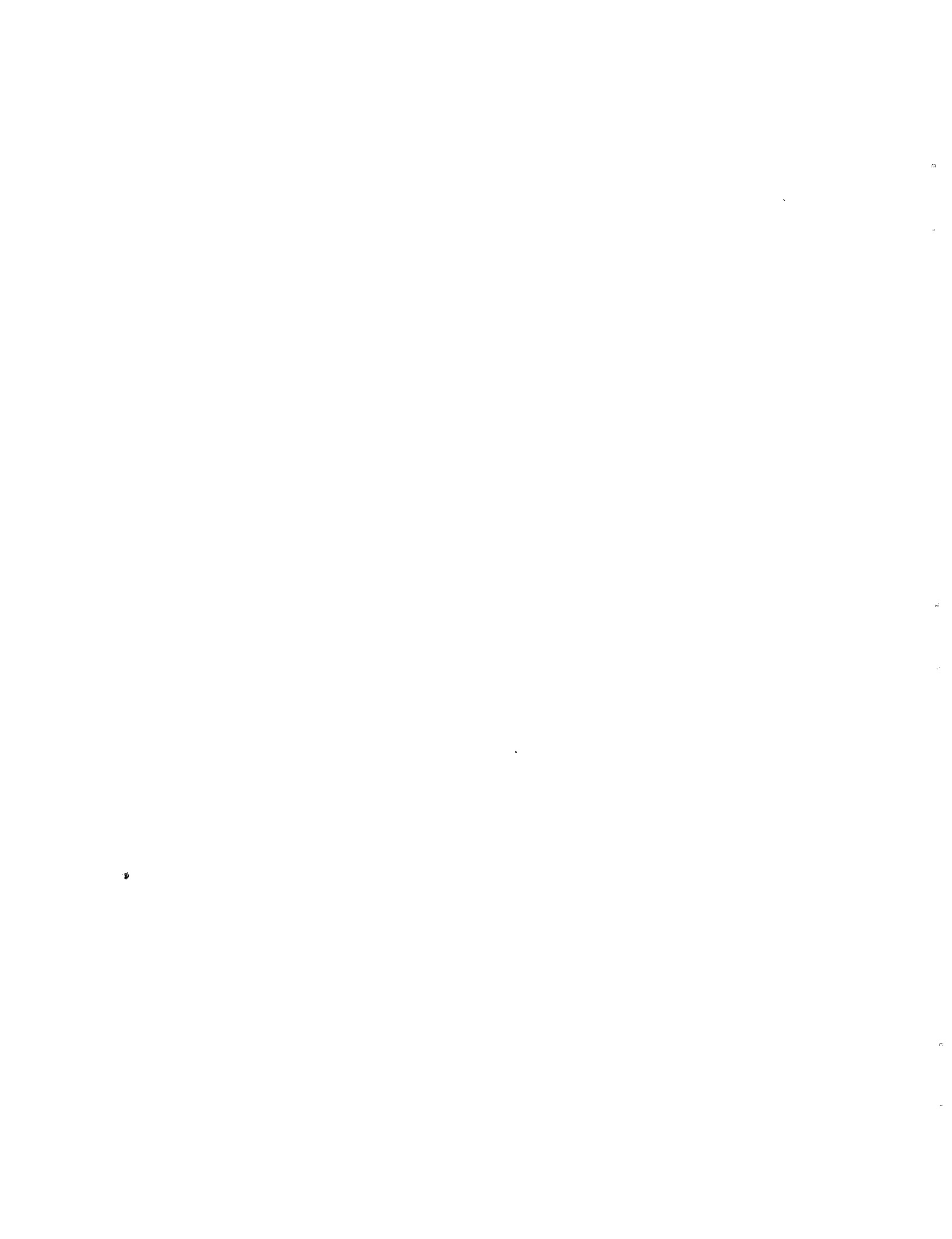


ECONOMICS OF SEASONAL GAS SUBSTITUTION IN
COAL- AND OIL-FIRED POWER PLANTS

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EXECUTIVE SUMMARY

The substitution of natural gas for high sulfur coal or oil in utility or industrial boilers is an attractive alternative to the use of flue gas desulfurization technologies for the purpose of reducing sulfur oxide emissions and the attendant sulfate ion deposition in precipitation. This alternative is particularly promising if implemented during the summer months when sulfate deposition is heaviest and natural gas is more readily available for utilities and industry.

Algorithms and example calculations are presented for estimating sulfur removal costs for large utility boilers retrofitted with (1) dual fuel use (parent fuel and natural gas) or (2) wet flue gas desulfurization. Both fixed and variable costs are estimated. Compared with flue gas systems, dual fuel use technologies have much smaller capital costs but larger variable costs because of the price differential between natural gas and the parent fuel.

The annual cost of utilizing the dual-fuel technology is principally dependent upon the fuel price differential, slightly dependent upon the capital cost of the technology, and not dependent at all upon the fuel sulfur content. On the other hand the flue gas desulfurization technology is strongly dependent upon both the capital cost and the fuel sulfur content. In comparing the costs of the two alternatives, fuel price differential and fuel sulfur are the significant variables, capital costs being well-determined.

