SEASONAL/EPISODIC CONTROL OF ACID DEPOSITION

James A. Fay and Dan S. Golomb
Principal Investigators
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Massachusetts Institute of Technology
Cambridge, MA 02139

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Abstract

This report contains the climatological, technical and economic factors for episodic and seasonal control of emissions in existing power plants. Analyzing a large data set of acid deposition for the years 1982-85, we find that the bulk of acid deposition comes down in a few precipitation episodes per year, mostly concentrated in the summer months. However, the episodes do not occur over wide areas, and are difficult to predict. About 75% of the annual acid deposition occurs during the summer half-year, April through September. Therefore, it would be effective to reduce acid precursor emissions, SO_x and NO_x, during that period. One method to accomplish the summer precursor emission reduction is substituting natural gas (NG) for oil and coal in large electric utility and industrial boilers. Gas contains no sulfur and emits less NO_x than oil or coal. The cost of a summer fuel substitution is primarily dependent on the delivered fuel price differential and only to a small extent on the retrofit cost for dual fuel use. For example, with a delivered fuel price differential of \$1.5/MMBtu, the annualized incremenmtal cost of electricity would be about 8 mills/kWh. For the same fuel price differential, the sulfur removal costs range from \$400 - \$1750 ton SO_2 depending on sulfur content of the fuel. If credit were given for the greater effect of summer emission reductions, the "effective" removal costs would be considerably less.

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EXECUTIVE SUMMARY

1. INTRODUCTION

It is expected that future "acid rain" legislation will impact major existing emission sources of acid precursors, such as coal- and oil-fired power plants. Power plants built after 1971 come under the New Source Performance Standards (NSPS) regulations; their emissions are already much smaller in comparison to many older plants. This study discusses one method of achieving emission reductions from pre-NSPS sources: natural gas substitution.

Emission reductions can be accomplished by installing flue gas cleansing devices ("scrubbers") and/or combustion modification (e.g. low-NO_x burners); by fuel cleansing (e.g. coal washing); or by fuel substitution (e.g. low sulfur- and nitrogen-content fuel, such as natural gas). Flue gas cleansing is capital intensive, because it requires major mechanical installations. On some existing plants, such installations are not practical because of space limitations and lack of disposal areas. Coal washing can remove only limited quantities of pyritic sulfur, not the organically bound sulfur and nitrogen. Substitution of natural gas for the parent fuel is not nearly as capital intensive as flue gas cleaning because most coal- and oil-burning power plants can be retrofitted by installing on the walls of the boilers additional or replacement natural gas burners. However, natural gas substitution can add significantly to the operational cost, especially where and when the price differential is large between the presently used fuel and natural gas.

The basic idea underlying this research is that substitution of natural gas need not be implemented throughout the entire year, but only during periods (seasons or episodes) when acid deposition is heaviest. In such a fashion, the more expensive, low-emission fuel is used during part of the year, while the regular fuel is used in the rest of the year.

This report contains the research findings on the climatological, technical and economic factors of seasonal/episodic control of acid deposition. In the Executive Summary, we attempt to summarize these findings; for more detailed information, the reader is referred to the individual chapters of this report, and to the appended publications.

2. CLIMATOLOGICAL FACTORS

2.1 Episodic Pattern

We investigated in some detail the episodic pattern of wet sulfate deposition. Some of the findings are described in the article "Seasonal, Episodic and Targeted Control of Sulfate Deposition" (Appendix A). In the northeastern U.S., more than 60% of the annual sulfate deposition comes down in 10-15 episodes (out of an average 50-60 precipitation events per year). It would be advantageous to reduce the sulfate content of these so-called "heavy episodes," because such a large fraction of the annual deposition is contained in them. Unfortunately, most heavy episodes do not occur simultaneously over wider geographic areas. Usually the heavy episodes are associated with convective storms, the spatial extent of which is limited. As a consequence, it would be difficult to delineate time periods and source regions in which to reduce emissions in order to reduce the sulfate content of the heavy episodes.

2.2 Seasonal Pattern

The seasonal pattern of both sulfate and nitrate deposition is reviewed in Chapter I. Here we summarize the results. Extensive data now exists showing that in Eastern North America (ENA), acid deposition is most pronounced in the summer months. In the environmentally sensitive areas of the northeastern U.S. and southeastern Canada, about 65-75% of the annual wet sulfate deposition occurs in the summer half-year, from April through September, and 45-55% in the summer third-year, from May through August. Nitrate deposition shows less seasonal variability, with 55-65% occurring in April-September, and 35-50% in May-August. Since hydrogen ion concentration (pH) is associated 2/3 with sulfuric acid and 1/3 with nitric acid, roughly 70% and 50% of H^+ is deposited in the summer half- and third-year, respectively in the acid-sensitive regions of ENA. The seasonal pattern gives rise to the proposition that acid precursor emission (SO_2 and NO_x) be curtailed during the summer months only, as the bulk of the acid deposition occurs in those months.

3. ATMOSPHERIC MODELING

For the evaluation of the efficacy of any emission reduction program, including seasonal emission reductions, it is necessary to have a suitable atmospheric model. Such models derive the quantitative relationship between a unit of emission at source x with the deposition at receptor y. Under EUP

sponsorship, our group developed appropriate source-receptor models, both for SO_2/sulfate and NO_x/nitrate, for annual and semi-annual averages (Fay, Golomb and Kumar, 1985, 1986a, 1986b). The annual and semi-annual transfer coefficients between 64 source regions in North American and 9 sensitive receptors in eastern North America are tabulated in Kumar (1986), and are available on magnetic tape. These transfer coefficients were obtained using 1980 emission inventories for SO_2 and NO_x, and 1980-82 average deposition data. Using that data base, the transfer coefficients have a mean error of about 20%.

4. SEASONAL CONTROL BY GAS SUBSTITUTION

If emissions were permitted to be reduced only part of the year, it may be more economic, at least in older power plants, to substitute natural gas for coal or oil in the summer months rather than installing high capital cost flue gas cleansing and combustion modification devices, such as scrubbers and low-NO_x burners. Levelized costs of installing retrofit equipment is the greater the shorter the remaining life time of the plant.

Several aspects of seasonal gas substitution were addressed under this project, ranging from technical feasibility, plant-specific costs, aggregate costs, gas availability, emission reductions and deposition reductions. These aspects are summarized in the following sections.

4.1 Technical Feasibility

The effect of seasonal gas substitution on boiler operation is described in Fay, Golomb and Zachariades (1986). Since boilers are usually designed for a specific type of fuel (and even for a certain kind of coal), it is not obvious *a priori* that substituting NG for the design fuel will avoid degrading the performance of the boiler, even if major modifications are undertaken. Burning different fuels in the same boiler can alter the heat transfer rates, the wall and tube temperatures, and the boiler efficiency. Fortunately, NG possesses combustion properties which make possible its use in coal- or oil-fired boilers with minimal effects on the boilers' performance.

There are a few examples of the use of NG in oil-fired boilers, and no recent ones of NG conversion of coal-fired boilers. However, extensive theoretical studies on the conversion of coal- and oil-fired boilers to use a variety of synthetic gas mixtures provides a basis for estimating the modifications needed and the resulting boiler performance if NG were to

replace coal or oil. Based upon these studies, we conclude that the boiler's maximum continuous rating (MCR) will be maintained upon NG substitution with only minor modifications to the boiler, such as addition of the gas burners, proper tilting of the nozzles, and windbox modifications. Furthermore, there will be no derating upon reverting to the parent fuel, oil or coal. On the other hand, there will be a slight drop of boiler efficiency, expressed as the heat content of the steam generated per fuel heat input. Efficiency drops of 3-5% are expected upon NG substitution for either coal or oil.

We verified the above conclusions by studying four utility boilers where summer substiution of NG for oil is actually practiced. In fact, two of the boilers were originally designed for coal burning. In no case was any derating experienced, although it should be noted that these boilers are usually not operated at full rating. Where measured, the efficiency drop was between 2-6%.

It should be mentioned that summer NG substitution would have additional benefits on plant operations; namely, reduced furnace corrosion and erosion; reduced soot and slag formation; less ash disposal; no particulate (fly ash) formation, vitiating the need for operation of electrostatic precipitators; and last but not least, reduced NO_x emissions.

4.2 Retrofit Cost

From the utility operators of units where dual fuel (oil/gas) capability was installed, we obtained estimates of the capital cost of conversion. These ranged from \$5.25/kW (1982 \$) to \$19/kW (1985 \$). Pipeline installation costs ae difficult to estimate since these costs ae highly dependent on location of the plant vis-a-vis high pressure transmission lines. In the investigated cases, the range was \$100-150/ft (1982-85 \$).

4.3 Aggregate Cost

In order to estimate the marginal and aggregate costs of seasonal gas substitution, a simulation model was developed. The model and its results are described in detail in Appendix B. The model simulates the substitution of NG for oil and coal in power plants in the eastern 31 states with the objective of minimizing the marginal and aggregate costs in regard to the reduction of wet sulfate deposition at one receptor only, the Adirondack Mountains, NY. The receptor was chosen because it is centrally located in the environmentally sensitive areas of eastern N. America.

The model roster includes 376 oil- and coal-fired power plants in the

eastern states; their present fuel use and cost, and the sulfur content of the fuel. The model calculates the amount of gas needed to replace the parent fuel for 6 months, April through September, and the incremental fuel cost based on 1983 fuel price differentials. (State-averaged gas prices are considered; individual plants may have to pay different prices for the gas.) Capital costs of installing gas burners, pipe-lines and other modifications are not included.

The model substitutes gas for oil or coal in plants by ranking simultaneously (1) the minimum gas-parent fuel price differential, and (2) the maximum impact on the Adirondacks. Aggregate costs are obtained for incremental deposition reductions. A deposition reduction of 30% at the Adirondacks, which is equivalent to the deposition reduction expected to result from a 10 million ton per year SO_2 emission reduction across the eastern states (e.g. the proposed 1985 Mitchell Bill, S.283), would entail the following quantities:

Number of plants affected	210	
Emission reduction in 6 months (SO_2)	4.8	Mt
Gas substituted	1.5	Tcf
Coal displaced	100	Mt
Oil displaced	100	Mbbl
Aggregate cost ($ 1983)	5.8	$B

The aggregate cost of $5.8 billion is within the range of $3.8 - 8 billion estimated to be the annualized cost of the proposed 1985 Mitchell Bill (10 Mtpy SO_2 emission reduction); the latter range depending on the estimator and the assumed control technology (i.e. scrubbers, coal-switching). It must be emphasized, however, that the comparison of aggregate costs of summer gas substitution with other (year-round) emission reduction methods was done on the basis of equal effects (deposition reduction) at a specific receptor - the Adirondacks. If the comparison is done on the basis of tons of SO_2 removed, the gas substitution is much more expensive, amounting (in the average) to $1200/ton SO_2 removed vs. $380 - 800/ton SO_2 of the other methods. Clearly, the choice of emission control methods is very much dependent on the goal of the policy: emission reduction per se, or deposition reduction at specific receptors.

We note that these comparisons are based on current fuel price differentials at plants that use only minor quantities of NG. For large scale gas substitution, the price differential may vary, and will depend on a firm gas supply for a long term.

4.4 Incremental Cost

In order to estimate the sulfur removal cost by gas substitution at an individual plant, it is useful to calculate the cost as a function of fuel price differential, fuel sulfur content, plant capacity, and other significant plant parameters. This we have done in Chapter II entitled, "Incremental Cost of Seasonal Gas Substitution in Coal- and Oil-Fired Power Plants." Here we summarize the findings.

The annual cost of utilizing the dual-fuel technology is principally dependent upon the fuel price differential, less dependent upon the capital cost of installing auxiliary equipment (burners, wind-box modifications, etc.), and not dependent at all upon the fuel sulfur content. On the other hand, the cost of removing sulfur (in units of \$/ton SO_2 removed) is inversely proportional to the fuel sulfur content. For example, for a plant with a heat rate of 10^4 Btu/kWh, capacity factor 0.6, levelizing factor 0.13, capital cost of installing gas burners of \$20/kW, and gas substitution for 6 months per year, the annual incremental cost is \$1.13/MMBtu (11 mills/kWh) if the fuel differential is \$2/MMBtu, and \$1.65/MMBtu (16.5 mills/kWh) if the differential is \$3/MMBtu (MM = million). For the same plant the sulfur removal costs in \$/ton SO_2 removed are as follows:

Fuel Price Differential	Fuel Sulfur (lb SO_2/MMBtu)		
(\$/MMBtu)	2	4	8
1	1211	605	303
2	2261	1130	565
3	3311	1655	828

As seen, the higher the sulfur content of the fuel, the cheaper it is to "remove" the SO_2 from the smoke-stack by gas substitution. We note that scrubbers are also more cost-effective (in terms of levelized sulfur removal cost, \$/ton SO_2) as the fuel sulfur content increases (Fay and Golomb, 1987).

However, the removal cost by gas substitution decreases faster with increasing sulfur content than by scrubbing.

The full advantage of gas substitution comes into play when the seasonal effect of sulfur removal is considered. Monitoring and modeling of acid deposition shows that roughly 3 times as much sulfate is deposited in the summer half-year (April through September) than in the winter half. Thus, it is as effective to remove 1 ton SO_2 from the smoke-stacks in the summer as is 1.5 ton year-round. We should, therefore, be willing to pay 1.5 times as much per ton SO_2 removed in the summer (by gas substitution) as for a ton removed year-round (by scrubbing). If this credit were given to the plants when practicing summer gas substitution, the "effective" sulfur removal costs would be 2/3 of those given above.

5. GAS SUPPLY AND COST

In Chapter III we survey the natural gas situation in the U.S., its production, reserves, distribution and prices.

Current demand is about 16 trillion cubic feet (tcf) per year, down from a peak 20.2 tcf in 1979. The average price in 1986 was $4.08/thousand cubic feed (mcf) but utilities paid far less, $2.44/mcf. As 1 cf of gas produces about 1000 Btu, the utility gas price in 1986 was about $2.5/MMBtu, approximately the same as the average utility oil price, and about $1 more than coal. Even allowing for increased gas use for pollution control, the delivered gas prices for electric utilities is expected to be in the $2.5 - $3.5/MMBtu range.

There is a fortuitous coincidence of seasonal variation in gas consumption and seasonal acid deposition. Gas consumption peaks in January-February at about 2 tcf/mo, and ebbs in May through October at less than 1 tcf/mo. As we noted in a previous section, acid deposition is about 3 times greater in summer than in winter. Thus, gas appears to be available for power plant use in the summer, coincident with the heavy deposition occurrences.

While greater summer use is not likely to strain the distribution system (it merely would take up the slack of summer demand), it would require greater production at the wells, since gas is not storable in large quantities. The current 250,000 mile interstate pipeline system has a capacity to delivery about 20-22 tcf/year, well above the current demand or

even increased demand, should some power plants elect to use summer gas as an emission control method.

There exists a widespread belief that gas is too precious a fuel for industrial use, in particular, for raising steam in a boiler. This belief is based in part on past experiences with gas shortages, and in part on the conjecture that gas reserves will not last long, at least, at affordable prices. From the best available data, we conclude that gas in North America (U.S. + Canada) will last for more than 40 years at prices competitive with other fuels, barring major shifts in demand. Unconventional and more difficult access gas could stretch that period much longer, albeit at unpredictable prices.

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ACID DEPOSITION PATTERNS IN EASTERN NORTH AMERICA

S.G. Zemba, D. Golomb and J.A. Fay

ABSTRACT

Four years (1982-1985) of acid deposition (sulfate and nitrate ion) data obtained at 77 stations of the Acid Deposition System in Eastern North America (ENA) are analyzed for annual, semi- and tri-annual patterns. Average annual sulfate concentrations over most of ENA range from 1.5-3 mg l^{-1}. Highest sulfate depositions (> 35 kg $ha^{-1}y^{-1}$) occur over W. Pennsylvania, the Virginias, E. Michigan, and S. Ontario between Lakes Huron and Erie. Sulfate isopleths generally stretch along a SW-NE axis. In the NE quadrant of ENA, 65-70% of the annual sulfate depositions occur in the April through September half year; some regions in S. Canada experience as much as 75%. The May through August third year accounts for 45-55% of the annual depositions in most of ENA.

Average annual nitrate concentrations range from 1-2 mg l^{-1} throughout much of ENA. Peak nitrate depositions (> 20 kg $ha^{-1}y^{-1}$) fall between Lakes Michigan and Ontario; 15 kg $ha^{-1}y^{-1}$ or more cover most of the Midwest, New York, New England and S. Ontario. Nitrate depositions are more evenly distributed throughout the year, with 55-65% and 35-50% occuring in the summer half- and third-year, respectively.

INTRODUCTION

This chapter presents an overview of recent spatial and temporal wet sulfate and nitrate deposition patterns in Eastern North America (ENA). Such knowledge may permit further refinement and calibration of atmospheric models, and in turn, more accurate estimates of the targetted emission reductions required to achieve stipulated deposition reductions. Proposals have been advanced, both in Europe and America, that standards be established with respect to depositions rather than emissions. Implicit is the assumption that meeting these standards would curb the degradation of the acid-sensitive environment (Persson, 1982; Hare, 1983). Also, it has been argued that deposition reductions could be realized more economically if emissions were reduced selectively from sources where the bulk of the precursor emissions originate (the "targetted" strategy) (Streets et al, 1984; Young and Shaw, 1985; Hordijk, 1986; Golomb et al, 1986). Golomb et al (1986) further proposed selective emission reductions during the heaviest deposition seasons (the "seasonal" strategy). However, a prerequisite of targetted and/or seasonal strategies is the knowledge of current deposition patterns.

The National Research Council reported the spatial distribution of anuual wet deposition of sulfate, nitrate, and hydrogen ions (pH) in ENA for the year 1980 (NRC, 1983). Seasonal distributions have been analyzed for individual monitors (e.g., Raynor and Hayes, 1982; Topol et al, 1986), individual networks (MAP3S/RAINE, 1982; Dana and Easter, 1987), and selected regions of the U.S. for the years 1978-1983 (Bowersox and Stensland, 1985). This study augments knowledge of acid deposition in ENA and represents the most recent and comprehensive overview to date.

DATA DESCRIPTION

The acid precipitation data presented in this paper are obtained from the Acid Deposition System (ADS) (Watson and Olsen, 1984) in the form of monthly summaries. The measurements are averaged over the four year period 1982-1985. This period is chosen to represent recent data and provide a fair number of qualified deposition monitoring stations. Locations are screened on the basis of two criteria. First, the precipitation coverage length (the percentage of time when the status of precipitation is recorded) at each monitoring site must exceed 90% for each of the 48 monthly summaries. Second, some stations have missing deposition values even though the precipitation coverage is adequate. Stations are further required to have valid deposition measurements in 3 of the 4 summaries for each of the 12 calendar months.

The screened ADS database yields 86 stations for the 1982-1985 period; the locations of 77 are shown in Fig. 1. (The other nine stations are sparsely scattered outside the bounds of Fig. 1 and are not considered in subsequent analyses.) Symbols which correspond to networks are plotted at the coordinates of each site. Five sites (Raleigh/Finley, NC; Oak Ridge/Walker Branch, TN; Dorset, MN; Bondville, IL; and Fernberg, ONT) have dual monitors operated by different networks. The ADS includes data quality measures as part of the monthly summaries (Lusis et al., 1986). Data completeness reflects the reliability of the deposition samples. Measurements are ranked from 1-4, where 1 represents high quality data and 4 corresponds to poor or missing entries. Averaged over the four year period, the mean value of data completeness for the stations in Fig. 1 is 1.76. ADS additionally ranks sites with respect to their geographical representativeness. Overall data quality, scaled 1-4, includes both completeness and representativeness measures. The mean value of overall data quality for the 77 sites is 2.32.

DEFINITIONS

Seasonal depositions are tabulated as sums of monthly values in a discontinuous manner. For example, a six month season beginning in October includes October-December and January-March of the same calendar year. Though this method ignores seasonal continuity, averaging over several seasons tends to reduce temporal differences.

Mean seasonal deposition is defined as the arithmetic average of seasonal depositions, taken as monthly depositions summed over an s month period. Considering the four year averaging period of this paper,

$$D_s = \frac{\sum^{4} [\sum^{s} D_m]}{4} \qquad (kg\ ha^{-1} y^{-1})$$

where the subscripts m and s refer to monthly and seasonal time intervals, respectively. Mean seasonal precipitation can be defined in an analogous manner:

$$P_s = \frac{\sum^{4} [\sum^{s} P_m]}{4} \qquad (cm)$$

Note that mean annual values are calculated by setting the season to the full twelve months of the year.

Mean seasonal deposition fraction is the arithmetic mean of the ratio of seasonal to annual deposition. Using consistent nomenclature,

$$F_s = \frac{\sum^{4} [\sum^{s} D_m / \sum^{12} D_m]}{4}$$

Species concentration in precipitation for a single episode is related to deposition and precipitation by

$$C = N \cdot D/P \qquad (mg\ l^{-1})$$

where N is a normalization factor balancing the units of the equation. Multiple episodes require a weighting scheme to derive average values of C. This paper circumvents episodic weighting by dividing the deposition and precipitation summed individually over the entire season. A mean seasonal species concentration in precipitation is given by

$$C_s = \frac{\sum^{4} [\sum^{s} D_m / \sum^{s} P_m]}{4} \qquad (\text{mg } l^{-1})$$

Many of the results are depicted as contour maps, i.e., isopleths and measurements superposed on a geographical projection. They are produced with software provided by the National Center for Atmospheric Research (McArthur, 1983). Local topographic and climatological variances can produce anomalies at isolated points and boundaries. Contour maps need to be carefully interpreted to draw physically relevant conclusions about the data.

PRECIPITATION

Fig. 2 presents mean annual precipitation (cm) over ENA. As in subsequent maps, some of the measurements are slightly offset to eliminate overlap. However, the actual monitor locations (Fig. 1) are used in calculating contours. Precipitation values typically range from 80-120 cm over the region. Amounts generally decrease from north to south, with local peaks and valleys in several areas. Precipitation amounts are unevenly distributed over quarterly periods. Generally, the lowest period of precipitation is January-March. Seasons of highest precipitation vary. The Great Lakes and Canada show July-September as their maximum quarter. The northeastern and midwestern U.S. have dual enhanced periods in April-June and October-December. The southern U.S. exhibits a slight elevation during the October-December quarter.

SULFATE

Mean annual sulfate concentration in precipitation C_{12} is contoured in Fig. 3. Most of ENA experiences concentrations of 1.5-3 mg l^{-1}. Elevated values generally exist near regions of high sulfur emissions. A distinct peak over the lower Great Lakes region is caused by several high measurements in southern Ontario. Contours of mean annual wet sulfate deposition D_{12} are plotted in Fig. 4. The contour pattern is oriented along a SW-NE axis. Depositions range from 20-35 kg $ha^{-1}y^{-1}$ over most of ENA. Ecologically sensitive areas in the northeastern U.S. and eastern Canada typically receive over 25 kg $ha^{-1}y^{-1}$. The 30 kg $ha^{-1}y^{-1}$ contour encompasses a large portion of the Ohio River Valley northward through the lower Great Lakes, with peak depositions of 35 kg $ha^{-1}y^{-1}$ and above experienced in a circular region over Pennsylvania and the Virginias. An elevated region also exists in southern Ontario, coincident with the area of peak concentrations.

The seasonal nature of sulfate deposition is addressed in Figs. 5-7. Fig. 5 plots mean monthly sulfate deposition fractions F_1. The one month fractions for the 77 measuring stations are sorted into boxes. The width of each box is proportional to the number of sites whose F_1 values fall within its range. An aggregate monthly average over the 77 monitors is shown as the connected set of star symbols. A horizontal line is drawn at F_1=1/12, the value which would correspond to equal monthly deposition. The months of April through August clearly show enhanced values at most sites, while the lowest values occur during December through February. Though scattered, the distribution of values for any given month tends to concentrate around the aggregate average. Slight geographical trends exist within the network. Stations in the northeast have slightly lower than aggregate values in January-April and slightly higher ones in June-August. Monitors in northwestern ENA experience

their largest deposition fractions in May, while values for the September-November period are close to the 1/12 mean. Deposition fractions at southern ENA stations generally peak in July. Also, southern values tend to exceed the aggregate averages during January-March, and are lower in September-November.

