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Typical Costs for Electric Energy Generation and Environmental Controls

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EPA REVIEW NOTICE

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Typical Costs for Electric Energy Generation and Environmental Controls

by

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ABSTRACT

Capital and annualized cost data are presented in tabular form for various conventional and advanced electric energy generation systems. The data are organized into three general categories:

1. Cost of Base Generation System (not including fuel or environmental control)

2. Incremental Fuel Costs

3. Incremental Environmental Control Costs

Total costs can be computed for a particular configuration by adding the appropriate incremental costs for fuel and environmental control to the cost of the base generation system. Costs assigned to environmental contral include systems for the control of sulfur, particulates, NO_x, and thermal discharges. Two examples of the use of the data are included. The accuracy of each estimate is indicated by a range of uncertainty. The cost figures are intended to provide an overview of environmental control costs for various electric energy generation options. Costs for actual installations would depend a great deal on site specific considerations.

CONVERSION TABLE

EPA policy is to express all measurements in Agency documents in metric units. Implementing this practice results in difficulty in clarity; therefore, conversion factors for non-metric units used in this document are as follows:

British	Metric
1 Btu/kWh	1.055 kJ/kWh
1 $/$10^6$ Btu	0.948 $/$10^6$ kJ

TABLE OF CONTENTS

TABLES

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1.0 Introduction

An electric utility today has several options for electric energy generation, each of which requires a different mix of environmental control technology. The cost of environmental control will vary markedly, depending upon the base generation system used and the availability of the energy source. This report consists of data in tabular form which can be used to compare incremental environmental costs for each base generation system option considered. Base generation systems include both conventional and advanced electric energy generation options. The cost figures are intended to provide an overview of environmental control costs for various electric energy generation options.

The data are organized into three general categories:

1. Cost of Base Generation System (not including fuel or environmental control)
2. Incremental Fuel Costs
3. Incremental Environmental Control Costs

Data are given for generating stations of 1000 and 500 MWe capacity. The environmental control costs are based on meeting present New Source Performance Standards.(1) With the cost organized in these three categories, total costs can be computed for a particular configuration by adding the appropriate incremental costs for fuel and environmental control technology to the cost of the base generation system. Examples are provided for specific kinds of power plant, fuel, and control technology.

The primary sources for cost data are conceptual design studies sponsored by EPRI, EPA, and DOE and the National Science Foundation's Energy Conversion Alternatives Study (ECAS). Other basic data came from a number of individual manufacturers. Specific data sources are given in Section 4.0.

The cost of a designated system can vary widely because of many factors. Because of differing requirements that govern feedstock conditions, efficiencies, and throughputs, comparison between specific systems is not easy. Differences in the stage of development of the various electric energy generation options make it difficult to precisely predict cost, operability and reliability. Consistency is the key, yet this is difficult to achieve when estimates come from different sources (as in this study). The procedure described in Section 2.0 attempted to put all costs on a consistent basis. The accuracy, of course, depends on the quality of the cost data and on the judgment used in adjusting the cost data to a consistent basis. The accuracy of each estimate was considered separately, and indicated by the range of uncertainty assigned to each.

2.0 Methodology

Published data on the cost of base generating systems, fuels, and environmental control technology were compiled from conceptual design studies performed under the auspices of EPRI, EPA, DOE and NSF. Other data came from individual vendors. Specific information sources are given in Section 4.0. The procedure used to make cost comparisons consistent for conceptual designs and costs from different sources is similar to one used in a recent EPRI study[2] which identified sulfur removal costs for various coal conversion options. The procedure used in this study was:

1. For each cost study of an individual power generating systems, total plant capital investment (not including escalation, interest during construction (IDC), working capital, or contingency) was divided into power plant investment and environmental control investment. Several cost studies were available for most of the different power generation systems.

   Environmental control investment included costs for the control of sulfur, particulates, NO_x, and thermal discharges. For pressurized fluidized-bed combustion, hot gas cleanup was considered a power plant cost, since clean gas for the turbines is a power plant requirement.

