

IMPLICATIONS OF FUTURE ENVIRONMENTAL REGULATION OF COAL-BASED ELECTRIC POWER

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INTRODUCTION

In the last two decades, environmental protection has come squarely to the forefront of national priorities (Figure 1). Since 1970, new federal laws for the control of air and water pollutants and solid wastes have affected virtually all of modern technology. Environmental regulations have grown more complex and more comprehensive, and future changes will continue to have major impacts (1, 2).

Coal-based electric power plants have been a primary focus of environmental regulations. Coal now provides well over half the US electricity supply, and is projected to be the main energy source for power generation into the next century (3). To gain perspective on the effects of future regulations, this paper begins with a review of the current environmental regulatory framework and its effect on coal-based power systems. It then examines the regulatory outlook for the next decade, focusing on the implications for new technology development and the competitiveness of coal as an energy source.

THE CURRENT REGULATORY FRAMEWORK

Table 1 summarizes some important elements of current environmental regulatory policy affecting US coal-fired power plants. The regulations fall into three general categories: (a) environmental quality standards, setting acceptable levels of pollutants in the environment, (b) performance standards, limiting discharges of specific substances to the environment, and (c) design standards, prescribing the control methods to be used. Environmental quality

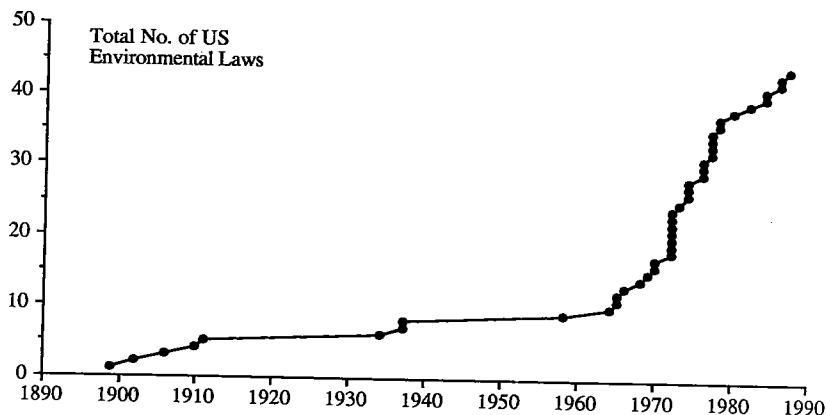


Figure 1 US laws on environmental protection (adapted from Ref. 1). The rapid increase over the past two decades indicates the importance of environmental concerns.

standards typically serve as the basis for enforceable performance or design standards. All three types of regulation may carry additional requirements for monitoring and reporting environmental data.

The current environmental regulatory structure is highly media-specific with separate laws governing air pollutants, water pollutants, and solid wastes. The regulation of hazardous and toxic pollutants is beginning to force some movement toward a more integrated approach, although traditional divisions of labor remain deeply rooted in existing institutional arrangements and professional disciplines.

Air Pollution Control

The Clean Air Act Amendments of 1970 in many ways inaugurated the modern era of environmental control programs in the United States. In 1971, the new US Environmental Protection Agency (EPA) promulgated primary national ambient air quality standards to protect human health and secondary standards to protect human welfare. Later, standards for the prevention of significant deterioration (PSD) were enacted to protect air quality in regions already achieving ambient standards.

Ambient standards under the Clean Air Act initially applied to sulfur dioxide (SO₂), total suspended particulates (TSP), nitrogen dioxide (NO₂), carbon monoxide (CO), and ozone (a measure of photochemical oxidants). In 1978, an ambient standard for lead was introduced, and in 1987 the TSP standard was superseded by a standard based on particles smaller than 10 microns (PM-10). To achieve ambient standards, each state imposed emission limits on individual sources as part of a State Implementation Plan (SIP). For coal-fired power plants, emission standards for SO₂ were the most difficult to

Table 1 Elements of environmental regulatory policy affecting coal-electric power plants

Air pollution control

- National Ambient Air Quality Standards (Primary, Secondary, Nondegradation)
- Federal New Source Performance Standards
- National Emission Standards for Hazardous Air Pollutants
- State and Local Standards (Air Quality, Emission Limits, Control Methods)

Water pollution control

- Federal Safe Drinking Water Standards
- National Pollutant Discharge Elimination System Limits
- Toxic and Hazardous Waste Regulations (Federal/State)
- State and Local Standards (Stream Quality, Effluent Limits, Treatment Methods)

Solid waste control

- Toxic and Hazardous Waste Regulations (Federal/State)
 - State and Local Standards (Classification, Disposal Methods)
-

achieve. They usually specified a maximum allowable mass of emissions per unit of energy input to the boiler (e.g. lbs SO₂/10⁶ Btu), although in some states fuel quality standards were specified (e.g. a maximum allowable sulfur content). Most utilities responded by seeking compliance fuels (lower-sulfur coals) or by switching from coal to oil or natural gas (a trend later reversed by the "energy crisis" of the mid-to-late 1970s). To comply with stringent state standards, some utilities were forced to add flue gas desulfurization (FGD) systems to existing coal units.

The 1970 Clean Air Act also required EPA to establish New Source Performance Standards (NSPS) for industries representing major potential sources of air pollution. Fossil fuel-fired steam generators were among the first process categories for which NSPSs were promulgated. NSPS requirements were intended to reflect the use of the "best available control technology" (BACT), and were to be periodically updated to reflect technological improvements. Congress thus put in place a dynamic, technology-forcing requirement that has profoundly changed the design of new coal-fired power plants. A 1979 revision of the NSPS for sulfur dioxide removed the original option of meeting an SO₂ emission limit by either using low-sulfur coal or installing an FGD system. Instead, new plants are now required to remove 70 to 90% of all SO₂ that could be formed from coal combustion (subject also to a maximum emission rate) (4). In effect, this revision required the use of flue gas desulfurization on all new pulverized coal-fired power plants. As a result of clean air regulations, installed FGD capacity has increased to more than 64,000 MW (20% of coal plant capacity), with an additional 25,000 MW planned or under construction (5). The 1979 NSPS revisions also reduced

Table 2 Trend in air pollution emission standards for new coal-based power plants (lbs/10⁶ Btu)

Pollutant	Pre-NSPS	1971 NSPS	1979 NSPS	1984 Calif. ^a
SO ₂	None	1.2	~0.1–0.9 ^b	~0.03–0.16 ^{c,d}
NO _x	None	0.7	0.5–0.6	0.13 ^d
TSP	~0.2 ^e	0.1	0.03	0.01

^a California permit limits for the Cool Water gasification combined-cycle plant steam generator (54).

^b Regulation requires 70 to 90% removal of potential SO₂ with a ceiling of 1.2 lbs/10⁶ Btu. Emissions vary with coal sulfur content.

^c Corresponds to 95 to 97% removal for low- to high-sulfur coals.

^d Actual emissions have been roughly half the permit limits.

^e Representative of state particulate emission standards for coal-fired boilers.

limits on particulate emissions by two thirds, and cut nitrogen oxides (NO_x) limits by 15 to 30% (Table 2).