Fig. 6 presents contours of wet sulfate deposition fraction for the April-September six month season. This time period is chosen to coincide with the highest deposition season at the northern receptors, which are more sensitive to acid deposition. Most of ENA receives 0.65-0.7 of its annual wet sulfate deposition during this season. (Equal semi-annual depositions would result in F_6=0.5.) Fractions 0.7 and above occur in southern Canada, Wisconsin, New York state, and a large region centered in central Pennsylvania. Symbols plotted adjacent to measured values indicate monitoring sites whose maximum six month season does not coincide with the April-September period. At southern latitudes the peak deposition season generally occurs earlier, yet 0.6-0.65 of their wet deposition still falls during April-September. Some northern ENA monitors tend to favor a later six month maximum season.

Four month wet sulfate deposition fractions for the May through August season is shown in Fig. 7. Values of 0.45-0.55 are typical over ENA. (Equal tri-annual depositions would result in F_4=0.33.) Peak values of 0.6 occur over parts of Pennsylvania and the Virginias. Island contours in New York state and Canada result from local variability in deposition fractions, the values of which range from 0.45-0.55. The shorter season shows more scatter in the measurements. As a consequence, there is greater variability in the season of maximum deposition. In general, southeastern ENA stations have four month maxima earlier than May-August, while roughly half of the Canadian sites have a later season.

NITRATE

Contours of mean annual nitrate concentration in precipitation are shown in Fig. 8. Concentrations of 1-2 mg l^{-1} occur over most of ENA. A local peak exists in the Great Lakes region, where values exceed 2.5 mg l^{-1}. Fig. 9 presents contours of mean annual nitrate deposition. Isopleths are oriented SW-NE in the eastern U.S. only. Nitrate depositions of 10-20 kg $ha^{-1}y^{-1}$ cover most of ENA. A peak centered over southern Ontario has values in excess of 20 kg $ha^{-1}y^{-1}$.

Figs. 10-12 depict seasonal nitrate deposition patterns. Mean monthly nitrate wet deposition fractions are presented in Fig. 10. Though less pronounced than sulfate, a seasonal pattern is also apparent in wet nitrate deposition. Fractions above average occur from April through August, while other months consistently fall below the annual mean of 1/12. Compared with aggregate averages, northwestern stations have slightly lower fractions in January and February, but compensating higher values in April and May. Southern stations show a pronounced peak in July, after which deposition fractions falls rapidly, resulting in lower than aggregate values from September to December.

The April through September six month nitrate wet deposition fraction is plotted in Fig. 11. The majority of ENA receives 0.55-0.65 of its annual wet nitrate deposition during this half year period. Peak values of 0.65 and greater occur in the northwestern quadrant of ENA. Values in the southern U.S. are typically 0.6-0.65. In northeastern ENA the fractions are generally smaller because maximum depositions shift to later months.

The May through August four month wet nitrate deposition fraction is shown in Fig. 12. Values typically range from 0.35 to 0.5 over ENA. Deposition fractions 0.45 or greater occur in the southeastern U.S., the eastern

seaboard, southern Michigan, and large regions of northwestern ENA. The lowest values, near 0.3, occur in portions of the Great Lakes region. Local peaks and valleys result from variability of data between stations. Though regional scatter is great, southeastern ENA stations generally exhibit a maximum deposition season earlier than May-August, while northern Canadian monitors favor a later season.

CONCLUSIONS

Analysis of 1982-1985 data from 77 stations in Eastern North America shows that the highest wet sulfate depositions, in excess of 35 kg $ha^{-1}y^{-1}$, are experienced over W. Pennsylvania, E. Ohio, and N. West Virginia; over 20 kg $ha^{-1}y^{-1}$ are deposited over most of ENA. The deposition isopleths are generally stretched along a SW-NE axis. Peak wet nitrate depositions of over 20 kg $ha^{-1}y^{-1}$ fall between Lakes Michigan and Ontario; over 15 kg $ha^{-1}y^{-1}$ covers most of northeastern ENA.

Seasonal effects are more pronounced in sulfate than in nitrate depositions. During the April through September half-year 65-75% of the annual wet sulfate deposition falls in most of ENA, but only 55-60% of the nitrate. In the northeastern sector, the May through August four month season accounts for 40-55% of sulfate and 35-50% of nitrate deposition.

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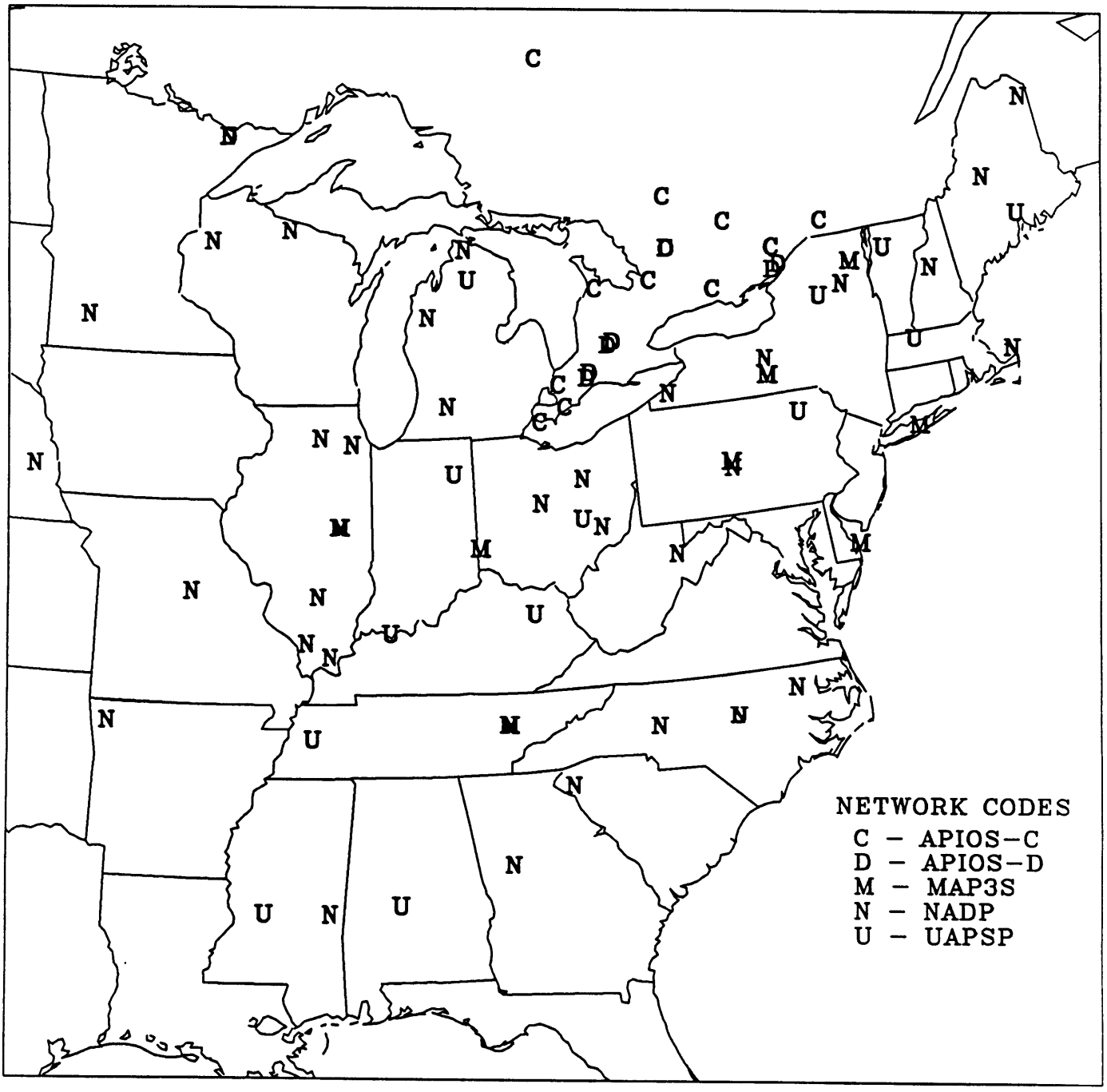

Fig. 1. Locations of the ADS monitors used in this study. Letters indicate individual networks.

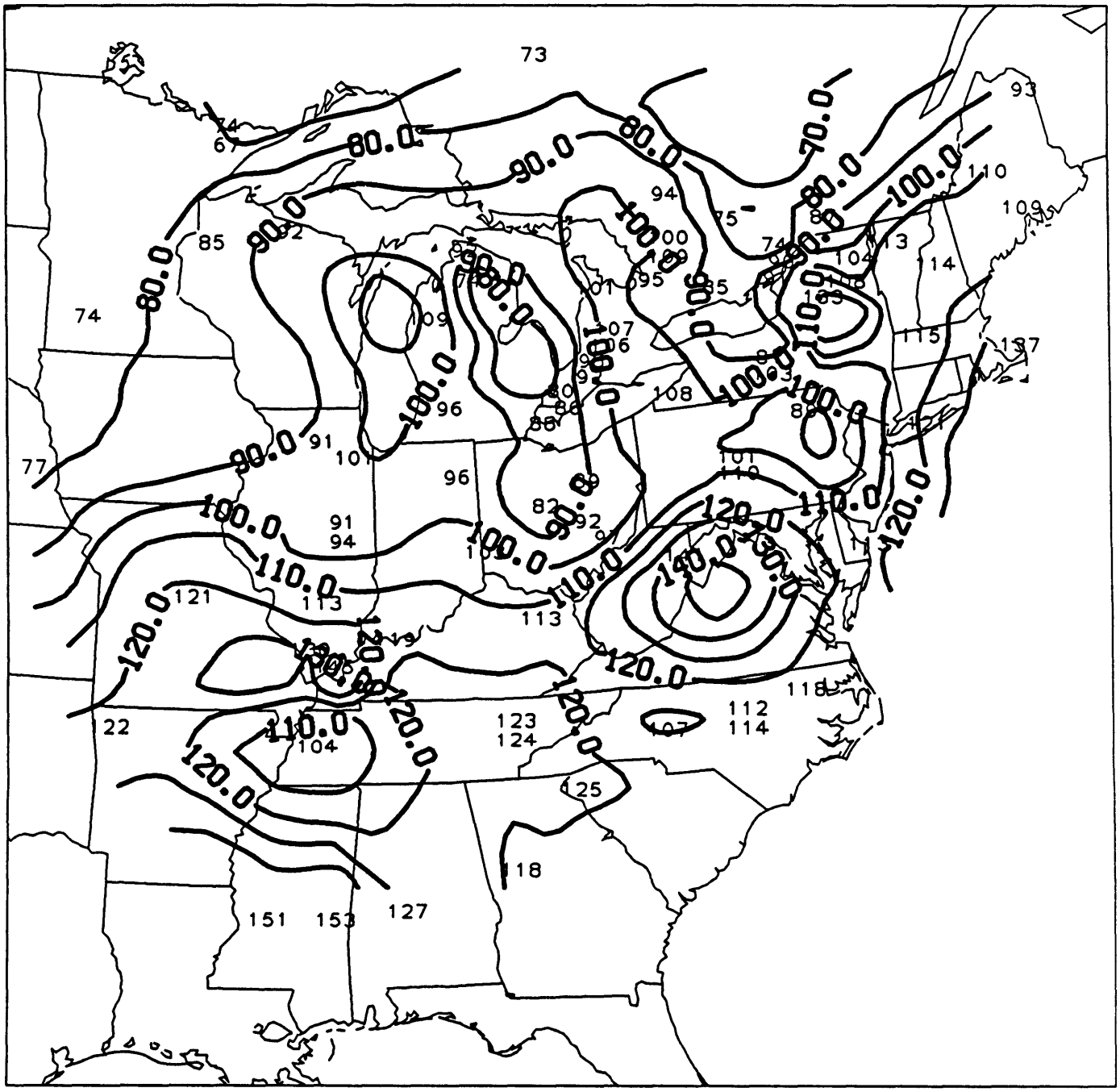

Fig. 2. Annual precipitation (cm). Small numbers are the measured values; contoured isopleths are computer generated.

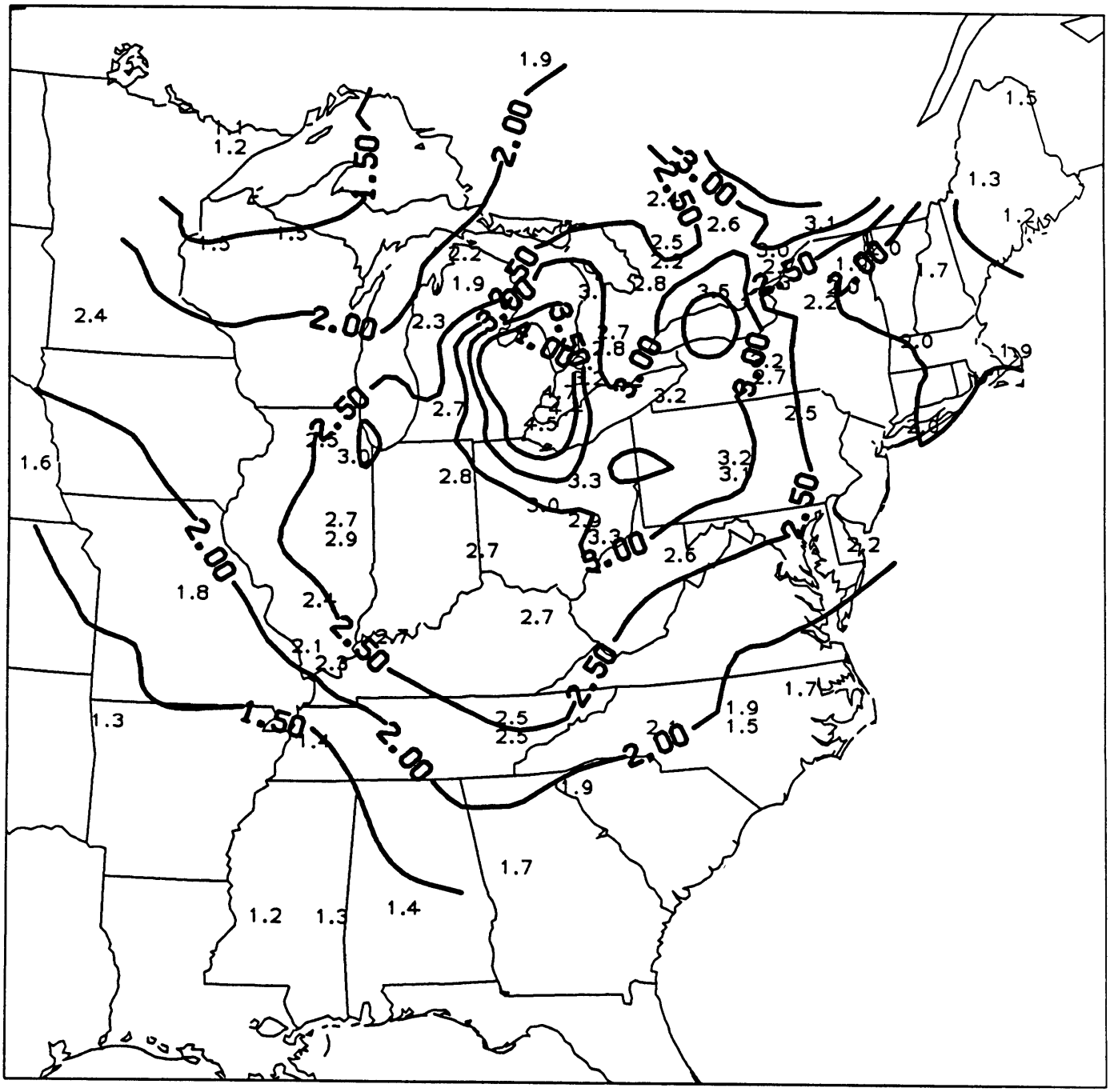

Fig. 3. Annual average sulfate concentration in precipitation (mg l^{-1}).

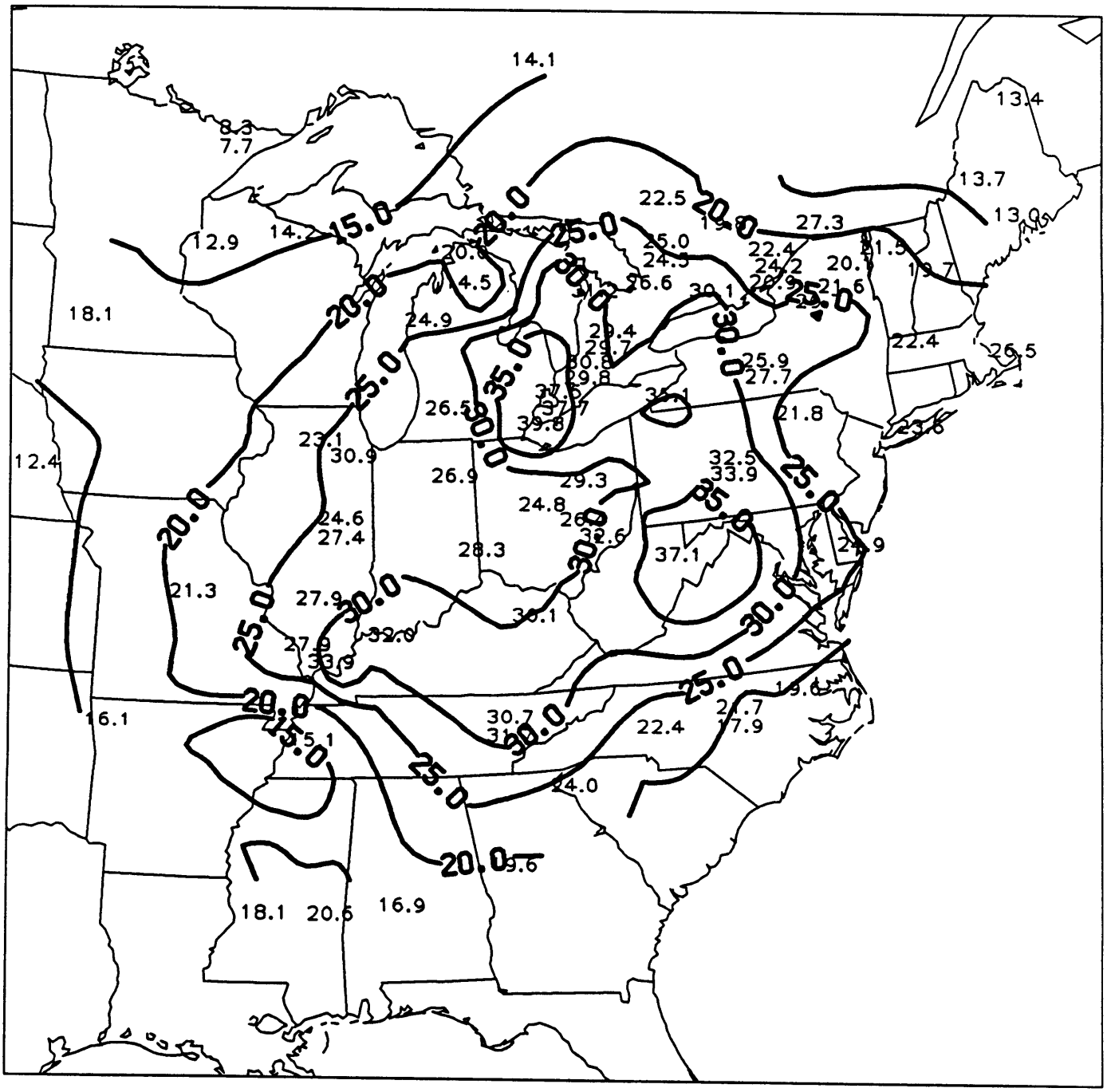

Fig. 4. Annual wet sulfate deposition (kg $ha^{-1}y^{-1}$).

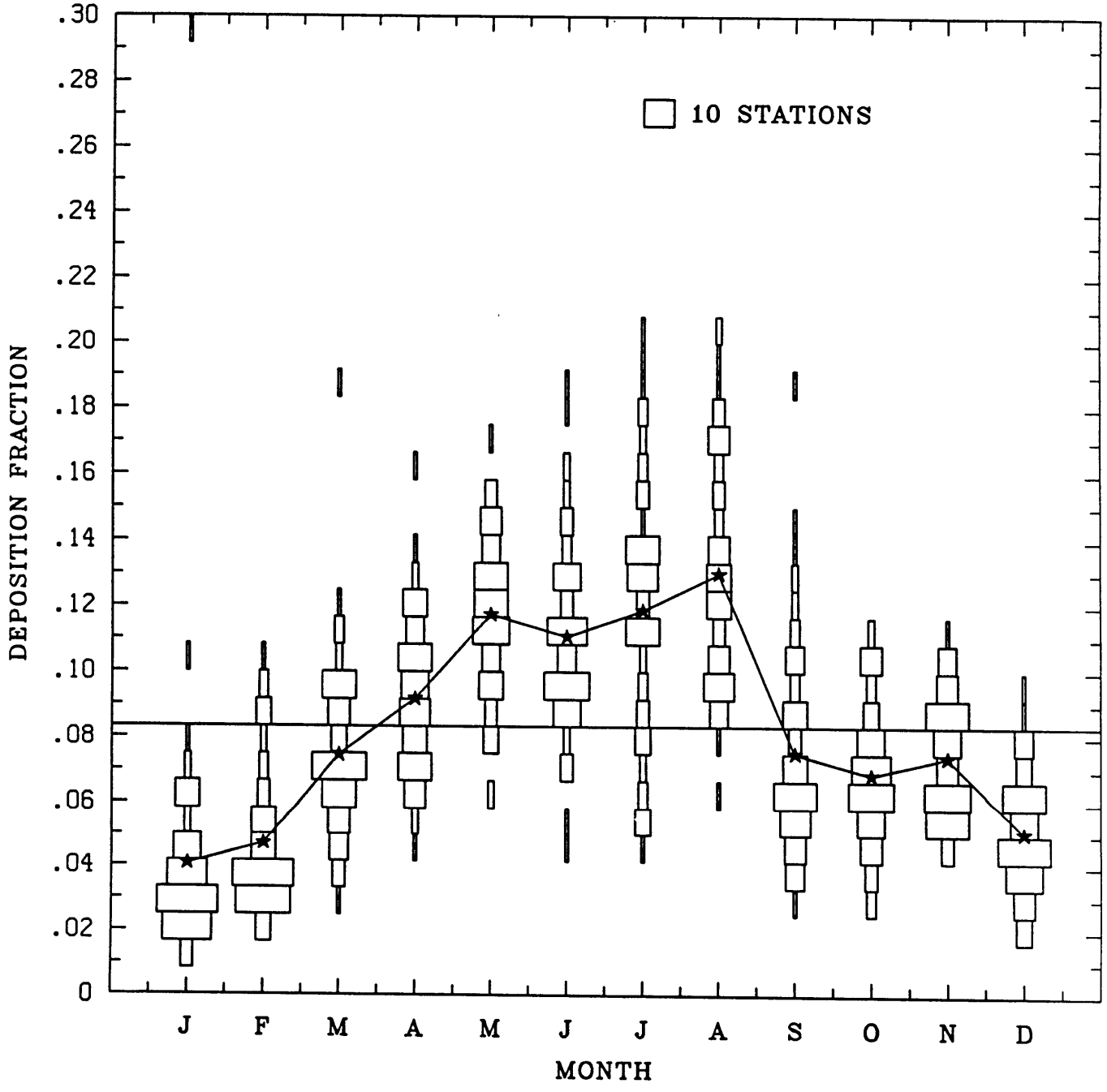

Fig. 5. Monthly sulfate deposition fractions. Width of each box is proportional to the number of stations within its range of deposition fraction. Horizontal line at 1/12 corresponds to equal monthly depositions. Star symbols are aggregate averages for each month.

