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COST-EFFECTIVENESS EVALUATION OF FLUE GAS DESULFURIZATION PROCESSES

RONNIE LEUNG-NEE TONG
The Energy Center

JOHN D. KEENAN
Associate Professor
Department of Civil and Urban Engineering

University of Pennsylvania

ABSTRACT

An economic dispatch model is developed to simulate the daily load dispatch operations of a power system. The model has been used to account for the operation of various flue gas desulfurization (FGD) systems and their impacts on the power system economic dispatch pattern and SO_2 emissions. The cost minimizing dispatch patterns and system operating costs of a power system with and without FGD can be simulated, and the SO_2 removal cost of various FGD systems calculated and compared. Simulations performed on a hypothetical test power system with nine coal-fired generating units showed that the lime and the Wellman-Lord processes are the two least costly FGD systems to operate. The limestone process is also competitive. The same three processes are also found to be the most cost-effective FGD systems. A sensitivity analysis showed that the most critical factor influencing the cost-effectiveness of a FGD system is the sulfur content of the fuel. A high sulfur fuel (coal, in this study) results in a large increase in cost-effectiveness, and a moderate increase in the system operating cost.

INTRODUCTION

One the key air pollutants is sulfur dioxide derived from fossil-fuel combustion. Its continuing importance in the future is evidenced by the probable expanded role of coal in the U.S. energy economy. In light of the New Source Performance Standards (NSPS) for coal burning utilities, SO_2 control will entail heavy reliance on flue gas desulfurization (FGD).

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The purpose of this paper is to quantify the impact of FGD processes on the daily load dispatch operations of a power system through the use of a simulation model. In this manner, the data are developed to provide an additional dimension for comparing the various FGD systems. The development of the simulation model is discussed elsewhere and most of the details will not be repeated here [1].

FLUE GAS DESULFURIZATION

Flue gas desulfurization refers to the scrubbing processes developed to remove SO_2 from combustion flue gas by reaction with an absorbent, which is usually an aqueous solution or slurry. Dry scrubbing processes are recently under development. However, these processes are novel and are not considered here.

FGD systems are categorized as either throwaway (non-regenerable), or regenerable systems. In the throwaway processes the SO_2 in the flue gas is removed by reaction with the scrubbing fluid and the resultant waste sludge must be disposed of properly. In comparison, the regenerable systems convert the removed SO_2 into salable products such as sulfuric acid or sulfur, which are then sold to offset partially the cost of the FGD system. The scrubbing reagents are usually regenerated for further use. Throwaway systems are preferred in current applications because of the more favorable economics, simpler system design, and greater operating experience. However, this picture may be reversed if the heavy social (environmental) costs of the throwaway sludge are to be internalized. Moreover, the cost of sludge disposal will increase as more throwaway FGD systems go into operation, and if more stringent waste disposal regulations are enacted.

On the other hand, although regenerable systems minimize waste product production, the long term marketability of the products is under question. As more systems are brought on-line, an over-supply may result and almost certainly drive prices down and reduce the marketability of by-products.

OPERATION OF FGD SYSTEMS

Over fifty types of FGD processes have been suggested, but relatively few as yet commercially applied. A breakdown by processes of the currently operating and projected FGD system capacity is shown in Table 1 [2]. To date, lime and limestone systems dominate the throwaway types, while the Wellman-Lord process is the most frequently used regenerable system.

With the implementation of the 1979 NSPS, it is expected that application of FGD systems will increase considerably. Whether FGD systems will operate effectively to meet the required environmental standards depends on many factors. Four of the most important ones are operational efficiency, system dependability, system cost, and energy penalty.

Table 1. Breakdown of FGD Capacity in U.S. in MW[2]

	Operating December 1979	*Operating plus Committed*	*Percent*	*Status*
Non-Regenerable				
Limestone	8,714	23,250	47.3	Commercial
Lime	6,209	11,702	23.8	Commercial
Lime/Limestone	20	728	1.5	Commercial
Limestone/Flyash	1,480	1,480	3.0	Commercial
Lime/Flyash	1,452	4,549	9.2	Commercial
Na_2CO_3 Scrubbing	925	925	1.9	Commercial
Double Alkali	1,170	1,170	2.4	Commercial
Spray dry, Lime	0	1,890	3.8	
Spray dry, NA_2CO_3	0	440	0.9	
Regenerable				
Magnesia	120	884	1.7	Commercial
Wellman-Lord	1,360	2,074	4.2	Commercial
Citrate	0	60	0.1	In startup
Aqueous Carbonate	0	100	0.2	1982 startup
Ammonia	0	0	–	2MW test at Air Products 25MW unit in France
Total	21,450	49,212	100.0	

Operational Efficiency

The operational efficiency of a FGD system is assessed as SO_2 removal. Depending on the system design and operating conditions, different levels of SO_2 removal can be achieved by different FGD processes. The typical achievable operational efficiency of twelve systems is summarized in Table 2 [2]. All the processes considered are capable of achieving at least 90 percent removal of SO_2, which is required in most cases under the 1979 NSPS. In other words, FGD alone can be used to meet the 1979 NSPS.