States retain the right to enact standards more stringent than the NSPS, and a number have done so. In California—long the bellwether state for environmental control legislation—the 100 MW Cool Water power plant operated by Southern California Edison meets emission standards for SO₂ and NO_x that are five to ten times more stringent than NSPS requirements (Table 2) and three times more restrictive for particulate matter (6). This advanced plant employs an integrated coal gasification combined-cycle (IGCC) system (described later in the paper), and is the only coal-based power plant now operating under California standards. In regions of the United States not yet attaining ambient air quality standards, technology for the “lowest achievable emission rate” (LAER) is required for new sources, while in PSD areas, BACT is mandated. Determinations of LAER and BACT are made at the state level on a case-by-case basis.

In general, the Clean Air Act has been effective in either reducing or capping nationwide emissions of regulated pollutants, and achieving the ambient air quality standards set in 1971 (7). The principal exception has been the standard for ozone. Despite significant curtailment of hydrocarbon and NO_x precursor emissions (especially from mobile sources), oxidant levels remain well above ambient standards in many parts of the country. Nor have current emission regulations been effective in curtailing the problem of acid rain, which emerged in the late 1970s as an important national and international problem attributed to emissions of SO₂ and NO_x. Both the oxidant and acid deposition problems will have significant implications for coal-based power generation in the years ahead.

Air pollutants regulated under the Clean Air Act also include chemical substances designated by EPA as “hazardous.” To date, EPA has promulgated

standards for eight hazardous chemical pollutants (asbestos, beryllium, mercury, vinyl chloride, coke oven emissions, benzene, inorganic arsenic, and fugitive volatile emissions). Under court order, a standard for radionuclides is to be proposed in early 1989. EPA also has published a Notice of Intent to propose standards for 10 additional substances, and has about 25 more chemicals under study. Many states also are developing air toxics programs (8). While such programs have not yet significantly affected coal-based power plants, the regulatory trend points clearly toward increasing concern about the carcinogenic effects of emissions of trace metals and organic species, including products of incomplete combustion.

The trend toward regulating increasing numbers of hazardous or toxic chemicals also has given rise to the concepts of risk assessment and risk management as tools for developing federal regulatory priorities and standards (9). This approach represents a major evolution in the regulation of environmental emissions. It calls for a quantitative assessment of the lifetime cancer risk from exposure to a chemical substance, followed by regulatory action to control risks judged to be unacceptably high. While the scientific basis for risk assessments and management is still relatively crude, the approach represents an important methodological advance in dealing with the complex issue of chemicals in the environment.

Water Pollution Control

Like the 1970 Clean Air Act, the Federal Water Pollution Control Act of 1972 established a dual-track policy, with both standards for acceptable water quality and limits on pollutant discharges. The 1972 Act directed EPA to establish water quality criteria as the basis for state standards protecting various water uses (including recreational uses and the protection and propagation of aquatic life), and also established the "national goal that the discharge of pollutants into the navigable waters be eliminated by 1985." The zero discharge goal continues to guide the development of wastewater regulations today.

For the most part, however, effluent discharge standards for industrial sources have been driven by the capabilities of treatment technology rather than by water quality criteria. The National Pollutant Discharge Elimination System (NPDES) requires the use of either "best available" or "best conventional" technology for existing plants, with New Source Performance Standards for new facilities. For power plants, NSPS limits apply to discharges of chlorine, acidity (pH), trace metals (Cr, Zn, Cu, Fe), organics (oil and grease), and suspended solids originating in cooling water and low-volume waste streams, with other trace contaminants (priority pollutants) regulated to nondetectable levels (10). For most new power plants, zero discharge of thermal emissions to waterways also is required.

The Water Quality Act of 1987 more explicitly addresses water quality standards for the 128 hazardous and toxic species designated by EPA as priority pollutants. The implications for many new and existing power plants could be significant. In the short term, plants located on priority water bodies where best available technology has been insufficient to achieve state water quality standards will likely have to undertake new and possibly extensive chemical and biological monitoring programs for trace metals and toxic organic species. Subsequent requirements to control these substances by early 1992 could result from new state regulations based on EPA water quality criteria guidelines. Plants with evaporative recirculating water cooling systems appear particularly vulnerable to new prohibitions on trace metals in blowdown stream discharges, plus possible restrictions on organic species, even if these substances originate outside the plant boundary (e.g. from makeup water polluted by agricultural runoff or heavy industry)(11).

Finally, recent amendments to the Safe Drinking Water Act (1986) have expanded the list of substances for which technology-based Maximum Contaminant Levels (MCLs) and health-based Maximum Contaminant Level Goals (MCLGs) are being established by EPA (12). These species and contaminant levels also can be expected to affect future power plant regulations directly or indirectly, as discussed later in the paper.

Solid Waste Control

Regulation of power plant solid wastes remains largely at the state and local level. Primary concerns are the prevention of surface water and groundwater contamination from runoff or leaching of chemical substances through soils. At the federal level, the designation of a solid waste as either hazardous or nonhazardous under the 1976 Resource Conservation and Recovery Act (RCRA) has been the most critical issue for coal-based power systems. Congress provisionally exempted high-volume utility wastes (fly ash, bottom ash, boiler slag, and FGD sludge) as nonhazardous under RCRA, pending additional study by EPA. While a final determination has yet to be issued, studies to date have confirmed that most high-volume utility wastes are indeed nonhazardous under current (1988) RCRA criteria. Other power plant wastes, however, such as chemical solvent wastes from the periodic cleaning of boiler tubes, are subject to current EPA test procedures that require special "cradle-to-grave" handling and disposal of wastes found to be hazardous.

EPA test procedures for hazardous waste determination continue to evolve, with uncertain implications for coal-based power systems. At the same time, state and local requirements for solid waste disposal have generally grown more stringent. Technologies to control air and water pollution have aggravated solid waste disposal problems by adding large volumes of FGD wastes, plus the residues from water treatment sludges and blowdown streams, to the

inventory of power plant wastes requiring land disposal. Such cross-media impacts of environmental regulations have now become widely recognized, and efforts to remedy such problems will be a major thrust in the design of future coal-based energy systems.

THE FUTURE REGULATORY OUTLOOK

Several emerging trends in environmental regulation will affect coal-based power systems significantly over the next decade and beyond. First, the "best available technology" approach embodied in current air and water regulations for new sources will continue to prevail, mandating further reductions of the pollutants now regulated. Second, the growing regulation of hazardous and toxic substances will increase the burden on monitoring and control of all gaseous, liquid, and solid discharges. In striving to minimize environmental risks, the ability to detect any level of hazardous chemical emissions will increasingly be the driving force for future environmental regulation. Third, improved methods for risk assessment and risk management, coupled with increased awareness of the cross-media impacts of regulation, will lead to more integrated, site-specific approaches to technology design and control, with emphasis on waste minimization and reuse. Fourth, the inability of current air regulations to deal adequately with regional and transboundary air pollution (specifically, acid rain and ozone) will require further reductions in SO₂ and NO_x emissions from existing sources as well as new ones. Finally, the problem of global climate change, with its implications for reductions of CO₂ and other "greenhouse gas" emissions, will emerge as an even more difficult issue to be reckoned with.

