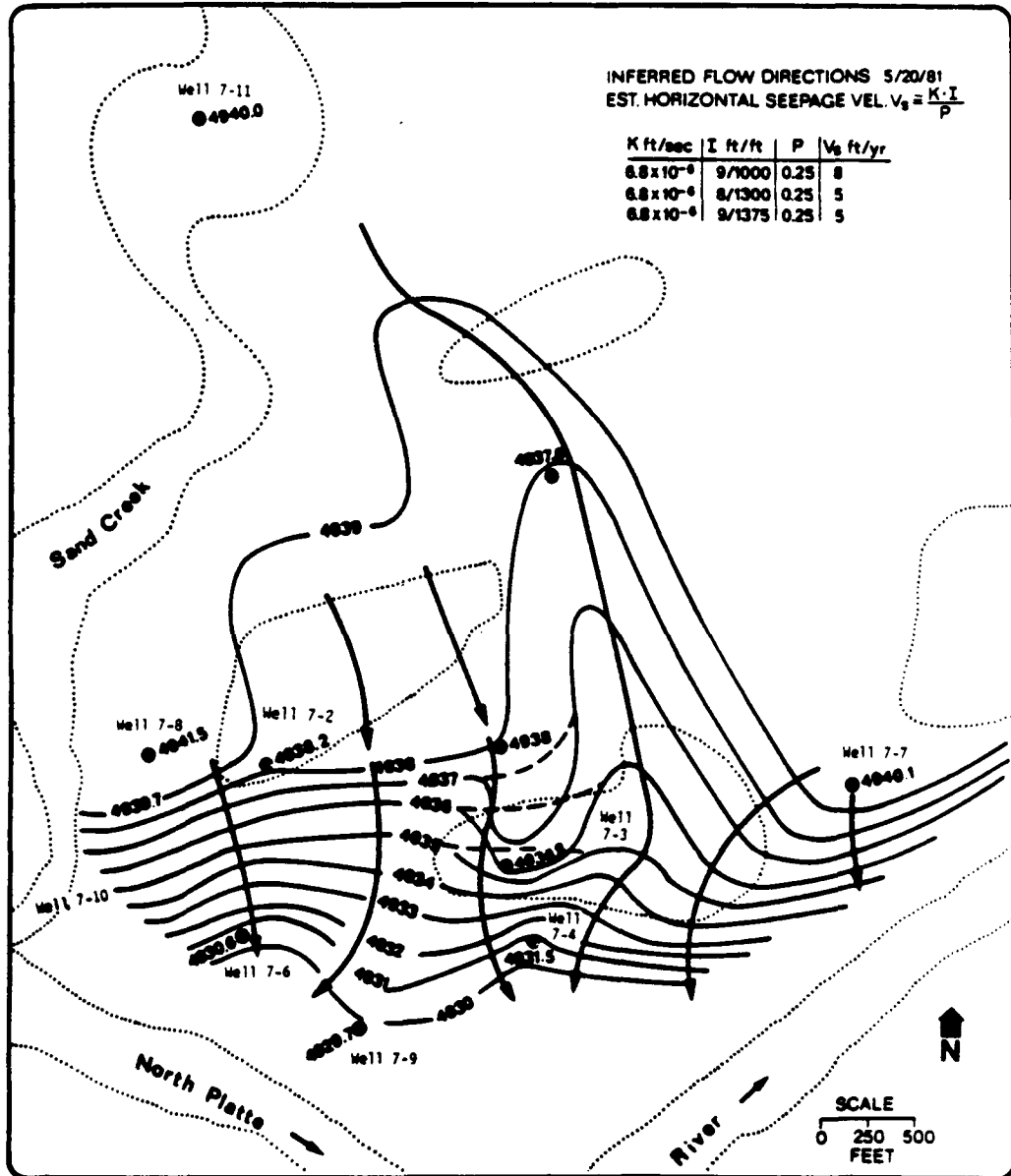
E.6.2 Results

Exhibit E-14 presents the results of chemical sampling at the Dave Johnston site. This includes samples from the downgradient and upgradient ground-water wells, fluids samples from within the wastes, and water samples obtained from beneath the waste. Results are discussed below.

Waste Solids. Fly ash was found to be layered with bottom ash in the active ash landfill. Permeability of the waste was found to range between 2×10^{-7} to 6×10^{-5} cm/sec.

EXHIBIT E-12

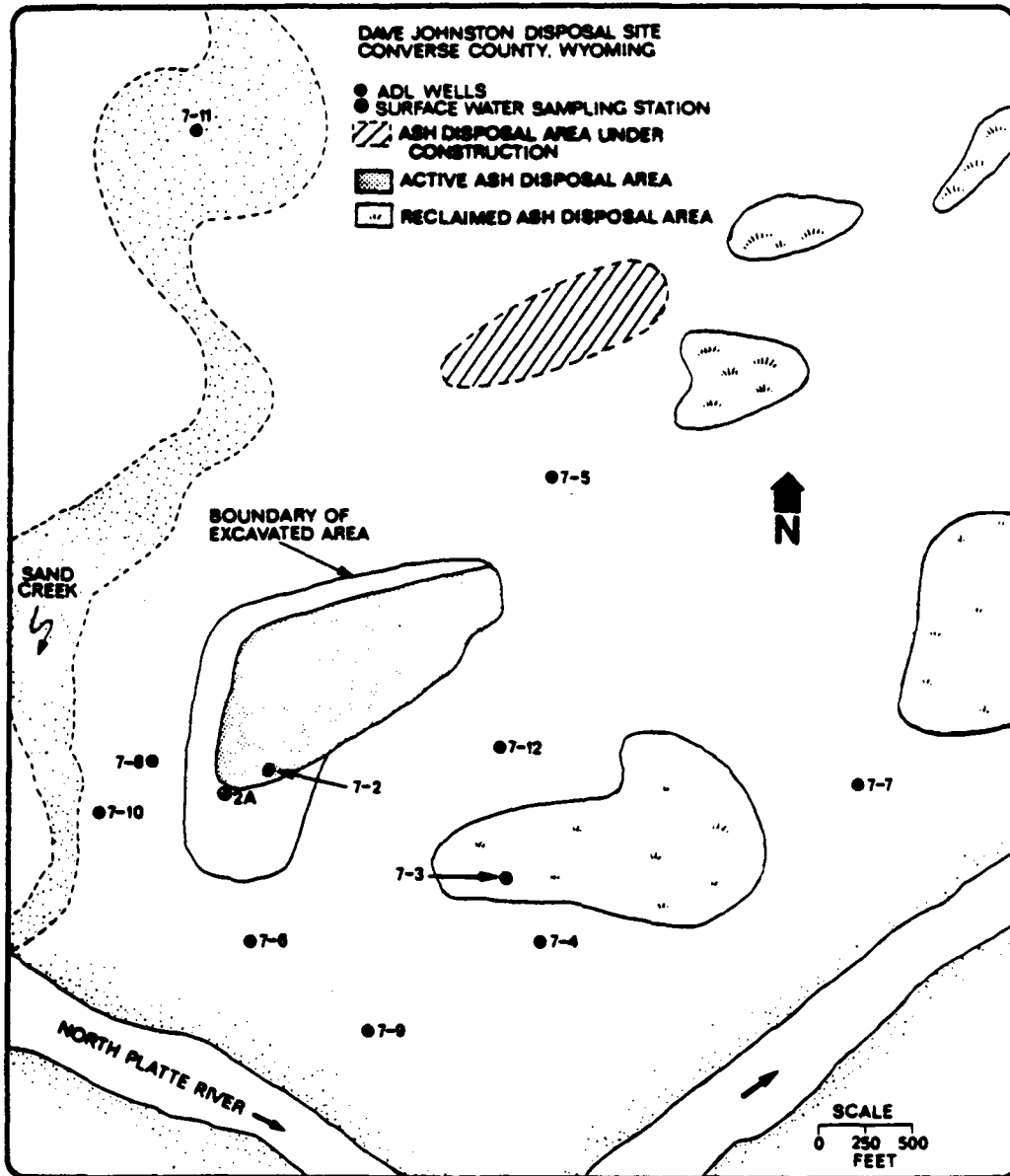
GROUND WATER FLOW DIRECTIONS AT DAVE JOHNSTON SITE



Source: Tetra Tech 1985.

EXHIBIT E-13

DISPOSAL AREAS AND SAMPLING LOCATIONS AT DAVE JOHNSTON SITE



Source: Tetra Tech 1985.

EXHIBIT E-14

CHEMICAL SAMPLING RESULTS FOR DAVE JOHNSTON SITE

DAVE JOHNSTON SITE
(no Surface Water data)

Units = ppm		Ground water						Under Waste						Waste		
PDMS	Drinking Water Standard	1/ Downgradient (3 wells)			2/ Upgradient (2 wells)			3/ Btw. Active/Inactive Area (1 well)			4/ Water Under Waste (2 wells)			5/ Pond Liquors (2 stations)		
		Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Samples Detect.	Ave. Conc.	Max. Exceed.
Arsenic (liq.)	0.05	2	0		3	0		0			4	0		NS	11/	
Barium	1	9	0		6	0		3	0		6	0		1	0	
Cadmium	0.01	9	6	3	6	3	3	3	2	3	6	4	3	2	2	5
Chromium (Cr VI)	0.05	9	0		6	0		3	0		6	0		0		
Fluoride	4.0	12	0		8	0		4	0		8	0		1	1	
Lead	0.05	9	0		6	0		3	0		6	0		0		10/
Mercury	0.002	0			0			0			0			NS		
Nitrate 11/	45	12	0		8	0		4	0		8	0		0		10/
Selenium (liq.)	0.01	2	0		3	0		0			4	0		NS		
Silver	0.05	9	0		9	0		3	0		6	0		0		
SDMS																
Chloride	250	12	0		8	0		4	0		8	0		2	0	
Copper	1	9	0		6	0		3	0		6	0		1	0	
Iron	0.3	9	0		6	0		3	0		6	0		2	0	
Manganese	0.05	9	1	3.2	6	1	4.6	3	0		6	3	8.4	2	1	1
Sulfate	250	12	12	5.8	8	4	5.1	4	4	5.1	8	8	6.2	2	2	9.8
Zinc	5	9	0		6	0		3	0		6	0		2	0	
pH Lab 12/	<=6.5	0			0			0			0			NS		10/
	>=8.5	0			0			0			0			NS		10/
pH Field 12/	<=6.5	9	0		6	0		3	0		6	0		NS		10/
	>=8.5	9	0		6	0		3	0		6	0		NS		10/

EXHIBIT E-14 (Continued)
CHEMICAL SAMPLING RESULTS FOR DAVE JOHNSTON SITE

- 1/ Wells 7-4, 7-6, and 7-9.
- 2/ Wells 7-5 and 7-11.
- 3/ Well 7-12. This well is located between the active and inactive ash landfills.
- 4/ Wells 7-2 and 7-3, but not 7-2A. The fluids collected from these wells are groundwater from beneath the waste.
- 5/ These "pond liquors" are fluids collected from within and on top of the landfilled wastes at station 7-2A.
- 6/ The number of samples with reported concentrations above the drinking water standard.
- 7/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 8/ The number of "pond liquor" samples with reported concentrations above the reported detection limits. An entry of "0" indicates that no sample had a detectable contaminant concentration; not that no samples were taken (see footnote 10).
- 9/ Ave. Conc. is the average of the reported concentrations of all "pond liquor" samples taken that showed a contaminant concentration above the detection limit. The reported pH measurements of the "pond liquors" are also averaged.
- 10/ NS = not sampled.
- 11/ The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPDWS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 12/ As indicated in footnote 6, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

Waste From In and Under Wastes. Results from fluid samples collected from wells emplaced within the waste indicated that these fluids or "pond liquors," when compared to Primary Drinking Water Standards, exhibited elevated concentrations of cadmium (up to 5 times the PDWS). Comparison of pond liquors to Secondary Drinking Water Standards showed elevated levels of manganese (up to 1 times the SWDS), and sulfate (up to 10 times the SWDS). No analyses were conducted for arsenic.

Water samples obtained from under the waste showed exceedances of the Primary Drinking Water Standards for cadmium (up to 3 times the PDWS). These samples also exhibited elevated concentrations of manganese (up to 8 times the SDWS), and sulfate (up to 6 times the SDWS).

Ground Water. Seepage velocities at the site were estimated to be only five to eight feet per year, due to the arid climate. This suggests that because the landfills had been in operation for less than 10 years, there may not have been enough time for waste leachate to have reached the downgradient wells. However, the active landfill was constructed in an excavation that may have intersected the underlying water table. This may have allowed contaminant migration via direct contact between the bottom of the fill and the ground water.

Primary Drinking Water Standards were found to be exceeded in the ground water of the downgradient wells for cadmium (up to 3 times the PDWS). Cadmium was also found to exceed the PDWS in the waste fluids and in waters from beneath the waste. Upgradient exceedances of the Primary Drinking Water Standards in ground-water samples were also found for cadmium (up to 3 times the PDWS).

Secondary Drinking Water Standards were found to be exceeded in downgradient ground water for manganese (up to 3 times the SDWS) and sulfate (up to 6 times the SDWS). These are the same contaminants observed at concentrations greater than Secondary Drinking Water Standards in the pond liquors and waters from beneath the waste. Upgradient exceedances of the Secondary Drinking Water Standards in ground-water samples were also observed for manganese (up to 4.6 times the SDWS) and sulfate (up to 5 times the SDWS). The ground-water well installed between the active and inactive waste landfills was observed to exhibit exceedances of drinking water standards for the same constituents observed in upgradient and downgradient ground water wells and at similar concentrations -- cadmium (up to 3 times the PDWS), and sulfate (5 times the SDWS) -- with the exception that no exceedance was observed of manganese.

Surface Water. No surface water samples were collected at the site.

Attenuation Tests. Attenuation tests conducted using background soils at the site showed the soil to have low attenuative capacities for a variety of trace metals, especially arsenic.

E.6.3 Discussion and Conclusion

All ground-water sampling conducted at the Dave Johnston site (both upgradient and downgradient) indicated levels of cadmium in exceedance of Primary Drinking Water Standards. Cadmium was also observed at elevated concentrations within and beneath the wastes. Secondary Drinking Water Standards were exceeded for manganese and sulfate in both upgradient and

downgradient ground water, and in fluids obtained from within and beneath the wastes of the disposal areas.

These results did not indicate whether migration of waste leachate to downgradient ground water had occurred, or whether the observed contamination was caused by a source other than the ash wastes. Other site information that can aid in interpretation of results at site are discussed below.

The estimation that leachate from the active waste area may not have reached downgradient wells by the time of sampling would suggest that there may have been other contamination sources besides the active disposal area. However, it may be possible that wastes had been in direct contact with the ground water, allowing for a considerable increase in the velocity of contaminant migration.

Outside of exceedances of drinking water standards, there did appear to be a general increase downgradient in ground-water concentrations of major ash constituents (e.g., chlorine, magnesium, sodium, silicon, and sulfate). These increases may be attributable to natural mineral weathering (as discussed below), or may be due to the effects of ash disposal.

Weathering of the mineralized soils at the site, in conjunction with the low ground-water velocities in this area, may have allowed natural solute pickup as ground water moved across the site toward the North Platte River. This pickup added to the difficulty of distinguishing the effects of waste leachate from the natural increases in downgradient solute concentrations. However, in wells screened below the disposal areas, it appeared that waste leachate had caused increases in solute concentrations (e.g., chlorine, sulfate, etc.). In wells

further downgradient from the disposal areas the effect of waste leachate were difficult to distinguish.

Interpretation of results from the Dave Johnston site was difficult due to its complex hydrogeologic regime and the many waste disposal locations of varying ages at the disposal site, including the two disposal areas studied. The actual location of the closed ash disposal sites was uncertain. These old disposal areas were probably located upgradient from the retired ash pond and may have also been upgradient of the active ash pond. Thus, leachate from past disposal activities, instead of weathering of soils, may have been the cause of upgradient contamination of ground water.

Leachate from the wastes may have eventually reached downgradient ground water and the North Platte River. If the ground-water contamination observed at the site was attributable to waste disposal, this contamination can be expected to increase as leachate reaches steady-state concentrations. It is also probable that, at least for the observed contamination by cadmium, the ground-water contamination may have been due to the ash wastes areas, active or closed, present at the site.

It should be noted that arsenic, which was found in elevated concentrations within waste fluids from the other ADL sites, was not tested for at this site. This information on arsenic would have been useful to contrast its concentration in the waste fluids with the low chemical attenuation observed for the soils of this site.

