International pollution control costs of coal-fired power plants

Here is a comparison of costs in the U.S., Europe, and Japan, a look at coal's competitiveness with other energy sources, and some thoughts on future technological developments

Edward S. Rubin
Center for Energy and Environmental Studies
Carnegie-Mellon University
Pittsburgh, Pa. 15213

In countries looking to coal as a major energy source for the generation of electricity, the cost of pollution abatement is a major concern. Such costs could affect coal's competitiveness with other energy sources. This problem was discussed extensively at an international symposium on costs of pollution abatement, held in Petten, The Netherlands, last year, and sponsored by the Organization for Economic Cooperation and Development (OECD) (*1*).

In general, pollution abatement costs depend on

- physical parameters related primarily to coal characteristics, power plant design, environmental control system design, and plant operation,
- applicable regulatory standards determined by public policy,
- economic and financial parameters such as interest rates, tax treatment, and raw materials' cost, and
- the definition of included and excluded items.

Differences in such factors are the principal cause of capital and operating cost variations across different studies. To compare the environmental control costs of coal-fired power plants, the specific pollutants being controlled should be carefully identified and any important differences in scope or definition made explicit. Unfortunately, many studies do not report their underlying assumptions in sufficient detail to permit rigorous comparisons for similar premises. The difficulties of making international comparisons can be further exacerbated by differences in nomenclature and costing methodology.

In this article, capital costs and annual revenue requirements reported in recent studies are presented together with a summary of key assumptions to illustrate the range of published costs for environmental control. All costs have been converted or adjusted to first-quarter 1982 U.S. dollars. Wherever possible, pollution abatement costs also are summarized as a fraction of total plant cost. Ranges of reported costs are given in terms of their mean value and uncertainty. Selected measures also are derived to show how different costs compare on the basis of similar levels of performance or effectiveness, and a simplified method is presented for estimating major pollution control costs for a range of user-specified assumptions.

Power plant pollution abatement systems may be characterized as controlling air pollutants, water pollutants, and solid wastes. Noise control systems also are considered an environmental control measure in a number of studies. However, the greatest attention is given to air pollution control, consistent with the concerns of the international community (*1*).

Sulfur oxide control

Control of sulfur oxide (SO_x) emissions most strongly dominates international discussions of environmental control costs since technological options are relatively expensive and not yet widely implemented in many countries. Control of SO_x emissions is achieved either by the use of low-sulfur fuels or by installation of a flue gas desulfurization (FGD) system. While the former remains the most prevalent method for existing power plants, FGD systems are increasingly being used at new installations, principally in Germany, Japan, and the U.S.

Where FGD is employed, wet lime or limestone scrubbing processes are used almost exclusively. In the U.S., a limestone scrubber producing a solid waste for disposal is the prevailing technology, while scrubbers in Germany and Japan typically use lime and produce gypsum as a by-product. Regenerative FGD systems producing by-product sulfur or sulfuric acid have been adopted only on a very limited scale where site-specific factors make it economical. The use of "dry" FGD systems currently is receiving considerable attention and development, but has not yet been widely implemented on a commercial scale. A number of major utility projects, however, are now in progress in the U.S.

Cleaning coal to reduce ash and sulfur content prior to coal combustion is also receiving significant attention in many countries. Techniques currently being developed in Germany and the U.S. involve better cleaning of small-sized, finely ground coal, with greater separation of mineral matter, including sulfur-laden pyrite.

However, costs increase considerably as finer coal sizes are treated. Currently, total costs for cleaning German coals (primarily for ash removal) are approximately \$3/metric ton (*2*). Estimated costs for new coal preparation plants in the U.S. range from approximately \$1–2/metric ton of cleaned coal for a relatively simple plant with no appreciable sulfur removal, to approximately \$4–6/metric ton for more complex plants able to

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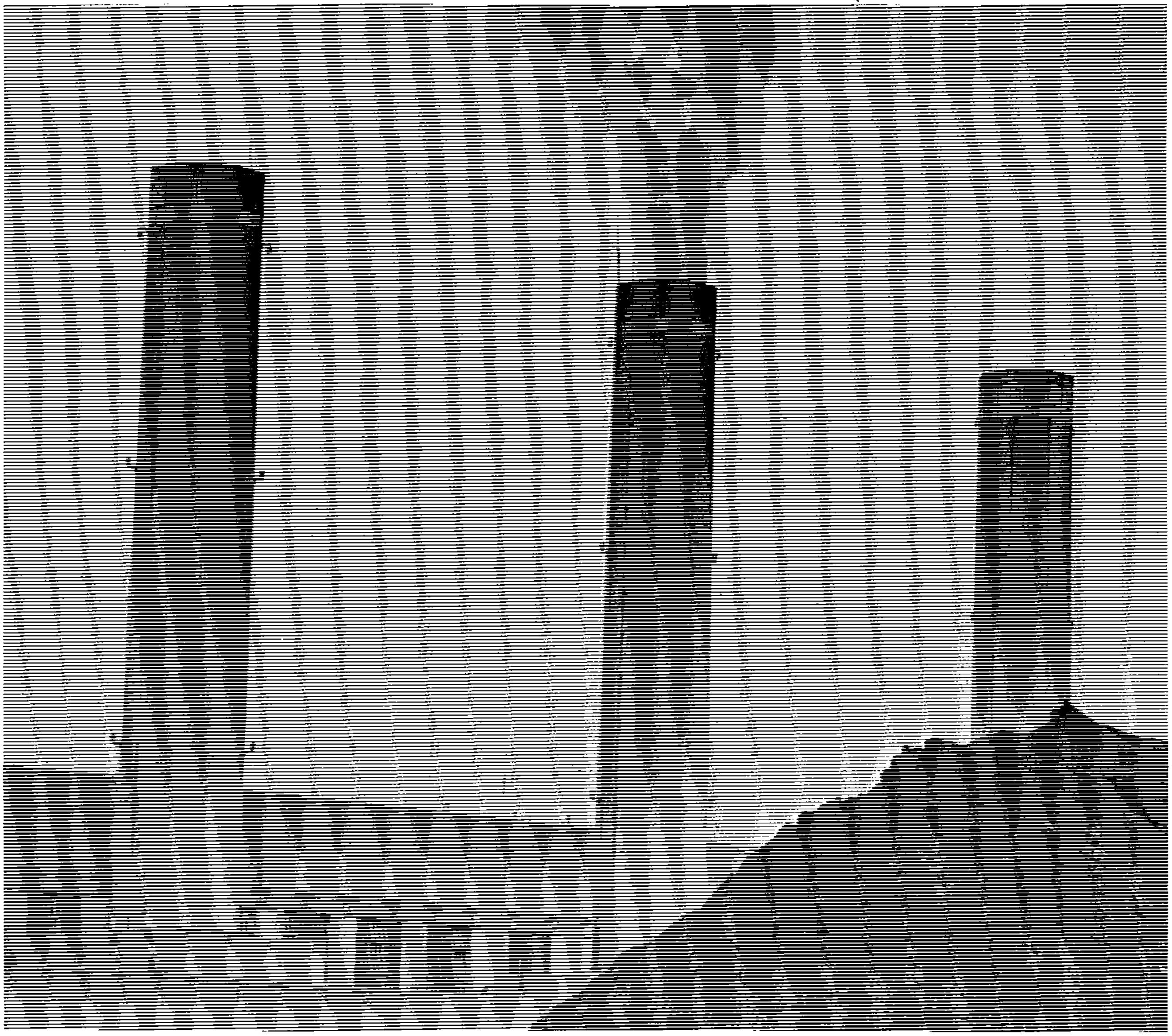


remove 20% to 40% of the total sulfur as well as significant amounts of ash (*3*). The value of coal lost with the cleaning plant refuse would add approximately 5–20% of the raw coal cost to these figures, depending on the level of cleaning. Currently, commercial processes employ physical cleaning and can only remove sulfur present in the form of mineral pyrite. Chemical processes able to remove organic sulfur are still under development. In many cases, however, clean coal alone is insufficient to meet environmental regulations, and FGD systems are required.