Sitting atop all this are several more general factors that will shape future environmental requirements. One is public pressure. From the mid-1960s through the mid-1970s, high national awareness and concern over environmental pollution led to the explosion of federal and state regulations reflected in Figure 1. Next came a decade in which public activism subsided while environmental professionals carried on. Now, in the mid-to-late 1980s, public concern about the environment is reemerging. Today's concerns are stimulated largely by widespread warnings of global climate change and depletion of stratospheric ozone—issues that teach of the potentially devastating effects of man-made chemicals in the atmosphere, and the need for absolute limits on future emissions. Coupled with growing concern about other environmental issues, from toxic wastes to acid rain to municipal waste disposal, a new era of public activism can be expected to spur public policy in the years ahead.

The revolution in computers and information processing, combined with greater public access to environmental data, will further catalyze change in the 1990s. The use of public right-to-know laws and legislative encourage-

ment of citizen lawsuits are already part of the environmental regulatory landscape (8), and will be an important part of the backdrop affecting coal-based electric power systems.

Regulation of Existing Sources

Two or three issues will likely dominate the environmental regulatory agenda for existing coal-fired power plants during the next decade. The first and most significant will be acid rain controls. To curtail acidic deposition in the eastern United States and Canada, recent Congressional proposals have called for SO₂ emission reductions ranging from 8 to 12 million tons per year (Mtpy) below the 1980 level of 24 Mtpy. Although acid rain control legislation appears imminent, substantial uncertainty remains as to an acceptable compromise on SO₂ and NO_x reduction levels, timetables for compliance, financial arrangements, and the degree of technological flexibility in reducing emissions. The program with the greatest current support would require an SO₂ reduction of 10 Mtpy by some time near the turn of the century. This would represent a decrease of about 40% in current US emissions, or about 65% in emissions from coal-burning power plants (13). NO_x emission reductions of 3 to 4 Mtpy also may be required, or accepted in lieu of some SO₂ reductions (e.g. based on equivalent acidifying potential). Control of NO_x emissions also could be part of a strategy to attain air quality standards for photochemical oxidants, or to fulfill a new international treaty obligation capping US NO_x emissions at pre-1987 levels (14).

Other regulatory issues also could force large reductions of SO₂ emissions from existing sources. One is the suggested need for a short-term (one-hour average) ambient air quality standard for SO₂ to protect against acute health effects. EPA has concluded that such a standard is not warranted at this time, but has left the door open for future action (15). Another issue is an ambient standard for fine particles smaller than 2.5 microns. Here too, EPA is considering whether a new standard is needed to protect health and/or visibility (16). Since sulfates are a significant component of fine particulates, control of SO₂ again would be part of any particulate control program. Adoption of an acid rain control program, however, would likely obviate the need for new air quality standards.

A further issue that could affect many plants in the 1990s will be new environmental restrictions in conjunction with power plant life-extension projects. Electric utilities now find it much less expensive to upgrade and maintain existing coal-fired power plants than to build new ones, with current studies suggesting that up to 20 or 30 years of continued service life can be achieved at costs only 20 to 30% of those of comparable new facilities (17). These costs would be too low to trigger a provision of the NSPS requiring new source standards to be met at facilities that undergo "reconstruction" (defined

as cases where cost exceeds 50% of equivalent new generating units). While more costly boiler repowering projects could require NSPS compliance, most plants would continue to emit at the higher rates typically permitted under existing State Implementation Plans. Many believe that prolonging plant lifetimes would circumvent the intent of the Clean Air Act to ensure a continual decrease in emission rates as new sources replace older ones (18).

One proposal is to adopt a "control or retire" regulation that would impose more stringent emission limits on any unit still operating beyond some predetermined age. Similar rules have been adopted in West Germany as part of an acid rain control program (19). The power plant life-extension issue in the United States also is closely coupled to future acid rain regulations, since NSPS levels, if imposed on older facilities, would preclude many of the less efficient but lower-cost removal options now being developed for acid rain controls. Even under current rules, both NSPS and PSD restrictions also apply to modifications or operational changes that result in a significant net increase in emissions of a regulated pollutant (independent of cost). In a recent landmark decision, EPA held that a renovation project to restore several existing utility boilers to their nominal capacity was not excluded as routine maintenance, repair, and replacement (20). This decision could have a major impact on life-extension plans nationwide.

Finally, as noted earlier, existing coal-fired power plants could become subject to new regulations on hazardous and toxic waste emissions. While future developments in this area remain far more speculative, measures to address site-specific problems cannot be ruled out in the decade ahead. To the extent that new controls or remediation may be required, the most likely targets would be wastewater discharges, existing ponds, or dry fly ash disposal sites deemed to threaten surface or groundwater supplies.

Requirements for New Facilities

While new power plant construction is currently rather limited, significant coal-fired capacity additions are projected near the turn of the century (Figure 2) (21). Environmental regulations for future plants can be expected to involve (a) a tightening of existing NSPS requirements for air and water pollutants; (b) more stringent requirements for solid waste disposal, reuse, and minimization; (c) new requirements for monitoring and reporting hazardous or toxic chemicals, with strict prohibitions on discharge; and (d) more detailed considerations of site-specific multimedia impacts and risks in establishing permit restrictions and emission control requirements.

NSPS requirements may be revised through Congressional action, legal challenges, or periodic EPA reviews. Reauthorization of the Clean Air Act and related issues of ozone and acid rain control, expected soon, could add impetus to changes in future regulations. Depending on the pace of new

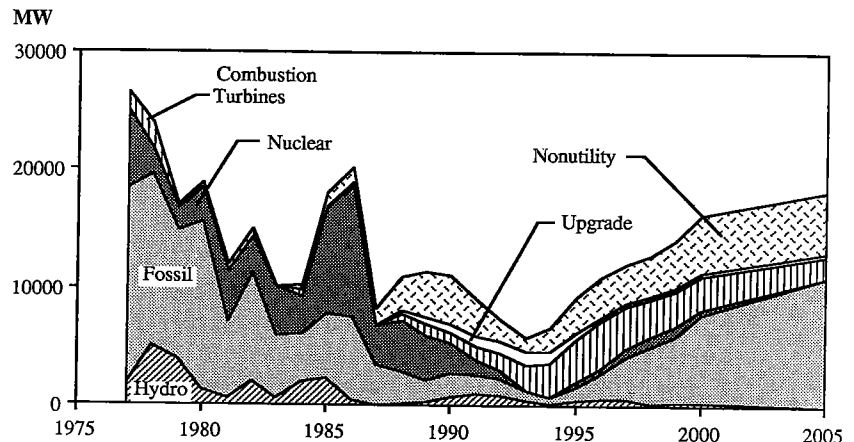


Figure 2 US generating capacity additions based on date of commercial operation (adapted from Ref. 21). Fossil steam capacity is primarily coal.

developments, the current NSPS could be revised once or possibly twice in the next decade.