The results of the analysis are expressed in terms of the break-even fuel price differential of gas and parent fuel; i.e., the value of this differential for which the annual average cost per unit of sulfur emission reduction is the same for both alternatives. This break-even price differential increases with the fuel sulfur content for any given plant, indicating that seasonal gas use will be most advantageous in boilers using the highest sulfur fuels. For typical conditions, this break-even price differential is in the range of \$0.88 - \$1.45 [1986\$/MMBtu] for a fuel sulfur range of 1 - 8 [lb SO₂/MMBtu]. This range lies within the range of historic values of gas-coal regional average price differentials available to utilities in the 1983-86 period, which was \$0.76 - \$1.80 [\$/MMBtu], indicating that a significant number of plants would have found dual fuel use more economical than flue gas desulfurization.

An emission-based comparison does not fully capture the economic benefits

of replacing high sulfur fuels with natural gas during the summer season because it ignores the fact that summer period emission reductions are 1.4 - 1.6 times as effective in reducing wet sulfate deposition as equal amounts of reduction spread throughout the year. If this seasonal deposition effect is credited to the natural gas technology, then the break-even price differential for equal deposition reductions is increased to \$1.46 - \$2.32 [1986\$/MMBtu], for the same typical conditions. This considerably increases the number of utility plants for which the dual fuel technology would have been economically advantageous, based upon historic prices for 1983-86.

Natural gas substitution for coal during the summer season also would reduce emissions of nitrogen oxides (NO_x). NO_x contributes to the formation of ground level ozone and nitrate ions in precipitation, both of which reach their highest levels during the summer season. This report does not consider the NO_x reduction benefits of seasonal gas substitution.

INTRODUCTION

The use of natural gas to replace high-sulfur coal or oil during the summer semi-annual period has been proposed by Golomb et al. (1986) as an effective measure for reducing acid deposition. They note that the rate of sulfate ion deposition is noticeably greater in summer than in winter throughout most of northeastern U.S. and eastern Canada despite the fact that summer and winter SO₂ emission rates are nearly the same. Thus, eliminating a ton of emissions in summer is much more efficacious than eliminating a ton in the winter. Furthermore, there is excess natural gas available in summer months because there is no demand for space heating. The option of using gas in utility and industrial boilers during the summer period when acid deposition is most intense deserves careful consideration.

The technology for dual-fuel firing (i.e., gas-coal or gas-oil) in utility boilers originally designed for coal or oil firing is readily available and its effects on boiler operation have been evaluated by Fay et al. (1986). They found that performance penalties for retrofitting such boilers are minor and capital costs are small. Installation of the technology can usually be accomplished during the annual boiler overhaul period. When gas is used during the summer season, operating problems associated with ash buildup on heat transfer surfaces, use of electrostatic precipitators and disposal of fly ash are eliminated. Operation of the retrofitted plant with its parent fuel during the winter season is unaffected, and conversion to the alternate fuel does not require taking the boiler out of service. Altogether, these effects are minor, especially compared to other sulfur reduction technologies.

The major consequence of summer gas use would be an increase in fuel cost (although for some current oil-fired plants there now exists a decrease), primarily because gas is more expensive per unit of heat content. But because sulfur emissions would be reduced, this additional cost may still be less than that needed for alternative retrofit technologies producing equal emission reductions, so that natural gas use could be a more economical measure to control acid deposition. The principal alternative retrofit technology, flue gas desulfurization, is capital intensive and therefore must be used year-round to justify its high capital costs. Which of these two possible technologies produces the lower cost of reducing sulfur emissions depends principally upon the fuel price differential between natural gas and the

parent fuel, but also upon the plant, fuel and retrofit technology characteristics.

This study presents an economic analysis of summer period natural gas substitution and compares it to wet flue gas desulfurization systems operated year-round. Fixed and variable costs are estimated for these alternatives on a common basis. Because future fuel prices are uncertain, the cost comparison between the sulfur control alternatives is expressed in terms of a break-even fuel price differential; i.e., the value of the difference between the gas and parent fuel prices that would provide an equal cost of eliminating a ton of sulfur oxide emissions. In addition, the break-even price differential that would produce an equal cost of reduction of the annual amount of sulfate deposition for the two alternatives is also estimated.

While there are other environmental benefits to be obtained from substituting natural gas for coal or oil in the summer period, such as reduced levels of nitrates in precipitation, ground level ozone, inhalable particles and visibility impairment, these are not considered in this analysis.

COSTS OF SEASONAL GAS USE

It is useful to divide the costs of substituting natural gas for coal or oil into two categories, fixed costs and variable costs. Fixed costs include principally capital costs, which turn out to be small compared to the variable costs. The latter consist primarily of fuel costs, maintenance and electric power costs (savings) for the electrostatic precipitators that are not used during the summer. In modeling these costs we make the following assumptions regarding the operation of the power plant:

(1) The plant produces power at the same average rate during both summer and winter seasons. This production rate is equal to the rated plant power (MW) times the capacity factor (CF).