2. Power plant capital costs (not including environmental costs) were adjusted to a single base year (mid 1975 was used since all but a

few of the original studies use this as a basis) and a base size (1000 MWe). Escalation factors were used to adjust all costs to a mid-1975 price. Scaling to the base size was done by using an exponential factor of 0.85 which was used by both EPRI[3] and Bechtel[4] in recent studies.

3. A single base power plant investment was selected as representative. In each case, this figure consists of total construction cost of the power plant; it excludes environmental control investment. As noted under "1", above, the power plant investment does not contain contingency, escalation, working capital, and interest during construction (IDC).

4. A contingency was then added with the amount obtained by the degree of definition; for each technology, a range or band of uncertainty was assigned; wider bands were attributed to less developed options. Interest during construction, together with startup costs, was applied to each plant investment at a rate of 30 percent. (For the liquid fuel options, a rate of 22 percent was used because of a significantly shorter construction period.) These are the factors used in the EPRI study[2]; they are equivalent to construction times of approximately 6 and 4 years at an interest rate of 10 percent. The total cost gives the probable range of capital requirements for each plant without environment controls.

5. Annualized costs were calculated for base load operation (0.65 capacity factor). This consisted of a fixed capital charge and an operations and maintenance (O&M) charge (fuel charges are broken

out separately under incremental costs). A fixed charge rate of 18 percent per year was applied to the range of capital costs calculated in "4". This covers interest on debt, return on equity, depreciation, insurance, and property and income taxes, both federal and local. Current utility experience in the U.S. shows this fixed charge rate varies from 15 to 22 percent. Both the EPRI[2] and ECAS[5] studies also used a fixed charge rate of 18 percent. Typical O&M charges were added to capital charges to obtain annualized costs.

6. Scaling of costs to a 500 MWe size was done using an exponential factor of 0.85 (i.e. $(500/1000)^{0.85} = 0.555$).

7. Environmental control technology investment and annualized costs were developed from representative base costs in the same manner as power plant costs.

8. Fuel costs for physically cleaned, chemically cleaned, solvent refined, and liquefied coals include plant charges for processing. Fuel costs are based on a heat rate of 10,000 Btu/kWh. Actual fuel costs will depend on the efficiency or heat rate of the power generation option and are adjusted by the ratio of the actual heat rate of the power generation option to 10,000. A typical heat rate was selected for each base generation system.

3.0 Cost Tables

Table 1 presents the results for the base generation systems, fuels and environmental controls considered. Using this table, costs can be computed for a particular configuration by adding the appropriate incremental costs for fuel and enviornmental control technology to the cost of the base generation system. Two examples are provided for specific kinds of power plant, fuel, and control technology.

Fuel costs are based on a heat rate of 10,000 Btu/kWh (an efficiency of 3412.2/10,000 = .34122). Typical heat rates for each base generation option are listed in Table 1. As shown in the examples, fuel costs can be adjusted to the specific base generation heat rate.

The data used to compile Table 1 are in Tables 2 through 7. Table 2 shows the escalation factors used to adjust all costs to mid-1975 dollars. Table 3 and 4 show the base cost, contingency, uncertainty, interest during construction, and startup factors used to obtain typical base generation and environmental control technology investments. Investment costs are for new plant construction; no attempt was made to determine typical costs for retrofit applications.

Published cost data, after adjustments, formed the basis for selection of the base investment figures. In general, base investment spreads in studies of conventional technologies were narrow; a median figure, consistent with other base systems, was selected. Spreads in the advanced technologies were greater and required engineering judgment in selecting the base investment. This was also reflected in the use of larger contingency and uncertainty factors. As these technologies come closer to commercialization, plant investment estimates will become firmer.

Table 5 and 6 show base generation and environmental control technology annualized costs. Annualized costs were calculated for base load operation (0.65 capacity factor) and consist of a fixed capital charge of 18 percent and a typical O&M charge. The sum of these two is the total annualized cost in Table 1. Typical utility capital charges are:

Cost of capital (capital structure assumed to be 50 percent debt and 50 percent equity)	
Bonds at 8 percent interest	4.00
Equity at 12 percent return to stockholder	6.00
Taxes	
Federal (50 percent of gross return or same as return on equity)	6.00
State (national average for states in relation to Federal rates)	2.00
Total rate applied to depreciation base	18.00

Table 7 shows the fuel costs used in this study.

