DYNAMIC ANALYSIS OF SULFUR DIOXIDE MONTHLY EMISSIONS IN U.S. POWER PLANTS

DISSERTATION

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By

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ABSTRACT

The Clean Air Act Amendments (CAAA) of 1990 marked a moving away from command-and-control air quality regulations towards a market-based approach, whereby polluters are assigned annual emission allowances, and are free to select the minimum-cost approach that will keep their actual annual emissions within this allowance limit. Within this context, the objectives of this research are to better understand (1) the temporal patterns of SO_2 emissions from power plants, and (2) the factors affecting fuel choice and SO_2 emissions.

Large power plant-related datasets from various sources are collected, processed, and combined for empirical analyses, to explain monthly fuel shipments, fuel consumptions, sulfur shipments, gross and net SO_2 emissions, and fuel choices. Because of the interdependency of these various sulfur dioxide, simultaneous equations estimation techniques are used.

The empirical findings are as follows. First, forecasts of electricity demand and fuel prices are the main determinants of the amounts and types of fuel shipments. The relationship between fuel shipments and forecasted fuel needs is very strong for the current month, and gradually weakens over future months, due to forecasting difficulties and the costs of fuel inventories. Second, net SO_2 emissions increase with allowances, although not proportionately, because of the likely effects of allowance banking and

trading. Third, each plant reduces SO_2 emissions gradually over time, to account for the future more stringent Phase II emissions constraints. Fourth, plants emit less in winter, possibly because higher electricity leads to reduced unit SO_2 emission abatement costs. Finally, plants with an FGD usually consume more high-sulfur fuels due to their potential abatement capability.

An integrated analysis of the effects of changing emission allowances and installing FGD is conducted through a simulation. Reducing allowances by 1% leads to an emissions reduction of 0.15% at the plant level. However, if allowances were reduced uniformly nationwide, this effect would be stronger because of reduced allowance trading opportunities.

Dedicated to my family

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I would like to share my happiness at this moment with my wife, who has always believed in me, and endured with me during difficult times. Without her unconditional sacrifice, it would not have been possible for me to complete this dissertation.

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CHAPTER 1

INTRODUCTION

The air pollutants generated from burning fossil fuels, such as coal, oil, and natural gas, in industrial and commercial facilities, and in electric power plants, have been the most influential factors in the deterioration of air quality (Goldstein and Izeman, 1990), and include: sulfur dioxides (SO_2), nitrogen oxides (NO_X), carbon oxides (CO and CO_2), particulate matters (PM), and toxics (*e.g.*, mercury, radio-active materials). Among these pollutants, SO_2, a caustic and colorless gas, is a precursor of acid rain (Corburn, 2001) and a factor in respiratory diseases such as asthma (Oftedal et al.). Acid rain is a well-known threat, as it affects human health, forests and crops, waters, and monuments (Aslan et al., 2001), in both dry and wet depositions.

Because of the negative impacts of SO_2, Title IV of the Clean Air Act Amendments (CAAA) of 1990 created a two-phased plan for SO_2 emissions reductions. Phase I, effective from 1995 through 1999, initially affected 263 units, mostly coal-fired utility plants located in 21 eastern and midwestern states, and an additional 182 units that were included as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, more stringent than Phase I and setting new restrictions on smaller, cleaner plants fired by coal, petroleum, and natural gas, began in 2000, and includes most power plants. In addition, the CAAA of 1990 marked a moving-away from command-and-control air quality regulations towards a market-based approach, whereby polluters (primarily fossil fuel power plants) are assigned annual emission allowances, and are free to select the minimum-cost approach that will keep their actual annual emissions within this allowance limit. Besides fuel substitution and installation of pollution abatement technology, a power company may shift allowances among its various generating units (the bubble concept[1]), and may trade them with other power companies (Brookshire and Burness, 2001). Since emissions trading became possible without regard to the locations of the trading plants within the U.S., a company with relatively high marginal costs of emission reduction has an incentive to complement its own emission reductions by purchasing allowances from companies with relatively low marginal costs of emission reduction. Overall, a significant global reduction in SO_2 emissions has been reported for most states (Butler et al., 2001).

Despite these efforts and promising results, a growing demand for electricity resulting from urban and economic development may bring back the issue of controlling

[1] Bubbles allow polluting companies with multiple emissions sources to combine their total emissions targets from these multiple sources. For instance, assume that a company must control SO_2 emissions from stacks at two *adjacent* plants. Without the bubble policy, the firm has to comply with emission allowances allowing only 5,000,000 lbs/year from each plant, totaling 10,000,000 lbs/year, although the marginal cost of emission controls for one plant is much higher than that for the other one. Using the bubble policy, the company is free to decide how to reduce SO_2 emissions at each plant, equalizing the marginal abatement cost of the two plants. The only restriction is that the total emission from an imaginary bubble surrounding the two plants must be no greater than 10,000,000 lbs/year (pp. 230-232, Ortolano 1997). Therefore, by pooling together all of a company's emissions as one source, this company does not need to meet separate standards for each plant.
(see, http://www.nira.go.jp/publ/review/99summer/anders.html;
http://www.ametsoc.org/sloan/cleanair/cleanairstationary.html)

SO_2 emissions to the “front burner”. To better confront this issue, it is important to understand the behavior of power plant operators in complying with the CAAA regulatory requirements, that is, how they combine annual SO_2 emissions allowances, fuel substitution, emission trading, anti-pollution technology, and all other relevant factors. The goal of this research is to better understand this balancing strategy, which combines both environmental and economic efficiency goals. More specifically, this research focuses on the intra-annual (monthly) scheduling of pollution emissions, and how this scheduling results from the interactions of various technological, economic, and policy factors.

The total annual emission from any power plant polluter is the aggregation of a continuous emission stream over the year. The emission rate varies over time (hour, day, month, season, etc.) because of (1) variations in the hourly load demand (kWh), resulting from both market demand and unit dispatching policy, and (2) possible variations in the type of fuels burned to generate power, and (3) possible variations in the efficiency of the pollution abatement equipment. Fuel prices vary over time, depending upon the international oil market, increasing demand for cleaner fuels, varying demands for certain types of fuels due to seasonal requirements for cooling and heating, the respective locations of plant and fuel sources (transportation costs), and inventory costs. How do these variations determine the type of fuel to purchase and burn over the course of the year? Fuel purchasing costs minimization is unlikely to lead, by itself, to the respect of the annual allowance limit, whereby the cumulative net emissions must not exceed this limit after accounting for allowance trades and transfers. It is also possible that emissions are lowered during periods of unfavorable meteorological conditions, in order to avoid violating ambient air quality standards[2]. Although these standards do not directly limit the amounts of pollution emissions, each plant must account for background pollution concentrations, because of regulations on nonattainment areas[3]. Emissions trading and/or abatement technology, such as scrubbers, can be used to achieve the cost minimization goal. Very likely, then, the actual emissions decisions by power plants must be the result of several interacting factors, as illustrated in **Figure 1.1**. The purpose of this research is to clarify these interactions, making use of publicly-available data on SO_2 emissions, fuel purchases and consumptions, electricity production, allowances, pollution abatement technology, and meteorology.

A statistical analysis methodology is developed, using these data, to provide new insights into the dynamic interaction of SO_2 emissions, fuel shipment, fuel consumption, fuel stock, electricity generation, costs of fuel purchases, abatement equipment, emission trading, meteorological conditions, and allowances. The estimated models should clarify the management/planning behavior of plant operators regarding how they trade-off decisions on net SO_2 emissions scheduling, fuel shift/mix, abatement techniques, and

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[2] The Clean Air Act requires the U.S. Environmental Protection Agency (EPA) to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. There are two types of standards. Primary standards set limits to protect public health, including the health of sensitive populations such as asthmatics, children and the elderly, Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. The primary standards for sulfur dioxides are 0.03 ppm/year, and 0.14 ppm/hour, which must not be exceeded more than once per year. The secondary standard is 0.5 ppm/3-hour, which must not be exceeded more than once per year. http://www.epa.gov/air/criteria.html.

[3] If the standard is exceeded four times in three years at one site, then the area is in violation of the standard and no longer in "attainment". It is then designated as nonattainment area. For such area, the State must provide a plan to show how the area will maintain the standard. http://www.epa.gov/reg3artd/airquality/nonattain.htm

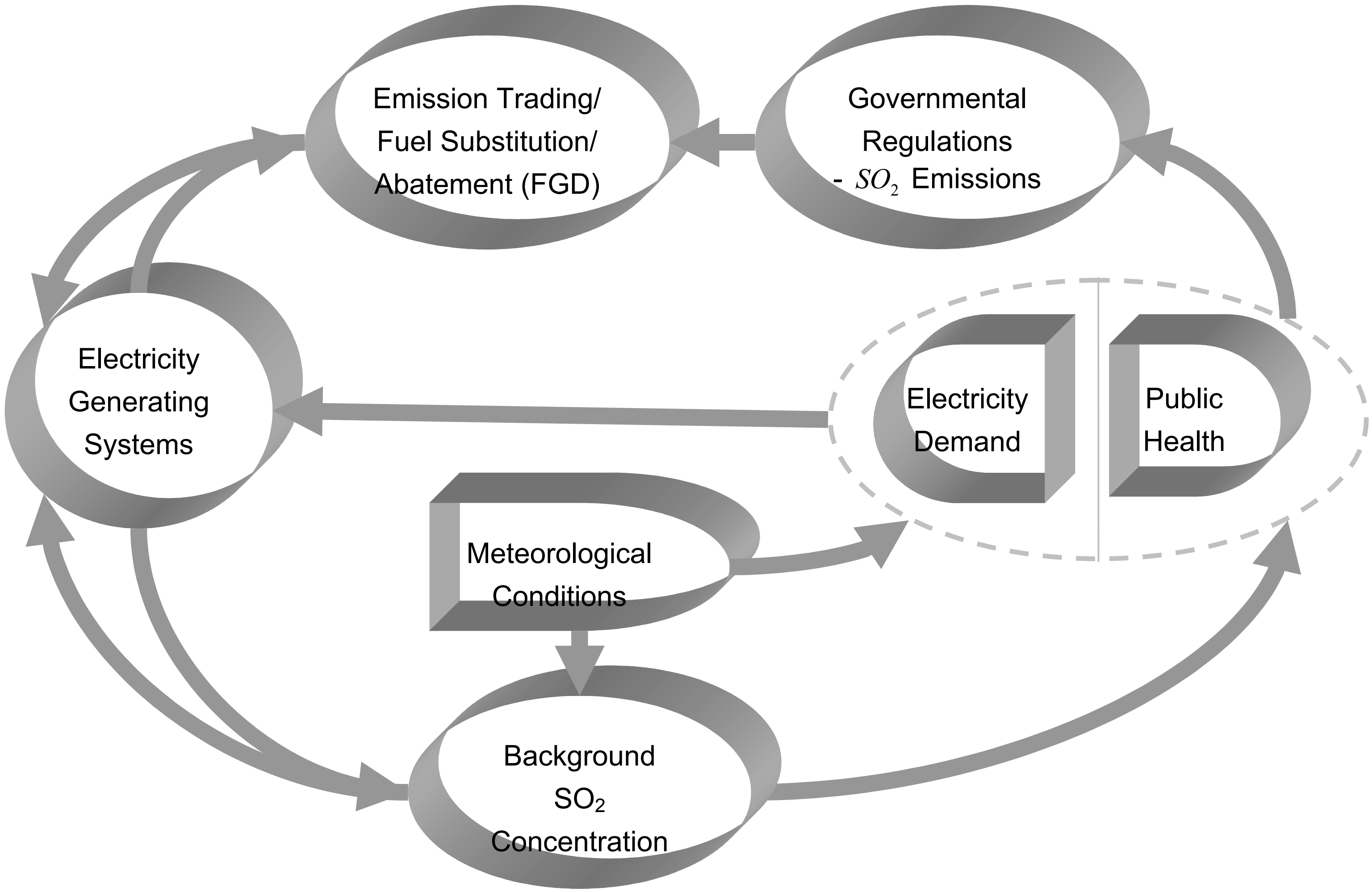

Figure 1.1: Interactions among environmental, energy, and regulatory factors

allowance trading. Ultimately, the understanding of such behavior should provide insights as to how to improve the effectiveness of SO_2 emissions regulation, possibly leading to a reexamination of the effectiveness of the 1990 CAAA.

The remainder of this dissertation is organized as follows. Relevant literature streams are reviewed in Chapter 2, and research gaps are delineated. Chapter 3 presents the methodological and conceptual framework of this research. Data sources and processing are described in Chapter 4. Exploratory statistical analyses are presented in Chapter 5. The empirically estimated models are presented in Chapter 6, and policy implications are derived. Conclusions and areas of further research are presented in Chapter 7.

CHAPTER 2

LITERATURE REVIEW

Electricity generation, gross SO_2 emissions, and net SO_2 emissions, are determined by the interactions of the compliance behavior of plant operators, consumers' electricity demand, energy prices, the regulation of SO_2 emissions, and, possibly, meteorological factors. The purpose of this research is to clarify these interactions. In order to better understand mechanisms for SO_2 emissions control, the historical and technical background of the Title IV of the Clean Air Act Amendments (CAAA) of 1990, the policy instruments for the reduction of SO_2 emissions, and various compliance options are reviewed, including the limitations of previous studies.

2.1 Title IV of the CAAA of 1990

In 1990, Congress passed the Title IV of the CAAA to reduce the total aggregate emissions of sulfur dioxide and nitrogen oxides (precursors of acid deposition), and to support the development of scrubber technology (Swinton, 1998). In order to achieve these objectives, a two-phases plan was designed, requiring an overall annual SO_2 emission reduction to below 1980 levels. Four hundred and thirty five (435) coal-fired units were required to comply with Phase I of the CAAA running from 1995 to 1999. Phase I units made up 28% of the 1995 coal-fired generating capacity, and were required to reduce SO_2 emission by as much as 67% of 1985 emissions and 45% of 1995 emissions (Hower et al., 1999). In Phase II, which began in 2000, the annual emission allowances allocations were reduced by 50 % and the number of affected units was increased noticeably (Brookshire and Burness, 2001). For this reason, utilities had to make long-term decisions during Phase I in expectation of Phase II regulations (Winebrake et al., 1995).

The 1990 CAAA initiated a radical reform towards a market-based or performance-based approach, away from traditional command-and-control regulatory schemes. Burtraw (1996) points out that the shift towards interutility allowance trading is another important step in the CAAA. Allowances are transferable, and trading prices are competitively determined. Utilities whose annual SO_2 emissions do not exceed their allowances can sell or bank their unused allowances. In contrast, utilities violating annual allowance limits must either pay fines or purchase allowances, *i.e.*, ‘polluting rights’, from other utilities. Butler et al. (2001) investigate the effects of CAAA, and find that there were significant reduction in SO_2 emissions in the eastern U.S., including Ohio, Indiana, West Virginia, Tennessee, Kentucky, Georgia, Missouri, and New York in the 1990’s. However, power plants in Texas, North Carolina, Illinois, Florida, and Alabama experienced SO_2 emission increases. This spatial discrepancy implies that the CAAA may not be an environmentally effective method of emission control in all U.S. regions, and may lead to environmental “hot spots” of high concentrations, hence with varying public health benefits across states, despite the minimization of total national abatement costs.

Interestingly, the CAAA did not establish a deposition standard, because of societal uncertainties related to the level of protection desired by public, the costs and benefits associated with such changes, and key scientific unknowns, such as the effects of the variability of meteorological conditions (Lynch et al., 2000). As an exception, the Los Angeles government has provided a two-zones trading system under the South California Regional Clean Air Incentives Market (RECLAIM) program, that carries ambient air quality standards (Stavins, 1998; Schwarze and Zapfel, 2000).

Title I (Provisions of attainment and maintenance of national ambient air quality standards) of the CAAA contains several explicit requirements pertaining to air quality dispersion and photochemical modeling, but only for *nonattainment* areas. However, Title IV (acid deposition control) of the CAAA does not contain any requirements which pertain to air quality dispersion modeling[4], and focuses more on national emission reductions, rather than on targeting specific sensitive receptors. The only requirement is to keep the net SO_2 emission rate up to a maximum of 2.5 pounds per MMBtu, without regard to the total emissions at the regional/state level. There is no specific provision for controlling the health and environmental costs of pollution in different regions. While setting the allowance limits necessarily reduces the aggregate level of SO_2 emissions, this reduction may be negligible in highly polluted areas, because of the purchasing of allowances from less polluted areas. If the CAAA had

[4] http://www.epa.gov/ttn/oarpg/gen/model.txt

focused more on geographically targeted emissions reductions in highly polluted areas, while limiting allowance trading across regional borders, it would have provided a more environmentally balanced approach.

2.2 Market Mechanism of Annual SO_2 Emission Allowances and Emission Trading

The fundamental problem of an emission policy is how to allocate the cost burden of reducing emissions, what requirements to place on emitting sources, and how to ensure compliance (Ellerman, 2002). In this section, three possible scenarios of using economic instruments for environmental policy are introduced and compared to the marketable permit approach of the CAAA, based on Ortolano (1996, Chapter 10), Chapman (1999, Chapters 5, 11, 12, and 13) and Ellerman (2002): 1) Taxing pollution; 2) Setting standards and fining violation; and 3) Creating marketable permits to pollute.

2.2.1 Taxing Pollution

If polluters do not internalize the environmental costs they create, no abatement will occur. In Figure 2.1, sulfur dioxide emissions are at point *E*, where the marginal cost (MC) of abatement is equal to zero. For simplicity, it is assumed that the *MC* declines linearly with emissions.

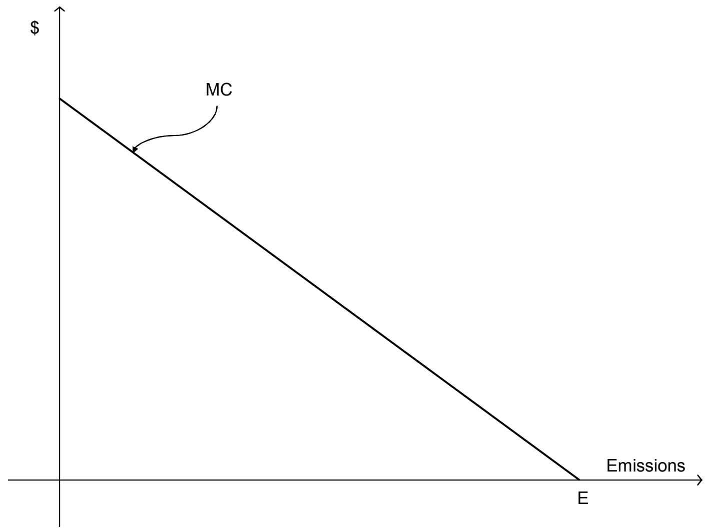

Figure 2.1: The Case of No Regulation

Assume now that a governmental agency imposes a tax (T) per ton of sulfur dioxide emission. Then, sulfur dioxide emissions shift to point *E** where *MC=T*, as outlined in Figure 2.2.

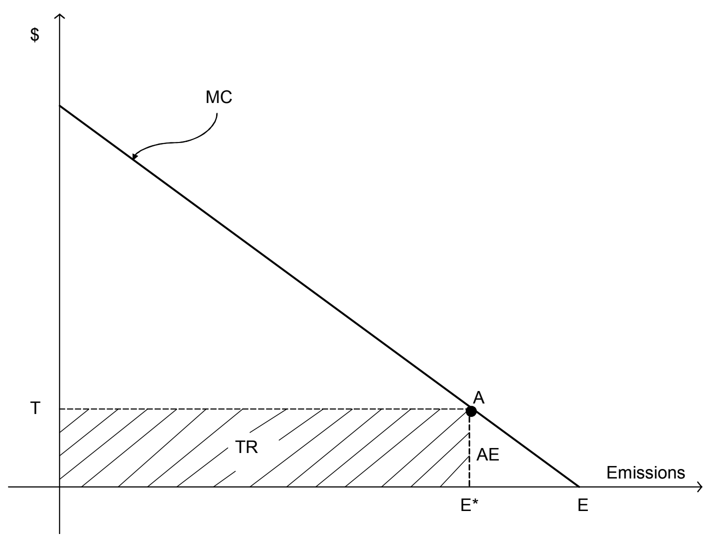

Figure 2.2: Taxing Pollution

Beyond point *E**, emission abatement is more economical than paying the tax, so the total abatement expenditure (AE) is $\frac{1}{2}(E - E^*) \times T$ (the triangle *AEE**). The shaded area indicates the total tax revenue $(TR = E^* \times T)$ of the governmental agency.

2.2.2 Setting Standards and Fining Violations

In this case, the regulatory agency sets emission standards, and violating this standard is subject to a fine *F*. Polluters release sulfur dioxide emissions up to point E^{**} regardless of the standard *S*, if the fine *F* is cheaper than the unit cost of abatement, as illustrated in Figure 2.3. The shaded area represents fine revenues for the governmental agency $\left(TR = \left(E^{**} - S\right) \times F\right)$.

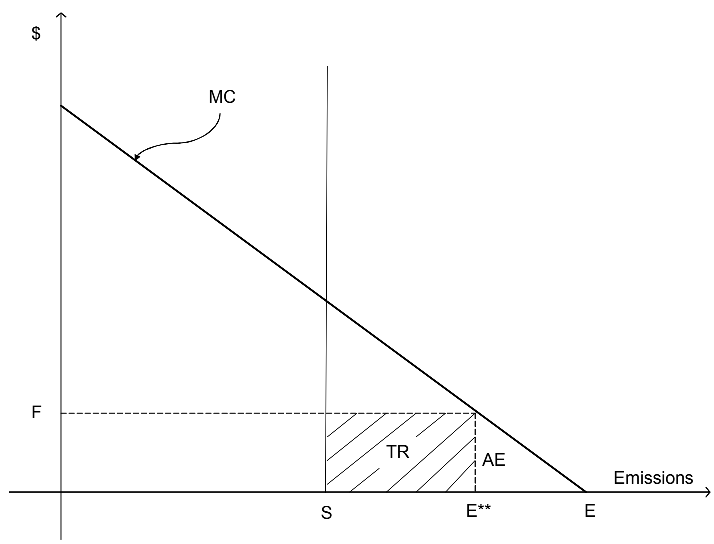

Figure 2.3: Setting Standards and Fining Violations

2.2.3 Creating Marketable Permits to Pollute

In a marketable permit system, the number of permits should correspond to the efficient pollution level E^{***}, where the auction price *AP* for permits is equal to the marginal abatement cost (MC). The only difference with taxing pollution is that the auction price is not predetermined but depends instead on the demand for permits. This outcome is illustrated in Figure 2.4.

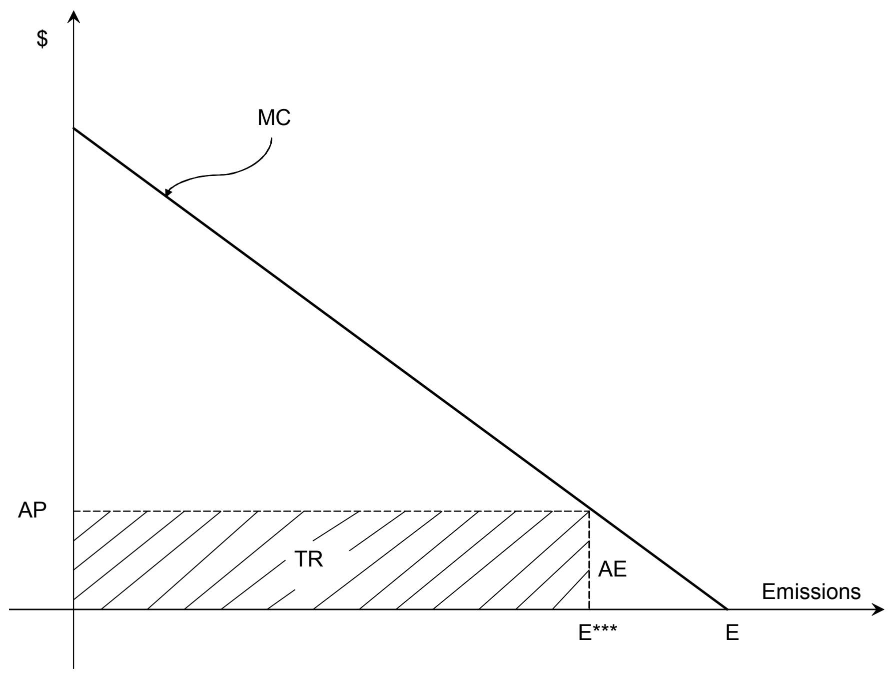

Figure 2.4: Creating Marketable Permits to Pollute

Consider a plant i that emits E_i without abatement. Let E_i^{***} be the allocated allowances for this plant, a_i the purchased allowances, and x_i the amount of pollution abatement. It follows that

$$E_i - x_i - a_i = E_i^{***} \tag{2.1}$$

The plant is assumed to minimize the total costs of abatement and emission trading, with:

$$Minimize \qquad TC = c\left(x_i\right) + pa_i \quad , \tag{2.2}$$

subject to constraint (2.1). p is the market price of allowances. The above constrained optimization is transformed into Equation (2.3), using the Lagrangian multiplier λ,

$$\Lambda\left(x_i, a_i, \lambda\right) = c\left(x_i\right) + pa_i + \lambda\left(E_i - x_i - a_i - E_i^{***}\right) . \tag{2.3}$$

The first-order optimality conditions are:

$$\frac{\partial \Lambda}{\partial x_i} = MC\left(x_i\right) - \lambda = 0 \tag{2.4}$$

$$\frac{\partial \Lambda}{\partial a_i} = p - \lambda = 0 \tag{2.5}$$

$$\frac{\partial \Lambda}{\partial \lambda} = E_i - x_i - a_i - E_i^{***} = 0 \tag{2.6}$$

Equations (2.4) and (2.5) imply:

$$MC\left(x_i\right) = p \tag{2.7}$$

The optimal level of SO_2 emission abatements in plant i is such that the marginal abatement cost is equal to the market price of allowances p, as illustrated in Figure 2.5.

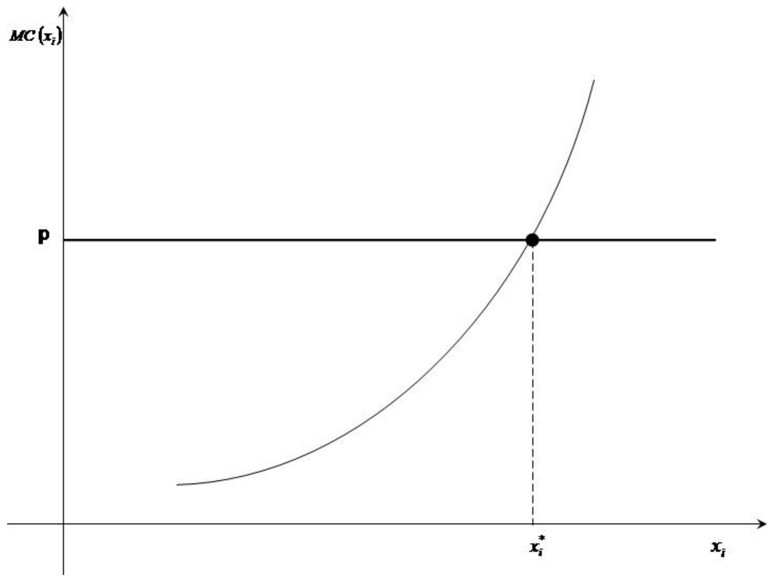

Figure 2.5: Optimal Level of SO_2 Emission Abatements and Market Price of Allowances

Since all plants face the same market-determined price, p, they reduce their emissions to the points where all marginal costs are equal, as illustrated in equation (2.8),

$$MC(x_1) = MC(x_2) = \cdots \;\cdots = MC(x_i) = \cdots\cdots = MC(x_n) = p \tag{2.8}$$

This outcome is the same as the outcome obtained when all plants are under the same ownership (national bubble), and the objective is to minimize the total cost of abatement:

$$Minimize \qquad TC = \sum_i c\left(x_i\right) \tag{2.9}$$

subject to the aggregate emission constraint:

$$\sum_i E_i - \sum_i x_i = \sum_i E_i^{***} \tag{2.10}$$

Therefore, the market-determined solution using allowance trading minimizes the aggregate abatement cost. However, since it does not internalize environmental and public health costs, this trading does not lead to a social optimum.

2.3 Emission Limits Compliance Options

The usual compliance options for satisfying the annual sulfur dioxide emission allowance limits are: 1) switching to lower sulfur fuel; 2) using abatement technologies such as flue gas desulfurization (FGD) facilities or scrubbers; and 3) purchasing emission allowances from other utilities or shifting allowances among the units of the same company. Other compliance methods include natural gas co-firing, FGD upgrade, sorbent injection, and repowering (Winebrake et al., 1995).

Fuel switching is a common compliance method, but is available only if a plant is equipped with fuel blending/mix combustors. Scrubbers or FGD are the most effective way of reducing SO_2 emissions, but entail high installation costs, although their maintenance costs are lesser than for other methods. Emissions trading is the most flexible compliance method, and does not entail additional costs. Ghandforoush et al. (1999) indicate that, while compliance options are known, their costs are not known with certainty. Manetsch (1994) points to the uncertainty in the premiums to be paid for low-sulfur coal and in the costs for installing scrubbers, for the switching to lower sulfur coals and for taking no compliance action (*e.g.* fine). Three major compliance options, the core strategies of U.S. utilities, are discussed in the following subsections.

2.3.1 Fuel Switching/Blending

Fuel switching entails a change to either a coal with a lower sulfur content, or a low sulfur fuel other than coal, typically natural gas, while fuel blending involves the mixing of high and low-sulfur fuels to satisfy the annual sulfur dioxide emission allowance limits (Zipper and Gilroy, 1998). Due to their lower capital investment requirements, fuel switching and/or fuel blending are regarded as the most economical ways of compliance (Wang et al., 1996; Ikeda et al. 2001). Wang et al. (1996) present a realistic long-run cost minimization model for electric power expansion, and find that fuel switching is less costly than scrubbing by 9.5 %.

However, in order to use fuel switching or blending as a compliance method, a boiler must be suitable for other fuels, besides the design fuel. Humphreys and McClain (1998) explain that boiler flexibility allows the fuel mix to move along an efficient frontier in response to market events. They suggest that discovering ways to move cheaply from one fuel to another is a key concern for utilities. However, Zipper and Gilroy (1998) point out that a coal-fired power plant is usually designed to burn a certain type of coal, so switching fuels may decrease the efficiency of the boiler. Moreover, Soderholm (2001) argues that even if the capacity to switch between fuels exists, the opportunities for fuel switching may be limited, and the degree of actual short-term interfuel substitution is not certain. Although there is clearly a possibility for substitution between fuels before the construction of a plant, once this plant's design is fixed in terms of capital equipment, the flexibility for fuel substitution is greatly reduced.

In general, coal is the most available fuel for electricity generation, as compared to oil and natural gas. The U.S. holds approximately 31 % of the word's recoverable coal reserves, making up 85 % of potential U.S. fossil fuel reserves. Despite the decrease in coal demand due to the CAAA, coal continues to be the main source of electric power generation, accounting for 56 % of the nation's electricity in 1996 (Dahl and Ko, 1998; Hower et al., 1999; Lee, 2002). Since the demand for coal is less responsive to price changes, the volatility of overall energy consumption costs could be reduced by increasing the share of coal within the overall consumption mix (Humphreys and McClain, 1998; Dahl and Ko, 1998; Ko and Dahl, 2001).

