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COAL-FIRED POWER PLANT UPGRADES

By A.F. Armor

THE WORLDWIDE STRATEGY IN LAWS AND REGULATIONS FOR THE CONTROL OF POLLUTION CAUSED BY COAL-FIRED POWER PLANTS

By Karl R. Moor

ENVIRONMENTAL CONTROLS FOR COAL-FIRED POWER PLANTS

By Dr. Ian M. Torrens

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INTRODUCTION

This folder contains three papers, two technical and one legal, presented by the World Environment Center sponsored speakers at the "Second International Seminar on Coal and Energy in Poland. The seminar was organized by the Institute for Chemical Processing of Coal in the town of Zabrze, Poland and was held from September 30 to October 4, 1991.

The first technical paper, under the title "Coal-Fired Power Plant Upgrades", was prepared and presented by Mr. Anthony F. Armor, Director of the Fossil Power Plants Department at the Electric Power Research Institute (EPRI) in Palo Alto, California. The second technical paper, entitled "Environmental Controls for Coal-Fired Power Plants", was prepared and presented by Dr. Ian M. Torrens, Director of Environmental Control Systems at the EPRI. The legal paper, under the title "The Worldwide Strategy in Laws and Regulations for the Control of Pollution Caused by Coal-Fired Power Plants" was prepared and presented by Mr. Karl R. Moor, Attorney at Law, of Balch and Bingham Inc. in Washington, D.C.

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COAL-FIRED POWER PLANT UPGRADES

A. F. Armor
Director, Fossil Power Plants
Electric Power Research Institute
Palo Alto, California, U.S.A.

Presented at:

Second International Seminar on Coal and Energy
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COAL-FIRED POWER PLANT UPGRADES

A.F. Armor
Director, Fossil Power Plants
Electric Power Research Institute
Palo Alto, California, U.S.A.

INTRODUCTION

Improvement in availability and efficiency of the more than 1200 coal, oil and gas-fired plants presently in service in the United States is seen as essential if the integrity of electric power supply in the United States is to be maintained through the 1990s. As the research arm of the U.S. utilities, EPRI is devoting considerable resources to this issue.

In the U.S. older plants make up a substantial part of the assets of most utilities, even as the average operating life of these units edges upwards. In fact, more than 1300 fossil units will be over 30 years old in the year 2000, so utility decision makers are seeking to maintain the effective use of these old plants through prudent upgrades

Dominant Issues

Such upgrade decisions must be made against a background in the U.S. which greatly restricts utility flexibility:

1. Not enough new plants are planned in the next 10-20 years to maintain reserve margins, even if no fossil plant capacity is retired. This is likely to lead to more short-cycle, crash options, such as the recent spate of gas turbine orders.

2. Old plants, greater than 30 years in age, can be operated indefinitely, but at progressively lower availability as maintenance demands increase.

3. Old plants are at risk when pitted against new construction since availability and efficiency are likely to be lower. They will also be called upon for more cycling duty further eroding these performance

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parameters. Therefore utilities must make full use of new technology in upgrading existing generation or they will be vulnerable to competition by aggressive independent power producers and co-generators for prime industrial loads.

4. The utility in planning a life optimization strategy must walk the fine line drawn by environmental legislation. In particular, a maintenance plan which triggers New Source Performance Standards can more than double the capital investment required for continued operation.

5. All upgrade decisions must be made in an environment of technical uncertainty. Decisions to replace, or not replace, key pieces of equipment can have far-reaching consequences in terms of future reliability. This implies greater dependency on state-of-the-art life estimation methods and modern decision-making theory.

As fossil-steam units get older, degradation mechanisms such as creep, fatigue, corrosion, and erosion may increasingly appear. These aging mechanisms can cause substantial reductions in plant availability and performance as the unit is operated beyond its normal service lifetime. Therefore, life assessment and refurbishment activities are needed to counteract the degradation of unit performance and ensure continued safe and economic operation of the total utility system.

FAILURE MECHANISMS

As with humans, ideas on plant aging mechanisms have changed over the years. Aging has been defined as accumulated wear due to the effects of creep, fatigue, erosion, and corrosion [1]. A great deal is now known about the rate of aging that was not obvious in the 1950s and 1960s. For example, frequent starting and stopping of fossil units is much more punishing on plant equipment than constant steady-state, base-load operation. This includes not only the fairly obvious mechanical and thermal fatigue problems of material loading and unloading, but also the not-so-obvious effects of boiler tubing corrosion due to excessive infiltration of oxygen into the boiler water during downtime, or the increase of acid deposition in boiler back-end equipment at part load operation. As examples of new design options for major equipment, Table I lists proven upgrades that will enhance the life of old fossil plants, particularly those targeted for cycling. Of all failure mechanisms in coal-fired power plants, the most pervasive, and probably the most costly in terms of availability, are boiler tube failures.

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Boiler Tube Failures

EPRI has identified, and found solutions to 22 mechanisms of tube failure. In a recent project at several U.S. utilities, a determined attempt was made to reduce the unavailability caused by tube failures. Using EPRI prepared guidelines to reduce tube failures an average improvement in availability of about 2% was seen at the participating utilities. A total saving of more than $250 million has been identified and documented. If extended across the U.S. utility industry, an estimated benefit of more than $500 million per year is likely. Below are listed the leading causes of tube failures as seen by these twelve participating utilities. A computerized version of the guidelines, now in use by more than 50 utilities, includes failure analyses, inspection and replacement techniques, and life estimation procedures. It is called the Boiler Maintenance Workstation (BMW).

Leading Boiler Tube Failure Mechanisms (1986 - 1988)

Rank	Mechanism
1	High-temperature creep
2	Fly ash erosion
3	Short-term overheating
4	Sootblower erosion
5	Welding defects
6	Waterwall corrosion (fireside)
7	Corrosion fatigue
8	Falling slag
9	Thermal fatigue
10	Vibration

REMAINING LIFE AND EARLY WARNING OF FAILURE

A knowledge of the remaining life of vital components permits rational decisions to be made on *when* and *how* to next inspect. This is particularly an issue for plants with severe start-stop duty or load cycling. Failure events far in the future are often quite speculative, and need only be known on a scale of years. As events move closer to the present, we enter the monitoring and diagnostics domain, where end of life must be defined to within months or weeks. Very near the present we are in a domain where decisions must be made within days, hours, or minutes. Finally, of course, past events are in the failure analysis domain.

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TABLE 1

EXAMPLES OF DESIGN AND MATERIAL ENHANCEMENTS FOR OLD FOSSIL UNITS

BOILER	TURBINE-GENERATOR CONTROLS	AUXILIARIES AND
Low NO_X, low excess air, and low load burners.	Improved LP turbine blading for better efficiency and reliability.	Improved feed pump designs to avoid fluid flow instabilities.
Variable pressure boilers that improve heat rate and minimize stress	Stronger materials for HP, IP and LP rotors (superclean steels)	Stronger feedwater heaters minimizing thermal fatigue.
FGD systems designed for cycling	Improved seals to avoid rub damage during start-up.	Heat pipe air heaters to improve thermal capability.
Stronger ferritic materials for headers, steam lines, and other thick wall components (super 9 chrome)	Hard particle erosion-resistant coatings for blades and diaphragms.	Startup/cycling advisor to minimize loss of material integrity.
New water chemistry instrumentation and monitoring	Better generator stator bar insulation and stronger end turn bracing.	Adjustable speed drives to improve part load efficiencies

Such plant equipment inspection decisions involve dealing with uncertainty at two levels:

1. The uncertainty associated with basic parameters such as future operating mode, flaw size, or material properties.

2. The uncertainties of the risks associated with poor decisions, impacting economic or safety goals.

Traditionally, such uncertainties have been dealt with by introducing heuristic "safety factors" that tend to provide large safety and operating margins. But this leads to a degree of conservatism that is often inconsistent with maximum utility and productivity of the plant. For example, consider a rotor containing flaws. Early in its operation, the question of whether its ultimate time to failure

is 40 or 60 years, appears almost irrelevant, especially if the plant operating life is expected to be 30 years. After 30 years of operation, this same uncertainty is vitally important when contemplating operation for another 20 to 30 years. At this point, or before, the owner can begin to take steps to reduce the uncertainty by increasing the frequency of inspection, or by periodic or continuous monitoring and diagnostics. Such reductions in the uncertainty of ultimate failure can extend the period of safe operation of the rotor, increasing its economic value to the owner.

Predicting Remaining Life

Several issues have emerged in utility application of the new life assessment methods [2] **First**, the accuracy of the remaining life estimate is often limited by a lack of knowledge of the as-built condition and operating history of the plant. **Second**, engineers have to make difficult and potentially expensive decisions about the quantity of inspection data needed for an accurate life estimate. **Third**, the life-limiting mechanism must be known if the remaining life is to be estimated accurately. **Fourth**, despite the advances in the field, there are still uncertainties associated with life assessments. Much current work is focused on quantifying the uncertainties and the development of probabilistic life assessment techniques, which are useful in making run/repair/replace decisions and in integrating life assessment methods into an overall plant maintenance strategy. Figure 1 lists life assessment tools developed recently by EPRI.

DIAGNOSTIC MONITORING

Utilities will increasingly turn to a rapidly developing technology, which permits older cycling units to operate without lengthy outages for major failures This is on-line monitoring for mechanical diagnostics. [3] As figure 2 shows, work at EPRI in diagnostics covers all fossil plant equipment, the goal in most cases being to detect incipient damage in advance of major failure. If equipment damage can be handled by normal maintenance, the huge costs of a forced outage can be avoided. According to the chart, signals from equipment may be just a few Hz (as in chimney and cooling tower vibration) or can be in the ultrasonic bands or beyond to the infrared, ultraviolet, X-ray and gamma ray bands. The entire electromagnetic spectrum can be utilized, the key elements being (1) on-line sensors, (2) data reduction software and (3) microprocessor. Although much has been achieved in diagnostics, many opportunities still remain in this field, and the successful utilities of the future will be able to plan maintenance and upgrade activities based on a day-to-day knowledge of machinery condition. Such a predictive maintenance strategy, based on a complete network of diagnostic monitors, has been developed at the EPRI/Philadelphia Electric diagnostic monitoring center located at the PECo Eddystone plant (figure 3).

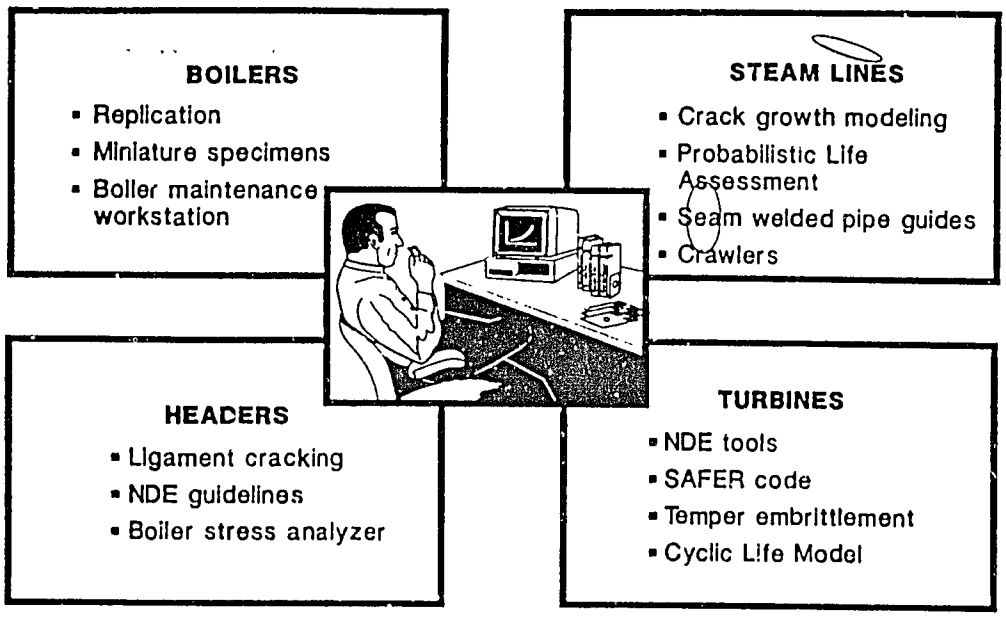

Figure 1. Life assessment tools for fossil plant equipment.

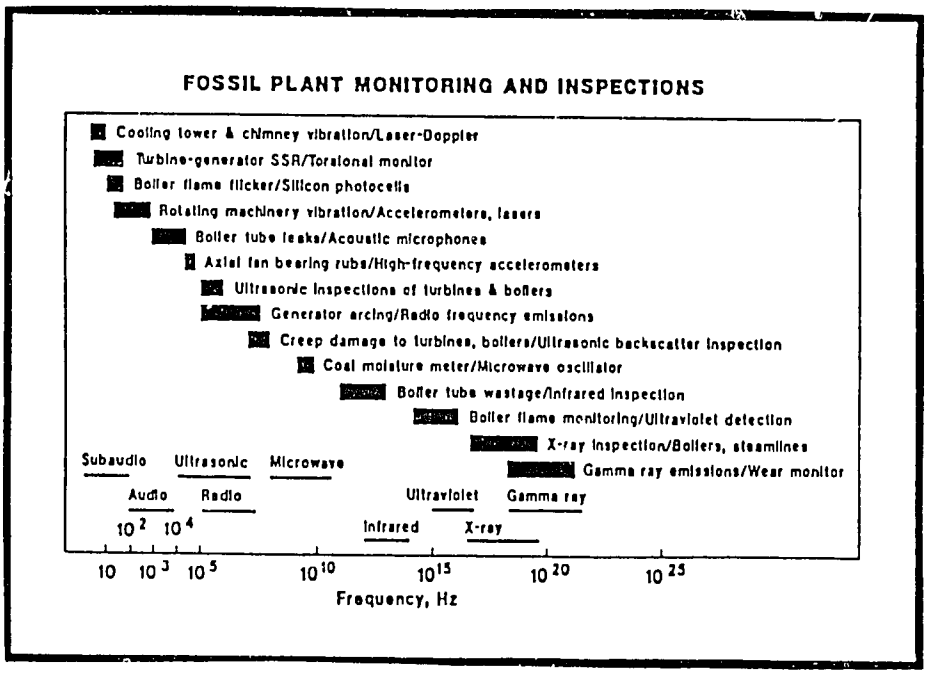

Figure 2. Diagnostic monitoring of fossil plant equipment covers the entire electro-magnetic spectrum. Signals range from a few Hz to the far end of the spectrum in the gamma ray band.

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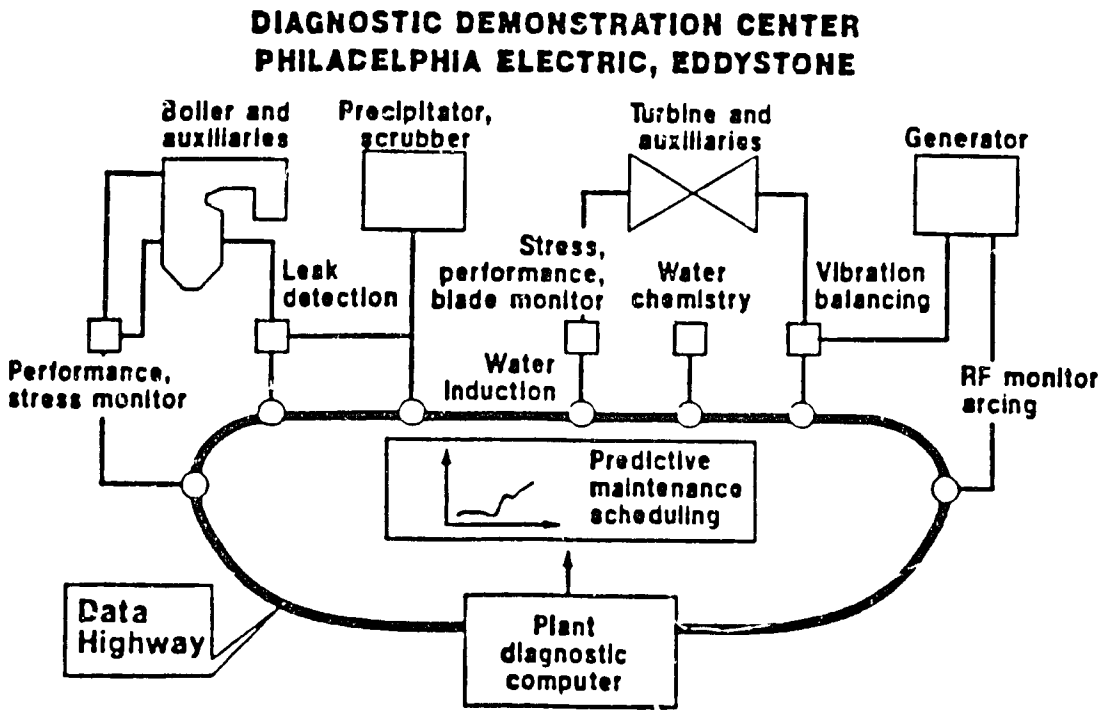

Figure 3. A data highway at Philadephia Electric's Eddystone plant ties together separate monitoring systems for boiler, turbine, generator, environmental controls, and balance-of-plant equipment.

Three diagnostic monitoring areas are particularly well advanced and are recommended for all fossil units: vibration signature analysis, boiler tube leak detection, and thick wall stress analyzers (see Figure 4). Many others have produced valuable savings in plant downtime for U.S. utilities, as noted in Figure 5. Opportunities for new on-line monitors still exist, as shown in Table 2.

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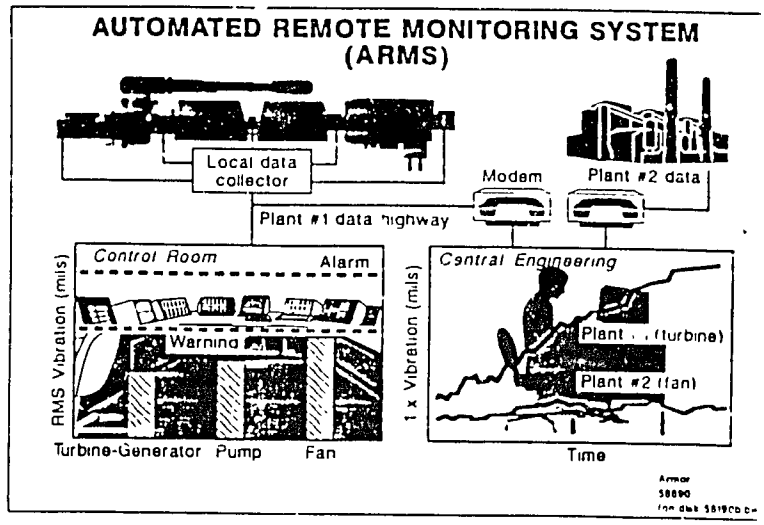
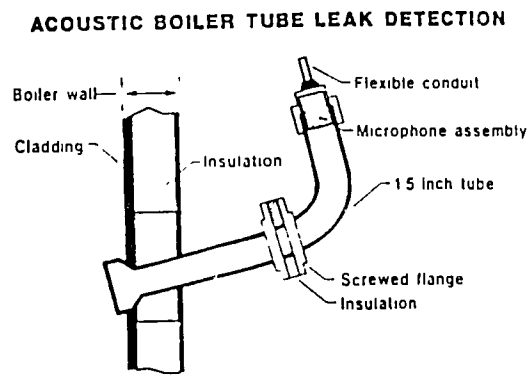
- **Rotating Machinery**

  This technology is now sufficiently advanced that detailed diagnoses of progressive damage in rotating machinery can be made routinely (from a central site). Thus power plants at long distances can be monitored by engineers from head office, as well as locally by control room personnel



- **Boiler Tube Leaks**

  Many fossil boilers are now equipped with acoustic listening devices that detect small leaks in water-wall, superheater, reheater or economizer tubes. About a dozen sensors per boiler will permit damage to be confined to a single tube, while maintenance can often be scheduled for a convenient weekend outage



- **Boiler Stress Analyzer**

  This on-line monitor tracks creep and fatigue damage to headers, steamlines, drums or other thick wall components Episodes of high temperature or high temperature difference result in microscopic material damage which the analyzer evaluates and accumulates Such devices permit boilers to be operated in a way that minimizes damage and extends life

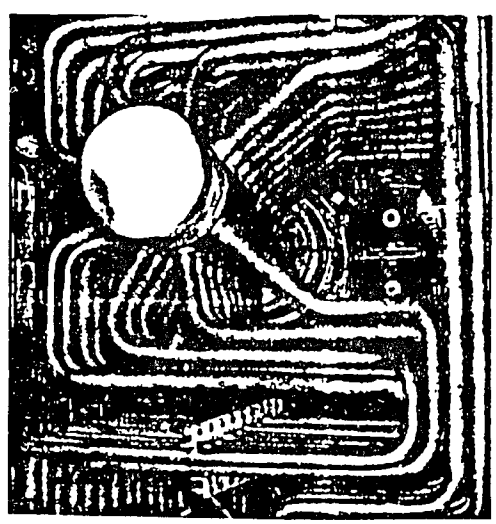


Figure 4. Three examples of diagnostic monitors

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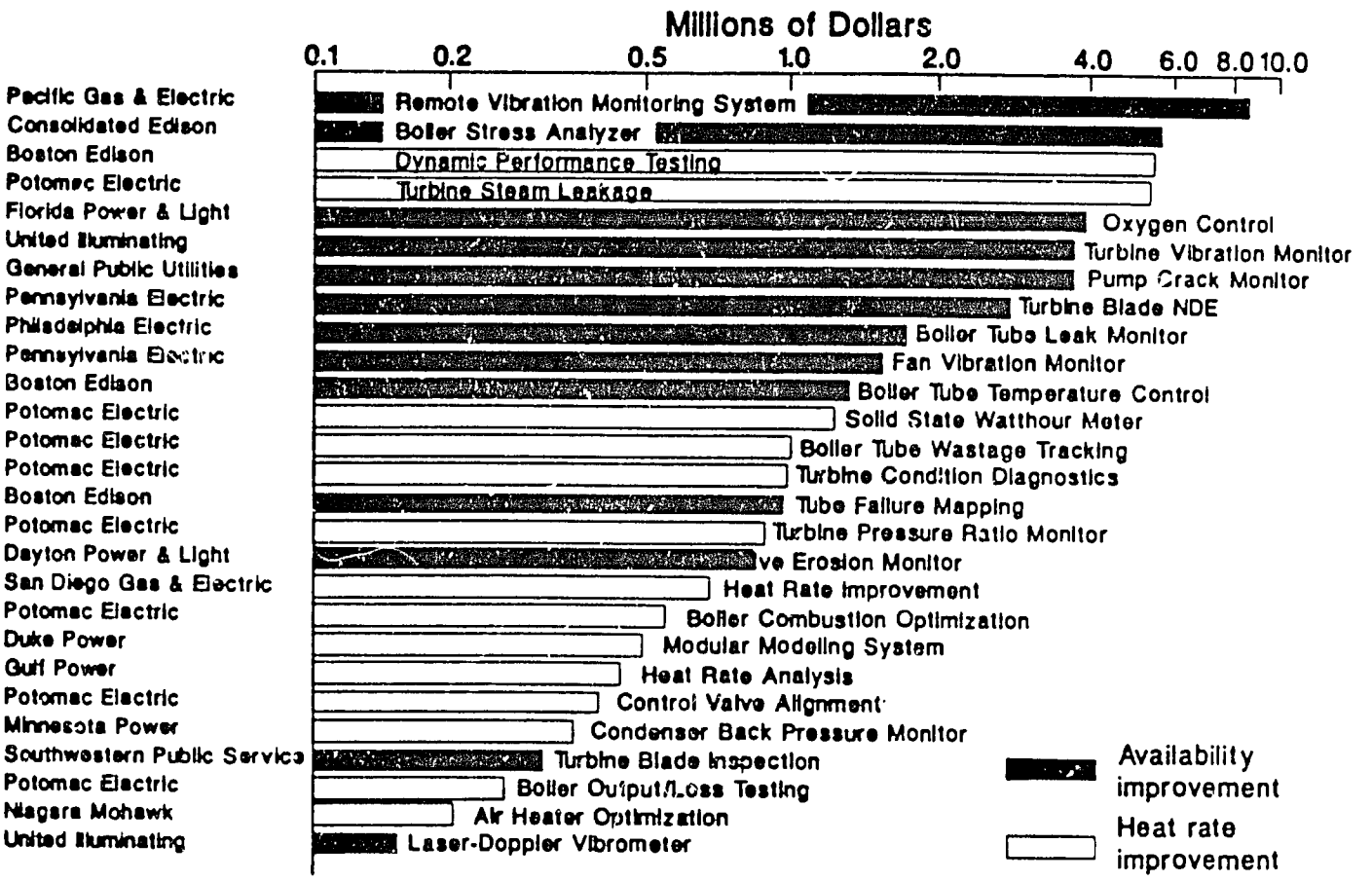

Figure 5. A sampling of the value of EPRI diagnostic monitors to U.S. utilities. Benefit/cost ratios often exceed 10:1 as utilities enthusiastically embrace the new computer-based diagnostic approaches.