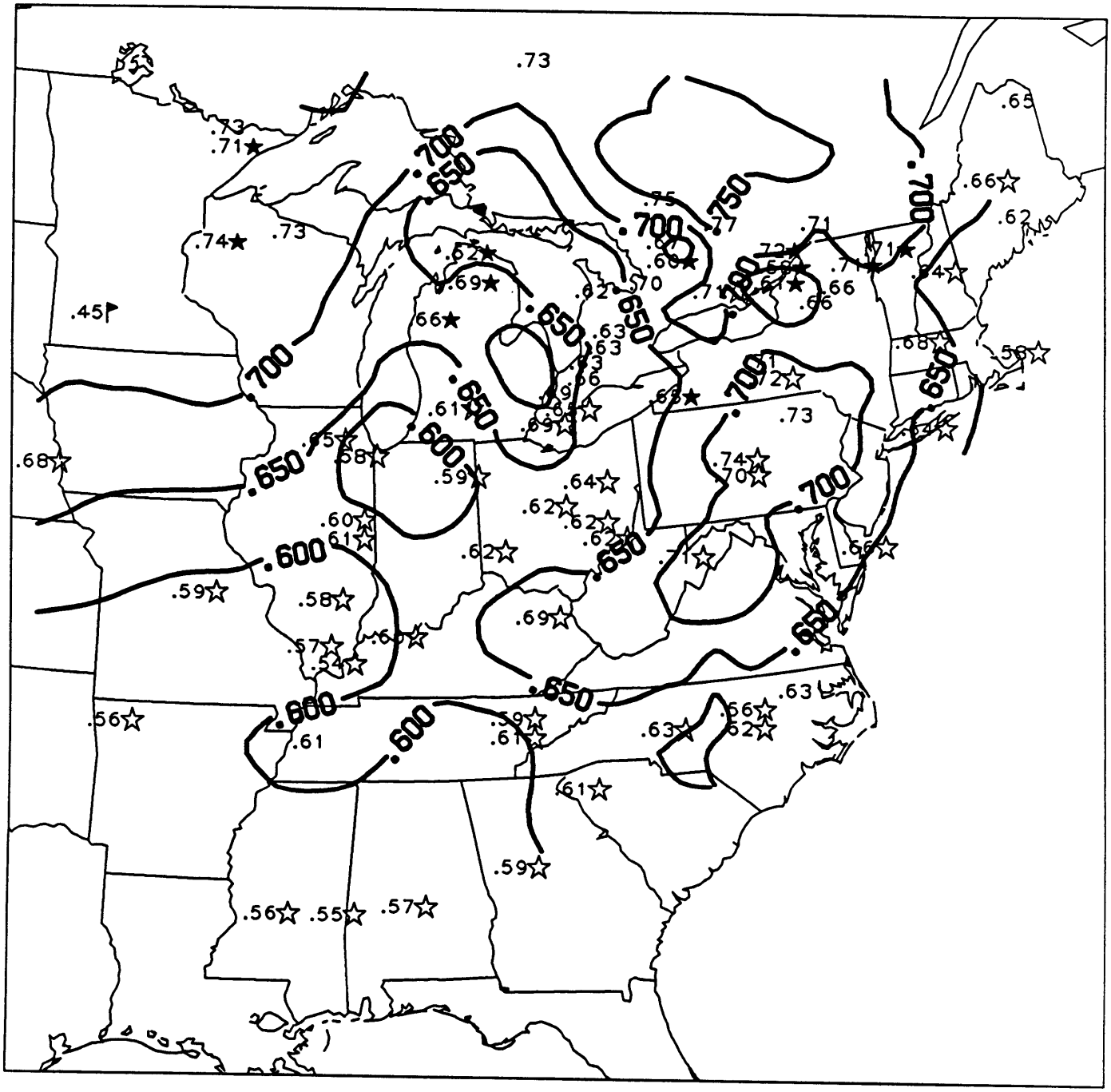

Fig. 6. Semi-annual wet sulfate deposition fraction for April-September. Open ☆ signify the maximum season occurs 1 month earlier; closed ★ 1 month later. Flag ⚑ marks site whose season differs by 3 months or more.

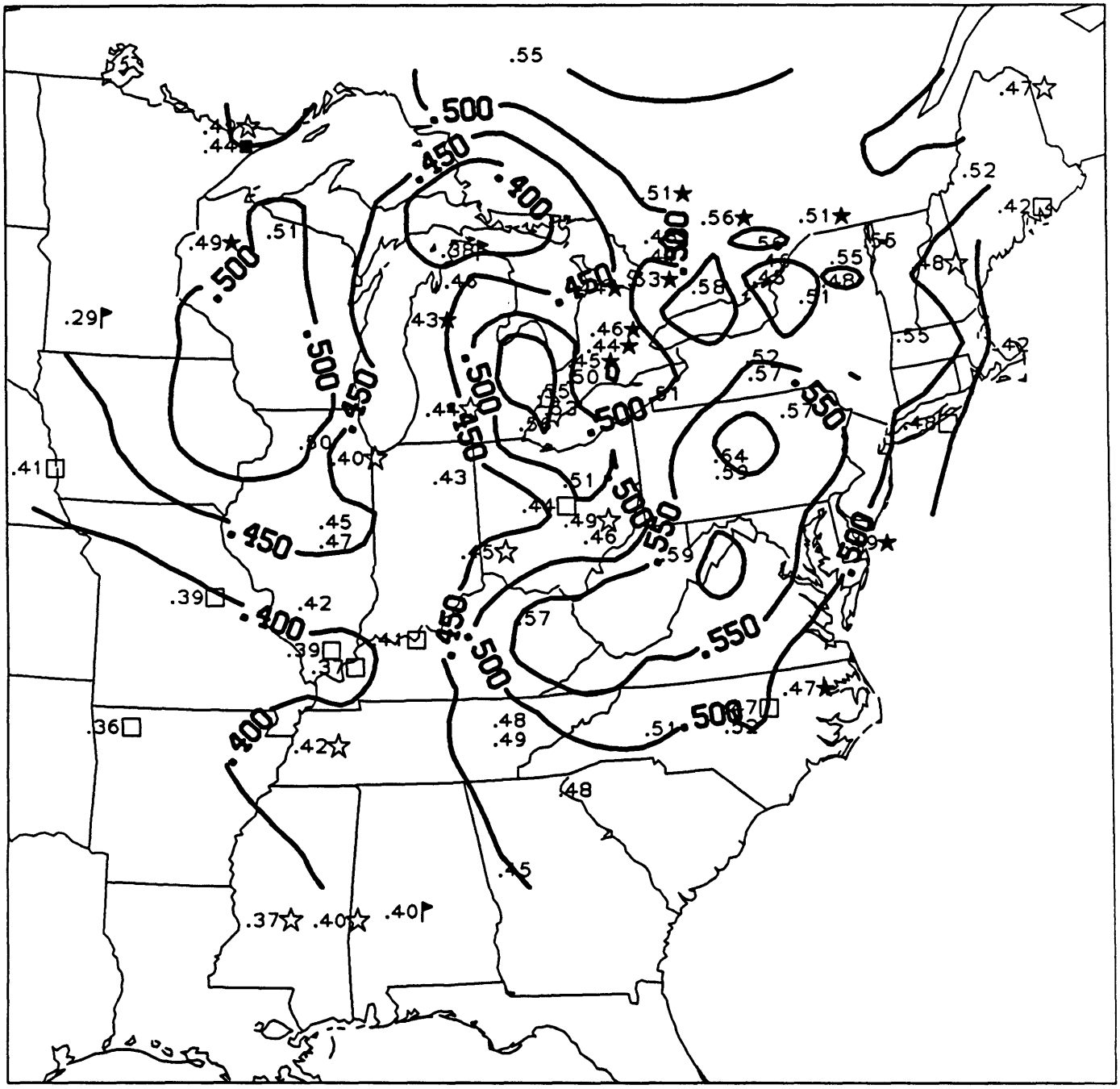

Fig. 7. Tri-annual wet sulfate deposition fractions for May-August. Open ☆ and □ signify the maximum season occurs 1 and 2 months earlier; closed ★ and ■ 1 and 2 months later. Flags ⚑ mark sites whose season differs by 3 months or more.

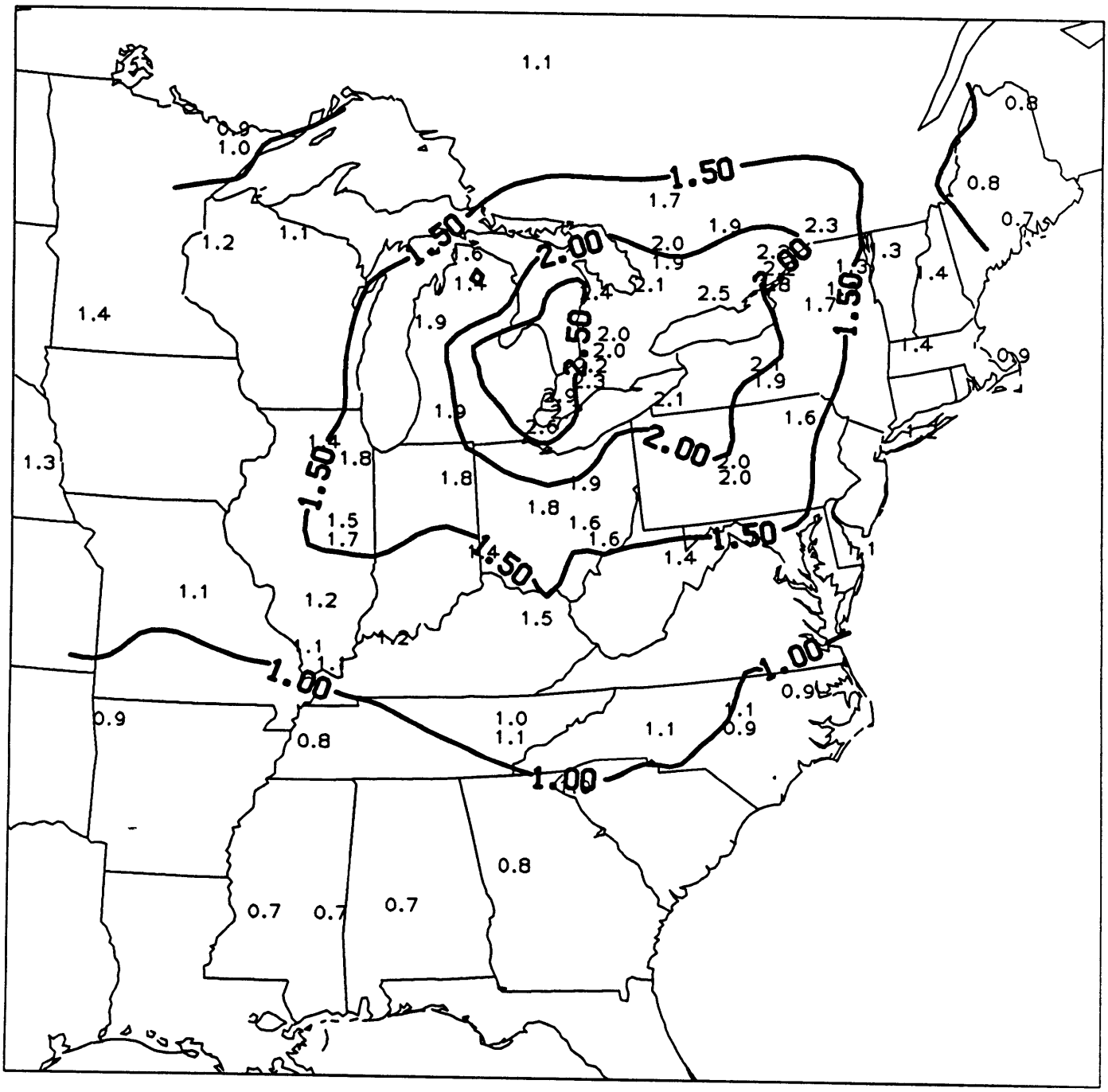

Fig. 8. Annual average nitrate concentration in precipitation (mg l^{-1}).

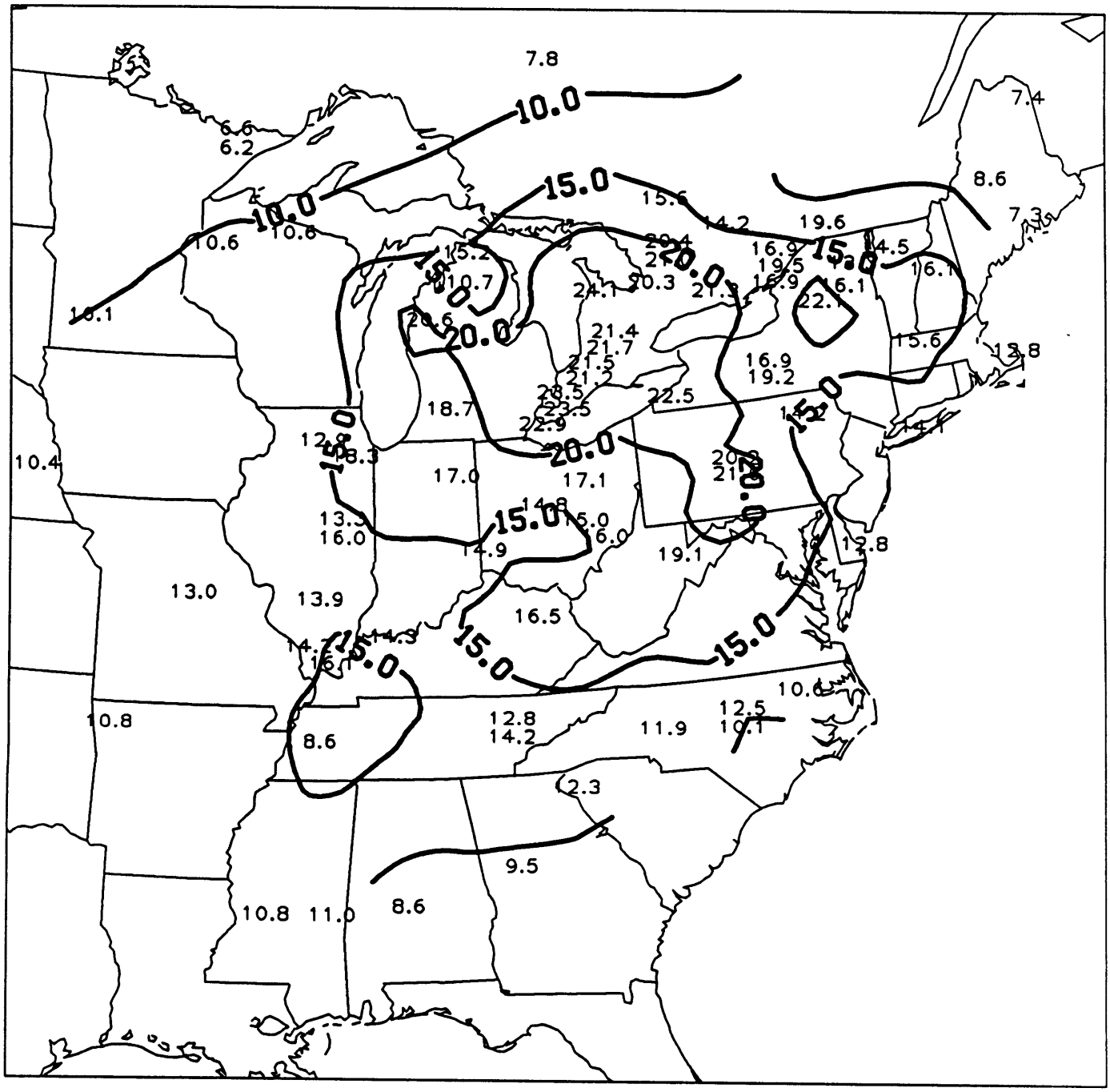

Fig. 9. Annual wet nitrate deposition (kg $ha^{-1}y^{-1}$).

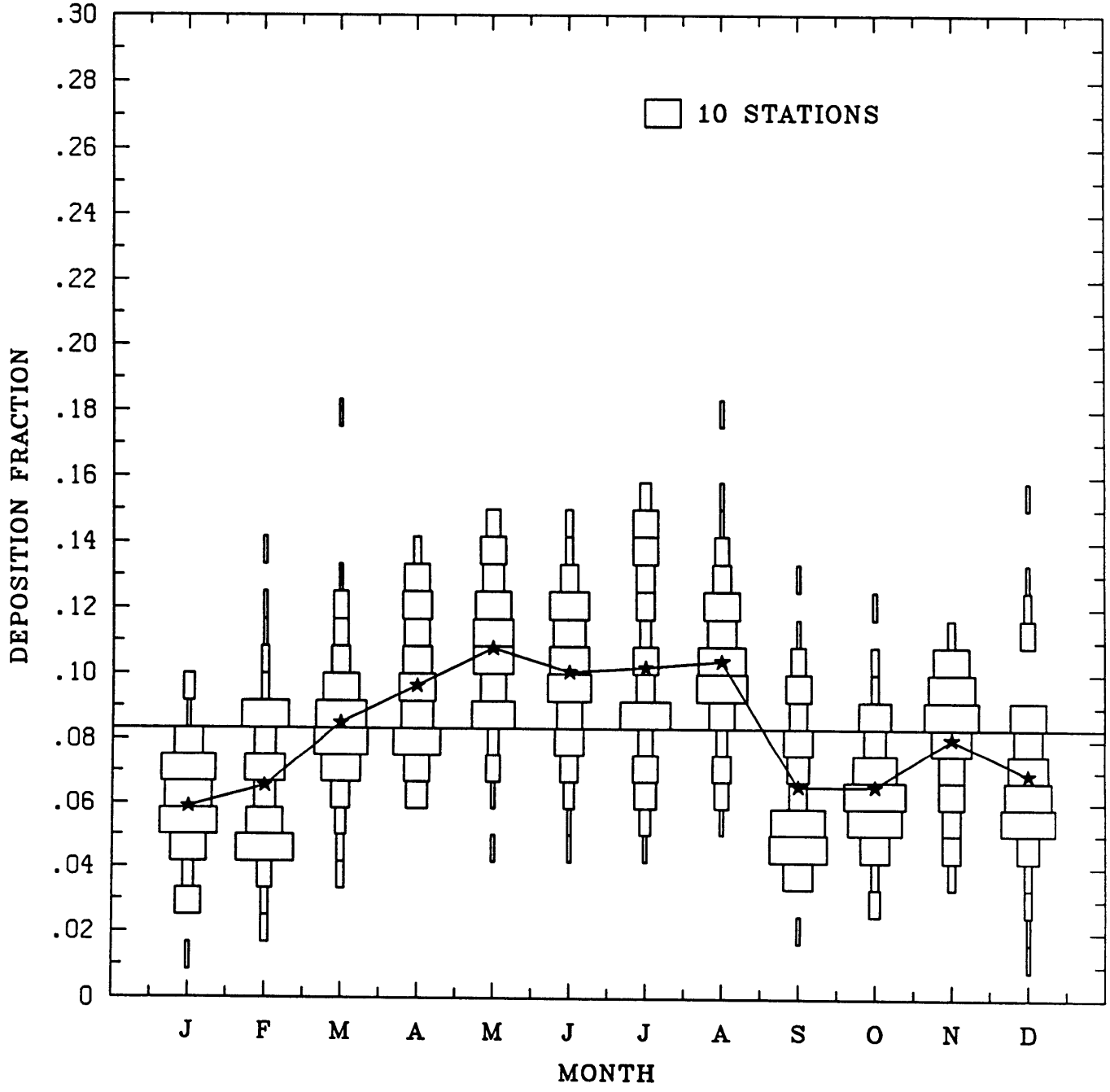

Fig. 10. Monthly nitrate deposition fractions. See comments in Fig. 5.

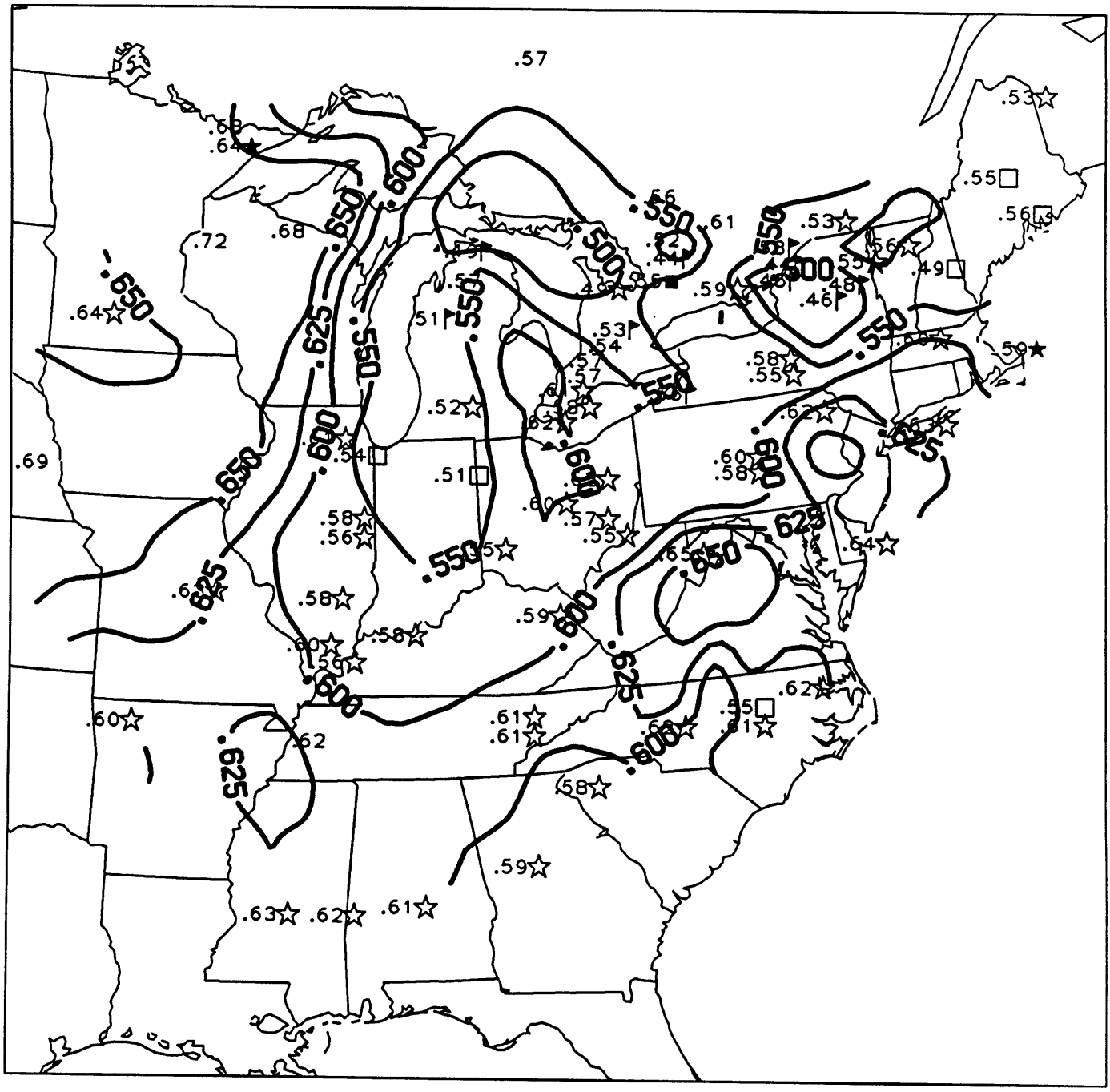

Fig. 11. Semi-annual wet nitrate deposition fraction for April-September. Open ☆ and □ signify the maximum season occurs 1 and 2 months earlier; closed ★ and ■ 1 and 2 months later. Flags ⚑ mark sites whose season differs by 3 months or more.