Although coal consumptions may help mitigate the impacts of market volatility, further changes in air quality regulations may preclude purchasing coals with relatively high sulfur contents. Hower et al. (1999) posit that, if profits from using coal decrease due to emission control costs, some utilities may switch their primary fuel to natural gas. The price elasticity of fuel substitution may be dramatically modified when environmental regulations are imposed. Eskeland et al. (1998) show that the emission elasticity depends upon how utilities can flexibly select fuels, the pollutant content of different fuels, and whether fuel stocks can be managed to substitute fuels with the goals of cleaner fuels or energy conservation.

2.3.2 Flue Gas Desulfurization Facilities (FGD)

Abatement technologies, such as FGD scrubbers, are viewed as the best option by environmentalists, because they clearly (by more than 95%) reduces sulfur dioxide emissions generated by fuel combustion. Swinton (1998) points out that the installation of a FGD unit is the most effective method for eliminating sulfur dioxide from the exhaust flow. Zipper and Gilroy (1998) describe several advantages of FGD facilities. First, utilities can meet their annual emissions allowances limits while continuously burning cheaper high-sulfur fuels. Second, utilities can maintain SO_2 emission levels well below the allowance limit and the unused allowances can be banked, sold, or used to offset emissions at other units. Last, a scrubber installation removes uncertainty about future sulfur dioxide regulations (*e.g*. Phase II compliance). Although FGD scrubbers have not been widely adopted due to their high capital investment costs, high operating costs, and large volumes of solid waste generated, it is worth noting that capital costs have fallen by almost 50% since the CAAA of 1990 (Zipper and Gilroy, 1998). However, Wang et al. (1996) argue that the installation of scrubbers not only requires high capital investments, but also decreases production efficiency, because of increased internal power requirements and required capacity derating.

2.3.3 Emission Trading/Auction

Emission trading may reduce overall compliance costs for utilities by a great margin, because a utility does not have to abate sulfur dioxide emissions and can, instead, purchase ‘tradable permits’. To stimulate the U.S. sulfur dioxide emission trading market, the auction process is selected as an effective approach, because it guarantees the availability of permits, allows new sources to buy their way into the market, and clearly reduces transaction costs (Svendsen and Christensen, 1999). In contrast to the high installation and maintenance costs of abatement technologies, such as FGD, or to volatile fuel purchasing costs, a tradable permit is a very flexible method of compliance. It is estimated that, if all the potential gains from trade are realized, abatement costs could be reduced by up to $3 billion after 2000 (Ben-David et al., 1999). Baumert et al. (2003) expect that emissions trading will serve as a cost-effective means of promoting compliance with emissions targets, generating financial transfers. Forsund and Naevdal (1998) also regard emissions trading as a potent policy instrument in environmental policy implementation. Walsh et al. (1996) explain that emission trading allows multiple generation units of different utilities to take advantage of economies of scale in emission control, and the different compliance options lead to cost reduction through competition. The potential gains from emission trading arise when different marginal abatement costs are equalized and the total abatement costs are minimized. Therefore, the greater the initial difference (the greater the heterogeneity in the market) in marginal abatement costs, the greater the potential gains from trade (Ben-David et al., 1999).

2.4 Limitations of Previous Research

Title IV of the CAAA of 1990 has brought noteworthy flexibility to utilities, so that they can adopt various cost-saving strategies combining various options such as emission trading, fuel switching/blending, scrubbing, repowering etc. These compliance options have affected fuel qualities in terms of sulfur contents and heat values. Cost minimization cannot be achieved without considering the linkages among these options, and market factors such as fuel prices and electricity demands. Although previous research has explored the factors affecting SO_2 emissions and their interactions under the new regulation scheme, several shortcomings in this research are worth mentioning.

2.4.1 Meteorological Factors

In previous research, the impacts of the temporal variability of meteorological factors, such as wind speed, on emissions decisions have rarely been discussed. It is possible that power plant operators make use of meteorological condition to emit more sulfur dioxide under favorable dispersion conditions and less under unfavorable ones

In order to assess the impacts of meteorological conditions on net sulfur dioxide emissions, it is necessary to understand the mechanisms of pollutants air transport, including buoyancy at the source, advection, and air turbulence en route from the source to the area of impact. Bourque and Arp (1996) investigate the cumulative amounts of sulfur dioxide deposited on land after several months. Goyal and Krishna (2002) find that low wind conditions weaken the transport and dispersion of pollutants, resulting in high ground-level concentrations, and that the highest ground-level concentration occurs during daytime convective conditions with moderate to weak winds. Yegnan et al. (2002) explore the impacts of wind speeds on concentrations, using a Taylor expansion of the basic Gaussian model to better assess uncertainty and complicated non-linear relationships. Consider the following Gaussian equation of pollution concentration,

$$C = \frac{Q}{2\pi u \sigma y \sigma z} \exp\left(-0.5\frac{Y^2}{\sigma y^2}\right)\exp\left(-0.5\frac{(Z-h_e)^2}{\sigma z^2}\right), \tag{2.11}$$

where Q is the emission rate, σy and σz are the dispersion coefficients in the crosswind and vertical directions, Y and Z are the lateral and vertical distances from the source, u is the wind speed, and h_e is the effective stack height. The partial derivative of the concentration with respect to wind speed is:

$$\frac{dC}{du} = K\left(\frac{1}{u}\exp\left(-0.5\frac{(Z-h_e)^2}{\omega z^2}\right)\left(\frac{Z-h_e}{\sigma z^2}\right)K_1^{'}\left(\frac{1}{u}\right)\left(\frac{1}{u^2}\right) - \exp\left(-0.5\frac{(Z-h_e)^2}{\sigma z^2}\right)\left(\frac{1}{u^2}\right)\right), \tag{2.12}$$

where K represents $Q/2\pi$, and the effective stack height h_e is a function of the plume rise, which changes with wind speed ($1/u$) and the downwind distance, with $h_e = K_1(1/u)$. The first-order derivative of h_e is $K_1^{'}(1/u)$. Since the effective stack height changes with wind speed $1/u$, the concentration derivative $(\partial C/\partial u)$ can change sign with distance, depending on the value of the effective stack height. A change in the sign of $\partial C/\partial u$ with distance means that concentrations close to the polluting source increase with wind speed and, further from the polluting source, decrease with wind speed. This feature was observed by Schnelle and Dey (1999). Based on these results, it is reasonable to assume that stronger wind speed may inhibit dispersion of air pollutants, while weaker wind speed may facilitate the dispersion away from the polluting sources.

2.4.2 Time and Seasonal Factors

In general, seasonality has a relationship with electricity demand, and increasing or decreasing electricity demand may be linked to changes in sulfur dioxide emissions. Pardo et al. (2002) develop a transfer function intervention model to examine the associations between electric load and seasonality, measured by cooling and heating degree days, and find that the effects of weather and seasonality are significant. Valor et al. (2001) emphasize that weather affects the electricity market because the demand for electricity is closely related to air temperature, and find that there is a nonlinear but positive relationship between weather and electricity demand. The link is always more significant in winter than in summer. The relationship between seasonal factors and electricity demands has been studied in past research. However, the relationship between seasonal variables and SO_2 emissions has not been clearly defined. Examining the sensitivity of sulfur dioxide emission to seasonality could be an interesting research issue.

Other time effects may provide additional valuable information, and may illustrate increasing or decreasing trends of SO_2 emissions over a certain period. For example, assessing the inter-annual variations of emissions between Phases I and II could provide a test of the effectiveness of Title IV of the CAAA. Another time effect could be related to the following: if a plant has emitted a large portion of its assigned annual SO_2 emission allowances during the first few months of the year, it might need to more tightly control net emissions through fuel mix/shift, abatement technology or emission trading, for the remainder of the year. Previous research has not addressed this issue.

2.4.3 Lack of Comprehensiveness

As a profit maximizer, a plant operator is trying to minimize overall operation costs while abiding by the requirements on SO_2 emissions. The compliance options may be flexibly utilized, considering *market factors* such as fuel purchasing prices and electricity demands*, regulatory factors* such as annual SO_2 emission allowances, and *other factors*, such as meteorological conditions and time/seasonal factors. Every compliance option and the above factors have different impacts on the amounts of sulfur involved in fuel shipments, fuel consumption and electricity generation, and net emissions. For example, if a plant has an FGD capacity, the plant operator may emit more SO_2 emissions at the burning (consumption) stage, because gross SO_2 emissions can be reduced further if necessary. In most of the previous literature, however, such systems dynamics have not been explored comprehensively. Instead, only partial relationships, such as between net SO_2 emission and compliance options or market factors or regulatory factors, have been analyzed. The purpose of this research is to fill this gap, using a set of empirical models embedded within a theoretical framework.

CHAPTER 3

CONCEPTUAL FRAMEWORK

A major shortcoming of previous studies is that the causal relationships between SO_2 emissions and other factors have been analyzed piecemeal, without considering the interrelationships among the variables in the different subsystems of the electricity generating process. In this chapter, these gaps are addressed, leading to a conceptual framework to model SO_2 emissions and energy shipments and consumptions, based on the cost-minimization behavior of the polluter – an electricity generation power plant.

3.1. Conceptual Framework Overview

The 1990 CAAA set annual SO_2 emissions allowances representing maximum annual SO_2 emissions for each plant, while allowing for the trading or transfer of these allowances. Besides emission trading, power plants operators are free to seek additional ways to further reduce their costs within this new regulatory regime, comparing the costs of purchasing higher quality fuels (lower sulfur content), emissions abatements, and emission trading.

The behavior of a plant operator depends upon the condition of interconnected subsystems, such as fuel shipments, fuel consumptions, electricity generations, and gross and net SO_2 emissions. For instance, a plant operator may emit more SO_2 from fuel burning in the electricity generating stage if he can reduce net SO_2 emissions through FGD facilities. If a high-quality fuel price increases, the operator may purchase a lower-quality fuel, and use emission abatement technology or emission trading as an alternative in the net SO_2 emission stage. How does a plant operator combine these different compliance options constitute an important research question. In order to answer it, a complete understating of the whole system is essential, and the interconnections among the various subsystems must be clearly defined. For this purpose, two conceptual frameworks, the perfect foresight model and the myopic optimization model, are discussed in the next two sections.

3.2 Perfect Foresight Model

This model is formulated to represent the optimization behavior of a power plant operator under conditions of perfect knowledge, to untangle the interactions of energy, environmental, and regulatory factors. It is assumed that, at the beginning of the annual cycle, the plant operator knows all the future values of the exogenous parameters (*e.g.*, fuel prices, electricity demands, etc.). Actually, only the past values and limited forecasts of the future values of these parameters are known at any time. However, the primary value of such a model lies in clearly delineating exogenous parameters and endogenous variables, and their fundamental relationships.

3.2.1 Perfect Foresight Model Constraints

Since allowances can be banked or purchased for future years usage, there are clearly inter-annual effects that take place. However, these effects are not considered here, for the sake of clarity in presentation. The time frame is a year, subdivided into T sub-periods. At any time, the power plant may purchase and burn any combination of fuels selected from a set of *k* fuels, with varying heat and sulfur contents.

The amount of electricity generated by a power plants at time *t* (*1* → *T*), KW_t, must meet some portion of consumers' demand in a given market, D_t. KW_t is directly related to the power plant heat input, which is function of the amounts X_{kt} of fuels $k \left(k = 1 \to K\right)$ burned at time *t*, and of the heat values of these fuels, $BTUC_{kt}$. These relationships can be summarized as follows:

$$KW_t = f_{KW}\left(D_t\right) \tag{3.1}$$

$$\sum_{k=1}^{K} BTUC_{kt} \cdot X_{kt} = f_H(KW_t) \tag{3.2}$$

The heat function f_H is often approximated linearly, with $f_H(KW_t) = \lambda KW_t$ where $\lambda =$ Heat input per *kW* output. In the above, X_{kt} is a decision variable, whereas D_t, KW_t, and $BTUC_{kt}$ are exogenous parameters.

The gross SO_2 emission, GE_t is a function of the SO_2 emission factors for fuel *k*, e_k, and the amounts of fuel *k*, X_{kt}, with:

$$\sum_{k=1}^{K} e_k X_{kt} = GE_t \tag{3.3}$$

Assume that the plant has enough FGD capacity (exogenous parameter) to treat any gross SO_2 emission flow. The net SO_2 emission, NE_t, is a function of the abatement efficiency , ε , and the gross SO_2 emission treated in period t, GET_t. The total gross SO_2 emission, GE_t is the sum of the treated and untreated gross SO_2 emissions. This is summarized by the following equations:

$$NE_t = (1-\varepsilon)GET_t \tag{3.4}$$

$$GET_t + GENT_t = GE_t \tag{3.5}$$

where $GENT_t$ = gross SO_2 emissions not treated in period *t*.

The fuel inventory system is characterized by a lagged accounting relationship between fuel shipments, SH_{kt}, fuel stocks, ST_{kt}, and fuel consumptions, X_{kt}. Fuels are shipped to a power plant to meet present and future fuel requirements to generate electricity, with:

$$ST_{k,t-1} - X_{kt} + SH_{kt} = ST_{kt} \qquad (t-1\text{: previous period}) \tag{3.6}$$

The purchasing cost of fuel k at time t, PC_{kt}, is a function of fuel qualities, such as the Btu value (BTU_{kt}) and sulfur content ($SO2_{kt}$) of the fuel purchased/shipped. If a plant operator is allowed to emit more SO_2, he may reduce fuel purchasing costs by using fuels with higher sulfur contents. There may, however, be a trade-off between heat values and sulfur contents. For instance, Western coals have both lower heat values and lower sulfur contents than Appalachian coals. In general:

$$PC_{kt} = f_{PC}(BTU_{kt}, SO2_{kt}) \tag{3.7}$$

Operations and management costs (O&M) at time t, OC_t, are a function of the power load, KW_t. SO_2 abatement costs, AC_t, and byproduct sales revenues, R_t, are functions of the gross SO_2 emissions *treated* in period t $(1 \rightarrow T)$, GET_t. These relationships are summarized as follows:

$$OC_t = f_{OC}(KW_t) \tag{3.8}$$
$$AC_t = f_{AC}(GET_t) \tag{3.9}$$
$$R_t = f_R(GET_t) \tag{3.10}$$

Finally, the net costs related to the sales and/or purchases of allowances, TPC, can be computed as follows:

$$TPC = UTC \cdot (PAL - SAL) \tag{3.11}$$

where

UTC : Unit price for an SO_2 emission allowance,

SAL : Amount of SO_2 emission allowances sold,

PAL : Amount of SO_2 emission allowances purchased.

The accumulated net SO_2 emissions during a year may not exceed the total annual emission allowances, A, after adjusting for allowance trading. It follows that:

$$\sum_{t=1}^{T} NE_t - SAL + PAL = A \tag{3.12}$$

The pollution concentration at any receptor should meet ambient air quality standards. At any time *t* during a given year, the SO_2 concentration at some control location, S_t, is a function of net SO_2 emissions, NE_t, and meteorological variables, such as wind speed, W_t. The sum of the SO_2 concentration, S_t, and the background pollution concentration, SB_t, must meet the ambient air quality standard, S_t^*. It follows that:

$$S_t = f_S(NE_t, W_t) \tag{3.13}$$

$$S_t + SB_t \le S_t^* \tag{3.14}$$

3.2.2 Perfect Foresight Model Objective Function

The total plant cost is the sum of the fuel purchasing costs, O&M costs, SO_2 emission trading costs, and pollution abatement costs, minus byproduct sales revenues. The objective of the power plant is to minimize

$$TC = \sum_{k=1}^{K} \sum_{t=1}^{T} PC_{kt} \cdot SH_{kt} + OC_t + AC_t + TPC - R_t \tag{3.15}$$

where

$TC =$ Total Costs
$PC_{kt} =$ Purchasing price of fuel *k* at time *t*
$SH_{kt} =$ Amount of fuel *k* purchased at time *t*
$OC_t =$ O&M costs at time *t*
$AC_t =$ Pollution abatement costs at time *t*
$TPC =$ Net costs of sales/purchases of allowances
$R_t =$ Byproduct sales revenue (fly ash, bottom ash, FGD byproduct, etc.)

In fact, however, the objective of the operators could be anything as long as it is not maximizing social welfare. Operators could be satisficers or revenue maximizers. However, policy decision makers, who are interested in minimizing pollution and its impact, have as objective function the maximization of aggregate social welfare, which has a public health component and a standard-of-living component. The former can be improved by reducing pollution emissions, but reducing emissions may decrease the standard of living because, *ceteris paribus*, it reduces output and/or increases prices. Public policy makers need to balance public health concerns against economic efficiency. This is clearly not the issue of concern for the plant operator.

3.3. Myopic Model

The perfect foresight optimization model presented in the previous section determines the optimal values of the endogenous variables (or decision variables), that represent the plant operator's decisions, subject to the constraints and the values of the exogenous variables (or parameters). The endogenous variables are the fuel shipments, SH_{kt}, the fuel consumptions, X_{kt}, and the net emissions, NE_{kt}. These variables are implicitly functions of all the exogenous variables, which can be subsumed into the vectors $\boldsymbol{Y_t}$ $(t = 1 \rightarrow T)$ for those varying with *t* (*e.g.*, fuel prices) and ***Z*** for those that do not vary with *t* (*e.g.*, allowances). It follows that:

$$\begin{aligned} SH_{kt} &= f\,(\boldsymbol{Y_t}\,|t = 1 \rightarrow T,\ \boldsymbol{Z}) \\ X_{kt} &= g\,(\boldsymbol{Y_t}\,|t = 1 \rightarrow T,\ \boldsymbol{Z}) \\ NE_{kt} &= h\,(\boldsymbol{Y_t}\,|t = 1 \rightarrow T,\ \boldsymbol{Z}) \end{aligned} \qquad (3.16)$$

The above functions could be obtained by solving the optimization model for a large number of combinations of values for the exogenous variables, and then relating the optimal values of the decision variables to the exogenous ones through curve-fitting, using regression analysis. However, the optimization model is a general framework, but not completely realistic, because it assumes perfect knowledge of all the parameters for the whole period. At any time *t*, the plant operator has perfect knowledge of the values of Z and of past observed values of Z_τ $(\tau = 1 \rightarrow t)$. He may also be able to make forecasts, over the period $[\,t+1 \rightarrow t+\theta\,]$, of some of the exogenous variables (*e.g.*, electricity demand, fuel prices), using in-house or external (e.g., governmental) forecasting models. Let Y_{t+k}^F be this subset forecast for time $t+k$.

At any time t, the plant operator optimizes myopically under a full knowledge of the past and a limited knowledge of the future. Therefore, only a subset of the variables/ parameters are likely to appear in equation (3.16). It is also likely that this myopic optimization process involves relating some endogenous variables to other endogenous variables, in addition to the exogenous variables. Equations (3.16) are then reformulated as follows:

$$\begin{aligned} SH_{kt} &= f\left(Other\ Endogenous\ Variables,\ Z_\tau \middle| \tau = 1 \to t,\ Y^F_{t+k} \middle| k = 1 \to \theta\right) \\ X_{kt} &= g\left(Other\ Endogenous\ Variables,\ Z_\tau \middle| \tau = 1 \to t,\ Y^F_{t+k} \middle| k = 1 \to \theta\right) \\ NE_{kt} &= h\left(Other\ Endogenous\ Variables,\ Z_\tau \middle| \tau = 1 \to t,\ Y^F_{t+k} \middle| k = 1 \to \theta\right) \end{aligned} \tag{3.17}$$

A set of reasonable causal relationships that reflect Equations (3.17) is outlined in the following subsections.

3.3.1 Exogenous *vs*. Endogenous Variables

The exogenous variables (parameters) include: (1) *electricity generation* (demands, KW_t); (2) *emission control factors*, such as abatement efficiency (ε), and FGD capacity (FGD); (3) *meteorological factors*, such as wind speed (W_t); (4) *time factors*, such as seasonality and a continuous time trend; (5) *policy factors*, such as the annual SO_2 emission allowances (A); and (6) *financial factors*, such as unit fuel purchasing costs (PC_t), O&M unit costs, SO_2 emission abatement unit costs, unit costs of emission trading, and byproduct unit sales revenue.

The endogenous variables can be grouped into five categories: (1) Btu shipments (MMBtu), (2) Btu consumptions (MMBtu), (3) sulfur shipments (lb/MMBtu), (4) gross SO_2 emissions (lb/MMBtu), and (5) net SO_2 emissions (lb/MMBtu). Plant operators select individual fuels, their quantities, and the timing of their shipments and consumptions. Each fuel is characterized by its price and heat and sulfur contents, that may vary with time. Because of the great diversity in fuels, it is impractical to include each individual fuel in an empirical analysis. Hence, only the aggregation of the fuels used by a plant operator is considered here, measured by both its energy value (MMBtu) and its total sulfur load (lb/MMBtu).

3.3.2 Btu Shipments Sub-Model

Btu shipments are a good starting point to determine the flow of energy throughout the system. Decisions on Btu shipments are determined by other endogenous variables, such as expected future fuel use. Various time lags between Btu shipments and future consumptions must be considered in this model.

Among the exogenous factors, fuel prices (unit fuel purchasing costs) and fuel inventory are likely to determine Btu shipments. Higher fuel prices are likely to reduce Btu shipments. The fuel stock level at the end of period $m-1$ is also likely to have an effect on fuel procurement, the higher the stock the lower the shipment. A generalized shipment model can then be formulated as follows:

$$\begin{pmatrix} Btu\ shipments \\ in\ month\ m \end{pmatrix} = f_{SH}\begin{pmatrix} Expected\ \ future\ Btu\ consumptions\ (m+k) \\ Fuel\ stocks\ (m-1) \\ Fuel\ \ prices\ (m) \end{pmatrix} \qquad (3.18)$$

3.3.3 Btu Consumptions Sub-Model

Because of basic engineering/physical considerations, fuel consumption is directly related to electricity generation, with:

$$\begin{pmatrix} Btu\ consumption \\ in\ month\ m \end{pmatrix} = f_{CON}\left(Net\ electricity\ generations\ in\ m\right) \tag{3.19}$$

3.3.4 Sulfur Shipments Sub-Model

Sulfur shipments, measured in terms of the sulfur amounts per Btu of shipment, may be influenced by gross SO_2 emissions, an endogenous variable. Past sulfur shipments, that reflect long-term contracts with suppliers, are also likely to influence current shipments. Exogenous variables, such as fuel prices, annual SO_2 emissions allowances, FGD capacity and abatement efficiency, can affect sulfur shipments. If a plant has higher allowances or has an FGD capacity, larger sulfur shipments are likely. Fluctuations in the prices of coal, petroleum, and natural gas may induce fuel shifts, hence sulfur shipments are likely to vary according to fuel prices. In addition, a continuous time variable and a seasonal dummy variable (winter *vs*. summer) may further explain sulfur shipments trends over months, seasons, and years. Based on these considerations, a generalized shipments model can be formulated as follows:

$$\begin{pmatrix} Unit\ sulfur \\ shipments \\ in\ month\ m \end{pmatrix} = f_{SSH} \begin{pmatrix} Unit\ gross\ SO_2\ emissions\ (m) \\ Unit\ sulfur\ shipments\ (m-k) \\ SO_2\ emission\ allowances \\ FGD\ capacity \\ Abatement\ efficiency \\ Fuel\ \ prices \\ Time\ index \\ Seasonal\ \ factor \end{pmatrix} \tag{3.20}$$

3.3.5 Gross SO_2 Emissions Sub-Model

Gross SO_2 emissions, measured in terms of pounds of SO_2 per Btu of fuels burned, are likely to be influenced by two other endogenous variables: sulfur shipments and net SO_2 emissions. Clearly, gross emissions are linked to the sulfur content of the fuel stockpile, which results from the accumulation of past and present shipments. However, the choice of which fuels to burn is also a function of the net amount of pollutants to be emitted into the atmosphere. The exogenous variables include abatement efficiency and FGD capacity. Higher abatement efficiency and FGD capacity should allow for higher unit gross SO_2 emissions. As for the sulfur shipments model, a continuous time index and a seasonal dummy variable are included. A generalized unit gross SO_2 emission model can be expressed as follows:

$$\begin{pmatrix} \textit{Unit gross} \\ SO_2 \textit{ emissions} \\ \textit{in month } m \end{pmatrix} = f_{SCON} \begin{pmatrix} \textit{Unit Net } SO_2 \textit{ emissions } (m) \\ \textit{Unit sulfur shipments } (m) \\ \textit{Unit sulfur shipments } (m-k) \\ \textit{Abatement efficiency} \\ \textit{FGD capacity} \\ \textit{Time index} \\ \textit{Seasonal factor} \end{pmatrix} \tag{3.21}$$

3.3.6 Net SO_2 Emissions Sub-Model

Gross SO_2 emissions are clearly a strong determinant of net emissions. The exogenous factors include: (1) *policy factors*, such as the annual SO_2 allowances; (2) *emission control factors*, such as the FGD capacity; (3) *meteorological factor*, such as wind speed; and (4) *time and seasonal factors*. A generalized model formulation is as follows:

$$\begin{pmatrix} \textit{Unit Net } SO_2 \\ \textit{Emissions} \\ \textit{in month } m \end{pmatrix} = f_{NE} \begin{pmatrix} \textit{Unit gross } SO_2 \textit{ emissions } (m) \\ SO_2 \textit{ emission allowances} \\ \textit{Emissions control factors} \\ \textit{Meteorological factor} \\ \textit{Time index} \\ \textit{Seasonal factor} \end{pmatrix} \tag{3.22}$$

3.3.7 Fuel Share Sub-Models

In the preceding sections, no distinctions were made among fuels (coal, petroleum, natural gas), and only the total energy value and sulfur shipments of all fuels were considered. To distinguish among fuels, two types of share models will be estimated, for fuel shipments and net electricity generations. The effects of fuel prices on fuel choices have been explored, among others, by Baughman and Joskow (1975). The analysis of fuel shipment shares should provide information on how the shipment of a certain type of fuel in month *m* is modified by the prices of fuels in month *m*. The electricity generation fuel share model is similar, but uses fuel prices in earlier month $m-k$, because of the lagged relationship between fuel shipments and fuel consumptions. The generalized forms of the share models are:

$$\begin{pmatrix} Fuel\ shipment\ share \\ in\ month\ m \end{pmatrix} = f_{SF} \begin{pmatrix} Unit\ fuel\ purchasing\ prices \\ of\ coal,\ petroleum,\ and \\ natural\ gas\ in\ month\ m \end{pmatrix} \quad (3.23)$$

$$\begin{pmatrix} Electricity\ generation \\ fuel\ share\ in\ month\ m \end{pmatrix} = f_{SG} \begin{pmatrix} Unit\ fuel\ purchasing\ prices \\ of\ coal,\ petroleum,\ and \\ natural\ gas\ in\ months\ m-k \end{pmatrix} \quad (3.24)$$

Synthesizing all the above models, Figure 3.1 illustrates the interrelationships among the endogenous and exogenous variables.

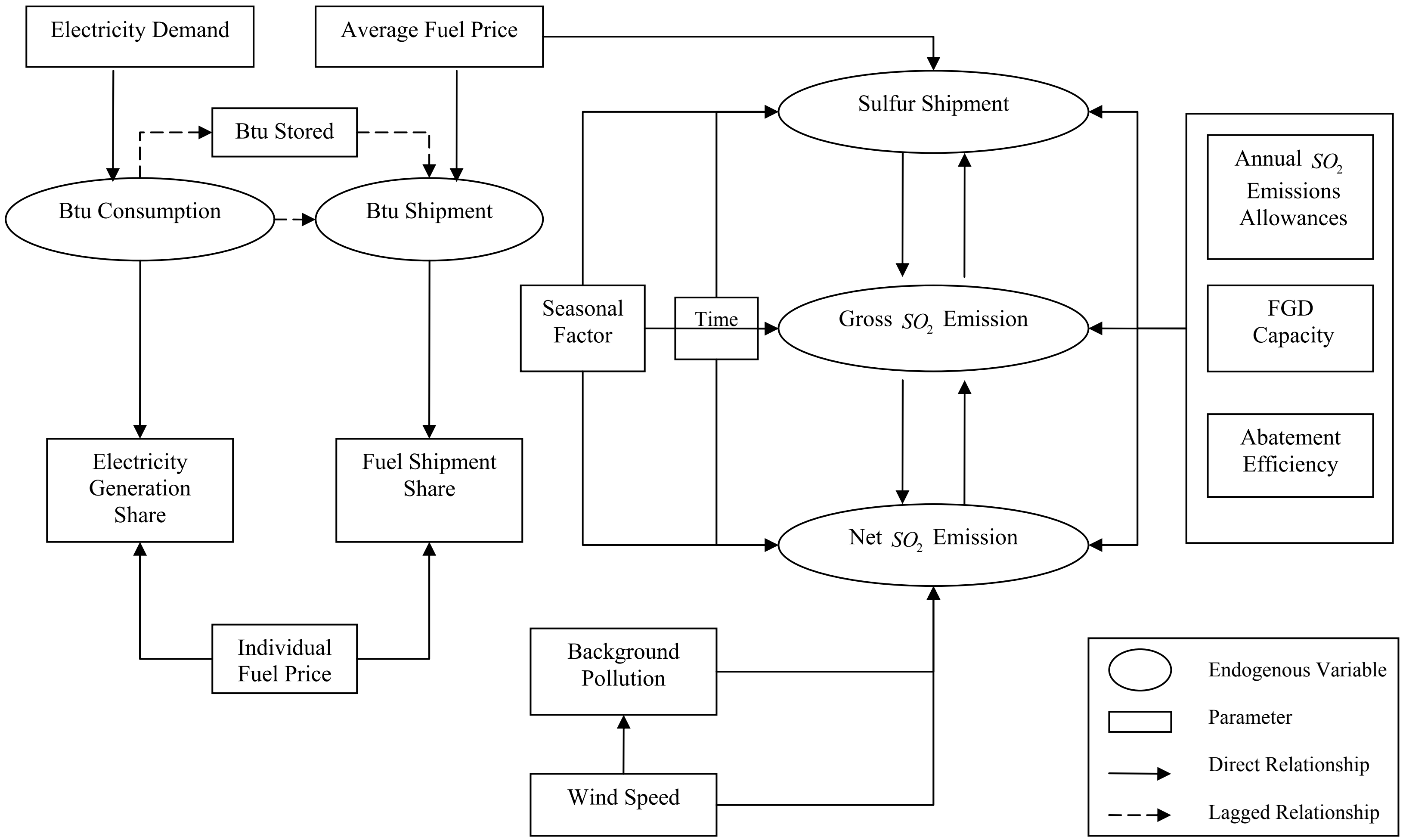

Figure 3.1: Expected interactions among energy, environmental, and policy factors

CHAPTER 4

DATA SOURCES AND PROCESSING

The empirical estimation of the models developed in Chapter 3 requires power plant-related data on: (1) *energy factors,* such as Btu values of fuel shipments, fuel inventories, and fuel consumptions, electricity generations, and fuel purchasing costs; (2) *environmental factors*, such as meteorological conditions and air pollution (sulfur contents of fuel shipments, net SO_2 emissions, gross SO_2 emissions, abatement efficiency, flue gas desulfurization facilities); and (3) *policy factors*, such as annual SO_2 emission allowances. These data are obtained from various databases produced by the Environmental Protection Agency (EPA)[5], the Energy Information Administration (EIA)[6], and the National Climatic Data Center (NCDC)[7].