What regulations are likely to apply to plants designed and built near the turn of the century? For SO_2 , a tightening of current standards (e.g. to 95% removal for both high- and low-sulfur coals) can be anticipated, reflecting advances in FGD and other clean coal technology. For particulate matter, limits on the emission of fine particles might supplement a tighter regulation based on total mass (e.g. 0.02 lbs/10⁶ Btu total and 0.01 lbs/10⁶ Btu less than 10 μ), reflecting improved technology as well as concern about the health effects of fine particulates (including air toxics). More significant reductions can be expected for NO_x emissions. Advanced combustion control methods will be capable of reducing NO_x to roughly half the current NSPS limit for pulverized coal plants (22), while emissions of 0.1 lbs/10⁶ Btu or less may be achievable with postcombustion NO_x removal systems now used on coal plants in Japan and Europe (23). Toward the end of the century, NSPS requirements are very likely to reflect such capability.

Future new source standards for water pollutants will likely move toward a zero discharge requirement for a larger set of trace metal and organic pollutants, with no detectable emission of total residual chlorine in cooling water discharges. Site-specific discharge standards (NPDES permits) will continue to play a stronger role than NSPS requirements for facilities located along priority waterways, approaching, insofar as technologically feasible, the goal of zero discharge of toxic pollutants.

State and local permit requirements and EPA hazardous waste and reuse regulations will continue to set the pace for future solid waste disposal rules.

Increasingly stringent requirements for the containment and monitoring of high-volume wastes can be expected. At some locations, federal Safe Drinking Water standards are likely to be invoked as a basis for surface and groundwater protection, dictating acceptable design of disposal sites. EPA test procedures defining hazardous wastes also can be expected to evolve. The new Toxicity Characteristic Leaching Procedure (TCLP) test method proposed by EPA (24) could increase the likelihood of some utility wastes being classified as hazardous because of the revised test procedures and the expanded list of organic and inorganic species included. The Electric Power Research Institute recently initiated projects to characterize chemically all power plant waste streams to better assess the potential for future hazardous waste problems and alternative treatment methods (25).

As the scientific basis for risk assessments becomes more sophisticated, the 1990s will also see an increased regulatory emphasis on risk minimization. This will demand a multimedia perspective of environmental emissions and control, with standards and technology tailored to ensure the lowest (acceptable) risk in the context of regional and/or site-specific circumstances. Extensive monitoring of process streams and ambient environmental quality will increasingly become an integral part of permit and regulatory requirements, with computer models used more extensively to predict emissions and assess the risks of chemical discharges.

What of the longer-term outlook past the year 2000? The crystal ball inevitably gets cloudier here, but at least two things are likely to happen. First, NSPS requirements will evolve and expand to reflect the emission-reduction capabilities of new coal-based generation technologies such as integrated gasification combined-cycle (IGCC) and pressurized fluid-bed combustion (PFBC) systems. The superior environmental performance of IGCC will increase the downward pressure on emissions from all coal-based power systems, as will state and local determinations of "best available control technology" and "lowest achievable emission rate."

Second, the environmental issues associated with greenhouse gases and global climate change will continue to grow in importance, focusing critical attention on the design and long-term use of coal-based (and other fossil fuel) energy systems. Given current knowledge, it is doubtful that the global climate issue will result in new environmental regulatory requirements before the turn of the century, although proposals already are emerging to curtail greenhouse gas emissions (26). Initially, actions affecting electric power plants are more likely to take the form of guidelines and incentives to improve energy efficiency, yielding reduced emissions of CO₂ per unit of electricity delivered, combined with reduced electricity demand. At the state regulatory level, the concept of least-cost energy planning will be increasingly advocated (and adopted) to require that any expenditures for new power plant capacity

be proven more cost-effective than end-use conservation measures. Such initiatives will force utilities to consider environmental emissions as an integral part of future capacity planning decisions.

IMPLICATIONS OF FUTURE REGULATIONS

The implications of future environmental regulations for coal-based energy systems include (a) immediate impacts on environmental control technology development and power system design; (b) immediate and long-term economic impacts related to power generation costs, and the competitiveness of coal and clean coal technology; and (c) social implications that include issues of worker training, plant management, and professional education in environmental control. Each of these areas is touched on briefly, with emphasis on the technological implications.

New Technology Development

Technological innovations in air pollution control are being strongly spurred by the problem of acid rain in North America, and by the emergence of stringent emission control requirements in other parts of the world, particularly Japan and West Germany. In the United States, the Department of Energy (DOE), the Electric Power Research Institute (EPRI), and the EPA have been the major sponsors of improved "clean coal technology," with strong participation by state programs, notably in Ohio and Illinois. As a result, full-scale demonstration projects of improved technology for SO₂ and NO_x control are now planned or in progress (Table 3). Some of the major implications foreseen for US power plants in the coming decade are highlighted below. More information on specific process developments can be found in the rapidly growing technical literature.

SULFUR DIOXIDE CONTROL Technologies being developed to reduce SO₂ emissions before, during, or after combustion have SO₂ removal efficiencies ranging from low (10 to 30%), to moderate (40 to 70%), to high (80 to 99%). Wet flue gas desulfurization (FGD) systems employing lime or limestone as a reagent are today the most effective means of SO₂ removal, achieving well over 90% removal efficiency in recent US applications (27). However, they are still expensive to install and operate reliably, and they generate large quantities of solid waste. In the next decade, significant cost-saving improvements in lime/limestone FGD systems can be expected, especially for retrofit applications. Elimination of spare absorbers and the use of larger vessels—improvements already found in European and Japanese systems (23)—are now scheduled to be demonstrated in the United States on high-sulfur coals (Table 3). These improvements, with better understanding of FGD chemistry and other process design simplifications, mean that the next

Table 3 DOE clean coal technology demonstration projects for coal-based power systems^a

Technology	Contractor/project location	Plant size
<u>Round 1 projects</u>		
Integrated gasification combined cycle w/hot gas cleanup	M. W. Kellogg & Bechtel, Inc./ Pennsylvania	60 MW
Pressurized fluidized bed combined cycle	American Electric Power/ Ohio	70 MW
Circulating fluidized bed combustion	Colorado Ute/ Colorado	110 MW
Slagging combustor w/sorbent injection	Coal Tech Corp/ Pennsylvania	1000 tons/d (100 MW)
Slagging combustor w/sorbent injection	TRW, Inc./ Ohio, New York	70 MW
Gas reburning & furnace sorbent injection	Energy & Environmental Research/ Illinois	40, 80, 117 MW
Furnace/duct sorbent injection/low NO _x burner	Babcock & Wilcox Co./ Ohio	105 MW
<u>Round 2 projects</u>		
Integrated gasification combined cycle	Combustion Engineering, Inc./ Illinois	40 MW
Pressurized fluidized bed combined cycle	American Electric Power/ West Virginia	330 MW
Circulating fluidized bed combustion	Southwestern Public Service Co./ Texas	250 MW
Combined SO ₂ /NO _x /TSP flue gas treatment	Babcock & Wilcox Co./ Ohio	5 MW
Combined SO ₂ /NO _x flue gas treatment	Combustion Eng. & Snamprogetti/ Ohio	35 MW
Advanced flue gas desulfurization	Southern Company Services/ Georgia	100 MW
Advanced flue gas desulfurization	Pure Air Co./ Indiana	529 MW
Selective catalytic reduction	Southern Company Services/ Florida	3 × 2.5 MW
Low SO ₂ /NO _x burner for cyclone boilers	TransAlta Resources Corp./ Illinois	33 MW
Coal reburning for cyclone boilers	Babcock & Wilcox Co./ Wisconsin	100 MW
Duct sorbent injection	Combustion Engineering, Inc./ Virginia	180 MW
NO _x combustion modification methods (two projects)	Southern Company Services/ Georgia (wall) Florida (tangential)	500 MW (wall) 180 MW (tang)