Tables 1 and 2 summarize the capital costs and revenue requirements, respectively, reported in recent studies (*3–15*). Table 1 shows reported capital costs of a wet lime or limestone FGD system for SO_x control (in 1982 dollars) ranging from \$72 to \$184/kW of installed capacity for plants in Germany, Japan, and the U.S. These values represent 11–18% of total power plant cost, with an average value of 13%, corresponding to approximately \$140/kW, excluding sludge disposal costs. Case studies on which these capital costs are based, however, reflect plant sizes ranging from 150 to 2000 MW, coals of different quality, and differences in environmental standards, FGD system design, and economic assumptions.

While a comprehensive analysis of the effect of such differences is limited by available information, some key insights are possible. Table 3 summarizes analytical models for simplified cost calculations that show the effect of key variables on pollution control costs (*16*). For a lime or limestone FGD system at a moderate-to-large-sized plant (500 MW or more), the variation in capital cost per kilowatt at a given location is primarily a function of the maximum sulfur or sulfur dioxide removal rate. This, in turn, depends principally on the coal sulfur content and the required SO_2 removal efficiency, as determined by the applicable emission standard. For the cases in Table 1, the maximum sulfur removal rates vary from approximately 1 to 16 metric tons of sulfur per million kWh (that is, coals of 0.5% to 4.0% S with net removal efficiencies of 30% to 95%). This accounts for a significant portion of the cost variations in Table 1. Some economies of scale also are achieved for larger units with lower heat rates.

More significant are design considerations such as full vs. partial scrubbing and the inclusion of redundant scrubber trains to enhance system reliability (common in U.S. plants but not in Japan or Germany). In addition, differences in key economic parameters and assumptions, such as interest rates and facility lifetime, also are pronounced (see footnotes to Tables 1 and 2). For example, FGD systems in

TABLE 1

Capital costs for pollution control at a new coal-fired power plant[a] (1982 U.S. $)

Reference no.	Plant size (MW)	Capital cost ($/kW) SO$_x$	Capital cost ($/kW) TSP	Capital cost ($/kW) NO$_x$	Capital cost ($/kW) Total env. control	% of total plant cost SO$_x$	% of total plant cost TSP	% of total plant cost NO$_x$	% of total plant cost Total env. control
Federal Republic of Germany									
(4)[b,c]	750	109	22						
(5)[b,d]	600		13						
(6)[b,e]	150	117 ± 18[f]				12–15			
	750	72 ± 8[f]							
(7)	(Not given)								27[g]
Japan									
(8)[h]	2000[i]	134	29	9	172[l]	11.8	2.6	0.8	15.2[l]
	2000[j]	154	31	29	214[l]	13.1	2.6	2.5	18.2[l]
	2000[k]	182	31	42	256[l]	15.0	2.6	3.5	21.1[l]
(9)[m]	2000[n]	0	12	5	56[q]	0	1.2	0.5	5.4[q]
	2000[o]	131	12–20	7–12	236–249[q]	10.9	1.0–1.6	0.6–0.9	20 ± 0.2[q]
	2000[p]	131	12–20	38	271–278[q]	10.6	1.0–1.6	3.1	22 ± 0.3[q]
U.S.									
(3)[r]	1000	143	45		218[s]	11.6	3.7		17.7
(10)	500[t]	175[w]	40						
	500[u]				176[s]				
	500[v]				244[s]				
(11)[x]	500[y]	90				11.3			
	500[z]	120 ± 10			165 ± 15[v]	14.5			20.0[v]
	500[aa]	180				20.6			
(12)[bb]	1000[cc]	121 ± 16	96 ± 11	14 ± 7	329 ± 57[ee]	11.6 ± 0.1	9.3 ± 0.1	1.3 ± 0.5	31.5 ± 1.5[ee]
	1000[dd]	184 ± 23	56 ± 6	13 ± 7	385 ± 71[ee]	17.5 ± 0.2	5.3 ± 0.1	1.2 ± 0.5	36 ± 2[ee]

Footnotes to Tables 1 and 2

[a] Unless otherwise specified, environmental control systems are assumed to be: a wet lime or limestone scrubber for SO$_x$, an ESP for particulates (TSP), and combustion modifications for NO$_x$.

[b] Calculated assuming 2.40 DM/U.S. $ and 5% inflation of reported costs to 1982.

[c] Assumes designs currently going on-line in Germany; SO_2 removal of 50–80%, fly ash removal above 99%, with plant operating 4000 h/y.

[d] Costs are based on a South African coal and include supplies, erection, and start-up, but not ducts, dust-handling system, or engineering. Plant operates 8000 h/y.

[e] Coal has 1.5% S. SO_2 emission limit is 650 mg/Nm^3. Plant operates 5000 h/y. Credit is taken for by-product gypsum.

[f] Excludes land cost. Equipment cost based on manufacturer's estimates. Details of project scope not reported.

[g] Details not reported. Appears to include all environmental controls for air, water, and land.

[h] Plant with two units. Coal of 1.2% S, 15–20% ash, $70/metric ton. Reported costs are adjusted to 240 yen/U.S. $. Plant capacity factor is 0.70. Discount rate is 10%.

[i] Level II emissions: 200 ppm, SO_2 (80% removal); 100 mg TSP/Nm^3 (hot-side ESP); 300 ppm NO$_x$.

[j] Level III emissions: 100 ppm SO_2 (90% removal); 30 mg TSP/Nm^3 (hot-side ESP); 150 ppm NO$_x$ [combustion modifications plus 50% selective catalytic reduction (SCR)].

[k] Level IV emissions: 50 ppm SO_2 (95% removal); 30 mg TSP/Nm^3 (hot ESP); 60 ppm NO$_x$ (combustion modifications plus full SCR).

[l] Only costs related to air pollution control were reported. No FGD sludge disposal costs or credits are included with SO_2 control.

[m] Plant with two units. Capacity factor 0.70. Coal of 1.2% S, 15–20% ash, 1.8% N_2, $70/metric ton. Costs at 240 yen/U.S. $. Reported 1981 costs inflated 5% to 1982. Interest rate 10%, inflation rate 5%, fuel escalation rate 8%.

[n] Model I emission levels: 1000 ppm SO_2 (no control); 400 mg TSP/Nm^3; 400 ppm NO$_x$.

[o] Model II emission levels: 100 ppm SO_2; 30–50 mg TSP/Nm^3 (ESP + FGD); (a) 300 or (b) 170 ppm NO$_x$ (combustion modifications, gas recirculation).

[p] Model III emission levels: 100 ppm SO_2; 30–50 mg TSP/Nm^3; 60 ppm NO$_x$ (Model II + SCR).

[q] Includes effluent control at 9, 15, and 17 $/kW for Models I, II, and III, respectively, plus "others" at 29, 71, and 72 $/kW accounting for 2%, 6%, and 9% of total generating cost for Models I, II, and III, respectively. This category includes dust control, noise control, ash disposal, and other miscellaneous costs.

[r] Reported 1981 costs inflated 5% to 1982. Coal of 2.0% S, 15% ash, $30/U.S. ton. Emission levels of 0.6 lb SO_2/MBtu and 0.03 lb TSP/MBtu. Plant capacity factor of 0.65.

[s] Includes cost of solid waste disposal, SO_2, and particulate control.

[t] FGD costs based on 4% S coal, 90% SO_2 removal. ESP costs based on 99.7% efficiency and 5×10^{10} ohm-cm resistivity, with 1980 costs inflated 20% to 1982. Plant operates 5500 h/y. Reported 1984 FGD operating costs adjusted to 1982 assuming 13.5% deflation of O&M costs, which were assumed to be approximately 50% of total revenue requirement.

[u] 0.7% S western coal. 1984 operating costs adjusted as in (t).

[v] 3.5% S eastern coal. 1984 operating costs adjusted as in (t).