The EPA provides the continuous emission monitoring system (CEMS) and SO_2 emissions trading and auction reserve databases. The EIA provides various power plant-related databases, such as the Federal Energy Regulatory Commission (FERC) Form 423,

[5] http://www.epa.gov
[6] http://www.eia.doe.gov
[7] http://www.ncdc.noaa.gov/oa/ncdc.html

the EIA Forms 767 and 906, and the Clean Air Act database browser (CAADB)[8], which includes Phase I and Phase II annual SO_2 emission allowances. Finally, the NCDC includes databases for meteorological conditions such as wind speeds and temperatures[9], and for the locations of weather monitoring stations[10]. The structure of the overall database for this research is illustrated in Figure 4.1.

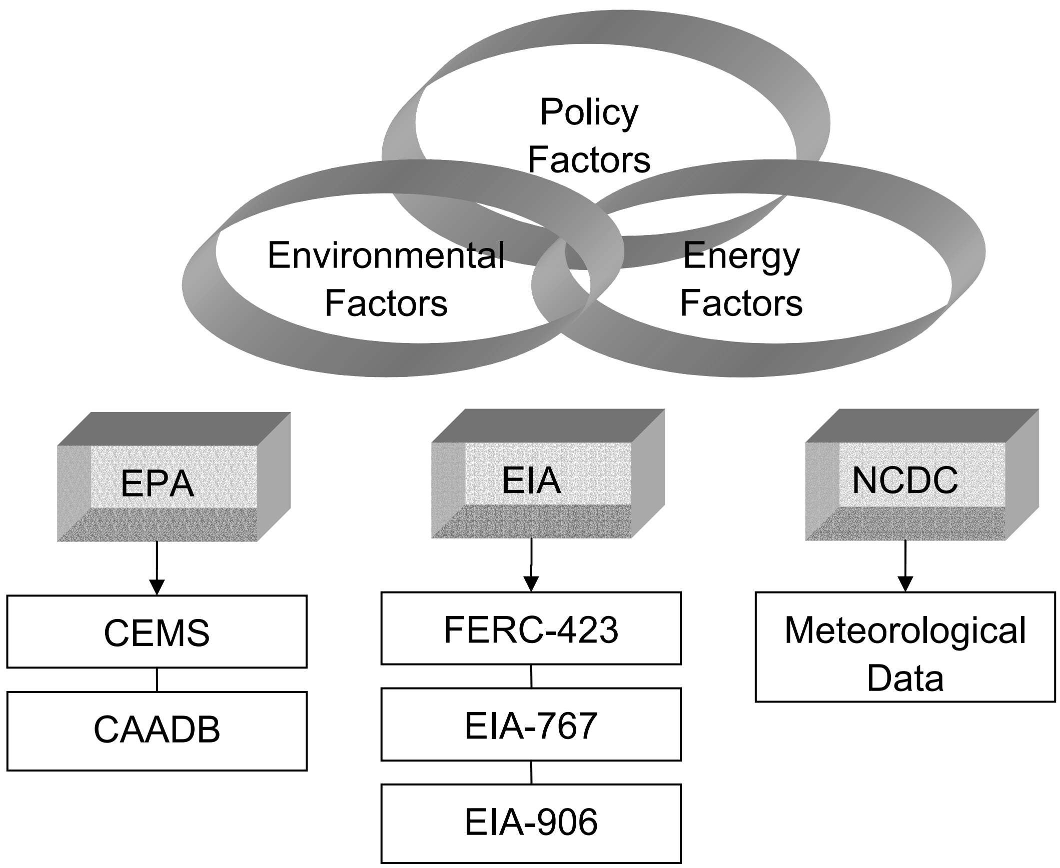

Figure 4.1: Structure of research database

[8] http://www.eia.doe.gov/cneaf/electricity/page/caa_browse.html
[9] http://www.ncdc.noaa.gov/cgi-bin/res40.pl
[10] http://lwf.ncdc.noaa.gov/oa/climate/climate data.html

4.1 Data Sources

4.1.1 FERC Form 423

FERC Form 423 includes data on all monthly fuel shipments to steam-electric and combined-cycle power plants with a capacity of at least 50 MW. More than 90 % of all fossil-fuel generating capacity in the U.S. is included in this database. The data can be summarized by company, plant, year and month, and include the plant nameplate capacity, coal-shipping mine types, general fuel type, specific fuel type, fuel quantity, Btu content, sulfur content, ash content, and fuel purchasing costs (including transportation and taxes). The precise definitions of all the variables in FERC Form 423, as well as a sample of the database are presented in Appendix A (Tables A.1 and A.2).

4.1.2 Form EIA-767

Form EIA-767 includes annual and monthly operations and design data for fossil- and nuclear-fueled steam electric plants with a generator nameplate capacity of 10 or more megawatts. This database includes 16 to 18 annual files, with data on boilers, cooling systems, generators, flue gas particulate collectors, and flue gas desulfurization units. The summary levels of this database are the plant, the boiler, the year and the month. Variables of particular interest are monthly fuel consumptions, heat content, and sulfur content for coal, petroleum, and natural gas; plant locations; monthly net electricity generations; SO_2 FGD removal efficiency, annual O&M expenditures, annual capital expenditure, and byproduct sales revenues. Detailed definitions of all these variables and data samples of Form EIA-767 are presented in Appendix A (Tables A.3 – A.16).

4.1.3 Form EIA-906

Form EIA-906 (formerly Form EIA-759) provides monthly operating data on power plants. The data are characterized by Census region, company, type of ownership, plant, prime mover, year, and month. The variables of particular interest are monthly fuel consumptions, fuel stocks, and net electricity generations. Fuel stocks can be useful to relate fuel shipments to fuel consumptions, and are found in this database only (see Appendix A, Tables A.17 and A.18).

4.1.4 The Clean Air Act Database Browser (CAADB)

The CAADB consists of several files, such as emissions, Phase I and II compliance, fuel shifts, and scrubbers. Emissions data include the actual total SO_2 emissions in 1985, 1990, 1994, and 1995, while Phase I and Phase II files include the annual SO_2 emissions allowances of the affected units. These allowances are limited to 2.5 pounds of sulfur dioxide per million Btu of heat input for both Phases I and II. The source of these data is the EPA TRAC system, which uses early versions of the National Allowance Data Base (NADB). Additionally, the compliance file indicates the primary methods of compliance for all plants that are affected by Phase I and II of the Clean Air Act Amendments (CAAA) of 1990. The fuel shifts file indicates how plants have shifted their primary fuels due to the CAAA of 1990. The scrubbers file provides information on all flue gas desulfurization (FGD) units installed in U.S. power plants. Detailed definitions of the variables and a sample of the CAADB are presented in Appendix A (Tables A.19 – A.26).

4.1.5 CEMS

CEMS is a "continuous emission monitoring system" used to estimate SO_2, NO_X, and CO_2 emissions. Under the Acid Rain Program of the EPA, the installation of a CEM system is mandatory for all units with a capacity over 25 megawatts, and for new units under 25 megawatts that use a fuel with a sulfur content greater than 0.05 percent by weight. The system monitors the continuous pollutant flow emitted into the atmosphere as exhaust gases from combustion and industrial processes. Before the introduction of CEM systems, the traditional emission regulation method was to maintain specific emissions rates by using mandatory technology. In contrast, a CEM system measures all emission flows from all regulated units, so that the emissions accumulated over a year can be compared to the annual emission allowances. If the accumulated emissions exceed the allowances, penalty fees must be paid for the excess emissions.

For SO_2 emissions, two major files were derived from the CEMS database: SO_2 emissions data (CEMSO2) and unit operating data (CEMUOP). The CEMSO2 file includes the measured SO_2 emission rate for any hour, and the corresponding adjusted SO_2 emission rate. Bias and inconsistency in the CEM data have been of particular concern to the EPA, so adjustments are possibly made for each hour after examining the calibration of the flow monitor. The CEMUOP file includes: the unit operation duration ($0-1\ hr$), the gross unit load during unit operation, and the heat input rate. For both the CEMSO2 and CEMUOP files, the summary levels are the plant, the stack, the year, the month, the day, and the hour. More detailed descriptions of the CEMS variables and a sample of this database can be seen in Appendix A (Tables A.27 – A.30).

4.1.6 SO_2 Emissions Trading

One of the important changes in the CAAA of 1990 is the introduction of marketable permits that allow distribution of allowances among the various generating units of the same company, and trading among companies. Trading-related data have been downloaded from EPA websites[11], including the total SO_2 emission allowance purchasing cost and the total reserved auction amounts. The summary levels are the power plant and the year. As a result of emissions trading, the plants that violate their annual allowance limits may select one of two options: paying violation fees or purchasing tradable permits. Since the purpose of emissions trading is to reduce global air pollution while maintaining efficient economic activities, trading-related variables can be viewed as policy variables (see Appendix A, Tables A.31 and A.32).

4.1.7 Meteorological Data

The global Surface Summary of Day file (version 6 – January 1994 to present), downloaded from the National Climatic Data Center (NCDC) official website[12], includes various meteorological data for over 8000 worldwide monitoring stations, with over 1000 in the U.S. The observed hourly data are summarized by day, and the selected variables are the mean temperature (Fahrenheit), the mean visibility (miles), the mean wind speed (knots), the snow depth (inches), precipitations (inches), etc. Detailed descriptions of the variables and a data sample can be found in Appendix A (Table A.33).

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[10] http://www.epa.gov/airmarkets/auctions/index.html, http://www.epa.gov/airmarkets/allocations/index.html
[12] http://www.ncdc.noaa.gov/oa/climate/climatedata.html#SURFACE

4.2 Data Processing

4.2.1 Overview

In this research, a large number of variables from various sources is considered, as illustrated in Appendix A. In order to use these variables, several conditions must be met. First, continuous monthly time series must be maintained. Hourly time series must also be maintained because, in the case of the CEMS, monthly data are the sums of hourly data. Second, the various files must have the same structure so that they can be merged easily. For example, the monthly fuel consumption data in Form EIA-767 are organized over 12 columns (one for each month), whereas the monthly fuel shipments in FERC Form-423 occupy just one column. In order to merge the two databases, one of these structures must be transposed to fit the other structure. Third, records having invalid values or abnormal ratios must be eliminated from the sample. For example, the ratio of net SO_2 emissions in CEMSO2 to gross SO_2 emissions in Form EIA-767 cannot, logically, exceed the value 1. Also, if some values for a given variable are abnormally higher or lower than most other values, they probably reflect a measurement or data input error, and must be deleted from the database. Fourth, the measurement units of related variables should be identical. For instance, fuel quantities in FERC Form-423 are measured in different weight or volumetric units, according to the fuel used, *i.e.*, coal, petroleum, and natural gas. A universal unit such as the MMBtu (million British thermal units) must replace the original units (*i.e.*, short tons, barrels, and cubic feet), so that comparisons and calculations can be performed (*e.g.* sulfur dioxide amount per MMBtu). Finally, all the databases used in this research must be summarized at the appropriate levels (plant, year, and month), so that they can be matched together. As an example, meteorological conditions, such as wind speeds or temperatures, are measured at monitoring stations, the locations of which do not exactly match the locations of SO_2 emitting power plants. Since the other databases have no weather monitoring station codes, this code is replaced by the closest plant code.

The Statistical Analysis System (SAS) software is used to process the data and resolve the above critical issues. Geographic Information Systems (GIS) tools such as TransCAD 4.0 and ArcGIS 8.2, are used for the geocoding of locations and the calculation of distances between meteorological monitoring stations and power plants. The data span the five-year period between 1996 and 2000. The sizes of the source files are: CEMS – 1.06 GB for CEMSO2 and 2.95 GB for CEMUOP; FERC Form-423 – 13.5 MB; SO_2 Emissions Trading – 9.2 MB; EIA Form-767 – 67.4 MB; EIA Form-906 – 10.7 MB; CAADB – 10.3 MB; and Meteorological Data/Monitoring Stations – 1.63 GB. The total size of the source data files is approximately 5.64 GB. The specific data processing procedures are explained below.

4.2.2 Processing of FERC Form 423

Although the final summary level of FERC Form 423 is the month, the monthly shipment data for a given plant occupy more than one record in the source file, because each record corresponds to a separate fuel shipment characterized by its origin (county) and type of fuel. It is therefore necessary to sum up the multiple records for a given month for further analysis. However, one problem in this aggregation is that the shipped fuels in each record have different heat values and sulfur contents, so that the physical fuel quantities cannot be simply summed up. For this reason, the physical measurement units for fuel quantities (thousand short tons, thousand barrels, and million cubic feet) are converted to a common measure, the million Btu (MMBtu). Using these MMBtu measures, and the aggregate sulfur amounts and fuel purchasing costs, unique values for sulfur (potential gross SO_2 emissions), and fuel purchasing costs per MMBtu are computed for each plant and month. The SAS program is presented in Appendix B (Program B.1). In order to check the accuracy of the computed variables, they are aggregated by state of origin and by state of plant location, and then compared to the same summary data in published EIA reports (Cost and Quality of Fuels for Electric Utility Plants 1996/ 1997/ 1998/ 1999/ 2000 and Electric Power Annual 1996/ 1997/ 1998/ 1999/ 2000). The computed numbers turned out exactly the same or very close to the published numbers.

4.2.3 Processing of Form EIA-767

From the source files of Form EIA-767, fuel consumptions (in MMBtu) and gross SO_2 emissions (in lb) are computed using the same procedure as in FERC Form 423, and the accuracy of the computed variables is also checked using EIA reports on energy trends. One additional manipulation involves changing the data file structure, because all monthly fuel consumptions data occupy the same record. This horizontal data structure is transformed into a vertical structure, using the loop and layer functions of SAS, and this method is also applied to the computation of net electricity generations (kW) (see SAS program in Appendix B (Program B.2).

4.2.4 Processing of Form EIA-906

This database has the same horizontal structure as Form EIA-767, and some of the variables are the same (fuel consumption and net electricity generation). In contrast to EIA-767, this database includes fuel stock data, without, however, quality variables such as Btu or sulfur contents. Since these fuel quality data are not available, it is impossible to calculate unit inventory variables. Moreover, stock data for 1999 and 2000 are completely missing in this database. The structure of this database is transposed into a vertical structure for final merging (see the SAS program in Appendix B: Program B.3).

4.2.5 Processing of CEMS

The enormous size of the CEMS database creates difficulties for data processing. For the CEMUOP file, initially 46 smaller files, including hourly gross electricity load and hourly heat input rate during unit operation for all fuels, are concatenated into 5 annual files (1996-2000), as the 46 files cannot be concatenated into one unique file, even with a powerful IBM personal computer (Pentium 4, 2.4 GHZ, 120-GB ROM, 1024-MB RAM). During this process, plants with codes with more than four-digits were eliminated because these plants are the most recently built ones and do not have records for the early part of the study period (1996-2000). The initial number of hourly observations, 104.2

million (2.95 GB), is reduced to 41,934 observations (1.6 MB) after summarizing the data by plant, year, and month.

The initial source files for CEMSO2 are concatenated into two files having 21.7 and 14.5 million observations, respectively. Before summarizing the hourly records into monthly records, the records having abnormal values are either corrected or eliminated. First, invalid dates, including year, month, day, and hour, are corrected by column realignment, or deleted from the database. If the number of erroneous hourly or daily records for a given plant is negligible, this plant is retained, so as to increase the size of the potential sample. Second, negative values for both adjusted and unadjusted SO_2 emissions are disregarded, because these values are very close to 'zero', meaning no emissions. Finally, some unique values such as '9999.9' or '99999.9' are treated as missing values, while 'zero' is kept as a legitimate value. After addressing the abnormal values issue, the values of adjusted and unadjusted SO_2 emissions are compared to determine which variable is more stable. As a result, the unadjusted emissions variable is eliminated from the database.

After deleting the invalid records from the CEMSO2 files, the ratios of net SO_2 emissions (CEMSO2) to gross SO_2 emissions (Form EIA-767), and the ratios of net (Form EIA-767 and Form EIA-906) to gross (CEMUOP) electricity generations are computed for each plant. Plants are eliminated when these ratios exceed threshold values, taken equal to 1.1 for the electricity generation ratio, and to 1.3 for the SO_2 emissions ratio (corresponding to the upper 95% quantile of the ratios distributions). Also, plants having negative ratios are deleted from the final sample. Additional plants are deleted due to a mismatch between SO_2 emissions and electricity generation loads: for instance, non-zero emission and zero load. The number of plants in the final sample is reduced to 405, out of 1,001 initially. In addition, a dummy variable indicating the existence of FGD facilities is created based on the net to gross SO_2 emissions ratios. (see the SAS program in Appendix B: Program B.4)

4.2.6 Processing of Meteorological Data

The NCDC files provide daily monitoring data of wind speeds and temperatures, by monitoring station. After concatenating the daily data files, monthly mean values are computed. Using a spatial analysis procedure available in TransCAD 4.0, the locations of power plants and weather monitoring stations are geocoded, and monitoring stations are assigned to the closest power plants, using the shortest straight-line distances between them. To reduce the number of missing values for meteorological variables, monitoring stations which have many missing values are disregarded. The maximum distances between plants and monitoring stations is 69 miles, and the mean distance 13.98 miles. A map of monitoring stations and power plants is presented in Figure 4.2.

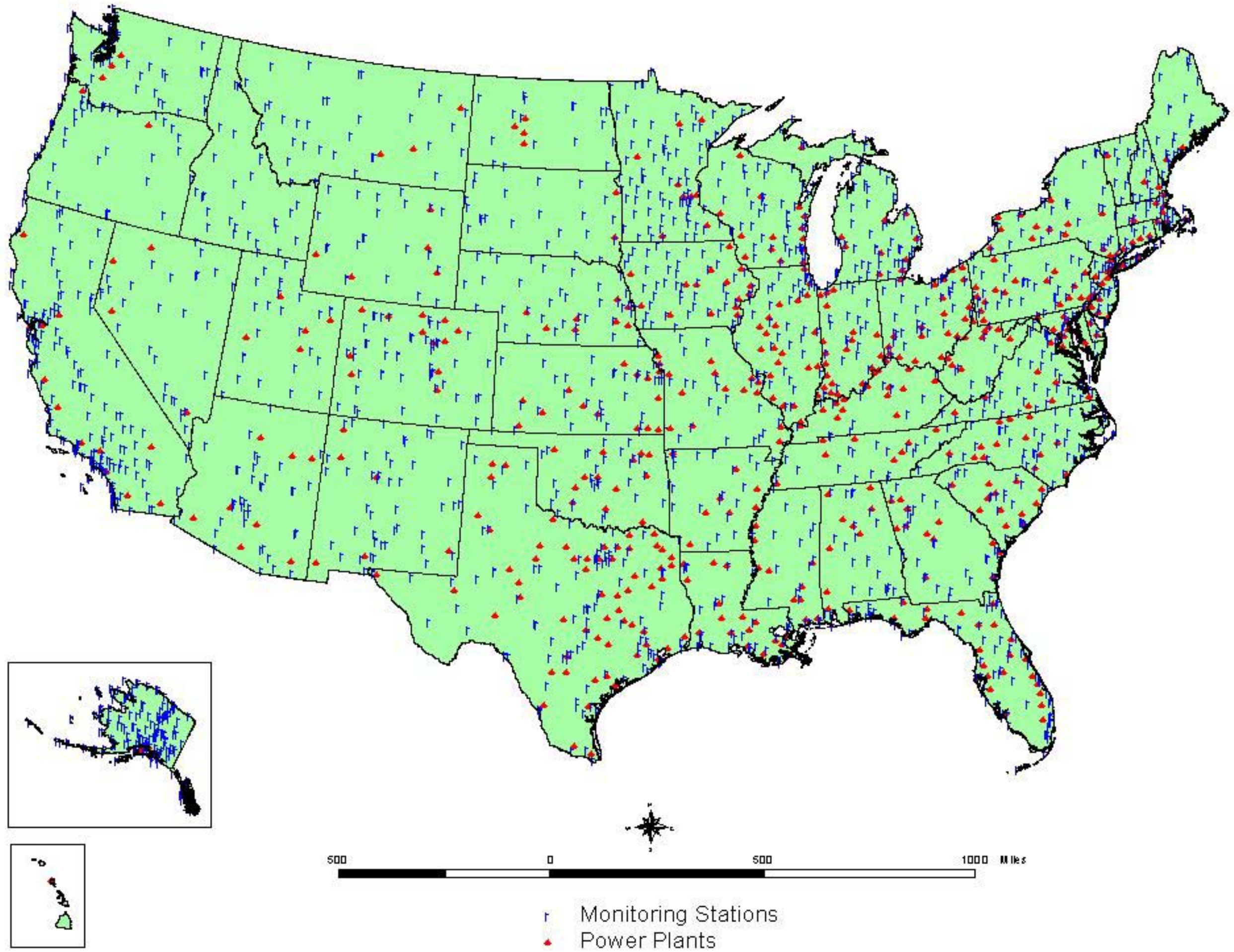

Figure 4.2: Locations of power plants and monitoring stations

4.3 Final Sample

All the above-mentioned variables, some other variables in the CAADB, and the emissions trading database are merged together. The combined database has 20,237 monthly observations and 126 variables. Some records with possibly abnormal values are coded 1 through 8, for further possible adjustment during model runs. The SAS program for the final data processing procedures and the complete list of the 126 variables are provided in Appendix B (Program B.5).

CHAPTER 5

EXPLORATORY ANALYSES

To achieve a better understanding of SO_2 emissions patterns at U.S. power plants, a series of exploratory analyses of recent trends of fuel use, fuel purchasing costs, sulfur dioxide gross and net emissions, and electricity generations, are presented in this chapter. This exploratory analysis consists of state level- and plant-level analyses, and various trends and relationships among energy, environmental, and regulatory factors are illustrated. The purpose of these analyses is (1) to uncover the effects of the 1990 CAAA, and (2) to assess the monthly, seasonal, and annual variations of SO_2 emissions and electricity generations, and their dynamic interactions. For state-level analyses, data is aggregated by census region to illustrate the regional trends of fuel use and SO_2 emissions. States are grouped into 9 census regions, as presented in Table 5.1 and displayed in Figure 5.1. Plant-level analyses make use of 1996 data for 10 randomly selected power plants.

Table 5.1: Census Regions and States

Census Region	States
East North Central (ENC)	Illinois, Indiana, Michigan, Ohio, Wisconsin
East South Central (ESC)	Alabama, Kentucky, Mississippi, Tennessee
Mid Atlantic (MA)	New Jersey, New York, Pennsylvania
Mountain (MT)	Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming
New England (NE)	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
Pacific (PA)	Alaska, California, Hawaii, Oregon, Washington
South Atlantic (SA)	Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia
West North Central (WNC)	Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
West South Central (WSC)	Arkansas, Louisiana, Oklahoma, Texas

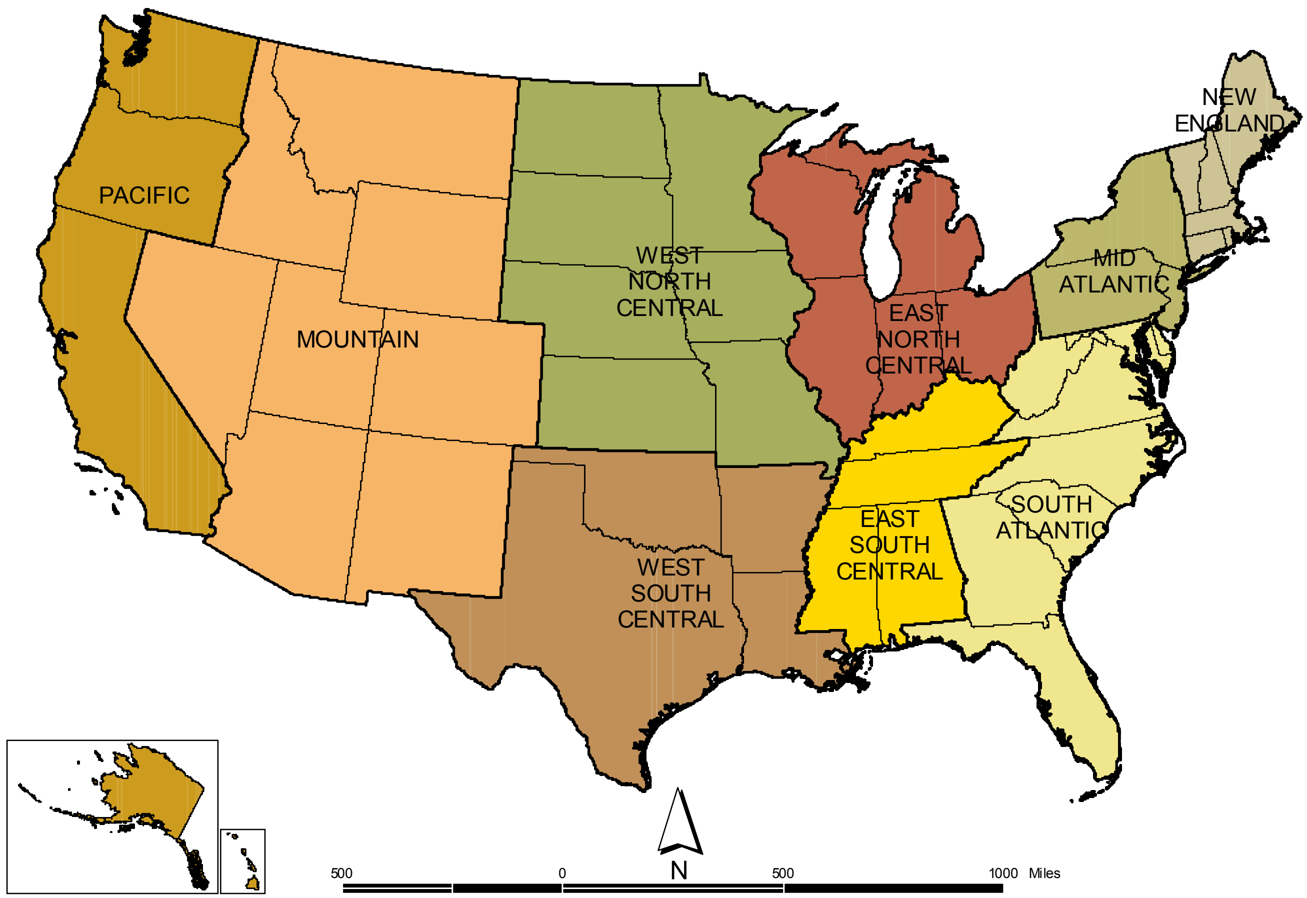

Figure 5.1: Census Regions and States

5.1 State-Level Analysis

5.1.1 Annual Trends

5.1.1.1 Annual Fuel Shipments and Consumptions

According to the Energy Information Administration (EIA), fossil fuels dominate the energy market, accounting for 85% of U.S. energy consumption. Among the three major fossil fuels (coal, petroleum, and natural gas), petroleum has had the largest share over the past several decades. On the other hand, coal has been used as the primary source for electricity generation at most U.S. power plants.

Table 5.2 presents fuel shipment patterns by census region during the period 1996-2000. Power plants in the East North Central (ENC), East South Central (ESC), Mountain (MT), South Atlantic (SA), and West North Central (WNC) regions, purchased mostly coal for electricity generation, with only small amounts of petroleum and natural gas purchased for probably reducing SO_2 emissions to meet the annual emission allowance limits. Among these regions, MT increased its share of natural gas shipments from 1996 to 2000. Power plants in the Mid Atlantic (MA) and West South Central (WSC) regions purchased more coal than other fuels, although not in a predominant fashion. In New England (NE), the shares of coal and petroleum shipments are close, and in the Pacific (PA) region the share of natural gas shipments is the largest. The average shares of coal, petroleum, and natural gas in the U.S. were stable over the five-year period, with a dominance of coal (more than 80%).

Table 5.2: Fuel shipments pattern by census region during the period 1996-2000

Census Region	Year	Coal	Petroleum	Natural Gas	Total (10^6 MMBtu)
East North Central	1996	98.6%	0.5%	0.9%	4198.6
	1997	98.2%	0.4%	1.4%	4386.1
	1998	97.5%	0.6%	1.9%	4562.1
	1999	97.7%	0.6%	1.7%	4393.9
	2000	98.6%	0.4%	0.9%	3650.6
East South Central	1996	96.5%	0.7%	2.8%	2354.6
	1997	96.7%	1.2%	2.1%	2453.4
	1998	95.1%	2.5%	2.4%	2447.7
	1999	95.1%	1.6%	3.3%	2386.3
	2000	95.4%	1.4%	3.2%	2324.5
Mid Atlantic	1996	79.8%	9.4%	10.8%	1605.2
	1997	78.9%	7.0%	14.1%	1719.3
	1998	76.4%	10.9%	12.6%	1842.5
	1999	73.6%	11.4%	15.1%	1425.3
	2000	59.7%	22.0%	18.3%	566.5
Mountain	1996	95.3%	0.1%	4.6%	2023.3
	1997	94.5%	0.1%	5.4%	2129.9
	1998	94.0%	0.1%	5.9%	2318.7
	1999	92.8%	0.1%	7.1%	2359.0
	2000	89.8%	0.2%	10.0%	2198.5
New England	1996	43.2%	33.9%	22.9%	417.1
	1997	35.9%	45.0%	19.1%	513.5
	1998	34.4%	54.0%	11.6%	419.8
	1999	30.9%	54.4%	14.8%	160.3
	2000	80.6%	7.5%	12.0%	64.1
Pacific	1996	17.9%	11.2%	70.9%	503.9
	1997	17.2%	8.2%	74.6%	555.5
	1998	27.1%	8.8%	64.1%	500.9
	1999	33.5%	17.2%	49.3%	393.9
	2000	19.8%	25.6%	54.6%	330.8
South Atlantic	1996	85.8%	6.6%	7.6%	4198.6
	1997	85.9%	6.6%	7.5%	4312.5
	1998	83.7%	10.0%	6.3%	4739.3
	1999	83.4%	9.3%	7.4%	4739.2
	2000	84.4%	8.5%	7.2%	4180.7
West North Central	1996	98.5%	0.2%	1.3%	2107.6
	1997	98.3%	0.3%	1.4%	2062.6
	1998	98.0%	0.2%	1.9%	2319.5
	1999	97.8%	0.2%	2.0%	2299.3
	2000	97.9%	0.3%	1.8%	2209.1
West South Central	1996	59.7%	0.2%	40.2%	3686.3
	1997	58.6%	0.3%	41.2%	3604.3
	1998	56.2%	0.3%	43.6%	4037.2
	1999	58.0%	0.1%	41.9%	4102.4
	2000	55.2%	0.2%	44.6%	3865.1
US	1996	84.2%	3.2%	12.6%	21095.3
	1997	83.6%	3.4%	13.0%	21737.1
	1998	82.6%	4.5%	12.9%	23187.6
	1999	83.4%	3.7%	12.9%	22259.7
	2000	82.9%	3.3%	13.8%	19389.9

Source: Computed from FERC Form 423

As can be seen in Table 5.3, fuel consumptions patterns are very similar to shipments patterns. Interestingly, the coal consumption share in 2000 is smaller than that in 1996 in every census region, implying increasing use of substitute fuels since the start of Phase II of the CAAA. As a result, the overall share of coal consumptions in the U.S. over 1996-2000 displays a decreasing trend. The fuel shipments and consumptions by individual states are presented in Appendix C (Tables C.1 and C.2).