System Dependability

The dependability of FGD systems, as measured by their average availability over total system life, is shown to have improved over time since the early 1970's [3]. This improvement may be attributed to better process designs and greater operating experience. In this study, a uniform FGD dependability of 95 percent is assumed.

Table 2. Flue Gas Clean-Up Processes

Type of Process	Active Component	SO_2 Removal Percent
Once - Through:		
Limestone	Limestone	90
Lime	Lime	95
Limestone + clean-up	Limestone/Lime	95
Double alkali	Sodium hydroxide/lime	95
Gypsum product:		
Chiyoda	Sulfuric acid	95
Regenerable scrubbing:		
Magnesia	Magnesia	95
Wellman-Lord	Sodium sulfite	95
Citrate	Sodium citrate	95
Aqueous Carbonate	Sodium carbonate	95
Ammonia	Ammonia	95
Dry high-temperature:		
Shell/UOP	Copper oxide	90
BF/FW	Active carbon	95

System Cost

FGD capital costs are composed of the direct costs for purchasing and installing the system; and the indirect costs due to spare parts, taxes, insurance and capital charges. Both PEDCo Environmental, Inc. [4] and TVA [5] have done detailed cost estimates on several FGD systems. Because of the difference in their working assumptions, results obtained in both cases are quite different. In this paper, the PEDCo figures are used because these data are most complete; their assumptions are more conservative and are applicable for a worse case study; and the analysis is more up-to-date and is believed to be more precise.

The PEDCo results show that the cost of FGD systems varies with plant size, degree of SO_2 control, and type of coal used. Generally speaking, both unit capital cost (\$/KW) and unit annual cost (mill/KWh) decrease with increasing plant size and decreasing sulfur content in coal. Although the capital cost of a FGD system is large and is an important factor in making the investment decision, once the FGD system is installed, it becomes a sunk cost. Therefore, in considering the power system operating cost in this study, only the annual operating cost is used.

Energy Penalties

The operation of a FGD system requires energy. The scrubbing recirculation pumps and booster fans are the primary energy consumers. Different FGD processes require varying amounts of energy for scrubbing liquor make-up, scrubbing liquor regeneration, and sludge disposal. Additional energy is also needed to reheat the flue gas and to produce steam in some of the systems. All these additional energy requirements constitute the energy penalty of a FGD system which represents the additional Btu's required to produce a net kilowatt-hour of electrical energy. In this paper, PEDCo data are used to assess energy penalties [4].

SYSTEM MODELING

As mentioned above, the focus of this research was to simulate the operating cost and SO_2 emission from an electric power system operating under economic dispatch, with and without FGD systems. Under these objectives, a general power system operation model was developed which is characterized by:

1. the total system operating cost function as a summation of the cost functions of the individual generating units;
2. the total system SO_2 emission function as a summation of the emission functions of the individual generating units;
3. the reliability of the generating units, related to their forced outage rates;
4. the daily system load curve; and
5. operation of FGD systems [1].

Economic Dispatch Model

A model to simulate the economic dispatch problem and to incorporate within it the operation of FGD options has been described [1]. The inputs required are the daily system load curve of the power system, determined on an hourly basis; whether FGD is used; which, if any, FGD process is used; the number of days to be simulated; number of generating units in the power system; the probabilistic unavailability (forced outage rate) of each generating unit; maximum and minimum generation limits for each unit; cost coefficients of the quadratic cost function for each unit; and, emission coefficients of the quadratic SO_2 emission function for each unit. In those cases where the operation of FGD is needed, additional data are needed. These are the SO_2 removal efficiency of the FGD system installed for each unit, and the operating cost of each FGD unit.