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TABLE 2: OPPORTUNITIES FOR NEW ON-LINE MONITORS (NONE YET IN COMMERCIAL OPERATION)

- Direct monitoring and measurement of creep damage in thick wall boiler and turbine components
- Detection of coal ash corrosion of superheater and reheater tubing
- On-line monitoring of acid deposition and corrosion of air heaters and other back-end equipment
- Detection of punching shorts and circulating currents in stator cores
- Monitoring of negative sequence currents and overheating of generator rotor iron
- Tracking of the onset and growth of "alligator" cracking in supercritical boiler water walls
- Detection of the growth and release of exfoliants on the steamside of boiler tubing
- Monitoring of hard particle erosion of turbine blades, nozzles and diaphragms
- Detection of tube leaks in fluidized bed boiler tubing
- Monitoring of creep-fatigue crack growth in steam lines
- Diagnostic monitoring of burner imbalances in boilers
- On-line detection of fouling of cooling tower fills and cooling tower performance deterioration
- On-line monitoring of fouling in condenser tubing

Expert Systems

The origins of expert-systems are outside the electric utility industry, but when applied to power plant equipment the goal is to tap the ability of the computer to store large amounts of "technical know-how," to access this data when needed and to make "intelligent" judgements about likely causes of failure or poor performance.

Particularly for mechanical diagnostics and for efficiency improvement, there is an opportunity to improve plant performance by channeling expert opinions to power plant operating and maintenance people. We are still in the very early

stages of the application of expert systems to power plants, but some utilities, particularly in the failure diagnostics area, are already utilizing these methods. [4]

Expert systems programs cannot replace human experts, but they can complement the decision-making process of an expert and serve as an advisor when expert help is not readily available. The state-of-the-art in expert systems has progressed rapidly in the last five years following initial success in the fields of medicine, weather forecasting, and computer sciences. A number of specific utility applications are underway (Figure 6).

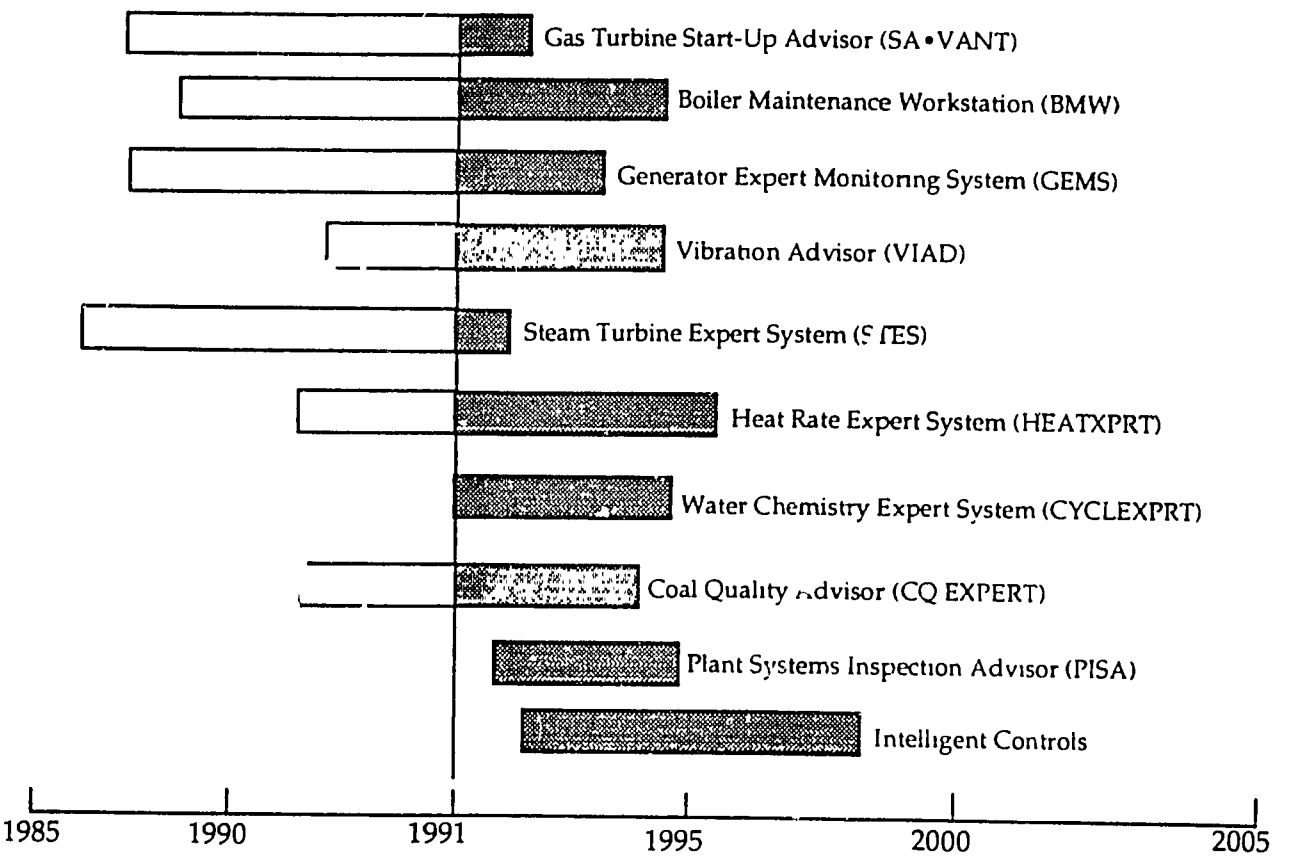

Figure 6. **Several expert systems are being developed for power plants and others are in the planning phase. Data from these early systems will point the way to cost-effective computer-based approaches.**

Plant Control

Ultimately, we anticipate increased computer control of power plant operations. If future problems can be predicted with accuracy, then it ought to be possible to "alter the future" using automated plant control procedures. In aerospace applications direct computer control has long been a necessity as the equipment became more complex. We see a parallel emerging in the utility business.

Power plants are becoming more process-oriented with the increasing complexity of environmental controls. They are likely to become even more so, as the utilization factor of the plant increases and as plant waste products are tapped for valuable raw commodities. Figure 7 describes the historical progress from single-loop equipment control towards such an integrated "coal refinery." Integration of diagnostics with controls is the immediate next step, and EPRI is demonstrating this at the El Segundo plant of Southern California Edison.

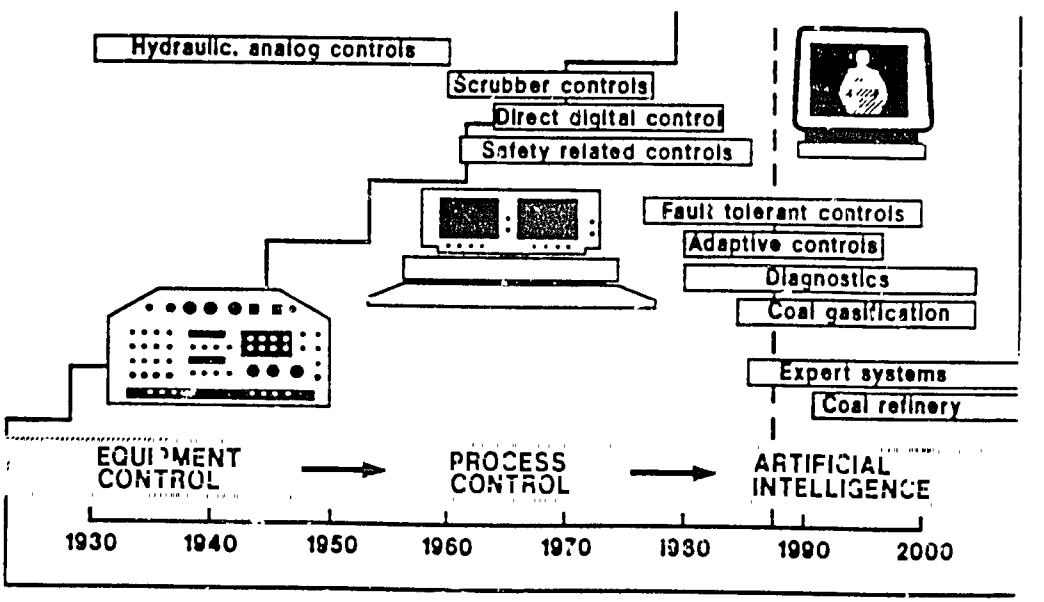

Figure 7. As power plant control procedures moved from controlling individual components to controlling combinations of flowstreams and machines (process control), so control rooms have switched to digital controls and CRT displays. The next step may be the introduction of expert system based algorithms and displays.

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IMPROVED MATERIALS

Working with the world's major suppliers of boilers, turbines and balance-of-plant equipment, EPRI has directed a re-assessment of materials and designs for coal-fired power plants. Particular attention is being given to temper embrittlement, creep and fatigue of headers and turbine rotors, boiler water wall thermal stressing and superheater/reheater coal ash corrosion. [5]

Better materials for new fossil plants, and also for the retrofit of old ones, will be critical if the optimum availability, efficiency and operability are required. Materials are available now that will extend life, will permit increases in steam temperature and pressure and that are fatigue resistant for cycling operation (Figure 8). Improved ferritic and austenitic materials exist for tubing and also for thick wall components. In the latter case, high chrome ferritic alloys have rupture strengths an order of magnitude greater than, for example, P22: 2 1/4 Cr1Mo.

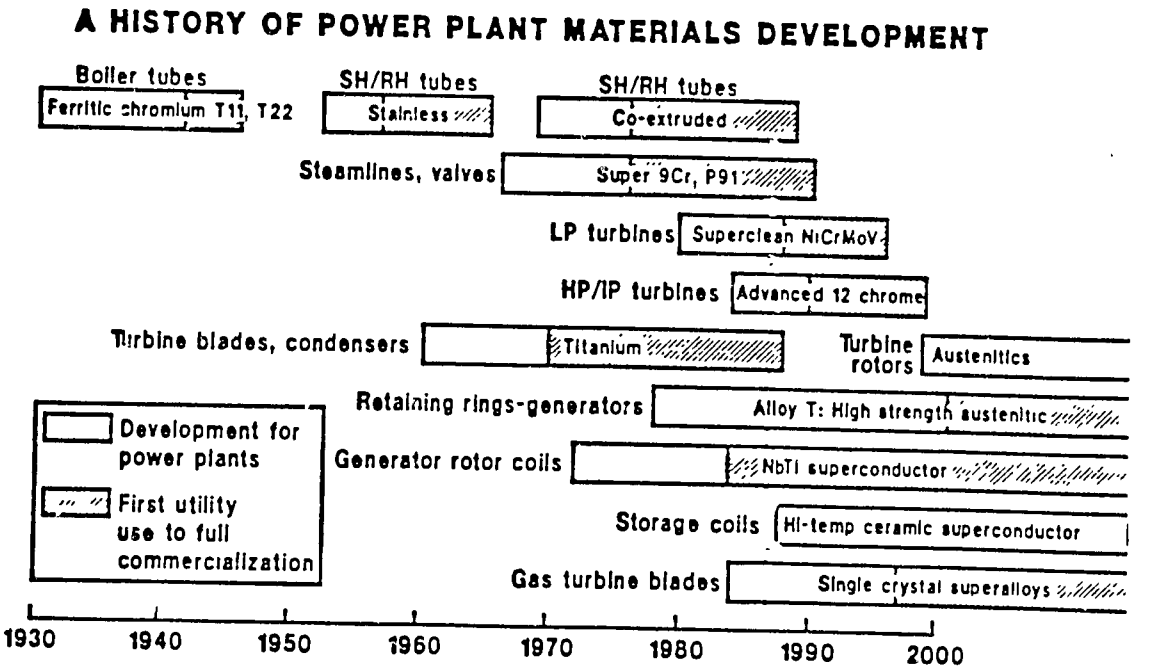

Figure 8. Better materials are now available for cycling fossil plants. These include super 9 chrome steel (P91), which permits thinner sections and lower thermal stresses. It can be used for headers, steamlines, valve bodies and turbine casings.

Of particular note are:

- Co-extruded tubing for superheaters, resistant to coal ash corrosion

- Super-9-chrome steel (P91), for steam piping, valves, headers, casings.
- Improved creep-resistant 12-chrome forgings for HP/IP turbines.
- "Superclean" 3.5 NiCrMoV rotors for LP turbines, resistant to temper embrittlement.

EPRI is working closely with U.S. utilities to retrofit improved materials into existing units. This will permit the industry to quantify the benefits of the retrofit, and thus encourage widespread application of better technology to all the installed generating capacity.

Examples are superclean turbine rotors with Duke Power, Super 9 chrome headers with Lower Colorado River Authority, and corrosion - resistant SH and RH tubing with Tennessee Valley Authority.

HEAT RATE IMPROVEMENT

Improvement of fossil power plant heat rate is a major objective for most utilities. The need to maintain or improve plant efficiency is brought about by:

- Rapidly escalating fuel costs.
- Regulatory incentives for improvement of plant performance.
- Growing heat rate penalties due to backfitted environmental controls, worsening of coal quality and an increase in average age of fossil plants.

Four major reasons for improving plant efficiency are:

- Reduced Fuel Costs. Typically 70-80% of utility operating cost is for fuel. Generally a pass-through cost to electricity consumers, a growing number of state PUC incentive programs seek to establish heat rate targets for fossil plants, which may restrict recoverable costs.

- Increased Capacity. Improved efficiency can often be used to increase the MW output of the unit (for the same fuel input). EPRI studies have shown a $1.8 billion advantage to the industry over 5 years if a one percentage point efficiency improvement can be applied in this way to baseload coal-fired power plants.

- Reduced Emissions. Plant emissions, including NO_x, SO_2, CO_2 and particulates are all reduced in proportion to heat rate as a consequence of burning less fuel per MW output.

- Reduced Cost of Emissions Control. Up to 40% of the cost of a new coal-fired unit is for the environmental control equipment. As plant retrofits in this area continue, size (and hence cost) reductions can be realized by improved plant heat rate.

Performance Monitoring

The on-line detection of deteriorating heat rate, called performance monitoring, is a rapidly growing technology in utility fossil plants. Since 1982, EPRI and Potomac Electric (PEPCo) have been developing and testing better instruments and sensors at the 575 MW Morgantown 2 unit. This coal-fired, supercritical unit is the site of the most advanced performance monitoring system in the U.S. Below are two examples of the work at Morgantown. [6]

Boiler Combustion Optimization Working with PEPCo, Combustion Engineering and Lehigh University, EPRI has successfully introduced a boiler combustion optimization program called HEATRT. With this program and using both special instrumentation and standard sensors, utilities can tune the boiler system so as to improve boiler efficiency and unit heat rate. To do so, utilities must have a means of methodically balancing many interdependent boiler parameters that govern unit performance. These include excess oxygen coal fineness, unburned carbon, exit gas temperature, fan and pulverizer power, auxiliary steam, and reheat spray flows.

One area of particular concern is the degree of acid deposition at various excess air levels. Figure 9 shows measured values of SO_3 deposited on the air preheater gas inlet duct.

Field tested and calibrated the program is now being used to establish optimum boiler settings for Morgantown 2. Already the program has allowed PEPCo to lower excess oxygen by 1% at this unit.

Reduced oxygen decreases SO_3 generation and may allow lower stack temperatures without increased pluggage of corrosion. Each temperature drop of 1°F in exit gas will produce a heat rate saving of about 1 Btu/kWh and PEPCo estimates a possible reduction of 45° F, roughly 45 Btu/kWh (11.3 kg cal/kWh) (in addition to the 15 Btu/kWh (3.8 kg cal/kWh) savings due to lower excess oxygen). The equipment covered by this computerized optimization procedure is shown in Figure 10. Once the set values of the parameters have been determined for a unit, an on-line performance monitor can track any perturbation of unit behavior.

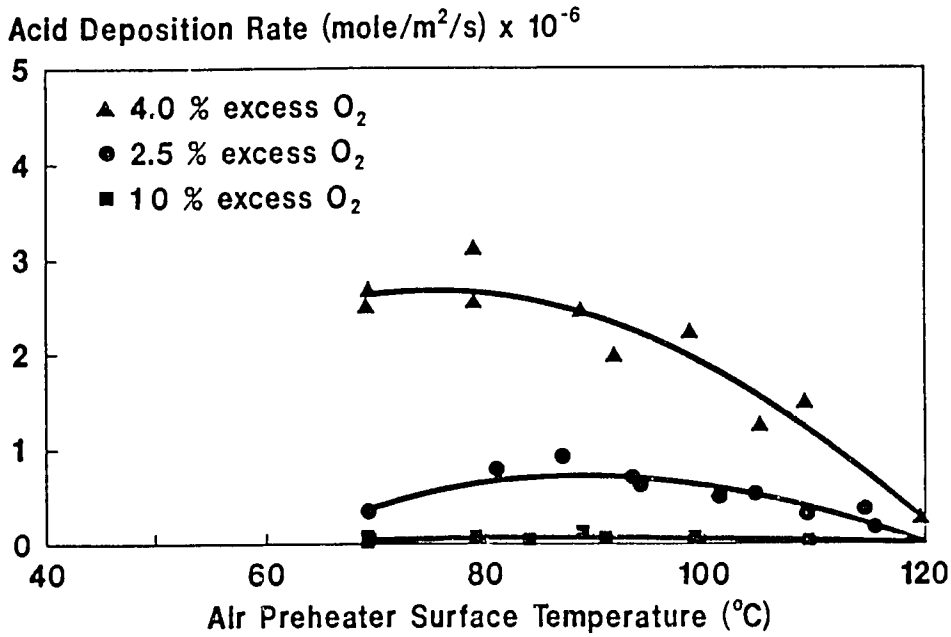

Figure 9. Potomac Electric, Morgantown 2 acid deposition on air preheater. These measurements permit exit gas temperature and excess air level to be selected for optimum performance.

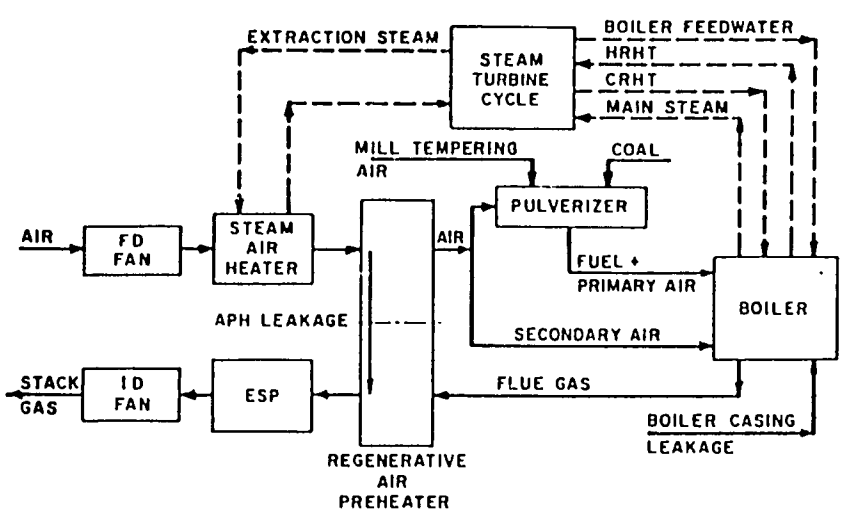

Figure 10. Potomac Electric, Morgantown 2, boiler combustion optimization program. Within the box, operating parameters are balanced for best performance.

Turbine Condition Diagnostics A performance monitor has been developed to track damage in HP/IP and LP turbines. Turbine thermodynamic data are used to infer the existence of degraded turbine components. This monitor therefore differs from mechanical diagnostics, commonly based on vibration or wear measurements. EPRI, PEPCo and Power Technologies, Inc have introduced a procedure based on measurements of steam flow, pressure and temperature as shown in Figure 11 (for the HP/IP turbine).