As presented in Table 5.4 and Table 5.5, the Btu unit values of shipments and consumptions are close to constant for any given census region. When these unit values are compared across census regions, MA, NE, and SA have the highest unit heat values for coal, while WSC, PA, and WNC have the lowest ones. In the case of petroleum, MA, NE, and SA have relatively higher unit Btu values, while MT has the lowest one. Finally, natural gas has relatively constant heat values across the states, except for ENC which has the lowest ones in the shipment stage. The average unit Btu shipments and unit Btu consumptions in the U.S. display very little variability. Patterns of unit Btu values for shipments and consumptions by individual states are presented in Appendix C (Tables C.3 and C.4).

5.1.1.2 Annual Fuel Stocks

There are no data available for coal and petroleum stocks in 1999 and 2000. Increases or decreases in the amounts of stocks (coal – short tons; petroleum – barrel) do not necessarily point to a shift in fuel use. Table 5.6 suggests that more than two-thirds of the census regions have reduced their coal stock share. This may reflect an increasing

Table 5.3: Fuel consumptions pattern by census region during the period 1996-2000

Census Region	Year	Coal	Petroleum	Natural Gas	Total (10^6 MMBtu)
East North Central	1996	98.6%	0.6%	0.8%	4311.3
	1997	98.1%	0.4%	1.5%	4434.8
	1998	97.5%	0.5%	2.0%	4525.8
	1999	97.4%	0.5%	2.1%	4501.6
	2000	97.8%	0.3%	1.9%	4701.4
East South Central	1996	96.8%	0.6%	2.6%	2347.0
	1997	96.6%	1.2%	2.1%	2401.4
	1998	94.7%	2.3%	3.1%	2413.1
	1999	95.5%	1.3%	3.1%	2457.4
	2000	96.3%	1.2%	2.5%	2548.3
Mid Atlantic	1996	81.3%	8.3%	10.4%	1536.5
	1997	79.7%	6.4%	14.0%	1685.5
	1998	76.4%	10.8%	12.8%	1773.5
	1999	73.6%	9.6%	16.7%	1727.3
	2000	77.7%	10.6%	11.7%	1762.3
Mountain	1996	96.2%	0.2%	3.6%	2062.3
	1997	96.2%	0.1%	3.7%	2152.2
	1998	95.7%	0.1%	4.2%	2278.5
	1999	95.4%	0.1%	4.5%	2284.6
	2000	93.9%	0.1%	6.0%	2410.7
New England	1996	47.3%	37.3%	15.3%	356.8
	1997	39.5%	47.5%	13.0%	486.5
	1998	34.0%	56.6%	9.3%	472.5
	1999	34.4%	57.2%	8.4%	421.6
	2000	45.4%	46.1%	8.6%	386.6
Pacific	1996	22.5%	12.9%	64.6%	471.7
	1997	18.4%	10.8%	70.8%	502.8
	1998	24.3%	9.8%	65.9%	552.9
	1999	22.3%	9.2%	68.5%	596.2
	2000	17.3%	7.0%	75.7%	810.7
South Atlantic	1996	89.0%	6.6%	4.4%	4042.6
	1997	89.2%	6.5%	4.3%	4279.0
	1998	86.2%	10.3%	3.5%	4462.3
	1999	86.0%	9.6%	4.4%	4506.6
	2000	87.3%	8.8%	3.9%	4626.2
West North Central	1996	98.4%	0.2%	1.4%	2105.1
	1997	98.2%	0.2%	1.6%	2131.3
	1998	97.8%	0.1%	2.0%	2241.9
	1999	97.7%	0.2%	2.1%	2241.5
	2000	97.8%	0.4%	1.8%	2352.8
West South Central	1996	60.3%	0.3%	39.4%	3637.4
	1997	60.6%	0.3%	39.1%	3676.3
	1998	55.8%	0.2%	44.0%	3919.9
	1999	56.6%	0.3%	43.1%	3912.7
	2000	57.0%	0.5%	42.5%	4022.8
US	1996	85.7%	3.1%	11.2%	20870.6
	1997	85.1%	3.4%	11.5%	21749.8
	1998	82.8%	4.7%	12.5%	22640.5
	1999	82.8%	4.3%	13.0%	22649.5
	2000	83.1%	3.8%	13.1%	23621.8

Source: Computed from Form EIA 767

Table 5.4: Unit Btu shipments by census region during the period of 1996-2000

Census Region	Year	Coal (Btu/pound)	Petroleum (Btu/gallon)	Natural Gas (Btu/cu.ft.)
East North Central	1996	10612.9	145641.1	675.8
	1997	10598.2	144482.4	766.2
	1998	10613.6	145892.3	829.9
	1999	10583.5	144828.3	819.7
	2000	10729.4	143646.2	770.5
East South Central	1996	11715.0	149718.0	1037.7
	1997	11584.5	154065.7	1035.5
	1998	11543.1	150721.4	1038.7
	1999	11381.0	155460.4	1026.7
	2000	11393.2	154088.7	1028.7
Mid Atlantic	1996	12467.6	149395.0	1027.9
	1997	12443.8	150331.8	1026.9
	1998	12495.1	150380.6	1030.1
	1999	12666.7	150351.9	1025.0
	2000	12804.1	151077.0	1019.8
Mountain	1996	9745.6	136550.3	1020.4
	1997	9722.9	135842.6	1021.8
	1998	9708.4	136246.8	1020.8
	1999	9755.2	135474.5	1023.7
	2000	9936.4	130601.8	1020.4
New England	1996	12566.5	152426.7	1031.5
	1997	12504.1	151950.6	1029.1
	1998	12504.6	151708.2	1028.7
	1999	12076.5	152354.2	1025.1
	2000	12009.9	150539.0	1034.7
Pacific	1996	8055.9	148800.3	1018.6
	1997	8154.9	149309.0	1015.4
	1998	8330.4	149114.1	1015.9
	1999	8443.6	149438.9	1006.2
	2000	8478.5	149613.6	1004.7
South Atlantic	1996	12287.7	151271.6	1012.3
	1997	12321.6	152020.2	1043.6
	1998	12310.3	151080.1	1048.2
	1999	12351.7	151509.6	1040.1
	2000	12268.0	151881.4	1037.8
West North Central	1996	8501.5	140164.4	984.7
	1997	8411.2	147346.8	986.2
	1998	8420.6	142078.8	1002.5
	1999	8373.6	142950.3	1007.6
	2000	8361.3	147185.0	1008.7
West South Central	1996	7798.0	141346.9	1027.1
	1997	7768.0	147329.1	1026.3
	1998	7851.4	150442.0	1027.7
	1999	7846.9	149492.4	1024.6
	2000	7857.7	144091.0	1023.5
US	1996	10273.9	150442.4	1016.4
	1997	10282.9	151290.8	1018.8
	1998	10259.0	150751.5	1021.2
	1999	10178.1	151029.9	1018.4
	2000	10139.4	150999.1	1019.2

Source: Computed from FERC Form 423

Table 5.5: Unit Btu consumptions by census region during the period of 1996-2000

Census Region	Year	Coal (Btu/pound)	Petroleum (Btu/gallon)	Natural Gas (Btu/cu.ft.)
East North Central	1996	10550.6	145086.5	1018.6
	1997	10495.7	143792.2	1014.3
	1998	10534.5	144406.4	1017.4
	1999	10529.4	144448.9	1018.9
	2000	10423.2	143314.7	1016.5
East South Central	1996	11769.6	150296.7	1026.3
	1997	11631.0	148577.0	1023.9
	1998	11578.0	148334.7	1031.8
	1999	11432.5	147098.8	1019.3
	2000	11422.4	142118.6	1020.2
Mid Atlantic	1996	12221.3	149587.6	1029.5
	1997	12525.9	149683.8	1028.2
	1998	12529.6	150095.5	1034.2
	1999	12615.8	149899.8	1027.5
	2000	12636.9	150071.0	1025.2
Mountain	1996	9793.6	141069.5	1016.4
	1997	9795.7	138616.1	1018.6
	1998	9762.8	140518.5	1022.4
	1999	9781.2	139017.9	1019.6
	2000	9833.2	141143.4	1016.5
New England	1996	12631.6	152036.6	1033.2
	1997	12649.9	151473.8	1030.8
	1998	12627.3	150910.5	1030.4
	1999	12655.6	151243.5	1030.5
	2000	12654.0	151633.1	1032.8
Pacific	1996	7853.6	148438.6	1024.8
	1997	7851.2	149413.3	1020.6
	1998	8104.3	149169.0	1022.6
	1999	8216.0	149425.3	1019.3
	2000	8090.4	149590.3	1019.3
South Atlantic	1996	12048.1	151485.9	1014.4
	1997	12224.3	152068.2	1016.9
	1998	12256.5	151141.3	1016.2
	1999	12288.4	151378.6	1021.6
	2000	12294.3	151255.2	1015.5
West North Central	1996	8406.2	144159.7	986.3
	1997	8371.8	143452.5	990.4
	1998	8344.0	140518.8	1002.7
	1999	8310.0	144186.6	1010.1
	2000	8342.3	146407.8	1011.5
West South Central	1996	7745.9	143374.4	1025.2
	1997	7698.7	147751.3	1024.4
	1998	7760.0	150392.3	1025.0
	1999	7743.4	148134.7	1022.4
	2000	7818.6	143755.3	1026.2
US	1996	10191.0	150401.2	1023.9
	1997	10218.0	150832.0	1022.9
	1998	10217.4	150435.5	1024.5
	1999	10197.0	150542.9	1022.0
	2000	10208.1	150232.4	1023.1

Source: Computed from Form EIA 767

Table 5.6: Total values and shares of end-of-year fuel stocks by census region during the period of 1996-1998

Fuel	Coal (10^6 short tons)	Petroleum (10^6 barrels)	Coal (10^6 short tons)	Petroleum (10^6 barrels)	Coal (10^6 short tons)	Petroleum (10^6 barrels)
Region	East North Central		East South Central		Mid Atlantic	
1996	330.1	22.5	108.6	14.8	77.7	74.5
ratio	0.94	0.06	0.88	0.12	0.51	0.49
1997	319.1	25.4	113.5	18.7	82.7	74.2
ratio	0.93	0.07	0.86	0.14	0.53	0.47
1998	347.4	31.0	130.1	26.4	87.8	90.9
ratio	0.92	0.08	0.83	0.17	0.49	0.51
Region	Mountain		New England		Pacific	
1996	202.6	113.7	211.4	9.1	246.0	71.8
ratio	0.64	0.36	0.96	0.04	0.77	0.23
1997	212.8	114.6	182.9	8.7	183.8	73.2
ratio	0.65	0.35	0.95	0.05	0.72	0.28
1998	221.1	120.9	186.0	11.5	154.2	84.7
ratio	0.65	0.35	0.94	0.06	0.65	0.35
Region	South Atlantic		West North Central		West South Central	
1996	202.6	113.7	211.4	9.1	246.0	71.8
ratio	0.64	0.36	0.96	0.04	0.77	0.23
1997	212.8	114.6	182.9	8.7	183.8	73.2
ratio	0.65	0.35	0.95	0.05	0.72	0.28
1998	221.1	120.9	186.0	11.5	154.2	84.7
ratio	0.65	0.35	0.94	0.06	0.65	0.35

Source: Computed from Form EIA 767

use of petroleum or natural gas instead of coal, because of regulations on sulfur dioxide emissions. Trends for end-of-year coal and petroleum stocks by states are presented in Appendix C (Table C.5).

5.1.1.3 Annual Fuel Prices

Decreasing demands for coal over the 1996-2000 period at most power plants, have led to unit coal purchasing cost decreases, as presented in Table 5.7. Since coal is the primary source of SO_2 emissions, strengthening regulation on SO_2 emissions has led to decreasing demands for coal. WNC uses the cheapest coal, while NE uses the most expensive one. The purchasing prices of petroleum and natural gas have fluctuated, but increased sharply in 2000 in most census regions, as a result of increasing market demands. Fuel price trends of individual states are presented in Appendix C (Table C.6).

5.1.1.4 Annual Gross SO_2 Emissions

Between 1996 and 2000, unit gross SO_2 emissions by coal (lb/MMBtu) have decreased in the majority of the census regions, as presented in Table 5.8. The decreasing unit gross SO_2 emissions point to the effectiveness of the CAAA of 1990. The trends of unit gross SO_2 emissions from petroleum between 1996 and 2000 (see Table 5.8) are mixed, with increases in some states, and decreases in others, implying that regulations on SO_2 emissions from petroleum do not affect all census regions uniformly. The primary purpose of the regulations is to control SO_2 emissions from coal burning, because coal is the dominant fuel at most U.S. power plants, and generates the greatest amounts of SO_2.

5.1.1.5 Annual Net SO_2 Emissions vs. Electricity Generations

As presented in Table 5.9, total net electricity generation has increased over the 1996-2000 period (+13.2%), due to an increasing demand for electricity. During the same period, both total and unit net SO_2 emissions have decreased by 9.9% and 20.7%, respectively, achieving large SO_2 emission reductions in all the census regions. The net SO_2 emissions trends by census region are illustrated in Table 5.10 and Figure 5.2.

Table 5.7: Unit fuel prices by census region during the period of 1996-2000

Census Region	Year	Unit Coal Price (cents/MMBtu)	Unit Petroleum Price (cents/MMBtu)	Unit Natural Gas Price (cents/MMBtu)
East North Central	1996	133.13	385.83	270.71
	1997	130.62	382.34	259.70
	1998	129.72	288.04	230.63
	1999	125.71	334.29	251.20
	2000	124.16	515.49	406.81
East South Central	1996	125.24	296.84	269.03
	1997	123.88	290.76	263.42
	1998	126.03	213.25	224.46
	1999	122.98	181.59	245.22
	2000	119.72	357.08	395.60
Mid Atlantic	1996	140.27	328.69	287.70
	1997	137.82	285.35	282.19
	1998	136.89	210.60	251.96
	1999	131.28	247.38	281.14
	2000	121.08	427.76	455.05
Mountain	1996	111.98	555.62	230.54
	1997	110.64	533.94	244.47
	1998	107.25	421.32	230.81
	1999	106.04	486.05	247.49
	2000	106.30	801.36	446.91
New England	1996	171.31	307.86	266.21
	1997	172.38	274.30	300.60
	1998	168.96	203.55	283.75
	1999	162.29	218.44	267.09
	2000	160.16	398.00	443.36
Pacific	1996	145.72	353.80	255.91
	1997	150.02	364.81	291.81
	1998	137.89	262.00	253.18
	1999	140.77	320.41	251.13
	2000	136.19	506.47	478.31
South Atlantic	1996	149.14	294.67	307.86
	1997	147.27	276.08	302.57
	1998	143.92	209.19	279.34
	1999	140.73	249.73	296.56
	2000	141.53	434.80	435.51
West North Central	1996	91.66	434.76	241.16
	1997	91.54	347.12	267.81
	1998	88.91	292.58	224.14
	1999	87.20	359.53	249.48
	2000	87.79	508.23	424.74
West South Central	1996	129.05	417.94	255.88
	1997	126.75	361.46	266.67
	1998	123.18	250.14	227.02
	1999	120.14	255.93	248.99
	2000	121.41	557.19	422.64
US	1996	128.69	315.74	264.08
	1997	127.17	288.07	275.91
	1998	124.92	214.03	238.13
	1999	121.39	252.79	257.37
	2000	120.01	445.29	430.22

Source: Computed from FERC Form 423

Table 5.8: Unit gross SO_2 emissions by census region during the period of 1996-2000

Census Region	Year	Unit Coal Gross SO2 Emissions (pound/MMBtu)	Unit Petroleum Gross SO2 Emissions (pound/MMBtu)
East North Central	1996	2.56	1.12
	1997	2.60	0.91
	1998	2.59	0.91
	1999	2.50	0.93
	2000	2.27	0.69
East South Central	1996	2.97	0.68
	1997	2.89	3.02
	1998	2.78	3.19
	1999	2.71	3.22
	2000	2.65	3.61
Mid Atlantic	1996	3.24	0.98
	1997	3.15	0.93
	1998	3.22	1.10
	1999	3.24	1.16
	2000	3.13	1.07
Mountain	1996	1.13	0.60
	1997	1.15	0.32
	1998	1.15	0.33
	1999	1.12	0.36
	2000	1.11	0.51
New England	1996	1.37	1.50
	1997	1.43	1.47
	1998	1.36	1.52
	1999	1.39	1.41
	2000	1.34	1.35
Pacific	1996	1.53	0.94
	1997	1.43	0.97
	1998	1.29	0.91
	1999	1.51	0.87
	2000	1.54	0.90
South Atlantic	1996	2.10	2.03
	1997	2.08	2.06
	1998	2.10	1.99
	1999	2.08	1.91
	2000	1.98	1.59
West North Central	1996	1.29	1.02
	1997	1.23	0.96
	1998	1.17	0.67
	1999	1.15	1.11
	2000	1.07	1.25
West South Central	1996	1.02	0.80
	1997	1.61	1.34
	1998	1.58	1.71
	1999	1.42	1.47
	2000	1.35	0.89
US	1996	2.05	1.51
	1997	2.11	1.62
	1998	2.09	1.68
	1999	2.03	1.61
	2000	1.92	1.42

Source: Computed from Form EIA 767

Table 5.9: Net electricity generations by census region during the period of 1996-2000

Census Region	Year	Net Electricity Generations (10^6 MWh)
East North Central	1996	523
	1997	518
	1998	527
	1999	555
	2000	584
East South Central	1996	293
	1997	303
	1998	302
	1999	307
	2000	317
Mid Atlantic	1996	265
	1997	273
	1998	291
	1999	295
	2000	305
Mountain	1996	221
	1997	230
	1998	244
	1999	247
	2000	258
New England	1996	57
	1997	63
	1998	66
	1999	68
	2000	71
Pacific	1996	85
	1997	85
	1998	93
	1999	95
	2000	123
South Atlantic	1996	584
	1997	604
	1998	643
	1999	649
	2000	663
West North Central	1996	233
	1997	235
	1998	246
	1999	249
	2000	258
West South Central	1996	410
	1997	412
	1998	440
	1999	438
	2000	445
US	1996	2671
	1997	2725
	1998	2853
	1999	2903
	2000	3023

Source: Computed from Form EIA 906

To examine whether net SO_2 emissions have actually increased or decreased after factoring in electricity demand, the following ratios are computed and compared in Table 5.11: (1) net SO_2 emissions (lb) to gross electricity generations (MW), (2) net SO_2 emissions (lb) to heat inputs (MMBtu) and (3) gross electricity generations (MW) to heat input (MMBtu). Ratios (1) and (2) display clear decreasing trends over 1996-2000, while ratio (3) is stable over these years in most states. This implies that net SO_2 emissions have actually been reduced, when accounting for electricity demand.

5.1.2 Monthly Trends

5.1.2.1 Fuel Shipments and Consumptions

Table 5.12 presents monthly data grouped by season: spring (March-May), summer (June-August), autumn (September-November), and winter (December-February). The monthly shares of fuel shipments and consumptions are compared, with a focus on seasonal patterns. As expected, natural gas is characterized by a close match between shipments and consumptions because large-scale gas storage is not possible at power plant sites. However, coal and petroleum display lagged patterns, although the length of the lag is not clear. For instance, coal shipments have the lowest values in February, while coal consumptions have the lowest values in April.

Coal consumption has two peaks, in the summer and the winter, but is heaviest in the summer, while coal shipments are evenly distributed over the months. Natural gas use is high in the summer, pointing to its primary use for generating electricity used for cooling.

Table 5.10: Net SO_2 emissions by census region during the period of 1996-2000

Census Region	Year	Unit Net SO2 Emissions (lb/MMBtu)	Total Adjusted Net SO2 Emissions (10^6 lb)
East North Central	1996	1.69	7300
	1997	1.74	7712
	1998	1.85	8381
	1999	1.55	6984
	2000	1.30	6096
East South Central	1996	1.56	3671
	1997	1.54	3697
	1998	1.70	4093
	1999	1.42	3489
	2000	1.26	3211
Mid Atlantic	1996	1.62	2482
	1997	1.59	2678
	1998	1.64	2909
	1999	1.45	2512
	2000	1.41	2480
Mountain	1996	0.46	956
	1997	0.47	1012
	1998	0.44	1009
	1999	0.38	868
	2000	0.34	816
New England	1996	1.05	374
	1997	1.01	492
	1998	1.08	512
	1999	1.06	445
	2000	0.88	339
Pacific	1996	0.41	168
	1997	0.31	140
	1998	0.50	246
	1999	0.39	209
	2000	0.24	196
South Atlantic	1996	1.41	5717
	1997	1.44	6147
	1998	1.58	7044
	1999	1.38	6227
	2000	1.16	5364
West North Central	1996	0.89	1881
	1997	0.86	1841
	1998	0.86	1934
	1999	0.80	1791
	2000	0.67	1578
West South Central	1996	0.43	1561
	1997	0.54	1983
	1998	0.51	1995
	1999	0.50	1943
	2000	0.41	1653
US	1996	1.16	24109
	1997	1.18	25702
	1998	1.25	28123
	1999	1.08	24468
	2000	0.92	21733

Source: Computed from Continuous Emissions Monitoring Systems (CEMS) database.

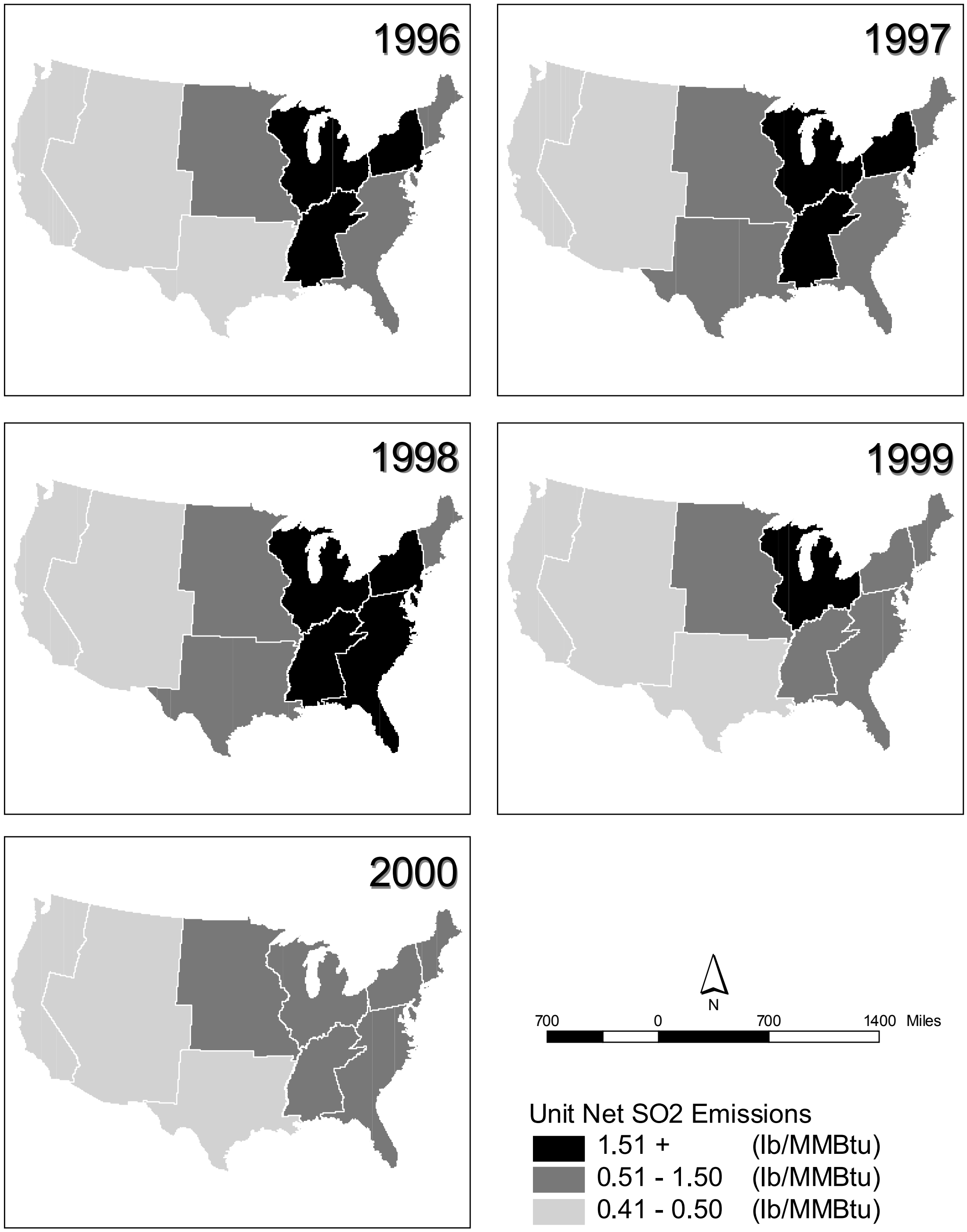

Figure 5.2: Unit net SO_2 emissions trends

Table 5.11: Ratios between gross electricity generations, heat inputs, and net SO_2 emissions

Census Region	Year	(1) Gross generations (MW)	(2) Heat Inputs (MMBtu)	(3) Net SO2 Emissions (lb)	(3)/(1)	(3)/(2)	(1)/(2)
East North Central	1996	599	6434	7300	12.19	1.13	0.09
	1997	622	6799	7712	12.39	1.13	0.09
	1998	712	7937	8381	11.77	1.06	0.09
	1999	634	6773	6984	11.02	1.03	0.09
	2000	671	6933	6096	9.09	0.88	0.10
East South Central	1996	342	3661	3671	10.73	1.00	0.09
	1997	352	3739	3697	10.51	0.99	0.09
	1998	411	4302	4093	9.96	0.95	0.10
	1999	364	3849	3489	9.59	0.91	0.09
	2000	396	3963	3211	8.11	0.81	0.10
Mid Atlantic	1996	196	2289	2482	12.65	1.08	0.09
	1997	210	2421	2678	12.78	1.11	0.09
	1998	245	2901	2909	11.86	1.00	0.08
	1999	236	2401	2512	10.65	1.05	0.10
	2000	234	2459	2480	10.62	1.01	0.09
Mountain	1996	207	2223	956	4.62	0.43	0.09
	1997	220	2391	1012	4.61	0.42	0.09
	1998	245	2649	1009	4.12	0.38	0.09
	1999	236	2532	868	3.68	0.34	0.09
	2000	259	2613	816	3.16	0.31	0.10
New England	1996	37	403	374	10.10	0.93	0.09
	1997	53	575	492	9.27	0.85	0.09
	1998	55	602	512	9.38	0.85	0.09
	1999	83	506	445	5.39	0.88	0.16
	2000	41	440	339	8.32	0.77	0.09
Pacific	1996	44	463	168	3.83	0.36	0.09
	1997	48	504	140	2.90	0.28	0.10
	1998	60	637	246	4.08	0.39	0.09
	1999	56	581	209	3.75	0.36	0.10
	2000	82	826	196	2.40	0.24	0.10
South Atlantic	1996	541	5537	5717	10.56	1.03	0.10
	1997	574	5872	6147	10.71	1.05	0.10
	1998	673	6892	7044	10.46	1.02	0.10
	1999	594	6114	6227	10.48	1.02	0.10
	2000	612	6052	5364	8.77	0.89	0.10
West North Central	1996	229	2526	1881	8.22	0.74	0.09
	1997	230	2578	1841	8.02	0.71	0.09
	1998	250	2847	1934	7.73	0.68	0.09
	1999	242	2727	1791	7.40	0.66	0.09
	2000	253	2758	1578	6.23	0.57	0.09
West South Central	1996	332	3418	1561	4.70	0.46	0.10
	1997	383	3996	1983	5.17	0.50	0.10
	1998	433	4515	1995	4.61	0.44	0.10
	1999	408	4321	1943	4.76	0.45	0.09
	2000	417	4410	1653	3.96	0.37	0.09
US	1996	2528	26954	24109	9.54	0.89	0.09
	1997	2692	28875	25702	9.55	0.89	0.09
	1998	3084	33282	28123	9.12	0.85	0.09
	1999	2852	29805	24468	8.58	0.82	0.10
	2000	2963	30453	21733	7.33	0.71	0.10

Source: Computed from Continuous Emissions Monitoring Systems (CEMS) database

Table 5.12 Shares of monthly fuel shipments and consumptions

		WINTER		SPRING			SUMMER			AUTUMN			WINTER	
	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL 10^6 MMBtu
Coal Btu Shipments	1996	7.75%	7.74%	8.14%	8.25%	8.38%	8.11%	8.64%	9.12%	8.40%	8.84%	8.27%	8.36%	17771
	1997	8.12%	7.89%	8.24%	8.04%	8.51%	7.97%	8.31%	8.64%	8.54%	8.67%	8.25%	8.83%	18170
	1998	8.48%	7.55%	8.24%	8.08%	8.15%	8.27%	8.53%	8.82%	8.49%	8.53%	8.34%	8.53%	19150
	1999	8.39%	8.18%	8.49%	7.93%	8.22%	8.23%	8.33%	8.97%	8.46%	8.51%	8.14%	8.15%	18563
	2000	8.77%	8.52%	8.97%	8.26%	8.68%	8.36%	8.55%	8.71%	8.12%	7.80%	7.63%	7.63%	16074
Coal Btu Consumptions	1996	8.74%	7.90%	7.92%	7.17%	7.73%	8.43%	9.23%	9.35%	8.19%	8.17%	8.36%	8.81%	17905
	1997	9.00%	7.53%	7.69%	7.31%	7.61%	8.19%	9.44%	9.20%	8.45%	8.49%	8.16%	8.95%	18519
	1998	8.61%	7.47%	7.90%	7.29%	7.99%	8.68%	9.59%	9.64%	8.66%	8.09%	7.64%	8.44%	18763
	1999	8.59%	7.37%	7.87%	7.41%	7.79%	8.59%	9.79%	9.52%	8.45%	8.13%	7.81%	8.69%	18747
	2000	8.65%	7.82%	7.68%	7.01%	7.80%	8.60%	9.11%	9.47%	8.44%	8.19%	8.12%	9.11%	19630
Petroleum Btu Shipments	1996	13.60%	6.56%	9.01%	8.19%	6.04%	8.92%	10.70%	10.34%	5.60%	6.00%	6.64%	8.40%	674
	1997	8.16%	7.94%	6.09%	5.72%	5.92%	8.51%	9.91%	9.87%	7.95%	9.10%	10.86%	9.97%	749
	1998	6.11%	5.59%	6.75%	7.44%	7.38%	8.58%	13.17%	12.11%	8.23%	9.42%	6.74%	8.48%	1052
	1999	10.65%	7.96%	8.74%	8.43%	8.59%	9.10%	10.79%	10.05%	7.74%	6.57%	6.12%	5.26%	834
	2000	3.03%	4.25%	4.08%	5.28%	8.31%	10.66%	12.08%	11.49%	10.25%	9.39%	8.70%	12.49%	634
Petroleum Btu Consumptions	1996	11.82%	12.47%	9.25%	4.75%	5.58%	8.57%	11.41%	9.32%	7.11%	4.52%	6.25%	8.96%	659
	1997	11.39%	5.99%	5.75%	4.95%	5.64%	8.70%	11.10%	9.53%	9.69%	9.06%	8.73%	9.46%	743
	1998	5.52%	5.12%	7.86%	5.99%	8.38%	10.66%	12.23%	11.90%	9.61%	7.12%	7.02%	8.59%	1069
	1999	10.49%	9.11%	9.40%	8.11%	8.79%	10.09%	12.54%	10.69%	7.23%	5.72%	3.73%	4.09%	979
	2000	7.42%	4.99%	4.12%	4.33%	7.28%	9.57%	8.88%	11.56%	9.64%	8.63%	7.50%	16.08%	909
Natural Gas Btu Shipments	1996	5.93%	5.07%	5.74%	6.17%	9.66%	10.96%	13.32%	13.34%	10.36%	8.31%	6.19%	4.95%	2650
	1997	4.78%	4.86%	6.70%	6.68%	8.16%	10.09%	13.54%	13.04%	11.32%	7.94%	6.09%	6.80%	2818
	1998	5.63%	4.24%	6.14%	6.32%	8.64%	11.34%	13.41%	13.39%	11.37%	7.91%	5.62%	5.99%	2986
	1999	5.87%	4.95%	6.67%	8.15%	9.03%	9.92%	13.08%	13.52%	9.32%	7.82%	5.81%	5.85%	2862
	2000	6.45%	5.72%	7.30%	7.61%	10.23%	10.26%	12.32%	12.64%	9.12%	6.75%	5.60%	6.01%	2682
Natural Gas Btu Consumptions	1996	5.84%	4.90%	5.66%	6.23%	9.89%	11.23%	13.35%	13.55%	10.33%	8.23%	6.10%	4.69%	2332
	1997	4.68%	4.74%	6.20%	6.46%	7.97%	10.24%	14.43%	13.30%	11.37%	8.16%	5.96%	6.50%	2507
	1998	4.93%	3.77%	5.81%	5.73%	8.58%	11.09%	13.99%	14.40%	11.81%	7.88%	5.73%	6.29%	2825
	1999	5.62%	4.24%	5.95%	7.46%	8.10%	10.33%	13.53%	13.77%	9.74%	9.14%	6.04%	6.09%	2935
	2000	6.00%	5.37%	6.59%	6.81%	9.82%	10.33%	12.24%	13.41%	9.77%	7.29%	6.19%	6.19%	3083

Source: Computed from FERC Form 423 and Form EIA 767

In contrast, petroleum consumptions display similar peaks in summer and winter, implying that petroleum is used relatively more in winter for heating, as compared to coal and natural gas.

