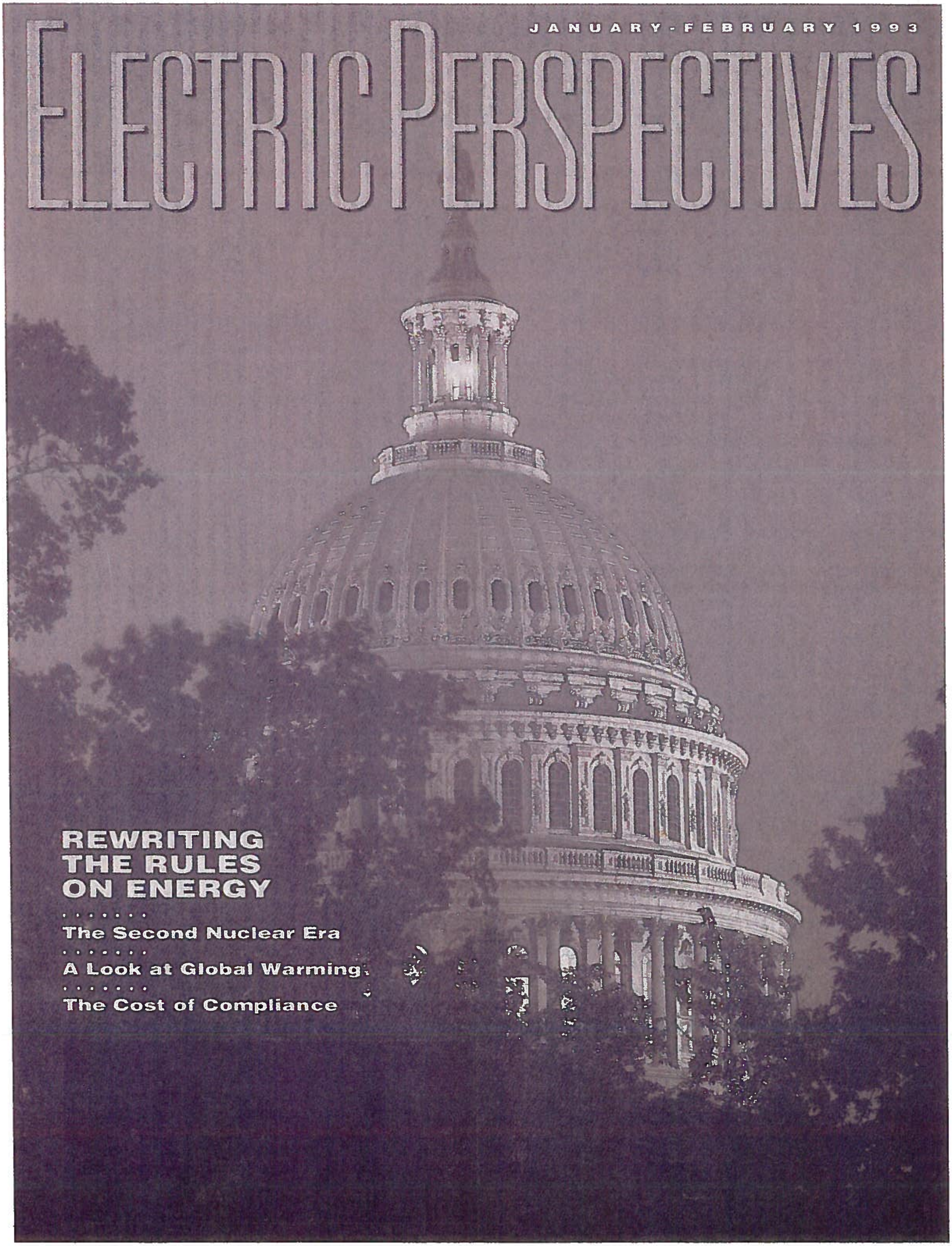
JANUARY-FEBRUARY 1993

ELECTRIC PERSPECTIVES



REWRITING THE RULES ON ENERGY

The Second Nuclear Era

A Look at Global Warming

The Cost of Compliance

CONFRONTING THE COST OF COMPLIANCE

BY BRUCE H. BRAINE

TO COMPLY with the Clean Air Act Amendments (the"Amendments") of 1990, electric utilities will certainly incur significant costs, borne ultimately by the electricity customer and the utility stockholder. While that compliance burden is heavy for many utilities, there are ways to take aggressive advantage of the current competitive nature of the emission-control market, as well as some of the regulatory alternatives included in the Amendments. It's one of the main ways utilities can reduce compliance costs and improve their own competitive position.

Of course, that's easy for *me* to say—my job is to describe options and to coach the utility once it has chosen its direction and schedule and jumped into the compliance water. But I'm well aware that I'm not the one who's jumping, the one who ultimately bears the risk of the aggressive decision. An electric utility can decide to jump in—or make its decision after it sees how others fare once they jump in. If it weren't such a broad economic question, the dilemma would be nearly existentialist. Each utility has a unique blend of considerations, its own decision tree concerning its customer base, fuel mix, state commission, state regulations, financials, and bond ratings, among dozens of other issues. Its decision to jump or to observe is weighty and complicated by deadlines and the real risk of failing. And regulatory treatment by public utility commissions, changes in market conditions, and future environmental regulations may affect *all* utilities' ability to contain their cost increases. So far be it from me to stand away from the shore and claim cheerily that the water is fine.

But still and all, I want to point out the options, whether they're universal or not: Whatever risk those changes bring could well be worth taking, particularly if the potential cost advantage is significant.

SOMEONE'S COST IS ANOTHER'S REVENUE—AND IN TERMS OF THE CLEAN AIR ACT AMENDMENTS, THE EMISSION-CONTROL INDUSTRY SEEMS TO HAVE THE UPPER HAND.