(2) Retrofitting a coal- or oil- fired boiler with natural gas burners for seasonal use results in a derating of the boiler and power plant by a factor called the derating factor (DRF), and a decrease in boiler efficiency by a factor denoted as the boiler efficiency factor (BEF), as described by Fay et al. (1986). The first of these effects is offset in part by the extra electric power produced since the electrostatic precipitators are not in use during the summer season. This latter saving can be described by an uprating

factor (URF) which acts in the opposite direction of the derating factor of the boiler. For simplicity, we assume that during the summer season the capacity factor is increased by the factor $(URF * DRF)^{-1}$, so there is no change in the power production rate, as assumed in (1) above. It turns out that these effects amount to only a change of a few percent.

(3) Maintenance costs of electrostatic precipitators and gas burners being very small (we estimate the former as less than 1 [\$/kw y], based upon Bloyd et al.; 1984), we assume that the savings in ESP maintenance in the summer season are balanced by the gas burner maintenance costs, so that there is no net maintenance cost increment for these components. However, there will be savings in the variable operating and maintenance (O&M) costs when using gas in place of coal. These may be expressed as a savings per unit of gas heat substituted [\$/MMBtu], which effectively reduces the cost of gas fuel. We assume that there are no savings in fixed O&M costs when using gas in place of the parent fuel.

(4) The price of winter fuel (coal or oil) will be higher than that of the same fuel used year-round, reflecting the increased storage costs and fuel inventory because it is not being used year-round. We express this increase by a fuel price factor (FPF) applied to the base case fuel price (FP). This factor is not determined in our model, but appears as an exogenous input to the cost model.

(5) Pipelining costs for natural gas are included in the gas price (GP). Transportation costs are assumed to be included in the fuel price. Also, hook-up costs are included in the capital cost of the conversion.

(6) There will be no fly ash to dispose of during the summer season. We allow no credit for the variable cost associated with such disposal, which we assume is negligible compared to the other costs being considered.

(7) The summer season is not necessarily six months in duration, but is given exogenously as a fraction (ϵ) of the year.

Variable Costs: Fuel Cost Increments

Because the variable costs dominate, we determine them first. We express the variable costs as increments in cost above the variable costs which would have been experienced if natural gas had not been used during the summer season. We begin by calculating the annual electric energy production (AEP [kWh/y]):

$$\text{AEP} = 8.76 \times 10^6 \text{ MW} * \text{CF} \quad [\text{kWh/y}] \quad (1)$$

and the annual heat requirement (AHR [MMBtu/y]):

$$\begin{aligned} \text{AHR} &= 10^{-6} \text{ AEP} * \text{HR} \\ &= 8.76 \text{ MW} * \text{CF} * \text{HR} \quad [\text{MMBtu/y}] \end{aligned} \quad (2)$$

where HR [Btu/kWh] is the plant heat rate. We next determine the summer gas heat requirement (SGHR [MMBtu/y]) as:

$$\text{SGHR} = \epsilon * \text{AHR} / (\text{URF} * \text{BEF}) \quad [\text{MMBtu/y}] \quad (3)$$

Here the product of the first two factors is the heat requirement of the displaced fuel while the remaining factors account for the corrections due to the use of gas in place of the original fuel. The winter fuel heat requirement (WFHR [MMBtu/y]) is easily found to be:

$$\text{WFHR} = (1 - \epsilon) * \text{AHR} \quad [\text{MMBtu/y}] \quad (4)$$

We are now in the position to determine the annual fuel cost increment (AFCI [\$/y]) by multiplying the seasonal heat requirements by the respective fuel prices and subsequently subtracting the current fuel cost. But before doing so we need to take credit for the reduction in variable O&M costs when gas is burned in place of the parent fuel, which we express as the specific variable O&M savings (SVO&MS [\$/MMBtu]). By comparing the variable O&M costs of coal, oil and gas boilers given by ICF (1983), SVO&MS would be in the range of \$0.17-0.22 [1983\$/MMBtu], depending upon boiler size.

This savings reduces the summer cost of fuel:

$$\text{AFCI} = \text{SGHR} * (\text{GP} - \text{SVO\&MS}) + \text{WFHR} * \text{FP} * \text{FPF} - \text{AHR} * \text{FP} \quad [$/y] \quad (5)$$

where GP [\$/MMBtu] is the natural gas price for summer gas and FP [\$/MMBtu] is the fuel price for year-round fuel. Substituting (3) and (4) in (5) we obtain:

$$\text{AFCl} = \text{AHR} * [\epsilon * (\text{GP} - \text{SVO\&MS}) / (\text{URF} * \text{BEF}) + (1 - \epsilon) * \text{FP} * \text{FPF} - \text{FP}] \quad [$/y] \quad (6)$$

It is convenient to introduce a definition of an effective fuel price differential (EFPD [\$/MMBtu]):

$$\text{EFPD} \equiv (\text{GP} - \text{SVO\&MS}) / (\text{URF} * \text{BEF}) - [1 - (1 - \epsilon) * \text{FPF}] * \text{FP} / \epsilon \quad [$/MMBtu] \quad (7)$$

and thereby express (6) in terms of EFPD as:

$$\text{AFCl} = \epsilon * \text{AHR} * \text{EFPD} \quad [$/y] \quad (8)$$

The effective fuel price differential will not be too different from the nominal fuel price differential, $\text{GP} - \text{FP}$, minus the O&M savings, SVO\&MS , since the modifying factors in (7) are not expected to be very significant.