^a As of December 1988 (58). Round 1 projects were selected in 1986 and 1987, and Round 2 projects in 1988. Both rounds included additional projects involving industrial processes or boilers. All Round 2 projects are tentative pending final contract negotiations.

generation of FGD systems could be 20 to 40% lower in both capital and operating costs than systems built in the early 1980s (23, 28). The use of organic buffering agents will improve reliability, allowing removal efficiencies of 97% or more to be achieved in future systems. Wet FGD systems appear effective in removing trace metals and organics from flue gases (29), although detailed performance data in this area remain limited.

Technical progress also is being made on the use of lime spray dryer (LSD) technology to achieve 80 to 90% SO₂ removal on medium- and high-sulfur coals in conjunction with an existing electrostatic precipitator (ESP) for particulate removal (30). This retrofit option could prove cost-effective for some facilities. Development of LSD technology able to meet NSPS emissions with high-sulfur coal using improved baghouse designs is part of the research planned for the new EPRI High Sulfur Test Center. In Europe, spray dryers now routinely achieve 90 to 95% sulfur removal on coals of 1 to 2% sulfur (31). The relatively low temperature of spray dryer operation also aids in collecting organics and trace metals that would otherwise remain volatilized.

A number of new combustion and postcombustion processes under development seek moderate SO₂ reductions at a cost competitive with coal switching for retrofit applications. The injection of a sorbent (e.g. limestone or hydrated lime) directly into the furnace is being demonstrated as part of the DOE Clean Coal Technology program. Preliminary tests at the Ohio Edison Edgewater plant have achieved the 50 to 60% SO₂ removal sought, although long-term tests remain to be conducted (32). Various schemes for injecting sorbents directly into the flue gas duct upstream of an existing particulate collector also are now being brought to the demonstration scale (33).

Physical coal cleaning, already commercially available, reduces the sulfur content of many US coals by roughly 10 to 30% (34). Current research on precombustion pollutant removal focuses mainly on production of "super clean" coals for use as a substitute for oil in fuels such as coal-water mixtures. Other advanced coal cleaning processes seek more economical sulfur reduction, which could be attractive for power plant applications in conjunction with combustion or postcombustion control measures (35).

By the early-to-mid 1990s, a variety of new or improved SO₂ removal options for existing coal plants will likely have been demonstrated. The question then remains as to what role these technologies will actually play in meeting future environmental regulations. Computer modeling of alternative regulatory scenarios offers some insight as to what might happen. Figure 3 shows the types and amounts of SO₂ removal technology selected by coal-fired power plants in the 31-state region of the eastern United States under an acid rain control scenario in which SO₂ emissions in 1997 are assumed to be reduced by 10 Mtpy (approximately 65%) below 1980 levels (36). The availability of low-cost retrofit technologies with moderate SO₂ removal

efficiencies decreases the requirement for more expensive FGD systems, while longer plant lifetimes increase the preference for retrofit technology over switching to lower-sulfur coal since costs are amortized over a longer period. Results for other scenarios (37) indicate that because of reduced flexibility, the use of low-cost SO₂ retrofit technology would be reduced or eliminated if future regulatory policy (a) requires NSPS emission standards to be met at plants undertaking life-extension programs in the 1990s; (b) requires utility SO₂ emission reductions substantially greater than 10 Mtpy nationwide to abate acid deposition; (c) imposes uniform emission standards on individual generating units as opposed to a statewide or regional "bubble"; (d) restricts the choice of coals that can be used for electric power generation; or (e) requires that emission reduction methods be specified before advanced technology options are fully demonstrated.

NITROGEN OXIDE CONTROL Technology development in the United States has focused almost exclusively on combustion control methods to minimize NO_x formation. Low-NO_x burners (LNB) are now standard for new coal-fired boilers, reducing uncontrolled NO_x emissions by about 50% for dry bottom boilers. US retrofit experience for coal-fired boilers is still relatively limited. EPRI has sponsored some work in this area, with additional NO_x control demonstrations under way in response to acid rain concerns (Table 3). These

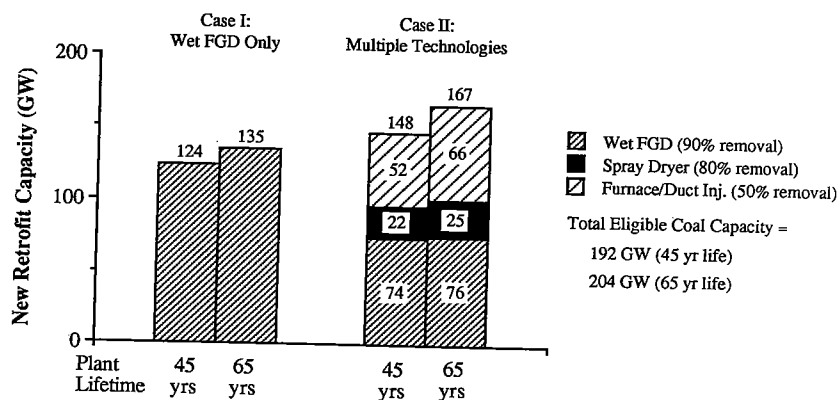


Figure 3 Estimated FGD retrofit capacity for acid rain control. These scenarios assume that SO₂ is reduced by 10 Mtpy below 1980 levels at coal-burning plants in the 31 eastern states while meeting regional energy projections for 1997 (36). Case I assumes only improved wet FGD systems are used in addition to coal switching, cleaning, or blending to achieve statewide emission reductions at least cost. Case II assumes new lower-cost technologies (furnace or duct sorbent injection, or lime spray dryers using upgraded electrostatic precipitators) also are available for 50 to 80% SO₂ removal. New retrofit options and extended plant lifetimes increase the preference for control technology over switching to low-sulfur coal. Newer clean coal technologies reduce annual average compliance costs by approximately 20% relative to current commercial technology.

demonstrations of slagging combustors, gas and coal reburning, and advanced burner designs are seeking NO_x reductions of approximately 50–70% for retrofit applications. Such reductions have already been demonstrated in Japan, where advanced combustion control systems have achieved emissions as low as 100 to 150 ppm ($0.2 \text{ lbs NO}_x/10^6 \text{ Btu}$) on coal-fired boilers (38).