[w] Waste sludge disposal excluded from capital cost but included in annual revenue requirement.

TABLE 2

Contribution of pollution control cost to total annual revenue requirement (1982 U.S. $)

Ref. no.	Cost basis*	Plant size (MW)	Reported annual cost (mills/kWh) SO$_x$	TSP	NO$_x$	Total env. control	% of total annual electricity cost SO$_x$	TSP	NO$_x$	Total env. control
Federal Republic of Germany										
(4)[b,c]	(F)	750	(8.7)	(1.0)						
(5)[b,d]	(F)	600		(0.4)						
(6)[b,e]	(F)	150	(6.6 ± 0.9)							
		750	(4.7 ± 0.5)							
Japan										
(8)[h]	(L)	2000[i]	8.7	1.5	0.4	10.6[l]	12.6	2.2	0.6	15.4[l]
		2000[j]	9.6	1.6	2.6	13.8[l]	13.3	2.2	3.6	19.1[l]
		2000[k]	10.9	1.6	4.3	16.8[l]	14.6	2.1	5.8	22.5[l]
(9)[m]	(L)	2000[n]	0	0.6	0.7	4.8[q]	0	0.7	0.3	5.6[q]
		2000[o]	8.9	1.0	0.7	16.0[q]	9.1	1.0	0.6	16.1[q]
		2000[p]	8.9	1.0	5.8	26.8[q]	8.1	0.9	5.3	24.3[q]
U.S.										
(3)[r]	(F)	1000	(8.5)	(1.5)		(11.2)[s]	(13.4)	(2.8)		(18.1)
(10)	(F)	500[t]	(9.4)[w]	(1.6)						
	(L)	500[u]				10.0[s]				
		500[v]				15.3[s]				
(11)[x]	(F)	500[z]	(5.5 ± 0.5)			(7 ± 1)[v]	(10.3)			(13.0)[v]
(12)[bb]	(L)	1000[cc]	10.6 ± 0.5	3.5 ± 0.3	0.4 ± 0.2	21.2 ± 2.7[ee]	11.8 ± 0.5	3.9	0.5 ± 0.1	23.5 ± 0.5[ee]
		1000[ee]	17.1 ± 0.6	2.0 ± 0.2	0.4 ± 0.1	31.2 ± 4.5[ee]	17.7 ± 1.1	2.1	0.4 ± 0.1	31.5 ± 1.5[ee]
Denmark										
(13)[ff]	(F)	400[gg]	(2.5)[jj]							
		400[hh]	(3.3)[jj]							
		400[ii]	(4.3)[jj]							
The Netherlands										
(14)	(F)	600				(6.7)[kk]				(12.7)[kk]
Sweden										
(15)[ll]	(F)	200	(2.9)[mm]							
		200	(5.7)[nn]							

* (F) = First-year cost basis (shown in parentheses)
(L) = Levelized cost basis

[x] All cases meet emission standards of 1.08 lb SO_2/MBtu and 0.03 lb TSP/MBtu. Plant capacity factor of 0.63. Base case coal of 1.5% S, 15% ash, costing $70/metric ton (Europe). Reported FGD costs include solid waste disposal by landfill.
[y] 1.0% S coal.
[z] 1.5% S coal (base case).
[aa] 3.5% S coal.
[bb] Plant with two 500-MW units, capacity factor of 0.65. 1981 EPRI Economic Premises. 1982 environmental standards. Reported costs inflated 5% to 1982.
[cc] Wyoming coal (0.48% S).
[dd] Illinois coal (4% S).
[ee] Includes solid waste disposal, plant cooling, water treatment, and noise control.
[ff] Base case plant using coal of 1.2% S, 10.7% ash, operating 6500 h/y (full load).
[gg] 1.0% S coal.
[hh] 2.0% S coal.
[ii] 3.0% S coal.
[jj] Dry spray tower scrubber removing 85% SO_2 with ESP particulate collector. Costs do not include ESP, land, engineering costs, administration, or taxes.
[kk] Includes full FGD, low-NO_x burners, advanced particulate control, noise and dust abatement. Urban area. Coal characteristics and emission levels not specified.
[ll] Costs assume 5.9 kroner/U.S. $. Reported 1981 costs inflated 5% to 1982. SO_2 removal via a wet–dry method. Details of coal and plant operation not specified.
[mm] Estimate by Swedish Coal Project (KHM).
[nn] Estimate by Fläkt Company.

Japan are assumed to have a seven-year life (*8*), while in many U.S. studies, a life of 30 y is assumed (*3, 10, 11*).

Annual costs

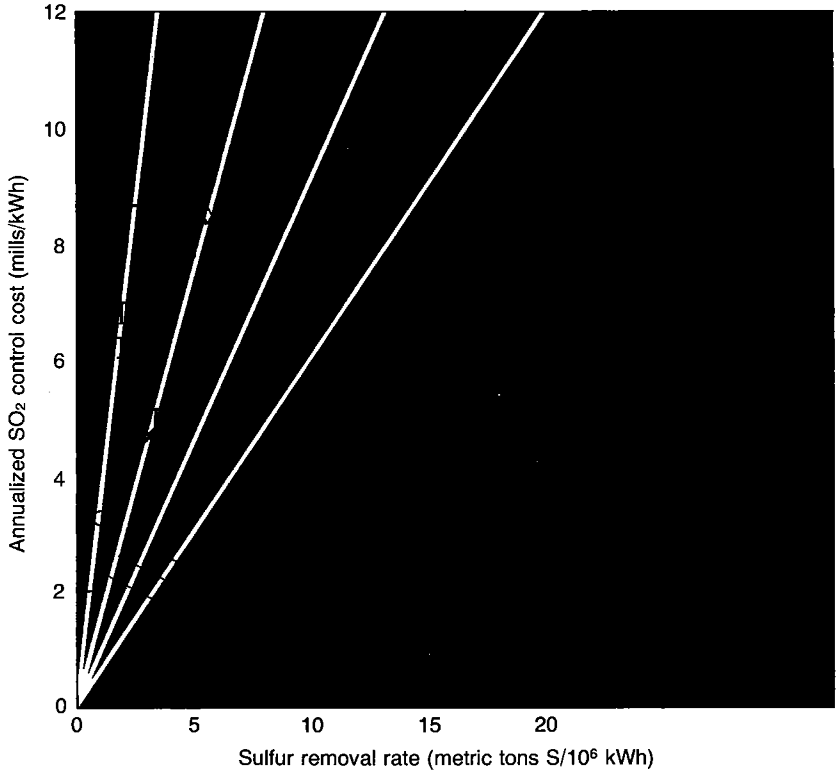
Table 2 summarizes the annual revenue requirement for pollution abatement reported in various studies. This includes certain fixed costs—principally the cost of capital—plus variable costs, such as utilities, labor, and maintenance, associated with system operation. Note that there are two different methods of presenting results. In the majority of cases, annual costs are reported for the first year of power plant operation (shown in parentheses). Other studies report a "levelized" annual cost, a measure of the lifetime annual average revenue requirement calculated from projected price escalations in various cost components. The calculation for both methods is presented in Table 3.

Levelized pollution control costs are typically 20–50% greater than corresponding first-year costs and more heavily reflect the contribution of variable costs to total revenue requirements. For most of the studies in Table 2, detailed information regarding the assumptions for levelized cost calculations is not available, so direct comparisons across all studies are not possible. Table 2, however, does show available data on the annual cost of pollution control systems as a percentage of the total annual cost of power plant operation, thereby permitting somewhat broader comparisons. SO_2 control costs for lime/limestone FGD systems range from 8% to 18% of total plant cost (excluding solid waste disposal), with the average of reported values being 12%. The highest relative costs are incurred at higher levels of SO_2 removal.

A comparison of annual cost data for comparable levels of performance is shown in Figure 1. Here, estimates of first-year revenue requirements in mills/kWh (1 mill = \$0.001) were derived and plotted against the calculated or estimated sulfur removal rate in tons/unit of electricity generated. The slope of a line through the origin then reflects the average cost of sulfur removal in dollars/ton of sulfur removed. This is a common measure of cost-effectiveness, useful for comparing different sulfur removal systems.