We now express this fuel cost increment in two specific ways. The first is to divide it by the annual current heat requirement to obtain the specific energy cost increment (SENCI [\$/MMBtu]):

$$\text{SENCI} = \text{AFCl} / \text{AHR} = \epsilon * \text{EFPD} \quad [$/MMBtu] \quad (9)$$

This is the cost increment, averaged over the current annual Btu's burned, of replacing the summer fuel by natural gas. Alternatively, we may express this in terms of the specific electric cost increment (SECI [¢/kWh]):

$$\text{SECI} = 10^{-4} \text{HR} * \text{SENCI} = 10^{-4} \epsilon * \text{EFPD} * \text{HR} \quad [¢/kWh] \quad (10)$$

Since the objective of using natural gas is to reduce the emissions of sulfur dioxide, we need to account for the annual reduction of these emissions (ASR [t SO₂/y]) due to the replacement of the original fuel by natural gas. Letting FSO_2 [lb SO₂/MMBtu] be the sulfur in the original fuel, the summer (and annual) emissions reduction becomes:

$$\text{ASR} = 5 \times 10^{-4} \text{FSO}_2 * \epsilon * \text{AHR} \quad [\text{t SO}_2/\text{y}] \quad (11)$$

It is usual to express this in the form of the specific sulfur removal cost (SSRC [\$/t SO₂]) by dividing (8) by (11):

$$\text{SSRC} = 2 \times 10^3 \text{ EFPD} / \text{FSO}_2 \quad [$/\text{t SO}_2] \quad (12)$$

Equations (9), (10) and (12) constitute the specific variable cost increments due to summer gas substitution, where the effective fuel price differential EFPD is given by (7).

Consider some typical cases. For a plant with a heat rate $\text{HR} = 10^4$ [Btu/kWh] using natural gas for six months, the specific energy and electric cost increments become:

$$\text{SENCI} = 0.5 \text{ EFPD} \quad [$/\text{MMBtu}]$$

$$\text{SECI} = 0.5 \text{ EFPD} \quad [¢/\text{kWh}]$$

so that a EFPD of 2 [\$/MMBtu] would entail cost increments of 1 [\$/MMBtu] or 1 [¢/kWh]. The specific sulfur removal cost SSRC, however, depends inversely upon the fuel sulfur, FSO₂.

The uprating factor URF may be determined from estimates of the amount of electric power required for electrostatic precipitators (P_{esp} [MW]) given by Bloyd et al. (1984):

$$P_{\text{esp}} = 10^{-6} (D * \text{SCA} + 0.155)G \quad [\text{MW}] \quad (13)$$

where typical values of the corona power density D and the specific collection area SCA are 1.5 [W/ft²] and 0.4 [ft²/cfm], respectively, and the gas flow rate G can be given approximately by:

$$G = 0.347 \text{ MW} * \text{HR} \quad [\text{cfm}] \quad (14)$$

Using these typical values, together with $\text{HR} = 10^4$ [Btu/kWh], and combining (14) with (13), we find:

$$P_{\text{esp}}/\text{MW} = 2.6 \times 10^{-3} \quad (15)$$

We thus find that the electrostatic precipitators use only about 1/4 % of the plant output. The corresponding value of URF is 1.0026.

There is not a great difference between the effective fuel price differential EFPD and the adjusted nominal price differential, $GP - FP - SVO\$MS$. Using typical values of $URF = 1.0026$, $BEF = .95$, $FPF = 1.1$ and $\epsilon = 0.5$ (six month summer period) in (7), we find:

$$EFPD = 1.05 (GP - FP - SVO\$MS) + 0.15 FP \quad [\$ / \text{MMBtu}] \quad (16)$$

The factor 1.05 in the first term represents the direct effect of the reduced thermal performance of the gas conversion while the second term reflects primarily the price premium paid for the seasonal use of the base fuel.

Fixed Cost

The only significant fixed cost is the capital cost of the conversion from coal or oil to natural gas. Assuming that the direct capital cost of this conversion is DCC_g [\$], that the indirect costs are added to this by multiplying DCC_g by an indirect cost factor ICF and that the total is annualized by a levelizing factor LF to give the annualized capital cost ACC_g [\$/y]:

$$ACC_g = DCC_g * ICF * LF \quad [\$ / y] \quad (17)$$

We will specify the DCC_g as the product of the plant power times the specific capital cost SCC_g [\$/kW]:

$$DCC_g = 10^3 SCC_g * MW \quad [\$ / \text{kW}] \quad (18)$$

Now convert the annual cost to a specific annualized capital cost $SACC_g$ [\$/MMBtu] or [¢/kWh] by combining (17), (18) and (2):

$$\begin{aligned} \text{SACC}_g &= 1.14 \times 10^2 \text{ SCC}_g * \text{ICF} * \text{LF} / \text{CF} * \text{HR} \quad [\$/\text{MMBtu}] \\ &= 1.14 \times 10^{-2} \text{ SCC}_g * \text{ICF} * \text{LF} / \text{CF} \quad [¢/\text{kWh}] \end{aligned} \quad (19)$$