In summary, the Dave Johnston plant in Wyoming was located in an arid region

with little ground-water recharge. The plant was relatively old and burned low sulfur western coal. There were a number of disposal areas at the site. The ADL study investigated two landfills southeast of the site, an active one and a closed one. These landfills were unlined and used for fly ash disposal. Exceedances of the Primary Drinking Water Standards were found in ground water upgradient and downgradient of the site for cadmium (up to 5 times the PDWS). These were the same contaminants found at elevated concentrations in waters within and beneath the wastes. Exceedances of Secondary Drinking Water Standards were observed in downgradient and upgradient ground water for manganese and sulfate. Both of these contaminants, along with boron, were found in elevated concentrations in waters beneath and within the waste. No samples were analyzed for arsenic in the waste fluids. Chemical attenuation by soils of the site were found to be low for trace metals such as arsenic.

Interpretations of the sampling results were difficult to make due to the occurrence of other potential contamination sources, in the form of older waste disposal areas at the site (the location and ages of which are uncertain); potential pickup of major ash constituents from mineralized soil solutes; and uncertainties in whether, and to what degree, leachate from the two landfills had reached the downgradient wells. Contamination from the two landfills could have increased until steady-state concentrations were reached. It appeared that at least some of the contamination observed, especially for contaminants such as cadmium, was due to leaching from the many ash deposits at the site.

E.7 SHERBURNE COUNTY PLANT

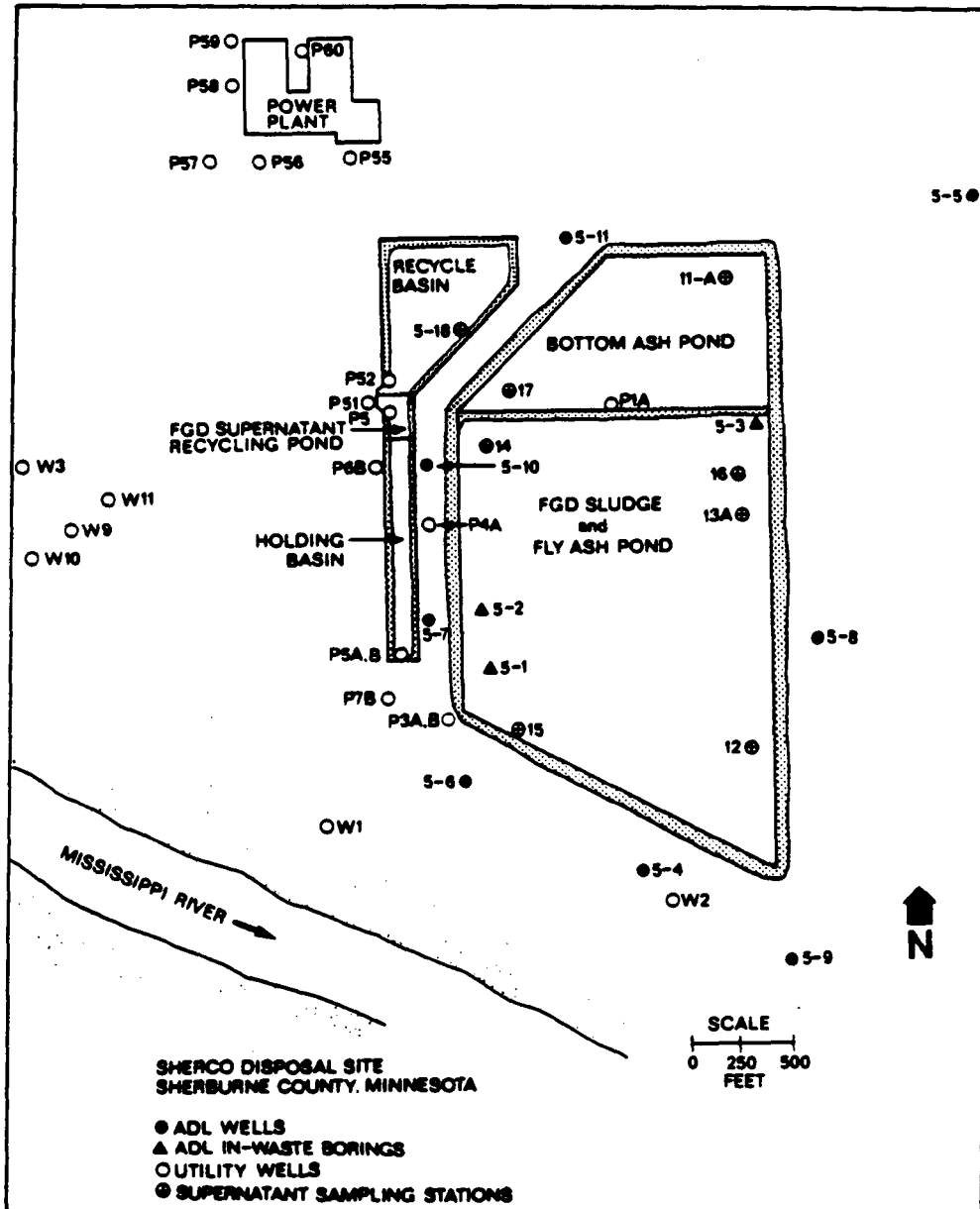
The Sherburne County Plant in Minnesota was located approximately 30 miles northwest of Minneapolis. The plant site was adjacent to the northeast bank of the Mississippi River, and consisted of two units, each equipped with fly ash alkali FGD scrubbers that used limestone. The plant used subbituminous coal from Montana and Wyoming with a sulfur content of 0.8 percent and an ash content of about nine percent.

Combined fly ash/FGD waste effluent was thickened and disposed of in a clay-lined pond which covered 62 acres and lay just southeast of the power plant (Exhibit E-15). Bottom ash was disposed of in a separate, adjacent, 18-acre clay-lined pond immediately north of the FGD sludge/fly ash pond. Overflow from these disposal ponds was directed into a clay-lined basin to the west of the bottom ash pond, effluents from which were recycled as a scrubber medium or for waste sluicing. The disposal ponds had been in use since 1976.

The Sherburne Plant was underlain by granite at a depth varying from 50 to 150 feet. Soils throughout the site area consisted of glacial drift (sands and gravels). Discontinuous lenses and layers of glacial till (dense mixtures of silt, sand, and clay) also occurred within the drift deposits. Ground water was in the unconsolidated glacial outwash (drift) sands and gravels. The water table was approximately 30 to 40 feet below the land surface. Ground-water flow was generally southwesterly towards the Mississippi River (Exhibit E-16). In general, there was no surface runoff in the site area with all precipitation infiltrating rapidly through the soils to the ground-water table. Annual precipitation was about 28 inches.

EXHIBIT E-15

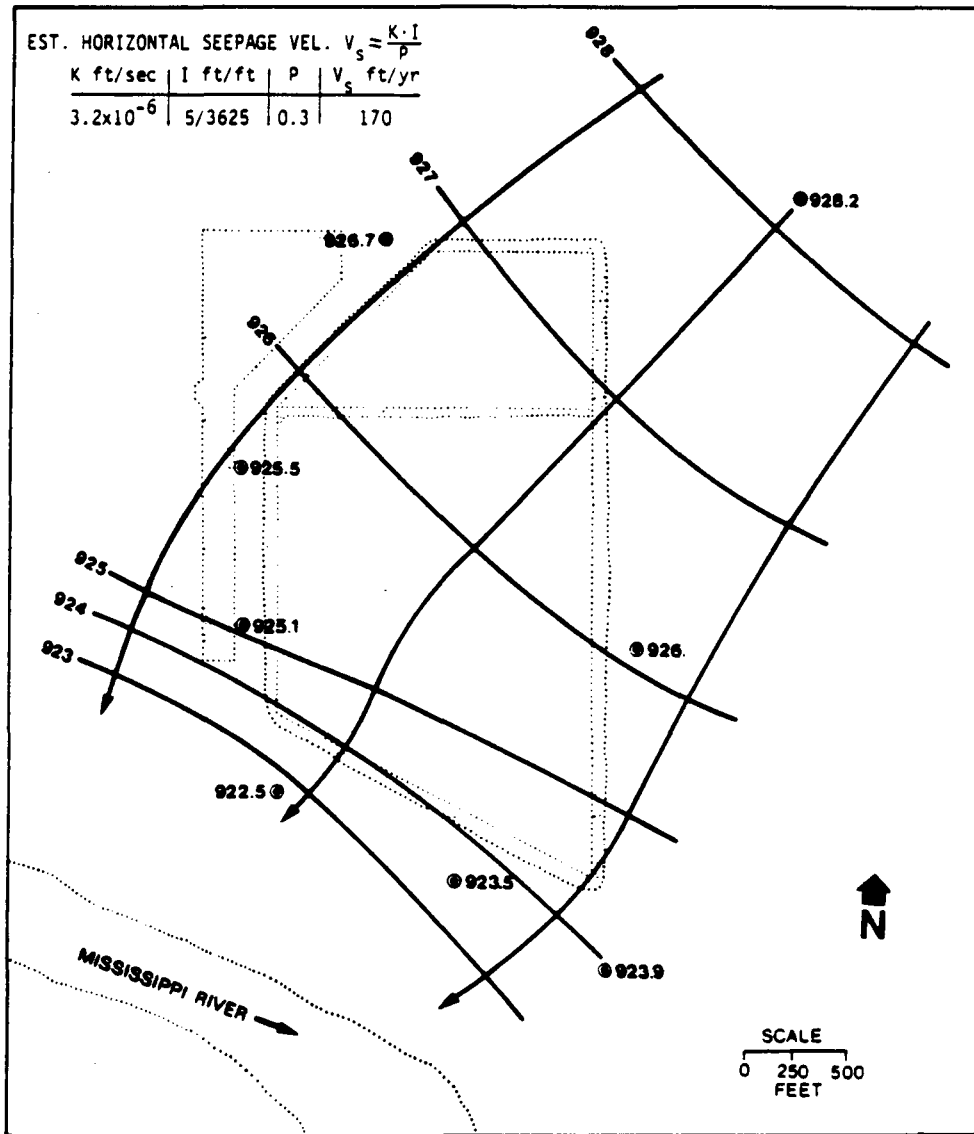
DISPOSAL PONDS AND SAMPLING LOCATIONS AT
SHERBURNE COUNTY SITE



Source: Tetra Tech 1985.

EXHIBIT E-16

GROUND-WATER FLOW DIRECTIONS AT SHERBURNE COUNTY SITE



Source: Tetra Tech 1985.

Factors that were considered to be important in the selection of this site's ponding operations for study included:

- Fly ash and sulfur oxides from the plant were removed simultaneously using external forced oxidation. This produced a waste that was sulfate-rich and easy to dewater and handle. Few other plants practice forced oxidation, but it had been identified as a potentially mitigative measure for FGD waste management and its use was expected to grow in the future.
- Pond lining and recycling operations were in use at very few other plants and were considered to be potentially mitigative features at future sites. The site afforded an opportunity to study linear performance in the ponding of wastes.
- Western coal was employed at the Sherburne County Plant. Generating capacity using western coal with FGD systems was expected to grow.
- The high-quality ground water and modest precipitation at this site and its isolation from other sources of potential contamination was expected to facilitate the identification of any waste-related ground-water contamination.

E.7.1 Sampling Approach

Two upgradient and six downgradient ground-water monitoring wells were installed and sampled to determine the presence of any leachate in the ground water. Samples were also taken of wastes from the two ponds, liner materials, soils, waste "liquors" (waters) from the ponds (including FGD waste interstitial water and FGD pond supernatants), liquids from within the clay liner of the fly ash/FGD pond, and liquids from soils beneath the liner.

Locations of the waste ponds, recycling pond, monitoring wells, and other sampling locations are shown in Exhibit E-15. Wells were sampled for

contaminant concentrations on three dates. Soil attenuation tests and a site water balance were also conducted. Earlier results from ground-water monitoring conducted at the site since 1977 were also available for review. The value of and trends in sampling and analysis results for the site, and comparison of ground-water concentrations with relevant EPA standards, are discussed below.

E.7.2 Results

Exhibit E-17 presents the results of chemical sampling at the Sherburne County (Sherco) site. This includes samples from the downgradient and upgradient ground-water wells, and fluid samples collected from within (interstitial water) and beneath the wastes. Results are discussed below.

Waste and Liner Solids. No significant stratification of the FGD waste was observed and, therefore, the permeability of the waste was observed to be fairly uniform throughout the deposit, ranging from 7×10^{-5} to 5×10^{-6} cm/sec (indicating low permeability). The earthfill pond liner was tested for permeability and was found to range from 5×10^{-7} to 1×10^{-7} cm/sec.

Waste Fluids. Results from fluid samples collected from wells placed within the FGD sludge/fly ash waste and from pond supernatant indicated that these fluids or "pond liquors," when compared to Primary Drinking Water Standards, exhibited elevated concentrations of cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride (up to 4.5 times the PDWS), lead (up to 28 times the SDWS), nitrate (up to 7 times the PDWS), and selenium (up to 25 times the PDWS). Comparison of pond liquors to Secondary Drinking Water Standards showed elevated levels of chloride (up to 2 times the SDWS), iron (up to 6 times

EXHIBIT E-17

CHEMICAL SAMPLING RESULTS FOR SHERBURNE COUNTY SITE

SHERBURNE COUNTY SITE
(no Surface Water data)

Units = ppm	PDMS	Ground water				Under Waste				Waste							
		1/				2/				3/				4/			
		Downgradient (3 wells)				Upgradient (2 wells)				Waters Under Liner (3 wells)				Pond Liquors (13 stations)			
Drinking Water Standard	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Detect.	Ave. Conc.	Max. Exceed.		
Arsenic 9/ (liq.)	0.05	3	0		3	0		4	1	1.8	6	0	0.028				
Barium	1	12	0		8	0		8	0		5	0	0.063				
Cadmium 10/	0.01	12	2	2	8	2	2	8	4	132	14	0	0.073	30			
Chromium 11/ (Cr VI)	0.05	12	1	1.2	8	0		8	3	7.6	3	0	0.35	16			
Fluoride 12/	4.0	12	0		8	0		8	2	2	9	9	9.5	4.5			
Lead 13/	0.05	12	0		8	0		8	2	103	1	1	1.4	28			
Mercury	0.002	0			0			0			NS						
Nitrate 15/	45	12	2	1.1	8	2	27	4	4	9.6	9	9	108	6.8			
Selenium 16/ (liq.)	0.01	3	0		3	0		4	0		7	0	0.06	25			
Silver	0.05	12	0		8	0		1	0		0						
SDMS																	
Chloride	250	12	0		8	0		8	1	2.7	12	12	183	1.9			
Copper	1	12	0		8	0		8	5	24	13	0	0.054				
Iron	0.3	12	0		8	1	1.9	8	8	86	13	0	0.46	6.1			
Manganese	0.05	12	2	22	8	1	1.4	8	1	788	11	0	5.8	316			
Sulfate	250	12	0		8	0		8	7	116	12	0	4880	42			
Zinc	5	12	0		8	0		8	3	17	7	0	0.31				
pH Lab 18/	<=6.5	0			0			0			NS						
	>=8.5	0			0			0			NS						
pH Field 18/	<=6.5	8	0		6	0		NR			0						
	>=8.5	8	0		6	0		NR			0						

EXHIBIT E-17 (Continued)

CHEMICAL SAMPLING RESULTS FOR SHERBURNE COUNTY SITE

- 1/ Wells 5-4, 5-6, and 5-9.
- 2/ Wells 5-5 and 5-11.
- 3/ Wells 5-1, 5-2, and 5-3. The fluids collected at these wells are groundwater from beneath the waste.
- 4/ Stations 5-1 S3, 5-1 S4, 5-1 U3, 5-2 U1, 5-2 S2, 5-3 (20 ft), 5-3 S9, 5-3 U4, 5-12, 5-13A, 5-14, 5-15, and 5-16. These "pond liquors" are fluids collected from within and on top of the landfilled wastes.
- 5/ The number of samples with reported concentrations above the drinking water standard.
- 6/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 7/ The number of "pond liquor" samples with reported concentrations above the reported detection limits. An entry of "0" indicates that no sample had a detectable contaminant concentration; not that no samples were taken (see footnote 14).
- 8/ Ave. Conc. is the average of the reported concentrations of all "pond liquor" samples taken that showed a contaminant concentration above the detection limit. The reported pH measurements of the "pond liquors" are also averaged.
- [Comment on footnotes 9-15:
Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard.]
- 9/ For some water samples collected from water under the waste, the reported detection limit of 0.074 was greater than the PDWS for arsenic.
- 10/ For some water samples collected from water under the waste, the reported detection limit of 1.5 was greater than the PDWS for cadmium.
- 11/ For some water samples collected from water under the waste, the reported detection limit of 1.5 was greater than the PDWS for chromium.
- 12/ For some water samples collected from water under the waste, the reported detection limit of 24.6 was greater than the PDWS for fluoride.
The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPDWS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 13/ For some water samples collected from water under the waste, the reported detection limit of 7.5 was greater than the PDWS for lead.
- 14/ NS = not sampled.
- 15/ For some water samples collected from water under the waste, the reported detection limit of 0.123 was greater than the PDWS for selenium.
- 16/ For some water samples collected from water under the waste, the reported detection limit of 1.5 was greater than the PDWS for manganese.