Studies reported to the OECD generally involved plants using either low-sulfur bituminous coals of about 1.0–1.5% sulfur, or high-sulfur coals of about 3.5–4.0% sulfur. For the latter cases the annual average FGD cost was equivalent to approximately \$750/metric ton S removed, while for the former cases the average cost was approximately \$2150/metric ton S removed. The analytical models in Table 3 indicate that with all other factors held constant, the FGD cost per unit of sulfur removed varies inversely with coal sulfur content. This is the principal factor responsible for the three-fold variation in the average cost between studies concerning high-sulfur and low-sulfur coals.

FIGURE 1
Cost-effectiveness of wet FGD systems for sulfur removal



[a] Assumes a nominal coal heating value of 31.4 MJ/kg (13 500 Btu/lb), net plant heat rate of 9500 Btu/kWh, 5% sulfur retention in ash.

[b] Same as (a), plus 80% SO_2 removal.

[c] Assumes 8% retention of sulfur in ash.

[d] Assumes net plant heat rate of 9500 Btu/kWh, 5% sulfur retention in ash. First-year cost assumed to be 87% of reported levelized cost.

[e] Assumes 9500 Btu/kWh, 5% sulfur retention in ash. First-year cost obtained from private communication.

[f] Assumes coal of 3.5% S, 11 700 Btu/lb based on private communication. Heat rate, sulfur retention, and cost indexes based on premises for TVA computer model.

[g] Assumes 5% retention of sulfur in ash.

[h] Coal characteristics, plant characteristics, and first-year cost estimates obtained from private communication.

However, the allowable SO_2 emission rate, as well as certain FGD design parameters, particularly the scrubber removal efficiency and the ratio of spare scrubber trains to operating trains, also influences the cost-effectiveness of FGD systems. Again, a systematic assessment of the importance of such factors across different studies using similar coals was precluded by data limitations. Nonetheless, Figure 1 suggests a much greater degree of similarity among national studies when data are viewed in terms of cost-effectiveness for a given coal quality. Overall, the cost-effectiveness of sulfur removal seen in Figure 1 ranges from approximately \$700 to \$3500/metric ton S removed, or \$350–1750/metric ton of SO_2.

Reported capital and operating costs for SO_2 removal systems other than wet lime/limestone scrubbing are based on relatively limited commercial applications. Hence, they are less representative than lime/limestone costs. For dry FGD systems, capital costs reported in a Danish study (*13*) are only about one-third the average costs reported for wet FGD systems, but do not include the costs of particulate collection, land, engineering, and other items typically included in the cost estimates of other dry systems.

A study by the U.S. EPA (*10*)

comparing wet and dry FGD systems indicates a lower cost for the dry system at sulfur contents of up to nearly 3.5% for U.S. bituminous coal, though other studies indicate cost advantages for dry FGD only at much lower sulfur contents, typically about 2% or less. For low-sulfur coals in the EPA study, dry FGD annual revenue requirements were up to 20% less than for a wet FGD system for comparable levels of sulfur removal plus total suspended particulate (TSP) control. Combined SO_2/TSP capital costs were 13% to 18% lower with dry FGD. Similarly, lower operating costs were reported for a spray dryer in Germany (*6*), while in Japan (*8*) levelized annual costs for SO_2/TSP control were 16% lower for an advanced dry FGD system than for a comparable wet FGD system. Dry FGD systems thus offer the potential for significantly reduced SO_2 control costs at coal-fired power plants using low-sulfur coal. But further demonstration of this technology at the commercial scale is needed so that more reliable estimates of capital and operating costs can be developed and refined.

Similar experience is needed for SO_2 removal using adipic acid or other organic acids in conjunction with wet limestone systems. This technique offers potential savings of about 5% and 7% on capital and operating costs, respectively, when it is used with high-sulfur U.S. coals (*10*). Less expensive reagents, such as dibasic acid (DBA), may offer still larger cost reductions with high SO_2 removal efficiencies. Alternative technologies such as limestone injection multistage burners (LIMB) are not yet sufficiently advanced to offer definitive economic estimates, though current expectations for LIMB are encouraging (*10*).

Particulate control

Electrostatic precipitators (ESP) are the most universally employed devices for fly ash control. Table 1 summarizes current capital costs reported by various sources. These range from \$12 to \$96/kW (1982 basis), with a typical value of \$35 ± \$10/kW for plants meeting current standards with coals of 1.2% S or more. Analytical models for a cold-side ESP (Table 3) suggest that the capital cost for a particular plant depends primarily on the coal ash content, sulfur content, and required particulate removal efficiency, with costs increasing significantly for low-sulfur coals. However, Table 1 also shows that on the average, particulate collection costs are less than 4% of total plant capital costs, and less than one-fourth the capital investment for FGD.

From Table 2, the annual revenue requirements for particulate removal are seen to be only about 10–30% of the values reported for SO_2 removal in any given study. As a percent of the total annual cost of electric power generation, particulate removal accounted for 1–4%, with an average reported cost of 2%.

For plants using low-sulfur coal, the use of flue gas conditioning can further reduce particulate operating costs by a modest amount when cold-side electric precipitators are employed (*5*). Advanced two-stage ESP designs also may reduce future cost by up to 10% for high-resistivity coals (*10*). Hot-side ESPs have been installed in a number of U.S. power plants burning low-sulfur coal and are incorporated into the Japanese plant designs cited above. While a hot ESP is generally less costly than a cold ESP for low-sulfur coal applications, operating difficulties at several existing units have brought a halt to their use at new plants in the U.S. At the same time, capital and operating costs for full-sized fabric filter systems, which are now coming into greater use in the western U.S., appear preferable to ESPs for low-sulfur coals (*3*). Current estimates of fabric filter costs also appear comparable to those for a hot-side ESP in advanced environmental control system designs in Japan (*8*). Firmer figures on fabric filter costs must await additional operating experience with full-scale utility operations. Based on current research, it appears that future fabric filter costs may be reduced about 10% with advanced design using electrical stimulation (*10*), in which dust particles are electrically precharged to enhance their capture in fabric filters.

Nitrogen oxide control

The cost of nitrogen oxide (NO_x) control depends significantly upon applicable regulatory requirements. For moderate NO_x reductions (up to about 50%), which are achievable through combustion modifications plus low-NO_x burners, Table 1 shows that capital costs for coal-fired power plants average about \$10/kW, or less than 1% of total plant capital costs. Similarly, Table 2 shows that annualized costs amount to about 0.4 mills/kWh, or an average of 0.5% of total plant operating costs.

Costs are substantially higher if flue gas treatment systems are required to achieve higher levels of control. Data reported for Japanese power plants employing selective catalytic reduction (SCR) systems, in addition to combustion modifications, indicate total capital costs on the order of \$40/kW, or a little more than 3% of total plant capital requirements (*8*, *9*). This would make SCR costs comparable to those for an ESP. Corresponding operating costs for advanced NO_x control are 4–6 mills/kWh, or almost 6% of total plant generating costs, when full SCR treatment is employed.

While SCR costs in Reference 1 come only from Japanese studies, at least one recent study in the U.S. (*17*) reports substantially higher capital costs (ranging from \$53 to \$95/kW on a 1982 basis) as well as higher levelized annual costs (6.5–13.0 mills/kWh) for two Japanese SCR processes. These cost differences appear to be attributable primarily to differences in economic premises, such as the treatment of contingencies and other cost factors; project scope, such as the effects of an SCR system on fan costs and construction of downstream components; and detailed process design, including removal efficiency and flue gas dust loading. It should be recalled, however, that experience with SCR on full-scale coal-fired power plants is still quite limited and remains to be commercially demonstrated in all countries other than Japan.