The capital cost is now in a form that can be added to the fuel cost increments, (9) and (10). Finally, we may divide (17) by (11) to find the specific sulfur removal cost of capital SSRCC_g [\$/t SO₂]:

$$\text{SSRCC}_g = 2.28 \times 10^5 \text{ SSC}_g * \text{ICF} * \text{LF} / \text{CF} * \text{HR} * \text{FSO}_2 * \epsilon \quad [\$/\text{t SO}_2] \quad (20)$$

As an example, if we assume $\text{SCC}_g = 30$ [\$/kW], $\text{ICF} = 1.7$, $\text{LF} = 0.13$, $\text{HR} = 10^4$, $\text{CF} = 0.6$ and $\epsilon = 0.5$, then we find:

$$\text{SACC}_g = 0.07 [\$/\text{MMBtu}] = 0.07 [¢/\text{kWh}]$$

$$\text{SSRCC}_g = 291/\text{FSO}_2 \quad [\$/\text{t SO}_2]$$

It can be seen that these are small compared to typical variable costs of (9), (10) and (12) above, being of the order of 10% of the latter.

COSTS OF WET LIMESTONE FLUE GAS DESULFURIZATION

The cost of retrofitting a wet limestone flue gas desulfurization system to a coal-fired boiler has been estimated by Bloyd *et al.* (1984) as a component of the Advanced Utility Simulation Model (AUSM). This cost model has been somewhat simplified by Fay and Golomb (1986). The following analysis is taken from these sources with costs updated using the Chemical Engineering Plant Cost Index (Chemical Engineering, 1987).

The FGD costs are divided into three categories: capital (fixed) costs, variable costs and energy costs. While the last of these is a variable cost, it is handled separately since the considerable electric power needed to operate the scrubbers is purchased from the grid. We treat each of these in turn.

Retrofitting existing plants with scrubbers is more expensive than equipping a new plant with the same pollution control system. This extra expense is usually taken into account by multiplying the direct capital cost

of the scrubbing system (the cost of the system as a component of a new plant) by a retrofit factor, which expresses the additional direct capital cost of fitting the system into an existing plant. Indirect costs, which must be added to the direct cost to obtain the total capital cost of the installation, are also higher in retrofit installations because of the extra engineering, greater contingencies, etc. Salmento *et al.* (1987) use a retrofit factor of 1.3 as typical for a large number of utility plants. Molberg and Rubin (1983) estimate that indirect costs add 45% - 100% to the direct cost of the retrofit and use 80% in an illustrative example. Using these typical figures, the total capital cost can be 1.9 to 2.6 times the direct capital cost of the system when installed in a new plant.

Fixed Cost

The specific capital cost SCC_f [1986\$/kW] for the FGD system is:

$$SCC_f = 8.22 \times 10^{-3} HR + 7090/MW \\ + [9.29 \times 10^{-4} + 1.38 \times 10^{-5}(ULC)]HR * FSO2 * \eta \quad [1986\$/kW] \quad (21)$$

where η is the sulfur removal efficiency of the scrubber and ULC is the cost of disposal land [10^3 1986\$/acre]. (As an example, if $HR = 10^4$ [Btu/kWh], $MW = 500$, $\eta = 0.9$ and $ULC = 10$ [10^3 1986\$/acre], then $SCC_f = 96.4 + 9.6(FSO2)$ [1986\$/kW].) Typical capital costs are in the range of 100-200 [1986\$/kW]. This is the direct capital cost, which must be multiplied by the retrofit factor RF to obtain the direct capital cost applicable to an installation in an existing plant, and then by the indirect cost factor ICF, to obtain the total capital cost. Using values of $RF = 1.3$ and $ICF = 1.7$, the total capital cost would be in the range of 220-440 [1986\$/kW].

The annualized capital cost ACC_f [1986\$/y] is then obtained by multiplying this product by the levelizing factor LF and the plant size 10^3 MW [kW]:

$$ACC_f = 10^3 \text{ MW} * SCC_f * RF * ICF * LF \quad [1986\$/y] \quad (22)$$

The annual heat requirement AHR [MMBtu/y] is:

$$AHR = 8.76 \text{ MW} * HR * CF \quad [MMBtu/y] \quad (23)$$

Thus, the specific energy cost of capital (SECC) becomes:

$$\begin{aligned} \text{SECC}_f &= \text{ACC}_f / \text{AHR} = 114 (\text{SSC}_f / \text{HR} * \text{CF}) * \text{RF} * \text{ICF} * \text{LF} \quad [1986\$/\text{MMBtu}] \\ &= 1.14 \times 10^{-2} (\text{SSC}_f / \text{CF}) * \text{RF} * \text{ICF} * \text{LF} \quad [1986\$/\text{kWh}] \quad (24) \end{aligned}$$

(For example, if $\text{SSC}_f = 150$ [1986\$/kW], $\text{CF} = 0.6$, $\text{HR} = 10^4$, $\text{RF} = 1.3$, $\text{ICF} = 1.7$ and $\text{LF} = 0.13$, then $\text{SECC}_f = 0.82$ [1986\$/MMBtu] = 0.82 [1986\$/kWh].)