TABLE 1

TYPICAL ELECTRIC ENERGY GENERATION SYSTEMS CAPITAL AND ANNUALIZED COSTS

Basis: Mid 1975 Dollars

	1000 MW_e		500 MW_e	
	Capital ($/$kW_e$)	Annualized (Mills/kWh)	Capital ($/$kW_e$)	Annualized (Mills/kWh)
Base Generation System (Typical Heat Rate, Btu/kWh)				
Conventional Fossil Fired Boilers				
High Sulfur Eastern Coal (9800)	385-470	13-16	430-520	15-18
Low Sulfur Western Coal (9200)	405-495	14-17	450-550	15-19
Liquid Fuel (9200)	240-295	8-10	265-330	9-11
Conventional Nuclear				
Light Water Reactor (10400)	605-740	20-25	670-820	23-27
Combined Cycle				
Liquid Fuel (7500)	215-265	8-10	240-295	9-11
Low Btu Gasification (8400)	525-710	18-24	585-790	21-27
Medium Btu Gasification (8200)	530-720	18-25	590-800	21-27
Fluidized Bed Combustion (FBC)				
Atmospheric FBC (9500)	420-565	15-19	465-625	16-21
Pressurized FBC (8800)	505-760	18-26	560-845	20-29
Incremental Costs				
Fuel*				
High Sulfur Eastern Coal		8-12		8-12
Low Sulfur Western Coal		11-15		11-15
Physically Cleaned Coal		10-14		10-14
Chemically Cleaned Coal		14-22		14-22
Solvent Refined Coal		25-30		25-30
Liquefied Coal		30-35		30-35
Liquid Fuel		15-25		15-25
Uranium		5-6		5-6
Environmental Control Technology				
Sulfur Control				
Flue Gas Desulfurization				
Limestone	61-82	3.1-3.8	68-91	3.5-4.2
Wellman Lord	70-95	3.2-4.0	78-105	3.5-4.4
Magnesia	72-108	3.3-4.4	80-120	3.6-4.9
Dual Alkali	75-112	4.1-5.3	83-124	4.5-5.5
Fuel Gas Cleanup				
Low Btu Gas	113-152	4.6-5.8	125-169	5.1-6.5
Medium Btu Gas	99-135	3.8-4.9	110-156	4.2-5.5
Fluidized Bed Combustion				
Limestone or Dolomite	16-27	1.1-1.5	18-30	1.2-1.6
Particulate Control				
ESP-Cold	22-27	0.9-1.0	24-30	0.9-1.1
ESP-Hot	25-34	1.1-1.4	28-38	1.2-1.5
Fabric Filter	36-48	1.5-1.9	40-53	1.7-2.1
Wet Scrubber	42-52	1.7-2.0	57-58	1.9-2.3
NO_x Control				
Combustion Modifications	10-12	0.4-0.5	11-13	0.4-0.5
Selective Catalytic Reduction	22-37	1.2-1.7	24-41	1.3-1.9
Water Injection for Turbines	3-5	0.6-0.7	3-6	0.6-0.7
Thermal Discharge Control				
Evaporative Cooling Tower				
Fossil	14-17	0.7-0.8	16-19	0.8-0.9
Nuclear	18-22	1.1-1.2	20-24	1.2-1.3

* Based on a heat rate of 10,000 Btu/kWh. See example for adjustment to Base Generation System heat rate.

3.1 Example A

For a 1000 MW coal fired boiler burning high-sulfur Eastern coal having a heat rate of 9,800 Btu/kWh, how much would the capital investment and annualized costs increase as a result of environmental control for particulates, NO_x, SO_x and thermal discharges?