In Table 5.13, unit Btu shipments and consumptions appear close to constant over the months, implying that power plants use fuels with stable heat values, at least during a given year.

5.1.2.2 Monthly Fuel Stocks

In Table 5.14, monthly coal stocks display their highest values in spring, while coal consumptions (see Table 5.13) have peaks in summer. This suggests that plant owners store the needed coal prior to the consumption seasons. Similarly, petroleum consumptions display a peak in January, and the highest stock values are in November, December, and January, again implying a lagged relationship between fuel stock and actual consumption.

5.1.2.3 Monthly Fuel Purchasing Costs

As can be seen in Figure 5.3, coal purchasing prices do not vary much, while petroleum and natural gas purchasing prices do fluctuate, seasonally and over the 5-year period. The fluctuation of fuel prices are caused by fuel market factors, especially demand and availability. Since petroleum and natural gas prices have been sharply higher since 1999, it is reasonable to expect that power plants owners will continue to use coal as the primary source of electricity generation, even though coal generates more sulfur

Table 5.13 Monthly unit fuel shipments and consumptions

		WINTER		SPRING			SUMMER			AUTUMN			WINTER
	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Unit Coal Btu	1996	10127.73	10299.00	10315.27	10390.87	10298.79	10316.42	10187.58	10292.15	10231.88	10335.89	10272.76	10216.33
Shipments	1997	10221.42	10326.23	10310.71	10433.24	10282.17	10230.00	10159.04	10243.03	10300.76	10364.69	10300.70	10232.52
(Btu/pound)	1998	10224.88	10242.48	10364.19	10291.73	10228.91	10277.59	10200.46	10245.84	10282.26	10236.31	10307.42	10212.27
	1999	10142.33	10225.97	10218.58	10186.31	10209.53	10209.84	10063.90	10193.35	10191.59	10214.44	10174.98	10106.81
	2000	10119.98	10165.27	10303.20	10350.86	10258.74	10213.46	10049.87	10090.88	10057.52	10092.95	10000.88	9940.65
Unit Coal Btu	1996	10141.39	10207.39	10228.25	10262.00	10229.39	10231.74	10233.33	10229.06	10169.74	10151.15	10117.12	10109.23
Consumptions	1997	10205.89	10178.59	10199.05	10295.80	10220.78	10154.92	10241.69	10205.20	10210.73	10259.15	10222.60	10227.98
(Btu/pound)	1998	10144.40	10147.23	10239.17	10216.81	10263.03	10278.85	10254.73	10278.12	10270.04	10182.16	10187.14	10131.35
	1999	10147.96	10177.82	10263.61	10201.42	10207.32	10232.25	10264.16	10269.41	10171.84	10160.92	10096.86	10151.21
	2000	10196.25	10193.45	10224.36	10249.82	10249.70	10256.20	10219.13	10213.18	10218.95	10148.61	10130.29	10203.03
Unit	1996	150046.90	149901.19	150598.07	150640.89	150392.90	150595.81	150820.09	151170.36	151623.55	150190.15	148715.09	150429.63
Petroleum	1997	150644.17	151515.69	151555.32	151474.07	151587.33	151496.03	151076.46	151482.52	151934.32	151256.41	150810.96	151095.25
Btu Shipments	1998	151458.49	151259.75	151728.41	151501.69	151650.53	151159.82	150695.76	150785.51	151444.92	150397.16	150661.94	147213.04
(Btu/gallon)	1999	150658.66	151673.26	151207.63	150808.90	151005.90	150937.88	150789.93	151189.91	151660.68	150988.08	151055.46	150361.03
	2000	150364.91	149851.16	151097.97	150860.29	150559.17	150995.46	151500.50	151789.34	152027.78	151512.44	151253.60	149283.53
Unit	1996	149890.25	149713.04	150404.81	149928.99	150295.21	150656.77	150748.62	150679.74	150792.36	150227.86	150314.89	150648.40
Petroleum	1997	150339.55	150352.35	150610.30	150542.31	150972.41	151170.68	151054.01	151248.05	151334.68	150876.89	150348.54	150587.33
Btu	1998	150125.66	150206.05	150493.33	150374.57	150416.77	150862.16	150404.08	150411.05	150561.42	150254.08	150387.35	150222.99
Consumptions	1999	150399.46	150464.76	150229.46	150627.68	150445.50	150552.30	150792.41	150916.98	150692.58	150377.23	150238.03	149996.65
(Btu/gallon)	2000	150245.66	149827.64	149291.85	150072.02	150755.60	150598.56	150649.43	150866.46	150640.59	150354.04	149838.90	149380.93
Unit	1996	1011.65	1019.52	1018.76	1015.72	1016.88	1017.33	1018.53	1019.64	1015.91	1012.53	1009.13	1015.50
Natural Gas	1997	1006.11	1016.64	1017.99	1016.92	1017.91	1021.06	1020.97	1020.83	1018.52	1018.84	1016.49	1024.28
Btu Shipments	1998	1011.57	1014.60	1012.29	1013.60	1020.28	1022.73	1027.86	1024.81	1022.95	1022.38	1021.20	1023.32
(Btu/cu. ft.)	1999	1030.00	1019.09	1018.71	1017.80	1019.61	1019.10	1019.95	1020.01	1016.69	1013.74	1008.15	1016.43
	2000	1015.14	1014.97	1021.98	1022.02	1020.27	1018.82	1019.23	1019.49	1017.83	1015.63	1016.34	1026.94
Unit	1996	1026.22	1028.93	1025.12	1022.57	1024.01	1024.47	1024.35	1023.02	1022.94	1022.36	1022.52	1022.27
Natural Gas	1997	1023.03	1021.44	1022.36	1023.01	1022.75	1023.41	1022.26	1022.94	1022.77	1023.59	1023.53	1023.69
Btu	1998	1022.72	1020.79	1020.45	1021.19	1022.55	1024.19	1027.98	1025.59	1024.92	1024.85	1024.66	1026.67
Consumptions	1999	1025.58	1023.13	1024.15	1022.79	1022.20	1023.71	1021.92	1022.09	1020.66	1019.28	1018.91	1021.47
(Btu/cu. ft.)	2000	1022.21	1021.54	1021.49	1022.26	1023.15	1023.55	1022.62	1023.89	1023.17	1023.07	1022.77	1026.58

Source: Computed from FERC Form 423 and Form EIA 767

Table 5.14 Shares of monthly coal and petroleum stocks**

1996 CSTK	1997 CSTK	1998 CSTK	MONTH	1996 PSTK	1997 PSTK	1998 PSTK
8.05%	8.14%	7.52%	JAN	9.00%	8.00%	8.47%
7.99%	8.23%	7.78%	FEB	8.08%	8.32%	8.45%
8.12%	8.62%	8.06%	MAR	7.64%	8.31%	7.92%
8.69%	9.04%	8.69%	APR	8.07%	8.48%	8.69%
9.01%	9.43%	9.00%	MAY	8.21%	8.61%	8.09%
8.77%	9.23%	8.88%	JUN	8.28%	8.44%	7.57%
8.30%	8.39%	8.24%	JUL	8.30%	8.23%	7.94%
8.13%	7.94%	7.81%	AUG	8.47%	8.21%	8.11%
8.24%	7.82%	7.86%	SEP	8.20%	7.89%	7.83%
8.47%	7.85%	8.27%	OCT	8.57%	8.11%	8.72%
8.31%	7.73%	8.81%	NOV	8.57%	8.53%	9.04%
7.91%	7.57%	9.10%	DEC	8.62%	8.85%	9.16%
1450	1312	1338	Total	553	551	584

Source: Computed from Form EIA 906A
** CSTK: Coal stocks (10^6 short tons); PSTK: Petroleum stocks (10^6 42 gal. bbl)

dioxides emissions. Rather than using fuel blending or fuel shift to meet annual sulfur dioxides emission allowance limits, purchasing abatement equipment or allowances through the emission trading market could be a cheaper method for compliance with SO_2 regulations.

The fuel shares of monthly shipments in Table 5.12 point to a possible relationship with fuel purchasing prices in Figure 5.3. For example, between December 1996 and February 1997, natural gas purchasing prices increased sharply, and the proportion of natural gas shipments over the same period decreased accordingly. In September-November 1996, November-December 1997, and November-December 1999, as petroleum prices increased, the shares of petroleum shipments over the same periods decreased accordingly.

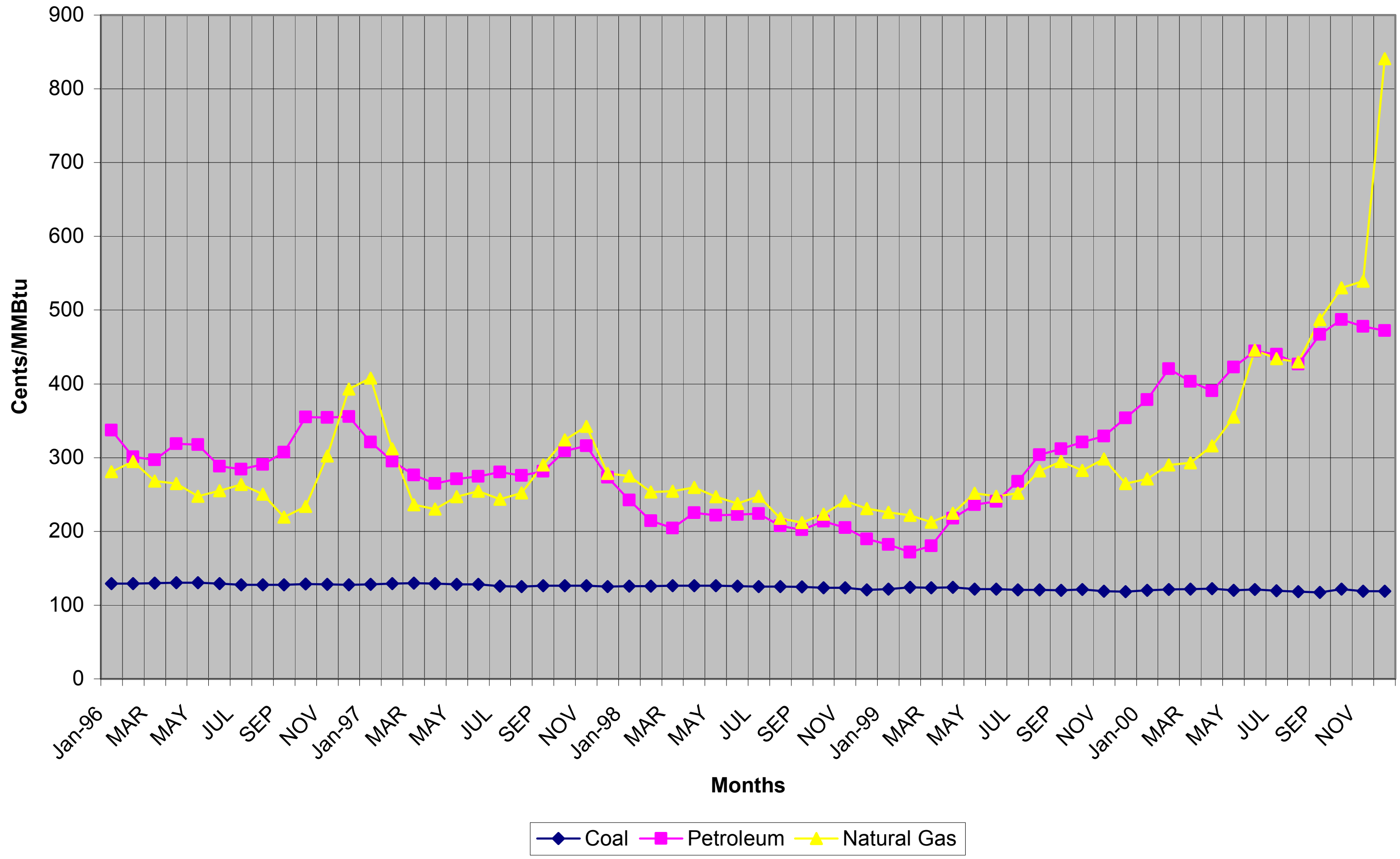

Figure 5.3 Monthly unit fuel purchasing costs (1996 – 2000)

5.1.2.4 Monthly Flows of Sulfur Dioxides

In Figures 5.4 and 5.5, the unit SO_2 shipments and unit gross SO_2 emissions are compared. For both coal and petroleum, there is a one-to-three month lag between unit SO_2 shipments and consumptions. For instance, the unit SO_2 shipment had a peak in August 1996, while the consumption had one in October 1996. Unit SO_2 shipment had its lowest point in March 2000, while consumption had it in May 2000. In Figure 5.5, gross SO_2 emissions are generally higher in the summer and the winter, reflecting heavier electricity demands for cooling and heating.

5.1.2.5 Monthly Net SO_2 Emissions/Gross Electricity Generations Load

In Table 5.15, the monthly net SO_2 emissions and gross electricity generation loads have their highest shares in the summer, followed by winter, due to increasing cooling and heating demands. Total SO_2 emissions increased until 1998, and then decreased sharply thereafter, while electricity loads display little changes between 1998 and 2000. This illustrates the effect of compliance with Phase II of the CAAA of 1990 regulating SO_2 emissions (Phase II started in 2000). The ratios of net SO_2 emissions to gross electricity generation loads are higher in winter, suggesting the use of a relatively poorer quality of coal in winter.

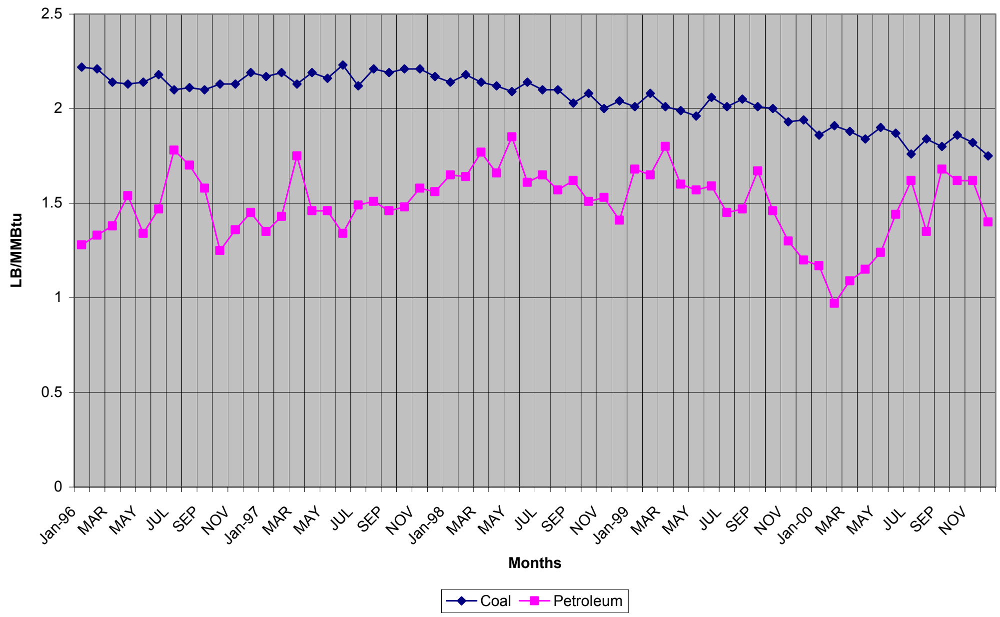

Figure 5.4 Unit sulfur dioxides shipments

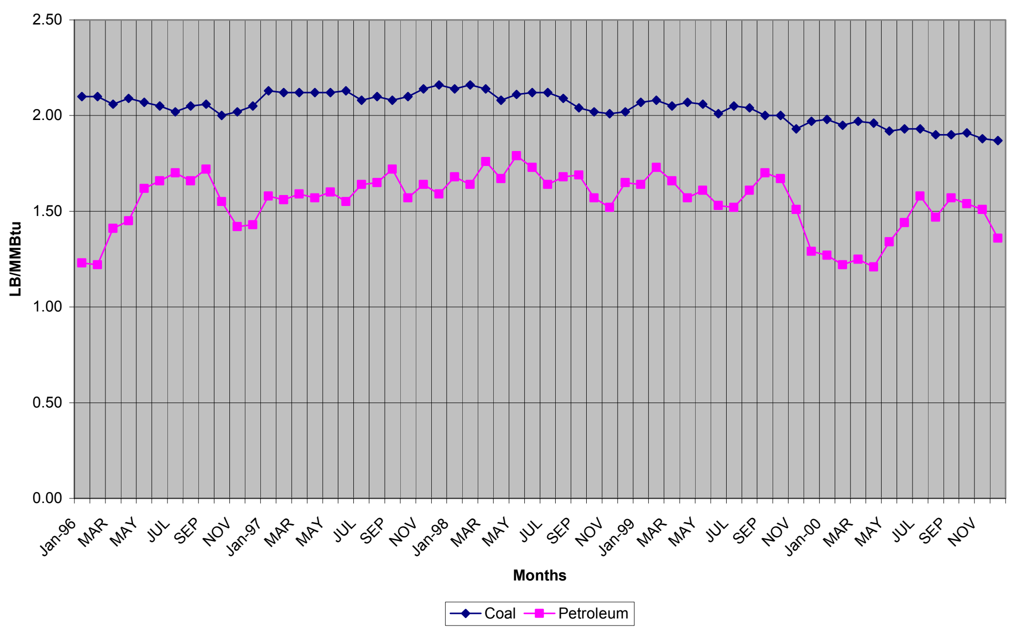

Figure 5.5 Unit gross sulfur dioxides emissions

Table 5.15 Monthly net SO_2 emissions and gross electricity generation loads

Adjusted SO2 Emissions					
	1996	1997	1998	1999	2000
JAN	8.71%	9.08%	7.82%	8.77%	9.10%
FEB	7.95%	7.36%	6.76%	7.46%	7.97%
MAR	7.99%	7.55%	7.28%	8.30%	7.76%
APR	7.37%	7.38%	6.62%	7.56%	6.91%
MAY	7.95%	7.63%	7.59%	7.77%	7.73%
JUN	8.66%	8.22%	8.31%	8.73%	8.56%
JUL	9.09%	9.50%	12.03%	10.20%	9.03%
AUG	9.27%	9.16%	11.82%	9.80%	9.37%
SEP	8.06%	8.45%	10.55%	8.19%	8.18%
OCT	7.80%	8.45%	7.14%	8.02%	8.04%
NOV	8.26%	8.23%	6.64%	7.24%	7.96%
DEC	8.88%	9.00%	7.43%	7.97%	9.38%
Total (10^6 lb)	24328	25902	28391	24646	21805

Electricity Generation Loads					
	1996	1997	1998	1999	2000
JAN	8.55%	8.67%	7.27%	8.21%	8.31%
FEB	7.76%	7.22%	6.33%	7.04%	7.42%
MAR	7.86%	7.53%	7.02%	7.77%	7.38%
APR	7.28%	7.25%	6.47%	7.47%	6.90%
MAY	8.07%	7.60%	7.41%	8.99%	8.00%
JUN	8.82%	8.39%	8.22%	8.73%	8.80%
JUL	9.34%	9.93%	12.43%	10.09%	9.39%
AUG	9.47%	9.50%	12.40%	9.76%	9.97%
SEP	8.11%	8.74%	11.08%	8.30%	8.61%
OCT	8.10%	8.43%	7.26%	8.07%	8.14%
NOV	8.20%	7.97%	6.71%	7.39%	7.91%
DEC	8.43%	8.76%	7.39%	8.18%	9.17%
Total (10^6 MWh)	2544	2710	3112	2876	2997

SO2/Load Ratios					
	1996	1997	1998	1999	2000
JAN	9.74	10.02	9.81	9.16	7.96
FEB	9.79	9.73	9.74	9.08	7.82
MAR	9.72	9.58	9.46	9.15	7.65
APR	9.68	9.73	9.34	8.67	7.29
MAY	9.42	9.59	9.35	7.40	7.03
JUN	9.39	9.36	9.22	8.57	7.08
JUL	9.30	9.14	8.83	8.66	7.00
AUG	9.36	9.21	8.70	8.61	6.84
SEP	9.51	9.24	8.69	8.45	6.91
OCT	9.21	9.58	8.97	8.52	7.19
NOV	9.63	9.87	9.03	8.39	7.33
DEC	10.07	9.82	9.17	8.35	7.44

Source: Computed from CEMS database.

5.2 Plant-Level Analyses

To further analyze the variability of Btu values, sulfur dioxide emissions, and unit fuel purchasing costs, 10 power plants were selected, with relatively high nameplate capacity and with data for 1996. Although statistical conclusions cannot be expected with such a small sample, the plant-level patterns may provide useful insights, that cannot be derived from national-level data. The selected plants are: Gorgas (Alabama), Cherokee (Colorado), Big Bend (Florida), Clifty Creek (Indiana), Paradise (Kentucky), Monroe (Michigan), Labadie (Montana), Keystone (Pennsylvania), Navajo (Arizona), and Gavin (Ohio).

5.2.1 Monthly Fuel Shipments, Consumptions, and Net Electricity Generations

In Figure 5.6, fuel shipments (MMBtu) display typical seasonal variations. For example, there are two peaks for shipments to these 10 plants, in spring (March – May) and autumn (September – November), implying that most plants receive fuels in advance of the heavier demands for electricity in summer and winter. In contrast, the fuel consumption (MMBtu) patterns, in Figure 5.7, display two peaks, in summer (June – August) and winter (November – January). Based on Figures 5.6 and 5.7, it can be assumed that there is one-to three-month lag between fuel shipment and consumption. Net electricity generation, in Figure 5.8, displays the same monthly pattern as fuel consumption, with peaks in summer and winter, due to increasing consumer needs for heating and cooling.

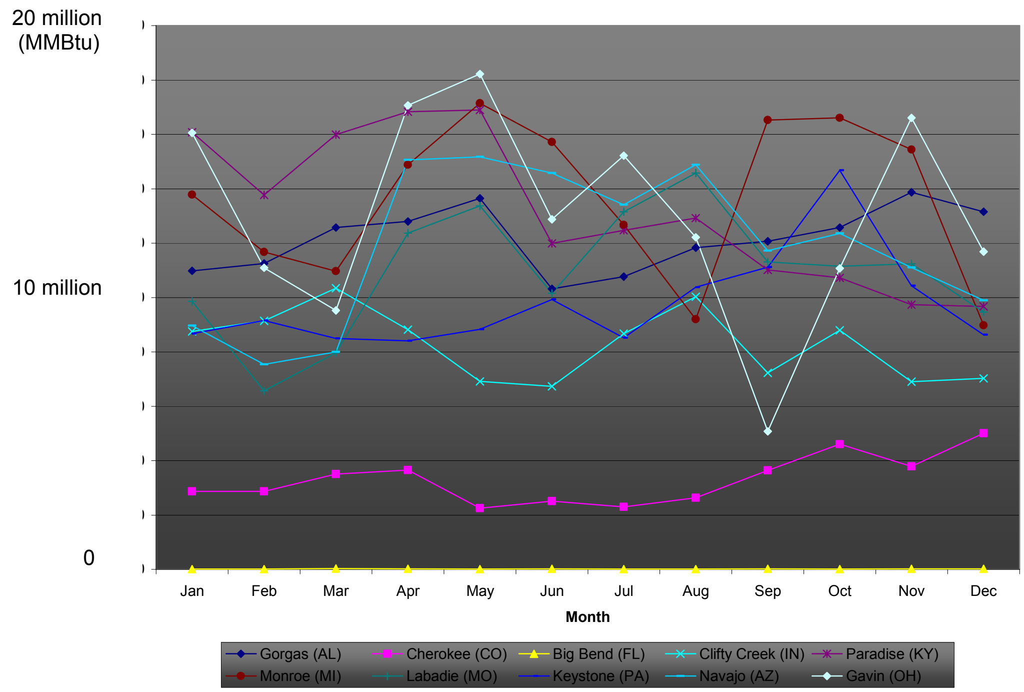

Figure 5.6: Monthly fuel shipments patterns at selected plants

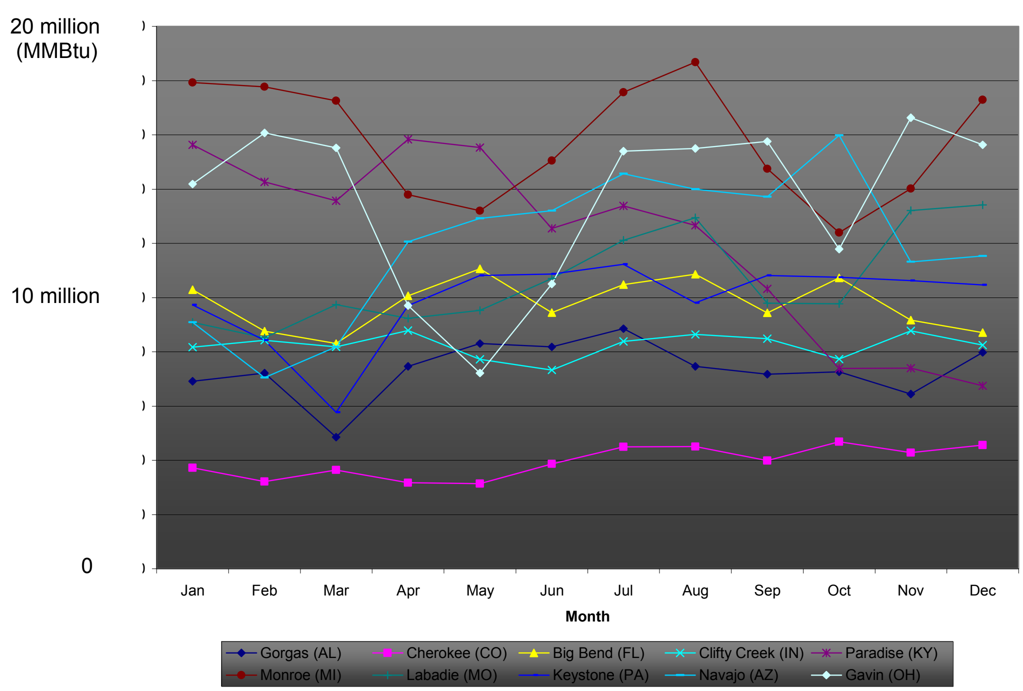

Figure 5.7 Monthly fuel consumptions patterns at selected plants

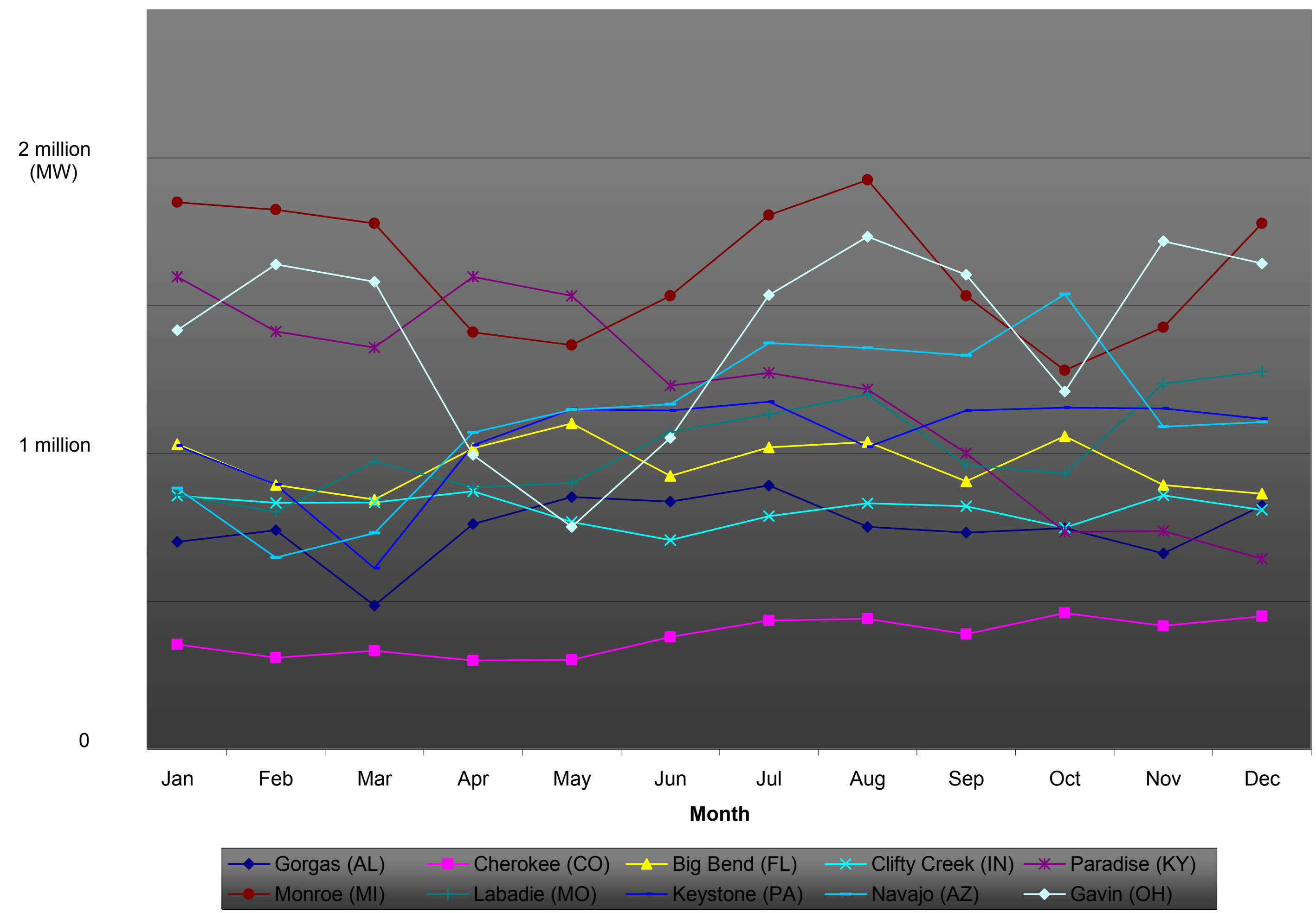

Figure 5.8 Monthly net electricity generations patterns at selected plants

Figures 5.9 and 5.10, where coal shipment and consumption patterns are examined, provide further insights. The trend for coal is very similar to the overall fuel trend, as coal is a major fuel source for electricity generation. In contrast, petroleum shipments and consumptions displayed in Figures 5.11 and 5.12, do not match the overall trend. Petroleum shipments seem negatively correlated with petroleum purchasing prices (Figure 5.3). For instance, in 1996, there were two periods of petroleum price increase, in March-April and August-September, and petroleum shipments decreased during these periods. Thus, it is likely that petroleum shipments are sensitive to both petroleum prices and seasonal demands. The lags between shipment and consumption for coal and petroleum vary between one and three months, but it seems that the petroleum lag is shorter than that for coal.

