Cost-Minimization Model for Reducing Sulphur Dioxide Emission from Coal-Fired Generating Stations

JAMES H. BOOKBINDER  
Department of Management Sciences  
University of Waterloo  
Waterloo, Ontario  
Canada N2L 3G1

N. SEKHAR  
General Electric Environmental Services, Inc.  
200 North 7th St.  
Lebanon, PA 17042

Abstract: To limit emission of sulphur dioxide, an electrical utility has several available options: (i) Burn low-sulphur coal, (ii) remove SO₂ from flue gases after combustion (Flue Gas Desulphurization or FGD), and (iii) remove sulphur from coal before combustion (Physical Coal Cleaning or PCC). Options (ii) and (iii) vary in their cleaning capabilities and scale economies. Pre-cleaning of coal followed by post-cleaning of flue gases may thus be less costly than either PCC or FGD alone to obtain a given level of sulphur removal. A mathematical programming model to determine the best combination of options is developed from empirical cost data and solved for typical conditions encountered by North American utilities. Sensitivity analyses are carried out with respect to the various operating and capital costs, as well as the maximum SO₂ emission level. The latter enables assessment by the regulatory authorities of proposed environmental standards. Finally, we show how the model can aid a utility in directing its R&D effort by estimating the target sulphur removal capability which should be sought for each control technique and the cost saving (ROI from R&D) if successful.

Coal is expected to play an important role in meeting our future energy demands. As is well known, combustion of coal for power generation produces a number of products which are undesirable and potentially hazardous to health. Strict emission regulations have been formulated and enforced to varying degrees in the United States by the Environmental Protection Agency (EPA) and in Canada by various Federal and Provincial agencies.

The greatest environmental concern in the past few years has arisen over the mass emissions of sulphur dioxide from coal-fired generating stations. Options available for control of this pollutant may be broadly classified as follows:

- Burn low-sulphur coal
- Remove sulphur dioxide (SO₂) from combustion flue gases after combustion: flue gas desulphurization (FGD)
- Remove sulphur from coal before combustion: physical coal cleaning (PCC).

Use of low-sulphur coal is clearly the simplest and most reliable, but less than 10% of the available coal reserves in the United States and Canada can meet the EPA emission guidelines. Low-sulphur coal is thus more costly, at best a partial solution.

Received January 1985; revised July 1985. Handled by the Applied Optimization Department.
For PCC and FGD, there are economies of scale in both the cost and performance functions. As a result, pre-cleaning of coal followed by post-cleaning of flue gases may be less costly than either pre-cleaning or post-cleaning alone to obtain a given degree of sulphur removal. This joint use of PCC and FGD, the main approach considered in our model, has been studied only qualitatively by Kilgroe [8]. Molburg and Rubin [9] have developed an extensive statistical database of costs for PCC and for three FGD systems. Their pollution control simulations did not consider a mix of control techniques. Neumeyer [10] employs a similar approach, studying the control options only individually rather than in combination. To the best of our knowledge, the present paper is the first to consider a mix of control techniques.

A major goal of our work is the quantitative analysis of this pollution control situation through a non-linear programming model. Solution furnishes economically optimum combinations of the two control strategies for a variety of cost and emission regulations generally encountered in the utility industry. Through sensitivity analysis, we show the cost implications to the utility of different possible environmental regulations concerning the maximum sulphur dioxide concentration. The model's results for the cost-effectiveness of various strategies can also direct R&D.

We remark that an early version of our work was presented in Bookbinder and Sekhar [2]. Zinn and Lesso [20] have reported a procedure which has been used by the Texas Air Control Board in controlling aggregate emissions from petro-chemical processing plants. Our present study may be viewed as the air pollution analogue of Fiacco and Ghaemi [7], in which was conducted an extensive sensitivity analysis of a non-linear water pollution control model. It should be noted that the costs included in our model are those related to the pollution control techniques. Through the SO₂ emission constraint, we can obtain the implicit cost of the pollution to the electrical utility, but not to the public at large. Estimation of the "societal" shadow price of pollution has been considered by Paryni and Grammas [12].