Using these measurements, it is possible to calculate on a continuous or periodic basis, section efficiencies, seal leakage flows and stage pressures. In turn,this permits a utility to track nozzle wear (due to hard particle erosion) and the condition of diaphragms, packings and blades. Using this monitor at Morgantown, PEPCo is able to plan and schedule turbine maintenance including the timely ordering of expensive long lead-time items.

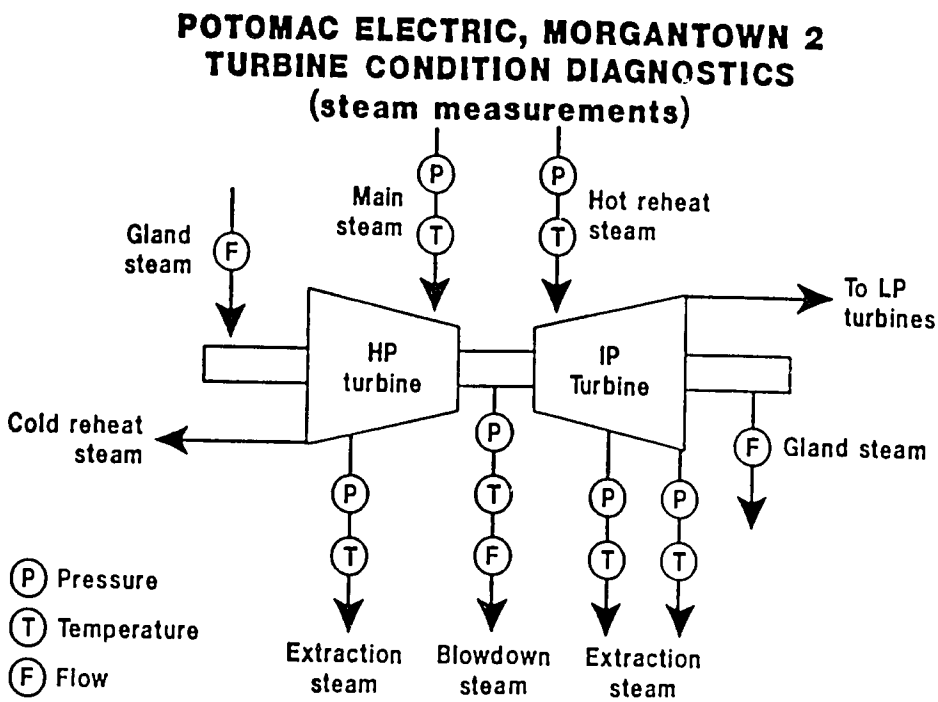

Figure 11. Steam measurements for the HP/IP turbine permit the calculation of section efficiencies, seal leakage flows, stage pressures.

NEW PULVERIZED-COAL PLANTS

There has been a perception that the pulverized-coal power plant has come to the end of the road, that advanced coal technologies will quite soon obsolete the PC plant with a scrubber, whose efficiency hovers around 35%. This perception may be premature, although the goal of a coal-based generating plant with near zero wastes and efficiency approaching 50% is technically possible within a 10 - 20 year time span.

There is good reason why the PC plant is still the primary choice of many utilities. First scrubbers have proved to be more reliable and effective than early plants indicated. Up to 99% SO_2 removal efficiency is possible. By the year 2,000, 60GW of U.S. coal-fired generation will likely be equipped with FGD systems. Second, the PC plant has the capability for much improved heat rate (about 8500 Btu/kWh, 2142 kg cal/kWh) even with full flue gas desulfurization. Worldwide, particularly in Japan, the trend has been to high efficiency, supercritical units, as table 3 indicates. Beyond these units, the PC-fired combined cycle with topping turbine (figure 12) has a projected heat rate of 7200 Btu/kWh, (1814 kg cal/kWh) which includes full scrubbing capability. Third, the PC plant is a proven, reliable power source with unit capabilities demonstrated up to 1300 MW using a single-shaft steam turbine. As for the currently installed generation, EPRI demonstration projects have shown that a 2-3% improvement in heat rate is possible at many existing fossil units (figure 13). Work at EPRI to support utilities considering conventional PC-fired units is focussed on the state-of-the-art power plant (SOAPP). This plant, commercially available now, uses steam at 4500 psig (31.0 MPa) and 1100°F (594°C), all ferritic materials for major boiler and turbine components, leading edge technology in environmental controls, and the latest techniques in waste heat utilization. It is modular, fuel flexible and designed for on-off cycling capability. The attributes of SOAPP are:

- 8500 Btu/kWh net heat rate (2142 kg cal/kWh)
- 85% equivalent availability
- Low load capability to 15%
- Compliance with environmental regulations
- 24-month construction time from first concrete
- Less than $1400/kW capital cost
- Less than $50/kW-yr non-fuel O&M

Table 3. High efficiency fossil plants overseas utilize supercritical pressures and higher steam temperatures.

Utility /Plant	MW	Steam Conditions psi, °F, °F	Year
Kyushu/Matsuura	700	3700-1000/1050/ ---- (25.5 Mpa - 538C/566C)	6/89
EPDC/Matsuura	1000	3700-1000/1050/ ---- (25.5 MPa - 538C/566C)	6/91
Chubu/Hekinan	700	3700-1000/1050/ ---- (25.5 MPa - 538C/566C)	9/91
EPDC/Wakamatsu	50	5250-1200/1100/ ---- (36.2 MPa - 649C/594C)	9/91
ELSAM/Esbjerg	400	3700-1040/1040/ ---- (25.5 MPa - 560C/560C)	6/92
Chubu/Kawagoe (gas/oil)	700	4750-1050/1050/1050 (32.7 MPa - 566C/566C/566C)	6/89, 6/90

Net Heat Rates 8200-9000 Btu/kWh
(2066 - 2268 kg cal/kWh)

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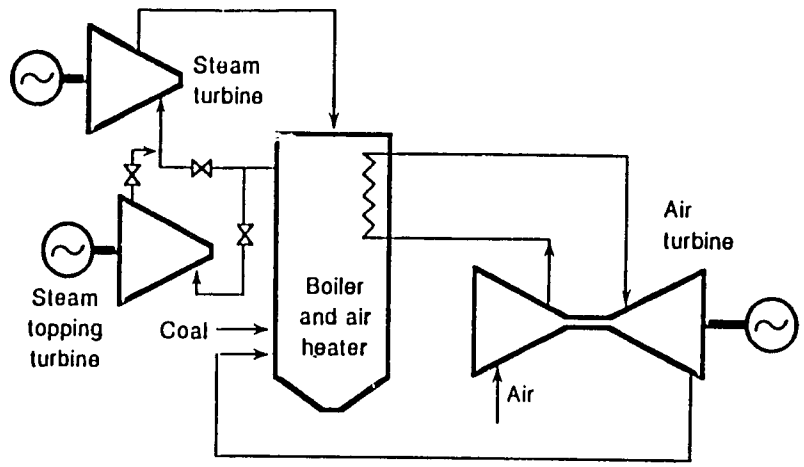

Figure 12. A pulverized coal combined cycle with topping steam turbine has a projected heat rate of 7200 Btu/kWh (1814 kg cal/kWh). The air turbine uses 1800°F (980C) air, or 2300°F (1260C) air with supplemental firing. The topping turbine uses steam at 1300°F (682C).

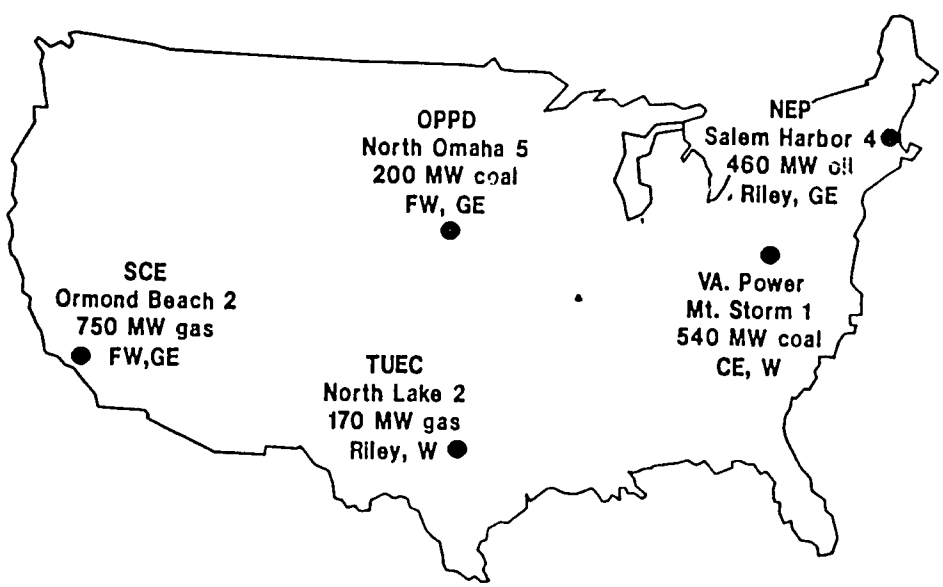

Figure 13. EPRI demonstrations of heat rate improvements at five sites have realized gains up to 500 Btu/kWh (126 kg cal/kWh). On average 200-400 Btu/kWh (50.4 - 100.8 kg cal/kWh) may be cost-effectively recovered by utilities.

EPRI's approach is to produce the design specifications for SOAPP in a format easily accessible to our member utilities. [7] Every major component of the SOAPP plant will be encapsulated in a detailed module which describes the design, materials, cost, and performance of the component. These modules will be accessible electronically by member utilities and continually updated as new data and information becomes available.
The first twelve modules, to be developed in the next 12 months, are listed below. They are the highest priority of the more than 60 modules planned, based on an assessment by the SOAPP utility advisory group:

- Electrostatic precipitators
- FGD systems
- Baghouses - pulse-jet
- Low excess air/low NOx burners
- Steam bypass system
- Steam generator materials
- Water chemistry
- Spiral wound waterwalls
- Turbine rotor materials
- Header type feedwater heaters
- Modular construction
- Adjustable speed drives

SUMMARY OF UPGRADE TECHNOLOGY

Table 4 summarizes some key technologies developed for EPRI which are recommended for upgrading old fossil plants and which found considerable application in the U.S. It is likely that such upgrades will greatly enhance the reliability, efficiency, and reduce the environmental emissions, of old coal-fired plants worldwide.

CONCLUSIONS

Advances in component designs and materials, and in diagnostic and life estimation procedures, have enabled U.S. fossil plants to continue to operate in an reliable and profitable fashion. Utilities will continue to turn to modern upgrade technology to preserve the economic life of old coal-fired units. Many of the advanced features have been made possible by recent spectacular advances in microprocessor technology, and all indications are that this will continue apace as ways are sought to preserve valuable power plant assets

Table 4. Technology for Fossil Plant Upgrades

EPRI Technology	Vendors, Contractors	Key Utility Users (U.S.)	Benefits to Eastern Europe Utilities
On-line diagnostic and performance monitors	GE, CE, W, B&W, MTI	PECo, TVA, PEPCo, SCE	Availability, Heat Rate
Component life assessment, NDE, SAFER, BLESS	FW, B&W, GA, GE, FA, Aptech	APS, OGE, CPL, PPL, TVA, PEPCO, HLP	Maintenance, spare parts
Boiler tube failure reduction, BMW	CE, B&W, GP, SWR, Battelle	OH, PSI, VP, TUE, BGE, PPL, SCE, PSO, GP, NEP, OGE, OE	Availability
Heat rate improvement for boilers, turbines, auxiliaries	B&V, PTI, S&W, S&L	PEPCO, TUE, NEP, PSC	Heat rate, emissions, fuel
Plant cycle chemistry instrumentation	S&L, B&W, B&V	OE, Penelec, CIPSCO	Reduced boiler and turbine corrosion
Materials advances for boilers, turbines	JSW, JCFC, Cameron, CE, GE, FE, B&W	LCRA, TVA, DP&L, Duke	Life extension
Turbine blade coatings, designs	GE, W, STI, Lehigh U, FAA	TUE, SCE, TVA, DP&L, PSE&G	Reduced blade erosion/corrosion
Combustion optimization for PC boilers: burner design and instrumentation	CE, B&W, F-W, Lehigh, EPT	PEPCO, NEP, SoCo, PSO, KP&L	Heat rate, emissions, reduced coal effects
Plant controls guidelines, compact simulators	Bailey, ABB-CE, S&L, B&V, W, Honeywell, L&N	SCE, CP&L, Duke, Centerior	Automated plants, fast cycling, training
New designs, and materials for feedpumps, fans, FWHs, condensers, cooling towers, env. controls	Sulzer, GE, Yuba, Senior, Marley	TUE, Con Ed, Minn P, LILCo, TVA, FPC	Reliability, life extension, heat rate
Motor and generator insulation assessment	W, Spectra, GE, IRIS	Delmarva, NiMo, NYPA, Seattle CL	Reliability
Coal cleaning	CQ Inc.	Penelec	Emissions, boiler availability

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THE WORLDWIDE STRATEGY IN LAWS AND REGULATIONS FOR THE CONTROL OF ENVIRONMENTAL POLLUTION CAUSED BY COAL FIRED POWER PLANTS

Presented by Karl R. Moor[1]

Balch & Bingham
1667 K Street
Suite 750
Washington, DC 20006

THE SECOND INTERNATIONAL SEMINAR ON COAL AND ENERGY

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[1] Prepared with the assistance of Miss Jackie Carney.

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THE WORLDWIDE STRATEGY IN LAWS AND REGULATIONS FOR THE CONTROL OF ENVIRONMENTAL POLLUTION CAUSED BY COAL-FIRED POWER PLANTS

The major purpose of this Second International Seminar on Coal and Energy is to share information about how to improve the quality of the environment even as we continue to use coal to produce energy. In this part of the seminar, I hope to explore first, the evolving environmental concerns that prompt emissions controls on coal-fired power plants and, second, to provide an overview of the range of policy tools that governments are using or considering in the effort to address those environmental concerns.

I. ENVIRONMENTAL CONCERNS UNDERLYING CONTROL OF EMISSIONS FROM COAL-FIRED POWER PLANTS

The regulation of emissions from coal-fired power plants is a story that is still unfolding. Early laws in the 1950's dealt with the most obvious problems caused by the use of coal -- smoke or plume blight. Later, in the 1960's and 1970's, individual nations began to take steps to deal with the less obvious problems that result from burning fossils fuels, such as acid precipitation and ozone formation. Understandably, the international community as well grew increasingly interested in taking action against the air pollution that crosses national boundaries, in particular, that group of pollutants that contribute to the formation of acid rain. More recently, on a local and regional level, there are signs that controls may be put in place to reduce the relatively small amount of air toxics produced by coal-fired power plants. In addition, the focus of control efforts is no doubt shifting toward controlling emissions of carbon dioxide (CO_2) that are believed to affect not simply nations or regions but the climate patterns of the entire globe. Below, we discuss, briefly, trends in coas use and then discuss the environmental goals that policy makers are attempting to attain

through emission controls. In the course of that discussion, we attempt to recognize that there are varying degrees of consensus about the need to control different types of emissions from coal-fired plants.

A. Coal is an important natural resource that will certainly continue to play a role in worldwide energy production.

During the 1980's, the annual average growth rate of energy production was 1.9 percent.[1] During that same period, total world consumption of coal remained steady, representing about 27 percent of the world's primary energy consumption.[2] World consumption of coal in 1988 exceeded 92 quadrillion Btu.[3] China and the United States accounted for approximately 21 and 20 percent, respectively, of the total, followed by the former U.S.S.R. at 15 percent. Other major consumers of coal included Poland, India, South Africa, and West Germany.[4]

While not universally the case, coal continues to play a particularly important role in energy production. In the U.S., the United Kingdom, Denmark, and Germany, for example, coal is used to generate over fifty percent of each country's electricity. The simple fact is that despite concerns about the environmental effects of coal use, nations cannot afford to ignore indigenous fuel supplies that may be both plentiful and inexpensive to mine. Moreover, the continued use of coal is in part due to that fact that commercially valuable deposits of coal are found on nearly all continents. Total reserves of anthracite, bituminous,

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[1] International Energy Annual 1989, Energy Information Agency, DOE/EIA-0219(89), February 1991, at ix.

[2] Id. at p. 118.

[3] Id. at p. 69.

[4] Id.

and subbituminous coal are estimated to be about 8.1 trillion metric tons, of which 1.1 trillion tons are known to exist.[5] Of this total, 430 billion metric tons are thought to be recoverable by standard mining techniques. In 1988, the U.S. produced 862 million tons of coal, China 849 million tons, the USSR 585 million tons and Poland 213 million tons. By and large, production follows proven recoverable resources wherein the U.S., the former USSR, South Africa, Australia, Germany, and, again, Poland possess respectively the most reserves. Interestingly, despite the fact that the U.S. produced over one billion tons of coal in 1990, Australia, not the U.S., proved to be the largest world exporter of coal.

B. High level of consensus on the need to mitigate harm caused by emissions of SO_2 and NO_x: forests, water, human health and manmade structures.

Among the most common air pollutants emitted from coal-fired power plants obviously are sulfur dioxide (SO_2) and nitrogen oxide (NO_x). For example, in the OECD countries it is estimated that coal combustion contributes 80 percent of energy-related releases of SO_2, while stationary sources contribute 49 percent of energy-related releases of NO_x.[6] Most nations have taken at least some steps to reduce emissions from a range of sources, including coal-fired power plants. In large part, these efforts have been motivated by evidence that SO_2 and NO_x emissions contribute to a range of environmental problems when SO_2 and oxides of nitrogen are chemically converted into acid rain. While debate

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[5] Figures supplied by the National Coal Association (United States), 1991.

[6] Energy and The Environment: Policy Overview, International Energy Agency, Paris, France, Table I, Importance of Energy Activities in the Generation of Air Pollutants, 26 (1989). The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organization for Economic Co-operation and Development (OECD) to implement an international energy program.

continues in the scientific community about the degree of harm acid rain causes, there appears to be an international consensus, at least on the part of policymakers, that reductions must be made in SO_2 and NO_x emissions to deal with several confirmed and disputed problems:

- the loss of fish in lakes because of the acidity of surface waters, first noted in Scandinavia;[7]
- the effect of acid rain and air pollution on trees and forests;[8]
- the corrosion of historic buildings in urban areas;[9] and,
- suspected effects of acid mists on human health.[10]

During the early 1970's, the Organization for Economic Cooperation and Development (OECD) served as the principal international forum for research, publicity and the development of policy principles and recommendations to deal with acid rain.[11] The OECD, however, lacked legal mechanisms for implementing policies.[12] Further

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[7] Boehmer-Christiansen & Skea, Acid Politics: Environmental and Energy Policies in Britain and Germany, 36 Belhaven Press, London, (1991).

[8] "Acid Rain, Air Pollution, and Forest Decline," Environment and Natural Resources Policy Division, Congressional Research Services, Library of Congress, 1 (Oct. 12, 1990).

[9] "This Common Inheritance: Britain's Environmental Strategy," Presented to Parliament by the Secretaries of State for Environment et al. at 148 (Sept. 1990).

[10] "Clean Air Act Amendments of 1989," Report of the Comm. on Environment and Public Works, U.S. Senate, 101st Cong. 1st Sess., Rep. No. 101-228 at 279 (Dec. 20, 1989).

[11] Boehmer-Christiansen & Skea, Acid Politics, at 25.

[12] Id.

international cooperation was believed necessary and, in fact, developed through the 1979 United Nations--Economic Commission for Europe (UN-ECE) Convention on Long-Range Transboundary Air Pollution wherein 34 nations from Western Europe, Eastern Europe and North America promised generally to reduce emissions and use best available control technology, where economically feasible.[13] Later within the framework of the convention, a number of countries committed to at least a 30 percent reduction in SO_2 emissions in their transboundary fluxes by 1993 compared to the 1980 level (i.e., the 1985 Helsinki Accord) and to make reductions in NO_x emissions under the 1988 Helsinki Accord. A selected review of various national and transnational responses to these acid rain concerns shows that:

> [C]ountries have developed different strategies and policies for the abatement of air pollution from stationary sources. The main methods have been ambient air quality standards, fuel quality standards and emission standards. The latter involves either setting maximum permissible quantities for emissions (such as SO_2, NO_x, and particulates) by facility type or requiring the use of best available control technologies. Some countries have switched to high-sulfur coal, gas or nuclear to diminish SO_2 emissions.... Some countries have set long-term objectives to limit deposition of acid air pollutants, either nationwide or in specified areas[14]

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[13] Id.

[14] Emission Controls in Electricity Generation and Industry, International Energy Agency, III-1 (1989).

These measures, and those outlined below, illustrate a widespread belief in the environmental impact of acid precipitation and the need for increasingly tougher pollution control programs. With respect to NO_x, there is a recognized need to reduce emissions to help control ozone formation. Since, however, automobiles and trucks often represent the single largest source of NO_x, controls on coal-fired power plants for ozone control purposes are not always a primary focus of policymakers.

1. European Efforts

In response to the environmental concerns mentioned above, the 1988 Council of European Communities Directive on Large Combustion Plants established ambitious reduction targets for SO_2 and NO_x reductions at plants of over 50 Megawatts (MW).[15] By 2003, overall emissions of SO_2 in the EC countries are to decline by 58 percent, while NO_x emissions are to decline by 40 percent. Generally, new plants in EC countries will have to rely upon best available technology ("BAT") for reducing NO_x, SO_2 and PM-10.

Consistent with the EC Directive, Britain -- in which over 70 percent of SO_2 emissions come from power plants -- has taken 1980 emission levels as its baseline and made a legally binding commitment to reduce emissions from existing plants by 20 percent in 1993, 40 percent in 1998 and 60 percent in 2003.[16] In addition, Britain will rely to a degree on low-Nitrogen oxide burners to reduce NO_x emissions from existing plants 15 percent by 1993

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[15] Council on European Communities Directive on the Limitation of Emissions of Certain Pollutants into the Air from Large Combustion Plants, 24 November 1988 (88/609/EEC-OJ L 336, 7 December 1988).

[16] "This Common Inheritance: Britain's Environmental Strategy," at 149.