17/ As indicated in footnote 6, the Max. Exceed column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

18/ NR = not reported.

the SDWS), manganese (up to 316 times the SWDS), and sulfate (up to 42 times the SDWS). Concentrations measured in the pond supernatant were generally higher than those measured in the interstitial waters of the wastes (e.g., 10,000 ppm sulfate in pond surface liquids and 2000 ppm in waste fluids). Pond liquors obtained from the smaller bottom ash pond also exhibited elevated concentrations of cadmium (up to 50 times the PDWS), and manganese (up to 9 times the SDWS). Because these fluids are not ingested, comparison to the drinking water standards is shown only to indicate the potential for contamination at the site.

Misc. Fluids. Results obtained from chemical analyses of the clay liner pore water showed concentrations of cadmium, chromium, iron, sulfate, and manganese that were above drinking water standards. Fluid samples obtained from under the liner showed elevated concentrations for most of the contaminants tested for, including arsenic, cadmium, chromium, fluoride, lead, selenium, nitrate, boron, sulfate, chloride, copper, iron, zinc, and manganese. It is unclear as to what these samples represented, and the method used to collect the liquid samples from the unsaturated soils beneath the clay liner may have resulted in these observed to be above drinking water standards values being greater than the trace below-liner concentrations. Concentrations of cadmium, boron, and manganese were observed in fluids obtained from the recycling basin.

Ground Water. Estimates were made of seepage velocities at the site. Results from these calculations indicated that enough time had elapsed for some constituents in the waste leachate to have reached the nearer downgradient wells (Wells 5-4 and 5-6). However, steady-state conditions had probably not been reached at the site (i.e., chemical equilibrium between the waste, leachate, and downgradient ground water had not occurred).

Primary Drinking Water Standards were found to be exceeded in the ground water of the downgradient wells for cadmium (up to 2 times the PDWS) chromium (up to 1.2 times the PDWS), and nitrate (up to 1.1 times the PDWS). Upgradient exceedances of the Primary Drinking Water Standards in ground-water samples were also found for cadmium (up to 2 times the PDWS) and nitrate (up to 27 times the PDWS). Secondary Drinking Water Standards were found to be exceeded in downgradient ground water for manganese (up to 22 times the SDWS). Upgradient exceedances of the Secondary Drinking Water Standards in ground-water samples were observed for iron (up to 1.9 times the SDWS) and manganese (up to 1.4 times the SDWS). It should be noted that concentration measurements for arsenic and selenium in the ground water were sparse.

Surface Water. No surface water samples were collected at the Sherburne County site.

Attenuation tests. Attenuation tests conducted with site soils and pond liquor solutions (spiked with trace elements) from the Sherburne County and Allen sites indicated that the sandy soils that prevailed over much of the site had a relatively low capacity to chemically attenuate trace metals. Tests of the clay liner soil indicated these materials had a somewhat better attenuative capacity.

E.7.3 Discussion and Conclusions

Exceedances of the Primary Drinking Water Standards for cadmium (up to 2 times the PDWS) and nitrate (up to 27 times the PDWS upgradient and up to 1.1

times the PDWS downgradient) were observed in both the upgradient and downgradient ground water at the Sherburne County disposal site. There were manganese exceedances in both upgradient wells (up to 1.4 times the SDWS) and downgradient wells (up to 22 times the SDWS).

Wastes fluids from the FGD sludge/fly ash pond exhibited high concentrations of several constituents; cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride (up to 4.5 times the PDWS), nitrate (up to 7 times the PDWS), lead (up to 28 times the PDWS), and selenium (up to 25 times the PDWS). Elevated concentrations were also observed for chloride (up to 2 times the SDWS), iron (up to 6 times the PDWS), manganese (up to 316 times the SDWS), and sulfate (up to 42 times the PDWS).

Although the wastes and fluids exhibited high concentrations of contaminants, leachate from these wastes did not appear to have migrated into or mixed with the ground water to any great extent. There were indications that some waste-related solutes had migrated to downgradient wells from the FGD sludge/fly ash pond. Concentration profiles of sulfate were greater downgradient than upgradient in the closer well, 5-4. Higher than background concentrations of solutes at downgradient well 5-6 may not have been associated with the disposal ponds, but may have reflected leakage that was reported to have occurred from holding ponds at the site. Possible explanations of results and future expectations are discussed below.

Nitrate exceedances of the Primary Drinking Water Standards were widespread at various locations at the site (including background), but seemed to be unrelated to disposal operations.

Observed solute concentrations (e.g., sulfate, boron) suggested that the clay liner had reduced the rate of release of leachate from the disposal pond. However, concentrations of waste-related contaminants in downgradient ground water may eventually increase, since leachate was not currently leaking out of the landfill at a maximum, or steady-state, concentration, and only a portion may have reached the downgradient wells at the time of sampling. In other words, only a small quantity of leachate had, at the time of sampling, mixed with the larger amounts of uncontaminated ground water. If the landfill had not contained a liner, estimates of leachate movement indicated that steady-state concentrations of leachate would have reached downgradient wells several years prior to the study.

Two other factors that could contribute to the observed lack of contamination in downgradient ground water include:

- Leachate that originally permeated the liner may have been less contaminated than the leachate currently found in the FGD wastes (leachate may not have yet been in equilibrium with the wastes, and early plant operations did not involve recycling plant water); and
- Most of ADL's wells were screened over a depth interval of 20 feet or greater, thereby yielding composite ground-water samples that may have exhibited lower contaminant concentrations than if the wells were screened only at a level and length commensurate with the expected migration of leachate.

The waste-related contaminant selenium may be of concern at this site since the surrounding soils may not chemically attenuate selenium, and its concentration in ground water could be higher than indicated once steady-state concentrations were achieved.

In summary, the Sherburne County Plant in Central Minnesota disposed of combined fly ash and FGD waste in one clay-lined pond and bottom ash in an adjacent clay-lined pond. Exceedances of the Primary Drinking Water Standards were observed in both upgradient and downgradient ground water for cadmium (up to 2 times the PDWS for both) and for nitrate (up to 27 times the PDWS upgradient and up to 1.1 times the PDWS downgradient), and in downgradient ground water for chromium (up to 1.2 times the PDWS). Waters from the pond wastes were found to exhibit high concentrations (relative to Drinking Water Standards) of several constituents including cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride (up to 4.5 times the PDWS at 26-33 °C), nitrate (up to 7 times the PDWS), lead (up to 28 times the PDWS), and selenium (up to 25 times the PDWS).

While the waste fluids exhibited high concentrations of contaminants, leachate from these wastes did not appear to have migrated into and mixed with ground water to a great extent. Ground-water samples collected at the site do seem to indicate that a few waste-related species (sulfate and boron) have migrated from the wastes. The clay liner appeared to have significantly reduced the rate of release of leachate from the disposal ponds, precluding the development of elevated trace metal contaminant concentrations at downgradient wells. Over time, downgradient wells may increase the level of contamination, since steady-state conditions have not been achieved between leachate from the landfill and the ground water. Without the clay liner, the leachate seepage rate would have been much greater, leading to greater contamination of ground water. Since the surrounding soils may not chemically attenuate it, the waste-related contaminant selenium may be of concern at this site once

steady-state concentrations in ground water are reached.

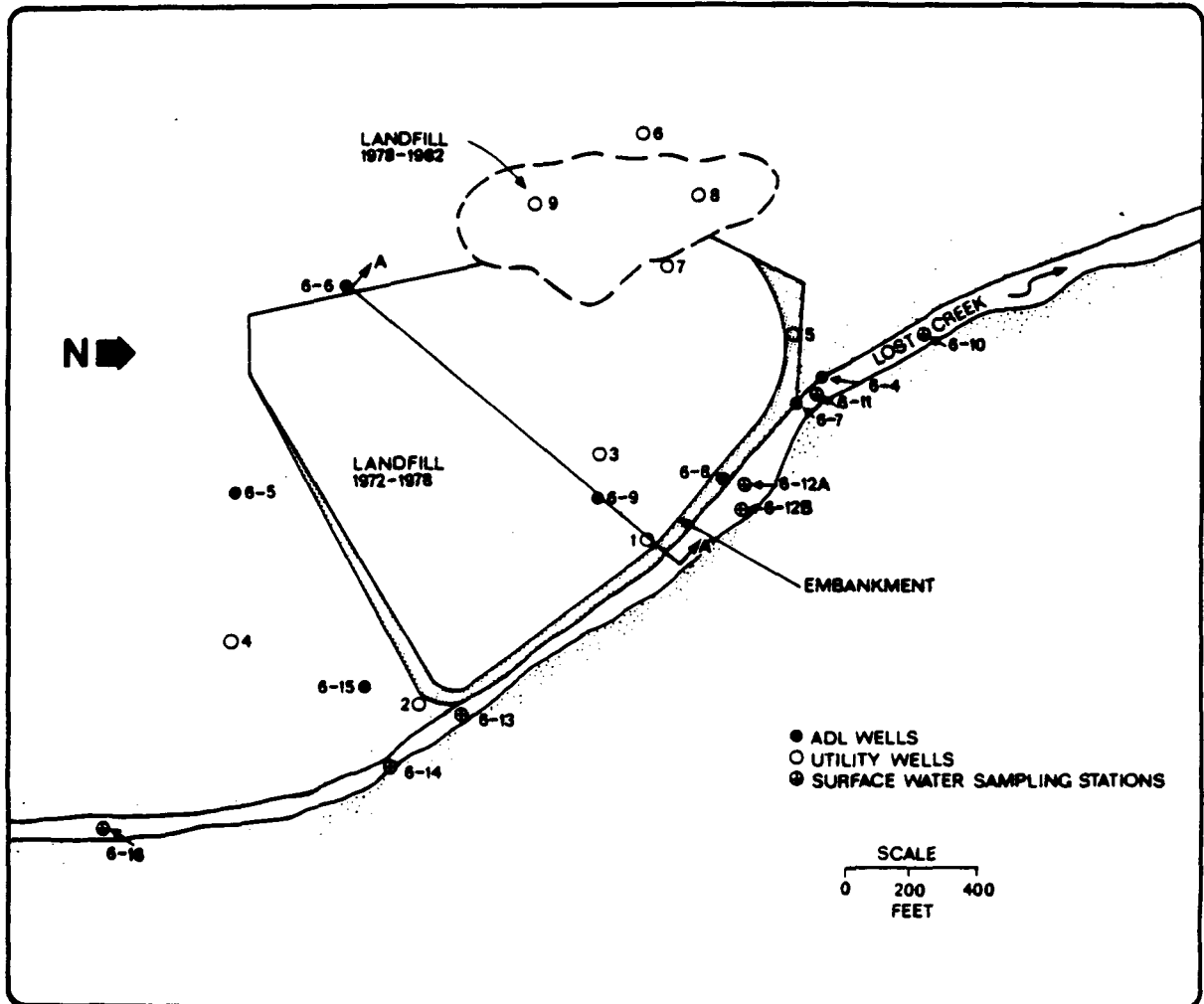
E.8 POWERTON PLANT

The Powerton Power Plant is located in Tazewell County, Illinois, approximately 10 miles south of Peoria. The site is located one mile south of the Illinois River, and the disposal area is another mile south of the plant. The existing facility began operation in 1972, although a smaller plant had previously operated at the site. Originally, bituminous coal with four percent sulfur was burned. In 1976, the plant began burning Montana subbituminous coal with 0.6 percent sulfur and six percent ash. At the time of the study, the Powerton wastes consisted of boiler slag that was dewatered and trucked to the disposal area, and fly ash which was collected from an electrostatic precipitator, stored, and then transported dry to the disposal area.

The disposal area consisted of two adjacent landfill areas which border Lost Creek (Exhibit E-18). The large portion of the disposal area was used from 1972 until 1978, and had since been reclaimed. The smaller area west of this section was operated from 1978 until 1982. The newer portion of the landfill occupies an abandoned borrow pit in which fly ash and slag were intermixed. In the older portion of the landfill, there were distinct layers of slag and fly ash. The newer landfill, and part of the older one, were underlain by a liner of Poz-O-Pac,⁷ which consisted of a chemically stabilized mixture of fly ash, lime, and bottom ash. The liner was reported to be five feet thick beneath the newer part of the landfill and only eight inches thick

EXHIBIT E-18

LANDFILL AREAS AND SAMPLING LOCATIONS AT THE POWERTON SITE



Source: Tetra Tech 1985.

beneath the older area. The surface area of the entire landfill was approximately 438 acres.

The following factors were considered to be important for selecting the Powerton landfill operation for study:

- The collection, handling, and landfill disposal of ash as practiced at Powerton was one of the prevalent practices nationwide in the utility industry.
- The interior climatic and hydrogeologic setting (relatively permeable soils and moderate, regular precipitation) were considered to be typical and allowed effects of landfill disposal of coal ash generated from western coal to be studied.
- While artificial lining of managed coal ash landfills was not a prevalent practice nationwide at the time of the study, this site was considered a useful opportunity to study a potentially mitigative practice.
- The retired landfill was bordered by a small stream (Lost Creek). Because there were no major point source discharges to Lost Creek, this was considered a good opportunity to study potential impacts of coal ash disposal on a small surface water body.

In the Powerton area, the bedrock consisted of limestone, sandstones, and shales. These were overlain by thick deposits of glacial outwash (sands and gravels). The older portion of the landfill was underlain by sand and silt deposits, within which are a number of clay lenses. The site receives an average of 36 inches of precipitation per year. The glacial outwash deposits made up the principal aquifer (water-bearing units) underlying the landfill. This aquifer discharged to Lost Creek. At the upgradient edge of the landfill (the western edge), the water table was approximately 35 feet below the fill. Along the downgradient edge (that bordering Lost Creek), the water table was within a few feet of the ash and occasionally intercepted the ash fill. All surface and ground-water flow was northeasterly towards Lost Creek, which

subsequently flowed to the Illinois River (Exhibit E-19).

E.8.1 Sampling Approach

At the Powerton landfill, three upgradient (one background, two peripheral) ground-water monitoring wells and three downgradient ground-water monitoring wells were installed (Exhibit E-18). Additionally, one well was drilled through the ash and slag wastes of the older landfill to sample waters directly beneath the fill. These wells were installed to determine (via chemical testing) the presence and vertical extent of any leachate. Additionally, chemical analyses were performed on surface water samples at the site. Samples were collected from six surface water stations in Lost Creek. Three of these stations were located upstream (6-13, 6-14 and 6-16), two were located in the middle of the site, and one was located downstream (6-10). No samples were collected of interstitial waters or liquors from within the wastes.

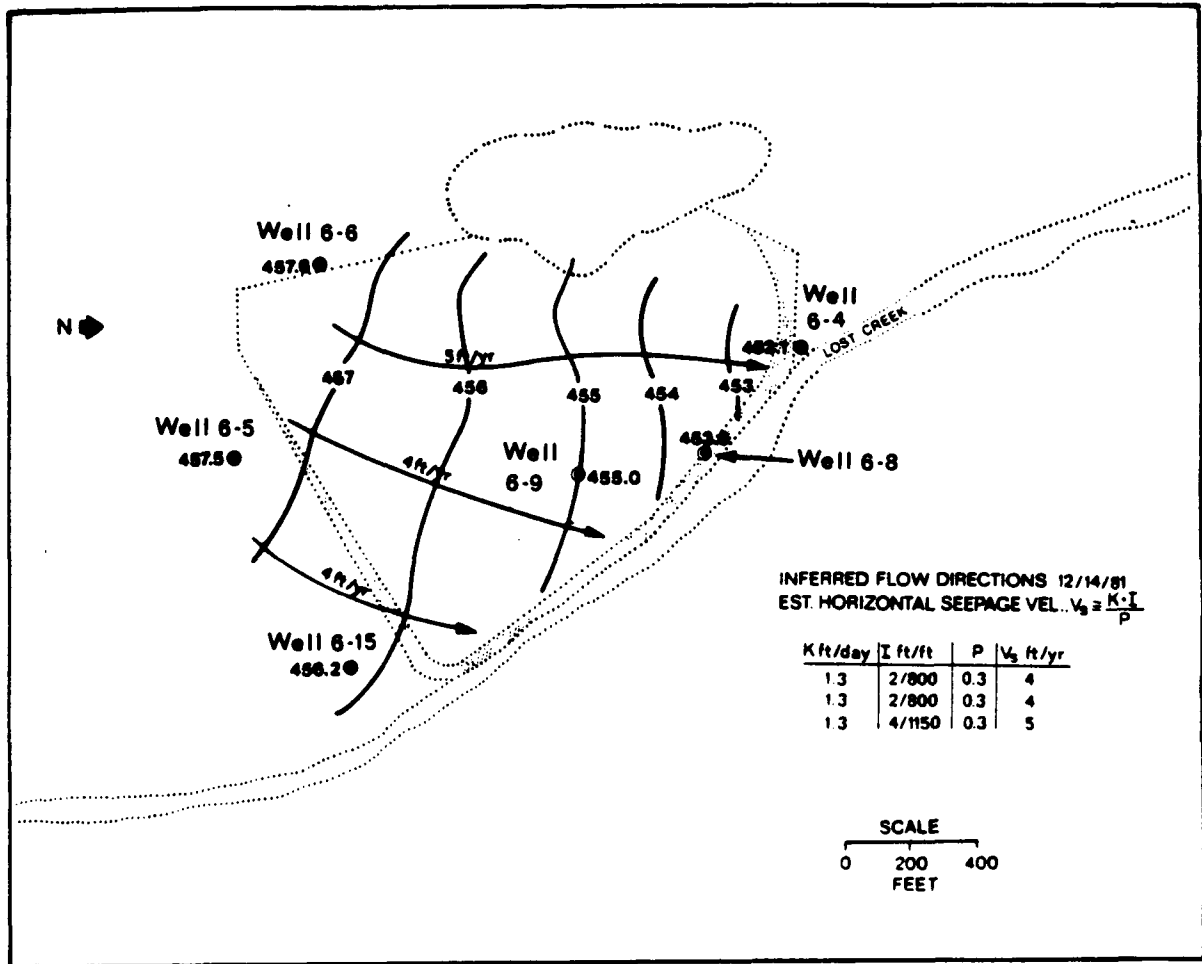
E.8.2 Results

Exhibit E-20 presents the results of chemical sampling at the Powerton site. This includes samples from the downgradient and upgradient ground-water wells, samples from the surface water stations, and water samples obtained from materials beneath the wastes. Results are discussed below.