Use of the most common FGD technique, namely scrubbing with wet limestone slurry, produces several cubic feet of sludge per ton of coal burned. Disposal of this sludge may create another environmental problem, a fact which motivated the work of Ravindran and Hanline [14]. These authors studied centralized coal-blending plants which could combine low-sulphur and high-sulphur coals, thereby producing a blend that would meet the environmental standards. Our approach, more "decentralized" in that coal is transported only to the site of the power plant, allows use of PCC as well, rather than solely FGD.

Control Techniques

North American coals contain about equal amounts of organic and inorganic compounds of sulphur, but physical coal cleaning can remove only the latter. Depending upon the location of the power plant, however, emission regulations may require removal of up to 90% of total sulphur, thus necessitating consideration of FGD as well.

Sulphur dioxide is removed in the FGD process by "scrubbing" the combustion gas with water containing active alkali chemicals such as limestone or sodium carbonate. Several FGD processes are available commercially, all more expensive than PCC. FGD can remove both organic and inorganic sulphur, achieving overall removal efficiencies of up to 95% [6].

In PCC, coal is crushed to separate inorganic sulphur (mostly pyrites) from the coal matrix, and the coal then agglomerated for storage and transportation. A greater degree of pyrite removal is achieved if the coal is ground to finer particle size. This increases the cost of pulverizing and requires more binding material for agglomeration, thus further increasing the cost. Several reviews on the subject of PCC are available ([11], [3], [17], [19]).

Process Description and Model Formulation

The process in Figure 1 is considered by many utilities to be the most viable. Coal from the mines, usually called "run-of-mine" coal or ROM coal for short, is passed through a PCC plant. There are \( X_0 \) Mg of "clean" coal in the ROM coal, whose sulphur content is \( S_0 \) (Mg of sulphur per Mg of clean coal). After cleaning of the coal and rejection of the dirty stream, the clean stream is shipped to the power plant containing an FGD facility. The "clean" coal in the reject stream and in the clean stream is \( X_1 \) and \( X_2 \) Mg, and the sulphur content \( S_1 \) and \( S_2 \), respectively. \( S_1 \) is the "equivalent" sulphur content of the clean flue gas stream leaving the FGD plant.

---

Figure 1. Mass flow diagram for "clean" coal and sulphur, of the emission control model optimized in this paper. Quantities underlined refer to sulphur, and those not underlined refer to coal.

March 1986, IEEE Transactions 35
\( X_o \), the total weight of coal to be treated, and \( S_o \), the initial sulphur content of the ROM coal, depend respectively on the size of power plant and the source of coal. Given these exogenous values, there are mass balance relations for coal and for sulphur of the form

\[
X_o = X_i + X_s, \tag{1}
\]

\[
X_o S_o = X_i S_i + X_s S_s. \tag{2}
\]

(Recall that the units of \( S_i \) are Mg of sulphur per Mg of (clean) coal.)

Our objective is minimization of total costs of sulphur removal to meet a specific emission regulation:

\[
\text{Min } Z = (Cost)_{pcc} + (Cost)_{rad} \tag{3}
\]

s.t.: Total sulphur removed \( \geq \) that required by emission regulation. \tag{4}

The cost functions have the general form, \((Cost)_{pcc} = f(X_o, S_o)\) and \((Cost)_{rad} = g(X_s, S_s - S_i)\).

It is assumed for each process, and verified by available data, that the cost is an increasing function of the amount of sulphur removed by that process. Constraint (4) will therefore hold as an equality at the minimum cost solution, and so can be rewritten as

\[
\beta X_o S_o = X_i S_i + X_s (S_s - S_i), \tag{5}
\]

where \( \beta \) is the fraction of total sulphur required to be removed so that the applicable emission regulations may be satisfied. An important observation from (5) is that, once the amount of sulphur to be removed by PCC is determined, the amount of sulphur to be removed by FGD is then fixed. All terms in the objective function (3) and in the constraint (5) are either exogenously given or can be expressed as functions of a single variable, say \( S_s \). This single-variable optimization problem is solved numerically using the Newton-Raphson technique.