ICF Resources estimates that under Title IV (acid rain) alone, annual electric utility costs will increase by up to \$3 billion dollars per year by 2000 due to the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) reduction requirements. Significant amounts of capital will go to flue-gas desulfurization technology (i.e., scrubbers), low-NO_x burner technologies, continuous emission monitors, and boiler and particulate control upgrade and replacement necessitated by shifts to lower-sulfur coals. In addition, utilities might have to invest substantially in other emission-control

Bruce Braine is a vice president of ICF Resources, Inc. (Fairfax, VA). He bases this article on an August 1992 report that ICF Resources and Smith Barney prepared for the Environmental Protection Agency (EPA): "Business Opportunities of the New Clean Air Act: The Impact of the CAAA of 1990 on the Air Pollution Control Industry." The report presents findings from ICF Resources and Smith Barney research, as well as a compilation of results from a wide range of already completed, publicly available studies.

Just one example: To meet Phase I requirements, Public Service Electric & Gas will spend $430 million to repower its 33-year-old Bergen Generating Station. The new gas-fired combined cycle system will effectively remove most NO_x and SO_2 and add 570 megawatts of capacity.

A CONCRETE EXAMPLE

By Eric R. Blume, associate editor

Just beyond the entrance to Allegheny Power System's Harrison Power Station in Shinnston, West Virginia, it's a like a trailer park. Mobile offices for construction companies line the right side of the road, and they seem as if they've been there for years. Further down the line, construction workers move purposefully, and we're told to remember that it is an active hard-hat area. All these people belong to companies subcontracted by United Engineers & Constructors, which Allegheny Power signed on as the main contractor for—and now you can see it to the left, big boots, heavy trucks, gawky backhoes, towering cranes, and oceans of concrete—the largest current construction project in North America.

It's Allegheny's $726 million Harrison Power Station magnesium-enhanced flue-gas desulfurization system going up . . . a scrubber.

"Scrubber" diminishes the reality—you're not talking about a bottle-brush or a simple smokestack filter. It is a massive project, whose goal is to reduce SO_2 emissions by 98 percent. And that requires a huge multistage process—from gas absorption to waste disposal—and structures covering virtually the same amount of ground as the generating plant itself:

- 2 lime storage silos, each 116 feet in diameter, which store enough lime to feed the system's 13,000-ton-per-week appetite (their construction involved the largest North American continuous concrete pour to date);
- a 1,000-foot chimney, housing an absorber at its 112-foot-diameter base, where a water-and-lime mixture (containing some magnesium) is sprayed into the boiler flue gas, mixes with SO_2, and precipitates to the bottom where it mixes with more lime to become a muddy solid—calcium sulfate;
- 4 200-foot-diameter thickener tanks, which receive the mud, take off water that rises to the top, and recycle it to the absorber;
- 15 centrifuges, which take the thickened slurry from the bottom of the tanks and remove even more water;
- a waste-processing building and three fly-ash silos, where the centrifuge "cake" mixes with fly-ash and yet more lime to become solid waste—a substance that in fact has use as gypsum—which is carted away by truck.

Courtesy Allegheny Power System

That's not counting the new lime-unloading rail spur, the lime-unloading building, or the project's other supporting structures.

The three utilities that make up Allegheny Power System—Potomac Edison, Monongahela Power, and West Penn Power—will use the Harrison scrubber to meet *all* their SO_2 reduction requirements for Phase I compliance. The scrubber removes 64 tons of SO_2 per hour (which comes to more than 555,000 tons per year), and that—plus $200 million in low-$NO_x$ burners and continuous emissions monitors at other plants—is enough to cover the combined service areas.

But the deadline for Phase II of the Amendments looms as well. Allegheny Power's preliminary plans call for scrubbing the company's Hatfield's Ferry Station near Masontown, Pennsylvania, at a cost of $800 million.

The numbers are staggering, and so is the construction site. You leave it with a greater appreciation of the physical effort it takes to install a compliance strategy—and the enormous financial decisions a utility makes.

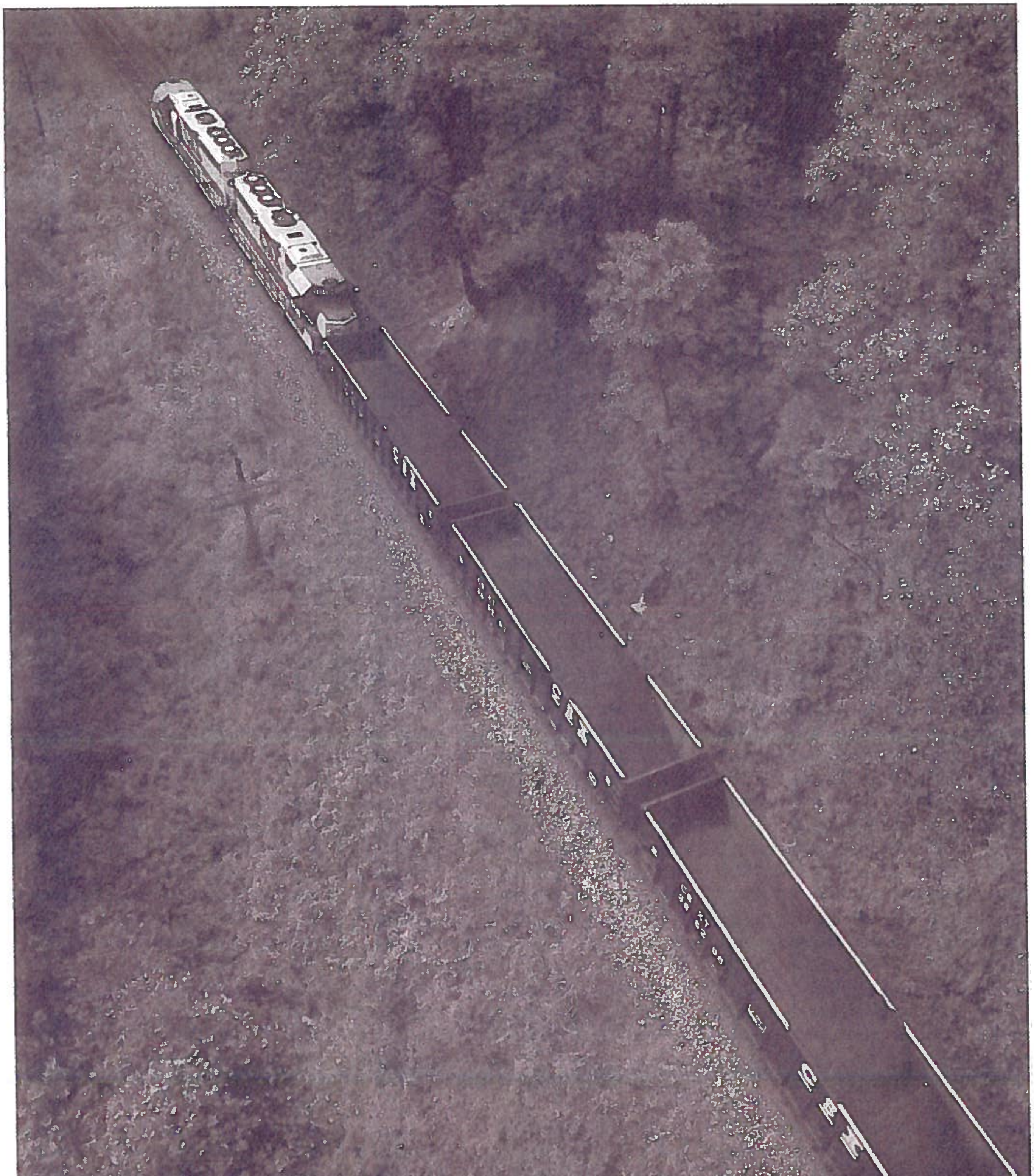
technologies—for example, selective catalytic reduction under the ozone nonattainment (smog) requirements of Title I, or new particulate control equipment, scrubbers, or even carbon absorbers under the air toxics provisions of Title III.