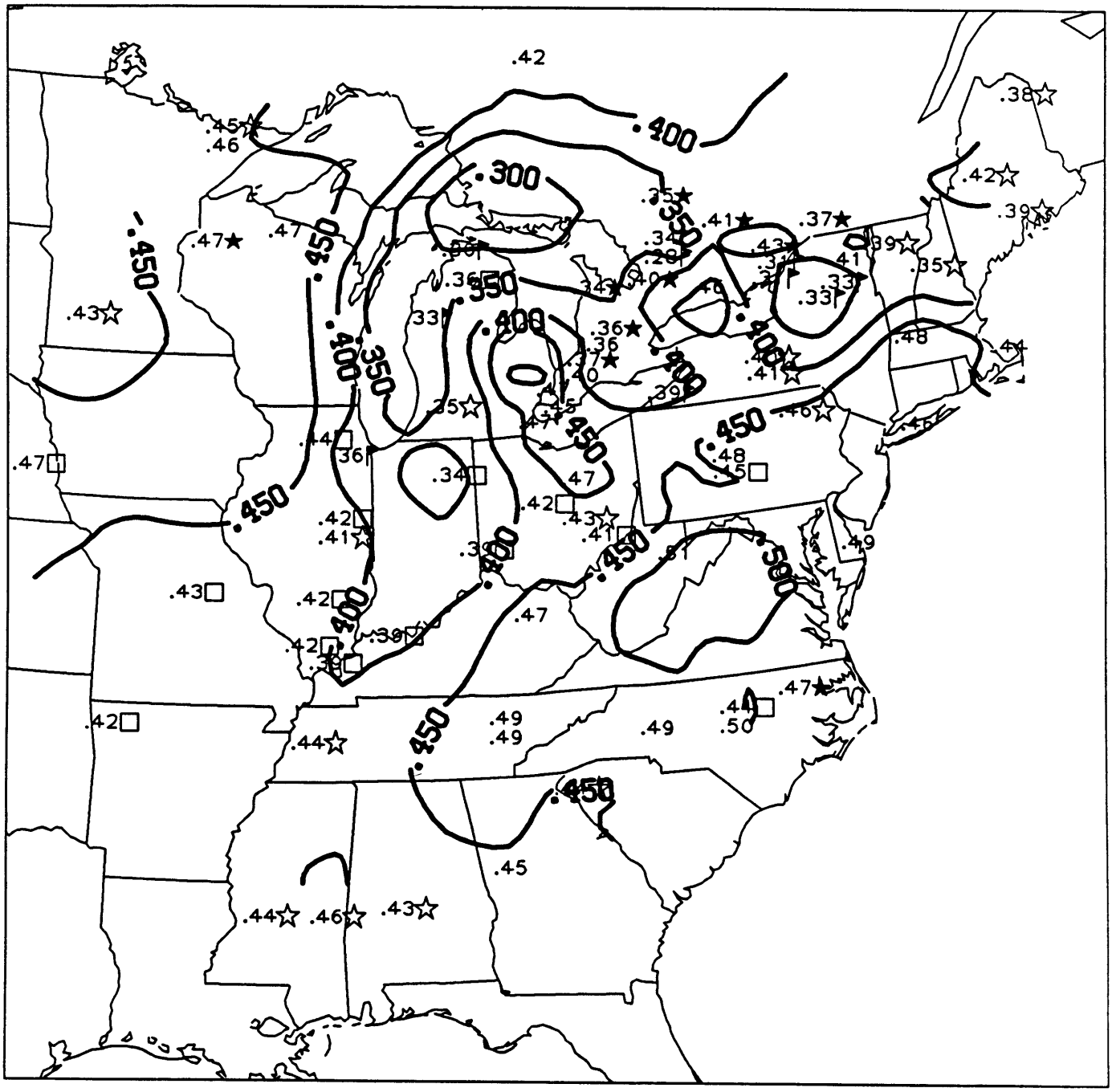

Fig. 12. Tri-annual wet nitrate deposition fractions for May-August. Open ☆ and □ signify the maximum season occurs 1 and 2 months earlier; closed ★ 1 month later. Flags ⚑ mark sites whose season differs by 3 months or more.

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

James A. Fay and Dan S. Golomb

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 for dual fuel use (parent fuel and natural gas). Both fixed and variable costs are estimated. Dual fuel use technology has small capital costs but large variable costs associated with 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, less dependent upon the capital cost of the technology, and not dependent at all upon the fuel sulfur content. When this cost is expressed as a ratio to the amount of sulfur emissions reduction; i.e., dollars per ton of SO2 controlled, it is inversely proportional to the fuel sulfur content. This cost-effectiveness ratio is a suitable measure for comparing alternative technologies for regional emission control.

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, it becomes more attractive as a cost-effective alternative to year round emission reduction control systems.

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 little 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 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 aditional 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 the incremental costs of instituting summer period substitution of natural gas for coal or oil in a utility boiler originally designed for either of these parent fuels. It considers both fixed and variable costs, expressing the annual total cost increment above the current costs in relation to the electric energy produced, the fuel heat consumed and sulfur reduction achieved over an annual period. In addition, it considers the additional advantage that summer period sulfur emission reduction possesses, i.e., a greater reduction in wet deposition than equal year-round reduction, by determining the effective annual sulfur removal cost.

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, consisting primarily of fuel costs. 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 used much less or not at all during gas combustion. 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 only to 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 [$/kw y], based upon Bloyd et al.; 1984), we assume that the savings in ESP maintenace in the summer season are balanced by the gas burner maintenance costs, so that there is no net maintenance cost increment for these components. However, there will be savings in the variable operating and maintenance (O&M) costs when using gas in place of coal. These may be expressed as a savings per unit of gas heat substituted [$/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]):

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

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

$$AHR = 10^{-6}\ AEP * HR$$

$$= 8.76\ MW * CF * HR \qquad [MMBtu/y] \tag{2}$$

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

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

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:

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

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:

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

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:

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

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

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

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

$$AFCI = \varepsilon * AHR * EFPD \quad [\$/y] \quad (8)$$

The effective fuel price differential will not be too different from the nominal fuel price differential, GP - 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]):

$$SENCI = AFCI / AHR = \varepsilon * EFPD \quad [\$/MMBtu] \quad (9)$$

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]):

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

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 FSO2 [lb SO2/MMBtu] be the sulfur in the original fuel, the summer (and annual) emissions reduction becomes:

$$ASR = 5 \times 10^{-4} FSO2 * \varepsilon * AHR \quad [t\ SO2/y] \quad (11)$$

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

$$SSRC = 2 \times 10^3 \; EFPD \; / \; FSO2 \quad [\$/t \; SO2] \tag{12}$$

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 $HR = 10^4$ [Btu/kWh] using natural gas for six months, the specific energy and electric cost increments become:

$$SENCI = 0.5 \; EFPD \quad [\$/MMBtu]$$

$$SECI = 0.5 \; EFPD \quad [¢/kWh]$$

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):

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

where typical values of the corona power density D and the specific collection area SCA are 1.5 [W/ft^2] and 0.4 [ft^2/cfm], respectively, and the gas flow rate G can be given approximately by:

$$G = 0.347 \; MW * HR \quad [cfm] \tag{14}$$

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

$$P_{esp}/MW = 2.6 \times 10^{-3} \tag{15}$$

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 ε = 0.5 (six month summer period) in (7), we find:

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

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 [$], that the indirect costs are added to this by multiplying DCC by an indirect cost factor ICF and that the total is annualized by a levelizing factor LF to give the annualized capital cost ACC [$/y]:

$$ACC = DCC * ICF * LF \quad [\$/y] \tag{17}$$

We will specify the DCC as the product of the plant power times the specific capital cost SCC [$/kW]:

$$DCC = 10^3\ SCC * MW \quad [\$/kW] \tag{18}$$

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

$$SACC = 1.14\ X\ 10^2\ SCC * ICF * LF\ /\ CF * HR \quad [\$/MMBtu]$$

$$= 1.14\ X\ 10^{-2}\ SCC * ICF * LF\ /\ CF \quad [¢/kWh] \tag{19}$$

The capital cost is now in a form that can be aded 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 [$/t SO2]:

$$SSRCC = 2.28 \times 10^5 \; SSC * ICF * LF / CF * HR * FSO2 * \varepsilon \quad [\$/t\ SO2] \qquad (20)$$

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

$$SACC = 0.07\ [\$/MMBtu] = 0.07\ [¢/kWh]$$

$$SSRCC = 291/FSO2\ \ [\$/t\ SO2]$$

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.

Total Costs

By combining the variable costs (9), (10) and (12) with the fixed costs (19) and (20), we obtain the total incremental costs, expressed as [$/MMBtu], [¢/kWh] and [$/t SO2]. These costs depend principally on the fuel price differential, GP - FP, and to a much smaller extent upon the many other parameters characterizing the plant performance or operation. For the purpose of illustrating the principal dependences, we select the following parameter values as being typical of a coal-fired boiler:

Plant heat rate HR = 10^4 [Btu/kWh]; Capacity factor CF = 0.6; Uprating factor URF = 1.0026; Boiler efficiency factor BEF = 0.95; Fuel price factor FPF = 1.1; Indirect cost factor ICF = 1.7; Levelizing factor LF = 0.13; Fuel price FP = 1.50 [$/MMBtu]; Specific capital cost of gas retrofit SCC = 20 [$/kW]; Summer period fraction ε = 0.5; Specific variable O&M savings SVO&MS = 0.20 [$/MMBtu].

Using these typical values, the annualized incremental cost of seasonal gas substitution, expressed as a ratio to the fuel heat and electric energy, is calculated and listed in Table 1 as a function of the price differential between gas and the parent fuel in the range - $1.00 to $3.00 per MMBtu. (The negative price differential is included because some oil-burning utilities can obtain summer gas at a lower price than oil.) The annualized incremental cost is nearly proportional to the fuel price differential because the latter is the dominant variable. These costs are independent of fuel sulfur content.

The total incremental cost compared to the sulfur emission reduction is shown in Table 2 as a function of fuel price differential and fuel sulfur content. The sulfur removal cost is approximately proportional to the fuel price differential and inversely proportional to the fuel sulfur content. Thus the costs are lower for high sulfur fuels and small price differentials, and vice versa.

The cost per unit of sulfur emissions avoided by gas substitution is a dominant factor in achieving regional emission reduction in the most economical manner. For all sulfur control systems, this specific cost decreases with increasing sulfur content of the fuel, indicating that plants with the highest fuel sulfur are the most cost-effective to control. For any given plant, however, the most economical technology for reducing sulfur (including seasonal gas substitution) depends upon the relative cost increments and sulfur removal fractions. Thus Table 2 can be compared with similar data prepared for alternative technologies in order to select the most economical alternative.

CREDITING SEASONAL DEPOSITION EFFECTS

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, assume that equal sulfate deposition results from 1 ton of

summer emissions and 1.5 tons of year-round emissions. For the purpose of comparing the cost-effectiveness of seasonal emission control with annual emission control (by scrubbing, for example) in a particular plant, the entries in Table 2 should be multiplied by 2/3 to determine the sulfur reduction cost equivalent to that of a year-round system having the same deposition effect. For any given fuel price differential and fuel sulfur content, this depositon effect makes the effective cost of sulfur control lower by the factor 2/3.

CONCLUSION

The use of natural gas during the summer period in utility boilers fueled with coal or oil will reduce the annual amount of sulfur dioxide emissions at an economic cost which is approximately proportional to the price differential between natural gas and the parent fuel, and is only slightly affected by the many other plant characteristics. When expressed as a ratio to the amount of sulfur emission reduction, the incremental cost is inversely proportional to the fuel sulfur content as well as approximately proportional to the fuel price differential. Such a cost ratio is required for selecting at each plant the most cost-effective technology for controlling regional sulfur emissions.

Because summer period sulfur emission reduction has a proportionately greater effect on wet sulfate deposition than year-round reduction, the effective cost of reducing sulfur emissions by summer gas substitution is reduced, compared to year-round reductions, by a factor equal to the ratio of deposition rates, summer/annual. This increases the range of fuel price differential for which gas substitution might be the economically preferred technology.

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TABLE 1

Typical Annualized Incremental Costs of Seasonal Gas Substitution, per Unit of Fuel Heat and Electric Energy[a]

Gas - Fuel Price Differential [$/MMBtu]	Annualized Incremental Cost [$/MMBtu], [¢/kWh]
- 1.00	- 0.45
0.00	0.08
1.00	0.60
2.00	1.13
3.00	1.65

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a. Exogenous parameter values: HR = 10^4 [Btu/kWh]; CF = 0.6; URF = 1.0026; BEF = 0.95; FPF = 1.1; ICF = 1.7; LF = 0.13; FP = 1.50 [$/MMBtu]; SCC = 20 [$/kW]; ε = 0.5; SVO&MS = 0.20 [$/MMBtu].

Table 2

Typical Sulfur Removal Costs of Seasonal Gas Substitution[a]
[$/t SO2]

Fuel Price Differential [$/MMBtu]	Fuel Sulfur[b] [lb SO2/MMBtu] 1	2	4	8
- 1.00	- 1780	- 890	-445	-222
0.00	321	161	80	40
1.00	2421	1211	605	303
2.00	4521	2261	1130	565
3.00	6621	3311	1655	828

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a. Exogenous parameter values: HR = 10^4 [Btu/kWh]; CF = 0.6; URF = 1.0026; BEF = 0.95; FPF = 1.1; ICF = 1.7; LF = 0.13; FP = 1.50 [$/MMBtu]; SCC = 20 [$/kW]; ε = 0.5; SVO&MS = 0.20 [$/MMBtu].

b. Fuel sulfur weight percent = 0.5 FSO2(10^{-4} x fuel heat value [Btu/lb])

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 SO2/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 [$/MMBtu]
FPF	Fuel price factor
FSO2	Fuel sulfur [lb SO2/MMBtu] (uncontrolled sulfur emission rate)
G	Gas flow rate [cfm]
GP	Gas price [$/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]
SACC	Specific annualized capital cost [$/MBtu or ¢/kWh]
SCA	Specific collection area [ft^2/cfm]
SCC	Specific capital cost [$/kW]
SECI	Specific electric cost increment [¢/kWh]
SENCI	Specific energy cost increment [$/MMBtu]
SGHR	Specific gas heat requirement [MMBtu/y]
SSRC	Specific sulfur removal cost [$/t SO2]
SSRCC	Specific sulfur removal cost of capital [$/t SO2]
SVO&MS	Specific variable O&M savings [$/MMBtu]
URF	Uprating factor
WFHR	Winter fuel heat requirement [MMBtu/y]
ε	Summer period fraction of year

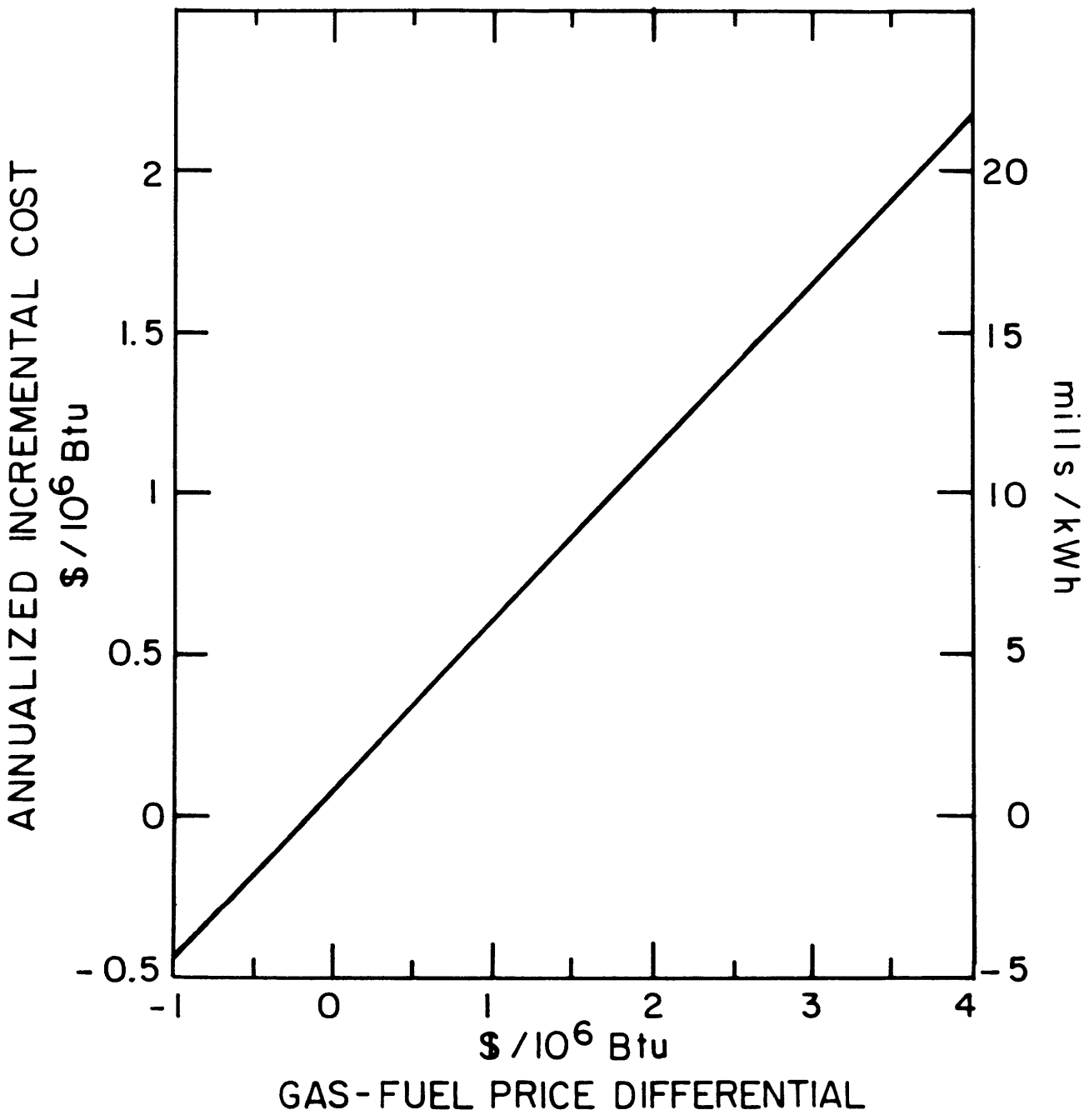

Figure 1. Annualized incremental costs of seasonal gas substitution vs. fuel price differential

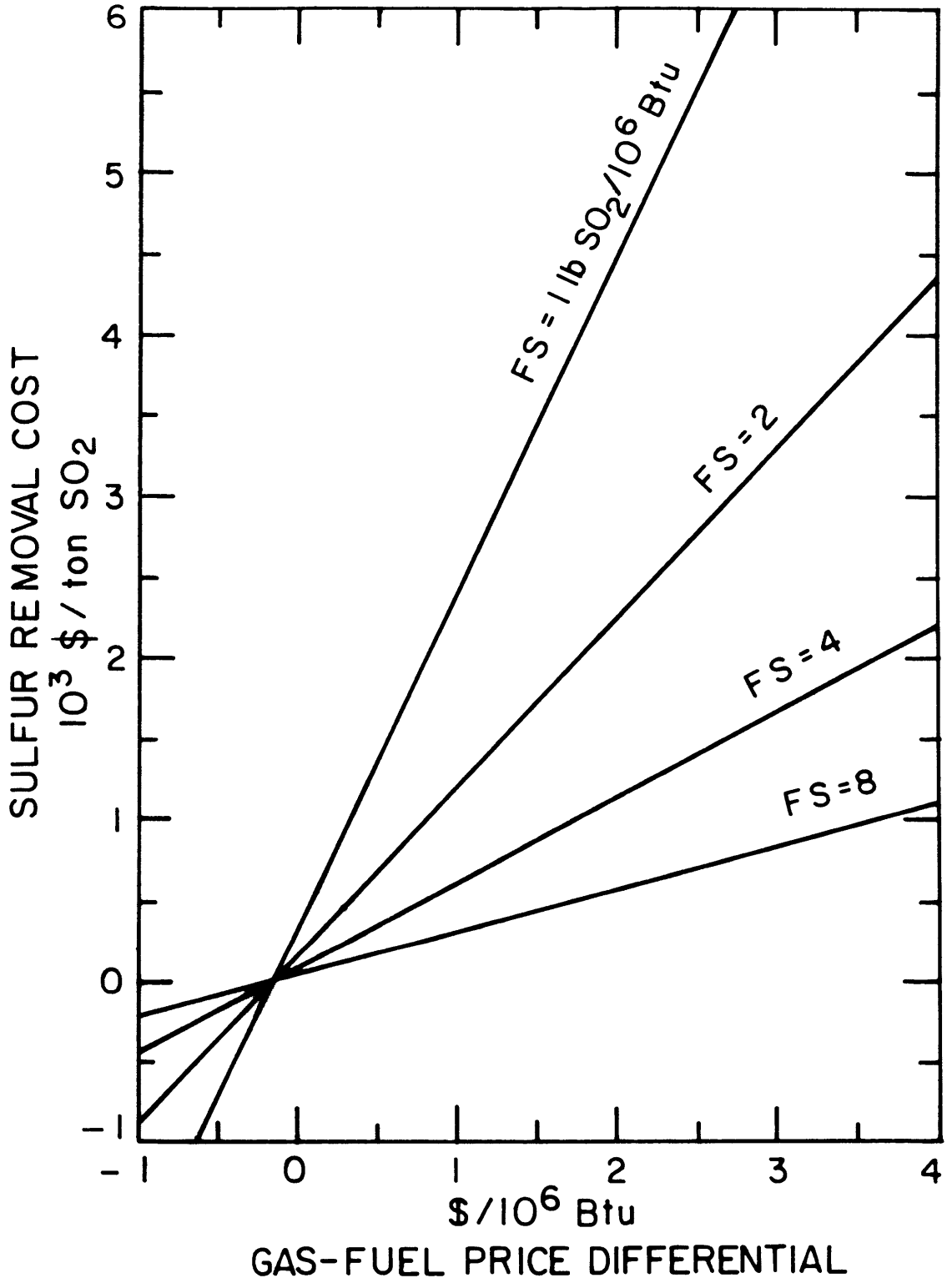

Figure 2. Sulfur removal costs by gas substitution vs. fuel price differential and uncontrolled fuel sulfur emission rate

Natural Gas Markets for Acid Deposition Control

Peter J. Poole

1 Introduction

This paper briefly summarizes our understanding of the seasonal natural gas market for electric utilities in North America. We argue that there are abundant gas reserves and ample deliverability to supply the needs of summer switching of coal-fired boilers to natural gas for pollution control.

The paper discusses North American reserves, production and demand, changes in market structure, prices, and pipeline deliverability. Current demand is about 16 trillion cubic feet of natural gas per year (16 x $10^{12}ft^3$/yr, or tcf*), down from a peak of 20.2 tcf/yr in 1979. Supply has exceeded demand for six years and the average natural gas price to all users has fallen from a high of $5.22/mcf in early 1985 to $4.08/mcf in 1986. The average price for gas paid by electric utilities is considerably lower, $2.44/mcf, approximately the same as the oil price on a per unit heat basis, because gas competes with heavy oil in peaking power plants. (See appendix for energy unit conversion factors.) Wellhead price is $1.86/mcf. Pipelines have apparently sufficient capacity to deliver gas at the historic peak level of 1.7-1.8 tcf/mo (or ~ 21 tcf/yr) and some analysts suggest there is much greater capacity than this. Certainly the daily peak delivery is much higher than this rate. The market structure is being made more competitive, and as a result, contract prices for large consumers such as the electric utility industry will likely approach marginal cost.

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* Gas volumes are conventionally reported in North America in units of trilion cubic feet [tcf], million cubic feet [mmcf, or MMcf], million BTU [MMBtu], and thousand cubic feet [mcf]. The SI conventions of giga [G, 10^9], mega [M, 10^6], and kilo [K, 10^3] are less confusing but are not used in this paper.

2 Continental Natural Gas Reserves and Production

The U.S. domestic natural gas reserves in the southern 48 states are estimated to last for 20-30 years at wellhead prices of $2-3/mcf. (Dollar values are given in constant 1985 U.S.$, corresponding to a CPI of 322.2. See appendix for CPI table.) This corresponds to proven reserves of about 160 tcf.

A standard indicator of future production capability is given by the reserve to production ratio (R:P ratio, i.e. the ratio of the number of years of proven reserves to the current rate of consumption.) This measures the inventory developed by the producers. Reserves increase with the resource rents expected by the industry in an unregulated market. In the wake of the second oil crisis and the 1978 wellhead price decontrol, people predicted high sustained oil and gas prices. For four years from 1979 to 1983 the new additions to reserves exceeded the annual consumption rate and the R:P ratio rose. The glut in the gas market in recent years (the so-called gas bubble) has caused producers to cut back on drilling. Consequently the R:P ratio is falling. Due to public concern over national energy self-sufficiency, regulations in the past have sought to maintain this ratio at a certain level to give consumers a feeling that gas supply is not in danger of depletion.

In recent years the R:P ratio in the U.S. has been as high as 12:1, partly due to industry's expectations that prices would be in the $4-$5/mcf range. Recent drilling activity indicates that this high ratio is uneconomic because the costs of exploration cannot be recovered by the time the gas is pumped and sold. Low exploration levels in 1986 have brought the ratio down to 8:1 in the U.S. In Canada until mid-1986, regulations compelled producers to maintain 25 years of reserves before gas exports would be allowed. This regulation has been relaxed and the market has responded dropping the inventory to 15 years. Considering the entire continent, the reserve to production ratio is expected to remain about 8:1 through the 1990's.(Kalt & Schuller, 1986; OGJ 1986b).