In Japan and West Germany, operating experience is beginning to accumulate on postcombustion systems, using selective catalytic reduction (SCR) to achieve 80 to 90% NO_x control on coal-fired power plants. While larger catalyst volumes have been needed to prevent air preheater pluggage and avoid fly ash odor problems caused by chemical reagents (ammonia), the catalyst replacement cost, which dominates the cost of the SCR process, has been reduced substantially over the past few years, yielding a net reduction in overall cost (39). No SCR systems are now installed on US coal-fired plants, however, and there are no performance data for medium- and high-sulfur coals, where problems of catalyst poisoning and air preheater pluggage are suspected (40). EPRI plans to begin pilot testing of SCR systems in the United States, and one demonstration is planned under the DOE Clean Coal Technology program. Despite the tendency of US utilities and research organizations to view SCR as an unnecessary and expensive technology, its role in power plant emission control could well grow in the mid-to-late 1990s as a benchmark technology for best available NO_x control.

PARTICULATE CONTROL The 1980s saw the emergence of fabric filter (baghouse) particulate collectors on new coal-fired power plants using spray dryer FGD systems with low-sulfur western coals (41). The use of fabric filters at new facilities can be expected to increase in response to future environmental regulations and increasing cost competitiveness with ESPs (including the use of lower-cost pulse jet designs). Regulatory trends favoring greater use of baghouse collectors include the control of fine particulates and trace metals, of which fabric filtration generally offers more efficient removal (42).

To ensure compliance with particulate emission standards in existing plants, flue gas humidification and other performance enhancements for existing ESPs are being developed for use with dry SO_2 removal processes (which increase particulate loadings and alter ash resistivity characteristics). The use of smaller pulse jet fabric filters as a retrofit technology also is being studied. The demonstration of effective, low-cost particulate removal will be critical to the viability of SO_2 retrofit technologies employing furnace or duct sorbent injection.

COMBINED REMOVAL PROCESSES A number of new flue gas treatment processes are being developed that use a single unit to remove more than 90% of SO_2 and NO_x , with recovery of sulfur or other by-products to minimize

waste disposal problems. Some of these processes are likely to reduce emission control costs by 20 to 30%, even taking into account future improvements in conventional technologies (43). Other combined removal systems seek moderate SO₂ and NO_x reductions during combustion (e.g. advanced burners coupled with sorbent injection). One novel process seeks combined removal of SO₂, NO_x, and particulates by using a high-temperature baghouse (Table 3). While it remains to be seen whether these processes prove technically and economically successful, those that do could see commercial service by the late 1990s.

WASTEWATER TREATMENT SYSTEMS Future developments in wastewater treatment technology will be driven largely by new environmental requirements to eliminate discharges of a growing list of potentially hazardous or toxic substances originating in coal ash, plant cleaning or treatment wastes, and plant makeup/intake water. Increasingly, the goal of zero wastewater discharge will be sought by power plant designers and operators to minimize or avoid the growing demands of environmental regulatory requirements. Zero discharge will be easiest to achieve (and is already being practiced using simple evaporation ponds) in arid areas where net evaporation exceeds rainfall. It will be more costly in eastern locations where annual precipitation is higher, requiring thermal treatment processes. Wider use of such technology could be one of the developments stimulated by future environmental regulations.

In the short term, the regulatory emphasis of the 1987 Water Quality Act will force the wider use and development of plant and in-stream monitoring methods for hazardous and toxic species (11). Additional treatment that might be required for trace metals removal would likely use iron-based flocculation technology recently developed for utility applications (44). Additional control of organics could pose greater difficulties, with technology development in this area becoming another focus of research in the 1990s.

SOLID WASTE DISPOSAL Technologies for dealing with power plant solid wastes can be expected to develop along two paths. One will be improvements in treatment and containment methods to prevent surface or groundwater contamination at landfills and pond disposal sites. The second, more important, will involve better ways to reuse and recover by-products, to minimize disposal problems or avoid them altogether. Many of the latter options have existed for some time, but the changing economics of solid waste disposal, driven in large measure by new environmental regulations, will militate against traditional land disposal in the next decade and beyond.

For plants with adequate space, landfill disposal of FGD wastes stabilized with fly ash or other fixation agents will continue to be viable. However, strict requirements for impermeable liners (natural or synthetic) and cachement/

recycle systems and groundwater monitoring will become increasingly routine. Waste from new flue gas treatment processes and advanced power generation systems also will undergo continued scrutiny to ensure that they pose no special disposal problems, as current studies indicate (45). Conversion of wet ash ponds to dry landfill sites also can be expected to accelerate under environmental pressures.

To minimize waste volumes and enhance recovery potential, future FGD systems will be designed to yield potentially marketable gypsum (calcium sulfate) rather than the sulfate-sulfite sludge current systems produce. Regenerative processes that produce by-product sulfuric acid or sulfur could also become more prevalent, although by-product markets will continue to be highly site-specific. More aggressive research and marketing efforts will seek expanded utilization of bottom ash and fly ash, about 25% of which is used today as an additive or fill material for road construction, cement, concrete, and other miscellaneous uses. Future uses could include higher-value markets; for example, strategic metals such as titanium and gallium could be extracted from beneficiated fly ash, the remainder of which could be used as a filler for plastics manufacture (46). In the longer term, one can envisage a completely integrated "coal refinery" recovering energy, metals, and chemicals from all of today's wastes (47). While that reality may still be a few decades off, we can expect to see increasing activity in the 1990s to exploit the full resource recovery potential of coal-based energy systems.

Advanced System Designs

After nearly two decades of a fragmented approach to environmental control, the concept of integrated environmental control is now emerging as the basis for power system design. This concept has several dimensions: (a) integrating across environmental media, so that emissions to air, water, and land are minimized by using fuel-pollutant profiles to "tune" integrated emission control devices to reduce or eliminate cross-media impacts; (b) combining into a single process, or (more desirably) into the power generation system itself, the control of pollutants currently treated by separate removal processes; and (c) combining a series of measures before, during, or after combustion to minimize overall environmental impacts and control costs.

Future coal-based power systems will employ integrated environmental controls in a variety of new plant designs. The most prominent systems now emerging are highlighted briefly below.

ADVANCED PULVERIZED COAL PLANTS New pulverized coal-fired power plants at the end of the century will offer improved performance, while meeting stringent environmental regulations with combinations of combustion and postcombustion air pollution control technologies closely integrated with water treatment and solid waste disposal systems (48a). Design options for

flue gas treatment will include separate (but improved) processes for SO₂, NO_x, and particulate control, as well as systems for the combined removal of SO₂ and NO_x and recovery of saleable by-products. New hazardous and toxic discharge regulations could also stimulate changes in construction materials. For example, titanium or stainless steel could become the preferred materials for steam condensers and boiler feedwater systems, with ultrapure water used to significantly reduce scaling and the need for chemical cleaning of boiler tubes. Advanced water purification technology, used today in West Germany, would also yield lower tube failure rates and higher plant availability.