The capital cost may also be expressed in terms of the amount of sulfur removed. To do this, first determine the annual sulfur removed ASR [t SO₂/y]:

$$\text{ASR} = 4.38 \times 10^{-3} \text{ MW} * \text{HR} * \text{CF} * \text{FSO}_2 * \eta \quad [\text{t SO}_2/\text{y}] \quad (25)$$

and then divide this into ACC_f to obtain the specific sulfur removal cost of capital SSRCC_f [1986\$/t SO₂]:

$$\begin{aligned} \text{SSRC}_f &= [212 + 3.2 (\text{ULC}) + (1876 + 1.62 \times 10^9 / \text{MW} * \text{HR}) / \text{FSO}_2 \eta] \\ &\quad * \text{RF} * \text{ICF} * \text{LF} / \text{CF} \quad [1986\$/\text{t SO}_2] \quad (26) \end{aligned}$$

(Continuing the example quoted above, with $\eta = 0.9$, then $\text{SSRC}_f = 117 + 1170/\text{FSO}_2$ [1986\$/t SO₂].)

Variable Cost

The variable cost of operating a FGD scrubber involves principally the costs of purchasing and handling of limestone and and disposing of the sludge from the scrubbers. Fay and Golomb (1986) give the following specific variable cost SSVC_f [1986\$/t SO₂]:

$$\begin{aligned} \text{SSVC}_f &= 20 + 2.37 (\text{RC}) + (281 + 6.01 \times 10^4 / \text{MW}) / \text{FSO}_2 * \eta \\ &\quad [1986\$/\text{t SO}_2] \quad (27) \end{aligned}$$

where RC [1986\$/t] is the cost of the limestone reagent. This may be converted to a specific energy variable cost SEVC_f [1986\$/MMBtu] by multiplying by (25) and dividing by (23):

$$\begin{aligned} \text{SEVC}_f &= 30/\text{MW} + 0.14 + (10.2 + 1.19 \text{ RC}) 10^{-3} \text{ FSO}_2 * \eta \quad [1986\$/\text{MMBtu}] \\ &= [30/\text{MW} + 0.14 + (10.2 + 1.19 \text{ RC}) 10^{-3} \text{ FSO}_2 * \eta] 10^{-4} \text{ HR} \quad [1986\$/\text{kWh}] \quad (28) \end{aligned}$$

Using the typical values quoted above and $\text{RC} = 10$ [1986\$/t], we find:

$$\text{SSVC}_f = 43.7 + 446/\text{FSO}_2 \quad [1986\$/\text{t SO}_2]$$

$$\text{SEVC}_f = 0.2 + 0.02 \text{ FSO}_2 \quad [1986\$/\text{MMBtu}] \text{ and } [1986\$/\text{kWh}]$$

While these variable costs are typically less than the fixed costs, they are still appreciable.

Energy Cost

The electric power and process steam required to run the FGD system can be costed out as an equivalent electric power requirement. Fay and Golomb give the following specific sulfur electric cost (SSEPC_f [1986\$/t SO₂]):

$$\text{SSEPC}_f = (2.17 + 68.6 / \text{FSO}_2 * \eta) \text{ EP} \quad [1986\$/\text{t SO}_2] \quad (29)$$

where EP [\$/kWh] is the price of electricity purchased from the grid. Again through use of (23) and (25), this can be converted to a specific energy electric cost SEEC_f :

$$\begin{aligned} \text{SEEC}_f &= (34.3 + 1.09 \text{ FSO}_2 * \eta) 10^{-3} \text{ EP} \quad [1986\$/\text{MMBtu}] \\ &= (34.3 + 1.09 \text{ FSO}_2 * \eta) 10^{-7} \text{ EP} * \text{HR} \quad [1986\$/\text{kWh}] \quad (30) \end{aligned}$$

This cost is typically smaller than the variable cost, but by no means negligible, representing about 5% of the plant output.

BREAK-EVEN FUEL PRICE DIFFERENTIAL

In comparing the cost of natural gas substitution to that of wet flue gas desulfurization, it is appropriate to focus on the cost per unit of emission reduction. In a regional or national emission control plan for reducing acid

deposition, the unit cost of emission reduction for each source may be a deciding factor in selecting the minimum cost combination of sources to be controlled. However, if large aggregate amounts of emission reduction are needed, it may be necessary to install scrubbers in some instances because they remove more sulfur, even though they may be more expensive than the seasonal use of natural gas. For this report, we consider only the unit cost of emission (or deposition) reduction as the decisive criterion, although we recognize other considerations may have to be taken into account.