Although the R:P ratio indicates the industry's perspective on economically recoverable natural gas, estimates of the remaining resource supply also consider estimated total resource potential. This resource level is properly considered to be that amount which would be recovered at a price level less than or equal to a competitive backstop resource price. Remaining resource estimates vary from about 1,100 to 1,400 tcf. (Reilly et. al., 1982.)

One common method of estimating future expected discoveries is given by the Hubbert curve, a bell-shaped curve indicating annual production on the vertical axis and year of production on the horizontal axis. The total production is given by the area under the curve. The rising portion of the curve represents increasing resource discoveries and resource use; the declining portion of the curve represents a period of declining discovery rates. Although this model lacks economic sophistication, it summarizes much geologic understanding of resource discovery patterns.

Many analysts consider that North Americans have already consumed between one-third and one-half of the total recoverable natural gas (at a price less than that of a backstop gas such as synthetic gas from coal gasification) and therefore that we are at or near the peak of the bell-shaped discovery curve.(Rose, 1986). About 600 tcf of natural gas has already been consumed in North America; perhaps 1100 -1400 tcf remain. Some of this would be produced at current prices and hence current rates of consumption -- say, 200 tcf, lasting about 15 years -- and some of this would only be pumped at higher real gas prices and lower conumption rates -- say, 600 tcf, lasting perhaps an additional 40 years.

(This short calculation assumes a static demand curve with a price elasticity of demand of -2, i.e. at 150% of the current price, only 75% as much gas would be bought. By comparison, Beltrano et. al. (1986) use the following long-term elasticities of demand for gas: residential users, -0.5; commercial, -1.0; industrial, -1.5; electric utilities, -2.0.)

Therefore, we can roughly estimate that natural gas would last in North America for more than 40 years without major shifts in demand or in the prices of competitive fuels. Price uncertainty remains basic to any reserve estimate such as this.

(One analyst considers the Hubbert Curve too conservative an estimate on total recoverable resources. W.L. Fisher claims that actual gas findings over the relatively short period 1977-'84 have been 70% more than that which an exponential decline in discoveries model (the Hubbert model) would have predicted (OGJ, 1986c). However, during this period, discoveries were about 1 tcf per 5 million feet drilled. In recent years, discoveries are about 1 tcf per 6 million feet drilled (OGJ, 1987d). A general criticism is that it lacks short or mid term economic insight. However, over the long run, it may model resource availability quite well.)

Some people argue that natural gas is too precious a fuel for industrial use, and that its social value merits its conservation for the benefit of future generations. This argument can be reduced to an argument for the use of a lower social discount rate (even negative) to permit current gas reserves (at near current real prices) to be available to future generations. The social preference to use a lower discount rate can be seen by policies requiring high reserve to production ratios. Or one can consider setting aside, outside the market of the current generation, geologically suitable land for future exploration. The economic analysis of such a policy is troublesome partly because of uncertainty about technical change and potential resources (e.g. new extraction techniques from conventional basins; entirely new geologic deposits such as the deep gas hypothesized by T. Gold). Even without uncertainty, it is problematic to determine what criteria to choose for determining how long into the future one should ration resources. For example, were land parcelled out and set aside in equal lots for each of the next ten centuries, one would soon leave present generations with little reserves. The problem of intergenerational distribution of resources is beyond the scope of this paper to thoroughly analyse this. (see, e.g. Solow, 1974.) The solution to this inter-generational allocation problem would ultimately be a political one.

While politicians favor resource exploitation justified by today's economic world, one cannot expect that society will set aside resources for future generations, and therefore, our estimates of adequate fuel avaliability seem appropriate in the near and medium future.

In summary, natural gas availability in North America is sufficient to sustain current demand at below peak 1979 prices for at least ten years and perhaps for even twenty years or longer. This is sufficiently long to span the interim during which fuel switching could be one of the solutions to acid deposition control before new coal plants are built (using scrubbers as per NSPS) or other new clean coal technologies are widely used.

Continental Supply

Domestic supply accounts for 90% of current U.S. natural gas consumption. The balance is primarily supplied from Canada via pipeline. Mexican gas no longer supplies the domestic market and liquid natural gas imports are too costly. The Mexican gas entering the market in the late 1970's and early 1980's was associated gas (found together with oil deposits). Once this was consumed, there was not sufficient unassociated gas available for export (Conoco, 1987). Liquid natural gas (LNG) costs at least $4/MMBTU before local distribution. (Kalt & Schuller, eds., 1986). Current supply of 16 tcf/yr comes mainly from shallow reserves in Texas, Oklahoma, and Louisiana. Production by major producing states in 1985 is given in Table 1.

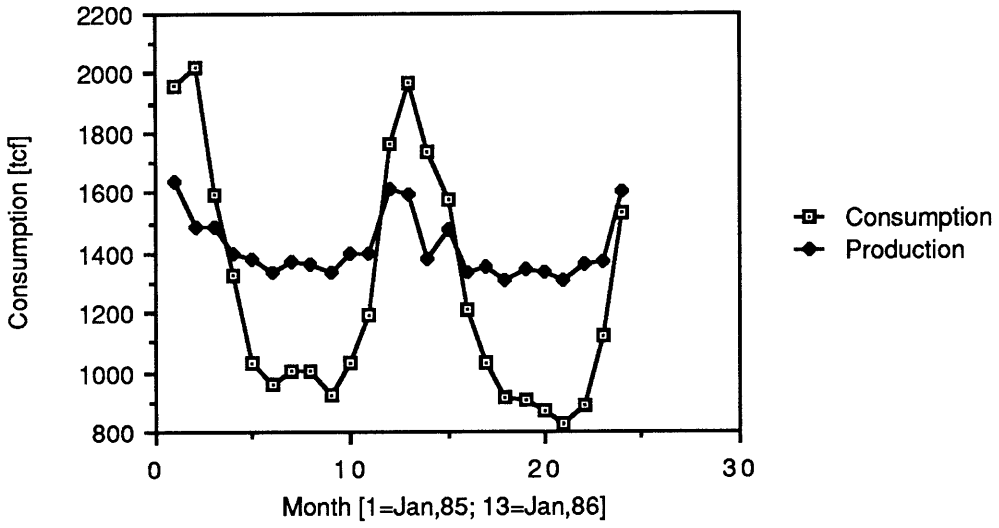
Table 1
U.S. Natural Gas Production in 1985

State	Production	% of Total US Production
Texas	6 tcf	35%
Louisiana	5 tcf	29%
Oklahoma	1.9 tcf	11%
New Mexico	0.91 tcf	5%
Four State Total	80%	
Canadian Exports to US	0.95tcf	

Gas supplies vary by month as shown in Figure 2.1. Note, the production peaks at 1.5 - 1.6 tcf/month from November through February. Production drops about 15% to 1.3 tcf/month in June and September. Consumption varies much greater. The imbalance between production and consumption is balanced by injections and withdrawals from seasonal underground storage.

Figure 2.1

Seasonal Variation in Production & Consumption



3 Domestic Natural Gas Consumption

Current natural gas demand of 15 tcf/yr is down from peak late 1970's levels of 20 tcf/yr. The present major consumers are not likely to increase demand back to the 20 tcf/yr levels.

Residential consumption is nearly saturated except in New England where less than one quarter of the residences use natural gas, compared to 80% in many parts of the country (Boston Gas, personal communication). The drop in oil prices may cause

residential demand growth to stop. For example, in 1986 heating oil prices dropped from 12% higher than gas prices to 25% lower.(OGJ, 1987a).

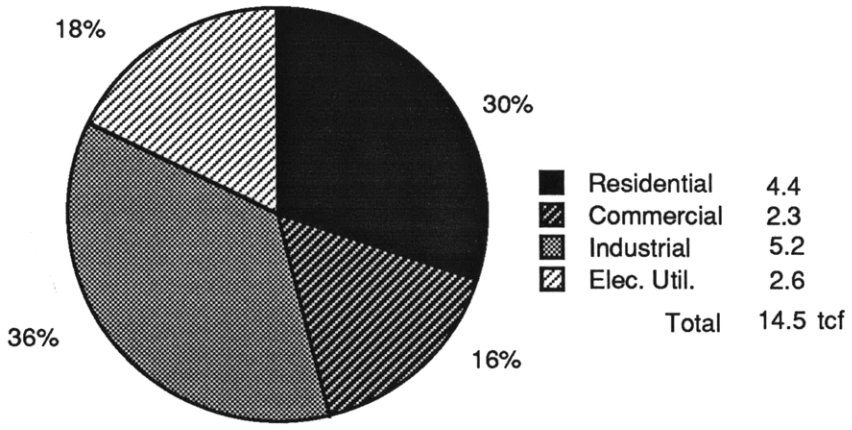
Industrial use has dropped considerably since the 1970's due to energy efficiency improvements in some industries and due to the decline of much heavy industry (OGJ, 1987a). Energy use per unit of output in the economy dropped 30% from 1977-1984, but gas use per unit output declined 50%. Industrial demand for gas in 1977 was 6.8 tcf but dropped to 5.8 tcf in 1984. In chemicals and refineries, gas use per unit output dropped by 40-50%. The emerging growth sectors for natural gas are industrial cogeneration, gas cooling, peak electric power production, and fuel substitution for emissions reduction.

The electric power sector has typically used gas for peak power generating units and has been used as a substitute fuel for residual oil. Demand in the electric power sector has been constrained by the 1978 Fuel Use Act (FUA 78) which prohibited the use of natural gas for new industrial boiler and electric power generation uses because of its intrinsic 'social value'. The law was passed to give residential consumers priority to the natural gas market in a time of perceived gas shortages on interstate markets. (Winter shortages in some residential markets in the mid-70's lead to the FUA restrictions. But while consuming regions were pinched, producing regions had excess supply.) Wellhead price decontrol from 1978 on and decreased overall demand has contributed to the gas glut on the interstate market in recent years. Society's perception has changed since FUA was enacted.

In May 1987, FUA was repealled. The pressure for change came less from a social concern for clean electric power production than from gas producers' anguish over slack demand and fallen prices. In the future, gas may be seen to be a 'socially valuable' fuel for pollution control, providing cleaner electric power production, particularly if the gas is burned in the summer time when it would not be competing with residential demand. (The appendix contains a table comparing emissions from fossil fuels.)

The current market demand for natural gas by end-use sector is given in Figure 3.1. The chart shows the large fraction of natural gas consumed by residential and commercial sectors. This demand varies seasonally as shown in Figure 3.2.

Figure 3.1
Natural Gas End Use Demand, 1986 [tcf]



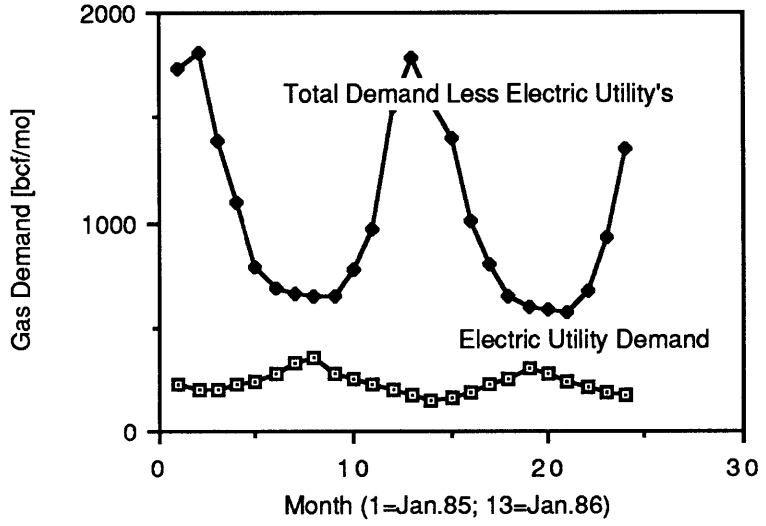
Winter gas consumption is about 8 tcf over the five months from November to March. The single peak month consumption is about 1.7-1.8/mo. Mid-year gas consumption from May-Sept. is about 6 tcf. Winter demand exceeds primary well pumping capacity by about 1.5 tcf, an amount that is easily extracted from underground storage. During the summer demand slump, consumption lags production by about 1 tcf. This excess primary production is placed in underground storage. (Storage in the gas system is mentioned briefly in section 6 together with distribution capacity.)

Gas consumption has declined in recent years because of structural changes in demand rather than because of resource supply constraints or economic price response. This drop in demand is one of the causes for a downward trend in gas prices. The balance of the price decline is due to changes in market structure and in prices for substitute fuels.

Considering a longer term, assuming price elasticities of demand similar to Beltramo et. al. (1986), the one dollar per mcf drop in prices from a $4-5/mcf level in 1985 would result in a 25-30% increase in natural gas demand, (i.e back to the 19-20 tcf/yr demand level) other things being equal. But other things are not equal: the structure of demand has changed, the market structure is not yet fully flexible, and the prices of substitutes remain somewhat volatile. The following two sections explain the recent changes in market structure and substitute fuel prices.

Figure 3.2

Seasonal Gas Demand



Note that the summer increase in gas demand by electric utilities is much smaller than the seasonal swings in gas demand by non-electric utility sectors.
Seasonal demand plots for residential, commercial, industrial, and electric utility sectors are presented for comparison in the appendix.

4 Market Structure and Recent Changes

The natural gas market in the USA is composed of four largely independent groups:

(1) the ~12,000 American natural gas producers;

(2) about 25 major interstate pipeline companies;

(3) a few thousand local distribution companies (LDCs) and large customers that tap directly into interstate pipelines; and

(4) Canadian producers and pipeline companies.

The upstream supply and downstream distribution ends of the market are largely competitive but the transmission pipelines have had the potential to exercise market (monopolistic) power.

Federal regulations dating to 1930 and 1954 intended to curtail market distortions caused by the potentially monopolistic parts of the industry. The 1954 regulations extended price regulation upstream to the most competitive sector, the producers. In the 1960's and 1970's it was evident that the government could not handle the abundance of regulatory paperwork it had made for itself and by the 1970's regulatory reform was underway.

Deregulation under the 1978 Natural Gas Policy Act removed price ceilings on wellhead gas sold to transmission companies. Pipelines were permitted to pass on costs to downstream distributors and users. Downstream consumers were given more power to refuse gas from pipelines in attempt to balance pipelines' apparent market power. Although the delivered price of gas to residential and electric utility users rose 130-140% from 1978-1985, all-out monopolistic pricing was offset by declining demand and substitute fuel price competition as we mentioned in the previous section.

Regulatory reform in the past two years has tried to provide more competition and flexibility in pipeline transmission. Downstream consumers and LDCs are permitted to play off one transmission company against another. A consumer can contract directly with a gas producer and arrange to have the gas delivered by one or more pipeline companies. A

consumer can contract for different quality service from the same company. For example, in place of take or pay contracts, a company can buy gas with either 99% deliverability in peak weeks or only, say, 50%. This particularly favors users such as utilities that can store some gas. Regulations encourage contracting between producer and consumer and seek to transform pipelines into common carriers in contrast to their former role as strategically placed wholesalers. Currently, while contractual practices are adapting to lower demand and more frequent transactions, many suppliers and pipeline companies are haggling over long-term contract renegotiations. (Broadman, 1986; Hall, 1986.) The market structure is changing to resemble other commodity markets with futures and spot markets. (Stalon, 1986; OGJ, 1987c).

A nagging unease over fuel price instability will cause some utilities to favor longer term contracts. Some New England and California utilities favor Canadian suppliers because of the latter's ability to contract for long-term supply. Local distribution companies requiring firm supplies in peak winter months for residential customers will also favor long-term contracts. Electric utilities will likely have more contract flexibility to choose suppliers and transmission companies offering the cheapest gas.

The spot market in recent years has achieved a prominent role in gas sales, and we expect it to be especially important in setting the price for summer gas sold to electric utilities. In 1986 a large fraction of the total interstate gas was sold on the spot market. Although conditions have especially favored a spot market in recent years (i.e. the glut in supply coupled with a drop in substitute fuel prices), the spot market is expected to account for 20% of gas sales.

This spot gas is most abundant in the summer, the period of slack demand. The consumers most ready to take advantage of this are the large industrial and commercial and electric utility users. As shown in the figure 3.2, electric utility gas demand already peaks in the summer. Some electric utilities may already have considerable experience in

purchasing on the spot market and will be well prepared to benefit from further flexibility in fuel contracting.

For the purpose of this paper, the best indicator of future contract gas for electric utilities that are planning gas use for emissions control would be the summer spot price. The spot price is a better indicator than the yearly average gas price paid by electric utilities, although this latter price would be a suitable high-range estimate on the expected price.

The growing flexibility in the market structure of gas sales in the United States will allow those electric utilities which follow and respond to the market closely to purchase gas at prices approaching the marginal cost of gas production and transmission. Given the abundant reserves of gas available and the excess of pipeline capacity, there will be ample low-cost gas availablity to many electric utilities. Of course there may be exceptions from time to time and from place to place. But the new flexibility in the gas market will allow many electric utilities to continue to use of expand into natural gas use.

5 Price History and Trends in Natural Gas

The current dollar and constant dollar prices of natural gas paid by electric utilities are given in Figure 5.1 a,b. Notice the price changes since 1970, particularly the rise in price together with the rise in crude oil prices in 1974 and in 1979. Gas prices levelled off in the early 1980's, rising slightly until they peaked in the winter of 1984-85. Prices began declining in 1985 but the steep price drop did not occur until 1986 when the world oil prices plumetted. Figure 5.1 reveals that gas competes head to head with heavy oil in the utility market. A full two-thirds of the utilities have access to both gas and heavy oil, i.e. 2 tcf/yr of the gas market has to compete head-to-head with oil prices.

Future prices of natural gas paid by electric utilities depend on: (i) the resource supply, (ii) the ongoing competitive trend in the market structure for natural gas, and (iii) the price competition with substitute fuels. These three factors have combined to keep a downward pressure on the price of natural gas. The resource supply appears adequate to sustain at least a ten year period of gas priced at about current levels. American supply security is further enhanced by Canadian resources. Alberta gas can be delivered to some regions of New York and New England about 10% cheaper than U.S. supplies. (WSJ, 1987). Gas demand is unlikely to increase to such an extent as to deplete resources much faster than present rates.

A more competitive market structure appears quite certain in the long-run. If the amount of gas being pumped is less than the capacity of the pipeline system then competition in the pipeline industry will increase. More looping between pipeline networks and greater contracting flexibility will further bind the market to competitive principles. Although some people worry that an unregulated pipeline sector would be prone to mergers as in the airline industry, this seems unlikely. Only if gas demand were to increase by, say, 30% (an unlikely prospect, as argued above), causing the value of pipelines to increase might non-competitive mergers occur. And mergers such as these would be fought by strong consumers such as electric utilities.

The price of substitute fuels poses much uncertainty, but again, the uncertainty is bounded somewhat by a better understanding of the changes in the international oil market over the past decade. The oil market remains influenced by OPEC, but to a lesser degree than in the early and mid-1970's. Erosion of the cartel's power has occurred as non-OPEC oil exporting countries expanded their share of the market in the 1970's. Moreover, the increase in the number of transactions at each stage from upstream producers to downstream consumers has fractured market power. As Professor M. Adelman describes the market, rather than thinking of it as a system of culverts linking producers directly to consumers, the market resembles a shattered windshield, cracked by a myriad of flexible

transactions that block market dominance by any one producer or cartel. Some oil analysts at the MIT Center for Energy Policy Research predict that oil will remain in a sticky range of about $14-22 for several years with a low probability of short term price rises up to $25-$30 or of price drops to $7-12. But oil as high as $35/barrel, while not impossible, would not be sustained for long periods, and so it seems inappropriate to consider for planning purposes. Consequently, at $18-$20 oil, heavy oil sells to electric plants at about 3.2 $/MMBtu, placing a competitive cap on gas prices of about 3.2 $/mcf (or about twice the cost of coal per unit heat.).

On average, therefore, we expect delivered gas prices for electric utilities to remain about 2.50-3.50 $/mcf. The lower end of the price range corresponds approximately to marginal cost plus 30-50 cents for transportation. Regionally gas prices may vary due to transportation charges, types of contracts, and pipeline behavior. The FERC suspects pipelines will discriminate in favor of its affiliate producers, especially in a glutted market. Most problems like this would occur when users have limited access to competing transmission pipelines. (OGJ, 1986a). The differences that exist currently are likely to diminish as old contracts work their way out of the system and purchasers are better able to buy gas on short term markets.

Fig. 5.1a, Current $ Gas Prices Paid by ElectricUtilities

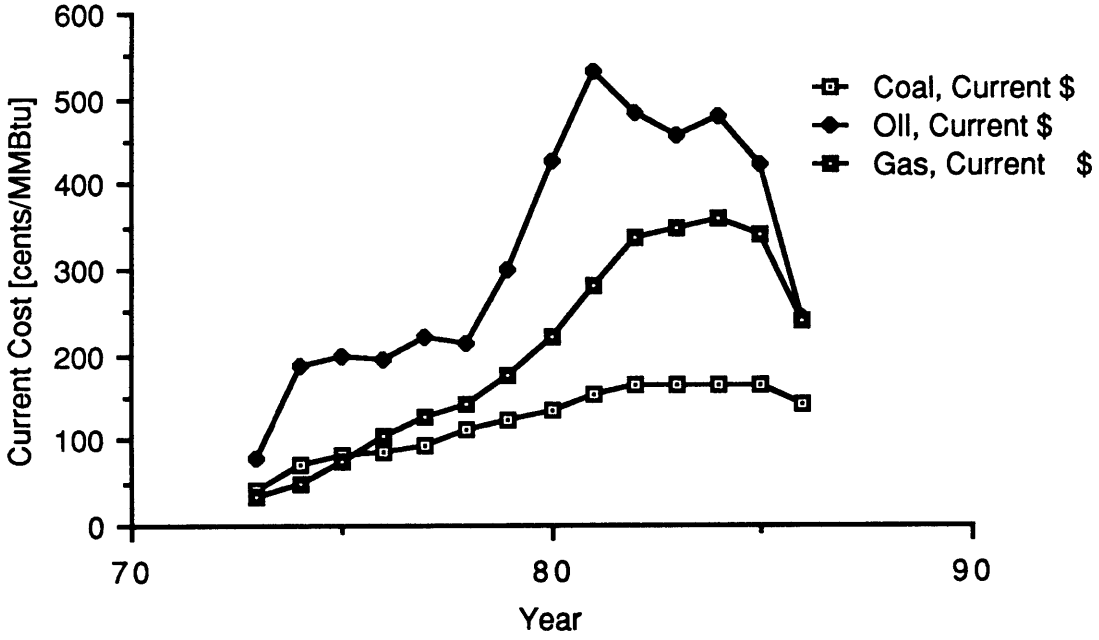
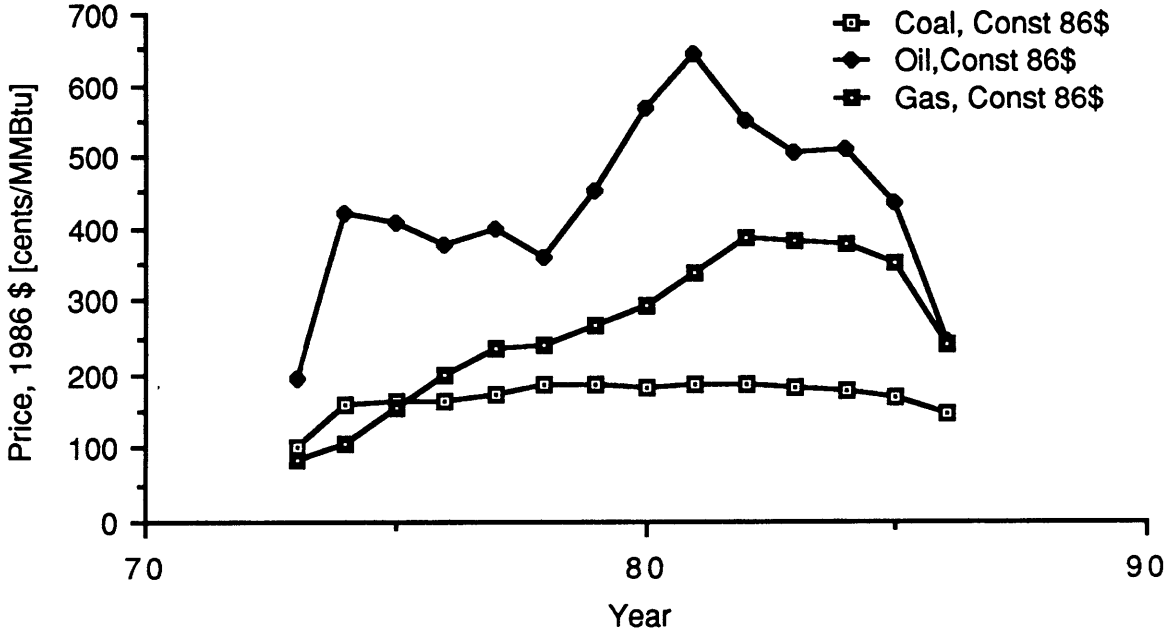


Fig. 5.1b, Constant $ Gas Prices Paid by Electric Utilities



6 Gas Deliverability and Storage

This section briefly describes that the North American gas transmission system has adequate capacity for supplying a potential summer gas demand of 2-3 tcf by electric utilities for emissions control.