The model operates by minimizing total system cost, where the cost of each generating unit is given as a quadratic function of the unit's hourly power output level.

$$C_i = \alpha_i + \beta_i P_i + \gamma_i P_i^2 \tag{1}$$

where

C_i = hourly operating cost of the ith unit

α_i, β_i, γ_i = cost coefficients of the ith generating unit

P_i = hourly power output level of the i^{th} unit

In addition, the SO_2 emission rate is determined as a quadratic

$$e_i = ea_i + eb_i P_i + ed_i P_i^2 \tag{2}$$

where e_i = SO_2 emission rate of i^{th}unit, lb SO_2/hr and ea_i, eb_i, ed_i are SO_2 emission coefficients of the ith generating unit.

Test Power System

The hypothetical power system is comprised of nine coal-fired generating units (Table 3). The heat rate coefficients are adopted from EPRI [6] as modified by El-Hawary and Christensen [7] and from Vertis [8]. It is assumed that the two largest units (unit 5, with a capacity of 800 MW, and unit 6, with a capacity of 1200 MW) are new generating units subject to the 1979 NSPS. The other units operate under the 1971 NSPS, with an emission ceiling of 1.20 lb SO_2 per million Btu fuel input. Eastern bituminous coal with 3.5 percent sulfur content and a heating value of 12000 Btu/lb is used to fire all units in the system. The coal price is set at $1.38/MM Btu [9]. The system daily load is derived by adopting a typical curve shape [1]. Ninety-five percent of the sulfur in the coal is released as SO_2. The probabilities of unit unavailability, represented by the unit forced outage rate are derived from EEI data [10, 11].

During simulations in which SO_2 removal occurs, it is assumed that the same FGD system is installed at each generating unit, and is operating at the efficiency required by the appropriate NSPS. The FGD systems considered are lime, limestone, magnesium oxide, double alkali, and Wellman-Lord. The FGD operating cost and energy penalties for each unit have been developed from a least squares linear regression of the PEDCo data [4]. The dependability of all FGD systems is taken to be 95 percent.

RESULTS AND DISCUSSION

In order to test the accuracy and variability of the FGD costs under varying operating conditions, a sensitivity analysis was carried out on the test power system. The lime FGD scenario was used as a reference case. The operational parameters investigated were the simulation time, the system load level, SO_2 control level, and sulfur content of the fuel. In the first case, the simulation time was varied over the range of one to seven days (see Table 4). In considering system load level, it was assumed that the shape of the system load curve

Table 3. Characteristics of Test Power System

	1	2	3	4	5	6	7	8	9
Maximum Generation Limit, MW	50	200	400	600	800	1200	335	345	321
Minimum Generation Limit, MW	5	50	100	150	200	230	0	0	0
Forced Outage Rate, Percent	2	5	7	8	10	12	5	5	5
Forced Outage Rate with FGD, Percent	7	10	12	13	15	17	10	10	10
SO_2 Reduction, Percent	78.35	78.35	78.35	78.35	90	90	78.35	78.35	78.35

Table 4. Range of Variation of Variables Used in Sensitivity Analysis

Parameter	*Range*
Simulation time, days	1 - 7
System Load Level, fraction of base case	0.9 - 1.1
SO_2 Control level, percent	78.35 - 90
Sulfur Content of coal, percent	3.5 - 7.0

remained constant. System load level variations were assumed to occur in a proportional way, i.e., each load increasing or decreasing to the same extent. SO_2 control level was accounted for by assuming every generating unit is subject to one uniform SO_2 reduction level which is varied in the analysis. The FGD operating costs, in $/MWh, and coal cost, in $/MM Btu, are assumed to be fixed in all scenarios. The sensitivity parameters used in the analysis are listed in Table 4.

Cost-Effectiveness Sensitivity

The results of the sensitivity analysis are listed in Table 5. The findings are discussed below.

Simulation time–The impact of simulation time was investigated by varying the length of simulation from one day (-66.67 percent of the reference case) to seven days (+133.3 percent of the reference case). It was found that reducing the length of the simulation time by 66.67 percent produces a more pronounced change (-3.72 percent) than increasing the length of simulation by the same amount (which produced a 2.66 percent change). Nevertheless, ranging the reference case simulation time (three days) from -66.67 percent to +133.3 percent produces no more than a four percent change in SO_2 removal cost (cost-effectiveness). This suggests that the removal costs are relatively insensitive to the length of simulation time. It follows that the accuracy of the SO_2 removal results will not improve to any large extent by increasing the length of the simulation period.

System load level–The system load levels were varied by +10 percent from the reference case system load (P_D). The corresponding percentage change in the cost of SO_2 removal is less than one percent. From this, it appears that a relatively large change in the system load level will only result in a relatively small change in the SO_2 removal cost of a FGD system.