Waste Solids. Permeability of the landfilled wastes ranged from a high of 3×10^{-2} cm/sec for the slag to a low of 1×10^{-4} cm/sec for the fly ash. In the

EXHIBIT E-19

GROUND-WATER FLOW DIRECTIONS AT THE POWERTON SITE



Source: Tetra Tech 1985.

EXHIBIT E-20

CHEMICAL SAMPLING RESULTS FOR POWERTON SITE

POWERTON STATION SITE
(no Pond Liquor data)

Units = ppm		Ground water						Under Waste						Surface Water (Lost Creek)					
POWS	Drinking Water Standard	1/ Downgradient (3 wells)			2/ Upgradient (1 well)			3/ Water Under Waste (1 well)			4/ Downgradient (1 station)			5/ Upgradient (3 stations)					
		Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.	Total Samples	Exceed. Samples	Max. Exceed.			
Arsenic (liq.)	0.05	8	0		2	0		3	0		1	0		2	0				
Barium	1	9	0		4	0		3	0		3	0		8	0				
Cadmium	0.01	9	8	3	4	2	1	3	3	2	3	2	2	8	5	2			
Chromium (Cr VI)	0.05	9	0		4	0		3	0		3	0		8	0				
Fluoride	4.0	9	0		4	0		3	0		3	0		8	0				
Lead	0.05	9	1	4	4	0		3	0		3	0		8	0				
Mercury	0.002	0			0			0			0			0					
Nitrate 8/	45	9	0		4	2	1.1	3	1	1.7	3	1	1.1	7	3	1.2			
Selenium (liq.)	0.01	8	0		2	0		3	0		1	0		2	0				
Silver	0.05	9	0		4	0		3	0		3	0		8	0				
SDMS																			
Chloride	250	9	0		4	0		3	0		3	0		8	0				
Copper	1	9	0		4	0		3	0		3	0		8	0				
Iron	0.3	9	4	42	4	0		3	0		3	0		8	0				
Manganese	0.05	9	9	194	4	2	11	3	3	6	3	2	2.2	8	2	1			
Sulfate	250	9	6	2.7	4	0		3	3	3.6	3	0		8	0				
Zinc	5	9	0		4	0		3	0		3	0		8	0				
pH Lab 9/	<=6.51	0			0			0			0			0					
	>=8.51	0			0			0			0			0					
pH Field 9/	<=6.51	9	1	6	3	0		2	0		3	0		8	0				
	>=8.51	9	0		3	0		2	0		3	1	8.5	8	2	8.5			

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EXHIBIT E-20 (Continued)
CHEMICAL SAMPLING RESULTS FOR POWERTON SITE

- 1/ Wells 6-4, 6-7, and 6-8.
- 2/ Well 6-6.
- 3/ Well 6-9. The fluids collected at this well are groundwater from beneath the waste.
- 4/ Station 6-10.
- 5/ Stations 6-13, 6-14, and 6-16.
- 6/ The number of samples with reported concentrations above the drinking water standard.
- 7/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH; where Max. Exceed. is the actual measurement.
- 8/ The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPQWS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 9/ As indicated in footnote 7, the Max. Exceed. column for the reported pH measurements is a tabulation of the actual measurements; not the maximum exceedance divided by the drinking water standard.

more recent section of the ash landfill, where slag and fly ash were mixed, the permeability of the waste was approximately 5×10^{-4} cm/sec.

Waste Fluids. No samples were collected of waters from within the landfilled wastes (waste liquors). Results from water samples collected from beneath the waste indicated that these waters, when compared to Primary Drinking Water Standards, exhibited elevated concentrations of cadmium (up to 2 times the PDWS), and nitrate (up to 1.8 times the PDWS). Comparison of these samples to Secondary Drinking Water Standards indicated elevated levels of manganese (up to 6 times the SDWS), and sulfate (up to 3.6 times the SDWS).

Ground-Water. Estimates of seepage velocities at the site indicated that waste leachate constituents could have reached downgradient ground-water wells and possibly Lost Creek by the time of ADL's sampling.

Primary Drinking Water Standards were found to be exceeded in the ground water of the downgradient wells for cadmium (up to 3 times the PDWS) and lead (up to 4 times the PDWS). Slight exceedances in upgradient ground water of the Primary Drinking Water Standards were found for cadmium (up to 1 times the PDWS). Note that the one upgradient well (6-6) bordered the landfilled wastes. Occasional exceedances of the Primary Drinking Water Standard for cadmium were observed in the two ground water wells peripherally located to the wastes.

Surface Water. The Primary Drinking Water Standard for cadmium was found to be exceeded occasionally at all surface water stations at the site. Cadmium was observed at up to 2 times the Primary Drinking Water Standard at the upgradient (upstream) stations and at the downgradient stations. Nitrate exceeded the

Primary Drinking Water Standards in both upgradient (up to 12.3 times the PDWS) and downgradient (up to 11.6 times the PDWS) surface water locations. Secondary Drinking Water Standards were found to be exceeded in both upgradient (1 times the SDWS) and downgradient (up to 2.2 times the SDWS) surface water locations for manganese.

Attenuation Tests. Attenuation tests conducted using pond liquor solutions (spiked with trace elements) from the Allen and Sherburne County sites and soils obtained from the Powerton site indicated that these soils generally had intermediate capacities to attenuate trace metals such as arsenic.

E.8.3 Discussion and Conclusions

The assessment of sampling results from the site focused on the effects of ash landfill leachate on downgradient ground-water quality, and the effects of ash landfill leachate on Lost Creek surface-water quality. Emphasis on analyzing the effectiveness of the Poz-O-Pac liner under the landfill was discontinued after a general absence of the liner under the older, larger, disposal area was discovered.

Cadmium was observed to exceed the Primary Drinking Water Standard in the downgradient ground-water wells (up to 3 times the PDWS). Cadmium was also observed at the Primary Drinking Water Standard on one occasion in the upgradient ground-water well. Since the upgradient well is located very close to the landfill border, the slightly elevated concentration of cadmium observed in this well's samples may have been from the leaching of cadmium. However, it must be noted that cadmium exceedances in surface water were observed upstream

as well as downstream (up to 2 times the PDWS), potentially indicating that the utility waste was not the source.

One exceedance of the Primary Drinking Water Standard for lead was observed at a downgradient ground-water well (up to 4 times the PDWS). However, the usefulness of this information was limited since lead was only reported to be detectable on one occasion and, in other samples, lead was not detectable at all. Elevated nitrate concentrations observed in ground water from various sampling locations could possibly be attributed to local agriculture activities. Trace elements such as arsenic and selenium were found to be similar to background concentrations and were below drinking water standards. These trace elements may not have leached from the landfill, or may have been chemically attenuated by the soil.

Chemical sampling results at the Powerton site indicated that leaching and migration of ash wastes had occurred since solutes had reached the downgradient wells. Major ash constituents that are observed to exceed Secondary Drinking Water Standards in the downgradient ground water at the site were sulfate (up to 3 times the PDWS), iron (up to 4 times the PDWS), and manganese (up to 194 times the PDWS). Of these contaminants, the elevated levels of sulfate might have been due to leaching from the waste. Only manganese was observed to exceed Secondary Drinking Water Standards at the upgradient well (up to 11 times the PDWS).

The ground-water concentrations of the major waste constituents indicated that leachate migration from the landfill might have reached approximately steady-state conditions with respect to the concentrations of these species in

the waste and downgradient wells. If this had occurred, further increases in the concentrations of such species would not be expected. Additionally, levels of trace metals in the ground water suggested that a combination of dilution and chemical attenuation was preventing the buildup of significant concentrations of these constituents at downgradient locations. Given these ground-water results, the Powerton site might have had some effect on ground-water quality, but increased degradation should not be expected.

The consistently elevated concentrations of boron observed in downstream surface water of Lost Creek would seem to indicate some leaching of this waste constituent since it is being detected in the surface waters of Lost Creek. This body of water may be substantially diluting the waste constituents; however, the small number of sampling stations do not allow further data analysis.

In summary, the Powerton Plant disposed of fly ash, bottom ash, and slag in an older landfill approximately one mile south of the site. More recent disposal operations consisted of disposing of intermixed fly ash and slag in a newer portion of the landfill. The newer landfill and part of the older one were underlain by a liner consisting of ash and lime (Poz-O-Pac). The downgradient ground-water wells exhibited levels of cadmium up to three times the Primary Drinking Water Standard and levels of lead at up to four times the Primary Drinking Water Standard. An upgradient well, located on the border of the landfill wastes, also exhibited an elevated concentration of cadmium at the level of the Primary Drinking Water Standard. Secondary Drinking Water Standards were exceeded in downgradient wells for iron, manganese, and sulfate, and in the upgradient well for manganese (but at a lower level of exceedance

compared to the downgradient measurement).

Results indicate that leaching and migration of ash wastes had occurred at the site, but it is difficult to determine how significant an impact the leachate has had, or will have, on ground-water quality. Dilution and chemical attenuation may have prevented the development of significant concentrations of trace metals such as arsenic and selenium at downgradient locations. The degree to which Lost Creek was diluting the waste constituents that may reach it may have been significant, but could not be determined from the available information.

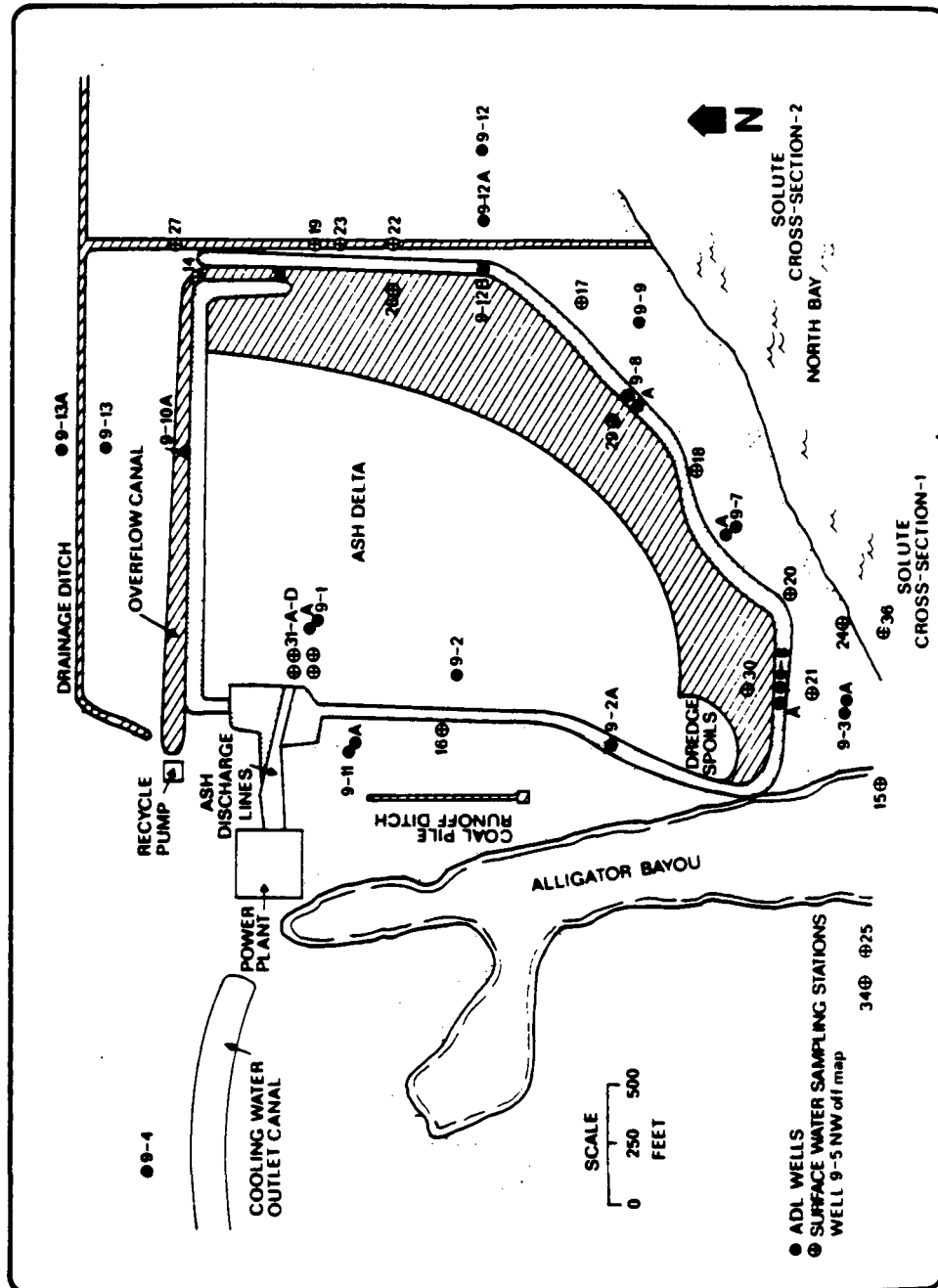
E.9 LANSING SMITH PLANT

The Lansing Smith power plant is located on a coastal plain approximately eight miles north of Panama City, Florida. The power plant lies approximately one-half mile inland from the shore of North Bay (within the St. Andrews Bay System) at the tip of Alligator Bayou. At the time of the ADL study, the two units at the site were equipped with electrostatic precipitators. The coal used was primarily low sulfur bituminous coal.

Fly ash, bottom ash, mill rejects, and coal pile runoff were sluiced to an unlined ash disposal pond which covers approximately 200 acres and lies generally between the power plant and the shore of North Bay (Exhibit E-21). The disposal pond has been in continuous use since 1965. The landfill was contained by dikes through the exterior slopes of which seepage had been

EXHIBIT E-21

DISPOSAL POND AND SAMPLING LOCATIONS AT
LANSING SHITH SITE



Source: Tetra Tech 1985.