The current interstate pipeline and supplementary underground storage system is designed to supply residential consumers far from the producing states during the peak demand on cold winter days. Peak gas deliveries reported in the 1970's indicates that the current 250,000 mile interstate pipeline system has a capacity to deliver about 20-22 tcf/yr, well above the current demand of about 15 tcf/yr. Currently the system may even have more capacity mainly because of greater flexibility in the transmission market but also because of some pipeline additions in certain regions of the country. The recent changes in the gas market structure provide an incentive for more pipeline interconnections (more looping) which reduce bottlenecks that might occur regionally. It has been estimated that with an additional 12 interconnections, the pipeline capacity would be extended to 34 tcf/yr. (Tussing, 1987). Increased deliverability of Canadian gas is planned. Current supplies to the US market are about 1 tcf/yr. Additional supplies of up to 1.05 tcf/yr are sought by some US consumers and Canadian producers but deliverability is hampered by pipeline extension slowdowns and a FERC ruling of May 1987. (WSJ, 1987; EMR,1987.) Nonetheless, there is at least 30%, and perhaps even 50% more capacity in the present pipeline system to deliver gas to consuming regions. Unit delivery costs of pipeline extensions appear to average about $0.30/mcf (OGJ, 1986b).

Underground storage is located both in producing states (e.g. old wells in the Gulf States) and in consuming regions (e.g. Illinois and California). These reservoirs are filled in the summer months at a relatively slow rate (100-300 bcf/mo) and then pumped at high rates (400-600 bcf/mo) in the 10-15 weeks of winter peak demand. About 2.1-2.2 tcf/yr is injected and withdrawn from underground storage. If summer demand increased by about

2-3 tcf/yr because of electric utility demand, there would still be adequate capacity in the gas supply and transmission system to replenish underground storage. (OGJ, 1986b).

7 Summary

The market for natural gas use in coal- and oil-fired power plants in the summer season to reduce pollutant emissions and control acid rain has the potential to grow. This use of natural gas will remove some of the slack in the gas market but will not cause a significant impact on the supply or price of natural gas. The availability of natural gas for residential use in winter will not be compromised by this demand. Natural gas markets and contracts have changed in the past several years. Changes in regulations have promoted greater numbers of transactions between producers and users of gas. The market behaves more and more like a commodity market with shorter term contracts and more spot market purchases. Gas sales to electric utilities compete directly with heavy oil. Competition between producers for additional sales further keeps prices for large users low and close to marginal cost. Continental reserves (economically recoverable reserves) of natural gas depend on the expected market price of gas. It is very likely that close to half of the historically recoverable gas reserve has been burnt already. The future resource base is likely to last at current rates of consumption (and at prices below those of backstop fuels) for more than thirty years.

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Appendix A

Energy Conversions and Units

Natural Gas:

Volumes reported are based on gas at 14.73 psia at 60 F.

The US DOE EIA uses the industry convention of 'MM' as an abbreviation for million and 'm' for thousand. e.g. MMBtu; mcf. Also, for billion cubic feet [$10^9 ft^3$], 'bcf' is used. For trillion cubic feet [$10^{12} ft^3$] the abbreviation, 'tcf' is used.

SI units are abbreviated as follows:

k	[kilo]	for	10^3
M	[mega]	for	10^6
G	[giga]	for	10^9
T	[tera]	for	10^{12}
Q	[quad]	for	10^{15}
E	[exa]	for	10^{18}.

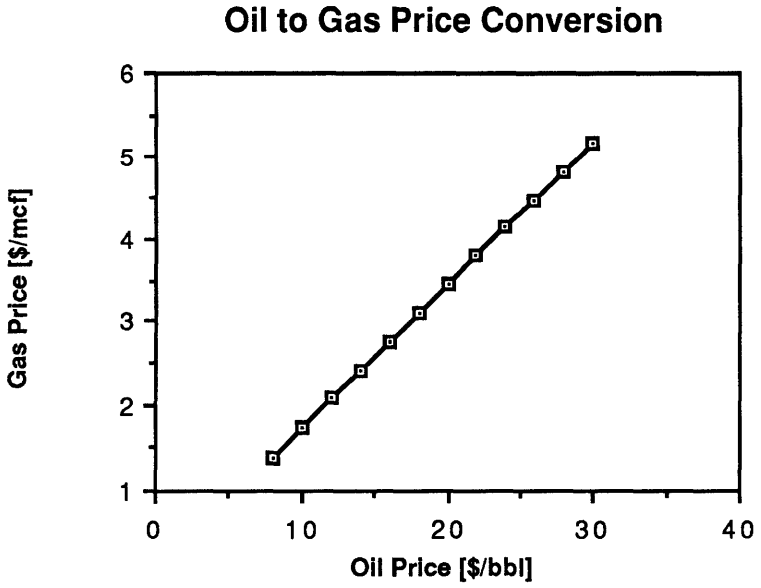
Energy Content of Natural Gas:

~1000 BTU/ft^3

37.3 MJ/m^3

Average heat content of natural gas sold to electric utilities in 1984: 1.03 x 10^6 BTU/ 10^3 ft^3 gas.

1 BTU = 252 calories = 1055 Joule = 2.93 x 10^{-4} kWh



Appendix B

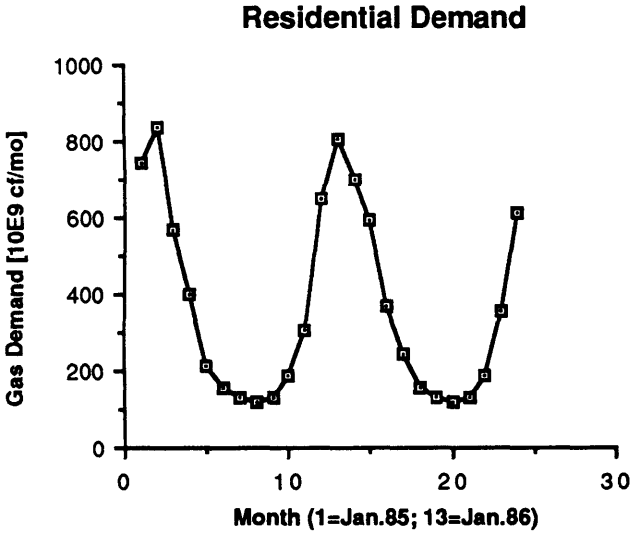
Comparison of Air Pollution Emissions of Standard Fossil Fuels[1]

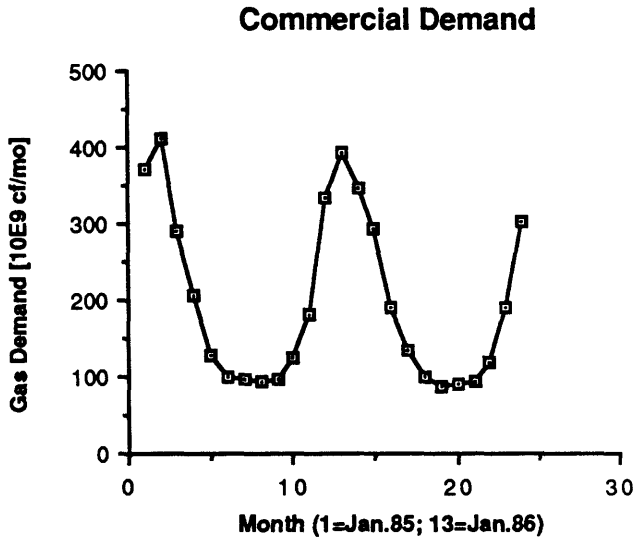
	Kilograms of uncrontrolled emissions per 10^9 Btu		
Air Pollutants	Gas	Oil[2]	Coal[3]
Sulfur Dioxide	0.5	1460	2600
Particulates	5	100	1200
Carbon Monoxide	9	14	14
Hydrocarbons	1	5	2
Nitrogen Oxides	100	180	400

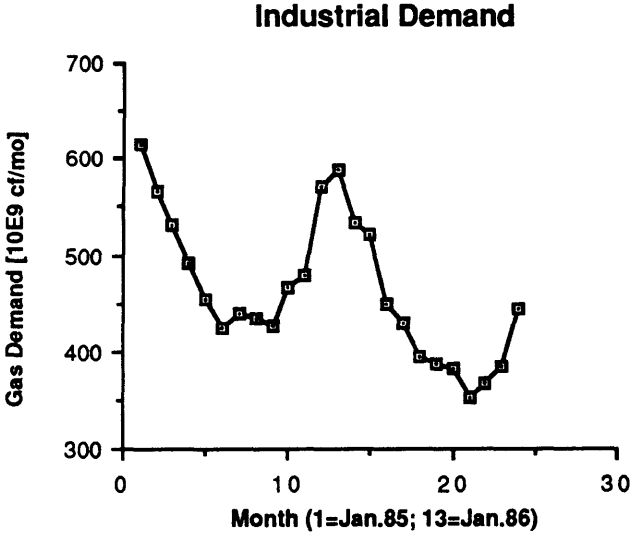
[1] Source: Based on data from Environmental Protection Agency and Natural Gas Association.
[2] About 3% sulfur by weight.
[3] About 3.6% sulfur by weight.

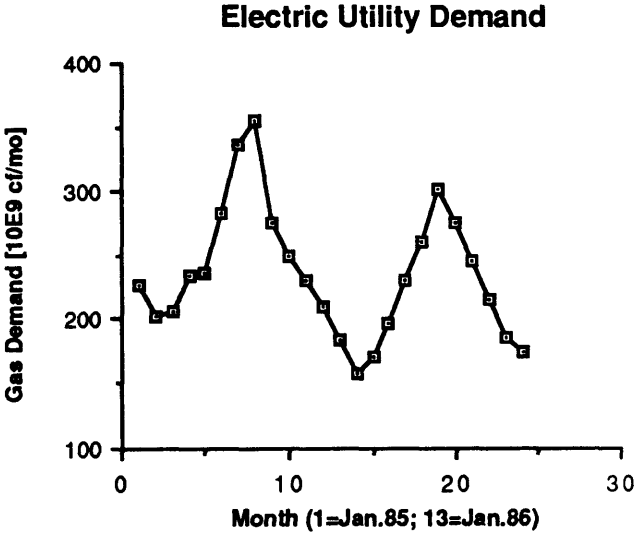
Appendix C

Comparison of Seasonal Natural Gas Demand by End-Use Sector









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Appendix "A"

Seasonal, Episodic and Targeted Control of Sulfate Deposition

Dan Golomb, James A. Fay and Subramanyam Kumar
Massachusetts Institute of Technology
Cambridge, Massachusetts

The large differences in seasonal rates of wet sulfate deposition observed at many receptors in eastern North America imply that reducing SO_2 emissions only in the summer half of the year (April–September) would bring about greater annual wet sulfate deposition reductions than reducing emissions by the same amount year-round. Targeting the emission reductions to those source areas which contribute the bulk of summer depositions in ecologically sensitive areas would increase further the gain factor, defined as the ratio of annual fractional deposition decrement to annual fractional emission decrement. In the northeastern U.S., between 10 and 15 rain episodes deposit about 60 percent of the annual wet sulfate; reducing emissions in the dry periods preceding these heavy deposition episodes could further increase the gain factor. However, it is difficult to predict these episodes, and they do not occur simultaneously over large regions of the country.

In order to reduce acid sulfate deposition, emissions of the precursor SO_2 need to be reduced. Two basic approaches to reducing emissions are distinguished: source-oriented and receptor-oriented. In a source-oriented approach, emissions are reduced in accordance with a source-related criterion; e.g., 1) a uniform emission cap for each source, such as 1.2 lb SO_2/MBtu; 2) a uniform emission cap at the state level, or some other geopolitical aggregation; 3) a uniform emission reduction below present emissions, at the state level; or 4) emission reduction at selected sources (such as the 50 largest emitters) to the maximum extent achievable by current emission control technology. In a receptor-oriented approach, a deposition target is chosen for a receptor in a particular ecologically sensitive area and emissions are reduced so as to reach the deposition target[1–5] while complying with other constraints, such as minimum cost. A receptor-oriented approach requires the availability of an atmospheric transport model. From the model one can determine the quantity of deposition at a receptor per unit emission from each source, called the transfer coefficient. Transfer coefficients will have different values depending upon the model averaging period: year, season, month, or individual precipitation episode.

Previous studies have assumed that emission reduction would occur year-round by use of flue gas scrubbing or fuel cleaning, or switching permanently to lower sulfur fuels. Noting that there is significant seasonal variation in wet sulfate deposition rates despite nearly equal seasonal emission rates, this paper investigates the potential of intermittent emission reduction for decreasing the annual amount of wet sulfate deposition. This strategic variant is considered as an addition to the source- and receptor-oriented alternatives previously mentioned. It is noted that reduction of summer emissions alone would be accompanied by a greater seasonal reduction in airborne sulfate with a concomitant improvement in visibility and reduction of human exposure to airborne particulate matter. Nevertheless, for the purpose of the current investigation, annual deposition amounts are used as the measure of emission control effectiveness.

First, the seasonal/episodic wet sulfate deposition patterns in eastern North America (ENA) are reviewed. Next, a previously described[6] long-range atmospheric model is adapted for analyzing case studies of targeted and seasonal control of sulfate deposition. Finally, it is shown that receptor-oriented approaches require less annual aggregate emission reductions than source-oriented approaches to achieve equal deposition reductions in ecologically sensitive areas.

Dr. Golomb is a research scientist, Prof. Fay is the environmental program director, and Dr. Kumar was a research assistant in the Energy Laboratory, Massachusetts Institute of Technology, Cambridge, MA 02139. Dr. Kumar's present address: Martin Marietta Environmental Systems, Columbia, MD 21045. This paper was submitted for peer review August 9, 1985; the revised manuscript was received December 23, 1985.

Annual Wet Sulfate Deposition Patterns

Wet sulfate deposition rates were obtained from monitoring sites throughout ENA, including the MAP3S, NADP and UAPSP networks in the U.S., and the APIOS, APN, and CANSAP networks in Canada.[7] At the MAP3S sites sampling was by event, at UAPSP and APN daily, NADP weekly, CANSAP daily (but composed monthly) and APIOS monthly. The data included the cumulative annual and trimonthly wet sulfate deposition and precipitation at each site. Data for the years 1980–82 at a total of 109 sites having a continuous record over the three years are analyzed.

Figure 1 presents the annual wet sulfate deposition rates in ENA as a function of the location of the monitoring site. The smaller numbers are the annual wet sulfate deposition measured at the sites of the monitoring networks mentioned above, averaged over the three years, 1980–82. Where two or more stations of the networks are clus-

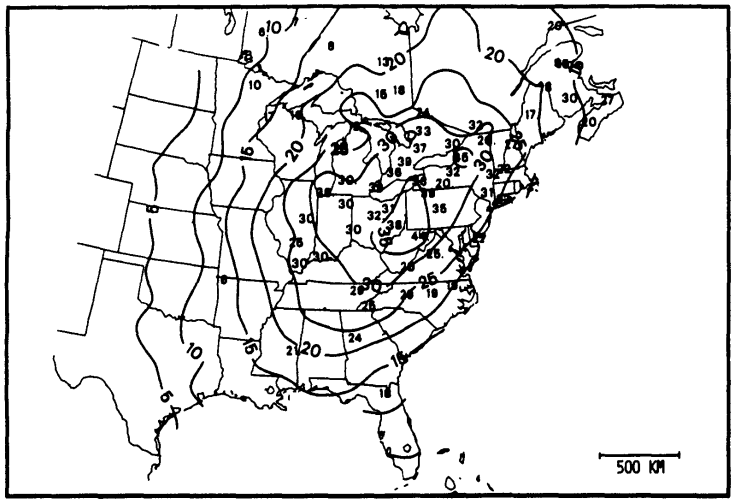

Figure 1. Annual average wet sulfate deposition in eastern N. America. Small numbers: measurements; contours (isopleths) with large numbers: model results (kg $SO_4^=$/ha yr).

tered, the average deposition at those stations is given in the figure. (The contours with the large numbers are modeling results, to be described later.) Largest annual deposition rates occur in the triangle formed by western Pennsylvania, eastern Ohio and northern West Virginia. Large annual depositions have also been measured north of Lake Erie, in Ontario. A particular "hot spot" occurs over the Buffalo region, probably because of the high annual rainfall there.

Seasonal Deposition Patterns

Seasonal patterns of wet sulfate deposition at three sites in the U.S. and one in Canada are shown in Figure 2. Each point represents a three-monthly cumulative deposition value (kg $SO_4^=$ per ha per three months) plotted by the middle month. It is seen that all sites receive maximum deposition doses in the summer months and minimum in winter. This is especially pronounced for the three northern sites. In 1982, the total annual sulfate deposition was significantly lower than in the previous years, but the summer peak is still noticeable.

Figure 3 provides a spatial overview of the seasonal deposition pattern in ENA. The ratio of the average midsummer (June–August) wet deposition rate to the average annual rate is plotted using spatial interpolation of the data from the 109 monitoring sites. The highest summer/annual ratio of 2 is found in the Ohio River valley. A broad band where the ratio is greater than 1.5 extends between Maine and Virginia westward to Wisconsin and Illinois. North of the Great Lakes in Canada and in the south-central U.S., the ratio appears to be about 1.0. However, in these regions there were few monitoring sites; therefore, this ratio is not accurately determined. The quantity of sulfate being deposited in precipitation is a function of the concentrations of airborne sulfate and the amount of precipitation. In the broad band in Figure 3 where the summer/annual mean deposition ratio is much larger than 1, airborne concentrations of sulfate tend to be higher in summer than in winter.[8]

A similar climatic analysis of precipitation chemistry was performed by Bowersox and Stensland.[9] They found that in much of the northeastern U.S. and southeastern Canada the ratio of warm season/cold season median sulfate concentration in precipitation is between 1.5 and 3. Rodhe and Granat,[10] analyzing the data from the European Air Chemistry Network, found that, on average, sulfate concentration in precipitation peaks between February and May, but wet deposition has its maximum in May to August, even though European SO_2 emissions are lower in summer.

Episodic Patterns

A high quality event monitoring network in operation, MAP3S,[11] is used for establishing episodic patterns. Data of nine MAP3S monitors over four years, 1979–82, are analyzed. Figure 4 shows a typical cumulative deposition curve at Brookhaven, NY, plotted in order of decreasing deposition per sample, not chronologically. There, on 27 July 1981, one event deposited 15 percent of the annual total, and nine events deposited a total of 60 percent. At the nine MAP3S sites, on the average, 10–15 episodes deposited 60 percent of the annual total wet sulfate. The events contributing to the 60th percentile are termed "heavy episodes." The smallest number of heavy episodes over the four-year period occurred at Urbana, IL (average 10 per year). At Brookhaven, NY, Lewes, DE, and Charlottesville, VA, there were 11 heavy episodes per year; at Oak Ridge, TN, Oxford, OH, and State College, PA, there were 13; and at Ithaca and Whiteface Mountain, NY, 15. As a rule, almost all of the heavy episodes occurred in the summer half of the year, from April through September. However, the heavy episodes did not occur simultaneously over large geographical regions. In the four-year period analyzed, only once (27–29 July 1982) did all nine MAP3S stations experience heavy episodes within a three-day span; usually only 2–4 stations reported heavy episodes within three days. A similar episodic pattern in western Europe was found by Smith and Hunt.[12] For example, at Cottered, England, in

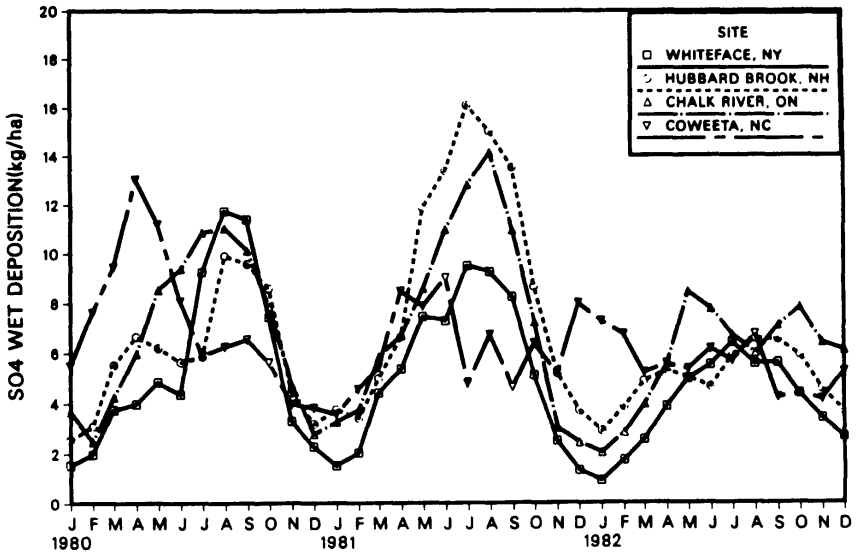

Figure 2. Three-monthly cumulative wet sulfate deposition plotted by middle month for 1980–82 at four sites (kg $SO_4^=$/ha per 3 months).

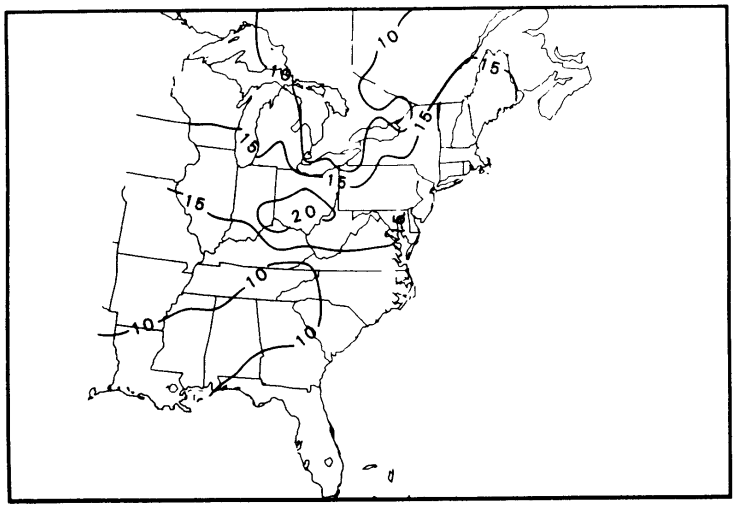

Figure 3. Ratio of summer (June–August) average wet sulfate deposition rate to annual average rate, 1980–82.

1974, about 30 percent of the annual deposition was brought down in five events.

Long-Range Transport Model

A long-range, annually and seasonally averaged sulfur transport model has been described in recent publications.[6,13] The model was optimized by using the data base of wet sulfate deposition described above. The annual and semiannual wet sulfate deposition was modeled at all sites for the three years 1980–82, the root mean square residual being 17–25 percent of the average deposition of all monitoring stations, depending on season.

Model Application

The long-range transport model is utilized to estimate deposition reductions that can be achieved at selected receptors by reducing precursor emissions at the sources, year-round or seasonally. The algorithm used for estimating annual emission/deposition relationship is:

$$(D_j)_{AN} = \sum_i (T_{ij}Q_i)_{AN}$$

$$= \sum_i (T_{ij}Q_i)_{SU} + \sum_i (T_{ij}Q_i)_{WI} \qquad (1)$$

where $(D_j)_{AN}$ is the annual amount of wet sulfate deposition (measured as mass of sulfur per unit area) at receptor j, T_{ij} is the transfer coefficient from source i to receptor j (mass of sulfur deposited per unit area per unit mass sulfur emitted), and Q_i is the emission amount of sulfur at source i. The summation of the products $T_{ij}Q_i$ are taken for annual (AN), summer (SU) and winter (WI) periods, respectively.