Logically, while many industries will incur compliance costs, significant growth in revenues and profits will belong to emission-control equipment manufacturers, engineering, design, and construction firms, and companies that produce or transport cleaner burning fuels. Between 1992 and 2000, Title IV of the Amendments will increase the revenues of emission-control equipment and clean-fuels suppliers by up to $21 billion cumulatively. About one half of that (approximately $7 billion to $11 billion) will go to low-sulfur coal producers and railroads. Most of the remainder will accrue to the emission-control equipment markets, primarily designers and manufacturers of scrubber and low-NO_x burner technologies. Boiler and particulate control equipment suppliers will benefit also, as utilities upgrade or replace boilers and electrostatic precipitators.

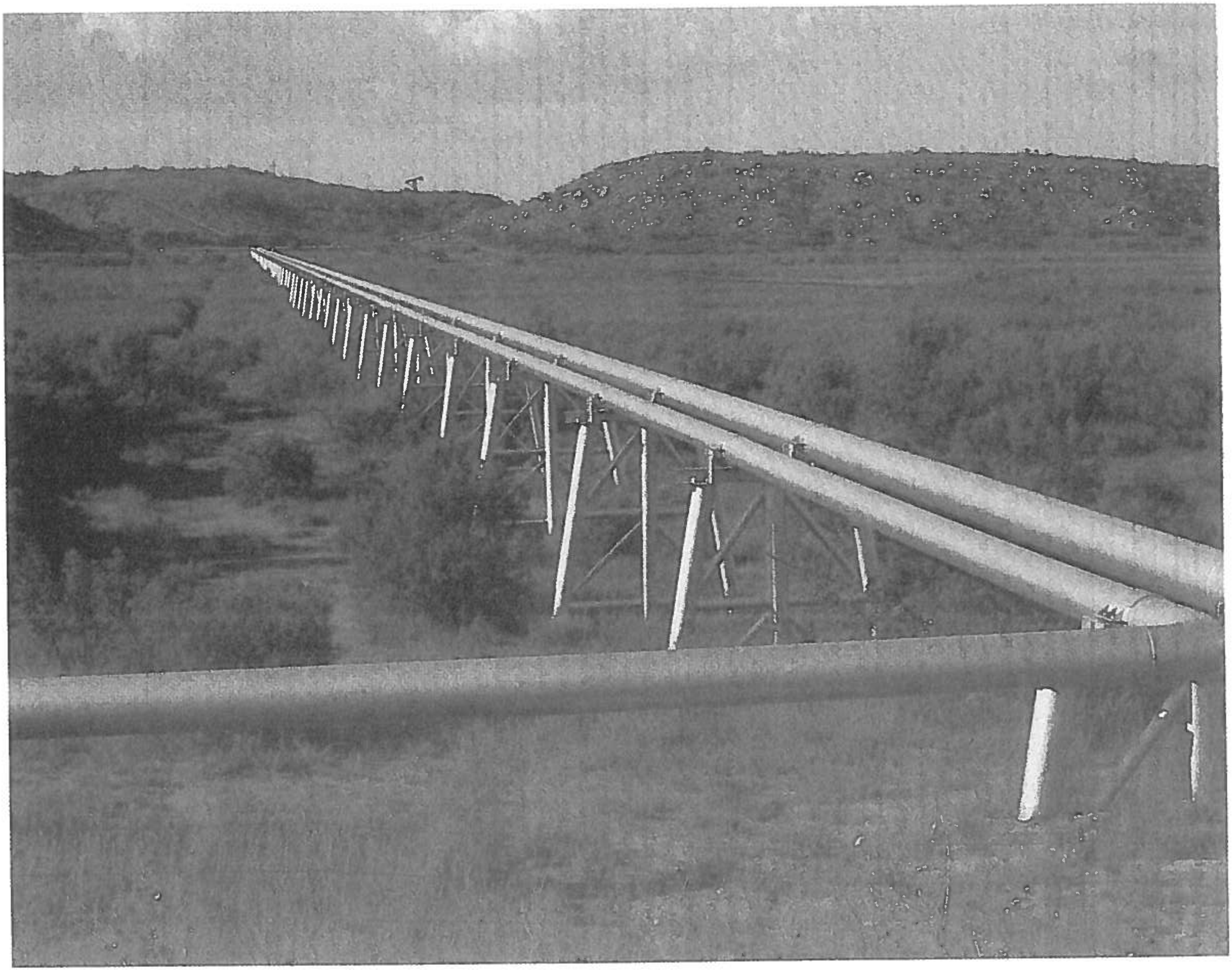
Notwithstanding these projected increases, the market structures for low-sulfur coal and natural gas, as well as for emission-control equipment, will undergo fundamental changes. In general, these markets have become very competitive—they have a relatively large number of companies with low profit margins. Prices have declined, reflecting technology advancements, overall productivity improvements, and (particularly with natural gas) government deregulation.