Solid waste disposal

Disposal of FGD sludge and fly ash may incur additional capital and operating costs, which often are included with the cost of air pollution control. For example, European FGD costs developed for the OECD (*11*) include landfill disposal of oxidized sludge, which accounts for approximately \$15/kW, or 12% of FGD capital costs (equivalent to approximately 2% of total power plant costs). U.S. capital cost estimates for total solid wastes—sludge plus ash—ranged from \$30/kW (*3*) to values of \$22 ± \$7/kW and \$56 ± \$18/kW (*12*). These corresponded to approximately 2%, 2%, and 5% of total plant capital costs, respectively.

Total annual revenue requirements for solid waste disposal by untreated ponding were reported in one U.S. study (*3*) to be 1.2 mills/kWh, or about 2% of total plant revenue requirements. In another (*12*), average solid waste disposal costs accounted for approximately 4% and 8% of total levelized costs for plants using low-sulfur coal and high-sulfur coal, respectively. Solid waste disposal costs depend on the quantities of sulfur and ash being disposed of (see Table 3), as well as on

TABLE 3

A simplified method for estimating environmental control costs for a new coal-fired power plant [a]

Part I: Identification of independent variables affecting cost

(1) **Environmental control systems design** [b]
- Boiler combustion modifications (low-NO_x burners)
- Electrostatic precipitator (cold-side)
- Limestone FGD system (with forced oxidation and partial bypass); η_{FGD}
- Landfill disposal of solid wastes

(2) **Power plant characteristics:** P, H, K

(3) **Coal properties (as burned):** a, s, h

(4) **Emission limitations:** S_{TSP}, S_{SO_2} (or η_{SO_2})

(5) **Economic factors:** C_e, C_l, C_R, F_f (optional: F_i, i, n, r_i, r_r)

Part II: Calculation of key plant and performance parameters [c]

(1) Pollutant removal efficiencies [d]	
η_{TSP}	$1 - [(h \cdot S_{TSP} \cdot 10^{-6})/0.80a]$
η_{SO_2}	$1 - \frac{1}{2}[(h \cdot S_{SO_2} \cdot 10^{-6})/(0.95s)]$
η_{FGD}	$\geq \eta_{SO_2}$
(2) Plant flow rates [d,e]	
m_A	$[0.80 \times 10^6(a/h) - S_{TSP}](5 \times 10^{-7}\,P\,H)$
m_S	$[0.95 \times 10^6(2s/h) - S_{SO_2}](5 \times 10^{-7}P\,H)$
G	$0.347\,P\,H$
α_S	η_{SO_2}/η_{FGD}
G_S	$\alpha_s\,G$
(3) ESP parameters [f]	
A_S	$k_1[-\ln(1-\eta_{TSP})]^{1.55}$ where, $k_1 \approx \begin{cases} 0.0470 & (s < 1.0\%) \\ 0.0364 & (1.0\% \leq s \leq 2.0\%) \\ 0.0244 & (s > 2.0\%) \end{cases}$
A	A_sG
P_{ESP}	$2.5 \times 10^{-6}\,A + 1.55 \times 10^{-7}G$
(4) FGD system parameters [g]	
R_m	$\begin{cases} 1.10 & (\eta_{FGD} < 0.67) \\ 1.10 + 16.3(\eta_{FGD} - 0.67)^{2.5} & (0.67 < \eta_{FGD} \leq 0.90) \end{cases}$
m_L	$1.5625\,m_sR_m$
N_o	$\alpha_s\,P/125$ (nearest integer)
N_s	1, ($N_o \leq 4$) 0.25 N_o, (truncated integer, $N_o > 4$)
P_{FGD}	$(1 + 3.5s)(0.332 + 0.217m_s + 4.20 \times 10^{-6}G_s) + \begin{cases} 3.63 \times 10^{-2}(G/H)(3.50\alpha - 2.50), & (\alpha_s > 0.715) \\ 0.0, & (\alpha_s \leq 0.715) \end{cases}$

Part III: Calculations of total capital and variable costs (million 1982 $) [h]

System or component	Total capital cost (TCC) [i]	Annual variable cost (AVC) [j]
(1) **Low-NO_x burners** [k]	$0.006\,P_g$	nil
(2) **Electrostatic precipitator** [l]	$78.51 \times 10^{-6}A^{0.91} + 10.16 \times 10^{-3}P$	$K(12.84 \times 10^{-8}A + 0.00876P_{ESP}C_e)$
(3) **Limestone FGD system** [m]	$(N_o + N_s)[5.508 + \frac{1}{N_o}(0.0803\,m_s + 2.057 \times 10^{-5}G_s)] + \begin{cases} 0.315m_L + 5.148, & (m_L < 28) \\ 0.140m_L + 10.094, & (m_L \geq 28) \end{cases}$	$K(0.00911\,m_LC_R + 0.143\,m_s + 3.65 \times 10^{-6}G_s + 2.00 + 0.00876P_{FGD}C_e)$
(4) **Solid waste disposal** [n]	$C_l \times 10^{-6}(6.90\,m_s^{1.017} + 1.80\,m_A^{0.9}) + (1.557m_s^{0.8} + 0.945m_A^{0.6} + 4.032)$	$0.154(m_sK)^{0.7} + 0.095(m_aK)^{0.6} + 1.275$

[a] Based on Reference 3. A more complete treatment of these models appears in Reference 16.

[b] These are selected as typical of current practice. Simplified cost models for other options also are presented in Reference 16.

[c] Other methods of calculating these parameters may be employed without affecting the cost of calculations in Parts III and IV.

[d] Assumes 80% of the ash and 95% of the sulfur in coal enters the flue gas stream (based on combustion of bituminous coal in a pulverized coal boiler). Other fractions may be directly substituted for other cases or assumptions.

[e] Gas flow rate estimation based on typical bituminous coals with 35% excess air (including leakage) and a temperature of 300 °F (149 °C). For other gas temperatures, multiply by T (°R)/760 or T (K)/422.

[f] Equations in Reference 16 give SCA as a continuous function of sulfur content, but have been simplified here to reduce algebraic complexity.

[g] Limestone stoichiometry assumes a constant liquid-to-gas (l/g) ratio of 90 gal/ft³. However, FGD costs do not vary significantly for other l/g values (and corresponding stoichiometries) within ±20% of this.

[h] Costs for other years may be estimated using the Chemical Engineering Plant Cost Index.

[i] This is the sum of direct capital costs plus indirect capital costs. The former includes equipment, materials, land, labor, and structures. The latter includes engineering, contractor fees, construction expense, startup costs, contingencies, working capital, and interest during construction. Reference 16 represents indirect costs as a fraction, f_i, of total direct cost. The total capital costs shown here assume $f_i = 0.5$ for combustion modifications and ESP, and $f_i = 0.8$ for the FGD and solid waste disposal systems. To use other values of f_i multiply the total cost shown here by $(1 + f_i)/1.5$ (or 1.8), except for solid waste and land cost (C_l) for which $f_i = 0.0$.