We now consider the question of which would be more economical, summer gas substitution or flue gas scrubbing, by comparing the specific sulfur removal cost [\$/t SO₂] of each alternative. Because the SSRC of the summer gas substitution retrofit is approximately proportional to the price differential between gas and the current fuel, while that of flue gas scrubbing is independent of fuel price, it is useful to calculate the price differential for which the SSRC is the same for both alternatives. We call this the break-even price differential.

The calculation is relatively straightforward. For the FGD system, the total specific sulfur removal cost is the sum of (26), (27) and (29). For the summer gas substitution, we sum (12) and (21), using (16) to define the effective fuel price differential. Equating the two results, we may solve for the price differential GP - FP.

As an example, we assume the following values for the exogenous parameters:

$$\begin{aligned} MW &= 500 \text{ [MW]}; HR = 10^4 \text{ [Btu/kWh]}; URF = 1.0026; BEF = 0.95; FPF = 1.1; \\ RF &= 1.3; ICF = 1.7; LF = 0.13; CF = 0.6; FP = 1.50 \text{ [1986\$/MMBtu]}; \\ SCC_g &= 20 \text{ [1986\$/kW]}; ULC = 10 \text{ [10}^3 \text{ 1986\$/acre]}; RC = 10 \text{ [$/t]}; \\ EP &= 5 \text{ [1986\$/kWh]}; \epsilon = 0.5; \eta = 0.9; SVO\&MS = 0.20 \text{ [1986\$/MMBtu]}. \end{aligned}$$

The break even fuel price differential is then calculated as a function of the fuel sulfur:

$$GP - FP = 0.80 + 0.081 \text{ FS}_{O_2} \quad \text{[1986\$/Mbtu]}$$

The linear relation between the break-even price differential and fuel sulfur found for this typical case would hold for all cases, albeit with different numerical values for the slope and intercept. Over the expected range of fuel sulfur of about 1 - 10 [lb SO₂/MMBtu], there is a considerable

effect upon the break-even price differential, higher sulfur fuels providing a greater opportunity for cost savings by gas substitution vis-a-vis scrubbing. The source of this dependence lies in the fact that the annual costs of scrubbing high sulfur fuel are greater than those for scrubbing low sulfur fuel because some components of these costs increase with the amount of fuel sulfur. Since the annual cost of gas substitution is independent of fuel sulfur, higher sulfur fuels provide a higher break-even price differential.

In Table 1 we list the specific sulfur removal cost components for the two alternatives and the break-even fuel price differential as a function of the fuel sulfur for the particular case whose exogenous parameters are given above. The gas alternative has annualized capital costs (relative to sulfur removed) which are 15-25% of those of the FGD system. (The total capital investment for the gas substitution technology is only about half as much; i.e. 8-13%, because only about half as much sulfur is removed by the gas substitution than by the FGD.)

The break-even fuel price differential listed in Table 1 ranges from \$0.88 [1986\$/MMBtu] for coal with a sulfur content of 1 [lb SO₂/MMBtu] to \$1.45 for 8 [lb/MMBtu] coal. In the years 1983-1985, the average monthly price differential between gas and coal at U.S. electric power plants was in the range \$1.50 - 2.00 [current\$/MMBtu] (Galeucia, 1986). Thus, the break-even fuel price differential in 1986\$ is somewhat lower than the average fuel price differential during 1983-85, although they are nearly the same for the higher sulfur fuel. Furthermore, the fuel price differential between gas and coal decreased significantly in 1986, reflecting the downward pressure of declining world oil prices. Galeucia (1986) found that nearly all oil-fired plants had negative oil-gas price differentials during 1983-85. We conclude that in 1986 nearly all oil-fired power plants and some coal-fired power plants could have chosen gas substitution as the more economical method of sulfur emission reduction.

DEPOSITION-BASED BREAK-EVEN PRICE DIFFERENTIAL

While summer replacement of high sulfur fuel by natural gas reduces sulfur dioxide emissions, it reduces the deposition of sulfate by an even greater amount. In summer, a greater fraction of the emitted SO₂ is converted to sulfate and is deposited than is the case in winter, when more of the SO₂ is

blown by winds over the Atlantic Ocean and Arctic region. In the foregoing comparison we have not taken into account the greater effect on sulfate deposition in the northeastern U.S. and southeastern Canada of reducing sulfur emissions in the summer season as compared to year-round. Typically, in this region deposition in the summer semiannual period (April-September) is 70% - 80% of annual deposition or a factor of 1.4 - 1.6 times the annual rate (Golomb et al.; 1986). Thus, removing a ton of SO₂ by gas substitution in the summer is as effective as removing 1.4 - 1.6 tons year-round, if the annual amount of wet deposited sulfate is the measure of the environmental effect to be lessened. We should therefore be willing to pay 1.4 - 1.6 times as much per ton of SO₂ removed in the summer (by gas substitution) as for a ton removed year-round (by scrubbing).