While the Amendments should re-

Powder River Basin coal can be an option for many utilities. One of the determining factors to consider is rail delivery price.



Trans Pixs / Uniphoto



sult in expanded profits in certain markets with high near-term demand (for low-NO_x burner technology installed prior to 1995, for example), the experience in the scrubber markets is more typical. Inflated expectations of a 25–30 gigawatt scrubber market in Phase I (based on some initial engineering firm estimates) have given way to a more reasonable—and competitive—13 gigawatt market in Phase I. Further, the Amendments' SO_2 allowance system and NO_x averaging provisions ought to enhance competition among varying types of coal, natural gas, and emission-control technologies.

Because many power-plant units are not required to control emissions until 2000 (in Phase II), some utilities may not have fully considered their alternative emission-control strategies. In fact, only a few of those affected in Phase II have identified all near-term options. This is certainly understandable from an environmental compliance standpoint, but perhaps not from a business standpoint. Some strategies require relatively prompt action. Opportunities to control escalating compliance costs—by taking full advantage of the emerging allowance market, by considering fuel switches and modifications, by developing new technologies, or by gaining improved regulatory treatment for conservation and demand-side management—are likely to be relatively short-lived.

It's time for those utilities to start their compliance portfolios.

Buy! Buy! Sell! Sell!

The fact that no SO_2 allowance trades occurred in 1991 worried some, but recent activity has strengthened the market's viability. In 1992, Wisconsin Power and Light's modest sales of 25,000 allowances resulted in cash payments of about $6.5 million, Alcoa sold 25,000 allowances at a comparable rate, and more trades are in the pipeline. In addition, the Commodities Future Trading Commission approved the Chicago Board of Trade (CBOT) proposal for a futures and cash market for SO_2 allowances; trading is scheduled to begin this spring. The EPA lottery (administered by CBOT) of a limited number of SO_2 allowances begins in March.

SO_2 allowances—each one bearing the right to emit one ton of SO_2— are a homogeneous "commodity" with no physical barriers to delivery (similar to a financial security) and, by Phase II, are allocated to virtually all electric utilities. According to an ICF Resources multiclient allowance study and earlier market analyses, the value of interstate utility trading could exceed $1 billion

Jim McNoe / Unphoto

annually during Phase II. Given the flexibility of spot sales, intrastate utility trades, and allowances that pass hands several times a year, trading could be several times that amount. CBOT has estimated that annual allowance trading will range from $5 billion to $10 billion a year—about the annual trading for wheat.

EPA released its final SO_2 and NO_x rules in November, and the IRS released some rulings on allowance tax treatements. Depending on how utilities view those rulings, it may take a longer time for them to lose their reluctance to trade and for the markets to take root.

Nonetheless, the recent transactions had reported prices of $250–$400 per ton—and that's a range that could provide some utilities with a unique market opportunity. Despite the falling price expectations over the last two

Many consider natural gas to be the winner in the Amendments, but the benefits for that market won't appear until the late 1990s.

years, these prices are probably still higher than the long-run value of allowances. In addition, future environmental legislation (on global climate change, for example) or changes in regulations (controls over SO_2 and NO_x near national parks, for example) drive up risks of low allowance prices. Selling allowances at current prices may be a timely strategy.

Many utilities can offset costs with allowance transactions today:

■ *Buying time.* Of course, a number can purchase allowances in lieu of other costly compliance options. Some utilities in the southeast, for example, are likely to have internal marginal compliance costs approaching or above $1,000 per ton. Why? Allowances are allocated based on the average levels of fossil operation from 1985 to 1987, during which many southeastern utilities operated coal-fired units at relatively low levels as a matter of course. As electricity growth increases, however, these units will see more action—and the utilities, therefore, will work even harder to keep their average emission rates low during Phase II in order to comply. Some might even need to install scrubbers for *low*-sulfur coal.

■ *Taking advantage of surplus.* A number of western and a few eastern utilities have more allowances than their current or likely future emission levels—even before they make further reductions. In general, these utilities have shifted to natural gas since 1985 because of lower costs or very stringent environmental requirements (as in California). Selling their surplus allowances can help offset costs: The estimated 300,000–400,000 annual surplus allowances over the first 10 years of Phase II could generate (at current allowance prices) more than $1 billion in revenues.

■ *Creating allowances by going from oil to gas.* Some utilities can switch from oil-fired to gas-fired generation at a low cost (even a cost savings, in some cases), thereby generating extra allowances for sale. According to its integrated resource plan, Consolidated Edison plans to pursue this strategy. The Long Island Lighting Company has made a similar proposal.

■ *Generating allowances by substitution.* The Phase I substitution regulations also provide a mechanism to reduce net compliance costs. They permit utilities to create allowances (beginning in 1995) at units not affected until 2000. The substitute unit receives allowances based on its 1985 SO_2 rate multiplied by "baseline" fuel consumption. In effect, the utility can generate allowance revenues at a low cost. To the extent that gas costs are cheaper than oil or low-sulfur western coal and gas displaces more expensive high-sulfur midwestern coal, there may even be a cost savings.