Part IV: Calculation of revenue requirement, levelized cost, and electricity cost

(1) **Annual revenue requirement** [o] — $ARR = F_f\,(TCC) + (AVC)$

(2) **Levelized revenue requirement** [o,p] — $LRR = F_f\,(TCC) + f_l(AVC)$

$$\text{where, } f_l = \frac{k(1-k^n)}{1-k}\left[\frac{i(1+i)^n}{(1+i)^n-1}\right] \quad \text{and } k = \frac{(1+r_i)(1+r_r)}{1+i}$$

(3) **Cost of electricity (annual or levelized)** — $C_{e,j} = \dfrac{(ARR) \text{ or } (LRR)}{8760\,P\,K}$

Part V: Illustrative example

Input parameters

(1) **Control system design**	$\eta_{FGD} = 0.90$ (with allowable bypass)
(2) **Power plant characteristics**	$P = 1000$ MW $H = 9500$ Btu/kWh (10 016 kJ/kWh) $K = 0.65$
(3) **Coal properties (as fired)**	$a = 0.120$ $s = 0.030$ $h = 12\,500$ Btu/lb (27 905 kJ/kg)
(4) **Emission limitations**	$S_{TSP} = 0.03$ lb/10^6 Btu (12.9 ng/J) $S_{SO_2} = 0.60$ lb/10^6 Btu (258 ng/J)
(5) **Economic factors**	$C_e = 60.0$ mills/kWh ($0.60/kWh) $C_l = \$5000$/acre ($12,355/hectare) $C_R = \$8.50$/ton ($9.37/mton) $F_i = 0.15$ ($i = 0.10$, $n = 30$, $r_i = 0.06$, $r_r = 0.0$)

Part VI: Calculated Costs

Component	Million 1982 $ (also $/kW for 1000-MW plant) TCC	AVC	ARR	LRR	$C_{e,j}$ (mills/kWh) 1982	Levelized
Low-NO_x burners	6.0	0.00	0.9	0.9	0.2	0.2
ESP	35.8	1.25	6.6	7.7	1.2	1.4
FGD system	168.9	23.32	57.7	69.3	10.1	12.2
Solid waste	29.4	3.78	8.2	11.5	1.4	2.0
Total	240.1	28.35	73.4	89.5	12.9	15.7

a = coal ash content, as fired (fraction)
A = electrostatic precipitator collector area (ft^2)
ARR = annual revenue requirement ($)
A_s = specific collection area (ft^2/acfm)
AVC = annual variable cost ($)
C_e = total cost of electricity (mills/kWh)
$C_{e,j}$ = electricity cost due to component j (mills/kWh)
C_l = waste disposal land cost ($/acre)
C_R = limestone reagent cost ($/ton)
F_f = fixed charge factor (fraction)
f_i = indirect cost factor (fraction)
f_l = levelization factor (dimensionless)
G_s = flue gas flow rate capacity through scrubber (acfm)
h = coal higher heating value, as fired (Btu/lb)
H = power plant heat rate (Btu/kWh)
i = nominal discount rate (fraction)
K = annual plant capacity factor (fraction)
LRR = levelized revenue requirement ($)
m_a = fly ash removal capacity (tons/h)
m_L = limestone reagent capacity (tons/h)
m_s = scrubber SO_2 removal capacity (tons SO_2/h)
n = book life of equipment (years)
N_o = number of operating scrubber trains (integer)
N_s = number of spare scrubber trains (integer)
P = net power plant capacity (MWe)
P_j = power requirement of component j (MWe)
r_i = inflation rate (fraction)
r_r = real-cost escalation rate (fraction)
s = coal sulfur content, as fired (fraction)
S_{SO_2} = sulfur dioxide emission standard (lb/10^6Btu)
S_{TSP} = particulate emission standard (lb/10^6Btu)
TCC = total capital cost ($)
α_s = fraction of flue gas being scrubbed
η_{FGD} = specified scrubber removal efficiency (fraction)
η_{SO_2} = required SO_2 removal efficiency (fraction)
η_{TSP} = required particulate removal efficiency (fraction)

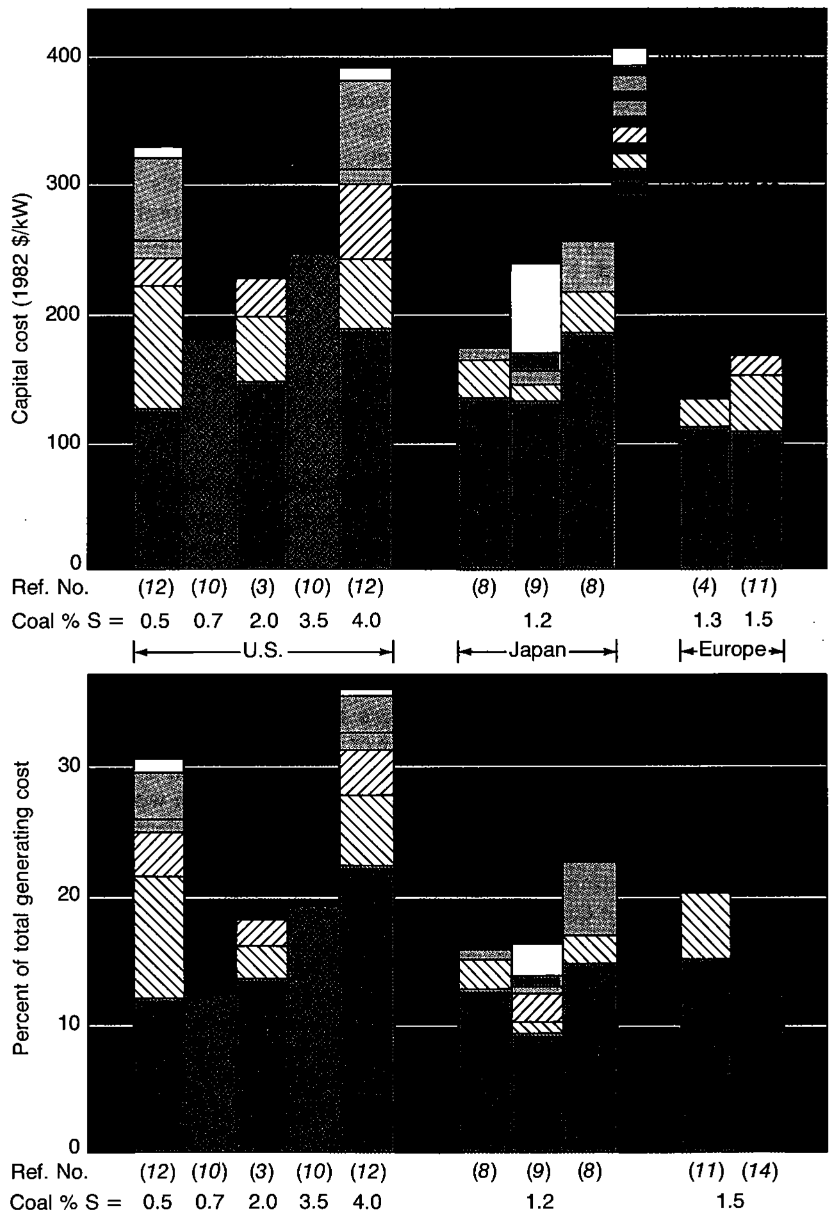
Metric conversion factors

1 acfm	= 4.719×10^{-4} m^3/s (actual)	1 Btu/kWh	= 1.054 kJ/kWh	1 lb/10^6 Btu	= 430 ng/J (g/10^6 kJ)
1 acre	= 0.405 hectare	1 Btu/lb	= 2.324 kJ/kg	1 ton	= 0.9074 mton
		1 ft^2	= 0.0929 m^2		

[j] Includes the cost of raw materials, operations, maintenance, plant overhead, administration, supervision, and utilities. The recommended electricity cost is the marginal cost for new capacity (with environmental controls), which is taken as an independent parameter here for simplicity. Reference 16 derives this value.
[k] Additional combustion modifications could increase capital costs by approximately a factor of two, with small increases in variable costs.
[l] Includes flange-to-flange costs plus ash-handling equipment.
[m] Models are based on a computer program developed by the Tennessee Valley Authority (TVA). Costs assume a midwestern U.S. location.
[n] Assumes codisposal of all fly ash and scrubber wastes (gypsum).
[o] Applies to any system or component. The fixed charge factor, F_f, includes the cost of capital, depreciation, income tax (including tax credits), insurance, ad valorem tax, and interim replacements. Typical values for U.S. power plants are approximately 0.15 ± 0.03. Calculation procedures for F_f are beyond the scope of this paper.
[p] The levelization factor f_l applies to variable cost items, which are assumed to escalate at a real rate, r_r, over inflation (r_i). If r_r and r_i are zero, the levelization factor is unity.

the method of waste disposal (*3*). Other site-specific factors also can affect disposal costs considerably. Limited data reported to the OECD indicate substantially higher waste disposal costs for plants outside the U.S., so that the figures cited above should not be generalized. Recovery of by-product gypsum from FGD systems, the prevailing practice in Germany and Japan, substantially reduces total waste disposal costs and may even generate an economic credit (*6*). There is general uncertainty, however, as to whether by-product markets can be maintained if worldwide coal use increases significantly in the future.