In evaluating deposition reduction options, it is assumed that the transfer coefficients derived from the 1980–82 data base will remain constant in future years even though the emission rates may change appreciably. It has been argued that the first order rate constant for conversion of SO_2 to $SO_4^=$ (one of the model parameters) may not be independent of the precursor SO_2 concentration; thus, large variations of Q_i might cause a change in T_{ij}. However, the 1980–82 comparisons of measured with modeled sulfate depositions showed no dependency of residuals on deposition rate, which varied by a factor of 8:1 throughout the network. We conclude, as did the National Research Council,[14] that current measurements show no evidence of nonlinear effects within the range of the spatial variation of pollutant concentrations. Further support for the absence of nonlinear effects is the comparison[6] of modeled sulfate concentrations at Hubbard Brook, NH, with observations for the years 1964–81. While year-to-year observed variations are greater than those of the model, the overall time trend was successfully replicated by the model, lending confidence that the three-year period 1980–82 is representative of meteorological conditions over a longer time span.

For source-oriented strategies, Equation 1 is used directly since source strengths are specified. For receptor-oriented strategies, linear programming is required to attain a specified deposition level. In the cases considered below we shall use both methods.

The efficacy of each case is evaluated in terms of a gain factor defined as

$$GF = \Delta D/\Delta E \qquad (2)$$

where ΔD is the decrement of annual wet sulfate deposition in percent below 1980–82 levels at an Adirondack, NY, receptor, and ΔE is the decrement of annual emissions in percent below 1980 levels in all 31 states east of or bordering on the Mississippi River plus the District of Columbia. (No reduction of Canada emissions is considered in any case.) The defined gain factor is specific to the Adirondack receptor. Clearly, a different gain factor would be obtained for another receptor even with the same emission reduction. The following case analyses are meant to be illustrative, without attributing special status to the Adirondacks. However, in view of the long-range transport aspects of sulfur, comparable gain factors would be obtained for receptors within a broad region encompassing northern New England, southeastern Ontario and southwestern Quebec.

Case 1: The Mitchell Bill (Source-Oriented Approach)

We examine the consequences of the emission reductions specified in a bill introduced by Senator Mitchell in the 1982 U.S. Congress (S.1706), and subsequently reintroduced in 1983 and 1984. The bill called for reducing SO_2 emissions by 9.1 million metric tons per

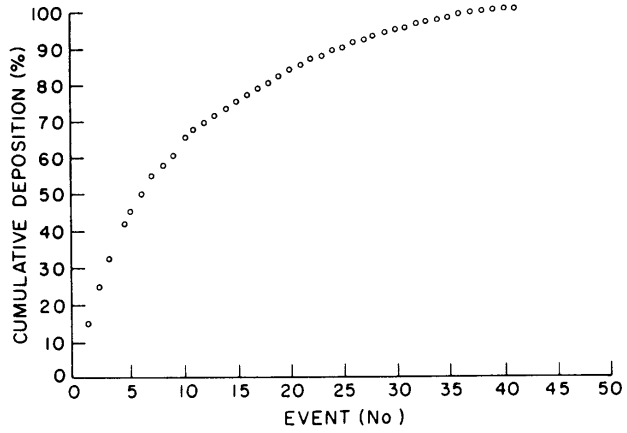

Figure 4. Cumulative wet sulfate deposition (percent) by event (No.) at Brookhaven, NY, 1981, plotted in decreasing order of deposition amount, not chronologically.

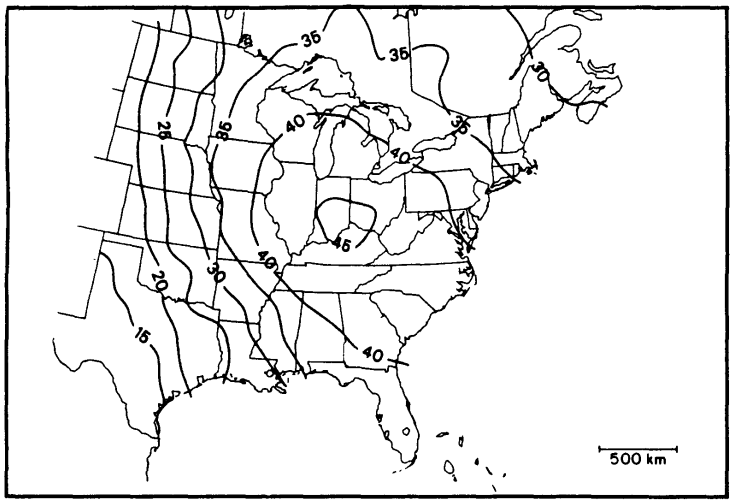

Figure 5. Modeled deposition reductions (percent below 1980 levels) which would result from the Mitchell bill emission reductions.

year in 31 states east of or bordering on the Mississippi River plus the District of Columbia. Since the 1980 annual emission rate of these sources was about 20 million tons, a 45 percent reduction would be needed. In this source-oriented approach, emission reduction quotas would be allocated to the states on the basis of their 1980 average emissions per unit of heat value.

The 1980 yearly emission rates[15] are listed in Table I, as well as the percent reductions that would be required by the bill.[16] Using the emission reductions in each state, and the annual transfer coefficients, the fractional deposition reductions are estimated at receptors throughout ENA. Figure 5 shows contours of the percent reduction of deposition resulting from the emission reduction requirements of the Mitchell bill. It is seen that in the high emission states of Ohio, Indiana and Kentucky the deposition reduction would be 45 percent, but in the ecologically sensitive Adirondacks the deposition reduction amounts to about 35 percent. Thus, the Adirondack gain factor as defined above is 0.78.

Table I. Sulfur dioxide emissions in 1980 in 31 eastern states and D.C., and required emission reduction (percent below 1980) for three cases achieving 35 percent deposition reduction in the Adirondacks, N.Y.

State	Emissions (kT/y)	Case 1 (Mitchell) (%)	Case 2 (Targeted) (%)	Case 3 (Seasonal-Targeted) (%)
AL	745	37	0	0
AR	106	5	0	0
CT	56	0	0	0
DE	98	19	34	23
DC	17	0	0	0
FL	1005	37	0	0
GA	882	54	19	14
IL	1250	50	24	15
IN	1672	57	54	37
IA	293	38	0	0
KY	1030	63	52	36
LA	354	0	0	0
ME	120	3	0	0
MD	268	33	51	35
MA	309	22	41	31
MI	807	26	16	11
MN	214	23	0	0
MS	261	37	0	0
MO	1160	68	26	17
NH	89	46	68	46
NJ	277	11	32	20
NY	941	21	54	36
NC	593	14	0	0
OH	2471	58	66	44
PA	1775	41	65	44
RI	9	0	0	5
SC	300	31	7	5
TN	997	63	39	27
VA	326	28	6	4
VT	7	0	0	0
WV	1030	53	52	36
WI	581	50	22	14
Total	20043			
Emission reduction (kT/y)		9000	7160	4900
Emission reduction (percent below 1980 eastern U.S. total)		45	36	24

Case 2: Targeted Deposition Reduction (Receptor-Oriented Approach)

In this case we assume that the desired deposition reduction in the Adirondacks is 35 percent, to match the Mitchell bill, but emission reductions are to be levied year round on states according to the following criteria: (a) no state is allowed to exceed 1980 emissions, and (b) each state contributes equal deposition at the target area per Btu burned at the source. The state-level emission reductions needed to satisfy these requirements are listed in Table I. The requisite aggregate annual emission reduction in all 31 states is 36 percent and the corresponding gain factor is 0.97.

Case 3: Seasonal-Targeted Deposition Reduction (Receptor-Oriented Approach)

We next assume emissions to be reduced in summer (April–September) only, so as to match the Mitchell bill annual deposition reduction of 35 percent in the Adirondacks. The emission reductions are allocated to the states according to the same criteria as in Case 2. The resulting required (annual) emission reductions by states are also listed in Table I. They amount to 24 percent of the 31 state annual total, giving a gain factor of 1.46.

Case 4: Seasonal Uniform Emission Reduction (Source-Oriented Approach)

As another example, we assume that all states uniformly reduce their summer (April–September) emissions by 50 percent, regardless of emissions per unit fuel heat value. This is an example of a source-oriented approach because emissions are reduced regardless of the source's location with respect to a sensitive receptor. However, this approach does take cognizance of the greater effectiveness of summer emission reductions. Assuming that summer and winter emissions are equal, the 31 states' annual emission reduction would be 25 percent. The modeled deposition reduction in the Adirondacks is 28 per-

Table II. Comparison of sulfate deposition control approaches.

Case	Approach	Reductions in 31 states (% below 1980 levels)	Deposition reduction in Adirondacks (% below 1980 levels)	Gain factor
1	Mitchell	45	35	0.78
2	Targeted	36	35	0.97
3	Seasonal-targeted	24	35	1.46
4	Seasonal-uniform	25	28	1.12

cent and the gain factor is 1.12.

Episodic Emission Control

Potentially, the largest gain factors could be obtained if emissions were reduced such as to prevent heavy deposition episodes. The long-range, long-term averaged sulfur transport model[6] is not suitable for estimating deposition reductions that could be achieved by episodic (intermittent) emission reductions. Trajectory models currently being developed may be applicable for episodic control. Most likely, emissions would have to be reduced during the dry periods preceding the heavy deposition episodes described previously. However, the heavy episodes do not occur simultaneously over large geographic areas. So, the problem becomes one of (a) identifying and forecasting the meteorological conditions that precede the heavy episodes; (b) identifying the source areas where emissions need to be reduced to prevent heavy episodes at the sensitive receptors. Validated episodic models would be required to quantify the gain factors of episodic control.

Discussion and Conclusions

The examples given demonstrate that lesser aggregate emission reductions would be required in receptor-oriented approaches (targeted and seasonal-targeted) than in source-oriented approaches to achieve the same deposition reduction at sensitive receptors. For comparing the efficacy of the various approaches, a gain factor specific to the Adirondacks was determined, which is summarized in Table II. Comparable gain factors would apply for nearby sensitive receptors, such as northern New England and southeastern Canada. However, for more distant receptors the emission reduction allocation and gain factors would be different. It is also emphasized that although aggregate emission reductions may be less in receptor-oriented approaches than in source-oriented approaches, these reductions may be greater for some sources and during the summer months.

While it may be expected that lesser emission reductions also mean lower costs, detailed economic analyses need to be performed to estimate individual source, state and national costs. Using the transfer matrices of six long-range sulfur transport models, Streets *et al.*[5] concluded that for equal deposition reductions in the Adirondacks, a targeted approach may be less expensive on the national level than a "nonoptimized" (source-oriented) emission reduction. In this paper, we suggest further potentially cost-saving approaches: seasonal and episodic control. Year-round emission control may include physical coal cleaning, low-sulfur coal substitution and flue-gas desulfurization (scrubbers). Seasonal and episodic control may place an increasing role on fuel substitution, including natural gas. The price differential between high-sulfur coal and natural gas is at present appreciable, but if used for a limited time during the year, the cost of achieving a targeted deposition reduction by natural gas substitution may be less than installation and year-round operation of control technology. Furthermore, at present, in many states, there appears to be a surplus of natural gas in the summer months because of its primary use for space heating in the winter months. This makes gas-for-coal summer substitution an attractive option for controlling wet sulfate deposition.

Acknowledgments

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Controlling Acid Deposition by Seasonal Gas Substitution in Coal- and Oil-Fired Power Plants

Gary Galeucia, Dan Golomb, and James A. Fay

Massachusetts Institute of Technology, Cambridge, MA 02139

Based on evidence that the rate of wet sulfate deposition in eastern North America is higher in the summer half of the year than in the winter half, seasonal control of emissions is proposed as a means of minimizing acid deposition control costs. This paper evaluates the proposal that natural gas be substituted for coal and oil in electric power plants during April through September. A model is presented that simulates the substitution of natural gas for coal and oil in power plants in the eastern 31 state region, so as to minimize total costs with respect to deposition reductions at an Adirondack receptor. The results of the model show: 1) the increased effectiveness of seasonal versus year-round controls; 2) changes in fuel consumption levels as a result of substitution; and 3) the costs of achieving various levels of deposition reduction at an Adirondack receptor. The costs of seasonal gas substitution are compared to cost estimates for other proposed control methods. The conclusion is that seasonal gas substitution is cost-competitive with other control methods, at least in some plants and states.

Recently, several proposals have been advanced that move away from broad-based reduction of acid rain precursor emissions toward more efficient policies that recognize the *spatial relationship* between emission sources and the areas sensitive to the acid deposition caused by these emissions [*1-4*]. This paper proposes that acid rain policy should step beyond the spatial relationship toward a recognition of the *temporal relationship* between emissions and depositions; namely, that there are significant seasonal variations in deposition rates despite a relatively constant rate of emissions. Just as it is more efficient to exert greater control of emissions from sources that are relatively close to sensitive areas, it is also more efficient to impose greater control of emissions at times when the deposition rates are highest.

Recent work in atmospheric modeling has shown that differences in seasonal rates of sulfate deposition create the opportunity for seasonal control of sulfur emissions as a more efficient means of reducing annual amounts of sulfate deposition [*4*]. By electing to reduce SO_2 emissions in the summer half of the year, there would result a larger reduction of annual deposition per ton of SO_2 removed than if the same quantity were removed year-round. It may prove to be less expensive to reduce deposition by controlling emissions in the summer half of the year, rather than year-round.

To evaluate this new strategy, seasonal substitution of natural gas for coal and oil in electric utility boilers during April through September is investigated. A model is presented that simulates the substitution of natural gas for coal and oil so as to minimize the cost of achieving various deposition reductions. The model is static in that it simulates reductions for a single year: 1983. It uses the actual price and consumption of coal, oil, and gas for that year. The model is concerned with emissions of sulfur dioxide (SO_2) from electric utilities in the 31 eastern states and the District of Columbia (D.C.) as well as the resulting wet deposition of sulfate (SO_4) at a single receptor in the Adirondack Mountains of New York. The results of the model exercise show: 1) the increased effectiveness of seasonal versus annual sulfur emission reductions, and 2) the cost of seasonal gas substitution. The cost, in terms of emission and deposition reductions achieved, is compared to cost estimates for other proposed control methods and strategies. An example is given for calculating the cost of deposition reduction for a source oriented strategy, to which the cost of a receptor oriented strategy ' easonal gas substitution can be fairly compared. The conclusion of the cost comparison is that seasonal gas substitution is cost competitive with the year-round control strategies, at least for some plants in some states.

The model does not consider in depth two important

factors: 1) the availability of gas supply, and 2) the capital cost for seasonal gas substitution. These factors are discussed briefly, with the conclusions that there may be restrictive limits to gas supply and deliverability, and that capital costs for seasonal gas substitution are probably very low relative to control methods such as flue gas desulfurization.

SEASONAL VARIATION IN DEPOSITION RATES

Analysis of several years of precipitation chemistry data has established that wet sulfate deposition rates in the northeastern U.S. and southeastern Canada are higher in the summer months (April-September) than in the winter months (October-Month) [4-5]. Figure 1 shows the seasonal patterns of sulfate deposition over three years at four receptors. Seasonal differences in sulfate deposition are evident.

The exact causes of the differences in seasonal deposition patterns are not well understood; they are probably linked to the faster conversion rate in summer of the presursor SO_2 emissions to the deposited SO_4 (sulfate) and to the seasonal storm tracks. Raynor and Hayes [6] observed that sulfate (and hydrogen) ion concentrations are highest in precipitation associated with cold fronts and squall lines, which occur most frequently in the summer months. The quantity of sulfate being deposited in a storm is a function of the previous trajectory of the polluted warm, moist air mass and the amount of precipitation in the storm. In winter, more of the unoxidized SO_2 is blown offshore and hence does not fall on the land as acid wet sulfate.

Although the chain of processes from emission of pollutants to eventual deposition of acid and acid-producing substances is complex and not fully understood, all evidence points to a linear relationship between emissions and deposition. Current scientific understanding indicates that reducing sulfur dioxide emissions would proportionally reduce the deposition of sulfate. The contribution of individual sources to the deposition at a given receptor may be estimated by means of atmospheric transport models.

ATMOSPHERIC TRANSPORT MODEL

The seasonal gas substitution model utilizes an atmospheric transport model for determining deposition effects of emission reduction [4, 7]. The model is empirically based in that the model parameters are determined from comparison with wet deposition measurements. The acid deposition model provides transfer coefficients that define the quantity of deposition at a receptor per unit of emission at a source. Transfer coefficients have been obtained for both annual and seasonal (summer/winter) periods [8]. The seasonal gas substitution model uses the summer transfer coefficients to relate deposition reductions at an Adirondack receptor to emissions reductions resulting from natural gas substitution. Table 1 lists the values of the seasonal transfer coefficients between the 31 eastern states plus D.C. and an Adirondack receptor. Table 1 shows that the summer transfer coefficients are about 2 to 3 times as large as the winter ones. In other words, summer emissions from the 31 eastern states cause nearly 2 to 3 times the deposition at an Adirondack receptor as an equal quantity of winter emissions.

Because the transfer coefficient T_{ij} is the ratio of the amount of deposition at receptor j contributed by source i divided by the emission amount from source i, the total deposition D_j at receptor j equals the sum of the products of the transfer coefficient T_{ij} times the emission Q_i:

$$D_j = \sum_i T_{ij} Q_i \qquad (1)$$

When seasonal transfer coefficients are used, the annual (A) deposition is obtained by summing separately the products of the seasonal transfer coefficients T_{ij} and emissions Q_i for summer (S) April-September and winter (W) October-March:

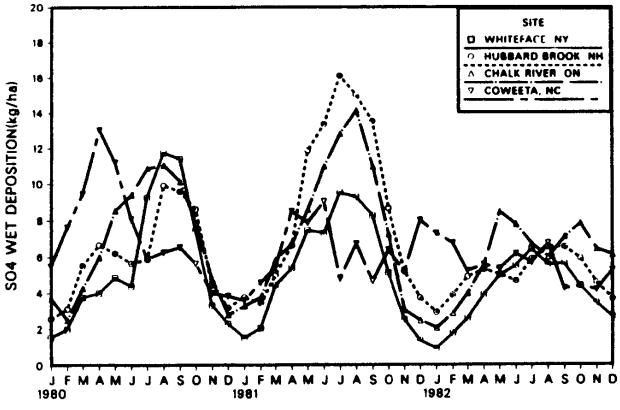

Figure 1. Seasonal patterns of wet sulfate deposition at four receptors in eastern North America. Three-monthly cumulative deposition (kg SO_4 per hectare, per three months) plotted by middle month. Except in Coweeta, NC, 70 to 80% of the annual deposition occurs between April through September. In 1982, the annual wet deposition was low everywhere, but the seasonal pattern still is noticeable.

TABLE 1. SEASONAL TRANSFER COEFFICIENTS FOR ADIRONDACK RECEPTOR
(kilograms sulfur per hectare wet-deposited per teragram sulfur emitted)

State	Winter	Summer
AL	0.2579	0.5908
AR	0.1742	0.3627
CT	0.7903	1.8720
DC	0.6007	1.6180
DE	0.6274	1.6360
FL	0.2300	0.4323
GA	0.2988	0.6938
IL	0.2805	0.7104
IN	0.3117	0.8085
IA	0.1852	0.4153
KY	0.3356	0.8671
LA	0.1650	0.3120
MA	0.7230	1.6480
MD	0.6287	1.6780
ME	0.5225	1.0410
MI	0.4045	1.0980
MN	0.1373	0.2772
MS	0.2068	0.4390
MO	0.2033	0.4641
NC	0.4397	1.1200
NH	0.8752	1.7890
NJ	0.7373	1.8810
NY	0.9127	2.1840
OH	0.4641	1.2940
PA	0.6339	1.7750
RI	0.7230	1.6480
SC	0.3486	0.8223
TN	0.3027	0.7463
VA	0.5310	1.4130
VT	1.2950	2.6180
WV	0.4979	1.3710
WI	0.2500	0.6106

Source: [8].

$$(D_j)_A = \left(\sum_i T_{ij} Q_i \right)_S + \left(\sum_i T_{ij} Q_i \right)_W \qquad (2)$$

By selecting a desired annual deposition quantity, the allowable level of emissions may be determined, which in turn determines the amount of gas substitution necessary to reach the reduced emission levels.

SO_2 Emissions: Most legislative proposals to date have focused on a 31 state region encompassing the states east of, and bordering on, the Mississippi River. Of the 26 to 27 million tons* of sulfur dioxide emitted in the continental United States in 1980, about 22 million tons came from the 31 state region [*10*]. Table 2 lists 1983 emissions of SO_2 attributable to the burning of coal and residual oil in electric power plant boilers in the 31 eastern states and D.C. The electric utilities included in this analysis are estimated to have contributed 16 million tons of SO_2 emissions in 1983. Emissions were calculated from annual electric utility coal and oil consumption data [9], neglecting any sulfur removal processes that have been used in that year. These emissions are used by the model for calculating deposition reductions at an Adirondack receptor.

Since sulfur emission rates in most states are fairly constant throughout the year [*10*], the model assumes that fuel consumption during April through September is equal to one-half of the annual fuel consumption.

TABLE 2. ANNUAL SULFUR EMISSIONS FROM COAL- AND OIL-FIRED POWER PLANTS IN THE 31 EASTERN STATES AND D C., 1983

State	Million Tons SO_2		
	Coal	Oil	Total
AL	0.536	0	0.536
AR	0.070	0	0.070
CT	0	0.054	0.054
DC	0	0.001	0.001
DE	0.060	0.016	0.076
FL	0.458	0.213	0.671
GA	0.843	0	0.843
IA	0.197	0	0.197
IL	1.210	0.010	1.220
IN	1.534	0	1.534
KY	1.225	0	1.225
LA	0.032	0	0.032
MA	0.077	0.149	0.226
MD	0.197	0.015	0.212
ME	0	0.011	0.011
MI	0.606	0.001	0.607
MN	0.157	0	0.157
MO	1.218	0.002	1.220
MS	0.091	0	0.091
NC	0.367	0	0.367
NH	0.512	0.017	0.068
NJ	0.088	0.016	0.104
NY	0.230	0.229	0.460
OH	2.071	0	2.071
PA	1.583	0.033	1.616
RI	0	0.002	0.002
SC	0.182	0	0.182
TN	0.674	0	0.674
VA	0.123	0.006	0.130
WI	0.456	0	0.456
WV	1.007	0	1.007
TOTAL	15.346	0.777	16.123

Calculated from [9].

*Tons are reported here in English units. 1 short ton = 0.907 tons metric.

TABLE 3 SUMMER AND ANNUAL SULFUR DEPOSITION CONTRIBUTED BY POWER PLANTS IN THE 31 EASTERN STATES AND D.C IN 1983 (kilograms sulfur per hectare per year)

State	Summer Deposition		Annual Deposition	
	Coal	Oil	Coal	Oil
AL	0.071	0	0.098	0
AR	0.006	0	0.008	0
CT	0	0.023	0	0.029
DC	0	0.001	0	0.001
DE	0.022	0.006	0.028	0.007
FL	0.044	0.021	0.068	0.032
GA	0.132	0	0.179	0
IA	0.018	0	0.026	0
IL	0.193	0.001	0.256	0.002
IN	0.279	0	0.362	0
KY	0.239	0	0.309	0
LA	0.002	0	0.003	0
MA	0.029	0.055	0.038	0.073
MD	0.074	0.006	0.091	0.007
ME	0	0.003	0	0.004
MI	0.150	0	0.188	0
MN	0.010	0	0.015	0
MO	0.127	0	0.178	0
MS	0.009	0	0.012	0
NC	0.092	0	0.119	0
NH	0.021	0.007	0.028	0.009
NJ	0.037	0.007	0.046	0.008
NY	0.113	0.113	0.141	0.141
OH	0.603	0	0.738	0
PA	0.632	0.013	0.756	0.016
RI	0	0.001	0	0.001
SC	0.034	0	0.045	0
TN	0.113	0	0.150	0
VA	0.039	0.002	0.049	0.003
WI	0.063	0	0.085	0
WV	0.311	0	0.381	0
TOTALS	3.464	0.258	4.401	0.333

Wet Sulfate Deposition: The amount of wet sulfate deposition at a receptor can be linearly related to the amount of sulfur emissions from sources as in Eq. (2). Total 1980 annual wet sulfate deposition from all U.S. and Canada sulfur sources at an Adirondack receptor was estimated to be 27.5 kilograms sulfate per hectare per year (kg SO_4 $ha^{-1}y^{-1}$) [7]. Table 3 contains the 1983 summer and annual deposition amounts at an Adirondack receptor calculated to have been contributed by the sources included in this analysis. (Note: It is necessary to multiply the figures in Table 3 by a factor of three in order to convert sulfur (S) to sulfate (SO_4). SO_4 is three times the molecular weight of S.) We calculate that electric utilities in the eastern 31 states in 1983 contributed 14.2 kg SO_4 ha^{-1} to an Adirondack receptor, or 52% of the 1980 base amount. Of the 14.2 kg annual total, about 80% is calculated to be deposited between April and October. Summer deposition is disproportionately higher because the summer transfer coefficients are much larger than the winter ones (see Table 1).