In short, utilities can sell allowances and increase revenues, or buy allowances and reduce compliance costs. Further, depending on the ultimate tax and regulatory treatments, allowance revenues could finance scrubbers or other emission-control measures.

But the opportunities to sell allowances at current market prices will be short-lived. Also, the extent to which one can take advantage of substitution plans will decrease over time.

The Low-Sulfur Coal Market

The coal market—for low-sulfur coal, in particular—has gone through many changes in the past several years. During the 1980s, underground coal-mine productivity increased annually at 7 percent per year, even though the growth in coal demand slowed. Average U.S. coal prices, measured at the mine, decreased by about 30 percent. Prices for low-sulfur coal from central Appalachia declined by an even greater percentage, with spot mine-mouth prices for low-sulfur compliance coals—which produce 1.2 pounds of SO_2 for each million British thermal units (MMBtu)—listing at about $23–$25 per ton today.

Even since the passage of the Amendments, low-sulfur coal prices have remained low. Relatively slack demand and competition from western sources (actively considered by utilities as far east as Georgia and New York) have contributed to the depressed prices. Although increased demand should result in some market tightening, ICF Resources contends, competition will be the force to hold down price increases. Further, western railroads, even with greater demands placed on them, likely will not suffer transportation bottlenecks—consider the fact that the major western railroads (Burlington Northern, Chicago North Western, and Union Pacific) plan to make more than $400 million in system investments.

Many utilities have examined the options of using lower-sulfur coal in boilers not originally designed to burn it. For their units designed to burn midwestern or even eastern higher-sulfur coals, utilities have focused particularly on western, subbituminous coals from the Powder River Basin (PRB) of Wyoming and Montana. This option not only provides a way to reduce compliance costs but also (in some cases) could yield net cost savings relative to current coal costs.

Using PRB coal in boilers designed to burn only bituminous coals will generally reduce unit performance and efficiency—low-sulphur coals have lower Btu content and higher moisture. That means more coal volume to produce energy—and therefore the unit often requires greater pulverizer and fan capacity to burn the coal. In addition, coal-handling procedures and equipment could also require modifications.

Utilities have widely considered PRB coal strategies only since 1990, primarily because of those technical concerns. The early engineering studies, too, were conservative regarding the effects of using western low-sulfur coal. Compounding the issue is the fact that during the late 1970s and 80s, many utilities signed long-term coal

TABLE 1

ECONOMIC COST OF A 10 PERCENT DERATE AT A 500 MW COAL UNIT
(Assuming Immediate Replacement Capacity Built)

Capital Cost (50 MW x 500 $/KW)*	$25 Million
Annual Capital Charges	$2.5 Million/year
Fuel Consumed (@ 65% Capacity Factor)	30 Trillion Btu
Cost of Derate	$0.08/MMBtu equivalent

*Cost of replacement capacity

Source: ICF Resources, Inc.

TABLE 2

AVERAGE DELIVERED 1991 SPOT PRICES FOR POWDER RIVER BASIN COAL TO MIDWESTERN PLANTS

Utility	Plant	$/Ton	¢/MMBtu
Kansas City Power & Light	Lacygne	13.78	80.87
Iowa Public Service Company	Neal	12.81	76.27
Iowa Power	Council Bluffs	11.90	71.67
Union Electric Company	Labadie	15.12	87.43
Wisconsin Public Service Company	Weston	19.79	112.86
Illinois Power Company	Havana	21.74	129.61
Illinois Power Company	Baldwin	21.29	121.84
Electric Energy, Inc.	Joppa	14.92	87.85
Northern Indiana Public Service	Michigan City	18.40	108.40
Indiana Michigan Electric	Rockport	18.81	110.48
Indiana Kentucky Electric	Clifty Creek	23.47	132.70
Tennessee Valley Authority	Paradise	19.17	113.14
Consumers Power Company	Cobb	22.19	125.90
Detroit Edison Company	Monroe	17.52	102.51
Ohio Edison Company	Burger	22.77	132.84

Source: FERC Form 423, ICF Resources, Inc.

contracts to mitigate price volatility and supply risks. As a result, some midwestern coal-fired plants are subject to high-sulfur coal contracts and have limited ability to reopen or terminate them. The Amendments have provided the impetus to look more closely at the low-sulfur subbituminous option; in some cases, through force majeure clauses or contract reopeners, they allow a utility to shift to these coals from present contracts.

Some midwestern utilities (Union Electric, Illinois Power, Northern Indiana Public Service, PSI Energy, TVA, and Ohio Edison among them) have tested PRB coals (either wholly or in blends) at boilers designed to use bituminous coals. In general, their results indicate lower capital costs or power-plant capacity derates than those estimated in the engineering studies. For example, while many earlier studies predicted derates of 15–20 percent or more for burning pure PRB coals, actual testing at TVA's Gallatin plant suggested an average derate of about 10 percent; and tests at other utilities show even smaller percentages. Even a 10 percent derate, while significant, still amounts to only about $0.08 per MMBtu equivalent fuel cost, as illustrated by Table 1.

Also, the combination of low relative mine-mouth PRB prices (about $4 per ton at the mine compared to $18–20 for midwestern high-sulfur coals) and competitive transportation rates offered by the railroads (two are vying for the business) has resulted in very competitive delivered prices. In fact, even without its low-sulfur characteristics, PRB coal can be inexpensive in comparison to high-sulfur midwestern coals. Spot prices of PRB coals (see Table 2) for a number of midwestern plants generally range from $0.72 to $1.33 per MMBtu, as compared with delivered high-sulfur coal prices of about $1 to $1.20 per MMBtu.

Finally, tests of PRB coals indicate that burning them could result in lower NO_x emissions. This factor could help offset the costs of meeting the NO_x limits under the Amendments.