FIGURE 2
Capital and operating costs for pollution control systems at a new coal-fired power plant



Other controls

The costs of water-related pollution control may include thermal and chemical effluent treatment. Reported capital costs in Japan (*9*) ranged from \$9 to \$17/kW (1–2% of total plant costs) for increasingly stringent levels of chemical control. Costs reported by the Electric Power Research Institute (EPRI) (*12*) for meeting current U.S. effluent standards were \$64 ± \$10/kW (6% of total plant costs) for plants using either high-sulfur or low-sulfur coal. This included \$40 ± \$6/kW for cooling towers, which were not included in the Japanese plant design. Corresponding annualized costs (in 1982 dollars) were approximately 0.7 mills/kWh for the model plant in Japan (*9*) and 2 mills/kWh for the new plants in the U.S. (*12*).

Noise control costs were included by EPRI (*12*) and the Japan Environment Agency (*9*) as a component of environmental costs. Capital costs in the former case averaged \$12/kW (about 1% of total plant cost), with annual operating costs of about 0.4 mills/kWh (0.5% of total generation costs). Slightly higher costs of \$12 to \$22/kW were assumed for the model plants in Japan.

Miscellaneous costs for the Japanese plant also included dust control measures. These had a negligible cost impact except for the most stringent control level, which involved the construction of coal storage silos at a 1982-dollar cost of approximately \$70/kW. Plant operating costs also included a small charge (0.5–1.5 mills/kWh) levied in Japan for the compensation of pollution-related health damage.

Total cost of control

In Tables 1 and 2, values of total environmental control costs reported in various studies are summarized. At face value, capital costs range from approximately 5% to 36% of total plant capital costs, while annual costs are 5% to 32% of total plant revenue requirements. As seen previously, however, these figures reflect not only different definitions of total environmental control, but also widely differing coals, plant configurations, and regulatory requirements.

Figure 2 gives a better picture of how various system components contribute to total costs at a well-controlled coal-fired power plant equipped with a wet FGD system for SO_x control, an ESP for particulate control, and combustion modifications for NO_x control. For these systems, a representative cost of air pollution control (excluding solid waste disposal) is approximately \$185 ± \$50/kW for capital costs, equivalent to 18% of total plant cost, and 15 ± 4% of total annual power-generating costs, according to data from selected studies for Europe, Japan, and the U.S. Approximately 75% of the air pollution control cost is for FGD, 20% for the ESP and 5% for NO_x control. In general, the high end of the range applies to U.S. plants using high-sulfur coals with high pollutant removal efficiencies, while the lower end applies to European plants using low-sulfur coals with moderate removal efficiencies. Solid waste disposal costs for fly ash and FGD sludge add approximately

\$30 ± \$15/kW to capital costs and 5 ± 3% to annual costs unless recovery and reuse are feasible.

The additional costs of water pollution control are \$16 ± \$8/kW for treatment of chemical wastes, plus \$40 ± \$6/kW if cooling towers are required for thermal effluent control. Corresponding increases in annual costs are approximately 1–3% of total generating cost. Pollution abatement costs, including air, water, and solid wastes, thus amount to approximately \$270 ± \$80/kW (26 ± 8% of total plant) for capital costs and 23 ± 7% of total generating costs for new plants meeting current environmental standards in Europe, Japan, and the U.S. The cost of noise control adds at least \$10/kW to capital costs and 0.5% to annual costs if noise is defined as a part of total environmental control. Miscellaneous costs for fugitive dust control remain negligibly small, but could become sizable under extremely stringent local standards requiring construction of coal storage silos. Similarly, more stringent requirements for NO_x control also would add significantly to these costs, as indicated earlier.

Competitiveness of coal

The competitiveness of coal relative to other fuels for electric power generation is of key international concern, particularly the relative costs of coal-based and oil-based electricity. While the importance of nuclear power is also clearly recognized, the essential conclusion drawn is that the average cost of a nuclear plant in OECD countries may vary by nearly a factor of two (from about \$1200 to \$2000/kW), thus making nuclear power either the cheapest or the most expensive option relative to fossil fuels (*11*). For the near term, new nuclear plants have been removed from consideration in some countries and therefore may not even be an alternative in many cases. Thus, there is high worldwide interest in coal vs. other conventional fossil fuels.

Two options are the most commonly considered for converting from oil or gas to coal for power generation. One is the construction of a new coal-fired unit, either in lieu of a new oil or gas unit, or as a replacement for an existing oil or gas unit that would be retired prematurely. The other is the physical modification of an existing boiler to accept coal as a fuel. For technical and economic reasons, physical modifications (boiler retrofits) are usually limited to units originally designed for coal.

Other options for burning coal in boilers designed for oil firing include the use of coal–oil or coal–water mixtures. The ability to use coal–oil mixtures (COM) has been demonstrated technically, and continued development and some commercialization are proceeding. Implementation, however, generally has been limited by economics and other factors. Coal–water mixture (CWM) fuels hold the potential of far more favorable economics since fuel oil expenses are totally avoided. Here, however, the results of current research and development projects are awaited so that the technical, environmental, and economic viability of CWM for commercial applications can be assessed more rigorously.

Comparisons with new plants

Table 4 summarizes several electricity cost comparisons between new coal-fired plants and new or existing plants using other fossil fuels, (*8*, *9*, *11*, *14*, *18*, *19*). In all cases, there is agreement that at prevailing 1981–82 fuel prices (when most of these costs were derived), electricity costs were lower for a new coal-fired plant than for a comparable new oil-fired plant. More recent drops in world oil prices during 1983 now indicate a less favorable economic climate for coal, at least in Europe and Japan where coal prices are approximately twice those in the U.S. In those regions, environmental control costs could have a more significant effect on coal's competitiveness with oil since they raise the breakeven oil price by several dollars per barrel in the generally sensitive price range.

Thus, in the absence of environmental control requirements, a new coal-fired power plant in Japan might cost less than a comparable oil-fired plant for oil prices above \$25/bbl, whereas oil prices might have to rise above \$30/bbl before a coal plant with strict environmental controls could be competitive. This would be just above current world prices. For the U.S., coal still remains economically preferable to oil for new plant construction, even with high environmental control costs, because of substantially lower coal prices.

In comparisons with existing facilities, a study for OECD (*11*) reported a 15% lower cost of electricity from a new coal-fired power plant in Europe with full environmental controls (including FGD) compared to an existing oil-fired plant at fuel prices of \$36/bbl for oil and \$70/metric ton for coal (see Table 4). These prices would favor early retirement of the oil plant and its replacement by a new coal-fired plant. This situation, however, contrasts with a Japanese power company study (*8*) indicating that at similar oil and coal prices electricity from a new coal-fired plant would still be about 15% more expensive than that from an existing oil-fired plant, making early retirement of the oil plant unattractive.

This qualitative difference results primarily from a \$340/kW difference in the "base" cost of the coal-fired power plant assumed in the two studies. Additional differences in pollution control costs produce a total capital cost difference of approximately \$400/kW. Thus, in the Japanese study, oil prices would have to rise above \$44/bbl before it would be economical to retire an existing oil-fired plant, as compared with \$31/bbl for the OECD European study. In this case, the cost of environmental control had a much less significant influence on the fuel choice decision than did differences in the estimated cost of the base power plant.

Table 4 also shows data comparing the costs of a proposed new coal-fired facility with existing gas-fired power plants in The Netherlands (*14*). Recent rises in gas prices have led to a situation in which coal-fired plants are now economically more attractive, with the magnitude of cost differences depending on environmental standards and other site-specific factors. Table 4 shows that the total annualized cost of one proposed new coal plant with full environmental controls would be 12% less than the average fuel plus operating costs for existing gas-fired plants.