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and 30 percent by 1998.[17] Over the next decade, Britain will invest over 6 billion pounds in control equipment for old and new plants to meet these commitments.[18]

Germany is considered one of the "green" states of Europe[19] based upon the fact it has imposed comprehensive and stringent environmental controls on emissions of SO_2 and NO_x from energy sources, including coal-fired power plants. German law generally requires sources to install best available technology to control emissions. Regulations implementing the law establish ambient air quality standards and emission limits for existing and new power plants.[20] Using a command and control approach, each power plant must adhere to the applicable standard. As noted by one set of authors, "[t]he German air-pollution control system is considerably more legalistic, with requirements specified in great detail for a limited number of largely technological objectives."[21] The Federal Immission Control Act of 1974 establishes the general framework under which the Federal government could, through the Federal Interior Ministry, establish regulations for controlling emissions, including those from coal-fired power plants.[22]

For example, SO_2 emissions have been regulated under the Large Firing Installation Regulation of 1983, which requires units larger than 300 MW to install flue gas

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[17] Id. at 150.

[18] Id. at 149.

[19] Boehmer-Christiansen & Skea, Acid Politics, at 287.

[20] Technical Instructions on Air Pollution Control (TA Luft) 1974, 1983 and 1986.

[21] Boehmer-Christiansen & Skea, Acid Politics, at 179.

[22] BImSchG.

desulfurization (FGD) devices capable of 85 percent removal of sulfur dioxide, and units with 100 to 300 MW capacity to install partial FGD devices.[23] Under this regulation, existing units must have been retrofitted by 1988; those units which were not retrofitted due to costs or age must be phased out by 1993. Not surprisingly, the use of FGD is significant in Germany -- for 40 percent of Germany's existing coal capacity, FGD is under construction or already in place.[24] Germany's efforts to control SO_2 have largely been successful; by 1990, electricity producers had exceeded the goal of obtaining a 75 percent reduction by 1993.[25]

Unlike their counterparts in the United States, German power producers must rely upon selective catalytic reduction (SCR) for the control of NO_x. Germany's NO_x limitations, the strictest in Europe, make the use of SCR essential.[26] These strict standards were established by Permanent Conference of Lander Ministers (representatives of the states of the Federal Republic) in 1984. The Ministers tightened the standards for new large plants (over 300 MW) and required existing plants to meet those standards at the earliest date possible.[27] By 1993, SCR technology is slated to be installed on 30,000 MW of hard coal-

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[23] International Energy Agency, Emission Controls, Annex 2.

[24] Id.

[25] By 1988, FGD had been installed on 26,000 MW of hard coal-fired capacity and 10,000 MW of brown coal-fired capacity. On the other hand, 12,500 MW of small hard and brown coal-fired capacity had been shut down. Boehmer-Christiansen & Skea, Acid Politics, at 200-201

[26] International Energy Agency, Emission Controls, Annex 2, Table 2.

[27] Id.

fired capacity.[28] On the other hand, brown coal-fired facilities may use combustion modification techniques or devices to reduce emissions of NO_x.[29] As the result of these efforts, Germany expects a 70 percent reduction in NO_x from utilities.[30]

Poland, of course, has established priorities that would reduce SO_2 emissions by 30 percent as compared to 1980 levels and reduce NO_x emissions by 10 percent. Other eastern European nations, such as Hungary and Czechoslovakia, have or are considering similar goals given that they face serious air pollution problems caused by SO_2, NO_x and particulates. As you know may know, 44 percent of Hungary's population (including 65 percent of city dwellers) is exposed to such pollution (Orosz, 1990). Thus, for example, Hungary has committed itself to reducing air pollution at existing power plants through modifications and imposing tougher standards on new plants.[31]

By some measures, past European efforts to reduce emissions of NO_x and SO_2 have paid off. For example, the Final Report on the Second Phase of the Dutch Priority Program on Acidification, released this year, reports that acid deposition in the Netherlands decreased by nearly 30 percent between 1980 and 1989 as a result of the general decrease in European SO_2 emissions.[32] According to some critics, however, past and current efforts

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[28] Boehmer-Christiansen & Skea, Acid Politics, at 200.

[29] Id.

[30] Id at 201 (citing Financial Times Business Information (26 May 1988), Power in Europe, No. 25).

[31] Draft of Proposals and Projects for Future Cooperation in the Environmental Sector, Ministry for Environment and Regional Policy, Republic of Hungary, Budapest, Appendix C (January 1991).

[32] [14 Current Reports] Int'l Env't Rep., No. 8, April 24, 1991, at 231.

are insufficient to remedy the continent's air pollution problems. The International Institute for Applied Systems Analysis' six year study on acid rain in Europe concluded that parts of central Europe were well in excess of acceptable acid deposition loads, that current European emission goals are inadequate, that the effects of acid rain could be stabilized by reducing SO_2 emissions by 60 - 80 percent (even as efforts to reduce NO_x emissions from nonpower plant sources continue), and that Eastern and Central Europe will need financial and technical assistance to undertake such changes.[33] The United Nation's efforts to update the Helsinki Protocols on SO_2 and NO_x reductions by and large, reflect these goals and the question may only be one of determining how each European nation will meet yet more ambitious reduction goals.[34]

2. North America

In 1980, the U.S. Congress established the National Acid Precipitation Assessment Program ("NAPAP") to conduct a comprehensive 10-year research program to determine whether additional emission controls were necessary to address concerns about acid rain in the U.S. and Canada. NAPAP's Final Report was due in 1990. The U.S. Congress and the President, however, decided that the effects of SO_2 and NO_x emissions were so clear that there was no need to delay action in the U.S. any longer. Thus, Congress passed and President Bush signed into law the Clean Air Act Amendments of 1990.[35] The general contours are as follows: the title is designed to reduce annual emissions of sulfur dioxide in

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[33] Id. at No. 10, 286-7.

[34] Id. at No. 12, 326.

[35] Clean Air Act Amendments of 1990, S. 1630, 101st Cong., 2nd Sess., 104 Stat. 2399, P.L. No. 101-549.

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the 48 contiguous United States by ten million tons from 1980 emission levels. With respect to nitrogen oxides, the Act's goal is to reduce emissions by approximately two million tons from 1980 emissions levels. Under the Act, emissions of SO_2 are ultimately controlled so that emissions from all utilities do not exceed an annual aggregate of 8.9 million tons. To accomplish this goal, the Act provides a two phased program of reductions. For purposes of Phase I, the Act identifies 107 high emitting units -- those emitting over 2.5 pounds of sulfur dioxide per mmBtu of fuel heat input -- and mandates that by January 1, 1995, annual sulfur dioxide emissions from these units be reduced by approximately 2.5 to 4.5 million tons. The emissions limitations in Phase II, on the other hand, capture virtually every steam-electric utility unit in the 48 contiguous United States and effectuate the 10 million ton reduction in annual sulfur dioxide emissions. Under the Phase II program, after January 1, 2000, utility units may emit no more than 1.2 pounds of sulfur dioxide per mmBtu.[36] In general, affected utility units in the United States during Phases I and II will have new emissions limitation obligations, monitoring and reporting requirements, permitting requirements, allowance allocations, and, excess emissions liabilities. Given the extended period over which reductions will occur, and the fact that science cannot now accurately predict the effects that result from source-specific emissions reductions of sulfur dioxide and nitrogen

[36] Under the new U.S. allowance trading program, individual units will be permitted to emit in excess of the 1.2 pound limit if the unit holds sufficient allowances. Moreover, units that employ designated clean coal technologies would be eligible to obtain an extension beyond the Phase II deadline -- to December 31, 2003. Clean Air Act Amendments of 1990, Conf. Rep. to Accompany S. 1630, No. 101-952, 101st Cong., 2d. Sess., Title IV, Section 409 (Oct. 26, 1990), 42 USC 7651h.

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oxides, the success of the U.S. program will undoubtedly remain an open questions for some time.

3. Asia

Japan has not to date experienced an acid rain problem, in part, because it has for a relatively long period had a system of stringent controls in place under the Japanese Air Pollution Control Act enacted in 1968.[37] Controls are established on the basis of the air quality in a number of polluted and unpolluted regions for both NO_x and SO_2.[38] Most existing coal fired plants and all new facilities are scrubbed and more than half of the coal fired facilities are equipped with SCR.[39] Despite these strict controls, Japan may in the future face an acid rain threat from Chinese and South Korean emissions of SO_2. That fact illustrates why nations have looked to international bodies and agreements to limit transboundary pollution, for Korea itself views Chinese emissions with alarm.[40]

C. Growing concern over emissions of air toxics (metals and the like).

Some have labelled toxic trace emissions as "nontraditional" pollutants because, unlike SO_2, NO_x, CO, and lead, toxic trace emissions from coal-fired plants have neither been extensively studied nor widely regulated.[41] As you know, however, the combustion of

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[37] Emission Standards for Major Air Pollutants from Energy Facilities in OECD Member Countries, OECD, Paris (1984) p. 18.

[38] International Energy Agency, Emission Controls, Annex 2.

[39] Id.

[40] Int'l Env't Rep. (BNA), Ref. File, South Korea, 288:0101 (Nov. 1990).

[41] The State of the Environment, OECD, 42 (1990).

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coal produces these trace emissions of toxic pollutants. These pollutants can cause birth defects, cancer, hormonal disturbances, and reproduction problems. Utility plant emissions of such substances fall into two major categories: solids found in the flyash portion of the flue gas (like manganese and nickel) and gases vaporized by the high temperature of the flue gas (like hydrochloric acid). The trace metal content and percent ash levels may vary greatly among coals from different regional areas, different mines within a particular region, and different coal seams within a particular mine.

Existing controls may or may not be effective in reducing emissions of air toxics. For example, in the U.S. particulate emissions are regulated by that nation's Environmental Protection Agency and the individual states by limitations on opacity, or density of smoke, and emission rates in lbs/mmBtu. Generally, in order to meet these standards, utilities install electrostatic precipitators with a particulate collection efficiency of ninety-nine percent, which may help reduce significantly trace emissions of air toxics. On the other hand, Czechoslovakian power plants burn brown coal that has a high arsenic sulfide content, and even when a plant has electrostatic precipitators it is capable of emitting a half a ton of arsenic daily (Tichacek & Cikrt, 1990).

Recently, in the U.S., there was intense and bitter debate over whether that country's new Clean Air Act should require further removal of air toxics at coal-fired power plants. Earlier in this decade, the U.S. Environmental Protection Agency had considered the question of whether additional regulation of power plants was necessary to control air toxic emissions in order to protect public health. The U.S. agency studied a number of compounds for which emissions data and some indicator of chronic toxicity exist: arsenic,

beryllium, cadmium, hexavalent chromium, formaldehyde, and radionuclides. The U.S. EPA generally found that with regard to these compounds additional regulation of power plants was unnecessary.

Many in the U.S. disagreed with the EPA's conclusion. Advocates of control pointed out that by virtue of the immense quantity of fossil fuel that must be burned to produce electricity -- several million tons of coal per year for a large coal-fired plant -- aggregate emissions of all such pollutants at a typical plant could well exceed 25 tons per year and, thus, make the power plant a "major source" of pollutants under the bill the U.S. Congress was considering. Of particular concern were emissions of mercury from coal-fired power plants. (Industry had estimated that for an average size electric coal-fired generating unit of 500 MW, about 340 pounds of mercury is emitted annually.) Given deep concerns about air toxic emissions, and mercury in particular, U.S. proponents of regulation argued that utility power plants should be subject to new emission standards -- requiring the installation of emission control devices beyond those required to deal with sulfur dioxide and nitrogen oxides.

In response, U.S. electric utilities argued that since there are no proven and reliable controls available for mercury emissions, the Clean Air bill, as originally drafted, would instead require the EPA to set a design equipment or work practice standard. This, they argued, could mean that utilities would be required to switch to burning natural gas or forced to install baghouses and lime injection technologies in a perhaps fruitless attempt to

control mercury emissions.[42] Forcing utilities away from abundant coal supplies or toward expensive controls without a complete and thorough scientific and technical rationale for controlling mercury emissions or other toxic emissions, utilities argued, would be the height of folly.

Given uncertainties about the availability of cost-effective controls and the lack of evidence about the contribution that utilities make to the creation of a human health problem, the U.S. Congress, in the end, decided that the U.S. EPA, over the next four years, should study air toxics emissions from utilities and the associated health risk. If a public health risk is found to exist, then the U.S. EPA must consider regulating these sources. Several OECD countries, by contrast, have passed legislation to limit emissions of individual trace pollutants that have been shown toxic.[43] Specifically, both Germany and Switzerland have required the use of best available control technology to limit such emissions.[44] On the whole, however, most nation's have not yet taken steps to monitor and control such emissions at coal-fired power plants. If any trend can be identified with respect to controlling these emissions, it would be that policymakers and the public will expect utilities to install controls, even if those controls do not hold the promise of completely eliminating all emissions of and risks from air toxics. Moreover, if the recent debate in the United

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[42] According to a utility industry sponsored cost study by Temple, Barker and Sloane, Inc., the capital cost of installing this control technology on U.S. facilities would be approximately $28.6 billion on a nationwide basis, while it would cost around $5.2 billion annually for those facilities to remain in compliance.

[43] The State of the Environment, at 47.

[44] Id.

States is any guide, this subject, when addressed, will prove contentious given the extremely high costs of control.

D. Relatively low level of consensus on the need to mitigate the greenhouse effects of CO_2 emissions.

A perhaps equally contentious issue is the "Greenhouse Effect;" and, just as concerns about acid rain helped determine the design of coal-fired power plants during the 1970's and 1980's, concerns about global climate change will likely shape the operation of coal-fired power plants in the 1990's and beyond. The reason is clear: the combustion of fossil fuel is the primary source carbon dioxide (CO_2) emissions, as well as other "greenhouse" gases. Moreover, coal combustion is a particular concern because of its high emission intensity (millions of tons of SO_2 produced per quadrillion BTu).[45] As you know, the "global" nature of the perceived climate change problem has stimulated a wide range of responses by environmental groups, national governments and international bodies.

Australia, Austria, Canada, Finland, Iceland, Japan, New Zealand, Norway, Sweden, Switzerland and the members of the European Community have committed to stabilizing CO_2 emissions by the year 2000. The Intergovernmental Negotiation Committee (INC), based upon the work of the Intergovernmental Panel on Climate Change (IPCC), is currently attempting to develop: 1) the necessary commitments for limiting and reducing CO_2 emissions and for protecting and enhancing CO_2 sinks, 2) the means of providing financial and technical support to developing nations, and 3) the legal and institutional mechanisms to enforce commitments. The third session of the INC was just completed in

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[45] "Global Climate Change," Congressional Research Service, Library of Congress, 4 (June 28, 1991).

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September and it appears that a framework for a convention will be ready in advance of the United Nations Conference on Environment and Development (UNECD) in June of 1992.

Proponents of preventative CO_2 controls have argued that industrialized nations should be prepared to reduce emissions by 20 percent to 50 percent from current levels within ten to twenty years.[46] Over time, the United States, the Soviet Union, Saudi Arabia and other oil producing nations have opposed specific targets and timetables for the reduction of CO_2 because of the scientific uncertainties about the nature of the problem, the questionable efficacy of reductions, and the high economic and social costs of controls.[47] Among the OECD countries, the U.S. and Turkey have not made commitments to stabilize or reduce emissions of CO_2. Instead, the U.S. will allow a 15 percent increase in emissions by the year 2000. Other nations have not been so reluctant, arguing that the uncertain state of the science should not be stand in the way of emission reductions immediately since the stakes for the environment are so high. Britain, for instance, has agreed to stabilize emissions at 1990 levels by the year 2005, while Germany plans to reduce emissions 30 percent by that same year.

Unfortunately, removing "greenhouse" gases after combustion is both difficult and expensive. Thus, policies designed to reduce emissions must rely upon increased energy efficiency, conservation, fuel switching, and renewable energy. Control proponents have

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[46] "Global Warming: The Debate - A Presentation on The Economic Debate: Preventative or Curative Action?," D.H. Perlman, The Royal Society, London, at 6 (March 7, 1991). The consensus recommendation of the 1988 Toronto global warming conference was for a 20% reduction compared to 1988 levels in human-sourced CO_2 emissions by the year 2005.

[47] The New York Times, November 5, 1990, at A5.

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suggested a number of means developing policies for reducing or offsetting CO_2 emissions that will be discussed below.

II. THERE ARE A RANGE OF POLICY TOOLS BEING USED TO CONTROL EMISSIONS FROM COAL-FIRED POWER PLANTS

If there is an emerging trend in the control of emissions from coal-fired power plants, it may be that there is growing sophistication in the approach that governments and international bodies are taking to limit emissions. The clearest contrast between the old and new is the movement from command and control toward the use of market incentives and tax policies. In part, innovative market and tax incentives/disincentives may be necessary because as mentioned CO_2 emissions are not as susceptible to traditional standard setting approaches. Below, we discuss generally the use of command and control, technology standards, marketable allowances or offsets, and, briefly, tax policies.

A. The most traditional approach is "command and control" in which uniform standards are promulgated by the government and adhered to by individual power plant operators.

1. Emission standards

As discussed initially, the earliest and still most common forms of air pollution control are requirements to install technology or to adhere to a particular emission rate. Thus, for example, most nations in Europe that have set emission standards have chosen 400 milligrams of SO_2 per normal cubic metre for existing facilities, and even stricter

standards for new facilities.[48] Adherence to these standards implies the use of technology capable of 85 percent to 90 percent removal, on par with flue gas desulfurization.[49] Similarly standards have been put in place for the control of NO_x emissions in both Europe and the U.S. The United States' new Clean Air Act established standards designed to achieve emissions reductions through the application of low-nitrogen oxides burner ("LNB") technology to wall-fired and tangentially-fired steam electric coal-fired utility boilers through a traditional command and control approach.[50] Poland, of course, has set a range of permissible limits on SO_2, NO_x, and dust emissions from coal-fired facilities depending upon the age of the facility and the type of coal used at the facility.[51]

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[48] International Energy Agency, Emission Controls, at III-6.

[49] Id.

[50] One of the major points of contention in the U.S. Congressional debate was whether utilities ought to be required to do more than install low nitrogen-oxide burners. The President's original proposal to the Congress contained an approach to NO_x reductions required utilities to control NO_x emissions through the use of "technology at the performance level of low NO_x burners." Various generations of low NO_x burners (LNB) have been and are being commercially developed and demonstrated for many types of boilers and appear to be a cost-effective and economical way to reduce NO_x emissions. The Senate bill sought to limit NO_x emissions from coal-fired utility boilers to specific numerical standards. It was argued that these standards could double the NO_x reductions sought by the Administration's bill and were so stringent that some sources would not be able to comply through the use of LNB technology. Instead, the use of selective catalytic reduction (SCR) technology could have been required. European experience with SCR did little to allay the concerns of U.S. utilities about the reliability and cost of SCR technology.

[51] Executive Order No. 92 of the Ministry of Environmental Protection, Natural Resources, and Forestry dated 12 February 1990.

2. Best Available Control Technologies

Emission standards, however, are often directly or indirectly determined by the availability of emission control technology, and there are a number of countries that employ so-called direct technology based standards, variously termed the best available, best practicable, or maximum available technology. The New Zealand Clean Air Act, for example, does not set fixed emission standards but requires the application of the "best practicable means" for reducing emissions.[52] This approach is in turn based on the British approach wherein the "best practicable means available" concept:

> ... takes into account a wide range of factors including potential environmental impact, available technology, cost and local circumstances. New BPM notes (or guidelines) for new plants over 700 MW^{th} were issued in 1988. These require 90% removal of SO_2 from flue gas.[53]

Similarly, Norway, in dealing with its few coal-fired facilities, imposes requirements on a plant by plant basis, requiring typically the installation of best available technology.[54] Once again, recent developments in the United States illustrate the extent to which technology based standards can be used to control air emissions.

Prior U.S. law required that nation's Environmental Protection Agency to list as a "hazardous air pollutant" any substance which could be reasonably anticipated to result in mortality or increase serious illness. Once a substance was listed as a hazardous air pollutant, the EPA under the Act had to establish an emission standard to protect the public

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[52] International Energy Agency, Emission Controls, Annex 2.

[53] Id.

[54] Energy and the Environment, at 40.

health.[55] In past years, the U.S EPA, however, had only listed eight such substances (mercury, beryllium, asbestos, vinyl chloride, benzene, radionuclides, inorganic arsenic and coke oven emissions) and issued air emission standards for seven of those.

Title III of the new U.S. Act, however, requires the EPA to list nearly 200 hundred specific substances as hazardous air pollutants and to regulate emissions of those substances through an initial technology-based regulatory scheme to be augmented by a subsequent standard based on health risk. As noted earlier, any facility that in the aggregate emits either (1) ten tons per year or more of any single pollutant or (2) twenty-five tons per year or more of any combination of pollutants would be a "major source" subject to regulation.[56] In addition, the Act permits regulation of an "area source," which it defines as any stationary source of hazardous air pollutants that is not a major source.[57] In the new program, the U.S. EPA will have to establish a list of all major sources of these pollutants and promulgate standards to achieve the maximum degree of reduction in emissions of each air pollutant, relying on the installation of the maximum achievable control technology ("MACT").[58]

Again, MACT or a similar concept may emerge as other nation's attempt to deal with air toxic emissions from coal-fired power plants. Essentially, MACT in the U.S. is the

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[55] Title III, Section 112(d)(1), 42 USC 7412.

[56] Title III, Section 112(a)(1), 42 USC 7412.

[57] Title III, Section 112(k), 42 USC 7412.

[58] As noted, earlier, during the course of the U.S. clean air debate, there was a heated controversy over whether or not electric utility boilers -- which emit a range of substances subject to control under the air toxics titles, including mercury -- ought to be subject to these MACT requirements.

highest degree of emission reductions mandated for a given group of source categories. The MACT standard can require a facility to utilize a wide range of control measures to reduce emissions. For example, a facility may have to install new control equipment, or achieve the necessary reductions through changing the materials being utilized, work practice changes, or, with process sources, tightening controls where leaks frequently occur. For new sources in the U.S. MACT is defined as a quality no less stringent than the emission controls achieved by the best controlled similar source. MACT is defined for existing sources as a standard no less stringent than:

1) For categories having 30 or more sources, the average emissions limit achieved by the best performing 12 percent of the sources; and

2) For categories having less than 30 sources, the average emissions limit achieved by the best performing 5 sources.

In determining the MACT standard for both new and existing sources, technological feasibility and cost are supposed to be considered.