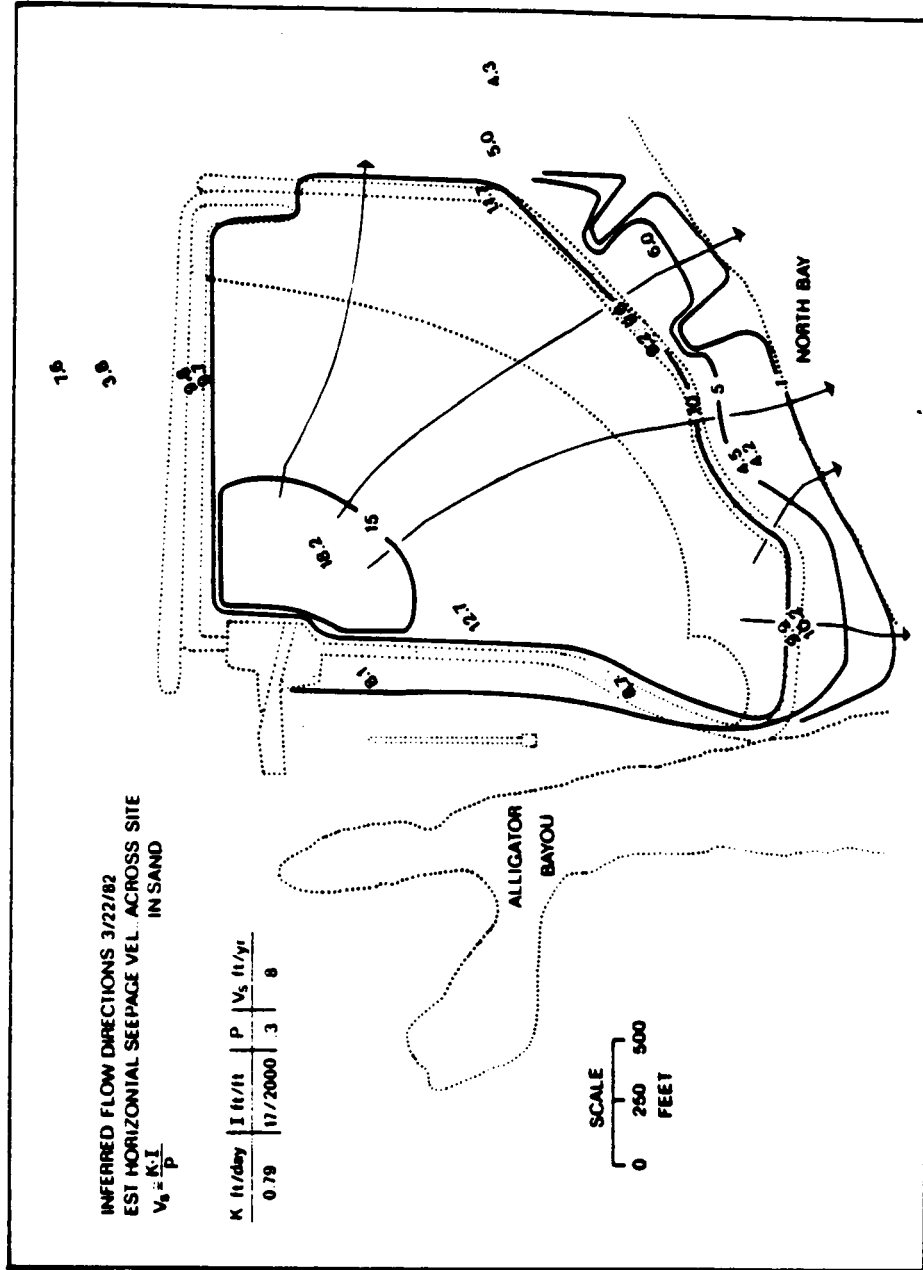
visually observed. Standing water in the disposal pond was channelled through a recycling canal and pumped back to the plant for reuse as sluicing water.

The plant was located on low-lying, almost level, marine terraces, which are drained by bayous and small creeks. The site experienced heavy precipitation (approximately 58 inches/year) and the low elevations of the site area had experienced flooding from both the river basin and coastal storms. Part of the land underlying the ash pond was once a swamp.

Surface deposits at the site consisted of thin topsoil and shallow organic deposits. Limestone of the confined Floridan Aquifer lay at a depth of approximately 90 feet, and was the principal water supply aquifer of the county. A thick layer of unconsolidated permeable silts and sands was between the Floridan Aquifer and the surface deposits. Due to saltwater intrusion, ground water in these deposits was not considered potable (and was not used as a drinking water supply at the time of the study). The water table at the site was close to the ground surface, resulting in swampy conditions. Ground water was in contact with the disposed ash materials. Regional ground-water flow was southeasterly towards North Bay (Exhibit E-22), however, flow patterns were multi-directional in the plant vicinity.

Surface water in the plant vicinity consisted of the ash disposal pond, the sluice water recycle canal, various drainage ditches and tidal creeks around the ash disposal pond, Alligator Bayou, and a cooling-water outlet canal, some of which contained seawater.

EXHIBIT E-22
GROUND WATER FLOW DIRECTIONS AT LANSING SMITH SITE



Source: Tetra Tech 1985.

Factors for including the Lansing Smith Plant in the ADL study were:

- The disposal method employed at the plant -- that of combined disposal of fly ash and bottom ash in an unlined pond -- was the most prevalent utility waste disposal practice in the nation.
- The disposal operation had been in existence for more than 15 years, allowing sufficient time for measurable leachate to reach the surrounding environment.
- The site was a coastal area and would allow the study of a situation where ash pond leachate and seawater would mix.
- The site experienced heavy precipitation in a setting of permeable soils and was expected to illustrate a maximal extent of leachate formation and transport in a pond disposal setting.
- Increases were anticipated in coal conversion of coastal oil-fired power plants, and there was a paucity of data and previous studies of coastal disposal operations.

E.9.1 Sampling Approach

Samples of wastes and soils were collected for physical and chemical testing. Samples of ground water, waste fluids (or pond liquors), and surface water samples were collected for chemical testing. A series of attenuation tests were performed using local site soils and pond liquor solutions (spiked with trace elements) obtained from the Allen and Sherburne County sites.

Twenty-four monitoring wells were installed throughout the site area (Exhibit E-21). There were three upgradient ground-water wells (9-4, 9-5, and 9-13A) and five true downgradient ground-water wells (9-3, 9-3A, 9-7, 9-7A, and 9-9). Eleven monitoring wells were drilled within the ash pond or through the dike (9-1, 9-1A, 9-2, 9-2A, 9-6, 9-6A, 9-8, 9-8A, 9-10, 9-10A, and 9-12B). Two

of these wells were used to sample water from under the waste. An additional five wells were located along the perimeter of the dike. In addition, 18 surface water sampling stations were established. Locations of site wells and surface water sampling locations were shown in Exhibit E-21.

E.9.2 Results

Exhibit E-23 presents the results of chemical sampling at the Lansing Smith site. This includes samples from the downgradient and upgradient ground-water wells, samples from wells emplaced within the waste to collect interstitial water or fluids (includes supernatant fluids), water samples obtained from beneath the waste, and surface water samples. Results are discussed below.

Waste Solids. The waste was generally found to be segregated into lenses of coarser and finer grained ash. A permeability of 9×10^{-4} cm/sec was measured for the coarser ash, and 3×10^{-5} cm/sec for the finer fly ash.

Waste Fluids. Results from fluid samples collected from wells emplaced within the waste indicate that these fluids or "pond liquors", when compared to Primary Drinking Water Standards, exhibit elevated concentrations of cadmium (up to 6 times the PDWS), chromium (up to 21 times the PDWS), and fluoride (up to 10 times the PDWS). Comparison of pond liquors to Secondary Drinking Water Standards showed elevated levels chloride (up to 61 times the SDWS), manganese (up to 7 times the SWDS), and sulfate (up to 6 times the SDWS). These fluids were also fairly alkaline (up to a pH of 11). Since these fluids are not ingested, comparison to the drinking water standards is shown to demonstrate the potential for contamination at the site.

EXHIBIT E-23

CHEMICAL SAMPLING RESULTS FOR LANSING SMITH SITE

LANSING SMITH STEAM PLANT

Units = ppm		Ground water						Under Waste			Surface Water (Alligator Bayou, North Bay, and a stream on the east side)						Waste					
PWS	Drinking Water Standard	1/ Downgradient (5 wells)			2/ Upgradient (3 wells)			3/ Water Under Waste (2 wells)			4/ Downgradient (6 stations)			5/ Peripheral (3 stations)			6/ Downgradient - Saline (2 stations)			7/ Pond Liquors (9 stations)		
		Total	Exceed. Samples	Max. Exceed.	Total	Exceed. Samples	Max. Exceed.	Total	Exceed. Samples	Max. Exceed.	Total	Exceed. Samples	Max. Exceed.	Total	Exceed. Samples	Max. Exceed.	Total	Exceed. Samples	Max. Exceed.	Samples Detect.	Ave. Conc.	Max. Exceed.
Arsenic (liq.)	0.05	5	0		4	0		3	0		2	0		1	0		3	0		8	0.0055	
Barium	1	14	0		6	0		4	0		13	0		8	0		5	0		18	0.26	
Cadmium	0.01	14	10	5	6	2	2	4	4	4	13	10	5	8	4	4	5	5	4	16	0.029	6
Chromium (Cr VI)	0.05	14	1	4	6	0		4	1	2	13	0		8	0		5	1	1.2	8	0.16	21.4
Fluoride 12/	4.01	14	5	13.5	6	0		3	1	2.2	13	5	6.5	8	2	2	5	2	20	3	20	10
Lead 13/	0.05	14	0		6	0		4	0		13	0		8	0		5	0		0		
Mercury	0.002	0			0			0			0			0			0			14/	NS	
Nitrate 15/	45	0			0			0			0			0			0			14/	NS	
Selenium (liq.)	0.01	5	0		4	0		3	0		2	0		1	0		3	0		8	0.0014	
Silver	0.05	14	0		6	0		4	0		13	0		8	0		5	0		0		
SDMS																						
Chloride	250	14	14	22.4	6	0		4	4	49	13	13	11.9	8	5	10	5	5	57.8	18	3790	61
Copper	1	14	0		6	0		4	0		13	0		8	0		5	0		10	0.11	
Iron	0.3	14	14	118	6	6	37	4	0		13	11	370	8	6	34	5	0		12	0.12	
Manganese	0.05	14	13	17.2	6	2	1.4	4	1	5.2	13	11	64	8	6	4.8	5	0		8	0.17	7.4
Sulfate	250	14	8	8.4	6	0		4	4	9.8	13	12	7.5	8	4	3.4	5	5	9.9	18	866	6.4
Zinc	5	14	0		6	0		4	0		13	0		8	0		5	0		9	0.12	
pH Lab 16/	<=6.5	6	4	4.4	2	1	6.5	1	0		6	5	3.3	3	2	3.8	1	0		6	9.3	
	>=8.5	6	0		2	0		1	1	9.5	6	0		3	0		1	0		6	9.3	11
pH Field 16/	<=6.5	13	10	2.9	6	4	6	3	0		10	5	4.1	7	4	3.4	5	0		12	9.1	6
	>=8.5	13	0		6	0		3	3	9.5	10	0		7	0		5	0		12	9.1	11

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EXHIBIT E-23 (Continued)**CHEMICAL SAMPLING RESULTS FOR LANSING SMITH SITE**

- 1/ Wells 9-3 (deep, south), 9-3 (low tide), 9-3A (shallow, south) 9-3A (low tide), 9-7A, 9-7, and 9-9.
- 2/ Wells 9-4, 9-5, and 9-13A.
- 3/ Wells 9-2 and 9-1. The fluids collected at these wells are waters from beneath the waste.
- 4/ Stations 9-18, 9-20, 9-21, 9-24, 9-34, 9-25, but not station 9-34 (dissolved solids).
- 5/ Stations 9-27, 9-23, and 9-22.
- 6/ Stations 9-15, 9-36.
- 7/ Stations 9-1A, 9-1 (screen at interface), 9-1 (6-8 ft), 9-2 (0-2 ft), 9-2 (4-6 ft), 9-14, 9-30, 9-29, and 9-26. These "pond liquors" are fluids collected from within and on top of the landfilled wastes.
- 8/ The number of samples with reported concentrations above the drinking water standard.
- 9/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.
- 10/ The number of "pond liquor" samples with reported concentrations above the reported detection limits. An entry of "0" indicates that no sample had a detectable contaminant concentration, not that no samples were taken (see footnote 14).
- 11/ Ave. Conc. is the average of the reported concentrations of all "pond liquor" samples taken that showed a contaminant concentration above the detection limit. The reported pH measurements of the "pond liquors" are also averaged.
- [Comment on footnotes 12-13:
Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated in this table as being below the drinking water standard.]
- 12/ For some water samples collected from downgradient groundwater, downgradient surface water, and "pond liquors," the reported detection limit of 25 was greater than the PDWS of fluoride. For some water samples collected from downgradient saline surface water and water under the waste, the reported detection limit of 50 was also greater than the PDWS for fluoride. Finally, for some water samples collected from peripheral surface water, the reported detection limit of 5 was greater than the PDWS for fluoride.
The solubility of fluoride in water is markedly affected by temperature. Of the temperature ranges and corresponding maximum allowable contaminant levels reported for fluoride in the NIPDWS, the range shown on this table (26.3-32.5 C) corresponds to the most stringent allowable maximum contaminant concentration.
- 13/ For some water samples collected from downgradient groundwater, water under the waste, downgradient surface water, peripheral surface water, downgradient saline surface water, and "pond liquors," the reported detection limit of 0.1 was greater than the PDWS for lead.
- 14/ NS = not sampled.
- 15/ As indicated in footnote 9, the Max. Exceed. column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

Water samples obtained from under the waste showed exceedances of the Primary Drinking Water Standards for the same constituents with high concentration levels in the waste fluids; cadmium (up to 4 times the PDWS), chromium (up to 2 times the PDWS), and fluoride (up to 2.2 times the PDWS). These samples also exhibited elevated concentrations of boron (up to 8 times the SDWS), chloride (up to 49 times the SDWS), manganese (up to 5 times the SDWS), and sulfate (up to 10 times the SDWS). The pH of these samples (up to 9.5) also indicated alkalinity.

Ground Water. Estimates were made of seepage velocities at the site. Results from these calculations appeared to indicate that there has been enough time for constituents in waste leachate to have reached downgradient wells and North Bay.

Primary Drinking Water Standards were found to be exceeded in the ground water of the downgradient wells for cadmium (up to 5 times the PDWS), chromium (up to 4 times the PDWS), and fluoride (up to 13.5 times the PDWS). These were the same contaminants found to exceed the standards in the waste fluids. Upgradient exceedances of the PDWS in ground-water samples were also found for cadmium (up to 2 times the PDWS). However, this exceedance was less common and at lower levels than the downgradient samples. Arsenic and selenium were found to be below the Primary Drinking Water Standards in the ground-water (and waste fluid) samples at this site.

Secondary Drinking Water Standards were found to be exceeded in downgradient ground water for chloride (up to 22 times the SDWS), iron (up to 118 times the SDWS), manganese (up to 17 times the SDWS), and sulfate (up to 8 times the

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SDWS). Except for iron, these were the same contaminants observed at concentrations greater than Secondary Drinking Water Standards in the pond liquors. Samples were found to be acidic (maximum low pH of 2.9). This differed from the alkalinity exhibited by the pond liquors.

Upgradient exceedances of the Secondary Drinking Water Standards in ground-water samples were observed for iron (up to 37 times the SDWS) and manganese (up to 1.4 times the SDWS). The Secondary Drinking Water Standards contaminants found at elevated concentrations in the pond liquors and in the downgradient ground water wells were not found to be elevated in upgradient ground water.

Surface Water. Primary Drinking Water Standards were exceeded in downgradient surface water samples for cadmium (up to 5 times the PDWS) and fluoride (up to 6.5 times the PDWS). In downgradient saline surface water samples, exceedances were observed for cadmium (up to 4 times the PDWS), chromium (up to 1.2 times the PDWS), and fluoride (up to 20 times the PDWS). In surface water samples collected peripheral to the ash disposal pond (east side), exceedances were found for cadmium (up to 4 times the PDWS) and fluoride (up to 2 times the PDWS).

Secondary Drinking Water Standards were exceeded in downgradient surface water samples for chloride (up to 12 times the SDWS), iron (up to 370 times the SDWS), manganese (up to 64 times the SDWS). These were the same contaminants found to exceed the Secondary Drinking Water Standards in peripheral surface water samples, although the levels of exceedance were lower. Both the downgradient and peripheral surface water samples were below the Secondary

Drinking Water Standards for pH (as low as 3.4). Saline surface water samples collected downgradient were found to exceed Secondary Drinking Water Standards for chloride (58 times the SDWS), and sulfate (10 times the SDWS). No true upgradient surface water samples were collected.

E.9.3 Discussion and Conclusions

Cadmium, chromium, and fluoride were observed to exceed the Primary Drinking Water Standards in downgradient ground water in a greater proportion of samples and at higher levels than upgradient ground water. Elevated concentrations of these same contaminants were observed in the interstitial waters of the wastes (pond liquors) and in waters from under the waste. Sulfate, chloride, iron, and manganese were observed to exceed Secondary Drinking Water Standards in downgradient ground water. These same contaminants, with the exception of iron and manganese⁸, were not observed at elevated concentrations at upgradient ground water wells. Sulfate, chloride, and manganese were observed at elevated concentrations in waters in and under the waste. These results, in conjunction with the fact that leachate migration from the waste was predicted to have reached downgradient wells, strongly suggest that degradation of the ground-water quality in excess of the drinking water standards at the site had occurred due to leaching of some contaminant from the ash wastes. At this site, the ground water was not used as a drinking water source. Sampling of the deep underlying aquifer showed no evidence of contamination by ash pond leachate (or by seawater).

Constituent concentrations observed at the site indicated that leachate migration from the ponded wastes had probably reached steady-state conditions

with respect to the concentrations of these species in the waste and downgradient wells. In this case, further increases in the concentrations of waste species in the downgradient ground water would not be expected.