System	Capital ($/kWh)	Annualized (mills/kWh)
1000 MW Conventional Coal Fired Boiler	385-470	13-16
Fuel		
High Sulfur Eastern Coal, $\frac{9,800}{10,000}$ x (8-12)	-	7.8-11.8
Subtotal (Base + Fuel)	385-470	21.8-26.8*
Environmental Controls		
Limestone FGD Process - SO_x	61-82	3.1-3.8
Cold ESP - Particulates	22-27	0.9-1.0
Combustion Modifications - NO_x	10-12	0.4-0.5
Fossil Cooling Tower - Thermal	14-17	0.7-0.8
Subtotal (Environmental Controls)	112-133*	5.2-6.0*
TOTAL	534-566*	27.4-32.4*

Percentage Increase in Costs Due to Environmental Control

- o Capital Investment, $\frac{\text{Environmental}}{\text{Base}} \times 100$ 25-33*
- o Annualized Cost, $\frac{\text{Environmental}}{\text{Base + Fuel}} \times 100$ 20-26*

* Ranges of calculated values obtained as sums and quotients were calculated by use of standard deviations: see, e.g. Ferencz[27].

3.2 Example B

For a 1000 MW pressurized fluidized-bed combustor burning high-sulfur Eastern coal having a heat rate of 8,800 Btu/kWh, how much would the capital investment and annualized costs increase as a result of environmental controls?

System	Capital ($/kW	Annualized (mills/kWh)
1000 MW Pressurized FBC	505-760	18-26
Fuel		
High Sulfur Eastern Coal, $\frac{8,800}{10,000}$ x (8-12)	-	7.0-10.6
Sub-total (Base + Fuel)	505-760	26.4-35.2*
Environmental Controls		
In Situ - SO_x	16-27	1.1-1.5
Particulates+	-	-
NO_x, not applicable	-	-
Fossil Cooling Tower - Thermal	14-17	0.7-0.8
Sub-total (Environmental Controls)	31-43*	1.8-2.3*
TOTAL	535-804*	28.5-37.2*
Percentage Increase in Costs Due to Environmental Control		
o Capital Investment, $\frac{\text{Environmental}}{\text{Base}}$ x 100	4.3-7.4*	
o Annualized Cost, $\frac{\text{Environmental}}{\text{Base + Fuel}}$ x 100		5.5-7.8*

+Due to turbine requirements, hot gas particulate control assigned to power system costs.

*Ranges of calculated values obtained as sums and quotients were calculated by use of standard deviations: see, e.g. Ferencz[27].

TABLE 2

ESCALATION FACTORS USED TO ADJUST ALL COSTS TO MID-1975 PRICE

De-escalation[a] Year	Factor	Escalation[b] Year	Factor
July 1978	0.8396	July 1975	1.000
July 1977	0.8900	January 1975	1.052
July 1976	0.9434	July 1974	1.176
		January 1974	1.353
		July 1973	1.433
		January 1973	1.500
		July 1972	1.554
		January 1972	1.610
		July 1971	1.669
		January 1971	1.751
		July 1970	1.838
		January 1970	1.929
		July 1969	2.025
		January 1969	2.126

(a) Based on 6% escalation rate per year (10).

(b) Based on escalation rate of 5% for material and 8% for labor compounded per year (10).

TABLE 3

Range of Investment Estimates For Base Load Fuel Conversion Plants 1000 MWe - No Pollution Control - Mid-1975 Dollars

Plant	Base Investment $/kW	Contingency %	Uncertainty %	IDC* & Startup Factor	Total Capital Cost $/kW
Conventional					
Eastern Coal	300	+ 10	± 10	1.30	385-470
Western Coal	315	+ 10	± 10	1.30	405-495
Liquid Fuel	200	+ 10	± 10	1.22	240-295
Nuclear	450	+ 15	± 10	1.30	605-740
Combined Cycle					
Liquid Fuel	170	+ 15	± 10	1.22	215-265
Low Btu Gas	395	+ 20	± 15	1.30	525-710
Medium Btu Gas	400	+ 20	± 15	1.30	530-720
Atmospheric Fluidized-Bed	315	+ 20	± 15	1.30	420-565
Pressurized Fluidized-Bed	405	+ 20	± 20	1.30	505-760

* Interest during construction

TABLE 4

Range of Incremental Investment Estimates for Environmental Control Technology (1000 MWe Size)