It is generally agreed that fixed requirements for the installation of technology are a blunt policy instrument for controlling emissions. Such requirements may result in the installation of obsolete technology and often do not take advantage of cost effective reductions obtainable by "bubbling" emissions from two or more facilities and reducing emissions where it is the least costly. Concepts like MACT -- which is not a static standard and is supplemented by health-based residual risk standards -- may be used, however, to fill the gap between simple standard setting and market based approaches, especially when emissions are not easily controlled and, generally have more localized effects.

B. Emerging market approaches that allow sources to develop the most cost efficient means of reducing emissions on a national, regional or worldwide basis.

Beyond recent U.S. efforts to institute a market based approach to deal with emissions of SO_2, which will be discussed below, marketable pollution allowances, credits or offsets have been most widely discussed in the context of dealing with CO_2 emissions. In fact, the concept of CO_2 emissions credit trading was outlined in a report released by the IPCC last year, and it has been pursued with some vigor by Finland, Norway and Sweden.[59] The IPCC outline discussed a relatively straightforward system of tradeable emissions permits:

> An emission permit system is based on the concept that the economic costs of attaining a given environmental goal can be minimized by allowing for the trading of emission rights. Once an overall limit on emissions has been set, emission entitlement amounting to that limit could be provided to emitting sources and free trading of such entitlement allowed. This would reduce the costs of meeting a given emission target because: (a) as in trade, comparative advantages between trading entities would be maximized; and (b) economic incentives would be created for the development of improved greenhouse gas limitation technologies, sink enhancement, and resource use efficiency (energy conservation).[60]

Various U.S. policymakers, perhaps caught up in the excitement of that country's experiment with a SO_2 trading program, have embraced the concept of a CO_2 trading

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[59] Int'l Env't Rep., at 242.

[60] Overview and Summaries issued as a part of the IPCC First Assessment Report, 31 (August, 1990).

program. An influential report prepared with the sponsorship of two U.S. Senators called for the establishment of an international trading system for greenhouse gases.[61] In addition, the U.S. Congress may soon consider a more limited approach that requires new and modified sources to obtain "offsets" of their greenhouse emissions.[62] Under the proposal, a large coal-fired power plant, for example, would have to purchase offsets from a variety of sources that have actually gotten real reductions in CO_2 emissions through fuel switching, sink creation, or conservation and efficiency improvements. While this and other "allowance" proposals may be part of a trend toward the use of market approaches, they, generally, are subject to a number of criticisms:

- there is the noninherent problem that nations have limited experience with these policy instruments (which means there is no tested administrative structure);
- there are concerns about the potential scope and size of the trading markets;
- existing subsidies and tax incentives can distort a potential market;
- lesser developed nations may lack the resources to either produce or purchase allowances or offsets; and,
- distortions in the market -- hoarding or market cornering -- are possible.

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[61] Project 88--Round II, Incentives for Action: Designing Market Based Environmental Strategies (1991).

[62] S. 1323 and H.R. 2663, 102nd Cong. 1st Sess. (1991) The bills have the title "The Carbon Dioxide Offset Policy Efficiency Act" and were introduced in the U.S. House Representatives and U.S. Senate on June 18, 1991.

Many of these types of concerns were raised during the course of the U.S. debate over its new SO_2 trading program and, to a degree, were addressed. That program is perhaps the most fully developed market approach to controlling pollution. There are a number of features of the U.S. system that could be helpful in the development of trading schemes elsewhere. Below, we outline the nature of that system and point out some of the ways in which it was modified to take into account the concerns of competing interests.

1. U.S. example of marketable pollution allowances.

While the goal of the U.S. Acid Deposition program (Title IV of the new U.S. Act) -- to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) -- is not novel, the marketable allowance system instituted in that title ties the U.S. electric utility industry together in entirely new ways. In the past, the various private electric companies may have shared common concerns about clean air regulations but, in the end, each electric utility faced the costs and consequences of clean air regulation alone. Under the regime established by the 1990 Act, a power producer in the United States may not be able to meet the emission reduction requirements without taking into account the plans and activities of other utilities or power producers.

2. The allowance system.

As noted earlier, emissions of SO_2 in the U.S. are ultimately controlled so that emissions from all utilities do not exceed the annual aggregate cap of 8.9 million tons (with each ton represented by one allowance). To comply with the Act, a U.S. power producer[63]

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[63] Under the U.S. Act, a "utility unit" that can be an "affected unit" (and, therefore, subject to the SO_2 cap and other provisions) is defined as a unit which serves as a generator that produces electricity for sale. Unless they opt voluntarily to participate in the allowance

will have a range of options: it can reduce or end utilization of a high emitting unit, install emission control technologies, switch to "cleaner" fuels, and/or rely upon the new allowance system to provide offsets for emissions at a facility. The only constant is that the power producer must hold emission allowances equal to the tons of SO_2 emitted from all of its units. Through the system of marketable allowances, the SO_2 reduction program is intended to maximize the range of choices that sources have in complying with the emissions limitation requirements. To reduce compliance costs and increase flexibility, electric utilities across the United States may in fact rely upon the sulfur dioxide emission allowance trading system to obtain additional allowances and, thus, meet the compliance goals of the Act.

3. What is an allowance?

An allowance under the program is an authorization issued to an affected source by the United States Environmental Protection Agency Administrator that permits the source to emit, during or after a specified calendar year, one ton of sulfur dioxide.[64] If a utility or power generator does not have any units eligible to receive emission allowances as "existing units," its new projects will have to obtain allowances from other sources in order to operate. New units may meet their obligations under these subsections of the Act by acquiring allowances from any source or person lawfully holding allowances anywhere in the country.[65]

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program, industrial sources of sulfur dioxide and nitrogen oxides will not have to reduce emissions in either Phase I or Phase II of the Acid Deposition program.

[64] Title IV, Section 402(3), 42 USC 7651b.

[65] Title IV, Section 403(e), 42 USC 7651b.

As noted, the Act specifies that an allowance is a limited authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide.[66] Once created, an annual allowance does not expire until used. Thus, for example, an allowance allocated to an existing unit under the bill in 1996 could be "banked" and used to offset one ton of SO_2 emissions during the year 2001. While allowances are issued to the owners and operators of existing utility units, the Act specifically states that an allowance does not constitute a property right and may be limited or terminated, impliedly, without compensation from the government.[67] At the same time, allowance transfers are supposed to be designed to carry out the "full menu" of prerogatives enjoyed by parties to conventional commercial contracts in the U.S. In other words, parties will be able to transfer allowances between and among themselves through commercial arrangements such as leases, sales agreements, and exchanges of emission allowances for electric power or capacity. In fact, "ownership" of allowances by brokers, investors and other market makers is encouraged to maintain fluidity in the allowance market, to link buyers with sellers, and to facilitate rational price-finding.

4. How many allowances will a power plant have or need?

Existing utility units are allocated allowances in Phase I and Phase II. The Act establishes a "baseline" for each unit. Based upon a calculation of baseline fuel consumption and emission rates, each Phase I unit is allocated allowances in a table provided in the Act. The baseline is the annual quantity of fossil fuel consumed by an affected unit, measured in millions of British thermal units over a given period -- generally

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[66] Title IV, Section 402(3), 42 USC 7651a.

[67] Title IV, Section 403(f), 42 USC 7651b.

1985 through 1987 for most existing units.[68] The baseline is then multiplied by an emissions rate -- the 1985 emission rate for most existing facilities -- to yield the number of allowances to which a unit is entitled. In Phase II, allowances are allocated on the basis of this same type of calculation, with some variations in the formula to take into account the special circumstances of various types of utilities and utility units. For example, existing utilities pointed out that many "clean" coal-fired units were underutilized during their baseline period. Accordingly, the Congress attributed to some existing units either a higher capacity factor or a higher emission rate in order to increase the number of allowances available for the units and, thus, permit increases in emissions from those units.[69] For new units coming on line after the date of enactment of the law, the baseline is the average annual quantity, in Btus, consumed in fuel by that unit multiplied by the allowed emission rates.[70]

5. Will allowances be "traded"?

The theory underlying the allowance system is straightforward. The Act, in stages, reduces the amount of sulfur dioxide that can be emitted at the nation's fossil-fired power units. To meet those new emission rates, an owner or operator of a unit can either reduce tons of emissions through some form of pollution control or purchase allowances that "cover" the emissions a utility unit produces in excess of those allowed by law. Again, in

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[68] Title IV, Section 402(4), 42 USC 7651a.

[69] Some 300,000 allowances will be available on a first-come-first-serve basis to utilities that utilize energy conservation measures and renewable energy technology. Title IV, § 404(f), 42 USC 7651c.

[70] Title IV, Section 405(g), 42 USC 7651d.

theory, allowances will be available to "cover" these excess emissions because the installation of controls at a given plant will reduce sulfur dioxide emissions to a point below the new emission standard. The U.S. Senate Report on the original version of S. 1630 gave this hypothetical to explain the incentive underlying a possible allowance transfer transaction:

> Unit A emits 25,000 tons of SO_2 annually and is allocated 10,000 allowances, requiring it to remove 15,000 tons of emissions to meet a 10,000 ton emissions limit. Unit A can remove 18,000 tons of emissions at a cost of $500 per ton. If it did so, it would need only 7,000 annual allowances to cover its own operations, leaving it with 3,000 unused allowances. Unit B emits 15,000 tons per year and is allocated 12,000 allowances. To remove 3,000 tons to meet its 12,000-ton/allowance limit would cost it $1,000 per ton. Unit B would clearly save money by purchasing unit A's 3,000 allowances at a price somewhere between $500 (unit A's cost) and $1,000 (unit B's cost) rather than incurring the $1,000 per ton cost of removing the emissions itself.[71]

The incentive to profit through sale of allowances should exist in those instances in which the market price for allowances exceeds the incremental cost of control at a particular unit. Thus, those utilities capable of controlling emissions relatively cheaply may "produce" and sell allowances. Moreover, efforts were made to ensure that allowance market would be structurally competitive. The initial allocation of allowances under the Act was developed so that allowances would spread over a range of utilities and somewhat evenly between the states. To emphasize this lack of market concentration, the authors of the U.S Senate Report, citing the President's Council of Economic Advisers, suggested that of the 5.1 million allowances issued to existing units with affirmative reduction obligations in Phase II

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[71] S.REP. No. 101-228, 101st Cong., 1st Sess., 318-19 (1990).

(representing only approximately 56 percent of the total allowances issued), only 26 percent would be awarded to the top 3 private utility holding companies. In turn, according to the U.S. Senate Report, the top 13 private holding companies together would be granted only 57 percent of this partial total, and the six states holding the most allowances would account for less than half of this partial total.[72]

In Phase I, the Act also provides incentives for overcontrol through the installation of scrubbers that may generate excess allowances which could also be marketed.[73] This provision was added to the Act to gain the support of representatives from high sulfur coal regions. Even with this provision, many high sulfur mines in the midwestern United States are expected to close, with a significant loss in mining jobs. As noted above, the Act does not limit a purchaser's ability to bank allowances for use in years subsequent to those for which they are issued. Thus, many believe that the allowance cap, the durable nature of allowances, the lack of market power on the part of major allowance holders, variations in the costs of emission controls, and the recent decision of the Chicago Board of Trade to become involved in stimulating allowance transactions through futures contracts will combine to create a market for allowances.

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[72] Id.

[73] Owners and operators of Phase I plants that elect to install continuous systems of emission reduction, in part, can qualify for an two year compliance extension and receive early-reduction bonus allowances for reductions achieved between 1995 and 1997. Title IV, Section 404(d), 42 USC 7651c.

6. How much will allowances cost?

According to some authorities, the estimated cost of each allowance available in the open market could range between a low of $200 and a high of $1500 (based on the allowance price set in a direct sale provision of the Act). There is, however, a surprising consensus of opinion on a narrower range in the value of Phase II allowances. The various U.S. consulting firms that have worked on allowance issues generally seem to agree that a Phase II allowance usable after 2000 is currently worth between $400 and $900 (in today's dollars). There is no reason to assume, however, that each private sale of allowances in any given year will be at a uniform price.

7. When and where can a U.S. utility purchase allowances for the operation of a project?

Currently in the United States, limited competition in the utility industry is permitted through so-called independent power producers who are allowed to build and operate generating units in a traditional utility's service territory. Throughout the clean air debate, there were a number of Independent Power Producers concerned that the market for allowances would not be as robust as the designers of the allowance system might wish. These power producers and a number of interests believed that they would be denied allowances by those who are eligible to receive the most allowances -- "traditional" utilities. Thus, they argued that the law should set aside a number of allowances for use by the Administrator to stimulate the sale of allowances and to protect the interests of IPPs. In the end, the Act was amended to include provisions that would withhold a fixed percentage of all available allowances for government run auctions and sales.

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The other means by which a utility might be able to obtain allowances is simply through contracting with holders of Phase I or Phase II allowances. Transactions involving allowances could be completed relatively soon because the Act specifically permits the transfer of allowances prior to their issuance. In other words, prospective holders of allowances will be permitted to record "pre-issuance transfers" and deduct the allowances already sold or transferred from the number of allowances that they will receive in 1995. As noted earlier, in the Phase I, the Act provides incentives for overcontrol that may generate excess allowances available on the open market. [74] In any event, the market for allowances may open quickly and should remain open so as long as there are willing buyers and sellers. Every utility in need of allowances probably will probably consider purchasing allowances not necessarily through a government sponsored auction or sale but through a private contract with an allowance holder.

8. Unresolved Questions about the U.S. Allowance System and its Application to Other Nations

Despite the steps taken in the U.S. Act to ensure the existence of a workable market, there are a number of concerns about the U.S. sulfur dioxide allowance system that illustrate the limits of market based approaches generally. First, there is a concern that individual states will encourage utilities to hoard allowances for future use, rather than transfer them at market prices, because allowances are thought to be a prerequisite for state economic growth. Obviously, this same type of problem would be just as likely to arise in a multinational or international allowance system because nations, rather states, would have

[74] Title IV, Section 404(e), 42 USC 7651c.

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concerns about the availability of SO_2 or CO_2 allowances during periods of economic growth and increased energy use.

Second, the current U.S. pattern of state control over certain aspects of environmental regulation may allow states to limit the use of allowances if emissions associated with allowances create environmental problems. In an international or transnational context, pockets of stricter environmental regulation which could interfere with a free trading of allowances are perhaps just as likely to exist -- particularly if "regional" pollutants like SO_2 or NO_x are the targeted pollutants, as opposed to pollutants of "global" concern like CO_2 or, perhaps, mercury.

Third, the U.S. electric utility industry is a complex amalgam of investor-owned, customer owned and quasi-governmental utilities. In addition, these various types of utilities are subject to a mix of state and federal rate regulation (and in some cases no regulation). Despite these complexities, the creators of the U.S. allowance system hoped that utilities, whether private or public, would have incentives to reduce the cost of compliance in their service territories. The allowance trading system may in fact reduce compliance cost but no one can be sure that utilities will embrace it with uniform vigor. Regulators in the United States are grappling with how utilities can be encouraged to participate in the system and bemoaning the fact that the most heavily regulated U.S. industry has essentially been asked to develop an entirely new free market. Given vast differences in the way that nations operate or regulate utilities and the fact market economies are only now being create in a number of countries, it probably is not safe to assume that utilities will be able to maximize the opportunities created by a new market for any particular pollutant.

C. Taxation of emissions to internalize externalities.

One of the other economic instruments that has been widely discussed as a means of controlling emissions, particularly of CO_2, is the application of a tax on emissions. Once again, the IPCC considered the concept of levying specific charges on emissions and a number of countries have given such proposals serious consideration. For example, in the U.S. some have suggested imposition of a "carbon tax" that would set a graduated rate for each fossil fuel -- natural gas, oil and coal -- based on carbon content. Obviously, the hope would be to drive users away from higher emitting fuels.[75] The EC, of course, is considering a very similar approach which would be expected to raise $35 billion and help stabilize carbon dioxide emissions at 1990 levels by the year 2000.[76] Denmark is expected to have in place by January 1, 1992 CO_2 tax on electricity, which will result in a tax in about $15 per metric ton of SO_2.[77] Germany and France have taken independent steps in the same direction.[78] Generally, all of these efforts are designed to reduce emissions, even as they "generate revenue which could provide a funding base for further pollution abatement, research, and administration, or allow other taxes to be lowered."[79]

Opponents of such taxes have made fairly consistent arguments. First, if a nation, or even a group of nations, imposes a unilateral tax there is the risk that it will make its

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[75] Project 88 -- Round II, Incentives for Action: Designing Market-Based Environmental Strategies.

[76] 14 Int'l Env't Rep., No. 18 (Sept. 11, 1990).

[77] Id. at No. 11 (June 5, 1991).

[78] Id.

[79] IPPC First Assessment Report, Vol. I, at 31.

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industries less competitive in the world market. Second, even if all nations imposed such a tax, the uneven use of fossil-fuels means that some nations will be better off competitively. Third, graduated fuel taxes strike particularly hard at coal rich nations. Fourth, carbon taxes tend to encourage the development of nuclear power plants, which obviously have their own set of opponents. Fifth, alternatives in the form of conservation or fuel switching may be so expensive that the tax does not drive power plants away from the use of fossil fuels like coal. Finally, absent compelling evidence of need, developing nations may be particularly loathe to add to the cost of electricity -- the basic input to virtually all other products.

III. CONCLUSION

As the result of ever closer scrutiny, coal-fired power plants are being asked to install new technology requirements, pay higher penalties and/or participate in newly created markets. Under any of these approaches, there are a number of facts that coal-fired power producers are confronting. First, more regulation of a greater number of pollutants is likely. Second, transboundary cooperation, particularly in Europe, is becoming the norm in most air pollution control efforts. Third, in developing and politically reforming countries, the high cost of technological, lack of energy research and development capability, and the difficulties in maintaining and monitoring compliance will demand international attention and assistance. Finally, the "reverse" externalities of pollution control -- socio-economic impacts on coal suppliers and the creation of pollution in controlling pollution (e.g., scrubber sludge or the capture of metals) -- may prove an intractable problem for coal producing nations. In the end, no form of regulation -- whether markets, taxes or standards

-- can disguise the fact that those who benefit from coal-fired generation will have to pay more and do more in the coming years in order to utilize the world's supply of coal.

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Environmental Controls for Coal Fired Power Plants

Ian M. Torrens

I. INTRODUCTION

Coal, with its vast reserves world wide, is likely to continue to furnish a large fraction of the primary energy needed for electricity generation well into the 21st century. Table 1 summarizes the expected global expansion in coal utilization for electric power production (an almost doubling over the next 30 years). But the twin goals of producing useful energy from coal more efficiently, and of minimizing environmental impacts from using coal to generate electricity, will continue to grow in importance as we approach the beginning of a new century. Environmental concerns have grown in many of the most industrialized countries during the past two decades, and developing economies are increasingly recognizing that it can be less costly to protect their environment than to clean up the damage caused by pollution or to live with it.

Great progress has been made and continues to be made in the technical means of preventing pollution for coal use. But successes in overcoming some of coal's environmental problems have been accompanied by identification of new environmental issues, often less obvious and more intractable as to their solution. Also, prevention is often costly, all the more so when the objective is control of pollutants in all environmental media. Nevertheless, coal will have to rise to meet the environmental challenge. The issues are both technological and economic -- in what ways and at what cost can this complex substance be transformed into useful energy while reducing its environmental impact to a level acceptable to society in the long term?

All through the 1980s the environmental debate with the strongest impact on how we use coal has been that on acid rain and related air pollution issues. A substantial number of countries have taken steps to reduce sulfur and nitrogen oxides, precursors of acid rain. In the United States the 1990 Clean Air Act Amendments (CAAA) will require utility power plants to retrofit technologies or switch fuels to meet sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions reduction requirements by the year 2000. These air pollutants are not the only targets of the CAAA. A new feature, compared to previous clean air legislation in the United States, is control of emissions of potentially toxic air pollutant emissions. Electric utilities are not immediately affected by the air toxics emission limits until the results of a three-year utility study by EPA are known; however, air toxics are rapidly becoming a major new focus of concern on the part of coal-burning utilities.

Another growing issue is waste management. The USA produces 70 million tons of coal ash each year; many landfills are reaching capacity limits, and it is increasingly difficult to obtain permits for new disposal capacity. Also, the flue gas desulfurization (FGD) plants, installed to reduce SO_2 emissions, in most cases produce large quantities of solid waste that require disposal unless a use can be found for it (e.g., gypsum for wallboard manufacture).

Improving efficiency of electricity generation (and use) is an effective means of minimizing environmental impacts in all media - air, water and land. Figure 1 shows the U.S. historical trend of increasing electrification while decreasing total energy per unit of economic output. During the economic expansion since 1982, electricity growth has paralleled GNP growth while real electricity price has declined 16% and overall energy efficiency has improved 11%. Continued productive improvement in energy efficiency, through electrification and by other measures, means that the rate of increase in primary energy consumption is expected to shrink, by 2010, to less than half the annual rate of U.S. GNP growth (Starr 1989). As these figures indicate, economic progress, energy efficiency and increased electrification have proceeded hand-in-hand, and continued economic growth is expected to raise electricity use to nearly 50% of U.S. energy consumption by the turn of the century.

Developing countries face hard choices because of the close coupling between the level of economic development and energy use, as indicated in Figure 2. This linkage is likely to increase the political pressure for greater energy efficiency in both the developing and developed world (Blair 1989). It is interesting to note that West Europe and Japan, both at economic levels comparable to North America and well beyond East Europe and the USSR, prosper on about one half of U.S. per capita energy intensity. This is only partially explainable by geographic scale differences. At the other extreme, countries at the bottom of the global economic ladder subsist on less than 10% of our per capita energy consumption.

The potential for improvement in overall energy efficiency, as represented by the energy/GNP ratio, is high in the emerging economies of Eastern Europe, as shown in Figure 3. A significant part of the efficiency gains to be realized over the coming decades will be in the generation and use of electricity, especially from solid fuel resources indigenous to these countries.