Findings at the site are somewhat difficult to interpret due to the site's estuarine setting and consequent intrusion and infiltration of seawater. Difficulties in interpretations also arise from the use of saline bay waters for ash-slucice make-up water. This is discussed below.

While the exceedance of Primary Drinking Water Standards for the trace metals chromium and cadmium in the downgradient ground water appeared to be directly related to the leaching of constituents in the ash, this may not have been the case for ash-related constituents that were found to naturally occur in seawater. For example, the use of bay water as slucice make-up and its presence in adjacent downgradient areas may have masked the potential for significant impact from the ash constituents sulfate, and chloride (which are observed in elevated concentrations in downgradient ground water).⁹ These constituents were found at similarly elevated concentrations in the bay waters, indicating that concentrations of these constituents were probably influenced by seawater. These seawater-related species were of concern only as Secondary Drinking Water Standards.

The use of bay waters as ash slucice make-up water may have diluted and reduced the availability of trace metals that might have otherwise been readily leachable from the surface layers of the ash. This could have resulted in lower concentrations of trace metals observed in downgradient ground (and surface) water than if seawater were not used.

A scrap metal disposal area located on the west side of the ash disposal pond at the Lansing Smith site may have been a contributor to the large exceedances of the Secondary Drinking Water Standards observed in the ground and surface waters. Attenuation studies conducted at the site indicated that chemical attenuation may be occurring in soils surrounding the disposal pond for arsenic, strontium, and calcium.

Since no upgradient surface water samples were collected at the site, few interpretations could be made of the available surface water data. On-site flooding and pond seepage which had occurred at the site may have contributed to the transport of leachate away from the disposal pond and into the surface water. As with ground-water samples, seawater would influence concentrations of seawater-related species in surface water samples. The elevated concentrations of fluoride observed in the saline, downgradient, surface-water samples -- and not in non-saline downgradient surface-water samples -- indicated that the concentrations of fluoride observed in the downgradient ground water at the site may have been influenced by, or even the result of, the use of seawater in site operations and its intrusion (by flooding) downgradient of the wastes.

In summary, the Lansing Smith plant in southern Florida disposed of a mixture of fly ash and bottom ash in an unlined disposal pond located in a coastal area. Concentrations greater than the Primary Drinking Water Standards were observed for cadmium (up to five times the PDWS), chromium (up to four times the PDWS), and fluoride (up to 13.5 times the PDWS) in the downgradient ground water at the site and, with the possible exception of fluoride, appear to be due largely to these contaminants leaching from the ponded ash wastes.

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Exceedances of Secondary Drinking Water Standards for several species (sulfate, chloride, manganese, and iron) were also observed in downgradient ground water. However, most of these species were seawater-related and their reported concentrations appeared to be influenced by the use in plant operations and infiltration of estuarine (saline) water at the site. Generated leachate migrates to a shallow, unused, tidal aquifer.

Ash disposal from utility operations at this site has had a measurable impact on ground-water quality. However, human health risks at this particular site were probably minimal since the ground and surface water were not used for drinking purposes.

E.10 QA/QC OF ADL TESTING DATA

As part of its study approach, ADL collected QA/QC samples at the six study sites. These included field replicates, laboratory splits, and field blanks. Standard solution and spiked solutions were also measured in the laboratory. Analysis of data produced by this QA/QC program included that:

- The variability introduced by the sampling and analytical procedures utilized in the study was less than the field variability. Thus the analytical methods used should have been capable of detecting concentration differences attributable to the field conditions.
- Analytical precision, as measured by the relative standard deviation, varied among constituents. For major ions (e.g., Mg, Cl, and SO₄), precision was high (RSD less than 10 percent); for the trace metals above detection, plus NO₃ and F₃, precision was lower (RSD greater than 20 percent).

Examination of the ADL field data indicates that:

- Most concentrations of Ag, Ba, Be, Br, Cu, Cr, Pb, PO₄, Sr, Th, Ti, and Zn were below detection limits.
- Reported detection limits for constituents were variable upon occasion, spanning two orders of magnitude for some constituents. Occasionally, the reported detection limits were above the drinking water standards.
- Overall, approximately 1.5 percent of the ADL chemical data may be outliers.

In general, QA/QC results do not indicate large shortcomings in the chemical data. However, caution must be used in interpreting the data using rigorous deterministic methods. Some of the constituents (e.g., cadmium) for which variations in detection limits were observed are of possible concern in regard to human health and coal combustion waste disposal practices. However, it is unclear from the available analysis information how significant these variations might be in regard to assessing the environmental impact of coal combustion wastes. It is possible that some of the constituents for which detection limits were reported to be in excess of drinking water standards, may be of greater concern than the data indicate.

NOTES

¹ Each physiographic region has a distinctive climate, particular vegetative types, characteristic soils, a particular water regime, and differences in principal natural resources.

² Data sources included precursor U.S. EPA study -- Versar, Inc., Selection of A Representative Coal Ash and Coal Ash/FGD Waste Disposal Sites for Future Evaluations, 1979 (Research Triangle Park, North Carolina. EPA-IERL, 2771, 1979) and a data base resulting from work by EPA, EPRI, TVA, DOE, and others.

³ At the time of the ADL study there were more than 350 steam-electric plants in the U.S. Of this number 340 had greater than 25 megawatts capacity and utilized coal for more than 80 percent of their power production. Approximately 55 percent of these plants were located in the physiographic regions that cover the Appalachian and Midwest areas of the country.

⁴ Sites with a generating capacity of less than 200 megawatts, very complex sites (both technological or hydrogeological), plants which sell greater than 50 percent of their ash output, and plants with disposal sites less than two years old, sites were eliminated from further consideration.

⁵ The Arthur D. Little report does not indicate if the discharges from the Allen Plant pond (or from the Elrama Plant pond described below) are permitted under NPDES. According to Section 402 of the Clean Water Act all discharges of pollutants to surface waters from point sources must be permitted. The effluent limitation guidelines for steam electric power generators are given in 40 CFR Part 423.

⁶ A Registered Trademark.

⁷ Registered Trademark.

⁸ Note that this exceedance was slight--only 1.4 times the SDWS in upgradient ground water--but was 17 times the SDWS in downgradient ground water.

⁹ Seawater could also influence concentrations of sodium; magnesium, and selenium were not found to exceed drinking water standards.

- Doc. Ex. 688g -
**DATA ON SAMPLE OF COAL-FIRED
 COMBUSTION WASTE DISPOSAL SITES**

PLANT NAME	ST	NUMBER OF GEN. UNITS	POPULATION WITHIN FIVE CONCENTRIC RINGS (KM)					TOTAL POPULATION
			0-1	1-2	2-3	3-4	4-5	
MCWILLIAMS	AL	3	314	0	0	0	1748	2062
INDEPENDENCE	AR	2	0	0	0	818	370	1188
CORONADO	AZ	3	0	0	0	0	0	0
NAVAJO	AZ	3	0	0	0	1016	10	1026
SPRINGERVILLE 1&3	AZ	2	0	0	190	0	0	190
SPRINGERVILLE 2	AZ	2	0	0	190	0	0	190
CHEROKEE	CO	3	626	522	7645	17558	37735	64086
off-site landfill			49	4894	22366	29981	40235	97525
CRAIG	CO	3	480	0	0	0	0	480
off-site landfill			0	0	0	1872	3670	5542
NUCLA	CO	3						
off-site landfill			0	0	0	0	1027	1027
VALMONT	CO	1	0	1644	0	8393	19020	29057
DEERHAVEN	FL	1	0	6	110	1306	353	1775
FJ GANNON	FL	6	0	74	658	4528	7818	13078
LANSING SMITH	FL	2	0	0	0	0	1669	1669
MCINTOSH	FL	1	2176	0	1125	9099	21917	34317
SEMIWOLE (FL)	FL	2	0	0	1280	0	0	1280
ARKWRIGHT	GA	4	0	0	1903	657	5356	7916
BOWEN	GA	4	0	0	740	0	158	898
SCHERER	GA	4	0	0	0	0	0	0
COUNCIL BLUFFS	IA	3	0	141	0	1744	441	2326
IOWA FALLS	IA	1	3141	3030	1424	0	0	7595
LANSING	IA	4	0	0	0	0	419	419
LOUISA	IA	1	0	0	0	0	544	544
PRAIRIE CREEK	IA	4	0	2696	7116	12854	16078	38744
off-site landfill			448	5722	17827	16720	15600	56317
STREETER	IA	2	3708	6099	2781	12251	20675	45514
CRAWFORD	IL	2						
off-site landfill			300	10862	27883	29225	54890	123160
PEARL	IL	1						
off-site landfill			0	0	0	0	170	170
WAUKEGAN	IL	2						
off-site landfill			2107	10278	6938	5353	6210	30886
BAILLY	IN	2						
off-site landfill			0	0	2570	1290	8073	11933
CAYUGA	IN	2	0	0	0	1457	0	1457
CLIFTY CREEK	IN	7	0	0	6686	5629	2688	15003
EW STOUT	IN	3	0	678	6604	14770	22169	44221
HT PRITCHARD	IN	4	0	0	0	0	1630	1630
MEROM	IN	2	0	360	0	0	0	360
MICHIGAN CITY	IN	3	0	6605	6617	11564	8107	32893
WHITWATER VALLEY	IN	2	3423	5361	7558	14346	9374	40062
NEARMAN CREEK	KS	2	0	0	383	12069	14912	27364
HENDERSON ONE	KY	2	2403	5512	4936	8271	369	21491
HENDERSON TWO	KY	2	0	0	0	0	3032	3032
MORGANTOWN	MD	2						
off-site landfill			0	0	0	1189	2367	3556
NANTICOKE	MD	1	300	0	0	766	0	1066
ADVANCE	MI	3						
off-site landfill			0	0	540	313	0	853
COLDWATER	MI	3						
off-site landfill			0	1020	4157	5263	0	10440
JH CAMPBELL	MI	3	0	0	2206	0	0	2206
JH WARDEN	MI	1	1529	971	0	697	358	3555
ALLEN S KING	MN	1						
off-site landfill			374	0	0	0	0	374
HIBBING	MN	3	0	0	0	0	88	88
off-site landfill			1065	3381	6028	3842	3028	17344
LITCHFIELD	MN	1	21	3522	2368	0	810	6721
NORTHEAST	MN	1	0	1446	1797	8704	11600	23547
RED WING	MN	2	0	100	11	913	895	1919
VIRGINIA	MN	3						
off-site landfill			1129	0	3351	5182	7650	17312

PLANT NAME	ST	DRASTIC VELOCITY		DEPTH TO GROUND WATER (Feet)	HYDRAULIC CONDUCTIVITY (Gal/day/sq.ft)	PERMEABILITY (Gal/day/sq.ft)	NET RECHARGE (inches)	GROUND-WATER HARDNESS (ppm CaCO ₃)
		CODE	OF AQUIFER					
MCWILLIAMS	AL	10Ab	-130	5-15	700-1000	1.0E+04	10+	80-120
INDEPENDENCE	AR	6Fa	-100	15-30	1000-2000	1.0E-02	7-10	180-240
CORONADO	AZ	4B	-1485	50-75	1-100	1.0E-03	0-2	180-240
NAVAJO	AZ	4B	-1485	50-75	1-100	1.0E-03	0-2	180-240
SPRINGERVILLE 1&3	AZ	2D	-220	30-50	300-700	1.0E+01	0-2	180-240
SPRINGERVILLE 2	AZ	2D	-220	30-50	300-700	1.0E+01	0-2	180-240
CHEROKEE	CO	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	180-240
off-site landfill		6Fb	-100	5-15	1000-2000	1.0E+04	7-10	180-240
CRAIG	CO	4A	75-7500	75-100	1-100	1.0E+00	0-2	180-240
off-site landfill		4A	75-7500	75-100	1-100	1.0E+00	0-2	180-240
NUCLA	CO							
off-site landfill		4B	-1485	50-75	1-100	1.0E+00	0-2	180-240
VALMONT	CO	6Db	-742.5	10	1-100	1.0E-01	4-7	120-180
DEERHAVEN	FL	11C	300+	0-5	2000+	1.0E+03	10+	>240
FJ GANNON	FL	11D	370-500	5-15	700-1000	1.0E+04	10+	>240
LANSING SMITH	FL	11D	370-500	5-15	700-1000	1.0E+04	10+	120-180
MCINTOSH	FL	11C	300+	0-5	2000+	1.0E+03	10+	180-240
SEMINOLE (FL)	FL	11B	-30	5-15	700-1000	1.0E+04	10+	>240
ARKWRIGHT	GA	8E	-500	5-15	1000-2000	1.0E+01	7-10	80-120
BOWEN	GA	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	80-120
SCHERER	GA	8E	-500	5-15	1000-2000	1.0E+02	4-7	120-180
COUNCIL BLUFFS	IA	7Ea	-30	5-15	700-1000	1.0E-02	4-7	180-240
IOWA FALLS	IA	7Eb	-30	5-15	700-1000	1.0E+05	10+	>240
LANSING	IA	7Ea	-30	5-15	700-1000	1.0E-02	4-7	>240
LOUISA	IA	7Eb	-30	15-30	700-1000	1.0E+04	10+	>240
PRAIRIE CREEK	IA	7Eb	5-15	700-1000	1.0E+04	10+	>240	
off-site landfill		7G	-1500	15-30	100-300	1.0E-02	7-10	>240
STREETER	IA	7Eb	-30	5-15	700-1000	1.0E+05	10+	>240
CRAWFORD	IL							
off-site landfill		7Eb	-30	5-15	700-1000	1.0E+04	10+	>240
PEARL	IL							
off-site landfill		7Aa	-1500	30-50	100-300	1.0E-03	4-7	180-240
WAUKEGAN	IL							
off-site landfill		7C	400	15-30	300-700	1.0E-01	7-10	>240
BAILLY	IN							
off-site landfill		7F	-300	15-30	100-300	1.0E+02	4-7	>240
CAYUGA	IN	7Ea	-30	15-30	700-1000	1.0E-01	4-7	>240
CLIFTY CREEK	IN	7Ea	-30	5-15	700-1000	1.0E-01	4-7	>240
EW STOUT	IN	7Eb	-30	5-15	700-1000	1.0E+04	10+	>240
HT PRITCHARD	IN	7Ea	-30	10-20	700-1000	1.0E-01	4-7	>240
MEROM	IN	7Ac	-3250	30-50	2000+	1.0E-01	4-7	>240
MICHIGAN CITY	IN	7H	-100	0-5	1000-2000	1.0E+04	10+	>240
WHITEWATER VALLEY	IN	7Ac	-3250	30-50	2000+	1.0E-01	4-7	>240
NEARMAN CREEK	KS	7Ea	-30	5-15	700-1000	1.0E-02	4-7	180-240
HENDERSON ONE	KY	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	120-180
HENDERSON TWO	KY	6Da	-742.5	15-30	1-100	1.0E-01	4-7	80-120
MORGANTOWN	MD							
off-site landfill		10Ab	-130	5-15	700-1000	1.0E+04	10+	<80
NANTICOKE	MD	10Bb	100-200	0-5	1000-2000	1.0E+01	10+	<80
ADVANCE	MI							
off-site landfill		7Ba	500-1000	5-15	1000-2000	1.0E+04	7-10	180-240
COLDWATER	MI							
off-site landfill		7Ac	-3250	30-50	2000+	1.0E-03	4-7	>240
JH CAMPBELL	MI	7F	-300	15-30	100-300	1.0E+02	4-7	>240
JH WARDEN	MI	7H	-100	0-5	1000-2000	1.0E+04	10+	120-180
ALLEN S KING	MN							
off-site landfill		7Bb	750+	0-5	100-300	1.0E+04	10+	>240
HIBBING	MN	90a	-742.5	15-30	1-100	0	7-10	180-240
off-site landfill		90a	-742.5	5-15	1-100	1.0E-02	7-10	180-240
LITCHFIELD	MN	7Aa	-1500	10-20	100-300	1.0E-03	4-7	>240
NORTHEAST	MN	7Eb	-30	5-15	700-1000	1.0E-03	10+	>240
RED WING	MN	7Ea	-30	10-20	700-1000	1.0E-02	4-7	>240
VIRGINIA	MN							
off-site landfill		90a	-742.5	15-30	1-100	1.0E-02	7-10	180-240