ATMOSPHERIC FLUIDIZED BED COMBUSTION AFBC is one of several new power generation options being commercialized in the United States (48b). In contrast to conventional furnace designs, fluidized bed boilers use a burning bed of relatively coarse coal particles suspended (fluidized) by an upward stream of air at approximately atmospheric pressure. Steam tubes are immersed directly in the fluidized bed as well as in the walls of the furnace, providing more efficient heat transfer at lower temperatures. For either new plant construction or repowering of existing units, AFBC offers a relatively compact design, suitable for modular construction, and the flexibility to burn a variety of solid fuels and low grade coals (2). AFBC systems employing both bubbling bed and circulating bed designs are being demonstrated as part of current clean coal technology initiatives (48c,d). The environmental advantages of AFBC include a relatively low combustion temperature, which significantly reduces NO_x formation; in-situ sulfur removal by the addition of limestone to the fluidized bed (eliminating the need for an FGD system); and a dry granular waste product that facilitates landfill disposal (although waste quantities typically exceed those of FGD). Table 4 compares the environmental performance of AFBC to that of other advanced designs. In the next decade, AFBC capacity is likely to increase, especially for repowering applications where it is an economical way to add new capacity (49).

PRESSURIZED FLUIDIZED BED COMBUSTION PFBC systems offer the promise of higher power generation efficiency and improved environmental performance compared with current combustion systems (48d, 49, 50). Combustion is carried out in a fluidized bed with a sorbent (dolomite or limestone) added for sulfur removal. Operation at high pressure (typically 10 to 15 atmospheres) permits a more compact, efficient design compared to AFBC systems. The higher efficiency is achieved in a combined cycle by extracting power from the high-temperature, high-pressure combustion gas, as well as from a conventional boiler steam cycle. PFBC's technical complexities have impeded development (50), but many of the problems have been solved, and two full-scale repowering projects using PFBC boilers and high-sulfur coal are being planned at US utility sites (Table 3). If these demonstration projects

Table 4 Potential performance and emissions of advanced coal technologies
(all emissions in lbs/MWh)^a

Parameter	PC (Adv)	AFBC	PFBC	IGCC
Heat rate (Btu/kWh) ^b	8600	9700	8700	9000
SO ₂ emissions ^c	3.4	3.8	3.5	0.7
NO _x emissions ^d	2.6 (0.9)	1.9 (1.0)	0.9	0.7
TSP emissions ^e	0.17	0.20	0.17	0.05
CO ₂ emissions ^f	1840	2150	1910	1880
Solid wastes ^{f,g}	330	405	310	180

^a Based on bituminous coal with 10,100 Btu/lb, 4.0% sulfur, 16.0% ash, and 57.5% carbon by weight. Emissions are normalized on a fixed electrical output to reflect the efficiency of each system.

^b Based on EPRI estimates for units of 500–750 MW (10). IGCC based on Texaco gasifier.

^c Assumes 95% removal for combustion systems and 99% removal for IGCC.

^d Assumes emission rates of 0.3 (PC), 0.2 (AFBC), 0.1 (PFBC), and 0.08 (IGCC) lbs/10⁶ Btu based on combustion controls. Numbers in parentheses assume additional postcombustion removal to achieve 0.1 lbs/10⁶ Btu.

^e Assumes emission rates (lbs/10⁶ Btu) of 0.02 for combustion systems and 0.005 for IGCC.

^f Assumes stoichiometries of 1.05 (PC), 2.5 (AFBC), and 2.0 (PFBC) for sulfur removal using lime, limestone, or dolomite, respectively.

^g Dry high volume wastes from ash and sulfur removal. PC assumes gypsum dewatered to 90% solids. IGCC includes elemental sulfur recovered as by-product (20% of total).

prove successful, PFBC could emerge as a leading technology for repowering and new plant capacity in the late 1990s and beyond.

INTEGRATED GASIFICATION COMBINED CYCLE IGCC is a two-step process in which coal is first gasified by reacting it at high temperature and pressure with steam (a source of hydrogen) and oxygen (or air). The product gas is then cleaned and burned to recover electrical energy in a combined-cycle system.

The Cool Water IGCC demonstration plant, operating in the southern California desert since 1984, has been justly hailed as the cleanest coal-based power plant in the world (51). The technical success of this project has been widely reported and has provided the basis for some highly optimistic projections of IGCC's potential impact on future SO₂ and NO_x emissions in the United States (13). As Table 4 indicates, IGCC offers greater control of air pollutants than combustion systems, together with zero or low wastewater discharge¹ and gasifier solid wastes (slag) that appear environmentally benign (52). The cost of IGCC, however, still exceeds that of conventional designs

¹The Cool Water plant achieves zero discharge by using a solar evaporation pond. A nonzero discharge design would be the more likely configuration in the eastern United States, although if necessary wastewaters could be treated to elimination.

according to most recent studies (53). However, an attractive aspect of IGCC is that it can be built in phases that initially may include only the gas turbines fired by oil or natural gas. These smaller modules (e.g. 100–200 MW) later can be combined and integrated with a coal gasifier and steam cycle, providing utilities with a high degree of flexibility in capacity planning and minimizing economic risks. A number of US utilities are conducting site-specific studies of IGCC designs based on the Cool Water prototype.

Several new demonstration projects are under way to develop IGCC technology that promises reduced costs and higher efficiency (Table 3). High-temperature gas cleanup is one of the keys to efficiency and simplicity, since it obviates the need for cooling the product gas, and for treating the complex wastewaters that result from condensation of organics and other constituents. Improved gas turbines and lower-cost oxygen production are among the other developments being sought. Integrating power generation with production of coal-derived fuels and chemicals from synthesis gas is potentially the most attractive scheme for utilizing gasification-based technologies in the future (54).

Economic and Social Implications

By influencing the price of electricity, the competitiveness of coal as an energy source, and the quality of the environment and human health, future environmental regulations for coal-based power systems will have direct and indirect effects on the economy and US society. A comprehensive discussion of such impacts is well beyond the scope of this paper. Several of the more direct effects, however, are discussed below.

GENERATION COSTS Environmental control systems for air, water, and solid waste emissions now account for one fourth to one third of the total cost of a new coal-fired power plant (23). Air pollution control costs roughly two to three times as much as water pollution control, and five to ten times as much as solid waste disposal (55). Control costs are highest for plants burning high-sulfur coal.

In the short term, new environmental control requirements will continue to raise the cost of coal-based power generation. The largest increases in the next decade will likely be for acid rain controls. Total annual costs for the United States have been estimated at \$2 to \$8 billion (in constant 1985 dollars)² depending on the magnitude of required emission reductions and the method for its allocation (56). The costs of the 10 Mtpy SO₂ reduction scenario described earlier (Figure 3) are estimated at about \$5 billion per year in the absence of new clean coal technology. This cost would increase average

²Note that many studies report levelized costs in inflated "current" dollars, yielding numerical values roughly twice those of the equivalent constant dollar levelized cost.

generating costs by about 5 to 25% in the midwestern states most heavily affected (37). The availability of lower-cost SO₂ retrofit technology could reduce the cost of an acid rain control program by roughly 20%, or about one billion dollars per year nationally. In all cases, the impact of higher generating costs on consumer electricity rates would depend significantly on the future generating mix and financial circumstances of individual utilities and on the specific requirements of acid rain legislation.