II. MEETING THE ENVIRONMENTAL CHALLENGES: CLEAN COAL TECHNOLOGY

Coal is rising to meet the environmental challenge, both through improved combustion and environmental control in the near term, and through the prospect of a shift in the direction of higher value added and environmentally benign coal processing by the early part of the 21st Century. Solutions which are being developed and demonstrated today or proposed for tomorrow fall under the generic heading of "Clean Coal Technologies." By improving the effectiveness of control technologies and reducing their costs, this concept seeks to reduce the policy conflict between coal use and the environment. Clean Coal Technologies have evolved into a family of precombustion, combustion/conversion, and postcombustion technologies, designed to provide the coal user with added technical capabilities and flexibility at lower cost in terms of environmental control. (EPRI 1988) (EPRI 1989) (DOE 1989) (Torrens 1990)

A major focus of clean coal technology development in the United States is the federal Clean Coal Technology (CCT) Demonstration Program administered by DOE.

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In March, 1986, the Administration requested Congress to commit $2.5 billion over 5 years to support clean coal projects which have matching funds from industry. To date there have been three rounds of project selections. There are now 35 projects funded or in negotiations with DOE, for a total value of $3.0 billion of which $1.2 billion from government and $1.8 billion from industry. Table 2 contains the Program's funding pattern, to date and anticipated (Round IV and V). Technologies being demonstrated under the CCT program include technologies whose purpose is strictly environmental control, and which are suitable for retrofit to existing plants, as well as technologies for repowering and for new coal power generation and industrial use. Table 3 provides a DOE status report for projects in Rounds I, II, and III of the CCT program, as of January 1991.

The U.S. utility industry is heavily involved in the CCT Program and provides host sites for 28 projects. The Electric Power Research Institute has involvement in 18 of these projects, providing total funding amounting to $18 million over the life of the demonstrations, mainly supporting test programs and performance assessments. Of the 28 projects, 12 involve some form of post-combustion SO_2 or NO_x (or combined) clean-up. There are two coal gasification and 5 fluidized bed combustion projects.

Clean coal technology development is international in scope, as Figure 4 illustrates. Approximately 100 clean coal demonstrations worldwide, in progress or planned, are aimed at assuring that the highly diversified energy market has an array of coal utilization options which together form the least cost option for eliminating or reducing conflict between coal and the environment.

III. STATUS OF CLEAN COAL TECHNOLOGIES

This section describes the main features of technologies to reduce pollutant emissions to air, water and land, and their current status. Depending on the specific technology, pollution control can occur before, during or after coal combustion; or combustion may itself be replaced by conversion of the coal into a clean liquid or gaseous fuel. In precombustion technologies, sulfur and other impurities are removed from the fuel before it is burned. Combustion technologies employ techniques to prevent pollutant emissions in the boiler while the coal burns. With postcombustion technologies, flue gas released from a boiler is treated to reduce its content of pollutants.

1. Pre-Combustion Cleaning

About 40% of all U.S. coal for utility boilers, and about 70% of eastern and midwestern bituminous coal, receive some cleaning, or beneficiation, prior to combustion. This is essentially all physical cleaning, and its purpose is largely to remove impurities and improve the coal's heat content. Physical cleaning can remove 30 to 50% of pyritic sulfur, or 10 to 30% of total sulfur content. Most physical cleaning processes rely on density differences or variations in other physical characteristics, crushing then washing the raw coal and removing the heavier impurities. Advanced physical cleaning processes are being developed and

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demonstrated. Most rely on grinding the raw material to much finer sizes, where various techniques specifically designed to separate ultrafine particles can be used. These advanced processes aim to separate up to 90% of the pyritic sulfur.

To remove the sulfur which is organically bound in the coal requires chemical or biological coal cleaning. Those processes are still in development, many of them at the experimental stage. The principal barriers to chemical cleaning are the energy required and cost of reagents, and the management of chemical waste products generated. Biological cleaning involves the use of bacteria or enzymes to "eat" the sulfur in the coal. Researchers are becoming more optimistic that new biotechnologies will make biological coal cleaning economic in the future, with removal of up to 90% of total sulfur.

2. SO_2 Control

Over 150 flue gas desulfurization (FGD) systems, on approximately 72 000 MW of generating capacity, are currently operating in the U.S. (Dalton, 1990). This represents about 20% of the total coal-fired capacity. Of the FGD systems, about 92% are wet scrubbers and 8% are spray dryers. All new pulverized coal fired units are scrubbed by law, and the 1990 Clean Air Act Amendments require some 9 million tons of SO_2 emission reductions from existing utility power plants by the year 2000. By the end of the century, an estimated 27,000 MW of FGD capacity on new plants are expected to come on line.

(a) Wet Limestone FGD.

Currently the predominant U.S. scrubbing technology of choice by utilities is lime or limestone wet scrubbing with landfill disposal of byproducts. The reagent is prepared (limestone is ground; lime is slaked) and mixed with water in a reagent preparation area. It is then conveyed as a slurry (approximately 10% solids) to an absorber (typically a spray tower) and sprayed into the flue gas stream. Sulfur dioxide present in the flue gas is absorbed in the slurry and collected in a reaction tank where the resulting calcium sulfite and/or sulfate crystals are dewatered.

Early experience of the U.S. utility industry with "scrubbers" was fraught with difficulties: inadequate understanding of the process chemistry resulted in frequent incidence of plugging and scaling of the scrubber components, corrosion and erosion of the materials of construction, poor handling characteristics and large land requirements for sludge byproducts, and high capital and operating costs. Improved understanding of system chemistry has led to increased reliability, and improved performance. Reliability has reached 98% + for new scrubbed capacity, and additives permit SO_2 removal to exceed 90% at an added cost that is not usually prohibitive. Future improvements in conventional lime/limestone FGD can be illustrated using three examples:

- process improvements such as the jet bubbling reactor used in the Chiyoda CT-121 Process;
- application of spray drying to high sulfur coal;

- an advanced, limestone FGD system producing gypsum with no reheat, and no redundant modules, for use at compact (e.g., space constrained) sites.

Each of these designs can achieve 90 to over 95% SO_2 control. The cost and performance advantages of the advanced system are a 20-50% capital cost savings and 20-40% operating cost savings over conventional FGD systems available today. The jet bubbling reactor and advanced limestone/gypsum designs can both make wallboard grade gypsum for sale or disposal.

Engineering and other improvements have succeeded in reducing the cost of wet FGD somewhat, compared to that of a decade ago, but it remains a relatively expensive item. Capital costs for conventional systems will vary depending on a number of factors such as fuel sulfur content and unit size. Preliminary results from the new round of EPRI cost estimation indicate that a state-of-the-art wet FGD system for medium-sulfur coal on a new plant could be built for less than $200/kW with annual operating costs in the range of 5 to 10 mills/kWh (see Figure 6). (Torrens and Radcliffe, 1990)

Depending on the conditions in an existing plant, especially space available and accessibility, retrofitting an FGD system can cost between one and three or more times that of installing it in a new plant. For the different FGD systems now available and a moderately difficult installation (retrofit factor 1.3 - approximately 30% more costly than in a new plant), the range of capital requirements and total levelized costs over 30 years with no inflation are estimated to be, (EPRI GS-7193, 1991).

1990 Dollars	Capital $/kW	$/ton SO_2 (Constant $)
Wet FGD (Range of System Types)	190-230	440-500
Spray Dryer	175	450

The above figures are subject to a ± 20% level of uncertainty.

(b). Regenerable FGD

Regenerable FGD systems can use diverse physical and chemical principles, but generally recover sulfur byproducts as concentrated SO_2, sulfuric acid, or elemental sulfur. The major advantage of regenerable FGD is elimination of waste products. However, it costs 30 to 50% more than the conventional limestone gypsum FGD process, owing to system complexity. (Torrens/Radcliffe, 1990)

(c) Spray-Dry FGD

This is the other principal method of SO_2 control used today. Calcium oxide (quicklime) mixed with water produces a calcium hydroxide slurry, which is injected into a spray dryer and dried by the hot flue gas as it reacts to collect SO_2.

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The dry product is collected both at the bottom of the spray tower and in the downstream particulate removal device where further SO_2 removal may take place. Capital costs can be substantially less than for wet systems, especially for low-sulfur coal applications. A total of 17 systems were operating as of mid-1987, all on relatively low-sulfur coal (less than 2%).

High-sulfur spray dryer applications have not been demonstrated over a long at commercial scale. Pilot testing has indicated that SO_2 removals in the eight ninety percent range are possible, with over ninety percent achievable under some conditions. However, a fabric filter retrofit may be required to maintain particulate control standards at greater than ninety percent removal, since the mass throughput of solids to the electrostatic precipitator (ESP) - the dominant particulate control technology in existing U.S. power plants - will at least double if a spray dryer is used.

(d) Sorbent Injection

This category of sulfur removal processes involves injection of a calcium-based sorbent directly into the furnace, into a lower temperature zone near the economizer, or downstream of the air pre-heater - in all cases without the addition of a special reaction vessel for SO_2 removal.

Furnace sorbent injection (FSI) refers to the injection of calcium-based sorbents (lime or limestone) into the radiant zone of the furnace where they calcine and then react to form $CaSO_4$ in the 1200-900°C temperature region. The sulfated sorbent is then collected along with the fly ash in the precipitator or baghouse. An alternative process, economizer injection (EI), is a similar process in which the sorbent is injected near the economizer at approximately 550°C.

SO_2 removal for FSI is a function of sorbent choice and quantity injected, but is typically 20-40% with limestone and 40-60% with lime at injection rates corresponding to calcium to sulfur ratios of two. The process is characterized by low capital costs ($50-100 kW), and simplicity of design and operation. But because of the lower efficiency of removal, the levelized costs expressed in terms of $/ton of SO_2 removed are somewhat higher than those typical of wet FGD. EI performance and costs are presently comparable to those for FSI; however, the lower temperatures at the injection location and the extremely fast reaction rates hold promise of performance improvements using sorbent enhancement techniques which are ineffective at FSI temperatures.

Duct sorbent injection refers to those processes where the sorbent is injected into low temperature flue gas downstream of the air preheater. SO_2 removal can be accomplished with either sodium- or calcium-based sorbents. In the case of calcium-based sorbents, it is necessary to humidify the flue gas to within 20-10°C of the saturation temperature in order to achieve sufficiently high reaction rates for economical SO_2 capture. This can be accomplished either through separate humidification followed by dry sorbent injection, or through slurry injection in the case of in-duct spray drying.

As with furnace sorbent injection, these processes are characterized by moderate sulfur capture (40 to 70% SO_2 removal), simplicity of design and operation, low capital cost and attendant savings in levelized removal costs. Several varieties of the basic technology are possible including in-duct spray drying using a slurry, dry duct injection using sodium or calcium sorbents, and a hybrid system which includes retrofit of a fabric filter after the existing ESP (HYPAS). In the last one, a dry calcium sorbent is injected into the clean gas stream following the ESP. All have capital costs of about $50/kW with the exception of the hybrid system which is about $100/kW due to addition of the baghouse. However, it is potentially capable of about 70% SO_2 removal (versus about 40-50% for the others) resulting in a cost effectiveness of about $600-650/ton of SO_2 removal, which makes it a potentially attractive alternative to other dry systems..

Each of the processes for which pilot-scale development is successful will require full-scale demonstration to resolve operating issues such as particulate control, waste management and disposal, and the severity of duct deposition, plugging, and corrosion. All sorbent injection processes, furnace or duct, increase the quantities and alter the characteristics of solid wastes for disposal, potentially increasing disposal costs due to the presence of unreacted sorbent.

(e) <u>High Sulfur Test Center</u>

The HSTC, located near Buffalo, NY, is the focus of a $65 Million, 10-year EPRI research program designed to reduce the cost, improve the efficiency, and increase the reliability of environmental control systems. The facility has been in operation since June 1987. Pilot and laboratory research is being conducted in various methods of environmental control including wet, spray dryer and dry sorbent injection FGD; selective catalytic reduction (SCR) for NO_x removal in high-sulfur applications; both reverse gas and pulse jet fabric filters and an electrostatic precipitator for particulate removal; and, the effects of the various combinations of environmental controls on the release of toxic substances in air, water and solids discharges.

The HSTC is jointly sponsored by EPRI, New York State Electric & Gas, Empire State Electric Energy Research Corporation, U.S. Department of Energy and the Electric Power Development Corporation (EPDC) of Japan As the HSTC evolves into an international center for R&D activity on emissions controls, we welcome visitors and would be receptive to inquiries about potential joint research efforts and cofunding from overseas utilities.

3. NO_x Control

(a) Combustion Modification

Combustion modification achieves some NO_x reduction through the redesign of burners or through rearrangement of the fuel and air flows to the furnace (such as overfire air or reburning) in order to control the mixing of the fuel and air in relationship to the local temperature patterns. Maintaining of fuel-rich conditions in the primary flame zone followed by gradual air addition later in the combustion process

minimizes NO_x formation. This basic approach is characteristic of the low NO_x burner and overfire air. Reburning involves the redirection of 10-20% of the total fuel to the upper-furnace region to create a zone for reduction of NO_x formed in the primary burner zone. Such methods are applicable to oil and gas units as well as coal.

Achievable reductions are typically 40-60%. Capital costs for retrofit low NO_x burners are estimated at $5 to $25/kW with no additional operating costs expec 1. Combustion modification has been widely applied at full scale on new units t· ıeet NSPS on coal-fired utility boilers and for both new unit and retrofit applicati on oil- and gas-fired units. Pilot development of retrofit approaches to coal uni: .s progressed to the point where technologies are ready for demonstration on a.. ıour major categories of existing boilers (tangentially-fired, wall-fired with circular burners, wall-fired with cell burners, and cyclone-equipped units).

(b) Post-combustion NO_x Control

Postcombustion NO_x control refers to flue gas treatment methods for conversion or removal of NO_x species after the furnace. The most common processes involve the injection of ammonia or ammonia-like compounds (e.g., urea) into the flue gas with or without a catalyst to promote the reduction of NO_x to nitrogen and water vapor. The most extensively developed process is selective catalytic reduction (SCR) in which ammonia is injected into the flue gas at about 440°C in the presence of a vanadium pentoxide catalyst.

NO_x reductions of 80% or more are possible with SCR alone and, if used in conjunction with a low-NO_x burner achieving 50% initial reduction, a combined efficiency of 90% can be obtained. Costs depend strongly on initial NO_x levels, catalyst cost and assumed catalyst life.

Their capital costs in Europe are averaging approximately $125/kW. These costs are consistent with EPRI's capital cost estimates for hypothetical retrofit installations which range from $100 to $150/kW. Levelized cost projections for both U.S. and Japanese installations are estimated at 4 to 9 mills/kWh (Cichanowicz, et al, 1990)

SCR has been applied commercially in Japan and Western Europe (primarily Germany and Austria). In particular, Germany now has some 25,000 MW of utility coal-fired capacity retrofitted with SCR. All of this existing and planned SCR application is on lower-sulfur coal, and there are questions as to whether catalyst lifetime may be substantially reduced by sulfur-laden flue gases. There are also issues related to catalyst poisoning by trace metals in the coal. EPRI is cooperating with others in the United States, including the Department of Energy, to investigate the performance of SCR at pilot scale under U.S. coal and boiler conditions.

The United States and Europe are paying increased attention to selective noncatalytic reduction (SNCR) technologies. The principle is similar to that of SCR, but no catalyst is involved. Results with urea injection show the potential for 30 to 50% NO_x reductions, and perhaps up to 75%, with NH_3 emissions below 5 to 10 ppm. Capital and operating costs are estimated to be $5 to $15/kW, and less than 3 to 4 mills/kWh, respectively.

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4. Combined NO_x/SO_2 Control

Combined NO_x/SO_2 processes offer the potential to reduce SO_2 and NO_x emissions for less than the combined cost of SCR and conventional flue gas desulfurization (FGD). Most processes are in the development stage and are not commercially available, although several have been applied to low sulfur coal-fired boilers.

More than sixty combined NO_x/SO_2 processes have been identified in a recent EPRI study. There are six broad categories:

- Solid adsorption/regeneration processes employ physical adsorption of SO_2 and NO_x onto a solid material, which is then exposed to high temperature and reducing gas, generating a concentrated SO_2 and NO_x stream for production of elemental sulfur or acids.

- Flue gas irradiation delivers a high energy charge to flue gas, forming radical species from NO_x and SO_2, which combine at low temperature with a reagent (such as ammonia) to form solid particles, captured by an ESP or fabric filter.

- Wet scrubbing employs additives for conventional lime/limestone scrubbers from solid nitrogen/sulfur compounds which can be precipitated and collected as a solid.

- Gas/solid catalytic operations employ several catalysts to reduce NO_x to N_2 by SCR and oxidize SO_2 to SO_3, the latter for condensation as sulfuric acid.

- Electrochemical operations reduce SO_2 to elemental sulfur and NO_x to N_2 without reagent by employing an electrically activated catalyst surface.

- Alkali injection uses additives for dry SO_2 removal systems to collect NO_x with SO_2 as nitrogen/sulfur compounds.

Engineering studies are presently in progress to estimate the capital and operating costs of selected NO_x/SO_2 controls that may offer viable alternatives to SCR and FGD. At present, cost analysis accuracy is limited by a lack of significant operating experience at conditions typifying U.S. utility application. Given this uncertainty, most candidate processes appear to require between $250 and $350/Kw, and 20-30 mills/KWh total levelized cost.

5. Particulate Control

Many utilities will be required to upgrade particulate controls at existing power plants, especially in response to new Clean Air Act Amendments. Existing electrostatic precipitators (ESPs) may have difficulty in meeting future fine particulate and/or air toxic standards, and those designed for use on boilers firing

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high-sulfur coal may not even be able to maintain current emissions if they switch to low-sulfur coal to comply with new SO_2 regulations.

Significant savings could be realized in these cases through the use of improved baghouse cleaning methods, replacement of an aging and underperforming electrostatic precipitator (ESP) with a pulse jet baghouse, advanced ESP controls, or improved flue gas conditioning systems. Examples of upgrade technologies that EPRI is developing and/or evaluating follow:

(a) Low Cost, High Performance Electrostatic Precipitators.
Field demonstrations have been, or are being, conducted on four electrostatic precipitator (ESP) upgrade technologies: intermittent energization; wide plate spacing; two-stage precharging; and an agentless flue gas conditioning system. These technologies can be used to improve the performance of existing ESPs or reduce the cost of new units.

(b) Particulate Controls for Advanced SO_2 Reduction Processes.
Guidelines are being developed for predicting the performance of particulate controls operating in conjunction with AFBCs, spray dryers, or sorbent injection processes for SO_2 control. These guidelines will help a utility engineer determine how well the existing or proposed particulate collector will function in this environment and what countermeasures should be considered if the performance is not expected to be satisfactory. The guidelines will be based on field tests at a variety of sites, complemented by laboratory tests and computer modeling. They are expected to be available in 1993.

(c) Pulse Jet Baghouses for Utility Applications.
Baghouses, or fabric filters, collect fly-ash in the same way that a domestic vacuum cleaner traps dust. They are generally cleaned by mechanical means or using a sonic horn after being taken off line. Pulse-jet baghouses provide a more vigorous cleaning force than conventional baghouses by using short pulses of higher pressure air. The pulse-jet configuration is also unusual because the bags collect ash on the outside rather than the inside. Metal cages on the inside prevent bag collapse. Unlike bags that collect dust on the inside, pulse-jet bags can be cleaned with the compartment remaining on-line. Figure 5 shows a pulse-jet baghouse, including the compressed air cleaning system, bag supports, gas flow patterns, and solids removal port.

Pulse jet baghouses are being evaluated at various utility sites. These tests cover a wide range of flue gas and fly ash characteristics, including products of heavy oil combustion. The demonstrations are being conducted on 1-MWe equivalent pilot baghouses using full-scale components in each compartment. These field tests are demonstrating that pulse jet baghouses, used extensively by domestic and foreign industry as well as foreign utilities, are also applicable and economical under U.S. utility conditions. An EPRI-patented process, the Compact Hybrid Particulate Collector (COHPAC), may become the most cost-effective ESP upgrade when very low emissions and opacities are required. This process takes advantage of the relatively low dust loading, leaving an ESP, even a poorly performing unit, to operate the pulse jet baghouse at 4-6 times normal filtering velocity. The

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consequent reduction in baghouse size (the same factor of 4-6) results in a very low-cost, yet high performance, upgrade. The first full-scale demonstration of COHPAC will take place in 1992 at a Texas Utilities power plant..

6. Air Toxics Control

Air toxics, a relatively new concern for the power industry, feature prominently in the 1990 Clean Air Act Amendments. There is a clear and urgent need to know what amounts of potentially toxic substances are produced and emitted from different plants, how effective today's control equipment is at removing these substances, and how and at what cost controls may be upgraded, if necessary.

In 1988, EPRI initiated the Power Plant Integrated Systems: Chemical Emissions Study (PISCES) to build a comprehensive database and chemical species evaluation model for estimating toxics emissions to all media (air, water, solid waste). Field measurements on two dozen priority chemical substances are in progress at EPRI pilot/demonstration facilities and full-scale power plants of member utilities.

The PISCES project is coordinated with other EPRI research on atmospheric transformations, health/ecological effects, and risk assessment.

7. Repowering Technologies

If a power plant is nearing the end of its scheduled life and major expense would be necessary to meet new or emerging emission limits, it may make sense to consider replacing the boiler with a new less polluting and more efficient technology for coal combustion or conversion. This is known as repowering. New technologies for repowering existing boilers include atmospheric or pressurized fluidized bed combustion (AFBC or PFBC), slagging combustors, or integrated gasification combined cycle (IGCC). All of these technologies are of course equally applicable to a new power plant.

(a) Atmospheric fluidized bed combustion (AFBC)
This is now an established technology for industrial boilers (10 to 25 MW). It is being demonstrated at utility boiler size (75 to 350 MW) in a number of demonstrations in the U.S. and abroad. It relies on jets of air to maintain a mixture of coal and limestone (to capture sulfur) in a turbulent suspension in the boiler while it is being combusted, at temperatures of 1400-1600F, about half of that in a conventional boiler. This reduces NO_x formation. AFBC boilers can meet new source performance standards for both SO_2 (at a calcium/sulfur ratio of about 2) and NO_x, without additional control equipment. They also permit the combustion of lower grade fuels. However, like FSI, AFBC results in additional waste quantities which may prove difficult to handle in the existing particulate control device.

(b) Pressurized fluidized bed combustion (PFBC)
PFBC follows the same principle as AFBC except that the boiler operates under 10 atmospheres of pressure. The increased energy of the exit gases can drive both a gas turbine and a steam turbine (combined cycle) potentially boosting generating

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efficiency to over 40%. The relatively small size of PFBC units is well suited to space-constrained sites and modular construction. Four commercial demonstration units each of about 70-80 MWe capacity are being constructed at utility sites in Sweden, Spain and the United States, each repowering an existing plant.