Other lower-sulfur options—coals originating from Colorado and Utah as well as central Appalachia—have been available at very competitive prices to date, and many midwest utilities have relatively good access to them, assuring a low-cost compliance option. The combination of these options provides utilities with unique opportunities for leverage on their current high-sulfur coal contracts as well as on renegotiating above-market contracts. Because the Amendments could lead to the termination or renegotiation of many higher-priced contracts and have led to the consideration of other coal sources, plants that are currently captive to specific railroads can even use this leverage to renegotiate their rail contracts as well. Other future options notwithstanding, utilities could reduce their use of these higher-cost plants or buy allowances to avoid using noncompetitively priced coal.

This situation will not last indefinitely, however: Low-sulfur coal markets may eventually tighten, and western rail competition may eventually lessen.

The Natural Gas Market

Many consider that the Amendments' principal winner was the natural gas industry. Yet most of the benefits for this side of the energy business will not materialize until the last part of this decade, as the Phase II SO_2 reductions loom and federal and state governments mandate low-emission vehicles for fleets beginning in 1998 (1996 in California).

Natural gas is expected to gain significant market share anyway—little of the projected demand is related to the Amendments. Many oil-fired plants already have switched to gas or are planning to switch soon. Regardless of environmental impact, utilities will build new gas combined-cycle plants, simply because gas prices are low enough and combined-cycle generating technologies have improved. Overall, U.S. gas consumption should increase from today's 18 trillion cubic feet (Tcf) to 23 Tcf by 2000, a jump of almost 22 percent. That's a turnaround from recent years: Due to sagging prices and lower volumes, gas utility sales sagged from $68 billion in 1984 to an estimated $46 billion in 1990, a drop of nearly 32 percent.

A LOOK AT REPOWERING

In the next 15 years, according to Bechtel Power Corporation, repowering with new combustion turbines or clean-coal technology will be the one of the major keys to containing electricity-generation costs, meeting the Clean Air Act Ammendments requirements, maintaining existing capacity; and even adding new capacity. There are four basic repowering options, which Bechtel reviewed in a recent paper:

- *Gas-fired steam boiler to gas-fired combustion turbine combined cycle system (CTCC):* Adding combustion turbines and heat-recovery steam generators to existing steam boilers could triple capacity. The heat rate typically would decline 35 percent.
- *Coal-fired steam boiler to gas-fired CTCC:* The benefits include the same capacity and efficiency increases as the first option, though the lower prices ofcoal offset some of the savings. True savings stem from emissions reductions and the fact that repowering may cost less than other forms of new or replacement power.
- *Coal-fired steam boiler to circulating fluidized bed combustion system (CFB):* Converting to CFB would not directly increase capacity but would increase efficiency, reduce emissions, and allow the use of lower-grade fuels. It could prove to be an economic replacement option as older plants deteriorate and suffer from low availability.
- *Coal-fired steam boiler to coal gasification combined cycle system:* Tripling the capacity of an older station is the main benefit, along with decreased heat rate and very clean emissions, even from low-grade fuel.

Bechtel emphasizes that the ability to repower is site-specific and that utilities should evaluate all these options on a system basis.

The depressed state of natural gas prices may offer good compliance options for electric utilities. Gas prices in 1991 appeared to have bottomed out at around $1.50 (annual average) per million cubic feet (Mcf), with some significant spot-market strengthening during late 1992 (though the price increases last September were probably temporary). Given favorable long-term contract terms offered by gas suppliers today, electric utilities should look carefully at potential ways to increase their use of gas as part of their compliance plan. There are several possibilities for them to consider:

- *Switching from oil to gas.* As mentioned earlier, electric utilities can, in some cases, switch from residual oil to natural gas at a net cost savings. In most locations, natural gas is competitive with or cheaper than low-sulfur residual fuel oil. Oil units that switch could be substitute units in 1995 and generate extra allowances and extra potential revenue. Also, recent pipeline expansions have directed gas to areas where supplies or transportation competition were limited.
- *Taking advantage of regulatory changes.* FERC's Order 636, when implemented, will make gas transportation capacity much more available to electric utilities.
- *Expanding capacity.* Electric utilities that need new capacity could repower oil/gas steam plants as combined-cycle gas units. (In such systems, the exhaust gases from a gas turbine go through a waste-heat recovery system, which in turn powers a steam turbine—the double-duty increases thermal efficiency.) To the extent that these units could switch from residual oil to gas, utilities can grasp the fuel-price and allowance advantages noted above. In addition, they acquire new capacity at a relatively low incremental capital cost, and plant efficiency significantly improves (generally by about 20–30 percent, though some claims are as high as 55 percent) with significant fuel savings. [See the sidebar, "A Look at Repowering."]

TABLE 3

MARKET SHARE FOR EMISSION-CONTROL EQUIPMENT
(By 1991 Revenues)

Air & Water Technologies	9.2%
Asea Brown Boveri	8.3%
General Electric Environmental	5.7%
Environmental Elements	5.5%
John Zink Company	4.7%
Wheelabrator	4.2%
Babcock & Wilcox	3.9%
Joy Technologies	3.9%
JWP	2.5%
Calgon Carbon	2.5%
SUBTOTAL	50.4%
Others	49.6%
TOTAL	100%

Source: Market Intelligence Research (Mountain View, CA) "The North American Air Pollution Control Technologies Market."

- *Switching from coal to gas.* Generally, because of coal's relatively low delivered fuel price, this conversion is not economically attractive, even when considering SO_2 emission reductions. Natural gas reburning or co-firing, however, provides NO_x reduction benefits and hence potential cost savings. Also, the ability to take advantage of lower summer prices for natural gas can be an attractive option for certain summer-peaking coal-fired units.

Technology Markets

Due to slowing demand in the 1980s, the emission-control equipment industry saw revenues and margins erode. Driven by the Amendments, however, the industry's average annual revenues for stationary sources should be higher (on average in 1990 dollars) by $2.3 billion to $3.4 billion from 1992 to 1995; and higher by $4.2 billion to $5.8 billion annually from 1996 to 2000. This growth adds substantially to the current $2.0 billion to $5.4 billion market.