5.2.2 Monthly Unit Fuel Purchasing Costs

Figure 5.13 shows that monthly unit fuel purchasing costs are higher in spring (March-May) and autumn (September-November), because better quality fuels must be used in summer and winter, under the assumptions that there is a one-to three-month lag between shipments and consumptions and that those expensive fuels have higher heat values and lower sulfur contents. In summer and winter, wind speeds are relatively stronger than in spring and autumn. Yegnan et al. (2002) and Schnelle and Dey (1999) found that stack pollutants concentrations increase with increasing wind speed, and that ground level concentrations further from the stack decrease with wind speed. That is, strong winds may prevent dispersion of air pollutants from the stack, causing a swirling

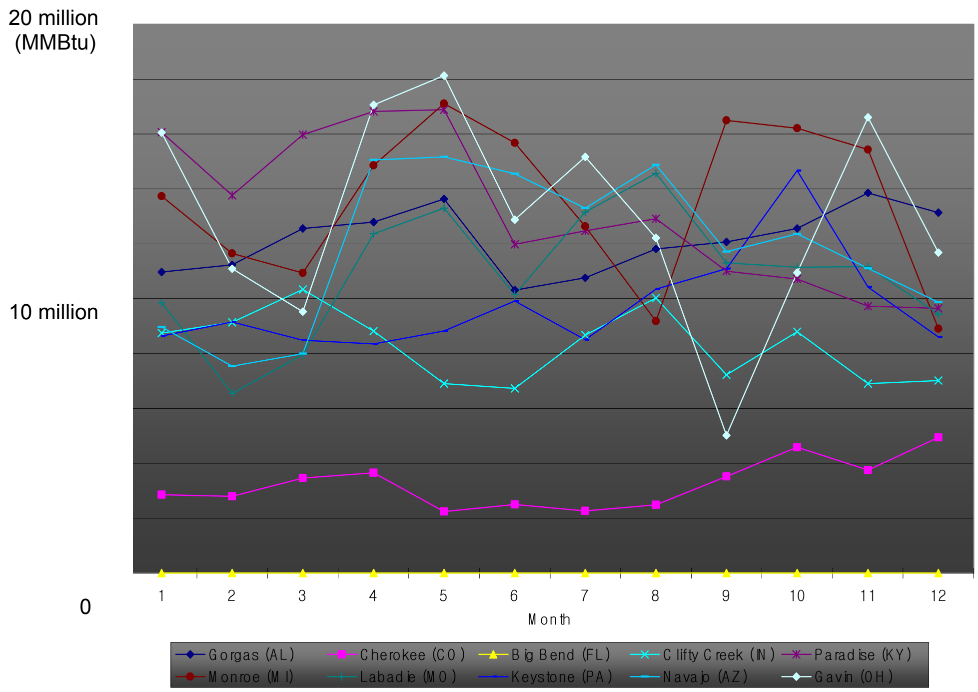

Figure 5.9 Monthly coal shipments patterns at selected plants

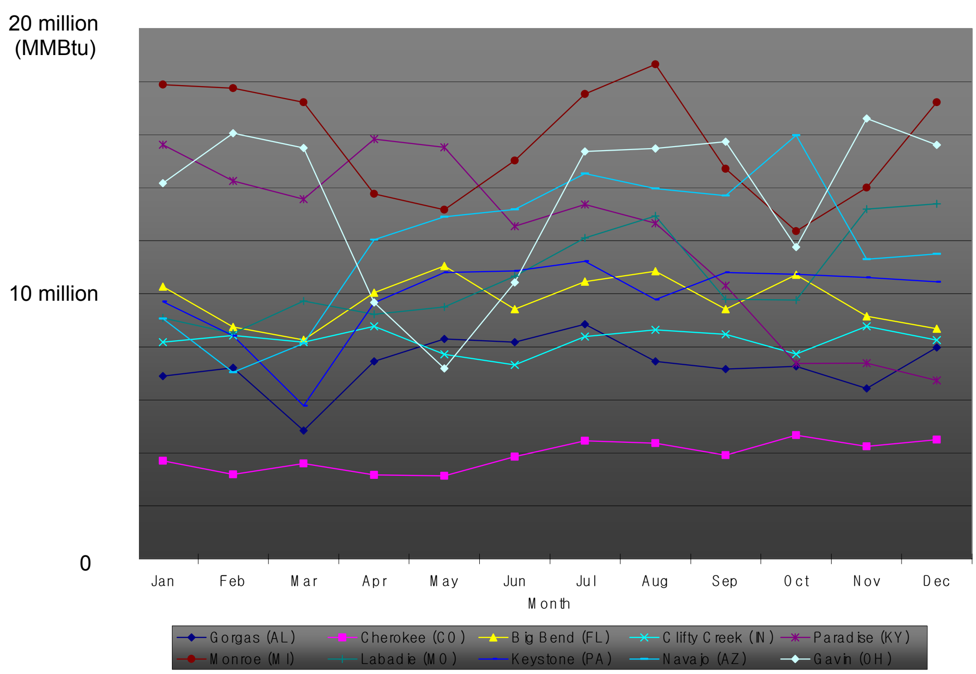

Figure 5.10 Monthly coal consumptions patterns at selected plants

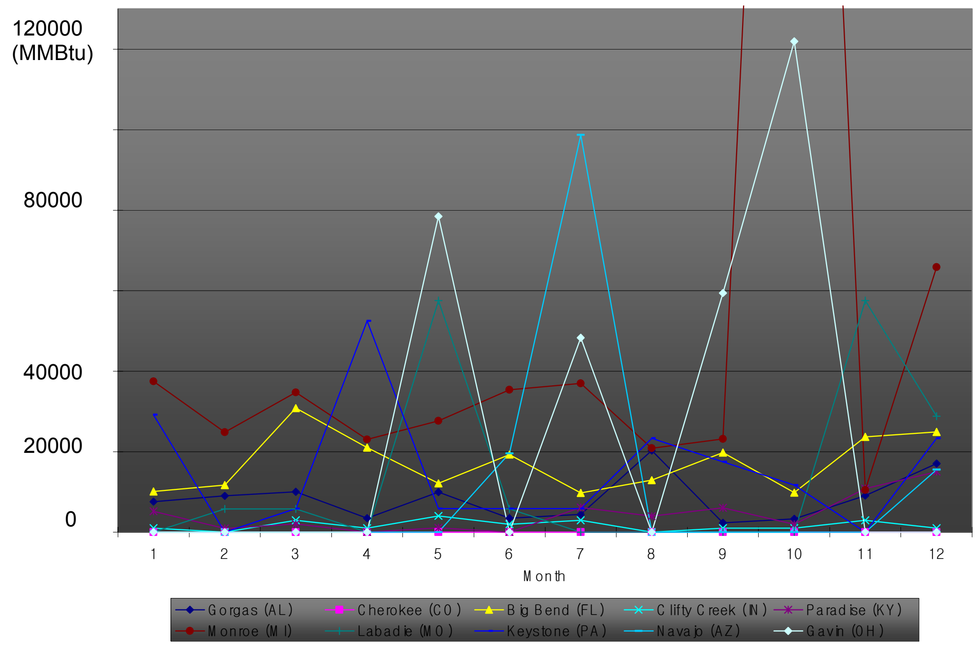

Figure 5.11 Monthly petroleum shipments patterns at selected plants

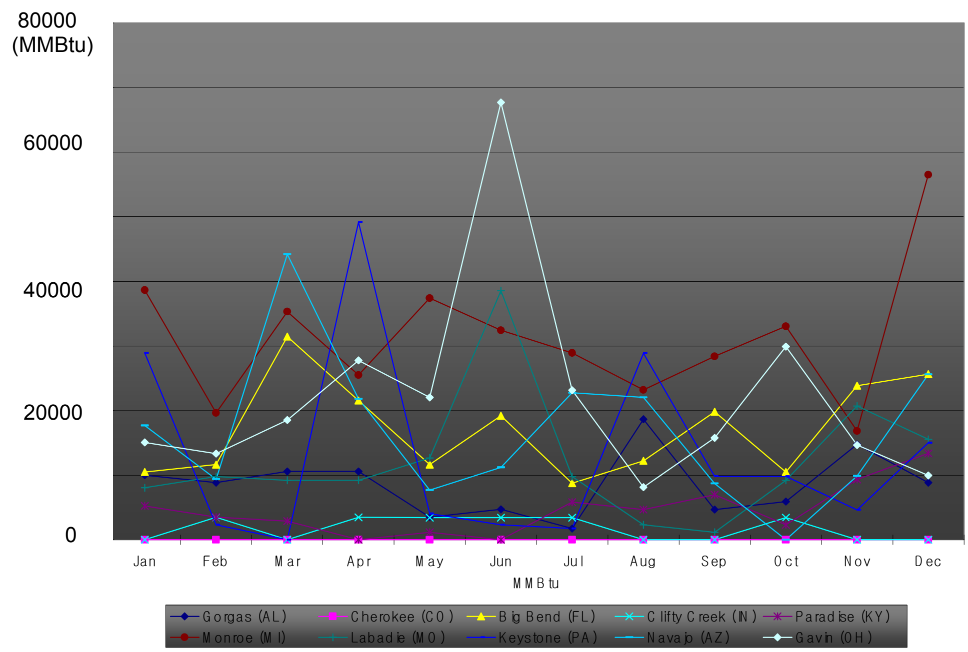

Figure 5.12 Monthly petroleum consumptions patterns at selected plants

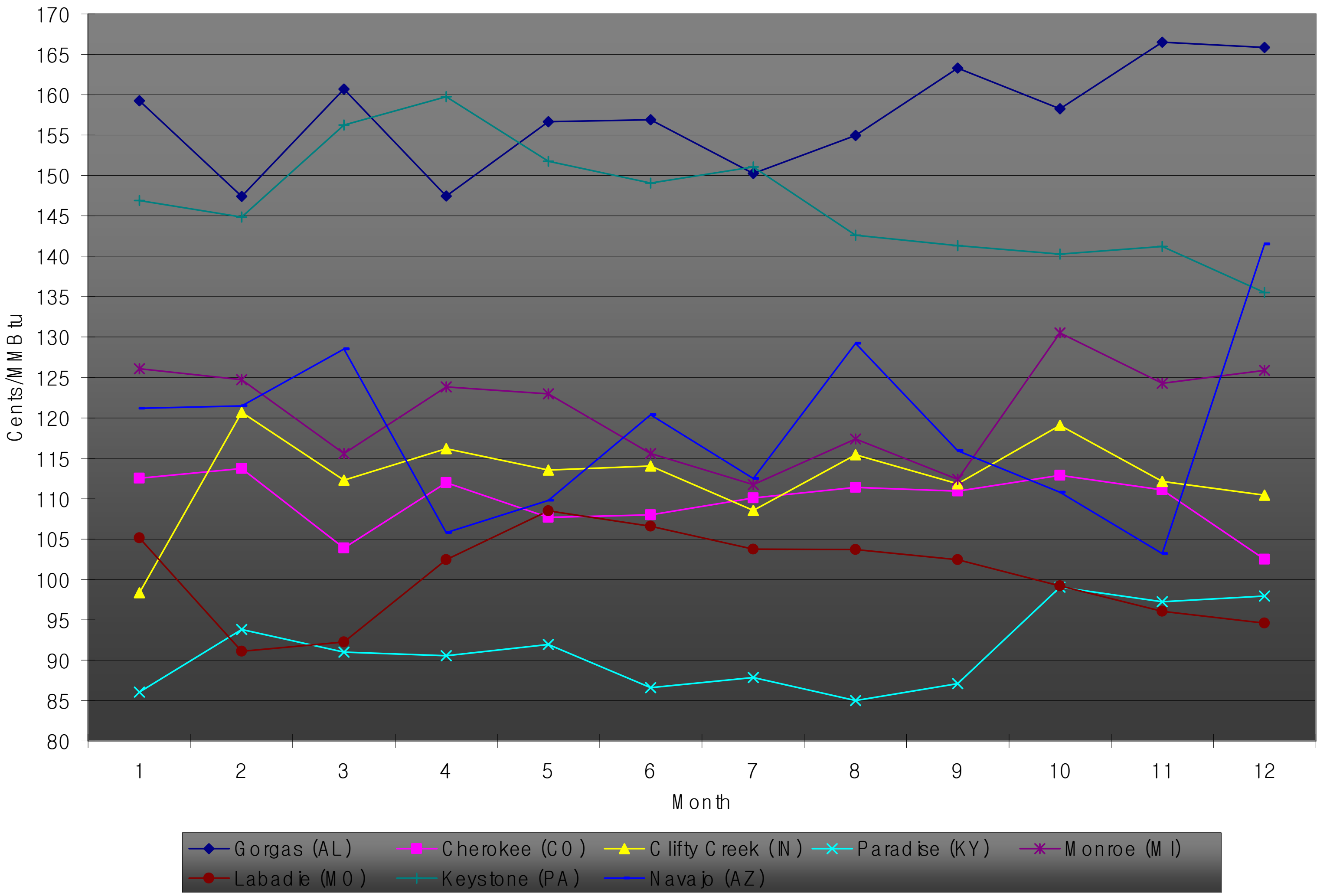

Figure 5.13 Monthly unit fuel purchasing costs patterns at selected plants

of air inside. Therefore, since stronger wind speeds can lead to an overestimation of the actual SO_2 emissions, plants operators may use expensive fuels having relatively lower sulfur contents in summer and winter.

5.2.3 Monthly Unit Gross SO_2 Emissions and Net SO_2 Emissions

This data comes from the Boiler Information (Fuel Consumption and Quality file of Form EIA-767). Sulfur in the database is recorded as percent by weight for each fuel type. In order to calculate SO_2 gross emissions, the atomic weights of sulfur (*S*) and oxygen (*O*) are used. Since the atomic weight of *S* is 16, and the weight of *O* is 8, one kilogram of *S* leads to the formation of two kilograms of SO_2.[13] Since the standard of the Clean Air Act Amendments (CAAA) regulation is 2.5 pound of SO_2 emissions per MMBTU, SO_2 emissions should be calculated in the same unit.

In Figure 5.14, unit gross SO_2 emissions do not display special peaks over the months. However, one can see increasing emissions in March-April and October-November, indicating that plant operators emit more SO_2 during the off-season (spring and autumn). Since there are relatively weaker wind speeds in spring and autumn, SO_2 emissions released from the stack and measured by the Continuous Emission Monitoring Systems (CEMS) may be underestimated. As a result, plant operators may strategically release more emissions during these periods.

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[13] Gross emissions measured in pounds (lb), tons, or kilograms are obtained. For coal, it is straightforward: 1 ton of coal at, say 3%, produces 30 kg of *S*, thus 60 kg of SO2. In the case of petroleum, gallon must be converted to weight, using an average density value.

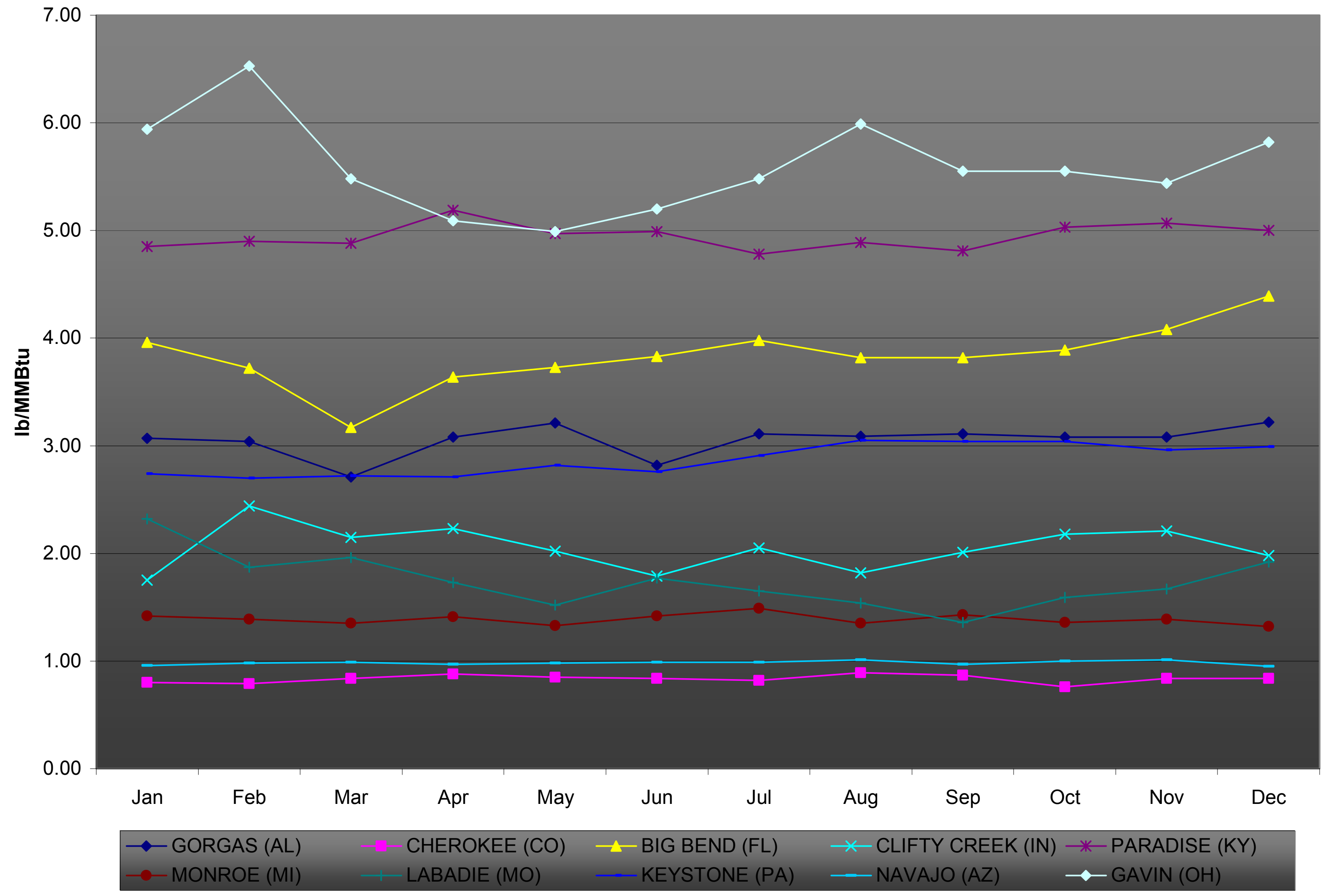

Figure 5.14 Monthly unit gross SO_2 emissions patterns at selected plants

Net SO_2 emissions (Figure 5.15) display no specific peaks in the summer and winter. Since much more fuel is likely to be used in summer and winter, due to increasing demands for cooling and heating, the net SO_2 emissions in these seasons should be higher. The reason why there is no or only a weak peak is that plant operators may reduce SO_2 emissions during summer and winter seasons to prevent an overestimation of SO_2 emissions under unfavorable meteorological conditions (*e.g.*, stronger wind speed).

5.3 Summary

Throughout the various exploratory analyses, several important insights have been derived as inputs to further analyses. First, the CAAA of 1990 has been an effective regulation to encourage the use of low sulfur fuels, especially low sulfur coal, at most plants. In the near future, however, frequent use of emission trading and increasing electricity demands may bring back the issue of controlling SO_2 emissions to the "front burner". For instance, as demand for electricity increases, increased allowances purchases from other plants in different locations are likely to take place in order to reduce the marginal costs of SO_2 emission abatement. This may lead, over time, to the degradation of the air quality in the region where the plant is located, despite compliance with the emission limits of the CAAA of 1990. Second, several lagged relationships between fuel shipments, stocks, and consumptions have been observed. The statistical significance of these lagged relationships will be examined in further analyses. Third, the unit fuel prices

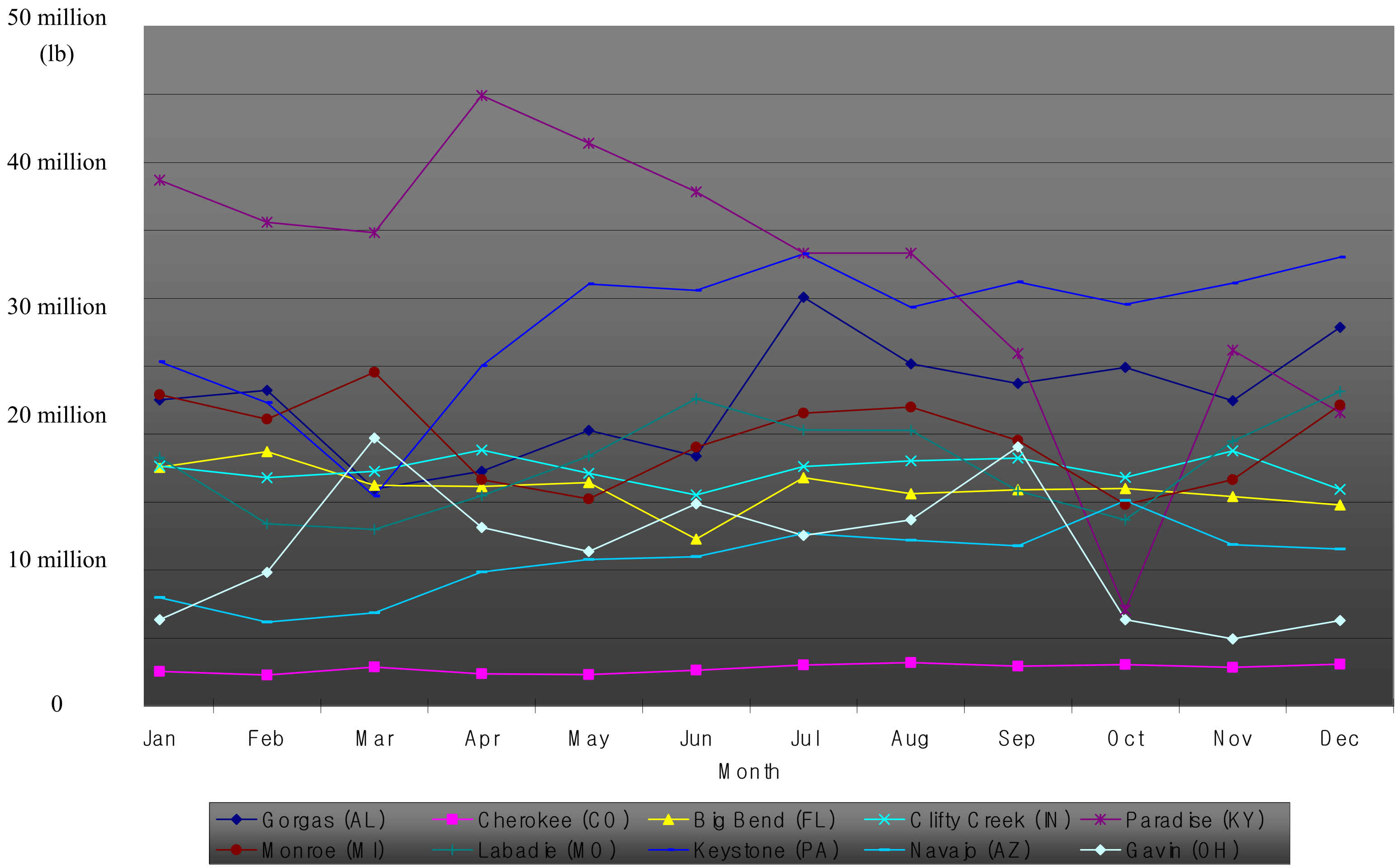

Figure 5.15 Monthly net SO_2 emissions patterns at selected plants

are likely to affect the overall fuel shipment/use patterns. When the price of a certain fuel increases, a plant operator is likely to purchase substitute fuels at cheaper prices, or use a mixture of fuels. Finally, the relationships between meteorological conditions and net SO_2 emissions patterns will be explored, to better understand a plant operator's possible strategy to use meteorological conditions to produce an underestimation of the actual SO_2 emissions. If meteorological conditions, such as wind speed, have a significant effect on the measurement of SO_2 emissions in the stack, a plant operator is likely to account for this phenomenon in emissions scheduling.

In order to comply with the CAAA annual limits, each power plant uses various compliance strategies, e.g., installing pollution control equipment, fuel switching, adjustments in generation dispatch, repowering, retirement, etc[14]. However, because of the uncertainty in future conditions, such as weather, fuel prices, etc., power plants can never minimize cost *ex-post*, although they minimize *ex-ante* expected cost, based on some assumed distribution of probabilities for the variables not known with certainty. The CAAA of 1990 provides more flexibility to meet the goal of cost minimization under such uncertainty, providing various market-based tools such as emission trading and banking.

[14] http://www.icfconsulting.com/Markets/Energy/doc_files/multi-pollutant-compliance.pdf
http://www.netl.doe.gov/publications/proceedings/98/98fg/hovan.pdf

CHAPTER 6

MODEL SPECIFICATION AND ESTIMATION

Consider a power plant that generates electricity using different types of fuels. Demand for electricity is determined by seasonal factors, such as cooling and heating. Fuel purchasing prices are dependent on market conditions, and are treated as exogenous variables. Since a plant operator may choose fuels in terms of Btu and sulfur contents, these characteristics can be viewed as decision variables. If not for regulation of SO_2 emissions, plant operators would use the cheapest fuels to maximize their profits. However, since the 1990 CAAA sets annual SO_2 emission allowances for most fossil fuel burning power plants, plants operators must find the appropriate mix of compliance options, such as fuel mix/shift, abatement technology, and emission trading, to meet the allowance limit at minimum cost. Also, meteorological conditions may affect SO_2 emissions, as plants operators may emit more SO_2 in favorable conditions, when the emissions detected in stacks are underestimated.

The endogenous variables, such as the Btu values and sulfur contents of shipments and consumptions, and the gross and net SO_2 emissions, interact with each other, implying potential simultaneity. In this research, endogenous variables are estimated as functions of each other as well as of exogenous variables, such as electricity demands, fuel prices, compliance option parameters, and meteorological conditions. If simultaneity is detected, 3-stage least squares (3SLS) estimation is used to obtain consistent and unbiased estimators, eliminating cross equation correlations. Some variables cannot be incorporated in the final models due to multicolinearity, and other variables must be replaced by available proxies. In most cases, multiplicative models are used to account for the interactions among the variables. The effects of fuel prices on type-of-fuel choice decisions are explicitly explored in the fuel share analysis. Finally the impacts of modifying such policy variables as the annual SO_2 emission allowances and FGD availability (taken as representing a command-and-control strategy) on actual sulfur shipments and gross and net SO_2 emissions for a selected plant, are computed using the estimated models.

6.1 Energy Analysis

6.1.1 Fuel Shipments (Btu)

The decision on the amount of Btu's to be shipped depends primarily on current fuel prices, and on current and future demands for electricity/fuel. In any given month *m*, the Btu consumptions in month *m* and in future months are treated as exogenous variables, based on exogenous forecasts of electricity demand linked to forecasts of market conditions. Exploratory graphical analyses for a few selected plants in Chapter 5 suggested a possible three-month lag between shipment and consumption. However, in order to more rigorously test this lag effect, the actual Btu consumptions over the next 12 months ($m+1 \rightarrow m+12$) were considered. Month m fuel consumption is also considered, as current fuel shipments may be used immediately or shortly after arrival at the power plant, in order to satisfy current energy/electricity needs. This is particularly the case with natural gas, which is impractical to store. Electric utility companies use models for the prediction of future electricity demand, considering seasonality, regional economic activity and growth, and demographic trends. Based on such forecasts, fuel supply contracts are often made several months before actual shipments. As a cost minimizer/profit maximizer, a plant would not purchase more fuel than needed, as this would entail unnecessary inventory costs. It is assumed that the short-term (*i.e.*, up to twelve months) future demand of electricity can be assessed with little uncertainty. In the present analysis, the actual electricity consumption in month ($m+k$) is taken as a proxy of this forecast. Hence, the following shipment model is estimated:

$$\ln BTUS_m = \beta_0 + \beta^{UPC} \ln UPC_m + \sum_{k=0}^{12} \beta_k^{BTUC} \ln BTUC_{m+k} \tag{6.1}$$

where:

$BTUS_m$: Btu shipments (MMBtu) in month m,
UPC_m : Unit fuel purchasing costs in month m,
$BTUC_{m+k}$: Btu consumption (MMBtu) in future month $m+k$.

The adjusted R^2 of the final shipment model is 0.704. The model estimates are presented in Table 6.1 (the corresponding SAS program is presented in Appendix D: Program D.1). Shipments are negatively related to fuel price, as expected. Since coal and petroleum are storable, plant operators may purchase more fuel when it is cheaper. The coefficients of the Btu consumption variables display a decreasing trend over the next six months. Adding month (*m+7*) consumption led to an insignificant estimate for month (*m+6*), most likely due to multicolinearity. Hence the final model includes future fuel consumptions up to month (*m+6*). As expected, the coefficient of current (*m*) month consumption is predominant (0.492), which suggests that a significant share of fuel-burning requirements in month *m* is satisfied by fuel shipments during the same month. Regarding future months, the coefficient values suggest three groupings. Fuel needs in month (*m+1*) are clearly next to *m* in importance. Months (*m+2*) through (*m+4*) have coefficients of similar magnitude [0.08 – 0.1], while months (*m+5*) and (*m+6*) have significantly smaller coefficients [0.04 – 0.05]. This decreasing trend points to the decreasing importance with time of future fuel needs in determining current fuel shipments.