SO_2 control level–Two SO_2 control levels were studied. The first case was one in which all generating units were subject to 78.35 percent SO_2 emission

Table 5. Results of the Sensitivity Analysis (P_D is System Load Level)

Case	*Dollars Spent 10^6*	*SO_2 Emitted, 10^6 lb*	*Cost of Sulfur Removal, \$/lb SO_2 Removal*	*Change of Variable from Reference Case, Percent*	*Change in Cost of Sulfur Removal Percent*
Reference Case	3.85	1.66	0.188	–	–
Sensitivity Scenarios:					
Simulation Time					
1 Day	1.27	0.56	0.181	-66.6	-3.72
5 Days	6.47	2.74	0.193	+66.6	2.66
7 Days	9.04	3.85	0.193	+133.3	2.66
System Load Level					
$0.9XP_D$	3.55	1.55	.186	-10	0.96 - 1.06
$1.1XP_D$	4.13	1.75	.188	+10	+0.3 - 0
SO_2 Control Level					
78.35%	3.78	2.04	0.189	–	+0.77 - .01
90%	3.94	0.94	0.183	–	-2.66
Fuel Sulfur Content					
7.0%	4.22	3.26	0.117	+100	-37.7

reduction control. This is equivalent to the 1971 NSPS (with 1.20 lb SO_2/MM Btu ceiling). The second case requires all generating units to have 90 percent SO_2 emission reduction. Due to the mixed NSPS nature of the reference case, the results obtained from the two sensitivity scenarios are not compared with the reference case. Instead they are compared with each other and the effect of tightening the SO_2 emission standard is studied. From the simulation run, it is shown that an increase in SO_2 emission control level from 78.35 to 90 percent (approximately 15 percent change) results in only a 3.7 percent decrease in SO_2 removal cost. This shows that the removal cost of the FGD systems is not sensitive to variations in SO_2 emission control level within the limits tested. Although it seems that the FGD SO_2 removal cost does decrease with most stringent SO_2 emission control, this decrease may not be large enough to offset the increased operating cost.

This observation results from the scale and characteristics of FGD systems. Once in place, the cost of FGD per unit of SO_2 removed is relatively constant, within the approximate range of 75 to 90 percent. On the other hand, if the required level of desulfurization is very high (>95 percent) or very low (< 50 percent), then we would anticipate a stronger relationship between SO_2 removal and its unit cost.

Sulfur content in coal– Assuming the cost of coal to be constant for the different types of coal under study (and that the cost coefficients remain unchanged also), operation of the same test power system was simulated using 7.0 percent sulfur eastern bituminous coal (12,000 Btu/lb heating value). The simulated SO_2 removal cost is 0.117 which shows a relatively large decrease (-37.77 percent) in the cost of SO_2 removal when dirtier coal (7.0 percent sulfur, compared with the 3.5 percent sulfur coal used in the reference case) is used. In other words, the sulfur content in coal will have an important impact on the cost of SO_2 removal. The FDG systems are most cost-effective when dirtier coals are used.

From the sensitivity analysis, it can be seen that variations in simulation time, system load levels, and even SO_2 emission control levels will have little effect on the cost of SO_2 removal. The results obtained for the simulated power system using 3.5 percent sulfur coal appear to be reliable data that will not vary much with changes in the system simulation parameters. On the other hand, it is also shown that variations in sulfur content in the fuel (in this case, coal) will bring about the greatest change in the FGD cost-effectiveness. An increase in sulfur content in coal tends to decrease the cost of SO_2 removal rather significantly.

The use of high-sulfur coal also results in a moderate increase in the power system operating cost (+9.6 percent) and a larger percentage increase in total system SO_2 emissions (+96.4 percent). This higher system operating cost is mainly due to the higher FGD operating cost required for scrubbing the dirtier fuel. (In practice, this increased cost is reduced to some extent by the usually lower fuel cost of the dirtier [high sulfur] coal.)

It is apparent that a cost minimizing electric utility will use the type of fuel that results in the least system cost. This is typically a relatively low sulfur, high Btu fuel. When the availability of this type of fuel is under question, as is usually the case, the increasing cost-effectiveness of FGD with fuel sulfur content will provide a better incentive for a shift to higher sulfur fuel.

EFFECT OF FGD SYSTEM

The simulation model was also run using different FGD techniques. The total simulation time in each run was three days. The FGD methods tested were the lime, limestone, magnesium oxide, double alkali, and Wellman-Lord processes. The results, summarized in Table 6, are presented in two forms. First, the total system operating costs are given in column 3. For the base case, without SO_2 removal, the operating costs are \$2.37 million. The addition of FGD technology increases total system operating cost to the range of \$3.81 to 4.06 million. The least costly options are the Wellman-Lord and lime processes, with the limestone technique fairly close.