Quite apart from revenue gains, the Amendments will change this industry in other ways. Notably, the potential customer base will widen. Titles I and III, for example, will extend air controls to some industries—electronics, fibers, and coatings manufacturers, for example—that have not traditionally needed such equipment.

A good number of equipment firms, large and small, will be competing for the new pool of revenues stemming from the Amendments. As indicated in Table 3, however, the industry's top ten players control half of the market—and they're positioned to maintain their current share.

Also, there should not be any concerns about meeting the increased demand for stationary-source control equipment, for three reasons:

- Both large and small firms are already geared up to meet the new and growing demand.
- The slow growth in the last half of the 1980s has left some excess capacity.
- In such markets as SO_2 control equipment, the near-term markets are much lower than anticipated, which has engendered competitive equipment pricing.

Clean-coal technologies also have spurred on new markets. Demonstration programs using retrofit SO_2 or NO_x control technologies—sorbent injection, for example—have shown considerable promise and potentially lower costs than many conventional designs. In addition, the Amendments permit changes in design philosophy, such as the use of a single absorber tower for wet scrubbing systems with no spares, which for conventional systems can reduce the costs per ton of pollutant removed.

The Amendments provide additional allowance incentives for such clean-coal repowering technologies as fluidized bed combustors and integrated gasification combined-cycle systems. Under the Phase II repowering extension provisions of Title IV, units contracting to install clean-coal repowering technologies receive an effective four-year delay (until 2004) in compliance. A unit planning to repower would receive additional SO_2 allowances, permitting it to operate at uncontrolled levels until the completion of the repowering project. Based on nonbinding submissions to the EPA, there is already some utility interest in this program. Several utilities, including American Electric Power and PSI Energy, plan to demonstrate these repowering technologies in the future. Approximately 10 gigawatts of older and smaller units, according to ICF Resources, will likely repower at the beginning of Phase II.

While there is less immediacy associated with advanced emission-control technologies, the electric utility industry should monitor developments closely—new choices could play an important role in Phase II compliance efforts.

Regulatory Treatment of DSM Investments

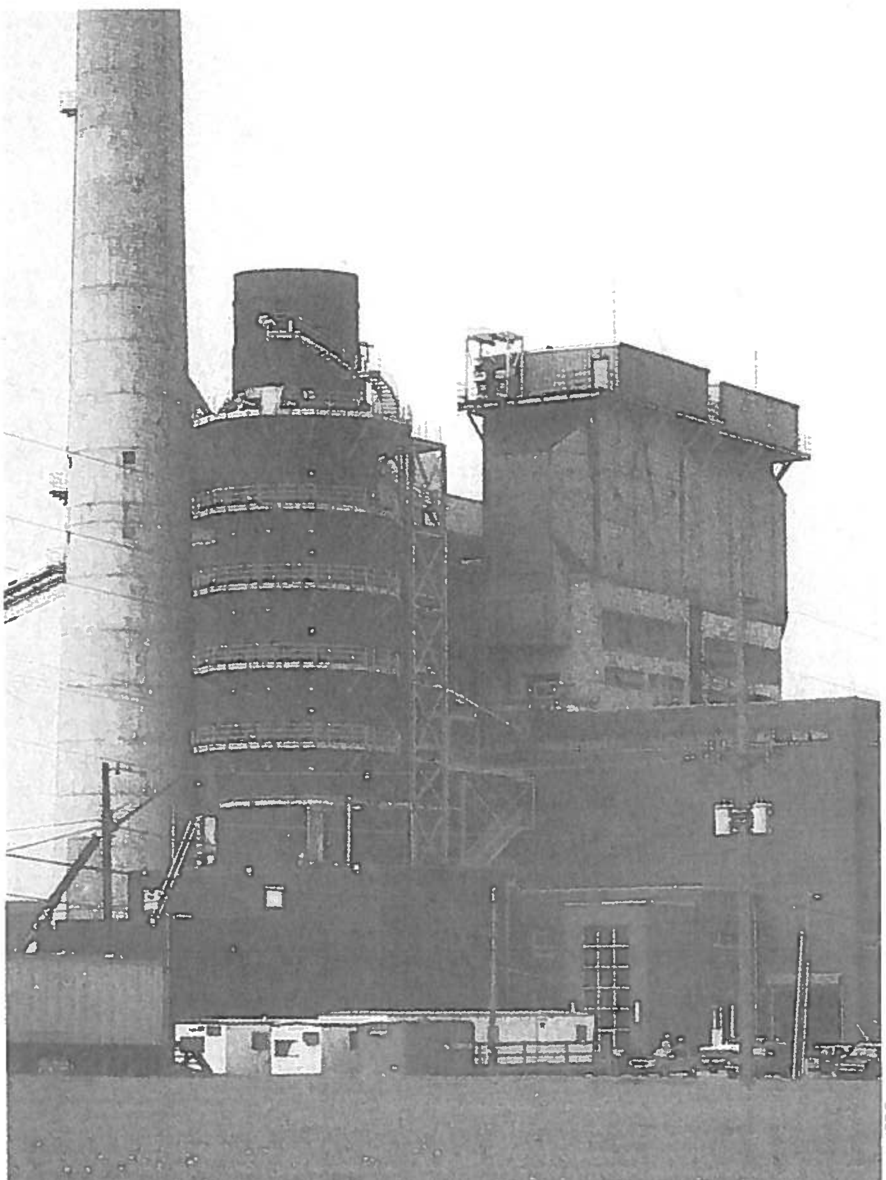
Over the past several years, utilities and regulators have made concerted efforts to reduce or eliminate regulatory disincentives for demand-side management programs (DSM). Nonetheless, many states still have only limited profit incentives associated with DSM—or none at all.