A comment is in order concerning our environmental constraint (5) in which a fraction of the total sulphur must be removed. In practice, \( \beta \) depends on how "dirty" the coal is, since the regulations specify both the % sulphur to be removed as well as the absolute SO\(_2\) emission per Million BTU heat input. The more restrictive of the two will apply.

The US Clean Air Act of 1978 and subsequent amendments for new emission sources are as follows:

A. If uncontrolled emission is \( > 1.2 \) lbs. SO\(_2\) per Million BTU: then 90% removal, or emission reduction to 1.2 lbs., whichever is more restrictive, is required.

B. If uncontrolled emission is \( < 1.2 \) lbs. SO\(_2\) per Million BTU: then 70% removal, or emission reduction to 0.6 lbs., whichever is more restrictive, is required.

Most major emission sources in the US and Canada have uncontrolled emissions \( > 1.2 \) lbs. These sources thus fall in category A, for which 90% removal is generally the more restrictive regulation. This is why we expressed the environmental constraint in the form of (5) and took \( \beta = 90\% \) (see the section on Solution Results).

Cost Functions

The cost data used in this paper ([11], [5], [13], [15], [18]) have been adapted to the following standard conditions:

(a) The base case is a 2,000 MW generating station operating at an annual "capacity factor" of 50%, i.e., for an average of 12 hours daily.

(b) The production capacity of the coal cleaning plant is matched to that of the generating station.

(c) The expected plant life is 30 years.

(d) The cost estimates are obtained by discounted cash flow with a fixed discount rate of 9%. Costs are expressed in 1980 dollars.

Empirical functional forms were then estimated for both the capital and operating costs of each process. Table 1 summarizes the cost functions.

Final Problem Form

Since all costs have been expressed on a unit weight basis, the feed \( X_o \) to PCC can be omitted from all equations. Moreover, if we define \( S \) as the weight of sulphur removed by PCC per unit weight of sulphur in the input stream, we have \( \alpha S_i = S_s \). The equality constraint (5) can therefore be rewritten as \( \beta S_o = \alpha S_i + (1 - \alpha)(S_s - S_i) \), or

\[
(1 - \alpha)(S_s - S_i) = S_s (\beta - \alpha). \tag{6}
\]

In words, the amount of sulphur removed by FGD equals the total amount of sulphur required to be removed by regulation \( (\beta S_s) \), less the amount of sulphur removed by PCC \( (S_s) \). Combination of (6) with the FGD operating cost of Table 1 yields

\[
(KP)_{rad} = C_r S_s (\beta - \alpha). \tag{7}
\]

The objective function (3) is the sum of (7) plus the four other PCC and FGD costs of Table 1. The final statement of our model is then
Table 1: Cost Functions for PCC and FGD

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Verbal</th>
<th>Sources of Empirical Data</th>
<th>Functions Estimated</th>
<th>Comments</th>
</tr>
</thead>
</table>
| PCC Operating    | Op Cost = sum of 2 terms, KL (cost of coal losses) +                  | Batelle [1]               | \( (KL)_{PCC} = \phi_c \cdot \alpha 
= \phi_c \cdot (0.0044 \cdot S_{0.80}) \), \( \phi_c \) = cost of coal in $/Mg, \( \alpha \) = fractional coal loss in PCC plant. | \( S \) = degree of desulphurization by PCC, \% by weight (0 < \( S \) ≤ 70). Recall that all costs calculated on a discounted cash flow basis, and are expressed in 1980 dollars. |
| PCC Capital      | Capital cost of PCC plant, in $/Mg of Coal processed                   | Phillips [13]             | \( (KC)_{PCC} = 0.0112 \cdot S_{0.92} \)                                                                                                     |                                                                                     |
| FGD Operating    | Operating cost in $                                                    | Saleem [16]               | \( (KP)_{FGD} = C_d(1 - \alpha)(S_2 - S_2) \)                                                                                               |                                                                                     |
| FGD Capital      | Capital cost of FGD, in $/Mg of coal processed.                       | Rosenberg [15], Sekhar [18] | \( (KC)_{FGD} = C_d(1 - \alpha) \)                                                                                                         |                                                                                     |

\[
\text{Min } Z = 0.0112 \cdot S_{0.92} + (\phi_c - C_d)(0.0044 \cdot S_{0.80}) + C_d S_{0.92} - C_d S_2 S_2. \tag{3}
\]

The optimization is with respect to \( S \), the degree of desulphurization by physical coal cleaning.