WHY NATURAL GAS?

Annual depositions can be reduced more easily by substituting lower sulfur fuels for higher sulfur fuels during periods with higher deposition rates. This paper evaluates the annual wet sulfate deposition reduction that would result from substituting natural gas for coal ! residual oil in utility boilers during the "summer" season, April through September.

Natural gas was chosen as a substitute fuel because it produces virtually no sulfur dioxide and can be readily burned in most oil- or coal-fired boilers. Seasonal gas sub-

stitution allows a continued utilization of existing coal resources in the winter half of the year, while requiring increased utilization of natural gas during the summer half of the year.

Important factors to be considered in seasonal natural gas substitution strategies include:

1. In the summer months there is currently excess capacity in the natural gas distribution system. According to Wilkinson [*11*], only 78% of the pipeline capacity is used in the summer months, and in some regions as little as 51%. (Summer gas supply and deliverability will be discussed later in this paper.)
2. Seasonal gas substitution could be implemented rapidly relative to the period needed to install flue gas desulfurization systems or develop new "clean burning" technology for a large number of plants. A quick implementation schedule would allay fears that further delays in reducing acid deposition might cause irreparable damage to the environment.

Additional benefits, beyond lower sulfate deposition, from seasonal gas substitution include:

1. Improved local air quality with lower ambient air concentrations of SO_2 and particulates during the summer months, when the highest levels usually are encountered.
2. Improved summertime visibility.
3. Increased potential for achieving attainment of air quality standards for SO_2 in non-attainment areas.
4. Decreased dependence upon imported oil.
5. Reduced sensitivity to fuel supply disruptions, e.g., coal strikes or oil embargos.
6. Increased reliance on domestic energy resources.
7. Decreased land requirements and cost for scrubber sludge and flyash disposal.

Natural gas has never been a favored utility boiler fuel in most parts of the eastern U.S., accounting for only about 10% of the total fuel heat consumed by electric utilities in the eastern 31 states [*12*]. The primary reason for this pattern of usage is that natural gas is a more expensive boiler fuel than is coal. This reason is certainly a viable one. There are two less viable reasons why natural gas may continue to be disfavored as a boiler fuel. The first concerns the perception that gas reserves are imminently exhaustible; the second is that gas use in utilities is legally constrained.

A reasonable estimate for the amount of the remaining conventional natural gas in the lower 48 of the United States that is recoverable under present and easily foreseeable technological and economic conditions is 12 to 25 $\times 10^{12}$ m^3 (430 to 900 trillion cubic feet [Tcf]), as of December 1982 [*12*]. (This resource estimate does not include Alaskan, Canadian, Mexican, or unconventional resources.) At a consumption rate of 20 Tcf per year, slightly higher than present consumption, the resource estimated above will last 21 to 45 years. One explanation for the perception of imminent exhaustibility is that in the 1970s, gas demand exceeded gas supply as a result of price controls on natural gas. The market disequilibrium created the image that we are running out of gas.

The perception of imminent exhaustibility led policymakers to restrict gas use, which in turn has created the second misconception, namely that gas use is restricted. Restrictions on gas use in electric utility power plants were enacted when the federal Powerplant and Industrial Fuel Use Act (PIFUA) of 1978 was signed into law on November 9, 1978. However, PIFUA restrictions were sharply repealed by the Omnibus Budget Reconciliation Act signed into law on August 13, 1981. Since the 1981 amendment, PIFUA restrictions on natural gas use do not apply to "existing" power plants at all. A power plant is "existing" if it was in service or under construction prior to November 9, 1978 [*13*]. Furthermore, exemptions are available to post-1978 power plants. Pre-1978 power plants contribute the bulk of total SO_2 emissions because 1) most generating units were built prior to 1978, and 2) older plants are subject to less restrictive pollution control regulations.*

THE SEASONAL GAS SUBSTITUTION MODEL

A model for evaluating the effects of seasonal gas substitution includes components for calculating sulfur emissions reductions, wet sulfate deposition reductions, changes in fuel consumption, and incremental expenditures for fuel purchases. The model's SO_2 emission sources are 376 utility plants burning coal or residual oil as a primary boiler fuel in the eastern 31 states and Washington, D.C. The criteria for including a plant in the model are that it have a rated capacity of 50 megawatts or larger, and at least 10% of the total heat has to be generated from either coal or oil. A complete description of the model, including the list of the 376 power plants and their fuel usage, is given by Galeucia [*14*]. Here we briefly summarize the model and its results.

The seasonal gas substitution model is a linear program (LP) that seeks to minimize the incremental spending on fuel purchases when natural gas is substituted for coal or oil. For each electric power plant i, there is a cost differential between a given heat content of gas and coal or gas and oil. Multiplying this cost differential by the quantity of heat required gives the incremental spending on fuel purchases by the power plant.

Minimization of the incremental spending for natural gas substitution is performed subject to two constraints. The first specifies the desired level of deposition, as has already been described above by Eq. (2). The second constraint requires that the same fuel heat value is consumed by each power plant under the gas substitution strategy as was actually required when no substitution occurred. The heat consumption of each source is equal to the heat content multiplied by the quantity of coal, oil, or gas consumed. Actual heat output was determined from fuel heat content and consumption data [9].

The LP model in its functional form seeks to minimize the sum of the products:

$$\text{MIN} \sum_i F_i G_i H^g \tag{3}$$

subject to:

$$D_A = \left(\sum_i T_{ij} Q_i \right)_S + \left(\sum_i T_{ij} Q_i \right)_W \tag{4}$$

$$G_i H^g = C_i H^c + O_i H^o \tag{5}$$

where the symbols are:

- C_i = quantity of coal displaced at power plant i
- D_A = annual target seasonal deposition quantity for a specified receptor
- F_i = fuel cost differential between gas and coal or gas and oil per unit of heating value
- G_i = quantity of natural gas substituted seasonally for coal or oil
- H^c = unit heating value of coal
- H^g = unit heating value of natural gas
- H^o = unit heating value of oil
- O_i = quantity of oil displaced

The Adirondacks receptor is used in the model because it is environmentally sensitive and centrally located with respect to other environmentally sensitive areas in the U.S. and Canada. By adding additional deposition constraints, the model could be made to consider more than

*Note added in proof: In 1987, Congress amended PIFUA. Public Law 100-42 essentially removes all legal constraints on gas use in existing utility boilers and industrial facilities.

one receptor. This would require the use of a set of transfer coefficients for each additional receptor. For simplicity of presentation, the model has been limited to a single receptor.

CALCULATING THE COST OF SEASONAL GAS SUBSTITUTION

Incremental spending on fuel purchases of natural gas by utilities is assumed to equal the product of the incremental quantity of natural gas consumed at a power plant as a result of substitution, the gas fuel heating value, and the cost differential per unit of heating value between gas and coal, or gas and oil, summed for all power plants (Eq. 3). It should be noted that the costs derived here for seasonal gas substitution are solely the result of the fuel price differentials between gas and coal or oil. Preliminary estimates of the incremental capital and operating costs associated with seasonal gas substitution indicate that the fuel price differential is by far the major cost.

The coal and oil prices used in the analysis are actual average prices per unit heating value paid by each power plant in 1983 [9]. The gas prices used are the state-average price paid by electric utilities in that state (Table 4). If no electric utility burned gas in a state, then the average price paid by industrial consumers was used [15]. From the gas prices listed in Table 4, it can be seen that prices vary significantly from state to state. The actual coal and oil prices, as well as the state-average gas prices, are not necessarily indicative of current and future prices, and therefore of price differentials, for these fuels. A fall in oil prices, which are dependent on the world market, could be expected to produce a decrease in natural gas prices because the two fuels are to some extent interchangeable. Coal prices are affected to a greater extent by production costs, and to a lesser extent by the prices of oil and gas because these fuels are not close substitutes. Hence, a fall in oil prices and a subsequent fall in gas prices should be accompanied by a relatively smaller decrease in coal prices. The result is that in a period of lower oil prices, a smaller price differential between gas and coal could be expected.

TABLE 4. AVERAGE COST OF NATURAL GAS AT ELECTRIC UTILITIES IN THE 31 EASTERN STATES AND D.C., 1983$

State	$/10⁶ Btu
AL	3.129
AR	3.211
CT	5.930(b)
DE	4.180
DC	4.480(a)
FL	2.529
GA	4.177
IL	5.291
IN	4.238
IA	3.747
KY	4.551
LA	3.150
MA	3.887
MD	4.480(a)
ME	7.660(b)
MI	4.388
MN	3.798
MS	3.325
MO	4.164
NC	4.860(a)
NH	6.000
NJ	4.046
NY	3.932
OH	5.169
PA	5.104
RI	3.753
SC	4.285
TN	3.870(a)
VT	4.220(a)
VA	4.202
WI	4.284
WV	4.546

(a) Average prices calculated from data reported on Form EIA-176.
(b) Average 1983 price paid by industrial consumers.
Sources: [9, 15].

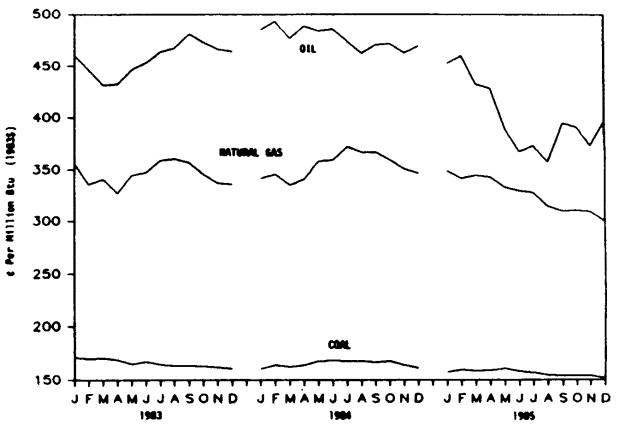

Figure 2. Average cost of fuel at U.S. electric power plants in 1983-85 (1 Btu = 1.055 kJ).

To test this hypothesis informally, it is useful to look at gas, coal, and oil prices and price differentials over time (Figure 2). Prices were adjusted to 1983 dollars using the U.S. Bureau of Labor Statistics producer index for crude energy materials. During the period 1983 to 1985, the price of oil rose fairly steadily throughout 1983 and into mid-1984, and then declined during the remainder of 1984 and throughout 1985. The price of gas followed a similar pattern to that of oil, but the rise and fall are less pronounced. The price of coal remained relatively stable throughout the period. The historic prices are used here as a first approximation and illustration of the fuel price differential trends in current years. A more detailed analysis should include forecasts of fuel prices and consider the increased demand for gas.

MODEL RESULTS

The model is exercised by selecting various target levels of deposition reduction. The model selects a power plant to use seasonal gas substitution based on: 1) its share of the deposition, and 2) the fuel price differential. The share of deposition is a function of the sulfur content of the fuel and the transfer coefficient between the power plant and the receptor. Power plants that have relatively large transfer coefficients and small price differentials will be selected first.

The target level of deposition was reduced in 5% decrements of the base value of 27.5 kg $ha^{-1}y^{-1}$ at an Adirondack receptor [7]. Corresponding levels of emissions reductions, gas substitution, coal and oil displacement, and resultant costs are calculated for each 5% decrement. These results are summarized in Table 5. For example, in the case of a 30% sulfate deposition reduction, 41×10^9 m^3 (1440 billion cubic feet [Bcf]) of natural gas are substituted in the summer half-year for 97 million tons of coal and 94 million barrels of oil at a cost of $5.858 billion (1983$). The resulting emission reduction would be 4.8 million tons of SO_2 per year.

The cumulative cost versus deposition reduction curve is shown in Figure 3. Cost is initially negative because there is a negative price differential between gas and oil at some plants.* Since the objective is to minimize cost,

TABLE 5. RESULTS OF SEASONAL GAS SUBSTITUTION MODEL

Dep. Red.[a] (%)	Em. Red. (10^6 tons SO_2)	Gas Subst. Bcf	Coal Displaced (10^6 tons)	Oil Disp. (10^6 bbl)	Total Cost (10^9 1983$)
5	0.6	337	8	79	−.204
10	1.3	501	20	84	.610
15	2.2	709	37	87	1.671
20	2.9	909	53	87	2.929
25	3.9	1179	76	87	4.403
30	4.8	1440	97	94	5.858
35	5.9	1795	127	95	7.867
40	6.9	2396	176	97	10.931

[a]Based on 27.5 kg $ha^{-1}y^{-1}$ total deposition of wet sulfate at an Adirondack receptor.

the seasonal gas substitution model chooses the plants with negative price differentials first. As larger decrements of deposition are sought, the model selects plants with ever smaller shares of deposition and ever larger fuel price differentials. At the 40% deposition decrement, virtually all power plants in the eastern United States would have to convert to summer gas substitution with an attendant annual fuel price differential of nearly $11 billion. Clearly, gas substitution ceases to be a preferred mode beyond a point where year-round emission control by fuel substitution (e.g., low-sulfur coal) or flue gas desulfurization becomes more cost effective. An overall optimized (least-cost) deposition-oriented control strategy would have to consider a plant-by-plant costing of emission control options. The options ought to include the whole range of emission controls, from summer gas substitution to year-round flue gas desulfurization.

COMPARISON WITH ALTERNATIVE DEPOSITION REDUCTION SCHEMES

The debate over alternative strategies for controlling acid rain has focused mainly on the expected costs of reducing SO_2 emissions. Total cost and $/ton of SO_2 removed are frequently used to compare alternative control strategies. In making these comparisons, a distinction should be made between source-oriented strategies aimed solely at reducing total emissions and receptor-oriented (or targeted) strategies that maximize the amount of deposition reduction at a receptor(s) for a unit of emission reduction. A direct comparison of the cost of receptor- and source-oriented strategies can be misleading; these strategies will not result in equal deposition reductions at a given receptor for equal emission reductions.

Morrison and Rubin [*16*] developed a model that computes the emission reduction and cost that would result from coal-fired utility plant emission caps of 1.5 and 1.2 lb. SO_2 per million Btu (0.68 and 0.54 kg SO_2 per gigajoules, respectively) using optimized combinations of switching to lower sulfur coal and flue gas desulfurization (FGD). The 1.5 and 1.2 lb. emission caps would result in annual emission reductions of 8 and 10 million tons SO_2 respectively. Based on the distribution of emission reductions across the eastern 31 states and the model transfer coefficients, these emission reductions would respectively yield 7.2 and 8.2 kg SO_4 $ha^{-1}y^{-1}$ deposition reductions at an Adirondack receptor, or 25% and 30% of the base value, respectively. Morrison and Rubin's calculated total cost ranges from $1.5-2.6 and 3.2-4.7 billion (1980$) for the 8 and 10 million tons emission reductions, respectively. Using a GNP deflator of 1.2 to adjust to 1983 dollars makes the cost range $1.8—3.1 and $3.8—5.6 billion, respectively. Using summer gas substitution in oil- and coal-fired power plants so as to equal the *deposition* reduction of the 8 and 10 million tons SO_2 scenario, the total cost would be $4.4 and $5.8 billion (1983$), respectively (see Table 5). Despite the higher overall costs of seasonal gas substitution, there are individual plants where seasonal gas use will provide cheaper sulfur deposition reduction than FGD.

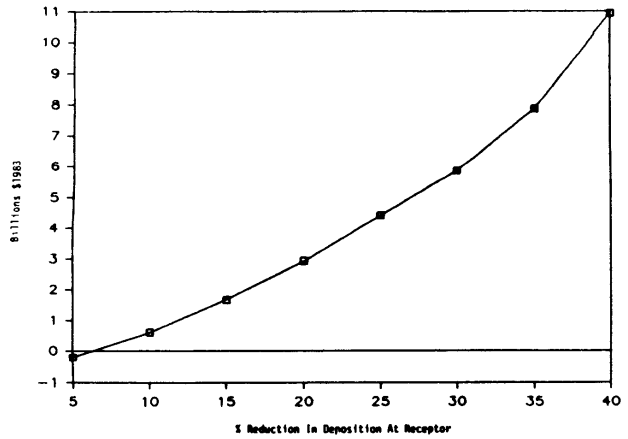

Figure 3. Cumulative cost curve for deposition reductions at Adirondack receptor. Deposition decrements achieved by summer gas substitution at eastern U.S. power plants. Calculations based on estimated total deposition from all U.S. and Canadian sources of 27.5 kg SO_4 $ha^{-1}y^{-1}$.

GAS SUPPLY FOR SUBSTITUTION

The seasonal gas substitution model has not considered gas deliverability constraints which may limit the amount of substitution that occurs within a state as specified by the model. A gas deliverability constraint would occur whenever the gas supply infrastructure lacks the necessary capacity to meet the incremental demand imposed by a level of gas substitution, or if total gas production is insufficient. In order to utilize gas substitution, the utility must access its gas supply from a gas distribution company's or gas transmission company's high-pressure pipeline. Transmission capacity can be expanded, but this may increase costs and make gas substitution less competitive relative to other control strategies.

*This condition raises the question of why these plants do not convert from oil to gas regardless of pollution concerns. Indeed, some oil-fired plants practice summer gas substitution purely on economic grounds, e.g. Boston Edison's Mystic Unit #7. We have not investigated why this practice is not in wider use. Existing long-term contracts and the availability of gas supply may play a role.

Because the primary use of natural gas is for space heating, summer demand is lower than winter demand in nearly all states. This condition favors seasonal gas substitution, but not in an unlimited or universal pattern. The ratio of summer sales volume to winter sales volume averaged 49% and ranged from 33% to 103% in the 31 eastern states and D.C. in 1984 (Table 6). The winter/summer sales ratio is only an indicator of general capacity and cannot be relied upon as a definitive measure of excess capacity available to every generating unit within a state. If it is assumed that the difference between winter and summer consumption is an approximate measure of available capacity, the aggregate difference between summer and winter volume is 2050 Bcf, which could provide approximately enough gas substitution for a 37% reduction in deposition (from Table 5). However, not every state has the necessary surplus summer gas required at all levels of deposition reduction. For example, for a 25% deposition reduction, only 14 states have the surplus needed to supply their share of the model's solution (Table 7).

OTHER COSTS

Preliminary findings concerning incremental capital and operating costs for seasonal gas substitution reveal two significant points. First, capital costs are low and implementation is quick. Using as an example the Boston Edison Mystic #7 unit, an oil-fired generating unit that converted to seasonal gas use, the boiler modification and gas supply construction cost $3.5 million for the 565 MW unit. The modification was completed in less than one year [17]. This is approximately $6/kW. In contrast, capital costs for limestone flue gas desulfurization (scrubbing) are between $175 and $317/kW [18], and have much longer lead times. Second, ash generation is reduced. If the variable component of ash disposal is significant, there is a potential cost saving from seasonal gas substitution. For example, if bottom and flyash variable disposal costs are $10/ton, a typical coal-fired power plant ash disposal cost would be $2.6/kW annually. Seasonal gas substitution could save one-half of this sum. The present value of these savings are close to or may exceed the capital costs associated with seasonal gas substitution.

The crucial determinant of the cost-competitiveness of gas substitution is the price differential between gas and coal and gas and oil. Since long term prices are impossible to predict with certainty, gas substitution is regarded as being financially risky when compared with other control methods. Actually, gas substitution may be less risky than more capital intensive control methods. Because there is a relatively small capital investment associated with gas substitution, a utility could easily abandon it if a more cost-effective solution became available, without forfeiting a large investment. Because of the large capital outlay needed for scrubbing equipment, a utility saddled with an expensive scrubber is financially limited if it wants to exploit less expensive control methods that may become available.

TABLE 6. NATURAL GAS DELIVERIES TO RESIDENTIAL, COMMERCIAL, AND ELECTRIC UTILITY CONSUMERS IN THE 31 EASTERN STATES AND D.C.

State	Summer Volume[a] (Bcf)	Winter Volume[b] (Bcf)	Summer Volume as a Percent of Winter Volume
AL	21.9	55.4	40
AR	37.9	68.7	55
CT	20.2	39.8	51
DE	8.1	9.5	85
DC	9.7	20.9	48
FL	112.4	109.1	103
GA	43.8	107.9	41
IL	202.5	510.5	40
IN	65.6	173.0	38
IA	35.6	96.6	37
KY	28.5	78.4	36
LA	233.7	234.7	95
ME	0.5	1.1	45
MD	33.6	71.9	47
MA	73.8	115.1	64
MI	152.3	370.0	41
MN	46.6	134.3	35
MS	49.8	59.6	84
MO	51.3	137.0	37
NH	2.7	6.1	44
NJ	129.3	208.6	62
NY	256.1	410.5	62
NC	18.2	47.2	39
OH	141.1	377.6	37
PA	111.4	282.2	39
RI	10.1	16.1	62
SC	10.6	25.7	41
TN	21.1	63.5	33
VT	0.9	2.2	42
VA	24.1	51.5	47
WV	16.1	43.2	37
WI	48.1	119.1	40
TOTALS	2007.6	4057.6	49

(a) Summer—April through September; and (b) Winter—October through March.

NOTE. Industrial gas consumption is not included here as the data are not yet reported by the Energy Information Administration. Exclusion of this component probably causes the ratio of summer-to-winter volume to be slightly overstated here.

CONCLUSIONS

Nearly all of the "acid rain" policy and policy analyses have focused on emission reductions and the cost of con-

TABLE 7. NATURAL GAS SUBSTITUTED FOR A 25% DEPOSITION REDUCTION

State	Gas (Bcf)	Sufficient Surplus (a)
AL	51	N
DC	1	Y
DE	19	N
FL	144	N
IA	3	Y
IL	20	Y
IN	73	Y
KY	61	N
MA	59	N
MD	40	N
MI	50	Y
MO	25	Y
MS	9	Y
NH	11	N
NJ	30	Y
NY	137	Y
OH	143	Y
PA	184	N
RI	1	Y
TN	41	Y
VA	3	Y
WI	2	Y
WV	68	N
	1176	

(a) The difference between winter and summer volume of sales is used as an approximate measure of summer capacity. If the difference between winter and summer sales (see Table 6) is greater than the incremental demand shown above, then Y

trolling emissions. But it is deposition, not emissions per se, that matters. Monitoring has shown that deposition rates are significantly higher during April through September than during October through March despite equal emission rates. Based on this evidence, it is more efficient to control emissions (and hence deposition) during the summer half of the year. The cost-effectiveness of any control method should be related to its effect on deposition rather than its effect on emissions. One ton of SO_2 removed in the summer half of the year has a greater effect on deposition than reducing that ton year-round. We find that in terms of equal deposition reductions in the Adirondacks, the costs of seasonal gas substitution may be comparable to year-round controls in some plants and states.

Seasonal substitution of gas for coal or oil is a reasonable option for some utilities to control sulfate deposition. However, it is not a panacea for solving the acid rain problem. The quantities of gas needed for substitution in order to make total deposition reductions of more than a few kilograms per hectare would exceed existing gas supply in many states. Some generating units are located too far from a gas supply or face fuel cost differentials that are too large to make gas substitution economically competitive with other control methods. An overall optimized, least-cost, receptor-oriented strategy probably will include a mix of year-round emission controls and seasonal gas substitution.

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Gary Galeucia is presently employed at Conoco, Inc. in Wilmington, Delaware. He was a Research Assistant at the MIT Energy Laboratory and earned his M.Sc. degree at the Sloan School of Management.

Dan Golomb is a Research Scientist at the Energy Laboratory and received his M.Sc. and Ph D degrees at the Hebrew University, Jerusalem. Before joining the Energy Laboratory, he was with the Environmental Protection Agency and the Air Force Cambridge Research Laboratory.

James A. Fay is Professor of Mechanical Engineering and serves as Director, Environmental Programs, at the Energy Laboratory He received an M.Sc. degree from MIT and a Ph.D. degree from Cornell University.