PLANT NAME	ST	NUMBER OF GEN.UNITS	POPULATION WITHIN FIVE CONCENTRIC RINGS (KM)					TOTAL POPULATION
			0-1	1-2	2-3	3-4	4-5	
ASBURY	MO	1	0	0	0	0	0	0
BLUE VALLEY	MO	3	0	0	560	11234	5225	17019
CHAMOIS	MO	2	0	0	0	0	683	683
HENDERSON (MS)	MS	2	0	0	0	809	1329	2138
BELEWS CREEK	NC	2	0	1009	0	0	0	1009
CAPE FEAR	NC	4	0	0	190	1047	0	1237
CLIFFSIDE	NC	1	0	982	0	0	1412	2394
HESKETT	ND	2	0	0	0	3115	4166	7281
OLIVER COUNTY	ND	1						
off-site landfill			0	0	0	0	0	0
NEBRASKA CITY	NE	1	0	0	0	0	0	0
BL ENGLAND	NJ	2	0	2473	595	3685	14370	21123
RATON	NM	2	1447	3267	3511	0	0	8225
ACME	OH	3	4762	22356	29567	47606	31578	135869
off-site landfill			530	4424	17427	24150	38884	85415
ASHTABULA	OH	5						
off-site landfill			198	939	3940	2494	3732	11303
JM STUART	OH	4	0	0	0	1657	1283	2940
PIQUA	OH	4	1927	7682	6147	5523	1302	22581
POSTON	OH	4	0	0	373	2383	1065	3821
RE BURGER	OH	5						
off-site landfill			0	0	991	0	0	991
WC BECKJORD	OH	6	0	429	0	2266	1785	4480
off-site landfill			429	0	0	3274	5779	9482
WH SAMMIS	OH	7						
strip mine disposal			0	0	0	4045	2443	6488
HUGO	OK	1	0	439	0	0	0	439
HOLTWOOD	PA	1	0	0	1584	797	0	2381
off-site landfill			0	0	1584	797	0	2381
HOMER CITY	PA	3	0	0	0	2772	2544	5316
MITCHELL (PA)	PA	1						
off-site landfill			675	4358	1485	9391	6509	22418
SEWARD	PA	2	0	675	0	0	4222	4897
CROSS	SC	4	0	0	0	0	488	488
URQUHART	SC	3	0	1489	0	662	6348	8499
FOREST GROVE	TX	1	0	0	0	503	1221	1724
GIBBONS CREEK	TX	1						
off-site landfill			0	0	0	0	0	0
JT DEELY	TX	2	492	0	0	1059	938	2489
SAN MIGUEL	TX	2	0	0	97	0	0	97
SANDOW	TX	1	0	0	0	0	0	0
BONANZA	UT	2	0	0	0	0	0	0
CHESTERFIELD	VA	4	0	716	204	2277	4349	7346
POTOMAC RIVER	VA	5						
off-site landfill			1940	9266	19344	24307	35048	89905
CENTRALIA	WA	2						
off-site landfill			1216	2151	3811	6096	4642	17916
COLUMBIA	WI	2	0	0	0	1215	0	1215
GENOA	WI	3	0	283	0	0	787	1070
HARRISON	WV	3	0	1237	2269	2091	2946	8543
KANAWHA RIVER	WV	1	724	1786	2986	2572	3152	11220
MITCHELL	WV	2	0	0	0	2181	1970	4151
MOUNTAINEER	WV	1	0	697	211	4880	255	6043
PHILIP SPORN	WV	5	0	908	0	960	2974	4842
NAUGHTON	WY	3	0	0	0	0	0	0

PLANT NAME	ST	DRASTIC VELOCITY		DEPTH TO GROUND WATER (Feet)	HYDRAULIC CONDUCTIVITY (Gal/day/sq.ft)	PERMEABILITY (Gal/day/sq.ft)	NET RECHARGE (inches)	GROUND-WATER HARDNESS (ppm CaCO3)
		CODE	OF AQUIFER					
ASBURY	MO	6Db	-742.5	15-30	1-100	1.0E+00	4-7	120-180
BLUE VALLEY	MO	7Ea	-30	15-30	700-1000	1.0E-01	4-7	180-240
CHAMOIS	MO	7Ea	-30	5-15	700-1000	1.0E-02	4-7	>240
HENDERSON (MS)	MS	10C	100-200	0-5	1000-2000	1.0E+04	10+	<80
BELEMS CREEK	NC	8C	-3000	30-50	100-300	1.0E-04	2-4	80-120
CAPE FEAR	NC	8E	-500	5-15	1000-2000	1.0E-01	7-10	<80
CLIFFSIDE	NC	8E	-500	5-15	1000-2000	1.0E-01	7-10	80-120
HESKETT	ND	7Eb	-30	5-15	700-1000	1.0E+04	10+	>240
OLIVER COUNTY off-site landfill	ND	7Ae	7.5-750	30-50	1-100	1.0E-03	4-7	>240
NEBRASKA CITY	NE	7Ea	-30	0-10	700-1000	1.0E-02	4-7	180-240
BL ENGLAND	NJ	10C	100-200	0-5	1000-2000	1.0E+04	10+	<80
RATON	NM	68	-130	15-30	700-1000	1.0E+01	4-7	120-180
ACME off-site landfill	OH	7Eb	-300	5-15	700-1000	1.0E+04	10+	>240
		7F	-300	15-30	100-300	1.0E+02	4-7	>240
ASHTABULA off-site landfill	OH	7F	-300	15-30	100-300	1.0E+02	4-7	180-240
JM STUART	OH	7Eb	-30	5-15	700-1000	1.0E+04	10+	>240
PIQUA	OH	7Eb	-30	5-15	700-1000	1.0E+04	10+	>240
POSTON	OH	68	-130	15-30	700-1000	1.0E+02	4-7	>240
RE BURGER off-site landfill	OH	60a	-742.5	15-30	1-100	1.0E-03	4-7	>240
WC BECKJORD	OH	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	>240
off-site landfill		7Ae	7.5-750	30-50	1-100	1.0E-03	4-7	>240
WH SAMMIS strip mine disposal	OH	60a	-742.5	15-30	1-100	1.0E-04	4-7	>240
HUGO	OK	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	80-120
HOLTWOOD off-site landfill	PA	8D	-148.5	5-15	1-100	1.0E-03	4-7	80-120
		8D	-148.5	5-15	1-100	1.0E-03	4-7	80-120
HOMER CITY	PA	60a	-742.5	15-30	1-100	1.0E-03	4-7	>240
MITCHELL (PA) off-site landfill	PA	6A	75-7500	30-50	1-100	1.0E-03	0-2	>240
SEWARD	PA	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	120-180
CROSS	SC	10C	100-200	0-5	1000-2000	1.0E+04	10+	<80
URQUHART	SC	8E	-500	5-15	1000-2000	1.0E-01	7-10	<80
FOREST GROVE	TX	10Ab	-130	5-15	700-1000	1.0E+04	10+	<80
GIBBONS CREEK off-site minefill	TX	10Ab	-130	5-15	700-1000	1.0E+04	10+	<80
JT DEELY	TX	10Ab	-130	5-15	700-1000	1.0E+04	10+	120-180
SAN MIGUEL	TX	10Aa	3000-	100+	300-700	1.0E-02	0-2	120-180
SANDOW	TX	60b	-742.5	15-30	1-100	1.0E-01	4-7	<80
BONANZA	UT	4D	100-300	50-75	100-300	1.0E+01	0-2	180-240
CHESTERFIELD	VA	8E	-500	0-5	1000-2000	1.0E+02	7-10	80-120
POTOMAC RIVER off-site landfill	VA	8D	-148.5	5-15	1-100	1.0E+01	4-7	80-120
CENTRALIA off-site landfill	WA	1Eb	-130	5-15	700-1000	1.0E+04	4-7	<80
COLUMBIA	WI	6Fa	-100	0-5	1000-2000	1.0E-02	7-10	>240
GENOA	WI	6Fa	-100	0-5	1000-2000	1.0E-02	7-10	>240
HARRISON	WV	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	180-240
KANAWHA RIVER	WV	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	180-240
MITCHELL	WV	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	>240
MOUNTAINEER	WV	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	>240
PHILIP SPORN	WV	6Fb	-100	5-15	1000-2000	1.0E+04	7-10	>240
NAUGHTON	WY	48	-1485	50-75	1-100	1.0E-03	0-2	>240

PLANT NAME	DISTANCE TO		SURFACE WATER NAME	MINFLOW (ft ³ /second)	MAXFLOW	PUBLIC WATER SYSTEMS (PWS) WITHIN DOWNGRADIENT PLUM (distance in meters)
	ST	(meters)				
MCWILLIAMS	AL	50	Conecuh River	357	1850	-
INDEPENDENCE	AR	340	White River	5740	22600	-
CORONADO	AZ	7900	Carrizo Wash	0	0	-
NAVAJO	AZ	3230	Colorado River	6830	41600	-
SPRINGERVILLE 1&3	AZ	9800	Little Colorado River	0	0	-
SPRINGERVILLE 2	AZ	9500	Little Colorado River	0	0	-
CHEROKEE	CO	80	South Platte River	92.4	676	1700; 1900; 2a6400
off-site landfill		350	Clear Creek	84.4	552	700; 5500; 6100
CRAIG	CO	2600	Yampa River	202	5270	-
off-site landfill		1850	Yampa River	202	5270	-
NUCLA	CO					
off-site landfill		4400	San Miguel River	77.9	1040	-
VALMONT	CO	12	South Boulder Creek (Valmont Res)	7.68	256	-
DEERHAVEN	FL	1000	Sanchez Prairie Swamp (Turkey Cre	0	0	1a2500; 1a2600
FJ GANNON	FL	35	Hillsborough Bay (salt)	0	0	-
LANSING SMITH	FL	30	North Bay (salt)	0	0	-
MCINTOSH	FL	90	Lake Parker	0	0	2a600; 1a2400; 2a5500; 1a700
SEMINOLE (FL)	FL	2200	St. Johns River	3240	12800	6100
ARKWRIGHT	GA	700	Ocmulgee River	1190	5230	-
BOWEN	GA	200	Etowah River	1480	3980	-
SCHERER	GA	125	Ocmulgee River	1160	3970	-
COUNCIL BLUFFS	IA	170	Missouri River	14600	44900	-
IOWA FALLS	IA	15	Iowa River	126	753	-
LANSING	IA	200	Mississippi River	16800	69000	100
LOUISA	IA	970	Mississippi River	32000	102000	-
PRAIRIE CREEK	IA	180	Cedar River	964	5030	-
off-site landfill		620	Cedar River	964	5030	-
STREETER	IA	1150	Cedar River	964	5030	14 a 4400
CRAWFORD	IL					
off-site landfill		65	Des Plaines River	383	1980	-
PEARL	IL					
off-site landfill		2100	South Fork Mckee Creek	62.7	200	2a6400; 4a8400
WAUKEGAN	IL					
off-site landfill		4150	Lake Michigan	0	0	2a2100; 2a600; 1a6700
BAILLY	IN					
off-site landfill		1200	Deep River (Duck Creek)	46.4	287	3a6700
CAYUGA	IN	210	Wabash River	2820	15900	-
CLIFTY CREEK	IN	265	Ohio River	26800	257000	4900
EW STOUT	IN	80	White River	583	3900	-
HT PRITCHARD	IN	240	White River	697	4660	-
MEROM	IN	2200	Wabash River (Turtle Creek)	3790	21100	-
MICHIGAN CITY	IN	25	Lake Michigan	0	0	-
WHITewater VALLEY	IN	1300	East Fork Whitewater River	31	269	-
NEARMAN CREEK	KS	550	Missouri River	17500	71600	7400
HENDERSON ONE	KY	80	Ohio River	34100	309000	100
HENDERSON TWO	KY	450	Green River	3520	31800	200
MORGANTOWN	MD					
off-site landfill		3750	Potomac River	7050	21600	-
NANTICOKE	MD	20	Nanticoke River	297	1230	700
ADVANCE	MI					
off-site landfill		220	Lake Michigan (Inwood Creek)	0	0	-
COLDWATER	MI					
off-site landfill		1130	South Lake (Coldwater River)	34	186	-
JH CAMPBELL	MI	420	Pigeon Lake (Lake Michigan)	0	0	-
JH WARDEN	MI	100	Lake Superior	0	0	100 (prob)
ALLEN S KING	MN					
off-site landfill		740	Lake Jane	0	0	1a4400; 1a5000
HIBBING	MN	950	Welcome River	18	41.7	2a1400
off-site landfill		4600	East Swan River	25.2	413	2400
LITCHFIELD	MN	200	Jewitts Creek	2.35	44.4	-
NORTHEAST	MN	200	Cedar River	26.2	137	800
RED WING	MN	180	Mississippi River	8450	36300	-
VIRGINIA	MN					
off-site landfill		800	Pike River	3.84	107	-

PLANT NAME	DISTANCE TO SURFACE WATER (meters)	SURFACE WATER NAME	MINFLOW (ft ³ /second)	MAXFLOW	PUBLIC WATER SYSTEMS (PWS) WITHIN DOWNGRADIENT PLUME (distance in meters)
MCWILLIAMS	AL	50 Conecuh River	357	1850	-
INDEPENDENCE	AR	340 White River	5740	22600	-
CORONADO	AZ	7900 Carrizo Wash	0	0	-
NAVAJO	AZ	3230 Colorado River	6830	41600	-
SPRINGVILLE 1&3	AZ	9800 Little Colorado River	0	0	-
SPRINGVILLE 2	AZ	9500 Little Colorado River	0	0	-
CHEROKEE	CO	80 South Platte River	92.4	676	1700; 1900; 2a6400
off-site landfill		350 Clear Creek	84.4	552	700; 5500; 6100
CRAIG	CO	2600 Yampa River	202	5270	-
off-site landfill		1850 Yampa River	202	5270	-
NUCLA	CO				
off-site landfill		4400 San Miguel River	77.9	1040	-
VALMONT	CO	12 South Boulder Creek (Valmont Res)	7.68	256	-
DEERHAVEN	FL	1000 Sanchez Prairie Swamp (Turkey Cre	0	0	1a2500; 1a2600
FJ GANNON	FL	35 Hillsborough Bay (salt)	0	0	-
LANSING SMITH	FL	30 North Bay (salt)	0	0	-
MCINTOSH	FL	90 Lake Parker	0	0	2a600; 1a2400; 2a5500; 1a7000
SEMINOLE (FL)	FL	2200 St. Johns River	3240	12800	6100
ARKWRIGHT	GA	700 Ocmulgee River	1190	5230	-
BOWEN	GA	200 Etowah River	1480	3980	-
SCHERER	GA	125 Ocmulgee River	1160	3970	-
COUNCIL BLUFFS	IA	170 Missouri River	14600	44900	-
IOWA FALLS	IA	15 Iowa River	126	753	-
LANSING	IA	200 Mississippi River	16800	69000	100
LOUISA	IA	970 Mississippi River	32000	102000	-
PRAIRIE CREEK	IA	180 Cedar River	964	5030	-
off-site landfill		620 Cedar River	964	5030	-
STREETER	IA	1150 Cedar River	964	5030	14 a 4400
CRAWFORD	IL				
off-site landfill		65 Des Plaines River	383	1980	-
PEARL	IL				
off-site landfill		2100 South Fork Mckee Creek	62.7	200	2a6400; 4a8400
WALKEGAN	IL				
off-site landfill		4150 Lake Michigan	0	0	2a2100; 2a600; 1a6700
BAILLY	IN				
off-site landfill		1200 Deep River (Duck Creek)	46.4	287	3a6700
CAYUGA	IN	210 Wabash River	2820	15900	-
CLIFTY CREEK	IN	265 Ohio River	26800	257000	4900
EW STOUT	IN	80 White River	583	3900	-
HT PRITCHARD	IN	240 White River	697	4660	-
MEROM	IN	2200 Wabash River (Turtle Creek)	3790	21100	-
MICHIGAN CITY	IN	25 Lake Michigan	0	0	-
WHITEWATER VALLEY	IN	1300 East Fork Whitewater River	31	269	-
NEARMAN CREEK	KS	550 Missouri River	17500	71600	7400
HENDERSON ONE	KY	80 Ohio River	34100	309000	100
HENDERSON TWO	KY	450 Green River	3520	31800	200
MORGANTOWN	MD				
off-site landfill		3750 Potomac River	7050	21600	-
NANTICOKE	MD	20 Nanticoke River	297	1230	700
ADVANCE	MI				
off-site landfill		220 Lake Michigan (Inwood Creek)	0	0	-
COLDWATER	MI				
off-site landfill		1130 South Lake (Coldwater River)	34	186	-
JH CAMPBELL	MI	420 Pigeon Lake (Lake Michigan)	0	0	-
JH WARDEN	MI	100 Lake Superior	0	0	100 (prob)
ALLEN S KING	MN				
off-site landfill		740 Lake Jane	0	0	1a4400; 1a5000
HIBBING	MN	950 Welcome River	18	41.7	2a1400
off-site landfill		4600 East Swan River	25.2	413	2400
LITCHFIELD	MN	200 Jevitts Creek	2.35	44.4	-
NORTHEAST	MN	200 Cedar River	26.2	137	800
RED WING	MN	180 Mississippi River	8450	36300	-
VIRGINIA	MN				
off-site landfill		800 Pike River	3.84	107	-