Table 6.1: Basic fuel shipment model

Variables	Coefficient	*t*-value
Constant	3.520	28.99**
Unit fuel purchasing price	-0.721	-45.67**
Fuel consumptions / *m*	0.492	39.51**
Fuel consumptions / *m+1*	0.147	10.06**
Fuel consumptions / *m+2*	0.099	6.69**
Fuel consumptions / *m+3*	0.084	5.64**
Fuel consumptions / *m+4*	0.078	5.03**
Fuel consumptions / *m+5*	0.042	2.69**
Fuel consumptions / *m+6*	0.051	3.75**
Adj. R^2	0.704	
Number of observations	17100	

** Significant at the 0.01 level

6.1.2 Energy Consumptions (Btu)

There is a purely technological (not behavioral) relationship between fuel input (Btu) and electricity generation, based on thermodynamical factors. This relationship is captured here empirically, with a second-order additive model, which allows for a possible non-linear relationship. The structure of the Btu consumption model is:

$$BTUC_m = \beta_0 + \beta^{GEN} GEN_m + \beta^{GEN2} \left(GEN_m\right)^2, \qquad (6.2)$$

where :

$BTUC_m$: Total fuel consumption (MMBtu) in month *m,*
GEN_m : Total net electricity generation (kWh) in month *m.*

The model estimates are presented in Table 6.2 (the corresponding SAS program is presented in Appendix D: Program D.2). The adjusted R^2 is 0.985. The first-order term is positive, with an extremely high t-value, while the second-order term is negative, implying that the fuel input (Btu) increases less than proportionately with electricity generation. The operating (fuel) costs of electricity generation are therefore characterized by economies of scale.

Table 6.2: Basic Btu consumption model

Variables	Coefficient	*t*-value
Constant	110940	20.05**
Net electricity generations (kWh)	10.24579	477.78**
(Net electricity generations)^2 (kWh)^2	-0.0000004	-24.34**
Adj. R^2	0.985	
Number of observations	22873	

** Significant at the 0.01 level

6.2 Sulfur Analysis

6.2.1 Sulfur Shipments Model

Sulfur shipments are defined as the amount of sulfur per Btu of fuel shipped, and may or may not vary over time. Some fuel supply contracts, often made several months before the actual shipments, may force a plant operator to purchase the same fuel, hence the same amount of sulfur. Other supplies may come from the spot market, and thus provide much more flexibility for plant operators to change fuel types/qualities to meet their annual SO_2 emission allowances. Initially, the impacts of cumulative SO_2 emissions on sulfur shipments and SO_2 emissions were tested, assuming that the closer one gets to the end of the year, the tighter the constraint, and the lower the emissions. Three variables were considered to test for these dynamic cumulative effects: (1) the ratio of accumulated net SO_2 emissions to the allowances for any month within the year; (2) a time index representing the actual month within the year ($1 \rightarrow 12$); and (3) a time trend index ($t = 1 \rightarrow 60$: 5 years of 12 months each) over the whole period 1996-2000. Variables (1) and (2) turned out to be insignificant, and only the time trend variable is used as a proxy for these dynamic effects.

The sulfur content of shipments may also vary with the season. Summer is defined as the May-October period, and winter as the November-April period. Fuel prices as well as the annual SO_2 emission allowances are also likely to have an effect on the quality of fuel shipped. Sulfur shipments in previous months are used as proxy variables representing the inertia effects of contracts. The gross SO_2 emission variable is used to test for interactions between shipments and fuel consumption/gross SO_2 emissions.

The Clean Air Act Database Browser (CAADB, see Appendix A: Table A.4), shows that only 263 coal-fired utility plants have been assigned annual SO_2 emission allowances in Phase I, while most power plants have been assigned allowances in Phase II (806 plants, with any type of fuel). Since Phase I allowances were applied from 1995 through 1999, several plants in the sample do not have allowances over this period. Allowance imputations, taken as equal to the actual net annual SO_2 emissions, were used for these plants, under the assumption that these imputed allowances would lead to the observed cost-minimization strategy under previous regulations on ambient air quality requirements. To validate the imputations, the plants with Phase I allowances, and with complete monthly time series in each year were selected as a sub-sample, and the actual annual net SO_2 emissions were computed and compared to the allowances. The average ratio of the annual allowances to the actual annual net SO_2 emissions is 1.04. The ratio displays some random variability, which can be regarded as resulting from the effects of emission trading, banking, and other types of transfers among plants or companies.

In summary, fuel purchasing prices, unit sulfur shipments in previous months $(m-k)$, unit gross SO_2 emissions in the current month (m), the annual SO_2 emission allowances, a time trend ($t = 1 \rightarrow 60$: 5 years of 12 months each), and a seasonal dummy variable (winter/summer), are used to explain variations in unit sulfur shipments. The fuel sulfur shipment model is:

$$\ln USO2S_m = \beta_0 + \beta^{UPC} \ln UPC_m + \sum_{k=1}^{3} \beta_k^{USO2S} \ln USO2S_{m-k} + \beta^{USO2C} USO2C_m + \beta^{ALLOW} ALLOW + \beta^{TIME} TIME + \beta^{WINT} WINT, \tag{6.3}$$

where:

$USO2S_m$: Unit sulfur shipment ($lb/MMBtu$) in month m,
UPC_m : Unit fuel purchasing cost in month m,
$USO2C_m$: Unit gross SO_2 emission ($lb/MMBtu$) in month m,
$ALLOW$: Annual SO_2 emission allowances,
$TIME$: Time trend (month: $t = 1 \to 60$ over 5 years (1996 to 2000)),
$WINT$: $=1$: if winter (November to April); $=0$: if summer (May to October).

6.2.2 Gross SO_2 Emissions Model

Gross SO_2 emissions are measured in terms of pounds of SO_2 per MMBtu. They are assumed a function of unit net SO_2 emissions in month (m), and unit sulfur shipments in month (m) and previous months $(m-1, m-2, m-3)$. Additional explanatory variables are FGD availability, the time trend ($t = 1 \to 60$), and the seasonal dummy (winter/summer). The annual emission allowance is not included in this model because its effect is not clear, due to the possibility of further emission abatement. The unit gross SO_2 emissions model is then:

$$\ln USO2C_m = \beta_0 + \beta^{UNE} \ln UNE_m + \sum_{k=0}^{3} \beta_k^{USO2S} \ln USO2S_{m-k} + \beta^{FGD} FGD \\ \beta^{TIME} TIME + \beta^{WINT} WINT, \tag{6.4}$$

where:

$USO2C_m$: Unit gross SO_2 emissions (lb/MMBtu) in month *m,*
UNE_m : Unit net SO_2 emissions (lb/MMBtu) in month *m,*
$USO2S_m$: Unit sulfur shipments (MMBtu) in month m ,
FGD : =1 if an FGD facility is installed; =0 otherwise,
TIME : Time trend (months: $t = 1 \rightarrow 60$ over 5 years (1996 to 2000)),
WINT : $= 1$: if winter (November to April); $= 0$: if summer (May to October).

6.2.3 Net SO_2 Emissions Model

To some extent, the sulfur content of fuel shipments and consumptions are linked to the annual SO_2 allowances. However, these allowances have the strongest impact on net SO_2 emissions, because a fine for violating the allowance limit will be imposed if the accumulated net emissions exceed this limit. To reduce net SO_2 emissions, a plant operator may utilize abatement technology and allowance trading. As in earlier models, the time and seasonal variables are also considered here. Finally, net SO_2 emissions must also be strongly linked to gross SO_2 emissions, which, together with the flow abated by FGD technology, is the primary determinant of net emissions.

Emission trading costs were not included in the final model, because of their weak effect on net SO_2 emissions. Indeed, these costs reflect the number of allowances purchased in a given year, but not their cumulative effects over years. Also, purchased allowances may be banked and not used immediately after purchase. Further research is needed to assess the impact of traded allowances. Hence, it is important to keep in mind that the allowance variable reflects the allowances assigned by the EPA to each plant, and not the effects of trading (sales or purchases of allowances), nor the effects of allowance substitution among plants under the same company ownership (bubble effect).

In addition, meteorological conditions variables, such as wind speeds, were excluded from the final net SO_2 emission model, due to their insignificance. Power plant operators appear not to consider meteorological factors in scheduling SO_2 emissions. The final estimated model is:

$$\begin{aligned} \ln UNE_m = \beta_0 + \beta^{USO2C} \ln USO2C_m + \beta^{ALLOW} \ln ALLOW + \beta^{FGD} FGD \\ + \beta^{TIME} TIME + \beta^{WINT} WINT, \end{aligned} \tag{6.5}$$

where:

UNE_m : Unit net SO_2 emissions (lb/MMBtu) in month *m,*
$USO2C_m$: Unit gross SO_2 emissions (lb/MMBtu) in month *m,*
$ALLOW$: Annual SO_2 emission allowances (lb),
FGD : =1 with FGD facilities installed; =0 otherwise,
$TIME$: Time trend (months, $t = 1 \rightarrow 60$ over 5 years (1996 to 2000)),
$WINT$: $=1$: if winter (November to April); $=0$: if summer (May to October).

6.3 Simultaneous Estimation of the Sulfur Models

6.3.1 Overview

In section 6.1, the Btu shipment and consumption models are estimated using OLS regression while assuming recursivity[15]. However, the sulfur dioxide flows in the

[15] The recursivity assumption in OLS regression is that the models should not involve feedback loops. Not only should there be no circular direct effects (A → B → C → A), but one must also assume that the error terms for the endogenous variables are uncorrelated with the regressors. Thus, for instance, the model should not contain a situation where one of the endogenous variables, Y_1, is partly caused by the endogenous variable Y_2, yet there is a correlation between the error terms for Y_1 and Y_2.

shipments, consumptions, and emissions stages are clearly interdependent, as can be seen in equations (6.3) – (6.5), so the presence of several endogenous variables requires another estimation tool, because simultaneity may cause the OLS parameter estimators to be inconsistent and biased. Simultaneous equations estimation is used when a high degree of correlation exists between residuals and regressors. In the first stage, new dependent variables, which do not violate the OLS recursivity assumption, are created. In the second stage, new dependent or endogenous variables are created to substitute for the original ones, and the regression is estimated by OLS, but using the newly created variables. However, 2SLS estimators are still not efficient because they do not use the available information on cross-equation correlations. In 3SLS estimation, by transforming the structural forms into reduced forms, all the jointly dependent variables are expressed as functions of all the predetermined variables, under the assumption that the covariance matrix is non-scalar, and that there is no serial dependence in the error term.

The dependent variables of the three sulfur models presented in the previous sections (sulfur shipments, gross SO_2 emissions, net SO_2 emissions) also appear as independent variables together with other exogenous variables. Because of this simultaneity and the possibility of cross-equation correlations, the 3SLS estimation procedure is implemented. Equations (6.3) – (6.5) are restated below in a more general form to outline the interdependency:

$$USO2S_m = f\begin{pmatrix} \underline{USO2C_m}, UPC_m, USO2S_{m-1}, USO2S_{m-2}, USO2S_{m-3}, \\ ALLOW, TIME, WINT \end{pmatrix} \tag{6.6}$$

$$USO2C_m = g\left(\begin{array}{c}\underline{UNE_m}, \underline{USO2S_m}, USO2S_{m-1}, USO2S_{m-2}, USO2S_{m-3}, \\ FGD, TIME, WINT\end{array}\right) \tag{6.7}$$

$$\mathrm{UNE_m} \quad = \mathrm{h}\left(\underline{\mathrm{USO2C_m}}, \mathrm{ALLOW, FGD, TIME, WINT}\right) \tag{6.8}$$

The underlined variables on the right-hand sides are the endogenous variables that are dependent variables in other equations. This model is called a *structural model*, because the three equations are interlinked by the endogenous variables. For the sake of clarity in exposition, $USO2S_m$ is replaced by X_t, $USO2C_m$ by Y_t, and UNE_m by Z_t, while the exogenous variables are represented by E_t^X, E_t^Y, and E_t^Z respectively. Equations (6.6) – (6.8) can then be represented as follows:

$$X_t = \alpha_0 + \alpha_1 Y_t + \alpha_2 E_t^X \tag{6.9}$$

$$Y_t = \beta_0 + \beta_1 X_t + \beta_2 Z_t + \beta_3 E_t^Y \tag{6.10}$$

$$Z_t = \gamma_0 + \gamma_1 Y_t + \gamma_2 E_t^Z \tag{6.11}$$

Solving the equations for the unknowns X_t, Y_t, and Z_t, with E_t^X, E_t^Y, and E_t^Z treated as parameters, the following reduced form of the model is obtained:

$$\begin{aligned} X_t &= \alpha_2(\alpha_1\beta_1 + 1)E_t^X + \alpha_1\beta_3 E_t^Y + \alpha_1\beta_2\gamma_2 E_t^Z + \frac{\alpha_0(1-\beta_2\gamma_1) + \alpha_1(\beta_0 + \beta_2\gamma_0)}{1 - \alpha_1\beta_1 - \beta_2\gamma_1} \\ &= \pi_{12}E_t^X + \pi_{13}E_t^Y + \pi_{14}E_t^Z + \nu_{1t} \end{aligned} \tag{6.12}$$

$$Y_t = \alpha_2\beta_1 E_t^X + \beta_3 E_t^Y + \beta_2\gamma_2 E_t^Z + \frac{\beta_0 + \alpha_0\beta_1 + \beta_2\gamma_0}{1-\alpha_1\beta_1 - \beta_2\gamma_1}$$
$$= \pi_{22} E_t^X + \pi_{23} E_t^Y + \pi_{24} E_t^Z + \nu_{2t} \qquad (6.13)$$

$$Z_t = \alpha_2\beta_1\gamma_1 E_t^X + \beta_3\gamma_1 E_t^Y + \gamma_2\left(1+\beta_2\gamma_1\right) E_t^Z + \frac{\gamma_0\left(1-\alpha_1\beta_1\right) + \gamma_1\left(\beta_0 + \alpha_0\beta_1\right)}{1-\alpha_1\beta_1 - \beta_2\gamma_1}$$
$$= \pi_{32} E_t^X + \pi_{33} E_t^Y + \pi_{34} E_t^Z + \nu_{3t} \qquad (6.14)$$

6.3.2 Results

The estimated models for unit sulfur shipments, unit gross SO_2 emissions, and unit net SO_2 emissions are presented in Table 6.3 (the corresponding SAS program is presented in Appendix D: Program D.3). The adjusted R^2 is 0.773 and the number of degrees of freedom is 48,816.

Table 6.3: Sulfur models – Simultaneous equations estimations

Variables	Unit Sulfur Shipments		Unit Gross SO_2 Emissions		Unit Net SO_2 Emissions	
	Coefficient	*t*-value	Coefficient	*t*-value	Coefficient	*t*-value
Constant	0.199	5.04**	0.579	18.87**	-1.174	-20.71**
Unit fuel price	-0.105	-10.52**	-	-	-	-
Unit sulfur shipments / *m*	-	-	-1.493	-10.55**	-	-
Unit sulfur shipments / *m-1*	0.408	13.85**	1.076	14.13**	-	-
Unit sulfur shipments / *m-2*	0.204	9.94**	0.609	14.00**	-	-
Unit sulfur shipments / *m-3*	0.144	6.96**	0.527	14.66**	-	-
Unit gross SO_2 emissions	0.235	3.20**	-	-	0.825	133.06**
Unit net SO_2 emissions	-	-	0.161	3.67**	-	-
Annual SO_2 emission allowances	0.008	5.23**	-	-	0.072	22.13**
FGD availability	-	-	0.287	4.88**	-1.336	-153.95**
Time Trend ($t = 1 \rightarrow 60$)	-0.0003	-2.61**	-0.001	-2.05*	-0.001	-3.85**
Winter	-0.004	-1.24	-0.016	-2.27*	-0.015	-2.10*
Adj. R^2	0.773					
Degrees of freedom	48816					

** Significant at the 0.01 level
* Significant at the 0.05 level

6.3.2.1 Sulfur Shipments

Fuel price has a negative effect on unit sulfur shipments, as fuels with higher-sulfur contents are cheaper than those with lower-sulfur contents. Indeed, since every plant has an assigned annual SO_2 emission allowance, lower-sulfur fuels are in higher demand, and their prices are higher. Unit sulfur shipments in previous months $(m-1, m-2, m-3)$ are positively related to unit sulfur shipments in the current month (m), suggesting some resiliency in the use of similar fuels over time, possibly because of contract constraints.

Increasing gross SO_2 emissions leads to increasing sulfur shipments, reflecting a plant operator's sense that increased gross emissions can be taken advantage of by using cheaper, higher-sulfur fuels. Annual SO_2 emission allowances are positively related to unit sulfur shipments. The higher these allowances, the higher the amount of SO_2 that may be emitted, hence the higher the amount of sulfur shipments. The time trend variable ($t = 1 \rightarrow 60$) is negatively related to unit sulfur shipments. Since 2000 is the initial year of Phase II regulations, all affected plants have had to reduce SO_2 emissions over time. However, the seasonal dummy variable is not significant in the sulfur shipment model.

6.3.2.2 Gross SO_2 Emissions

The unit net SO_2 emissions in month (m) and the unit sulfur shipments in the previous months $(m-1, m-2, m-3)$ have positive effects on gross SO_2 emissions. However, the unit sulfur shipment in the current month (m) has a negative impact on unit gross SO_2 emissions. This can be interpreted as follows: if a plant operator ships more lower-quality fuels with higher-sulfur contents in month m for future use and therefore for increased future gross emissions, it may need to reduce gross emissions in month m because of the annual allowance limit. The FGD dummy is positively associated with gross emissions. If a plant has an FGD abatement system, using lower-quality fuels with higher-sulfur contents may be efficient, because this will decrease fuel purchasing costs in the shipment stage. Although a greater cost is incurred when a plant installs an FGD facility, once it is in place FGD operation costs are lower than the differential costs of shifting from higher-sulfur to lower-sulfur fuels. The time trend variable ($t = 1 \rightarrow 60$) is significant and negatively related to unit gross SO_2 emissions. The seasonal variable (winter dummy) has also a negative sign. The average heating and cooling degree-days in the U.S. are presented in Table 6.4. Energy needs for heating are 3-4 times larger than energy needs for cooling, and this is likely to translate into higher electricity requirements in winter. Plant operators are therefore likely to use lower-sulfur fuels in winter to compensate for the increased burning of fossil fuels. Another interpretation may be that the unit cost of SO_2 emission abatement may be lower when plants are fired at higher production level.

Table 6.4: Average heating and cooling degree-days in the U.S. (1996-2000)

	1996	1997	1998	1999	2000
Heating Degree Days	4690	4523	3946	4153	4447
Cooling Degree Days	1186	1167	1414	1301	1240

Source: Energy Information Administration - http://www.eia.doe.gov/emeu/steo/pub/a2tab.html

6.3.2.3 Net SO_2 Emissions

Unit gross SO_2 emissions have a strong positive effect on unit net SO_2 emissions, as expected in view of the natural flow of SO_2 emissions. The annual SO_2 emission allowance variable has also a positive effect on net SO_2 emissions, as expected. In contrast to the gross SO_2 emission model, the FGD dummy variable has a negative sign, implying that plants with an FGD facility have lower net SO_2 emissions, as expected. The time trend variable ($t = 1 \rightarrow 60$) is negatively linked to net SO_2 emissions, pointing to decreasing SO_2 emissions over the 5-year study period. Finally, the seasonal variable (winter dummy) has a negative sign, implying lesser use of higher-sulfur fuels or more effective SO_2 emission abatement at higher production levels in winter.

Consider the coefficients of the annual SO_2 emission allowances and FGD dummy variables. When holding all the other variables constant, a 1% decrease in allowances leads to a 0.07% decrease in net emissions, while installing an FGD facility results in a reduction of net emissions by 74% (exp(-1.336)=0.26). The lesser impact of changes in the annual allowances is likely due to emission trading, banking, and other transfers among plants or companies.

The coefficients of the exogenous variables in the reduced form models are presented in Table 6.5. These coefficients will be used in Section 6.5 to conduct a simulation impact analysis. Summarizing all the above models, the structure of the simultaneous equation model is illustrated by the flow chart in Figure 6.1.

Table 6.5 Coefficients of the reduced form sulfur models

Endogenous Variables \ Exogenous Variables	Intercept	Fuel Price	Unit sulfur shipments in month $m-1$	Unit sulfur shipments in month $m-2$	Unit sulfur shipments in month $m-3$
Unit Net SO_2 Emissions	-1.11149	0.10656	0.31629	0.20649	0.21161
Unit Gross SO_2 Emissions	-0.07598	0.12909	0.38318	0.25016	0.25636
Unit Sulfur Shipments	0.21643	-0.07492	0.49803	0.26241	0.20410

Endogenous Variables \ Exogenous Variables		Annual SO_2 Emission Allowances	Time Trend $(t=1 \rightarrow 60)$	Seasonal Dummy (Winter)	FGD Availability
Unit Net SO_2 Emissions		0.07112	-0.00103	-0.02252	-1.28763
Unit Gross SO_2 Emissions		-0.00084	-0.00023	-0.00947	0.05863
Unit Sulfur Shipments		0.00825	-0.00034	-0.00663	0.01379

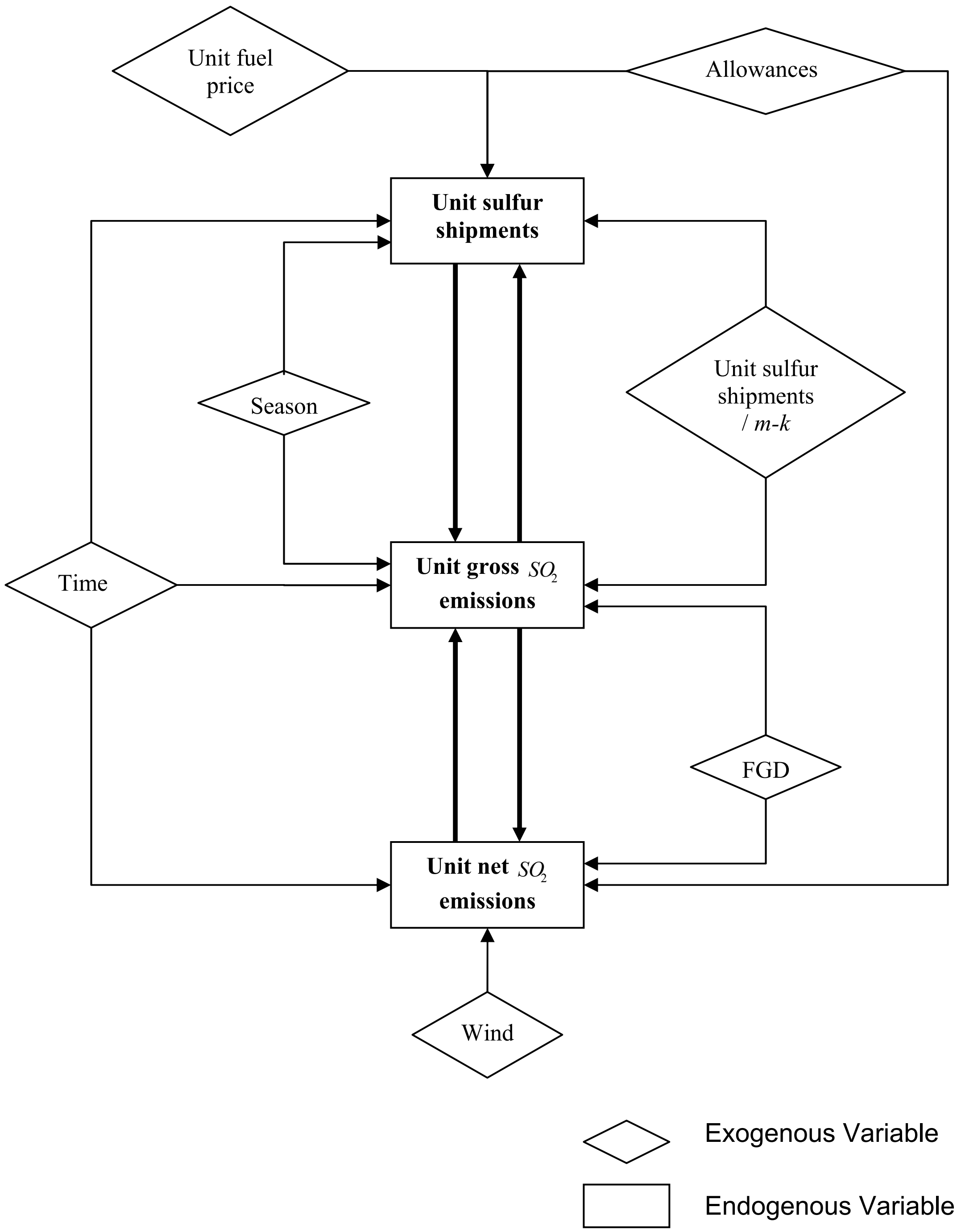

Figure 6.1: Structure of the simultaneous interactions in the sulfur models

6.4 Fuel Share Analysis

As the price of a given fuel increases, the shares of this fuel in the total energy shipment and total energy consumption decrease, while the corresponding shares of substitute fuels increase. Since there is a lag between fuel shipment and actual usage for electricity generation, the fuel prices for earlier shipments are likely to affect the shares of fuels used for current electricity generation. In this section, the effects of fuel prices on fuel choice decisions, at both the shipment and electricity generation stages, are explored.

6.4.1 Fuel Shipment Share Model

Baughman and Joskow (1975) have estimated the effects of fuel prices on residential appliance choice. Let x_i be a set of variables characterizing technology i, and $C(x_i) + \varepsilon(x_i)$ the non-random and random components of the services produced by technology i. Under the assumption that the error terms $\varepsilon(x_i)$ are independent and distributed according to the Weibull distribution, the probability of choosing alternative i among *k* alternatives follows the multinomial logit model:

$$\Pr_i = \frac{e^{C(x_i)}}{\sum_{j=1}^{k} e^{C(x_j)}} \tag{6.15}$$

The logarithm of the odds of any two particular choices i and j is then:

$$\log(\Pr_i / \Pr_j) = C(x_i) - C(x_j) \tag{6.16}$$

Baughman and Joskow have estimated this logit model using maximum likelihood techniques. Similarly, Bjorner and Jensen (2002) estimate a logit model, with the ratio of energy costs shares taken as a function of the ratio of fuel prices (with logarithms on both sides).

The previous models provide the basis for the approach selected here. When three fuels (*e.g.*, coal, petroleum, and natural gas) can be substituted one for the other at time t, the logarithm of the ratio of the share of fuel 2 $\left(SH_{2t}\right)$ to the share of fuel 1 $\left(SH_{1t}\right)$ is estimated with the following equation,

$$log\left(\frac{SH_{2t}}{SH_{1t}}\right) = \alpha_0 + \alpha_1 \, log \, P_{1t} + \alpha_2 \, log \, P_{2t} \tag{6.17}$$

where P_{1t} and P_{2t} are the prices of fuel 1 and 2 at time t. Equation (6.17) is transformed into

$$\frac{SH_{2t}}{SH_{1t}} = \alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2} \tag{6.18}$$

Analogously,

$$\frac{SH_{3t}}{SH_{1t}} = \alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3} \tag{6.19}$$

Since the sum of the shares of the three fuels is equal to 1, with

$$SH_{1t} + SH_{2t} + SH_{3t} = 1 = \left(1 + \alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2} + \alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3}\right) SH_{1t} \ , \tag{6.20}$$

the shares of each fuel are computed as follows:

$$SH_{1t} = \frac{1}{1+\alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2} + \alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3}} \tag{6.21}$$

$$SH_{2t} = \frac{\alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2}}{1+\alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2} + \alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3}} \tag{6.22}$$

$$SH_{1t} = \frac{\alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3}}{1+\alpha_0 P_{1t}^{\ \alpha_1} P_{2t}^{\ \alpha_2} + \alpha_0 P_{1t}^{\ \alpha_1} P_{3t}^{\ \alpha_3}} \tag{6.23}$$

If a plant uses only two fuels (1 & 2), then only equation (6.18) is estimated. Using the earlier model notations, the shipment share model is expressed as

$$\ln \frac{SSH_{2,m}}{SSH_{1,m}} = \beta_0 + \sum_{f=1}^{2} \beta_f^{UPC} \ln UPC_{f,m} \ , \tag{6.24}$$

where:

$SSH_{f,m}$: Share of fuel f shipments in month *m,*

$UPC_{f,m}$: Unit fuel purchasing price of fuel f in month *m.*

The estimation results are presented in Table 6.6. While the R^2 is generally low, all the coefficients are very significant and with the correct signs. In the cases of plants with only two fuels, one of which being coal, the particularly low R^2 may be due to the dominance of the coal share, as indicated in Table 6.7.

In all cases, the share of a fuel is inversely related to the fuel purchasing price. For example, in plants with coal and petroleum, as coal price increases, the share of petroleum increases while the share of coal decreases. In plants with all three fuels, the ratio of petroleum share to coal share is elastic with respect to both petroleum and coal prices, while the ratio of natural gas share to coal share is also elastic to both coal and natural gas prices, although the natural gas price elasticity is close to -1. In plants with coal and petroleum, the ratio of petroleum share to coal share is inelastic. The dominance of coal (99.4%) may weaken substitution effects in these plants. In plants with coal and natural gas, the ratio of natural gas share to coal share is elastic with regard to coal price, and inelastic with regard to natural gas price. Finally, in plants with petroleum and natural gas, the ratio of natural gas share to petroleum share is elastic with regard to both petroleum and natural gas prices.

Table 6.6 Shipment share models

Variables	Plants with three fuels		Plants with coal and petroleum	Plants with coal and natural gas	Plants with petroleum and natural gas
	Petroleum/Coal	Natural Gas/Coal	Petroleum/Coal	Natural Gas/Coal	Natural Gas /Petroleum
Constant	0.671 (0.41)	-11.111 (-8.65)	-4.948 (-10.51)	-8.638 (-13.15)	-5.952 (-3.23)
Coal purchasing price	3.170 (15.27)	2.791 (13.90)	0.600 (10.26)	1.898 (18.74)	-
Petroleum purchasing price	-3.427 (-19.63)	-	-0.630 (-11.15)	-	3.395 (9.86)
Natural gas purchasing price	-	-1.162 (-7.79)	-	-0.908 (-13.19)	-2.436 (-7.65)
Adj. R^2	0.416	0.191	0.034	0.100	0.173
Number of observations	1216	1056	7450	5248	493

Numbers in parenthesis are *t*-values

Table 6.7 Shares of fuel shipments in sample data

Fuel Mix	Coal	Petroleum	Natural gas
All three fuels	90.42 %	5.96 %	3.62 %
Coal and petroleum	99.41 %	0.59 %	-
Coal and natural gas	96.09 %	-	3.91 %
Petroleum and natural gas	-	67.81 %	32.19 %

6.4.2 Electricity Generation Share Model

The electricity generation fuel share model is similar to the shipment share model, except for the use of fuel prices in month $m-3$ for coal and petroleum. However, since natural gas is not storable at power plants, the price of natural gas in the current month m is used. In the case of the ratio between coal and petroleum, the model is as follows:

$$\ln \frac{SSG_{2,m}}{SSG_{1,m}} = \beta_0 + \sum_{f=1}^{2} \beta_f^{UPC} \ln UPC_{f,m-3} \, , \tag{6.25}$$

where

$SSG_{f,m}$: Share of net electricity generations (MWh) by fuel f in month *m*,
$UPC_{f,m-3}$: Unit fuel purchasing price of fuel *f* in month $m-3$.