An important issue for PFBC is hot gas clean up, which is needed if the combined cycle is to realize its full potential for improving generating efficiency. Research efforts are in progress to clean the 1500F gases exiting the boiler without cooling them, so that they can drive a gas turbine directly. Various techniques are being tried, such as filtering with ceramic candles, ceramic cross-flow filters or granular beds.

(c) Slagging Combustors
These are cylindrical devices based on the cyclone concept, where combustion takes place in the device and the hot combustion gases pass into the boiler. The combustion temperature is high enough to produce slag instead of ash. Developers claim that the high NO_x levels which would normally be associated with high combustion temperatures are reduced by combustion stoichiometry controls, to less than 250 ppm (0.34lb/MBtu). Also, sorbent injection is claimed to reduce SO_2 emissions by 50-80%.

(d) Integrated Gasification Combined Cycle IGCC.
A number of processes are at the demonstration stage in the USA and Europe. The basic principle is synthetic gas production followed by combustion in a turbine generator and recovery of the heat using a steam bottoming cycle to generate additional electricity. Using current technology, such an IGCC plant should be able to reach 42% efficiency.

Environmental protection also depends directly on the gasification process. Sulfur can be recovered chemically from the coal gas in elemental form, which can then be sold. Formation of nitrogen oxides is inhibited during combustion by saturating the coal gas with water vapor to reduce flame temperature. The volume of solid waste produced by a gasification-based plant is less than half that of a conventional coal plant with scrubbers, and the product is an inert slag that can be used as a construction material.

Several U.S. utilities are actively pursuing IGCC projects, following successful demonstration of the concept at EPRI's 100 MW Cool Water facility, which operated from 1984 to 1989. In addition, Destec, a wholly owned subsidiary of Dow Chemical Company, is currently operating a 160 MW IGCC plant, in Plaquemine, Louisiana. Abroad, SEP -- the joint operation authority for electricity production in the Netherlands -- is now constructing a 250 MW IGCC plant based on Shell gasification technology. This plant is scheduled to start operation in 1993. (Torrens 1990)

IV. WASTE & WATER MANAGEMENT

Utility waste and water management falls into three broad categories:

- high volume wastes re-use and disposal

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- chemical and toxic waste management
- water quality management

1. High Volume Wastes

Currently, about 18% of utility fly ash is sold for use in other industries. The most prevalent use is as a substitute for cement in concrete. This application is limited, however, by ash composition and engineering requirements. More than 50 other uses of fly ash have been documented, but many of these are limited by market size, material specifications, or transportation costs.

To help promote ash utilization, one potentially large market for coal ash is highway construction. EPRI has sponsored six demonstrations of fly ash use in highway construction across the nation. Each project was selected to examine a specific type or application of ash. These demonstrations--using both western and eastern coal ash--are proving the effectiveness and value of ash in engineered fill applications (e.g., embankments and pavement base courses). Groundwater monitoring at the sites is verifying the environmental acceptability of using fly ash in roadways.

Design manuals and material specifications developed by the program provide utilities, highway departments, and contractors with guidelines for using fly ash in construction. Videotapes documenting construction applications are also available. The program's fly ash utilization manual helps utilities establish ash marketing programs.

If ash and FGD waste cannot be used, it must be disposed of safely. Today, ponding and landfilling are the predominant means of ash and FGD by-product management. EPRI is helping utilities meet environmental requirements for ponds and landfills through its ash and FGD by-product disposal manuals, site upgrade guidelines, and ASHDAL (ash disposal) and SLUDGECOST (FGD by-product disposal) cost-estimating computer codes.

2. Chemical and Toxic Wastes

Utilities handle, store, and discharge chemical substances in the generation of electricity. Regulators are focusing on how these substances are managed and their impact on human health and the environment. They are also investigating cases of potential contamination from other utility operations, such as former manufactured-gas plants and leaking underground storage tanks.

The costs of managing chemical and toxic materials are likely to rise as regulations restricting traditional disposal methods take effect. Materials designated as hazardous will be particularly affected. For these substances, source reduction and recycling, followed by detoxification, stabilization, or encapsulation, may be the only management alternative.

EPRI's PISCES project (see Section III.6) also has a strong water and waste component in the database and field measurement activities. This will provide utilities information on the quantities and fate of chemical substances in waste streams.

Low-volume wastes include a variety of small, intermittent power plant streams, such as boiler and cooling tower blowdown, chemical cleaning wastes, washwaters, process and floordrain wastewaters, coal pile runoff, and used oils. Noncombustion wastes include asbestos, paint cans, antifreeze, spent solvents, and treated wood.

The costs and techniques of managing these wastes vary, depending on whether they are classified as hazardous or nonhazardous. Because disposal costs for hazardous waste can be five to ten times that for nonhazardous waste, classification of only a small minority of substances as hazardous could greatly increase utility disposal costs.

EPRI helps utilities manage low-volume wastes by sampling and characterizing typical power plant streams. Results have been published in a reference manual, which also describes treatment and disposal alternatives and their costs. A similar reference manual exploring innovative minimization, handling, and treatment approaches will be published following an investigation of noncombustion wastes.

3. Water Quality Management

Managing water quality is becoming more important as utilities contend with fewer high-quality water sources and stringent wastewater discharge requirements. As a result, many utilities are reducing water consumption. Further, utilities are confronting chlorine discharge limits that can lead to increased condenser biofouling and heat rate penalties.

One of the EPRI's goals is to maximize the efficiency of plant water use while maintaining process performance. It is achieving this goal by developing (1) innovative water management and treatment technologies and (2) methods to detect and minimize condenser scaling, corrosion, and biological fouling.

Integrated water management products include the WATERMAN computer code, which determines water flows and balances throughout a plant. By integrating water flows and by recycling or reusing water, utilities can substantially reduce makeup water needs. In addition, WATERMAN allows utilities to evaluate water recycle and reuse approaches.

Cooling systems are the largest water users in a power plant. Therefore, reducing cooling system makeup water demand is an important element in plant water management. Reduced water use, however, can lead to condenser scaling and corrosion, which can cause heat rate penalties. Proper cooling water chemistry management requires a balance between these two demands. EPRI has developed a family of computer codes to help utilities maintain proper water chemistry in recirculating cooling systems.

Power plants frequently experience biological fouling (biofouling) of condenser tubes by algae and other microorganisms. This results in increased turbine backpressure, shortened tube life, and increased condenser maintenance.

Utilities traditionally have controlled biofouling by bulk chlorination. However, EPA restrictions on residual chlorine in cooling water discharge are forcing utilities to explore other alternatives. One promising option is targeted chlorination.

In targeted chlorination, chlorine is sequentially injected into various sections of the condenser inlet tubesheet for short durations. The chlorine contact time and concentration are sufficient for biofouling control, yet downstream mixing and dilution enable compliance with EPA discharge limits. A computer code, FOULCOMP, assists utilities in optimizing chlorine use.

4. Future Waste and Water Management Strategy

In recent decades, strict regulation of power plant discharges and waste disposal has become routine. EPRI and the utility industry expect this trend to continue. Long-term R&D strategy that will allow future environmental standards to be met at the least possible cost, centers around integrated management systems that possess the following attributes:

- maximum recycling and reuse of wastes
- no detectable toxic waste discharge
- minimal water discharge
- waste processing to extract products of commercial value
- minimal cooling system fouling, scaling, and corrosion
- reliable monitoring techniques for regulated substances
- stabilization and containment of all discharged wastes

With this strategy, EPRI is helping utilities move toward full environmental compatibility, without sacrificing economic competitiveness.

V. TOOLS FOR SELECTION OF CONTROL TECHNOLOGIES

Section III describes generic categories of clean coal technologies with in some cases an indication of cost ranges. However, when it is a matter of retrofitting an existing power plant, no two situations are identical: fuels, boiler configurations, even space available for new pollution control equipment, all play a role in the decision on how a utility will meet new emission reduction requirements. For example, a decision to install a sorbent injection technology rather than FGD for SO_2 reduction may depend not only on the percentage reduction required but also on the space constraints of

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the site, and on the capacity factor of the plant (with a lower capacity factor, the lower capital cost of sorbent injection is advantageous compared to FGD).

To help its member utilities in making these decisions, EPRI has developed or is developing a number of tools, mainly in the form of easy-to-use computer codes. Principal among these are FGDCOST (which compares the cost of different SO_2 control technologies applied to a specific plant); FGDPRISM (which simulates wet FGD process chemistry for application to performance, cost and reliability improvement); and NO_xPERT (which helps utilities select a NO_x reduction technology, again adapted to a specific plant configuration). Summary descriptions of these codes follow. They are being integrated with other plant-specific EPRI codes (e.g. CQIM-Coal Quality Impact Model) in a Clean Air Technology (CAT) Workstation, which utilities can use in their strategic planning for response to the 1990 Clean Air Act Amendments.

FGDCOST

EPRI has recently updated its economic evaluations of commercially available FGD systems Revised cost estimates are now available, with technical and commercial evaluations, for up to 26 different FGD processes, including both wet and dry technologies.

FGD Processes Evaluated:

Limestone/Forced Oxidation
Limestone/Wallboard Gypsum
Limestone/Dual Alkali
Lime Dual Alkali
Magnesium-Enhanced Lime
Limestone/Inhibited Oxidation
Limestone/DBA
Pure Air/Mitsubishi
CT-121
Lime Spray Dryer
Furnace Sorbent Injection
Economizer Sorbent Injection
Duct Sorbent Injection
Duct Spray Dryer
Tampella LIFAC
Lurgi CFB
SOXAL
Wellman-Lord
MgO
Saarberg-Holter
NSP Bubbler
Passamoquoddy
ISPRA Bromine
HYPAS
Damp/ADVACATE
NOELL/KRC

A new computer model, FGDCOST, will help utilities tailor cost estimates to specific plant sites. The model is a menu-driven, spreadsheet template (one spreadsheet for each technology) that uses internally stored design information to help users estimate capital, O&M, and total levelized costs. User inputs include economic criteria, boiler/coal characteristics, site conditions, and adjustments for retrofit difficulty. The new model will supersede EPRI's RETROFGD cost-estimating code. Figure 6 shows cost ranges for several FGD technologies calculated by FGDCOST.

FGDPRISM

Better understanding of FGD chemistry can lead to greater efficiency and reliability in wet scrubber operation. For this reason, EPRI developed the FGD Process Integration and Simulation Model (FGDPRISM), a personal computer program that simulates wet lime/limestone scrubbing chemistry. The model evaluates how changes in the hundreds of variables involved in the scrubbing process affect FGD system performance.

FGDPRISM embodies the results of over 10 years of EPRI research into the fundamentals of FGD process chemistry. It allows purchasers of desulfurization systems to compare the performance of various candidate designs. System designers can refine absorber and reaction tank parameters through performance simulations. Utilities currently operating FGD systems can simulate physical or chemical modifications without full-scale testing. These applications will result in engineering labor, capital, and O&M savings.

NO_xPERT

NO_xPERT is a PC-based computer model for screening NO_x control technologies. It features the EPRIGEMS standard user interface, and can be used to:

- predict NO_x emissions for individual boilers, plants, and the utility system
- select NO_x controls to meet emissions reduction targets
- provide cost estimates of NO_x reduction retrofits

NO_xPERT is based on the best available correlations of NO_x with fuel, boiler/burner type, and other combustion parameters. The model can analyze any of the four major boiler types and accounts for variations in duty cycle, design vintage, and structural constraints.

Technical and cost uncertainties are provided, as is a condensed NO_x control technology tutorial. NO_xPERT can help utilities substantially reduce the engineering hours required deciding how best to meet NO_x reduction requirements with their specific plant configurations.

VI. CONCLUSION

Power plant environmental control is not inexpensive. On the aggregate, environmental systems on a new coal-fired plant are estimated to amount to some 40% of the total capital cost. The U.S. utility industry will be spending some $5-7 billion per year on SO_2 and NOx retrofit controls retrofitted to existing plants, when the CAAA compliance program is completed in 2000. Controls on air toxics if utilities are regulated would add to this bill.

In an emerging economy like Poland's, pollution control competes for development capital with badly needed modernization of all industrial plants. It is important therefore to achieve the "biggest bang for the Zloty", in terms of cost-effectiveness

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and reliability of control equipment to be installed to meet future environmental standards. This implies:

1) careful and impartial evaluation of the technological options, both generically and on a plant-specific basis;

2) translation of the cost basis into Polish cost accounting methods and use of Polish parameters (e.g. labor and materials costs);

3) multi-media planning, for adequate solid waste management and waste water treatment;

4) a sound training program for plant operators and supervisors: a FGD system is a chemical plant and needs to be treated as such if it is to be reliable.

Strategic emission reduction planning should also consider the most cost-effective ways of achieving desired overall goals in a region. For example, is it better to impose 50% SO_2 reductions on two power plants or to leave one alone and reduce emissions in the other by 95%? The CAAA in the U.S. provide utilities with options like this by "bubbling" their total required SO_2 emission reductions. This is an initial step in a trend towards a more market-oriented approach to pollution reduction.

There are no major technical barriers to reducing pollution from power generation in Poland very substantially. Clearly, the most difficult issue is the availability of scarce financial resources to cope with the retrofit needs of Poland and other emerging Eastern European economies. Development cooperation from abroad, such as the Department of Energy-sponsored retrofit project, provide a beginning. But the total funding available from international development organizations is likely to be far exceeded by the capital needs. Consequently, international investment would appear to be the major potential source for acceleration of the modernization of Poland's power generation sector. How to attract that investment, however, goes beyond the scope of this paper or EPRI's technical expertise.

There has seldom been a time when this phrase "changing world" was more applicable than to the world of 1991. The countries of Eastern Europe are in the center of the political and economic maelstrom. Reaching the level of prosperity of the advanced economies of the OECD will be no easy task.

But if it is to be done, electricity, environment and technological innovation will inevitably play a pivotal role.

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Table 1

Coal-Fired Generating Capacity Growth

	1990 Installed Coal Capacity (GW)	Expected Coal Growth 1990-2000		Expected Coal Growth 2000-2020	
		%/Yr	New GW	%/Yr	New GW
N. America	340	1.0	30	2.0	180
W. Europe, Japan, Australia	220	2.0	40	1.5	100
E. Europe, USSR	250	1.1	30	1.5	100
China, India, Africa	200	1.3	30	2.0	110
Pacific Rim, S. America	60	7.5	60	4.7	190
TOTAL	1040		190		680

Source: Frisch, J.R., 1986

Table 2

CLEAN COAL TECHNOLOGY PROGRAM
Funding Profile
(Basis: FY 1991 Budget Request)

Fiscal Years ($ Million)

CCT	1986	1987	1988	1989	1990	1991	1992	1993	1994	TOTALS
I	99.4	149.1	149.1							397.6
II			50.0	190.0	135.0	200.0				575.0
III					419.0	156.0				575.0
IV						100.0	250.0	250.0		600.0
V							150.0	225.0	225.0	600.0
TTL:	99.4	149.1	199.1	190.0	554.0	456.0	400.0	475.0	225.0	2747.6

Source: DOE/FE-0219P 1991

TABLE 3

CCT Demonstration Projects, by Technology Category

Technology Category	Project Sponsor	Demonstration Project	Solicitation
Precombustion Cleaning			
Coal Preparation	ABB Combustion Engineering, Inc., and CQ, Inc.	Development of the Coal Quality Expert	CCT I
	Western Energy Company	Advanced Coal Conversion Process Demonstration	CCT I
Clean Combustion			
Advanced Combustion	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	CCT III
	The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	CCT-II
	The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO_x Cell-Burner Retrofit	CCT-III
	The Babcock & Wilcox Company	LIMB Demonstration Project Extension[a]	CCT I
	Coal Tech Corporation	Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control	CCT I
	Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	CCT I
	Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	CCT III
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	CCT II
	Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions for Coal Fired Boilers	CCT II
	TransAlta Resources Investment Corporation	Low-NO_x/SO_x Burner Retrofit for Utility Cyclone Boilers	CCT II
Fluidized-Bed Combustion			
Atmospheric Circulating	The City of Tallahassee	Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project	CCT I
	Colorado-Ute Electric Association, Inc.	Nucla CFB Demonstration Project	CCT I
Pressurized	The Ohio Power Company and The Appalachian Power Company	PFBC Utility Demonstration Project	CCT II
	The Ohio Power Company	Tidd PFBC Demonstration Project	CCT I
	Dairyland Power Cooperative	Alma PCFB Repowering Project	CCT III

[a] Two technologies are being demonstrated in this project: LIMB, which uses sorbent injection in the boiler, and Coolside, which uses sorbent injection downstream of the boiler

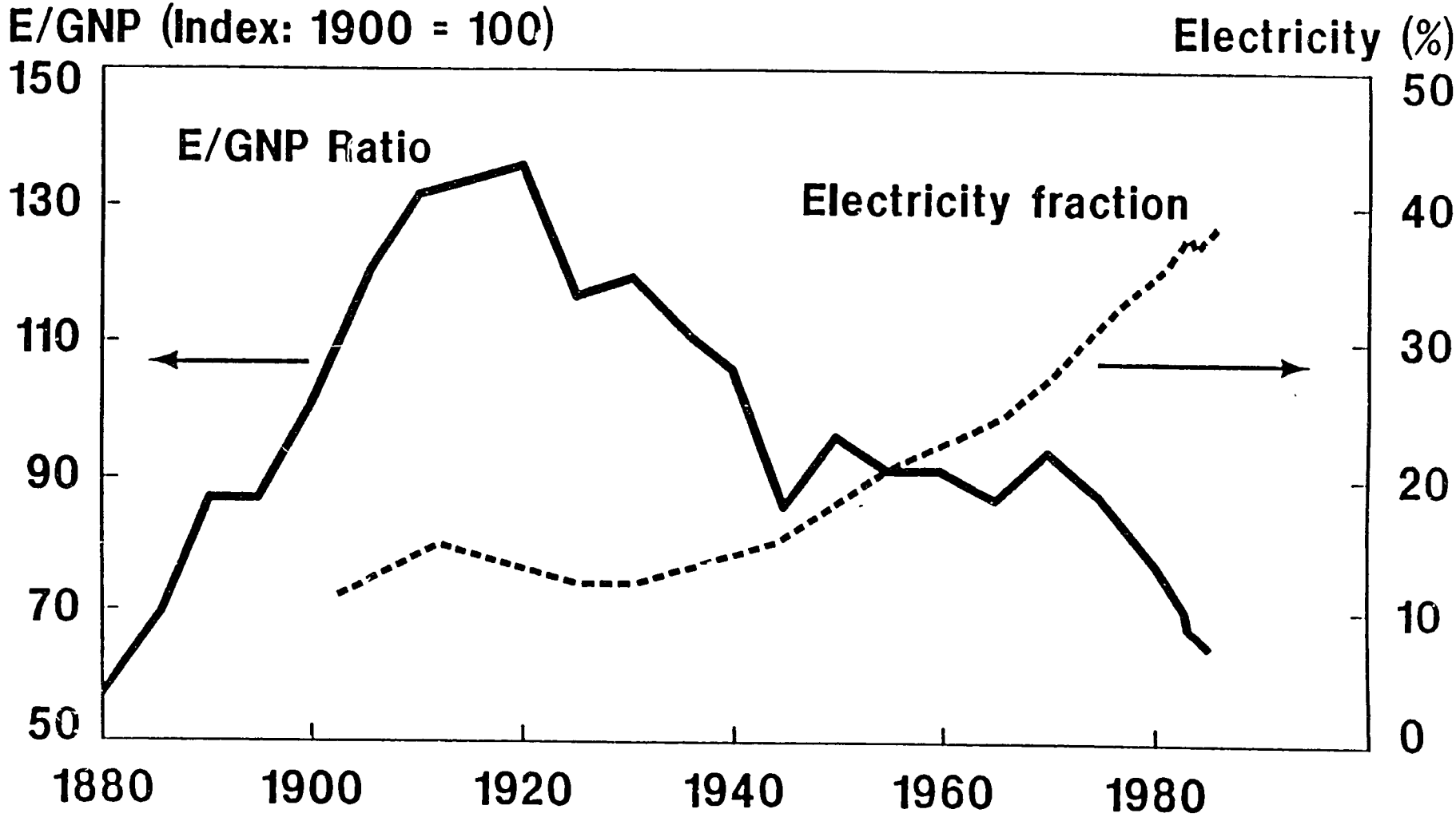
TABLE 3 (continued)

CCT Demonstration Projects, by Technology Category

Technology Category	Project Sponsor	Demonstration Project	Solicitation
Postcombustion Cleaning			
Flue Gas Cleanup—Combined SO_2/NO_x Control	ABB Combustion Engineering, Inc.	WSA-SNOX Flue Gas Cleaning Demonstration Project	CCT-II
	The Babcock & Wilcox Company	LIMB Demonstration Project Extension (Coolside Only)[a]	CCT-I
	The Babcock & Wilcox Company	SOX-NOX-ROX Box Flue Gas Cleanup Demonstration Project	CCT-II
	MK-Ferguson Company	Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System	CCT-III
	Public Service Company of Colorado	Integrated Dry NO_x/SO_2 Emission Control System	CCT-III
Flue Gas Cleanup—NO_x Control	Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers	CCT-II
Flue Gas Cleanup—SO_2 Control	Airpol, Inc.	10-MW Demonstration of Gas Suspension Absorption	CCT-III
	Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	CCT-III
	Bethlehem Steel Corporation	Innovative Coke Oven Gas Cleaning System for Retrofit Applications	CCT-II
	LIFAC–North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	CCT-III
	Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	CCT-II
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	CCT-II
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	CCT-II
Coal Conversion			
Gasification Combined-Cycle Systems	ABB Combustion Engineering, Inc.	Combustion Engineering IGCC Repowering Project	CCT-II
	Clean Power Cogeneration Limited Partnership	Air-Blown/Integrated Gasification Combined-Cycle Project	CCT-III
Mild Gasification	ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	CCT-III
Coal Liquefaction	Air Products and Chemicals, Inc., and Dakota Gasification Company	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH®) Process	CCT-III
	Ohio Clean Fuels, Inc.	Prototype Commercial Coal/Oil Coprocessing Plant	CCT-I
Direct Coal Use in Iron Making	Bethlehem Steel Corporation	Blast Furnace Granulated-Coal Injection System Demonstration Project	CCT-III