	Base Investment ($/ kW	Contingency (%)	Uncertainty (%)	IDC* & Startup Factor	Capital Investment ($/kW
Sulfur Control					
FGD					
Limestone	50	10	±15	1.30	61-82
Wellman lord	55	15	±15	1.30	70-95
Magnesia	58	20	±20	1.30	72-108
Dual Alkali	60	20	±20	1.30	75-112
Fuel Gas Cleanup					
Low Btu Gas	85	20	±15	1.30	113-152
Medium Btu Gas	75	20	±15	1.30	99-135
Fluidized Bed Combustion					
Limestone or Dolomite	14	20	±25	1.30	16-27
Particulate Control					
ESP - Cold	18	10	±10	1.22	22-27
ESP - Hot	22	10	±15	1.22	25-34
Baghouse	30	15	±15	1.22	36-48
Wet Scrubber	35	10	±10	1.22	42-52
NO_x Control					
Combustion - Mod	8	15	±10	1.22	10-12
Selective Catalytic Reduction+	20	20	±25	1.22	22-37
Water Injection for Turbines	3	10	±15	1.22	3-5
Thermal Discharge Control					
Evaporative Cooling Tower					
Fossil	11	10	±10	1.30	14-17
Nuclear	14	10	±10	1.30	18-22

*Interest during construction

+(SCR)

TABLE 5

BASE GENERATION SYSTEMS ANNUALIZED COST

Plant	Capital (mills/kWh)	O&M (mills/kWh)	Total Annualized (mills/kWh)
Conventional			
High Sulfur Coal	12.17-14.86	1.00	13-16
Low Sulfur Coal	12.80-15.65	1.06	14-17
Liquid Fuel	7.59-9.33	0.47	8-10
Light Water Reactor	19.13-23.39	1.20	20-25
Combined Cycle			
Liquid Fuel	6.80-8.38	1.64	8-10
Low Btu Gas	16.60-22.44	1.83	18-24
Medium Btu Gas	16.75-22.76	1.74	18-25
Fluidized Bed Combustion			
Atmospheric (AFBC)	13.28-17.86	1.36	15-19
Pressurized (PFBC)	15.96-24.03	2.06	18-26

TABLE 6

ENVIRONMENTAL CONTROL TECHNOLOGY ANNUALIZED COSTS
FOR 1000 MWe INSTALLATIONS

	Capital (mills/kWh)	O&M (mills/kWh)	Total Annualized (mills/kWh)
Sulfur Control			
FGD			
Limestone	1.93 - 2.59	1.20	3.1 - 3.8
Wellman Lord	2.21 - 3.00	0.95	3.2 - 4.0
Magnesia	2.28 - 3.41	1.00	3.3 - 4.4
Dual Alkali	2.37 - 3.54	1.72	4.1 - 5.3
Fuel Gas Cleanup			
Low Btu Gas	3.57 - 4.81	1.04	4.6 - 5.8
Medium Btu Gas	3.13 - 4.27	0.64	3.8 - 4.9
Fluidized-Bed Combustion			
Limestone or Dolomite	0.51 - 0.85	0.60	1.1 - 1.5
Particulate Control			
Electrostatic Precipatator - Hot	0.70 - 0.85	0.15	0.9 - 1.0
Electrostatic Precipatator - Cold	0.79 - 1.07	0.30	1.1 - 1.4
Fabric Filter	1.14 - 1.52	0.36	1.5 - 1.9
Wet Scrubber	1.33 - 1.64	0.40	1.7 - 2.0
NO_x Control			
Combustion Modifications	0.32 - 0.38	0.10	0.4 - 0.5
Selective Catalytic Reduction	0.70 - 1.17	0.50	1.2 - 1.7
Water Injection For Turbines	0.09 - 0.16	0.50	0.6 - 0.7
Thermal Discharge Control			
Cooling Tower			
Fossil	0.44 - 0.54	0.30	0.7 - 0.8
Nuclear	0.57 - 0.70	0.50	1.1 - 1.2

TABLE 7

FUEL COSTS (BASED ON 10,000 BTU/kWh HEAT RATE)

	$\$/10^6$ Btu	Mills/kWh
High Sulfur Coal	0.80 - 1.20	8 - 12
Low Sulfur Coal	1.05 - 1.95	11 - 15
Physically Cleaned Coal	1.00 - 1.40	10 - 14
Chemically Cleaned Coal	1.40 - 2.20	14 - 22
Solvent Refined Coal	2.50 - 3.00	25 - 30
Liquefied Coal	3.00 - 3.50	30 - 35
Liquid Fuel	1.50 - 2.50	15 - 25
Uranium	0.45 - 0.55	5 - 6