As an example, if we assume that equal sulfate deposition results from 1 ton of summer emissions as from 1.5 tons of year-round emissions, then the break-even coal-gas price differential which would give equal cost of equal annual deposition reductions is, for the parameter values used above,

$$GP - FP = 1.34 + 0.123 FS_{O_2} \quad [1986\$/Mbtu]$$

In this case the break-even price differential range of Table 1 would be \$1.46 - \$2.32 [1986\$/MMBtu] which is well within the average gas-coal price differential paid by utilities in 1983-85. This enhanced price differential captures the greater benefit (in terms of lessened deposition of acid sulfate in precipitation) of reducing sulfur emissions preferentially in the summer season as compared to year-round reduction.

CONCLUSION

The use of natural gas during the summer season in utility boilers fueled with coal or oil will reduce the annual amount of sulfur dioxide emissions at an economic cost which is principally dependent upon the price of natural gas relative to the parent fuel. Viewed as a sulfur emissions control measure, the cost of this emission reduction per ton of SO₂ removed is the appropriate criterion for use in an economic analysis. It is found that the fuel price differential that will yield an equal cost of sulfur removal as a typical flue gas desulfurization retrofit is in the range of \$0.88 - \$1.45 [1986\$/MMBtu]

for fuels containing 1 - 8 [lb SO₂/MMBtu], respectively. If the summer gas scheme is given credit for the greater wet deposition rates of sulfate encountered in the northeastern U.S. during the summer period, this break-even fuel price differential increases to \$1.34 - \$2.32 [1986\$/MMBtu]. In either case, the break-even price differential is significantly dependent upon the fuel sulfur content because of the dependence of the cost of flue gas scrubbing on fuel sulfur. Thus the power plants having the higher fuel sulfur content are the more favorable ones for summer gas substitution.

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TABLE 1

Comparison of Costs of Flue Gas Desulfurization and Natural Gas Retrofit
Technologies^a

	Fuel Sulfur [lb SO ₂ /MMBtu]			
	1	2	4	8
<u>Sulfur Removal Cost [1986\$/t SO₂]</u>				
FGD				
Fixed (Capital)	1287	702	410	263
Variable	490	267	155	99
Electric	391	201	106	58
GAS				
Fixed (Capital)	291	146	73	36
Break-even Fuel	1878	1023	596	384
Total	2169	1169	670	420
<u>Break-even Fuel Price Differential [1986\$/MMBtu]</u>				
	0.88	0.96	1.12	1.45

a. Exogenous parameter values: MW = 500 [MW]; HR = 10⁴ [Btu/kWh]; URF = 1.0026; BEF = 0.95; FPF = 1.1; RF = 1.3; ICF = 1.7; LF = 0.13; CF = 0.6; FP = 1.50 [1986\$/MMBtu]; SCC_g = 20 [1986\$/kW]; ULC = 10 [10³ 1986\$/acre]; RC = 10 [1986\$/t]; EP = 5 [1986\$/kWh]; ε = 0.5; η = 0.9; SVO&MS = 0.20 [1986\$/MMBtu].

NOMENCLATURE

ACC	Annualized capital cost [\$/y]
AEP	Annual electric production [kWh/y]
AFCI	Annual fuel cost increment [\$/y]
AHR	Annual heat requirement [MMBtu/y]
ASR	Annual sulfur reduction [t SO ₂ /y]
BEF	Boiler efficiency factor
CF	Capacity factor
D	Corona power density [W/ft ²]
DCC	Direct capital cost [\$]
DRF	Derating factor
EFPD	Effective fuel price differential [\$/MMBtu]
FP	Fuel price [\$/MMBtu]
FPF	Fuel price factor
FSO ₂	Fuel sulfur [lb SO ₂ /MMBtu]
G	Gas flow rate [cfm]
GP	Gas price [\$/MMBtu]
HR	Heat rate [Btu/kWh]
ICF	Indirect cost factor
LF	Levelizing factor
MW	Plant rated electric power [MW]
P _{esp}	Electric power of electrostatic precipitator [MW]
RC	Reagent cost [\$/t]
RF	Retrofit factor
SACC	Specific annualized capital cost [\$/MBtu or ¢/kWh]
SCA	Specific collection area [ft ² /cfm]
SCC	Specific capital cost [\$/kW]
SECC	Specific energy cost of capital [\$/MBtu or ¢/kWh]
SECI	Specific electric cost increment [¢/kWh]
SEEC	Specific energy electric cost [\$/MMBtu]
SENCI	Specific energy cost increment [\$/MMBtu]
SEVC	Specific energy variable cost [\$/MMBtu]
SGHR	Specific gas heat requirement [MMBtu/y]
SSEPC	Specific sulfur electric cost [\$/t SO ₂]
SSRC	Specific sulfur removal cost [\$/t SO ₂]

SSRCC	Specific sulfur removal cost of capital [\$/t SO ₂]
SSVC	Specific sulfur variable cost [\$/t SO ₂]
SVO&MS	Specific variable O&M savings [\$/MMBtu]
ULC	Cost of disposal land [10 ³ \$/acre]
URF	Up-rating factor
WFHR	Winter fuel heat requirement [MMBtu/y]
ϵ	Summer period fraction of year
η	sulfur removal efficiency

Subscripts

f	Scrubber retrofit
g	Gas conversion