Comparisons for retrofit plants

Comparative costs of oil- and coal-based electricity for boilers retrofitted to coal firing also are indicated in Table 4. A U.S. EPA study (*19*) considered boiler conversions with and without FGD systems for base-load and intermediate-load plants with remaining amortized lives of 10 and 20 y. In all but one case, the converted boilers yielded significantly lower electricity costs than the oil-fired plant. Despite the prevailing economic advantages, such replacements are not occurring at a rapid rate because of such factors as uncertainty over future oil prices, capital availability, and difficulties in finding acceptable sites (*19*).

One case of a recent conversion from oil to coal in the U.S. involves the Brayton Point Station in Massachusetts (three units totaling 1150 MW).

TABLE 4

Comparative electricity costs for conversions from oil or gas to coal

Country	Reference No.	Case Description	Percent savings in electricity cost with a coal-fired plant instead of: new oil plant	existing oil (gas)
Replacement by a new coal-fired power plant				
Japan	(*8*)[a]	Coal @ \$70/mton, Level III Control		
		+ Oil @ \$30/bbl	−1	−21
		\$35/bbl	7	15
		\$40/bbl	16	7
		Coal @ \$90/mton, Level III Control		
		+ Oil @ \$30/bbl	−10	−25
		\$35/bbl	−2	−20
		\$40/bbl	7	−14
	(*9*)[b]	Coal @ \$67/mton, oil @ \$39–\$42/bbl		
		w/ Model I Control	32	
		w/ Model II Control	25	
		w/ Model III Control	17	
The Netherlands	(*14*)[c]	Case 3 plant w/ full env. control		(11)
Europe	(*11*)[d]	Coal @ \$70/mton, with FGD		
		+ Oil @ \$36/bbl		15
Conversion of an existing plant to coal firing				
The Netherlands	(*14*)[c]	Case 4 plant with full env. control		(21)
U.S	(*18*)[e]	Brayton Point Station without FGD		37
	(*19*)[f]	Low-cost conversion without FGD		
		Base load, 20-y life		40
		Int. load, 10-y life		34
		High-cost conversion, with FGD		
		Base load, 20-y life		18
		Base load, 10-y life		7
		Int. load, 20-y life		7
		Int. load, 10-y life		−7

[a] See footnotes h and j, Table 1, for key assumptions.
[b] See footnotes m–p, Table 1, for key assumptions.
[c] See footnote kk, Table 1; for key assumptions.
[d] See footnotes x and z, Table 1 for key assumptions.
[e] Cost savings based only on 1982 fuel costs of 4.11¢/kWh for oil and 2.58¢/kWh for coal. Breakeven cost of entire project estimated to be \$6/bbl of oil (equivalent) price difference between coal and oil.
[f] Based on an oil price of \$29/bbl and levelized coal prices of \$1.70–\$2.05/10^6 Btu, with capital costs of \$200/kW for FGD retrofit and \$140–\$410/kW for converting a boiler and upgrading a precipitator.

In this case, retrofitting of an FGD system was not required. The total project cost amounted to \$167/kW, of which approximately one-half was for environmental control equipment (*18*). The savings realized from reduced fuel costs were expected to result in a project payback period of less than two years, with continued cost savings thereafter.

Finally, Table 4 shows the case of a proposed conversion from natural gas to coal in The Netherlands. This unit was initially designed to burn low-calorific-value gases, as well as mixtures of fuels; hence it was suitable for conversion to coal. Even with full environmental controls (including FGD), the electricity produced by this unit was estimated to be 25% cheaper than that from existing gas-fired plants.

Summary of findings

Significant differences in reported capital and operating costs for pollution control are seen to be derived from markedly different premises regarding applicable environmental regulations, coal characteristics, plant design parameters, project scope, and economic and financial assumptions. However, in examining the case of SO_2 control, one finds that cost estimates in different countries exhibit much greater similarity when expressed in terms of the cost-effectiveness of pollutant removal for similar fuels and environmental constraints. Typical 1982 costs for a well-controlled power plant, including air pollution control, water pollution control, and solid waste disposal, are on the order of 26% ± 8% of total plant capital cost (\$270 ± \$80/kW) for plants in Europe, Japan, and the U.S. Air pollution control and disposal of associated solid wastes account for approximately 80% of this figure, with FGD systems contributing the major share (approximately \$140 ± \$35/kW, excluding waste disposal). Corresponding annual revenue requirements for environmental control are approximately 23% ± 7% of total power-generating costs, of which approximately 85% is attributable to air pollution control and solid waste disposal.

In general, the high end of the cost range reflects air pollution control levels of 90% or more for SO_2, up to 50% for NO_x, 99.5% or more for fly ash (particulate matter), plus stringent control of both chemical and thermal water pollutants. In contrast, the low end of the cost range generally represents less stringent SO_2 removal requirements (permitting only partial flue gas treatment), coupled with moderate NO_x controls, by-product use of solid wastes, and minimal water treatment requirements.

For SO_2 removal requirements below about 40%, the use of physical coal cleaning might allow emission limits to be met without the need for

FGD, reducing costs substantially. On the other hand, a need for more stringent NO_x controls, requiring flue gas treatment systems such as those now beginning to emerge in Japan, would increase capital costs and revenue requirements by at least an additional 3% and 5%, respectively, of total plant costs cited above, although significant uncertainty still remains as to the actual cost of such systems. In the future, advanced control technologies, as well as advanced processes using coal either for direct combustion or for conversion to other liquid and gaseous fuels, holds the promise of higher degrees of pollution control at relative costs comparable to or less than those for conventional systems (*20–25*).

Electricity cost comparisons

Comparisons between electricity costs for new coal-fired plants and new oil- or gas-fired plants indicate that at a coal price of $70/metric ton, typical of Europe and Japan, a new coal-fired power plant with strict environmental controls is more economical than a new oil-fired plant for oil prices about equal to the current world price. At the much lower U.S. coal prices, however, coal is clearly the fuel of choice relative to oil.

Indeed, new coal plants may generate electricity even more economically than existing oil-fired plants, making early retirement of such facilities economically attractive in some locations. Such comparisons are strongly dependent on the local prices of oil and coal, which have continued to fluctuate in recent years. Breakeven oil prices of approximately $35/bbl or more are indicated at coal prices of $70/metric ton, with capital cost estimates for the base power plant, as well as environmental control equipment, also seen to be key factors in decisions to replace oil with new coal facilities.

Conversion from oil or gas to coal by retrofitting existing coal-capable boilers, where technically feasible, also appears economically attractive in a number of situations. The actual rate of such conversions, however, is still low. Among the reasons cited for this are uncertainty over future oil prices, unavailability of capital, lack of suitable sites, regulatory or permitting delays, and the lack of appropriate infrastructure for the delivery and handling of coal and associated solid wastes.

Finally, cost comparisons performed for the OECD between new coal-fired plants and new nuclear plants indicate nuclear power to be either the least expensive or most expensive option for electricity production because of the nearly twofold range in costs associated with current nuclear plant designs in various countries. Moreover, social and political factors also continue to inhibit or preclude nuclear power in many locations. Thus, an expanded use of coal in compliance with strict environmental standards is foreseen for many countries in the coming decades.

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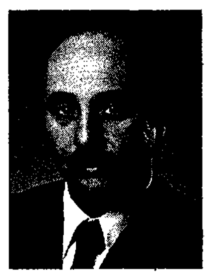

***Edward S. Rubin** received his PhD in mechanical engineering from Stanford University in 1969, working in the area of advanced power generation systems. He then joined Carnegie-Mellon University, where he currently holds the position of professor jointly in the Department of Mechanical Engineering and the Department of Engineering and Public Policy. He is also the director of Carnegie-Mellon University's Center for Energy and Environmental Studies. Rubin's educational and research activities have been concerned with environmental control and energy conversion systems, with principal emphasis on coal utilization technologies for electric power generation, synthetic fuels production, and industrial energy use.*