4.0 Data Sources

The primary sources for cost data are conceptual design studies performed under EPRI, EPA and DOE sponsorship and ECAS conducted by NSF. Other data came from individual manufacturers. The specific data sources are discussed below:

4.1 Base Generation Systems

Capital investment estimates for conventional fossil fired plants were compared from several sources. These included studies by Ebasco[6] and Bechtel[4] for EPRI, ECAS[7, 8], a study by TVA for EPA[9], and a Gilbert study for DOE[10]. After adjustments to a common basis and removing environmental control costs, the base power plant costs varied $\pm$ 7 percent. Representative base costs were selected for each of the options based on this comparison. Capital investment estimates for the conventional nuclear option were based primarily on the Ebasco study[6].

Combined cycle capital investment data were compared using a Gilbert study[10] for DOE and Stone & Webster[11] and GE[12] studies for EPRI. Capital investments varied up to 40 percent between the studies depending mainly upon the type of process chosen. The cost figures used were based primarily upon the Gilbert study which assumed a low pressure, two-stage, entrained-bed gasifier. The wider range in the estimates is reflected by a higher contingency and range of uncertainty.

The source for investment estimates for fluidized bed combustion (FBC) included the ECAS studies[7,8], a Gilbert study for DOE[13], a TVA study for EPA[9], and a GE study for EPRI[12]. After adjustments to a common basis, investments for atmospheric units ranged within 10 percent and for pressurized with 15 percent. Representative costs were selected for each system based on a comparison of these studies.

Conventional fossil fired O&M costs were taken from a Gilbert study for DOE[10] and were based on the Federal Power Commission publication "Steam Electric Plant Construction and Annual Production Expenses"[14]. O&M costs for a nuclear option were taken from an EPRI report[3].

Combined cycle and AFBC O&M costs were obtained from the GE study for EPRI[12]. PFBC O&M costs were obtained from the ECAS study [7].

4.2 Fuel

For coal, petroleum and uranium, costs from published data[3,15] and present prices information[16] were compiled and representative values selected. Because of transportation costs, low sulfur coal was estimated to cost $0.25/10^6 Btu more than high sulfur coal[2].

Fuel costs for physically cleaned, chemically cleaned, solvent refined and liquefied coals are based on high sulfur feed coal, but also reflect charges for plant investment including capital charges plus operating and maintenance costs. Battelle[17] coal cleaning costs were used. Solvent refined and liquefied coal costs were from a report by Gilbert[13].

4.3 Environmental Control Technology

In addition to the conceptual design studies, flue gas desulfurization costs were obtained from studies by PEDCO[18], the Federal Power Commission[19] and Davy Power Gas[20]. Representative capital and O&M costs were selected after a comparison of these studies. The Wellman Lord FGD process is based on sulfuric acid as the product. Fuel gas cleanup capital and O&M costs were based primarily on the Gilbert costs study[10]. Sulfur control costs for fluidized-bed combustion were estimated from the ECAS studies[7].

Particulate control cost data were obtained, in addition to the conceptual design studies, from an Industrial Gas Cleaning Institute Study for EPA[21] and published cost models by Research-Cottrell[22]. Again, a comparison of these studies was made and representative costs selected.

Data for NO_x control was taken from EPA published data for combustion modifications[23] and selective catalytic reduction[24]. Data for water injection for turbines were obtained from the standard support document[25].

Cost data for cooling towers were based on costs reported in the conceptual design studies and a recent EPA study[26].

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16. ABSTRACT The report gives typical costs for electric power generating plants and their environmental controls for installations of 1000 and 500 MWe capacity, including the expected range of uncertainty. Total annualized costs for a particular configuration can be computed by adding the appropriate incremental costs for fuel and environmental control equipment to the cost of the base generation system. Fixed charges are computed on the basis of 18% of the capital investment; cost data are corrected to mid-1975. Two examples of the use of the data are included. The data and method are intended to provide an overview. Actual installation costs may differ widely from those found from information in this report because of site-specific considerations.

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