Solution Results and Sensitivity Analysis

Typical runs of the model were for an initial sulphur content \( S_0 = 5\% \), and for required total sulphur removal of \( \beta = 90\% \). The pyritic sulphur content of the coal was assumed to correspond to a maximum sulphur removal by PCC of 70\%. Table 2 shows the model results for the conditions of: binder requirement = 4\%; capital cost of FGD = $2/Mg of coal. For example, if the FGD operating cost is $500/Mg of sulphur removed and the cost of coal is $30/Mg, the optimal sulphur removal by PCC is \( S^* = 27\% \). The degree of desulphurization by FGD is therefore 63\%.

Sensitivity of the optimal solution \( S^* \) was explored with respect to the following parameters: (1) \( \phi_c \), cost of coal; (2) \((C_d, n_2)\), binder requirement; (3) \( C_d \), capital cost of
FGD; and (4) $C_1$, operating cost of FGD. Figure 2 shows typical effects: The optimal degree of desulfurization by PCC, $S^*$, decreases almost linearly as $\phi$ increases. Negative slope is expected, since for higher coal prices, the cost of coal losses and hence the cost of physical cleaning increases.

![Figure 2](image-url)

**Figure 2.** Coal cost $\phi$ vs $S^*$, optimal degree of desulfurization by PCC.

The optimal solution is illustrated in Figure 3 to be quite sensitive to the binder requirement. The binder cost is a major portion of total cost in any PCC operation. PCC becomes less attractive than FGD as the binder content increases, but note that $S^*$ is then less sensitive to any additional increase. The total PCC cost is so great for high binder levels that any further binder requirement results in a less significant cost increase on a fractional basis.

![Figure 3](image-url)

**Figure 3.** Required binder % vs $S^*$.

Suppose that with further research, the binder requirement of a process can be reduced from 8% to 6%. Figure 3 shows that this will have a fairly small effect upon $S^*$ and upon the cost as well. If, however, the initial binder requirement were 4%, then the same 2% reduction can double or triple $S^*$, with an attendant reduction in total cost of up to 10%.

<table>
<thead>
<tr>
<th>Table 2: Optimal Sulphur Removal by PCC, $S^*$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CONDITIONS: BINDER REQUIREMENT = 4%</td>
</tr>
<tr>
<td>FGD CAPITAL COST = $2/Mg</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FGD Operating Cost ($/Mg)</th>
<th>$10$</th>
<th>$15$</th>
<th>$20$</th>
<th>$25$</th>
<th>$30$</th>
<th>$35$</th>
<th>$40$</th>
<th>$45$</th>
<th>$50$</th>
</tr>
</thead>
<tbody>
<tr>
<td>200</td>
<td>4</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>300</td>
<td>14</td>
<td>11</td>
<td>7</td>
<td>5</td>
<td>4</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>400</td>
<td>44</td>
<td>38</td>
<td>32</td>
<td>27</td>
<td>22</td>
<td>19</td>
<td>17</td>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>500</td>
<td>50</td>
<td>44</td>
<td>38</td>
<td>32</td>
<td>27</td>
<td>22</td>
<td>17</td>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>600</td>
<td>68</td>
<td>61</td>
<td>54</td>
<td>48</td>
<td>42</td>
<td>36</td>
<td>30</td>
<td>24</td>
<td></td>
</tr>
<tr>
<td>700</td>
<td>65</td>
<td>59</td>
<td>53</td>
<td>46</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Blank entries are to be interpreted as $S^* = 0$ in the upper-right portion of the table, and as $S^* = 70$ in the lower left. Also, $S^* = 70$ for FGD operating cost $\geq 800$, for all values of coal cost.