FIGU[redacted]1

U.S. ENERGY/GNP RATIO & ELECTRICITY FRACTION 1880-1985



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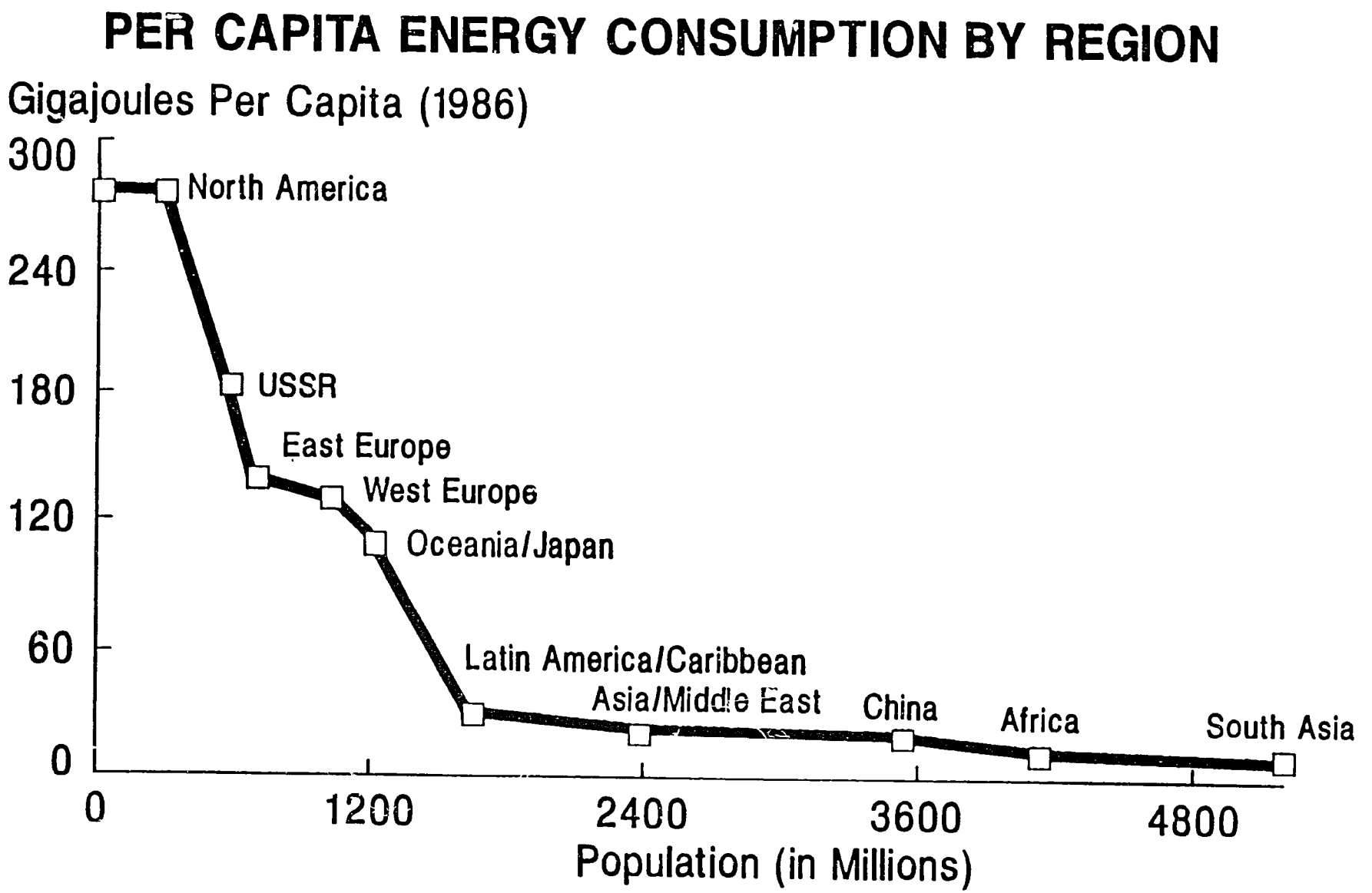
35968.

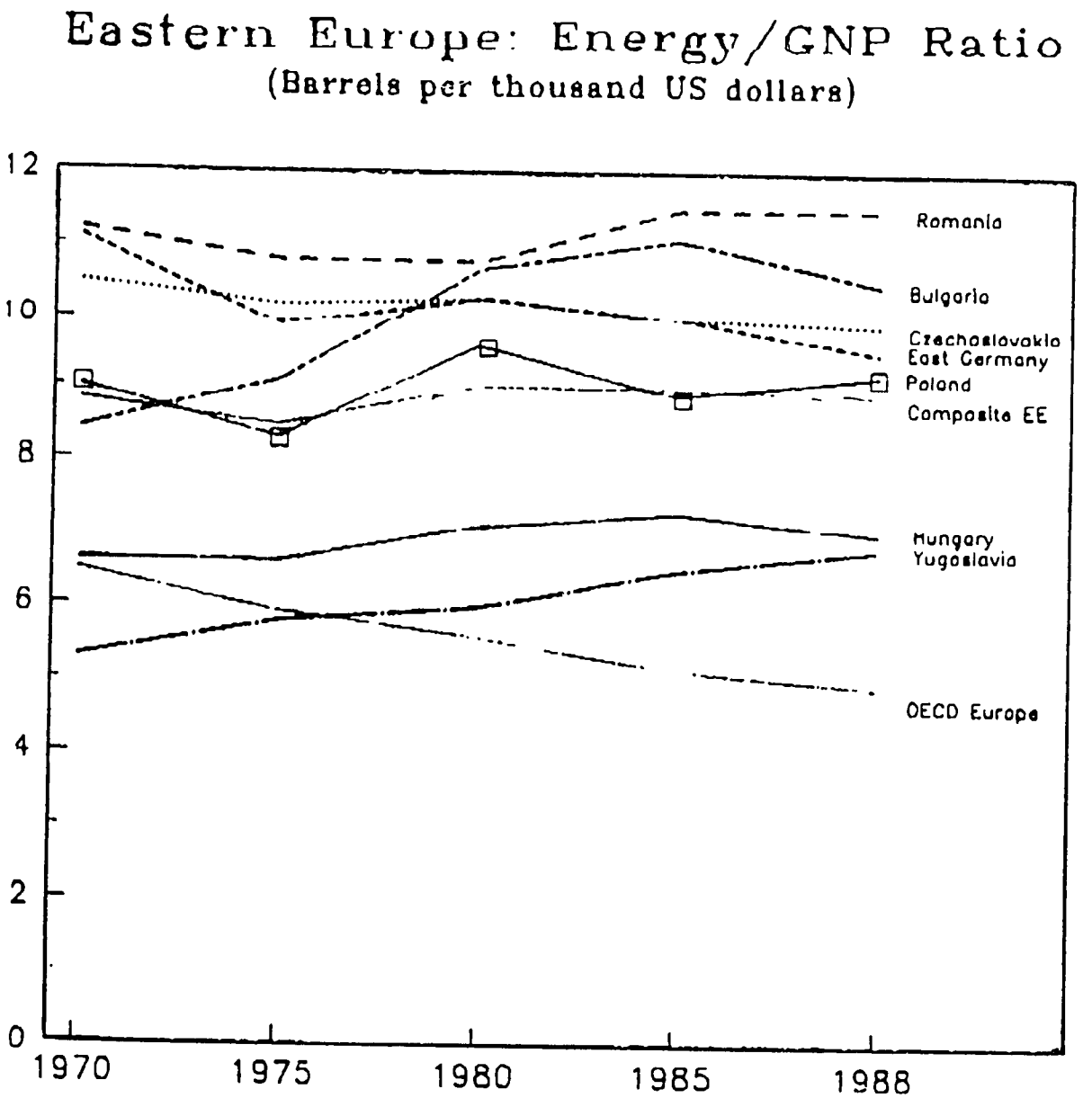
FIGURE 2



Source: World Resources 1989; RFF analysis

0386.08

FIGURE 3

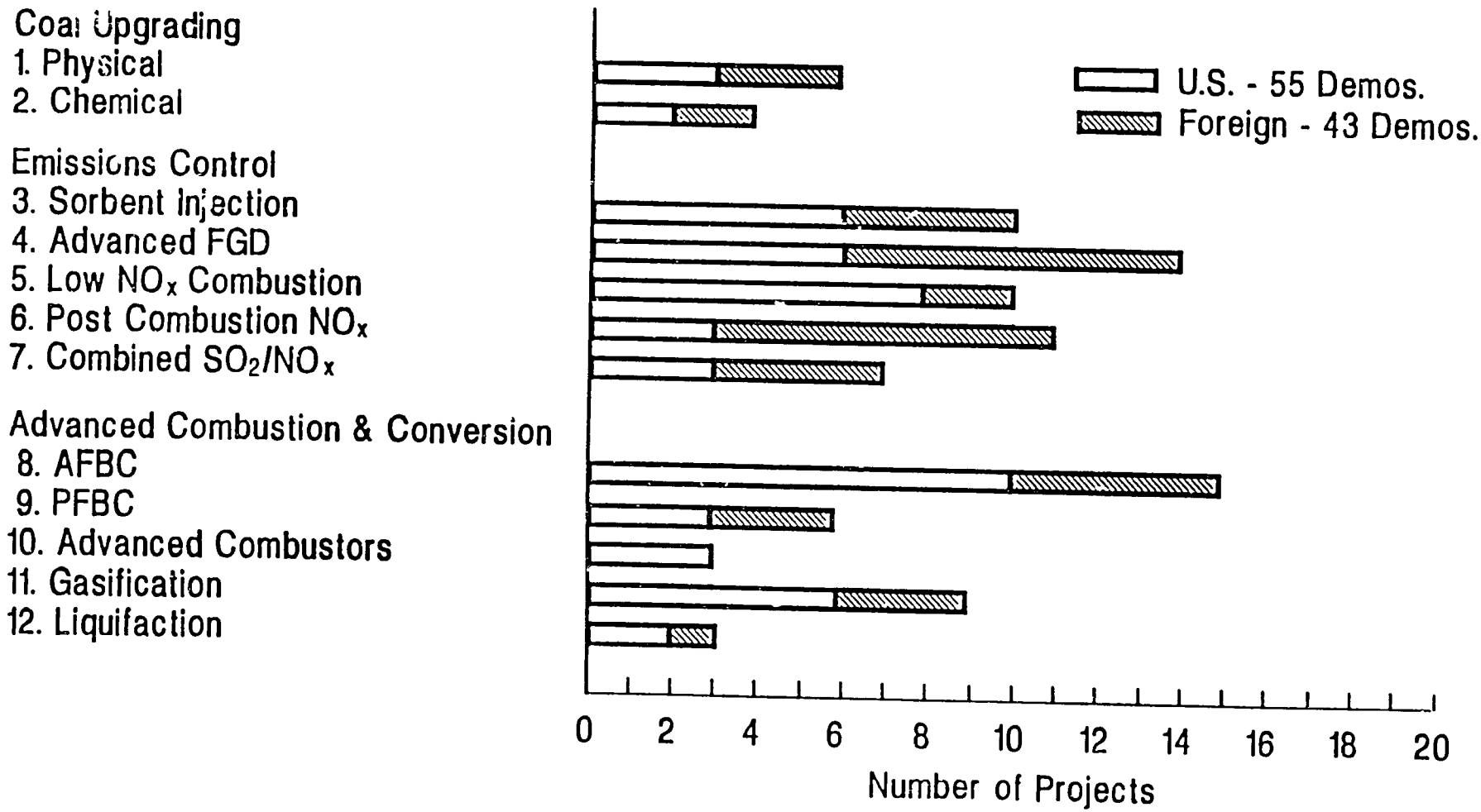


GNP data represented in 1988 US dollars.

Source: International Energy Agency

FIGURE 4

CLEAN COAL DEMONSTRATIONS



0392e.37

FIGURE 5

TYPICAL PULSE JET FABRIC FILTER CONFIGURATION

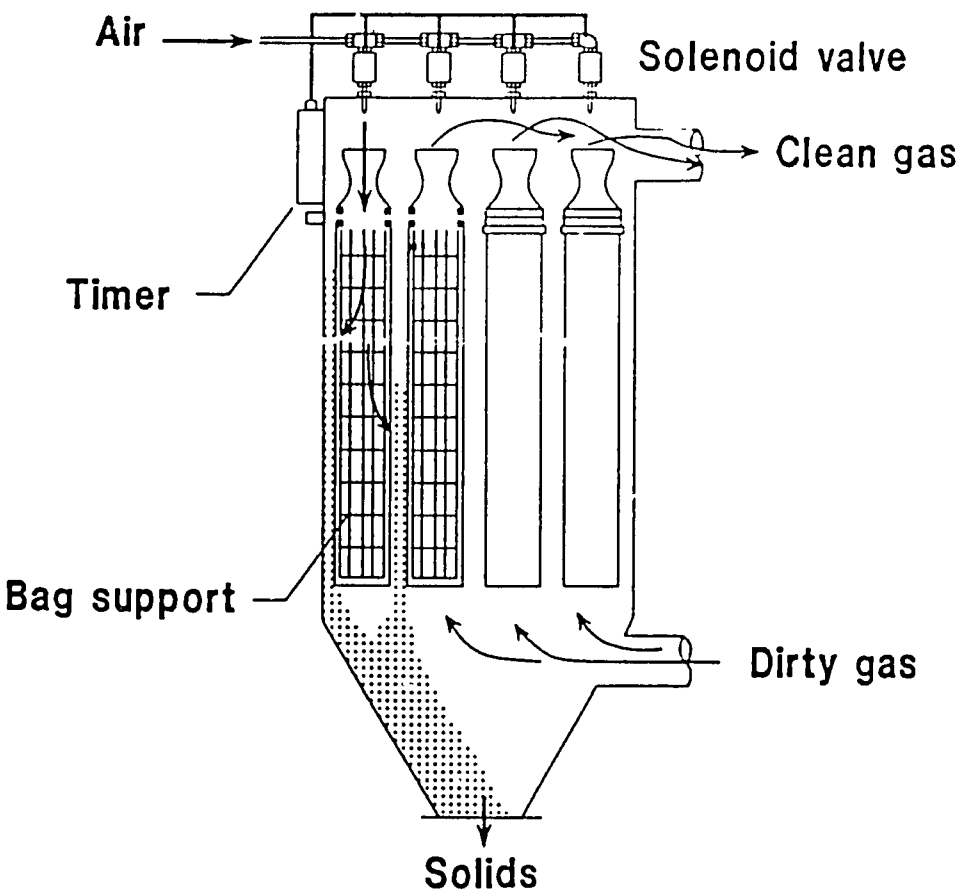
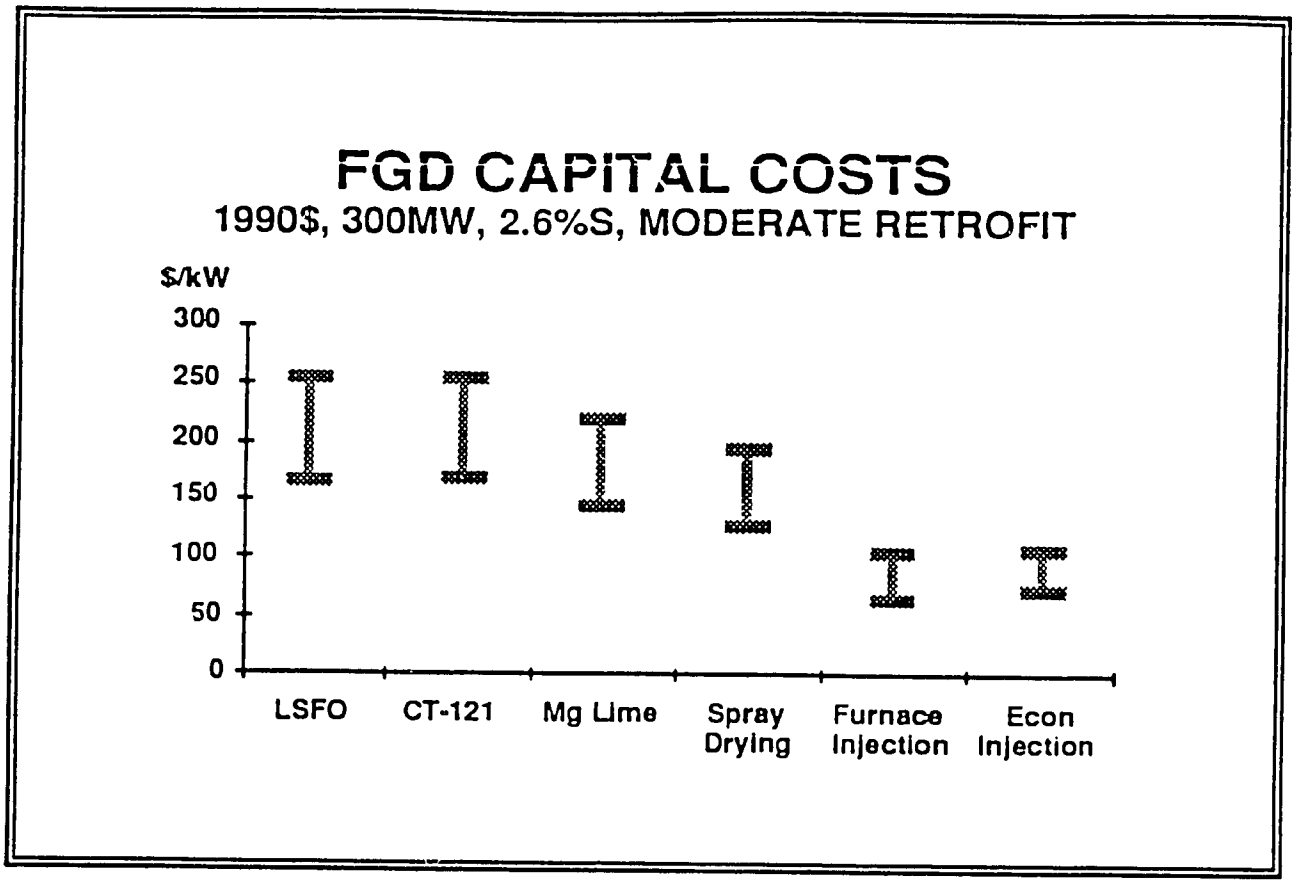
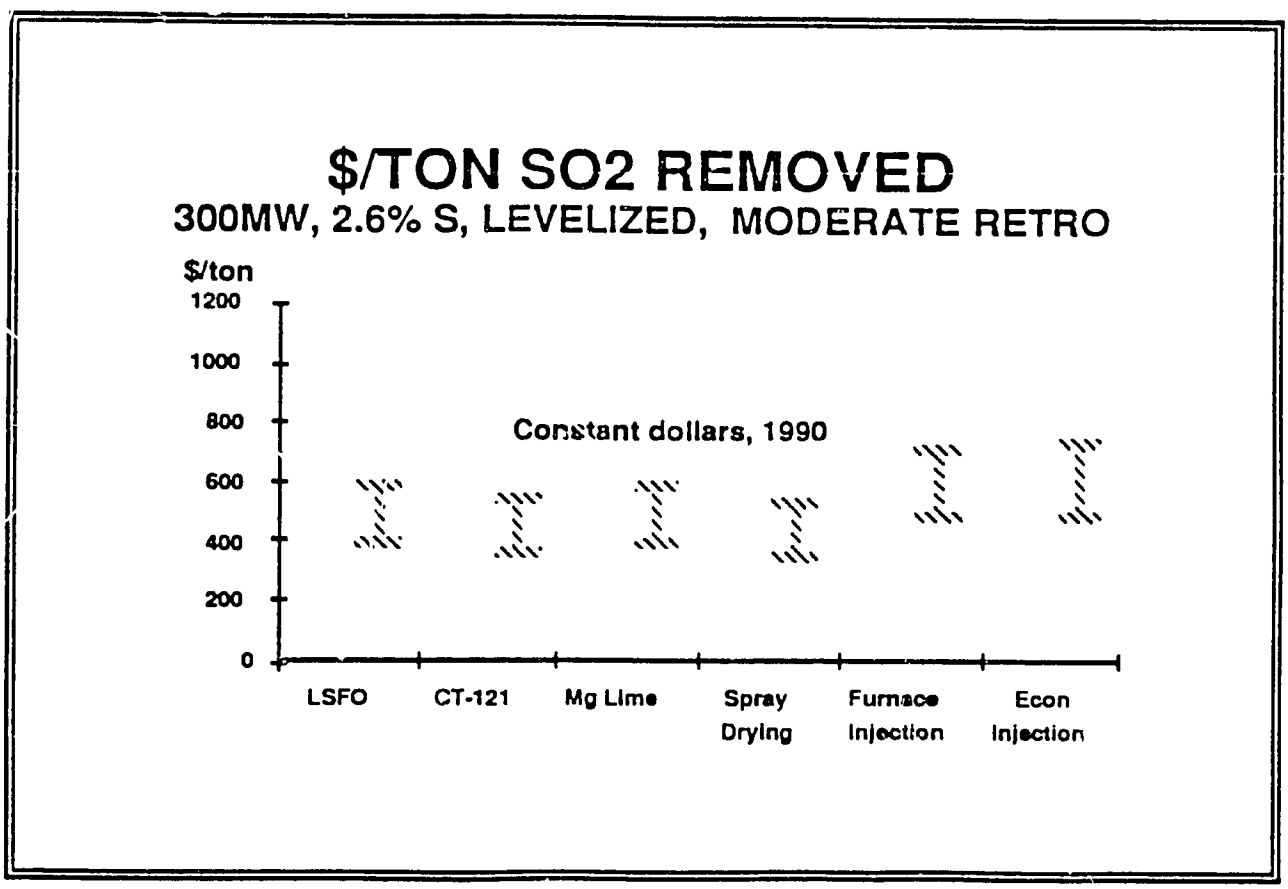


FIGURE 6


FGD CAPITAL COSTS
1990$, 300MW, 2.6%S, MODERATE RETROFIT
$/kW
300
250
200
150
100
50
0
LSFO
CT-121
Mg Lime
Spray Drying
Furnace Injection
Econ Injection


$/TON SO2 REMOVED
300MW, 2.6% S, LEVELIZED, MODERATE RETRO
$/ton
1200
1000
800
600
400
200
0
Constant dollars, 1990
LSFO
CT-121
Mg Lime
Spray Drying
Furnace Injection
Econ Injection

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