The Amendments provide for some incentives. The amount of SO_2 emissions are largely a function of fossil generation, so programs that reduce that generation (particularly the coal-fired sort) can increase the net supply of saleable allowances. In addition, the Amendments include a reserve of conservation allowances to be awarded to utilities with approved conservation programs based on a set formula and the number of kilowatthours saved. [See the sidebar, "Taking Advantage of Nega-Allowances."]

Neither incentive in itself is likely to provide significant cost savings to utilities pursuing conservation investments. There simply aren't that many incentive allowances, and cost savings associated with DSM still come from the avoidance of new generating capacity. But the Amendments do contain a requirement that all utilities applying for conservation allowances must have a rate structure that "guarantees net income neutrality." The intent of this provision was to "encourage the development of ratemaking frameworks that put conservation on an equal footing with electricity generation." In short, utilities in states without net income neutrality can use this provision as ammunition and work with their commissions over the next several months to develop a better regulatory framework.

Marketing New Technologies

In addition to the near-term revenue-enhancing and cost-reducing options in the allowance, fuel, and technology markets, utilities have longer-term diversification routes—marketing new emission-control technologies, ser-



Courtesy: ICF Resources

Clean-coal technologies are creating new markets. Sorbent injection systems (like this one, with up to 80 percent SO_2 removal) may be an appropriate retrofit for a coal-fired plant.

TAKING ADVANTAGE OF NEGA-ALLOWANCES

The Environmental Protection Agency (EPA) wants utilities to know that they can earn "nega-allowances"—the value of allowances saved by reducing emissions by one ton of SO_2 through conservation and energy efficiency. The Clean Air Act Amendments of 1990 allow utilities to meet SO_2 reduction goals in conjunction with energy conservation programs.

It might seem like sleight-of-hand, but it could be helpful. EPA figures in the reductions in modified total resource cost (TRC) tests, which are often included in integrated resource plans. Once the value of the reduced emissions is quantified and factored in, the cost-effectiveness of a seemingly marginal conservation program can often be highlighted.

The Amendments provide for bonus allowances when a utility adopts a conservation plan; reduced utilization provisions (cutting down on the use of heavy-emission plants) give utilities allowances as well. But nega-allowances through conservation "accrue" automatically after compliance deadlines—the EPA does not require verification of reductions or energy savings derived from conservation programs.

Still, many utilities look on conservation and DSM as having extremely marginal roles in their compliance strategies. As part of its recently filed Title IV compliance plan, however, Centerior Energy Corporation includes a three-year, $35 million commitment to conservation programs for Cleveland Electric Illuminating and Toledo Edison.

Once it's finally passed by the Public Utilities Commission of Ohio, the plan will make Centerior the first midwest electric utility to use DSM as an explicit atmosphere cleanup tool.

At the same time, Centerior has agreed to consider purchasing emission allowances, as long as the prices of low-sulfur coal and allowances themselves are favorable. That breaks ground as well: For all the talk about the allowance market, most utilities have been leery of it. In fact, in a good number of Phase I compliance plans, the strategy of choice has been to build scrubbers, seemingly without much reliance on allowances.

At the October 1992 EEI Financial Conference, Eileen Claussen, director of the EPA office of atmospheric and indoor air programs, exhorted utilities to lengthen their list of compliance options. "Utilities can save hundreds of millions of dollars if they plan right," she said.

"Don't just look at scrubbers or low-sulfur coal," she urged. "Look at the allowance market, at gas cofiring, conservation and demand-side management, and other nontraditional options." Otherwise, a utility plan that simply scrubs or switches coal supplies is half-baked, she concluded.

EPA Administrator William Reilly echoed Claussen's sentiments at the October news conference to release the final SO_2 regulations. "We hope that in the way [utilities] respond to the law," he said, "they do not lose sight of the [market's] very substantial economic benefits."

vices, and expertise developed while complying with the Amendments.

The most promising growth area is the international emission-control market. In Europe, the European Commission has enacted numerous emission directives, which are certain to expand as eastern European countries accelerate the modernization of their economies. The World Bank estimates that it will take $200 billion to arrest eastern European air problems.

The newly industrialized nations of East Asia—South Korea, Hong Kong, Taiwan, and Singapore—also promise growth. Finally, the new North American trade agreement with emission-heavy Mexico may augur a strong U.S. export market.

The Amendments' technology-forcing aspects may represent the U.S. emission-control industry's strongest future competitive advantage. This might just reverse the trend of the 1980s, when firms in Japan and in Europe—responding to increasingly stringent emission-control requirements in their domestic markets—invested in and developed a new generation of emission-control technologies.

The electric utility industry can also participate in international markets through joint ventures, as many utilities are already doing in power projects overseas. In the same manner, they could market emission-control engineering, planning, and other services. New demand- and supply-side process improvements (even energy-efficient light bulbs) could travel abroad as well, especially if they represent lower capital-cost alternatives—particularly important for eastern Europe and Mexico, where capital is relatively scarce.

Choose or Lose

Obviously, electric utilities are aware of the risks in near-term compliance strategies. Capital investments hold more risks than noncapital expenditures—a scrubber investment, most pointedly, is in fact largely irreversible. Thus, if market or regulatory conditions change unexpectedly (if new global climate change legislation reduces the value of SO_2 allowances, for instance), the scrubber becomes more of an albatross than other compliance options, such as expenditures for fuel or allowances.

Banking allowances for eventual sale can be iffy as well—it is possible to buy too many. Banking them is different from (and riskier than) saving them to cover internal needs. Like a financial instrument, they carry market risks. Changes in environmental regulations or market conditions could reduce their value over time. As with other investments, utilities should diversify their portfolios and avoid overinvesting in allowances—they probably should constitute only a small portion of the utility's total financial assets.

But despite the costs, electric utilities must try to take advantage of strategies to reduce them and enhance competitiveness. They need to move aggressively, however, on current market conditions and specific regulatory alternatives, some of which could disappear in just a few years. ◆