We found the effect of FGD capital cost $C_1$ to be in the direction expected: As $C_1$ increases, less sulphur should be removed by FGD. What was unexpected, however, was the virtual insensitivity of the optimal solution $S^*$ to $C_1$, even when $C_1$ was doubled from $2$ to $4$/Mg of coal, $S^*$ increased by only 2% in all cases. Many qualitative discussions of the two control techniques and their combinations for SO$_2$ emission control emphasize the higher capital cost of FGD and especially the uncertainty of $C_1$ for different situations. Our analysis implies much less significance of the FGD capital cost.

Figure 4 demonstrates that $S^*$ is sensitive to the FGD operating cost $C_1$, and that this sensitivity is more pronounced when the binder requirement is smaller. As the binder requirement decreases, the contribution of the FGD operating cost to the total cost becomes more significant, and so does the sensitivity of the optimal solution to any change in this operating cost.

An important practical application of this paragraph and the preceding one would occur when several FGD processes are being considered for combination with a PCC plant. From among these processes with differing capital and operating cost characteristics, one should probably choose an FGD process with a relatively low operating cost, even if its capital cost is high.
Typical cost parameters for a utility operating in Ontario, Canada are: Cost of coal, \( \phi_c = 30\$/Mg; FGD \) capital cost, \( C_c = 3\$/Mg of coal; FGD \) operating cost, \( C_o = 900\$/Mg of S removed; Binder \) requirement = 8\%. The optimal solution is \( S^* = 44\% \) and the corresponding minimum cost is \( Z^* = 37.56\$/Mg \) of coal processed. Let us suppose by further research and development that the binder requirement can be reduced from 8\% to 6\%; or with the same effort, \( C_c \) can be reduced from $3 to $2/Mg of coal, or \( C_o \) from $900 to $700/Mg of sulphur. However, due to limited availability of funds only one of the projects can be undertaken. The potential savings on successful completion of each of these projects can be calculated from the optimal solutions to our model, and are summarized in Table 3, Part A.

From the results, it seems that research in FGD operating cost should be preferred to the other two alternatives. It must be realized, however, that if another utility experiences different cost conditions, the preceding choice of R&D project may not be optimal. To highlight this point, suppose that the cost parameters of the other utility are the same except that the coal cost is $10/Mg. This is not unreasonable. Several utilities in the United States are located near or at the coal mines and the cost of coal in such cases is low (Salcat [16]). Savings from successful completion of these same research projects are in Table 3, Part B.

| Table 3: Comparison of Cost Savings from Different R&D Investments |
|------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| **PART A**        |                 |                 |                 |                 |                 |                 |                 |
| Alternatives      | Coal Cost (\$/Mg) | Binder (% by wt) | FGD Capital Cost (\$/Mg of Coal) | FGD Op. Cost (\$/Mg of S Removed) | \( S^* \) (% of Total Sulphur) | \( Z^* \) (\$/Mg of Coal) | \( AZ \) (Potential Savings) (\$/Mg of Coal) |
| 1. Base case A    | 30              | 8               | 3               | 900             | 44              | 37.56           | —               |
| 2. Binder research| 30              | 6               | 3               | 900             | 65              | 35.11           | 2.45            |
| 3. FGD capital cost research | 30 | 8 | 2 | 900 | 43 | 36.69 | 0.87 |
| 4. FGD operating cost research | 30 | 8 | 3 | 700 | 20 | 32.03 | 5.53 |

| **PART B**        |                 |                 |                 |                 |                 |                 |                 |
| Alternatives      | Coal Cost (\$/Mg) | Binder (% by wt) | FGD Capital Cost (\$/Mg of Coal) | FGD Op. Cost (\$/Mg of S Removed) | \( S^* \) (% of Total Sulphur) | \( Z^* \) (\$/Mg of Coal) | \( AZ \) (Potential Savings) (\$/Mg of Coal) |
| 1. Base case B    | 10              | 8               | 3               | 900             | 55              | 34.63           | —               |
| 2. Binder research| 10              | 6               | 3               | 900             | 70              | 30.11           | 4.52            |
| 3. FGD capital cost research | 10 | 8 | 2 | 900 | 54 | 33.79 | 0.84 |
| 4. FGD operating cost research | 10 | 8 | 3 | 700 | 36 | 31.13 | 3.50 |