PLANT NAME	STATE	DISTANCE TO SURFACE WATER (meters)	SURFACE WATER NAME	MINFLOW (ft ³ /second)	MAXFLOW	PUBLIC WATER SYSTEMS (PWS)
						WITHIN DOWNGRAIDENT PLUME (distance in meters)
ASBURY	MO	4600	Spring River (Blackberry Creek)	472	1480	-
BLUE VALLEY	MO	1040	Little Blue River	63.4	251	-
CHAMOIS	MO	40	Missouri River	37700	114000	-
HENDERSON (MS)	MS	1400	Yazoo River (Tchula Lake)	11000	41300	1600
BELEWS CREEK	NC	730	Dan River	323	684	600
CAPE FEAR	NC	50	Cape Fear River	1690	5690	224800
CLIFFSIDE	NC	50	Broad River	1120	2040	-
HESKETT	ND	170	Missouri River	14700	37900	1200
OLIVER COUNTY off-site landfill	ND	990	Nelson Lake (Square Butte Creek)	133	345	-
NEBRASKA CITY	NE	55	Missouri River	17000	52500	-
BL ENGLAND	NJ	50	Great Egg Harbor Bay (salt)	0	0	-
RATON	NM	3700	Raton Creek	0.579	7.37	-
ACME off-site landfill	OH	20	Maumee river	1100	11900	-
ASHTABULA off-site landfill	OH	50	Ottawa River	35	498	-
JM STUART	OH	300	Lake Erie (Cowles Creek)	0	0	-
PIQUA	OH	70	Ohio River	22400	215000	800; 4900
POSTON	OH	50	Great Miami River	157	1740	8500
RE BURGER off-site landfill	OH	250	Hocking River (Hamley Run)	163	1610	400; 2100;5200;8500
WC BECKJORD off-site landfill	OH	1475	Pipe Creek	7.76	65.6	-
WH SAMMIS strip mine disposal	OH	80	Ohio River	23000	207000	-
HUGO	OK	1350	Ohio River	23000	207000	-
HOLTWOOD off-site landfill	PA	1200	Ohio River (Croxtton Run)	9850	83300	226100
HOMER CITY	PA	50	Red River	4630	22100	-
MITCHELL (PA) off-site landfill	PA	800	Susquehanna River	19700	66400	-
SEWARD	PA	660	Susquehanna River	19700	66400	-
CROSS	SC	1770	Two Lick Creek	110	619	223700
URQUHART	SC	850	Monongahela River (Peters Creek)	3510	18300	-
FOREST GROVE	TX	10	Conemaugh River	562	3500	-
GIBBONS CREEK off-site minefill	TX	340	Lake Moultrie	0	0	-
JT DEELY	TX	90	Savannah River	6670	14800	-
SAN MIGUEL	TX	180	Walnut Creek	0.12	48.6	-
SANDOW	TX	2200	Navasota River (Panther Creek)	190	1290	-
BONANZA	UT	4450	San Antonio River	303	786	500 (prob)
CHESTERFIELD	VA	1200	La Parita Creek	1.24	12	-
POTOMAC RIVER off-site landfill	VA	100	Alcoa Lake	0	0	-
CENTRALIA off-site landfill	WA	18000	White River	250	2350	-
COLUMBIA	WI	40	James River	3580	13600	-
GENOA	WI	120	Holmes Run (Backlick Run)	18	76.5	-
HARRISON	WV	930	Chehalis River	181	5190	2000 (prob)
KANAWHA RIVER	WV	100	Wisconsin River	4720	14400	-
MITCHELL	WV	50	Mississippi River	15200	62300	-
MOUNTAINEER	WV	400	West Fork River	378	1990	1800 (prob)
PHILIP SPORN	WV	30	Kanawha River	4120	23600	122100;126700
NAUGHTON	WY	40	Ohio River	10200	86200	7300
	WV	80	Ohio River	14400	122000	-
	WV	90	Ohio River	14400	122000	-
	WY	700	Hams Fork	20.7	829	-

**METHODOLOGY FOR CALCULATING THE COST OF
ALTERNATIVE WASTE MANAGEMENT PRACTICES**

This appendix discusses how the cost estimates presented in Chapter Six in terms of dollar per ton of waste disposed were calculated for different types of waste disposal. These dollar per ton cost estimates included the costs of current waste disposal practices and the costs of various measures to mitigate potential environmental impacts.

The cost estimates in Chapter Six were developed primarily from two reports:

- Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, June 1985.
- Utility Solid Waste Activities Group, Edison Electric Institute, and the National Rural Electric Cooperative Association, Report and Technical Studies On the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982.

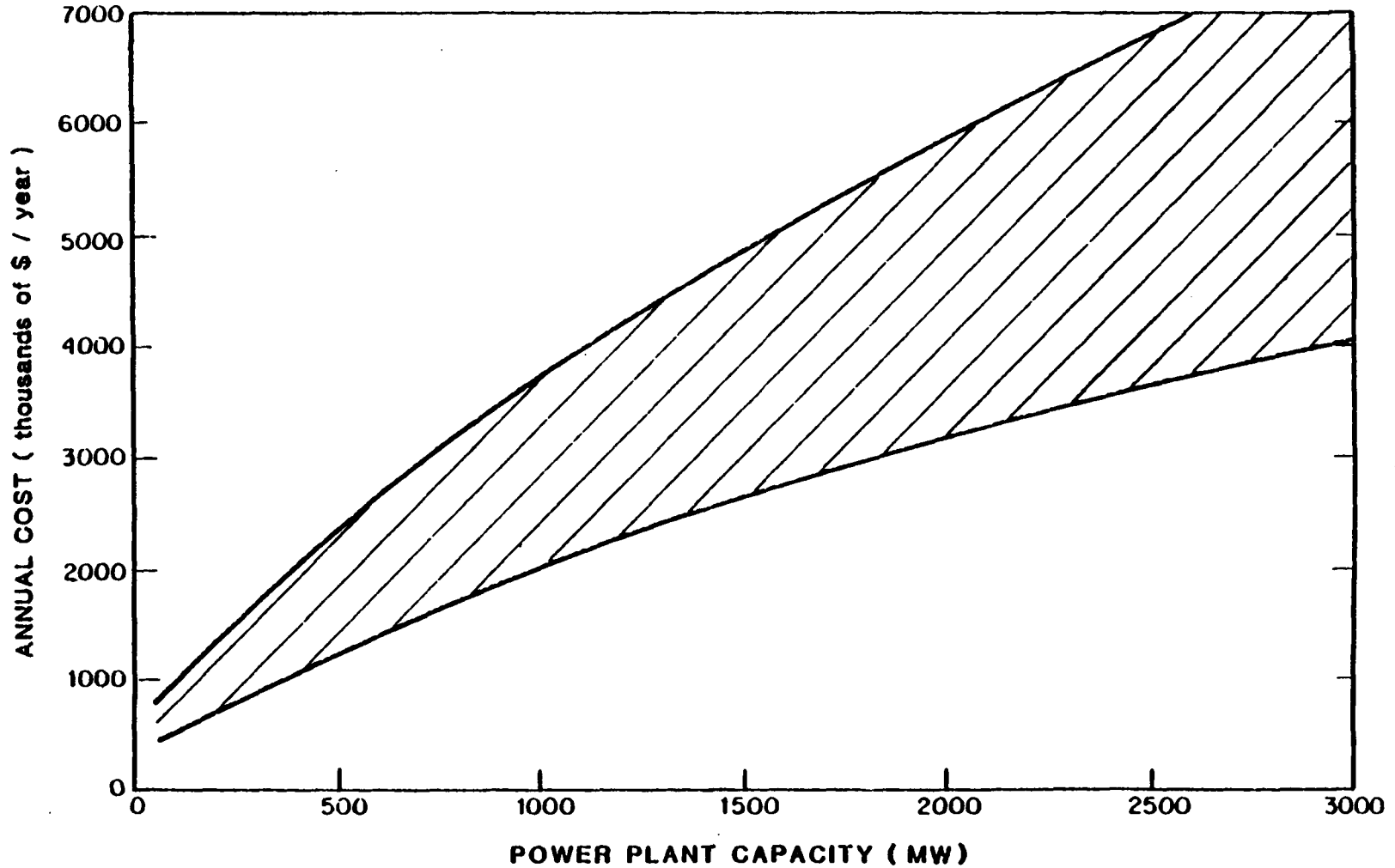
The Arthur D. Little (ADL) study was funded by the Agency under EPA contract 68-02-3167. Its purpose was to evaluate current coal-fired electric generating plants. Specific tasks involved characterizing coal-fired utility wastes, gathering environmental data, assessing environmental effects, and evaluating the engineering and costs associated with these disposal practices. The Utility Solid Waste Activities Group (USWAG) report was submitted to EPA to assist the Agency in meeting its mandate under Section 8002(n). This report and its supporting technical studies analyzed the environmental and health effects of the disposal and utilization of fossil fuel combustion by-products from electric utility power plants.

In these two reports, costs were presented for various disposal practices. However, due to differences in analytical methods between the two studies it was often difficult to compare the various cost estimates. To circumvent this problem all disposal cost estimates in these studies were converted to the same basic unit -- dollar per ton of waste disposed. That is, the cost for each type of disposal procedure was expressed in terms of the cost to dispose of each ton of waste generated over the life of the facility. It was felt that this cost measure would allow comparisons to be made between the cost of current waste management practices and the cost of alternative waste management practices.

An example should help illustrate how the dollar per ton cost estimates were developed throughout this report. In the ADL study the total cost of basic waste disposal (i.e., disposal in unlined ponds or landfills) was shown to vary as a function of the size of the electric power plant (e.g., see Exhibit G-1). To convert these costs by power plant size into costs per ton of waste disposed, estimates were made of the amount of waste generated as the size of the power plant varied. There are several variables that can influence the amount and type of waste generated at a power plant, including size of the power plant, ash content of the coal, type of boiler, efficiency of the boiler, utilization rate, and the type of pollution control technologies employed. Despite these many variables, assumptions can be made to estimate the approximate amount of waste that would be generated at a "typical" power plant.

For example, the "dollar per ton of waste disposed" estimates presented in this report generally assume a 500 Mw power plant. This size was chosen to be

EXHIBIT G-1
ANNUAL COST OF FLY ASH PLACEMENT AND DISPOSAL IN AN UNLINED POND
(late 1982 dollars)



Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, June 1985.

representative of a "typical" power plant, although the size of each generating unit and the number of units at a site do vary (see Chapter Two for further discussion). To determine the amount and type of waste generated at a 500 Mw power plant, the following assumptions were made:

- Coal Properties -- 2% sulfur, 13% ash, 10,500 Btu/lb.
- Load Factor -- 70% (6132 hours per year)
- Heat Rate -- 10,250 Btu per kilowatt-hour
- SO₂ Removal -- 90% (wet lime scrubbing)
- Lime Stoichiometry -- 1.1
- Fly Ash/Bottom Ash Ratio -- 80%/20%

These assumptions were taken from the ADL study (see p. 1-17, Table 1.7) and result in the annual production of 154,000 tons of fly ash (308 tons/Mw), 38,500 tons of bottom ash (77 tons/Mw), and 132,000 tons, (264 tons/Mw), of dry FGD waste (if the power plant is scrubbing the flue gases).

To determine the cost per ton to dispose of the wastes produced from a 500 Mw power plant using these assumptions, the next step was to obtain the total annual costs for waste disposal from the ADL study (see pages 6-74 to 6-130 of the ADL study). For disposal in unlined ponds these costs were approximately \$1.3 million to \$2.4 million for fly ash and \$275,000 to \$510,000 for bottom ash. For landfill disposal these costs were about \$785,000 to \$5.1 million for fly ash and \$165,000 to \$310,000 for bottom ash. All of these costs were in late 1982 dollars.

The ADL cost estimates (or cost estimates from other studies when applicable) were then converted to fourth quarter 1986 dollars. This was necessary to ensure that all costs reported in this study were consistent with one another. The GNP implicit price deflator was used for this purpose. For the fourth quarter of 1986, the value of this index was 115.2 (1982 = 100; late 1982 = 101.39). The ADL costs were escalated by 13.6 percent to obtain fourth quarter 1986 cost estimates.

In fourth quarter 1986 dollars, the total annual costs for disposal in unlined ponds would be about \$1.4 million to \$2.6 million for fly ash and \$310,000 to \$580,000 for bottom ash. For landfills these annual costs would be \$890,000 to \$1.7 million for fly ash and \$185,000 to \$350,000 for bottom ash.

These annual costs were divided by the total amount of each type of waste produced annually to determine the cost per ton of waste disposed annually at a representative 500 Mw power plant. For ponding these costs are \$9 to \$17 per ton for fly ash (e.g., assuming production of 154,000 tons of fly ash then \$1.4 million ÷ 154,000 tons = \$9.09 per ton) and \$8 to \$15 per ton for bottom ash (assuming production of 38,500 tons of bottom ash). For landfills these costs are about \$6 to \$11 per ton for fly ash and \$5 to \$9 per ton for bottom ash.

For some waste control strategies, such as liner installation, the cost per ton will depend on the size of the disposal area affected. The size of a waste disposal area will vary depending on the amount of waste generated, the type of facility (landfill or pond), depth of disposal, amount of liquid present, and frequency of dredging, among other factors. Given the amount of waste assumed

in this analysis to be generated at a representative 500 Mw power plant, a landfill was assumed to occupy 45 acres at a depth of about 30 meters and to have an average lifetime of 20 years. A wet surface impoundment was assumed to occupy 145 acres at a depth of 10 feet, with dredging occurring every five years.

Using these size estimates for disposal areas, the increase in cost per ton of waste disposed for installing a liner (or for other practices related to the size of the facility) can be calculated. For example, in the ADL study the installed cost of clay liners ranged from \$4.40 to \$15.50 per cubic yard (see Arthur D. Little, Inc., p. 6-132). For a liner 36-inches thick, these installed costs would lead to a cost range of \$21,000 to \$74,000 per acre. For a 45-acre landfill, total costs would range from \$945,000 ($\$21,000/\text{acre} \times 45$ acres) to \$3.3 million ($\$74,000/\text{acre} \times 45$ acres), or about \$140,000 to \$480,000 on an annualized basis (using a 14.5 percent capital recovery factor, e.g., $\$945,000 \times 0.145 = \$137,025$). Since 192,500 tons of waste are produced annually, the increase in costs to install a clay liner is \$0.70 ($\$140,000$ divided by 192,500 tons) to \$2.50 ($\$480,000$ divided by 192,500 tons) per ton of waste disposed.

Applying this same procedure for a 145-acre wet surface impoundment, total costs would range from \$3.0 million to \$10.7 million, or \$440,000 to \$1.6 million on an annualized basis. This corresponds to about \$2.25 to \$8.10 per ton of waste disposed.

This approach was used throughout Chapter Six to develop the dollar per ton cost estimates for current waste disposal activities and potential alternatives. The technical and economic assumptions used to develop these cost estimates (e.g., the capital recovery factor, disposal area size, etc.) are representative for the electric utility industry. However, actual costs may vary as a result of various site-specific factors that are not addressed in this study.

Chapter Six also provides estimates of the impact of waste disposal on the cost of generating electricity (e.g., see Exhibit 6-9 or 6-10). For these estimates, the cost to generate electricity was assumed to be 18 mills (\$0.018) per kilowatt-hour at existing coal-fired power plants based on the following assumptions:

- A 500 Mw power plant operating in the Midwest.
- No capital charges are included since the capital has already been committed (i.e., it is a sunk cost).
- No flue gas desulfurization equipment is required.
- Capacity factor is 70 percent.
- Heat rate is 10,000 Btu per kilowatt-hour.
- Coal price is \$1.50 per million Btu.
- Operation and maintenance costs are about 3 mills (\$0.003) per kilowatt-hour, with disposal costs ranging from less than 0.5 to 1.0 mill depending on type of disposal practice.

For future coal-fired power plants the assumed generation cost was about 47 mills (\$0.047) per kilowatt-hour based on the same assumptions except:

- Capital costs were approximately \$1,100 per kilowatt, including FGD equipment and associated transmission hookup charges.
- Operation and maintenance costs were about 8 mills (\$0.008) per kilowatt-hour. These costs are higher compared to existing power plants due to the additional operation and maintenance costs associated with the FGD process.

In Exhibit 6-9 costs were also presented for generating electricity with natural gas. At an existing gas-fired power plant, total generation costs were assumed to be about 35 mill (\$0.035) per kilowatt-hour based on the following assumptions:

- No capital charges are included since capital costs are sunk.
- Capacity factor is 70 percent.
- Heat rate is 9000 Btu per kilowatt-hour.
- Gas price is \$3.75 per million Btu.
- Operation and maintenance costs are about 2 to 2.5 mills per kilowatt-hour.

Generation costs at future gas-fired power plants were assumed to be about 49 mills (\$0.049) per kilowatt-hour based on the same assumptions listed above for existing gas-fired power plants except capital costs were included at a cost of approximately \$550 per kilowatt, including associated transmission hookup charges.