For new pulverized coal plants, the tighter emission constraints envisioned for the late 1990s could add perhaps 20 to 40% to current pollution control costs (5 to 10% to generation costs), mainly for NO_x control if SCR is required. Integrated control systems and improvements to current technologies can be expected to offset these higher costs to some degree (43). Advanced power generation systems such as FBC and IGCC could minimize environmental control costs, since emissions control is more highly integrated with the power generation system.

Only crude estimates are available at this time regarding the possible cost impacts of greenhouse gas controls. Current reports indicate that removal of CO₂ from combustion gases would raise the cost of electricity by 35 to 80%, with the final fate of CO₂ still remaining uncertain (57). Recent studies indicate that power plants are not a significant source of N₂O emissions. New research efforts are being launched to improve the information base for assessing the control technology implications of global climate issues.

COAL MARKETS Acid rain regulations could have pronounced effects on regional coal markets in the 1990s, since the least costly method of reducing SO₂ emissions is switching to low-sulfur coals. The impacts would fall on the midwestern high-sulfur coal mining industry and further aggravate the economic burdens of that region. Efforts to stabilize coal markets by using clean coal technology and applying incentives to use local coal are thus expected to be part of any compromise on acid rain controls. In the long run, requirements to use best available technology will stabilize coal markets by removing incentives for large-scale coal switching. In the interim, plant repowering and life-extension programs that require new emission reductions also will help minimize coal market disruptions, since technology-based solutions are favored.

PLANT SITING Future environmental regulations are likely to affect the siting of new coal-based power plants in two ways. In the long run, as emission control requirements grow more stringent, environmental constraints will become less dominant a factor in site acceptability since all new facilities will be very tightly controlled. In the more immediate future, existing regulations for the prevention of significant deterioration and the

attainment and maintenance of ambient air and water quality standards will continue to affect power siting decisions in many parts of the country. To minimize the burden of regulatory requirements as well as costs, repowering and life extension projects will be preferred over new plant construction, and new capacity additions will be located adjacent to existing sites insofar as possible. Proximity to markets for by-products will inevitably grow in importance as the cost of waste disposal becomes prohibitive. New limitations on total atmospheric loading to control the regional problems of acid deposition and photochemical oxidants could impose some new constraints on site acceptability. Existing state and EPA policies for emissions trading, banking, offsets, and bubbling are likely to provide the framework for future developments in these areas. These policies define the methods by which new emission sources can be accommodated in regions not yet complying with the ambient air quality standards.

TRAINING AND EDUCATION The last decade has seen two important shifts in utility attitudes toward environmental regulation. First, environmental control systems are no longer viewed simply as unwelcomed "add-ons," secondary in importance to the generation of electricity. Rather, it has become clear that they are as essential to power generation as the proper operation of boiler feedwater pumps or turbines. At the utility management level, the higher priority being accorded environmental control implies a growing need to train and motivate power plant supervisors, technicians, and workers responsible for maintenance and operation of pollution control systems. Many utilities have begun to move in this direction, and more concerted efforts can be expected in the future.

A second point, touched upon earlier, is that environmental management is now coming to be viewed more holistically in the context of a sophisticated regulatory framework demanding lower and lower emissions of more and more chemical substances to all environmental media. One implication is that at the professional level, engineers and environmental scientists must be trained to deal more comprehensively with problems affecting all environmental media. At the utility management level, much closer teamwork among environmental specialists, power plant designers, and plant operators will be required for all aspects of utility operation. Close coordination with information specialists and internal environmental auditors also will be needed as continuous monitoring requirements become more widespread, and the explosion in personal computers imposes greater requirements for data analysis and information processing.

INTERNATIONAL COMPETITIVENESS In parallel with developments in the United States, environmental regulations in other parts of the world, princi-

pally Japan and West Germany, have stimulated international activity to develop clean coal technologies for new and retrofit applications. A measure of this activity is seen even in the DOE Clean Coal Technology program; nearly a third of the projects selected in the first two rounds of funding involve Japanese or European technology (58). Competition from Japan, West Germany, Sweden, Finland, Denmark, and elsewhere can be expected to grow in the 1990s and beyond in response to expanding markets, including developing countries where pollution control measures are still relatively rudimentary. While international competitiveness involves broader aspects of government-industry relationships (49), the technological base and know-how associated with the deployment and commercialization of clean coal technology will be a major factor in capturing new markets. To the extent that future environmental regulations help accelerate (and not impede) the pace of US technology development, the potential to export US technology will be significantly enhanced.

DEMAND FOR COAL-BASED GENERATION The broader question about future environmental regulations is how they will affect the overall demand for coal-based electricity. This complex issue can be only touched upon here. The main factors affecting coal's competitiveness for power generation will be the price and availability of electricity generated from natural gas, oil, nuclear fission, or renewables (hydro, solar, etc), including purchases from independent power producers and neighboring countries. Even with strict environmental controls, however, coal-based systems are likely to remain the preferred technology for baseload power generation. While future environmental constraints could make coal less competitive in some regions, innovative clean coal technologies also will help open new markets now restricted by stringent environmental regulations or by other capacity planning considerations. Current projections thus foresee continued expansion of coal use well into the 21st century (49).

The emerging environmental issue of greenhouse gases and global climate change poses perhaps the greatest uncertainty for the long-term use of coal and other fossil fuels. Renewed interest in nuclear power as an alternative to fossil fuel can be foreseen, as can more immediate efforts to reduce energy demand by improving the efficiency of end-use devices and power generation and distribution technologies. As scientific attention focuses more intensely on the climate change issue, new legislation and accords will be proposed to stem the rise in greenhouse gas emissions. All of these developments will place downward pressure on the growth of new coal-based energy systems as we enter the 21st century. Still, coal will continue to provide most of the nation's electricity for the foreseeable future, albeit with increasing attention to minimizing environmental impacts.

CONCLUSION

There is a tendency, in looking into the future, to weigh heavily the more immediate past, and to project that current trends will likely continue (at least for a little while longer). While there is often a sound basis for such expectations, one must also understand how (and when) expectations will change as today's underlying premises cease to be valid.

The environmental control programs inaugurated two decades ago can be thought of as a second major phase in the industrial revolution begun more than a century earlier. In "century two" we and other nations are redesigning our entire technology base to reflect a new perspective in which the environment is no longer a free good or "externality," but a major part of the economic equation governing the way we do business. As this transition is completed over the next several decades, many environmental concerns of the day will subside. For coal-based power systems, we will have become proficient in eliminating chemical emissions to the air and water that pose significant risks to human health, restoring to the ground (or oceans) only benign materials and by-products. The pace—not the direction—of this change is at the heart of today's regulatory uncertainties.

Beyond this current transition, however, awaits a third, more challenging phase. This is the recognition that man's impact on the environment is not only regional or national but truly global in nature, with effects dominated by total environmental loading, not simply local exposure or concentration. The potential social and technological implications of global environmental change are pervasive (59, 60); the world is now awakening to these prospects and beginning to gear up to their challenges.

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