Base case and alternatives as in Part A except that coal cost \( \phi_c \) is now $10/Mg.
As will be noted, binder research is now preferred to either FGD operating cost or capital cost research. Intuitively this makes sense, because when the coal cost is low one would tend to favor physical coal cleaning to FGD. Research related to PCC is likely to yield higher returns.

That different utilities can have different optimal R&D choices cannot be overemphasized. An electrical utility, perhaps more than in any other industry, is subject to a prevalent “band wagon” effect in research and development. This is partly because the utilities are regulated, hence their profits are guaranteed, but more likely because there is a free and open exchange of information between utilities. Our results indicate that, when the same R&D strategy as other electrical utilities is followed, the opportunity costs may be significant.

Imputed Cost of Changes in Environmental Regulations

All of the results presented to this point have been for the case of an emission requirement of 90% removal of sulphur dioxide. We have also studied the impact on the optimum control cost as the environmental standard is varied. The control cost decreases as anticipated when the emission regulations become less stringent, with the cost decrease per unit change in the emission regulation dependent on the cost structure within which the utility is operating. For example, decreasing the control standard from 90% to 80% would decrease the control cost by $2.49/Mg of coal for Case 1 (binder requirement = 2%; \( \delta_b = 30 \text{Mg/kg}; C_c = 2 \text{Mg/kg}; C_g = 500 \text{Mg/kg} \)), whereas the decrease would be $3.51/Mg of coal for Case 2 (6%; same; 3/Mg; 700/Mg).

This cost information is useful in financial planning by a utility, but perhaps more importantly, in the formulation of emission requirements. The regulatory authorities need to know the incremental costs for individual utilities, to estimate the aggregate cost increase to society at large of a “cleaner environment” (requiring \( \beta = 90\% \) vs. \( 80\% \)). A meaningful cost-benefit analysis can help establish appropriate emission guidelines.

Further Research

Our model contains the two control techniques viewed by many utilities as most technologically and economically viable for the near future. However, two additional alternatives bear mention, chemical treatment [11] and solvent refining of coal (SRC). Each is more expensive than PCC, but can remove both organic and pyritic sulphur.

The most general control model would thus include all four techniques (PCC, FGD, chemical treatment and SRC). As shown in Figure 5, this model allows for coal to be directly fed to any of the four options, as well as for coal “cleaned” by one process to receive sequential treatment by one or more of the other procedures. There is no flow between FGD and SRC, however, because the product of either of these two processes would likely be clean enough to burn without further treatment by the other.

![Figure 5. Schematic diagram of a control model including four sulphur removal options.](image)

The mathematical model associated with Figure 5 is considerably more complicated than Equation (8). This is under investigation and will be the subject of a future publication.

REFERENCES


James H. Bookbinder is a Past-President of the Canadian Operational Research Society (CORS) and is Chairman (1986-88) of the ORSA Transportation Science Section. Before joining the Management Sciences Department of the University of Waterloo in 1982, he had a decade of experience in industry and consulting, most recently (1978-82) as Director of Operations Research at the Toronto Transit Commission.

Dr. Bookbinder holds an MBA from the University of Toronto and a Ph.D. from the University of California, San Diego. His research concerns production/inventory management and physical distribution, with special interest in direct collaboration with industrial practitioners.

N. Sekhar has a Master's Degree in Chemical Engineering from the University of Waterloo and an MBA from the University of Toronto. He is Manager of Process Technology at General Electric Environmental Services, responsible for the design, development and marketing of air pollution control process technology.

From 1980-85, Mr. Sekhar was with the Engineering Group at Bechtel Power Corp., and was involved with energy and environmental projects on several continents. Earlier in his career, he was for 10 years a member of the Chemical Research Department at Ontario Hydro, one of the largest electrical utilities in North America.