The results are also shown in terms of the cost of sulfur removal in terms of dollars spent per lb SO_2 removed. These values are found in column 5 of Table 6. The same sequence of random numbers (random link) was used in each run. Therefore, the forced outage patterns and the total system power output are the

Table 6. Effect of FGD Method on Sulfur Removal Costs

Case (1)	*FGD System Used (2)*	*Total System Operating Costs, 10^6 \$ (3)*	*Total System SO_2 Emission 10^6 lb (4)*	*Cost of Sulfur Removal \$/lb SO_2 Removed (5)*
Base	–	2.37	9.52	–
1	Lime	3.85	1.66	0.188
2	Limestone	3.96	1.65	.202
3	Magnesium Oxide	4.06	1.71	.216
4	Double Alkali	4.04	1.67	.213
5	Wellman-Lord	3.81	1.70	.184

same in all simulation runs. As a result, the total system operating costs and SO_2 emissions can be compared using the SO_2 removal costs shown in column 5. These are calculated as the additional operating costs in dollars divided by the SO_2 removal in pounds. The most economical units are Wellman-Lord and lime. Limestone is also competitive.

Under the conditions and assumptions used here, there is a one-to-one correspondence between the total operating costs and the SO_2 removal costs, which is a measure of cost-effectiveness. As defined here, the SO_2 removal cost depends both on operating costs and the degree of SO_2 removal. Therefore, it is possible that the option which minimizes operating cost may differ from the one which minimizes the SO_2 removal cost. Such a condition develops because the various FGD processes provide different levels of SO_2 removal efficiency. In other words, economic optimality in terms of incremental benefits per unit of additional operating cost, cannot be guaranteed by the decision of the utility to minimize operating costs. Thus, the model discussed here can be used not only to determine operating costs for the power system but also the economic efficiency of various policy options.

APPLICATIONS OF SIMULATION MODEL

The model developed here can be used to consider the following problems. It has been assumed that the same FGD system is installed throughout the whole power system in each scenario. This assumption can be relaxed and the model used to consider the most cost-effective mix of FGD devices for a particular power system. Similarly, the general FGD dependability of 95 percent assumed here for all FGD processes can be replaced by actual dependability figures (as they become available) representative of the type of FGD system being considered. This will give a more realistic cost-effectiveness result.

When suitable data are available, the model can also be applied to a power system made up of a generation mix of different types of fossil-fuel-fired generating units. The model is also applicable for investigating the cost-effectiveness of different options of emission control standards. This will provide a firm basis for environmental policy analysis regarding power system SO_2 emissions.

Provided that the relevant operational data are available, the computer model can be applied to simulate the operation and cost-effectiveness of other (more novel) SO_2 abatement options besides wet scrubbing FGD systems.

In this study, a constant fuel cost was assumed for all types of coal. In reality, the fuel cost varies with the type of coal used and a higher sulfur coal would typically be less expensive than a cleaner (lower sulfur) coal. When this fact is taken into consideration, the increased system operating cost simulated in the sensitivity analysis for the use of dirty coal will be offset, or even reversed, to some extent, while the FGD cost-effectiveness for the use of higher sulfur coal will be improved further. Thus, if the actual fuel costs of the different types of coal are available for use, the model can also be applied to determine the optimal mix of coal types used for the various generating units for attaining the lowest system operating cost, and the best cost-effectiveness.

Conclusions

An economic dispatch model incorporating the costs of flue gas desulfurization has been developed. Simulations were performed on a hypothetical test power system consisting of nine coal-fired generating units. The simulations indicated that the lime and Wellman-Lord processes are the two least costly FGD systems to operate. The limestone process is also competitive. The same three processes are the most cost-effective in terms of dollars spent per lb SO_2 removed.

A sensitivity analysis demonstrated that the most important determinant of FGD cost-effectiveness is the sulfur content of the fuel. System operating costs increase and the SO_2 removal cost decreases as the sulfur content of the fuel increases. The duration of the simulation time, system load level, and SO_2 control level were found to have a limited influence on cost-effectiveness.

The simulation model can be readily extended and applied to a variety of issues. These include a determination of the most cost-effective mix of FGD devices for a particular power system and the optimum mix of coal types within the power system. The model also provides a tool for environmental policy analysis.

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Direct reprint requests to:

John D. Keenan
Towne Building
220 South, 33rd Street, D3
Philadelphia, PA 19174