The estimation results are presented in Table 6.8, and the overall shares of fuels used for electricity generation in the different fuel mix cases are presented in Table 6.9. Overall, the results are similar to those of the shipment share models.

Table 6.8 Electricity generation share model

Variables	Plant with three fuels		Plants with coal and petroleum	Plants with coal and natural gas	Plants with petroleum and natural gas
	Petroleum/Coal	Natural Gas/Coal	Petroleum/Coal	Natural Gas/Coal	Natural Gas /Petroleum
Constant	2.943 (1.25)	-24.106 (-14.97)	-5.931 (-12.49)	-10.932 (-16.76)	-1.318 (-0.51)
Coal purchasing price / m-3	2.938 (8.77)	4.287 (19.36)	0.749 (12.77)	1.595 (15.81)	-
Petroleum purchasing price / m-3	-3.639 (-15.87)	-	-0.623 (-10.83)	-	1.233 (2.50)
Natural gas purchasing price / m	-	-0.179 (-1.04)	-	-0.235 (-3.32)	-1.165 (-2.49)
Adj. R^2	0.361	0.266	0.046	0.061	0.016
Number of observations	720	1105	6527	4158	372

Numbers in parenthesis are *t*-values

Table 6.9 Fuel shares of electricity generations in sample data

Fuel Mix	Coal	Petroleum	Natural gas
All three fuels	88.68 %	6.21 %	5.11 %
Coal and petroleum	99.56 %	0.44 %	-
Coal and natural gas	96.93 %	-	3.07 %
Petroleum and natural gas	-	60.20 %	39.80 %

6.5 Simulation Analysis

The purpose of this section is to explore, in a more integrated way, variations in power plant SO_2 emissions induced by changes in the level of annual emission allowances and in the availability of an FGD facility. The comparison of the effects of these two factors may provide useful insights into the effectiveness of the CAAA of 1990.

The monthly equations estimated in Section 6.1 and 6.3 are used to simulate the monthly operations of a representative power plant, and summary variables are then computed for the whole period 1996-2000.

6.5.1 Method

A plant is selected from the sample, with a complete (no missing values) time-series of data over 1996-2000 (60 months). The selection criteria is the completeness of the time series of all the exogenous parameters (*e.g.*, fuel prices, electricity generation), so that the endogenous variables can be computed over the whole period. Various combinations of the allowance and FGD variables are considered, while keeping all the other exogenous variables at their actual observed values. For each combination, Btu shipments and Btu consumptions are computed using the coefficients of Equations (6.1) and (6.2) in Tables 6.1 and 6.2, and sulfur shipments and gross and net SO_2 emissions are computed using the reduced forms of the simultaneous equations (Table 6.5). The Mohave plant in Nevada, a large multi-fuel plant with a capacity of 1,636 MW and no FGD, is selected for this simulation exercise. The FGD variable can take only two values: FGD=1 and FGD=0. Shifting from FGD=0 to FGD=1 will indicate by how much SO_2 emissions can be reduced when installing scrubbers. The annual SO_2 emission allowance is varied by multiplying the actual allowance by the following multipliers: 0.1, 0.3, 0.5, 0.7, 1, 2, 3, 4, 5, and 6. Hence, the total number of (FGD, Allowance) combinations is 20 (2×10). The simulation model is programmed in FORTRAN (see Appendix D: Program D.4).

The Btu consumption in every month m is computed using the actual electricity generation (demand for electricity). Using the regression coefficients in Table 6.2, the equation for the computation of Btu consumption in month m is

$$\begin{aligned} BTUC_m &= 11940.0 + 10.24579 * GEN_m - 0.0000004 * \left(GEN_m\right)^2 \\ &(m = 1 \rightarrow 12) \end{aligned} \tag{6.26}$$

Since Btu shipments depend on future fuel demands and current fuel prices (see Table 6.1), the fuel shipment requirement is determined using the following equation,

$$\begin{aligned} \ln BTUS_m = 3.520 - 0.721 * \ln(UPC_m) &+ 0.492 * \ln(BTUC_m) \\ + 0.147 * \ln(BTUC_{m+1}) &+ 0.099 * \ln(BTUC_{m+2}) \\ + 0.084 * \ln(BTUC_{m+3}) &+ 0.078 * \ln(BTUC_{m+4}) \\ + 0.042 * \ln(BTUC_{m+5}) &+ 0.051 * \ln(BTUC_{m+6}) \end{aligned} \tag{6.27}$$

In simulating SO_2 emission-related variables (sulfur shipments and gross and net SO_2 emissions), the coefficients obtained from the reduced forms of the simultaneous equations are used, together with the multipliers of the allowance and FGD variables. The values of the output variables in month m are determined by the following equations:

Sulfur Shipments

$$\begin{aligned} \ln(USO2S_m) = 0.21643 - 0.07492 * \ln(UPC_m) &+ 0.49803 * \ln(USO2S_{m-1}) \\ + 0.26241 * \ln(USO2S_{m-2}) &+ 0.20410 * \ln(USO2S_{m-3}) \\ + 0.00825 * \ln(XALLOW) &- 0.00034 * (TIME) \\ - 0.00663 * (WINT) &+ 0.01379 * (XFGD) \end{aligned} \tag{6.28}$$

Gross SO_2 Emissions

$$\begin{aligned}\ln(USO2C_m) = 0.07598 + 0.12909 * \ln(UPC_m) + 0.38318 * \ln(USO2S_{m-1}) \\ + 0.25016 * \ln(USO2S_{m-2}) + 0.25636 * \ln(USO2S_{m-3}) \\ - 0.00084 * \ln(XALLOW) - 0.00023 * (TIME) \\ - 0.00947 * (WINT) \qquad + 0.05863 * (XFGD)\end{aligned} \tag{6.29}$$

Net SO_2 Emissions

$$\begin{aligned}\ln(UNE_m) = -1.11149 + 0.10656 * \ln(UPC_m) + 0.31629 * \ln(USO2S_{m-1}) \\ + 0.20649 * \ln(USO2S_{m-2}) + 0.21161 * \ln(USO2S_{m-3}) \\ + 0.07112 * \ln(XALLOW) - 0.00103 * (TIME) \\ - 0.02252 * (WINT) \qquad - 1.28736 * (XFGD)\end{aligned} \tag{6.30}$$

where

$XALLOW = \alpha \cdot ALLOW$ ($\alpha = 0.1, 0.3, 0.5, 0.7, 1, 2, 3, 4, 5, or\ 6$)
$XFGD = \beta$ ($\beta = 0\ or\ 1$)
ALLOW = actual allowances for the selected plant.

This simulation process is illustrated by the flow chart in Figure 6.2. The monthly shipment rates (lb/MMBtu) and emission rates (lb/MMBtu) are then multiplied by the corresponding Btu shipments and consumptions, to obtain the total amounts of sulfur shipped and of SO_2 emitted. These flows are then summed up over the 60 months, and average annual variables are computed. These computations are summarized below:

$$Annual\ Sulfur\ Shipments = \frac{1}{5}\sum_{m=1}^{60} USO2S_m * BTUS_m \tag{6.31}$$

$$Annual\ Gross\ SO_2\ Emissions = \frac{1}{5}\sum_{m=1}^{60} USO2C_m * BTUC_m \tag{6.32}$$

$$Annual\ Net\ SO_2\ Emissions = \frac{1}{5}\sum_{m=1}^{60} UNE_m * BTUC_m \tag{6.33}$$

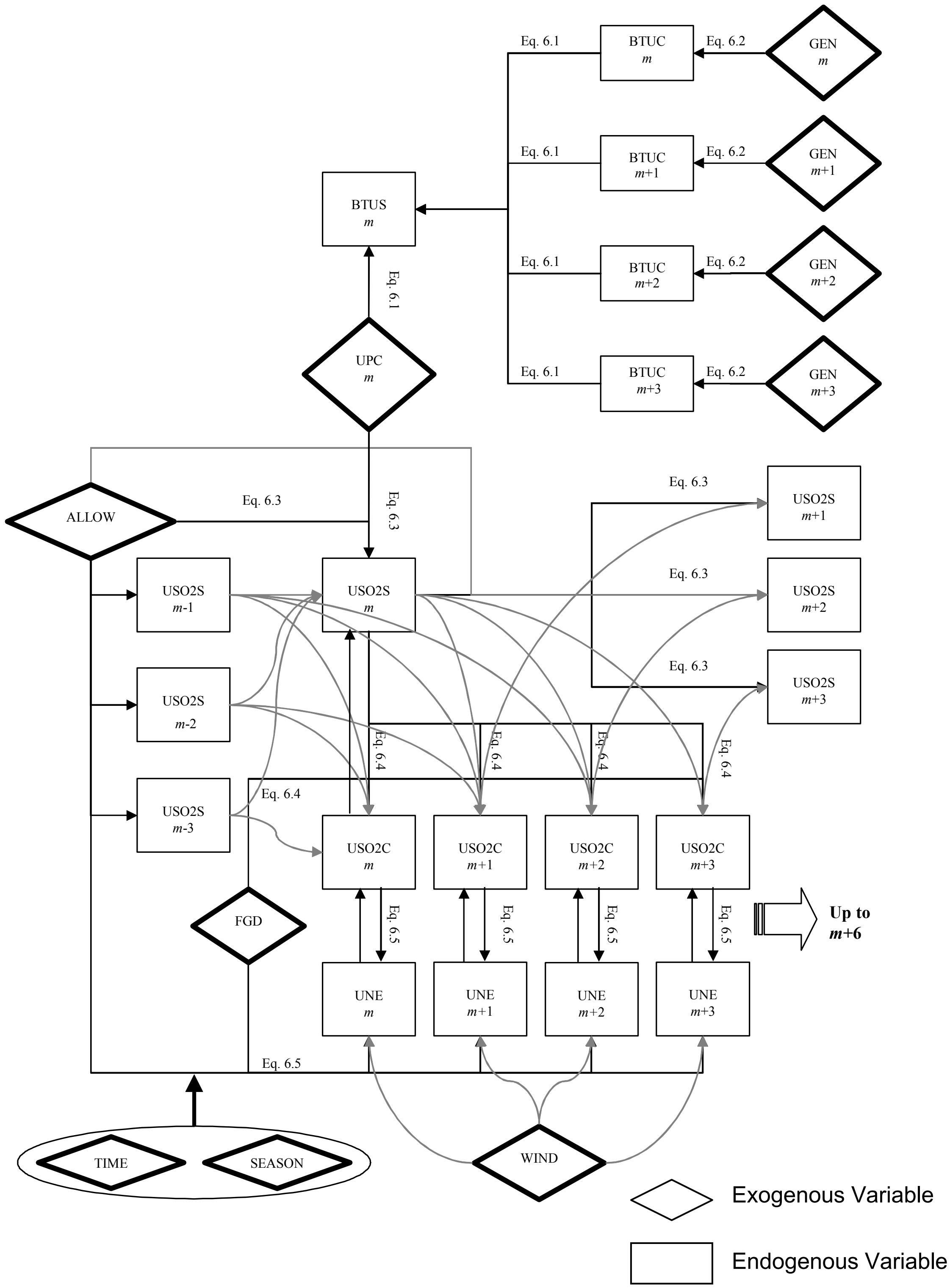

Figure 6.2: Simulation Process

6.5.2 Sensitivity Analysis

The number of observations in the simulation program output is 1200 (10 multipliers for annual emission allowances × 2 multipliers for FGD × 60 months). The average annual amounts of sulfur shipments and gross and net SO_2 emissions for each combination of allowance and FGD are presented in Table 6.10.

Table 6.10 Annual average sulfur shipments and SO_2 gross and net emissions for various allowance and FGD combinations

Combination	Allowance Multiplier	FGD	Annual Net SO_2 Emissions (lb)	Annual Gross SO_2 Emissions (lb)	Annual Sulfur Shipments (lb)
1	0.1	0	87274444	92501684	37817198
2	0.1	1	27216429	113902561	45167884
3	0.3	0	102213627	101900841	42471738
4	0.3	1	31947232	125894584	50923320
5	0.5	0	110062755	106670308	44866821
6	0.5	1	34436063	131987632	53890358
7	0.7	0	115579477	109961819	46531569
8	0.7	1	36187087	136195074	55954054
9	1	0	121748139	113586290	48376235
10	1	1	38146567	140832147	58242263
11	2	0	134753436	121054939	52211460
12	2	1	42279988	150392708	63004966
13	3	0	143034417	125698387	54618656
14	3	1	44914372	156341342	65998323
15	4	0	149234117	129123111	56405571
16	4	1	46886767	160730746	68219939
17	5	0	154238999	131855680	57837172
18	5	1	48480995	164236126	70002595
19	6	0	158458481	134141156	59039239
20	6	1	49825421	167166954	71499157

In order to more precisely assess the effects of the allowance and FGD variables on the three sulfur-related outputs, the logarithms of these outputs are regressed on the logarithm of the allowances and on the FGD dummy variable. This regression analysis is implemented using a SAS program (see Appendix D: Program D.5), and the results are presented in Table 6.11.

Table 6.11 Regression analysis of the simulation model outputs

	Intercept	$\ln$ (Annual SO_2 emission allowances)	FGD availability (0,1)	Adj. R^2
$\ln$ (Net SO_2 Emissions)	18.618**	0.147**	-1.160**	1.000**
$\ln$ (Gross SO_2 Emissions)	18.549**	0.093**	0.216**	0.999**
$\ln$ (Sulfur Shipments)	17.696**	0.111**	0.186**	0.999**

As expected, the *R*-squares for both models are very close to 1, as the allowance and FGD variables are the only variables that vary when computing the monthly outputs. However, the models in Table 6.11 summarize intertemporal effects that are not necessarily apparent in the monthly equations.

The emission allowances and FGD availability have their strongest effects on net SO_2 emission. A 1% increase in allowances leads to a 0.15% increase in average net emissions. While one might, on the surface, expect a one-to-one correspondence (*i.e.*, a unit elasticity) between allowance and net emissions, it is important to remember that the allowance measure used here is only one component (though an important one) of the total allowances that constrain net emissions, the balance being related to allowance trading and bubble substitution. The coefficient of the FGD dummy cannot, of course, be interpreted as an elasticity. The net emission is proportional to exp(-1.160*FGD), hence when a plant shifts from no FGD (FGD=0) to an FGD (FGD=1), emissions decrease by 69% (exp(-1.160)=0.31). Similarly, a 1% increase in emission allowance leads to a 0.111% increase in sulfur shipments and a 0.093% increase in gross SO_2 emissions. In contrast to the no FGD case, the availability of an FGD leads to increases of 20% in sulfur shipments (exp (0.186) =1.20) and of 24% in gross SO_2 emissions (exp (0.216) =1.24).

As discussed earlier, however, these results do not allow for a conclusive comparison of the effectiveness of a market-based approach (SO_2 emission allowances) and a command-and-control approach (FGD installation) due to the following reasons. First, the 0.15 percent reduction in emissions, resulting from a 1 percent reduction in emission allowance, represents a short-term impact at the individual plant level, reflecting of variety of possible adjustments made available by the allowance system. The effect of a 1% reduction in allowances might be very different if implemented over all plants nationally. Under the assumption that there is no idle emission abatement capacity nationally, a one percent reduction in emission allowances nationwide would likely be met by a similar 1 percent reduction in emissions nationwide. Although there could still be variations in adjustments at the individual plant level, emissions reductions would likely be larger than 15%. With larger emission allowance reductions nationally (*e.g.*, 50%), power plants would be unlikely to have enough allowances to sell, and therefore trading might be minimal and the impacts of reduced allowances might be stronger than those of installing FGD facilities.

One might also be concerned about the possibility of environmental “hot spots”, with relatively high levels of ambient air pollution, due to allowance trading. Under current environmental laws, there is no strict regulation on plant-level emissions, and there is no possibility within the law for the government to react to hot spots by changing allowances. If regional hot spots are an issue, this problem could be solved by allowing local governments to reduce emission allowances for individual plants linked to these hot spots. For example, if a hot spot were associated with the Mohave plant, it could be eliminated by enforcing a reduction in its allowances by roughly six-to-seven times the size of the reduction in emissions one would like to achieve. Alternatively, stronger regulatory systems on regional ambient air pollution concentrations, such as the South California Regional Clean Air Incentives Market (RECLAIM) program, may be an effective way of controlling regional polluters. Lastly, providing more incentives for installing FGD facilities may be the simplest and most effective way of solving the hot spots issue.

CHAPTER 7

CONCLUSIONS

The SO_2 emission rate of a power plant varies over time and is determined by the interactions of fuel market factors, the cost-minimizing behavior of the plant operator, and policy instruments. These interactions are measured by such variables as fuel purchases, fuel consumptions, sulfur shipments, gross SO_2 emissions, and net SO_2 emissions. Plant operators are assumed to minimize pollution abatement costs and other operation costs, so their strategy is to maximize SO_2 emissions subject to emission limits.

This research suggests that the behavior of a power plant operator can be summarized in seven points. First, each plant determines the amounts and types of fuel shipments based on expected electricity generation requirements and fuel prices, with fuel shipments decreasing with increasing prices. Since coal and petroleum are storable for several months, each plant may defer some fuel purchases when fuel prices are relatively high. In addition, the price increase of a certain fuel may lead to using more of a substitute fuel. Second, each plant forecasts near-term fuel demand, with up to a six-month lag between fuel shipment and consumption. The relationship between fuel shipments and the forecasted fuel consumptions is very strong for the current month, and gradually weakens over future months, due to forecasting difficulties and the costs of holding fuel inventories over longer periods. Third, each plant is trying to emit as much SO_2 as possible within the annual emissions limit. As the allowance increases, net SO_2 emissions increase, although not proportionately, because of the likely effects of allowance banking and trading. The net SO_2 emissions rate is elastic with regard to allowances. Fourth, each plant reduces SO_2 emissions over time, most likely to account for the future more stringent Phase II emissions constraints. Due to contract constraints on fuel amounts and types, power plants cannot extensively and instantaneously reduce SO_2 emissions through fuel substitution, so this decrease is gradual. Fifth, plants use lower-sulfur fuels in winter. Since demand for electricity for heating in winter is higher than for cooling in summer, plant operators appear to use lower-sulfur fuels in winter to compensate for the increased burning of fossil fuels. It is also possible that higher production reduces unit SO_2 emission abatement costs, because of economies of scale, and therefore plant operators may further reduce net SO_2 emissions within the same compliance budget. Sixth, plants with an FGD usually consume more high-sulfur fuels. Since each plant can control net SO_2 emissions at the abatement stage at low operating costs (although the capital costs for FGD facilities are high), it is not necessary to purchase low-sulfur fuels, which are expensive. Finally, it turns out that meteorological conditions do not affect net SO_2 emission rates.

Under the CAAA of 1990, polluters are assigned annual emission allowances, and are free to select the minimum-cost approach that will keep their actual annual emissions within this allowance limit. At the global level, *i.e.*, national level, the total net SO_2 emissions have been effectively reduced by the CAAA. Several market-based approaches, such as emissions trading, transfer, and banking, have allowed some plants to emit more SO_2, while other plants sell their unnecessary allowances, increasing their profits, so that the global level of SO_2 emissions has been reduced, and overall economic efficiency has been increased.

For this reason, the Bush Administration recently suggested an air pollution initiative called 'Clear Skies', that would improve over the gains achieved since the passage of the 1990 CAAA:

> "*By taking this action, and I urge Congress to take the action, we'll have more affordable energy, more jobs and cleaner skies … What we're talking about is good for the working people of this country. What we're talking about makes sense for those who work for a living … By combining the ethic of good stewardship and a spirit of innovation, we will continue to improve the quality of our air and the health of our economy, and improve the chance for people to have a good life here in America.*" *http://www.jsonline.com/news/nat/ap/sep03/ap-bush092003.asp*

However, the cap-and-trade system has been criticized by many environmentalists asserting that the Bush air pollution plan would weaken current limits under the CAAA of 1990.

> "*Even though it would be a reduction, it is significantly less than the Clean Air Act would require over time. … Clear Skies sets a long-term cap on emissions, but doesn't require anything from individual plants. If a certain plant wants to avoid controls and keep on showering its neighbors with sulfur dioxide," it can do so*

under Clear Skies by buying emission credits from a clean plant a thousand mile away." http://www.jsonline.com/news/nat/ap/sep03/ap-bush092003.asp

Although it turns out that the CAAA of 1990 is very effective at the global level, whether it is effective at the plant or local level has been questioned by some environmentalists. As Stavins (1998) suggests, there are several concerns regarding the cap and trading system. First, tradable permits are often perceived as 'licenses to pollute'. Second, damages from pollution to human health and ecological safety are hard to quantify or monetize. Third, once market- based permits are assigned, they are more difficult to tighten over time than command-and-control standards. Finally, tradable permits may lead to localized 'hot spots' with relatively high levels of ambient pollution.

Environmental "hot spot" problem could be solved by allowing local governments to modify/reduce the emission allowances for individual plants linked to a local hot spot. Stronger regulations on regional ambient air pollution concentrations may be an alternative for controlling regional polluters. If the concern is about public health and local environmental quality, obviously the command-and-control strategy might be better than the market-based approach. However, as economists are continuously asserting, the economic benefits obtained by lowering the marginal abatement costs of power plants across the country are huge, and the long-term economic effects of the cap and trading system cannot be discarded.

One clear finding of this research is that actual net SO_2 emissions from power plants are not determined by any single factor, but, rather, by the interactions among several energy, environmental, and policy factors, that must be considered simultaneously.

This research could be extended as follows. First, because of data limitations, it was not possible to effectively deal with the dynamics of allowance trading, banking, and transfer. Since these dynamics may take place over several years of trading, with allowance accumulation, more data over longer periods could produce new insights. Second, in connection to the previous issue, using company-level data that aggregate plant-level information could provide insights into the dynamics of allowance transfers within the same company. Finally, this research has explored the mechanism of SO_2 emissions, but the relationship between emissions and ground-level concentrations was not examined. Analyzing this relationship at a monthly (or shorter-term) time scale could provide new insights into local pollution issues.

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APPENDIX A

DATA SOURCES

Table A.1: FERC Form-423 (Cordant.dbf – Company and Plant Names)

CO_ CODE	DASH	PLT_ CODE	CO_NAME	PLT_ NAME	FILLER1	REGION	STATE	RETIR_CODE	FILLER2	CAPACITY	FILLER 3
017609	-	2341	Southern California Edison	Mohave	409S	8	32		5	1636	052721-45000
014006	-	8102	Ohio Power (AEP)	Gavin	101N	3	39		2	2600	054028-05000

Table A.2: FERC Form-423 (F423YYYY.dbf)

CO_ CODE	PLT_ CODE	YEAR	MONTH	BOM_ DIST	ORIG _ST	MINE_ TYPE	PLT_ REGION	PLT _ST	GENER _FUEL	SPECF _FUEL	CONTR _TYPE	CONTR _EXPR	QUANTITY	BTU	SULFUR	ASH	COST	UNIT_ TYPE	COUNTY
017609	2341	96	01				08	32	3	NG	6	0	103000	1025	0.00	0.00	238.50	1	
017609	2341	96	01	18	04	S	08	32	1	BIT	1	0	185000	10982	0.54	10.10	179.90	1	017
014006	8102	96	01	04	39	S	03	39	1	BIT	1	0	28300	10860	2.68	12.00	111.40	1	053
014006	8102	96	01	04	39	S	03	39	1	BIT	1	0	28300	10860	2.68	12.00	111.40	1	079
014006	8102	96	01	04	39	S	03	39	1	BIT	1	0	29100	10860	2.68	12.00	111.40	1	163
014006	8102	96	01	04	39	U	03	39	1	BIT	1	0	625200	11349	3.51	12.00	152.10	1	105

BOM_DIST	BOM District (Coal Only)
ORIG_ST	State of Origin (Coal Only)
MINE_TYPE	S=Surface, U=Underground
PLT_REGION	Location of Plant (Region)
PLT_ST	Location of Plant (State)
GENER_FUEL	Generic Fuel (1=Coal, 2=Petroleum, 3=Gas)
SPECF_FUEL	Specific Fuel (BIT/SUB/FO2/FO6 etc.)
QUANTITY	Coal - one thousand short tons, Oil - one thousand barrels, Gas - one million cubic ft
BTU	Btu Content (Coal - Per Pound, Oil - Per Gallon, Gas - Per Cubic Ft.)
SULFUR	Sulfur Content (percent weight)
ASH	Ash Content (percent weight)
COST	cents /million Btu (all costs including transportation, taxes, etc.)
UNIT_TYPE	1=Steam

Table A.3: Form EIA – 767 (Bair.dbf – Boiler Information: Air Emission Standards)

PLANT_ID	BOILCODE	YEAR	FUELTYPE	STATPART	STATSULF	STATNITR	EMISPART	EMISSULF1	EMISSULF2	EMISNITR	MCPART	MCSULF	MCNITR	TIMEPART
2341	1	1996	COL	ST	ST	FD	0.1000	8200.0000	0.0000	0.7000	PB	DH	NP	OH
2341	2	1996	COL	ST	ST	FD	0.1000	8200.0000	0.0000	0.7000	PB	DH	NP	OH
8102	1	1996	COL	ST	FD	NA	0.1000	7.4100	0.0000	0.0000	PB	DP		DT
8102	2	1996	COL	ST	FD	NA	0.1000	7.4100	0.0000	0.0000	PB	DP		DT

TIMESULF	TIMENITR	YRPART	YRSULF	YRNITR	COMPPART1	COMPPART2	COMPPART3	COMPSULF1	COMPSULF2	COMPSULF3	COMPNITR1	COMPNITR2
OH	OH	1980	1973	1971	MS			MS			MS	
OH	OH	1980	1973	1971	MS			MS			MS	
MO		1974	1974	0	MS			MS				
MO		1975	1975	0	MS			MS				

PLANT_ID	Plant Code
BOILCODE	Boiler Identification
YEAR	Data Year
FUELTYPE	Primary Fuel Expected to be Burned Next Year
STATPART	Type of Statute or Regulation - Particulate Matter
STATSULF	Type of Statute or Regulation - Sulfur Dioxide
STATNITR	Type of Statute or Regulation - Nitrogen Oxides
EMISPART	Emission Standard Specified - Particulate Matter
EMISSULF1	Emission Standard Specified - Sulfur Dioxide Part 1
EMISSULF2	Emission Standard Specified - Sulfur Dioxide Part 2
EMISNITR	Emission Standard Specified - Nitrogen Oxides
MCPART	Unit of Measurement Specified - Particulate Matter
MCSULF	Unit of Measurement Specified - Sulfur Dioxide
MCNITR	Unit of Measurement Specified - Nitrogen Oxides
TIMEPART	Time Period Specified - Particulate Matter
TIMESULF	Time Period Specified - Sulfur Dioxide
TIMENITR	Time Period Specified - Nitrogen Oxides
YRPART	Year Boiler was or is Expected to be in Compliance - Particulate Matter
YRSULF	Year Boiler was or is Expected to be in Compliance - Sulfur Dioxide
YRNITR	Year Boiler was or is Expected to be in Compliance - Nitrogen Oxides
COMPPART1	Strategy for Compliance - Particulate Matter (1st)
COMPPART2	Strategy for Compliance - Particulate Matter (2nd)
COMPPART3	Strategy for Compliance - Particulate Matter (3rd)
COMPSULF1	Strategy for Compliance - Sulfur Dioxide (1st)
COMPSULF2	Strategy for Compliance - Sulfur Dioxide (2nd)
COMPSULF3	Strategy for Compliance - Sulfur Dioxide (3rd)
COMPNITR1	Strategy for Compliance - Nitrogen Oxides (1st)
COMPNITR2	Strategy for Compliance - Nitrogen Oxides (2nd)

Table A.3 continued

TIMESULF	TIMENITR	YRPART	YRSULF	YRNITR	COMPPART1	COMPPART2	COMPPART3	COMPSULF1	COMPSULF2	COMPSULF3	COMPNITR1	COMPNITR2
OH	OH	1980	1973	1971	MS			MS			MS	
OH	OH	1980	1973	1971	MS			MS			MS	
MO		1974	1974	0	MS			MS				
MO		1975	1975	0	MS			MS				

COMPNITR3	STRAT1	STRAT2	STRAT3	OPSTAND	EC
	SS			N	1
	SS			N	2
	CU			N	1
	CU			N	2

TIMESULF Time Period Specified - Sulfur Dioxide
TIMENITR Time Period Specified - Nitrogen Oxides
YRPART Year Boiler was or is Expected to be in Compliance - Particulate Matter
YRSULF Year Boiler was or is Expected to be in Compliance - Sulfur Dioxide
YRNITR Year Boiler was or is Expected to be in Compliance - Nitrogen Oxides
COMPPART1 Strategy for Compliance - Particulate Matter (1st)
COMPPART2 Strategy for Compliance - Particulate Matter (2nd)
COMPPART3 Strategy for Compliance - Particulate Matter (3rd)
COMPSULF1 Strategy for Compliance - Sulfur Dioxide (1st)
COMPSULF2 Strategy for Compliance - Sulfur Dioxide (2nd)
COMPSULF3 Strategy for Compliance - Sulfur Dioxide (3rd)
COMPNITR1 Strategy for Compliance - Nitrogen Oxides (1st)
COMPNITR2 Strategy for Compliance - Nitrogen Oxides (2nd)
COMPNITR3 Strategy for Compliance - Nitrogen Oxides (3rd)
STRAT1 Existing/planned Strategies to meet Title IV of CAAA 1990 - S02 (1st)
STRAT2 Existing/planned Strategies to meet Title IV of CAAA 1990 - S02 (2nd)
STRAT3 Existing/planned Strategies to meet Title IV of CAAA 1990 - S02 (3rd)
OPSTAND Boiler Standards Under Which the Boiler is Operating
EC Equipment Count (by plant)

Table A.4: Form EIA – 767 (Bdesign.dbf – Boiler Information: Design Parameters)

PLANT_ID	YEAR	BOILCODE	INSRVDATE	RETDATE	MAXFLOW	FRMCOAL	FRMPETRO	FRMGAS	FRMOTHER	WASTEHEAT	PRIMEFUEL1	PRIMEFUEL2	PRIMEFUEL3
2341	1996	1	471	0	5451	392.5	0.0	7750.0	0.0	0	COL	GAS	
2341	1996	2	1071	0	5451	392.5	0.0	7750.0	0.0	0	COL	GAS	
8102	1996	1	574	1235	9775	543.0	0.0	0.0	0.0	0	COL		
8102	1996	2	375	1235	9775	543.0	0.0	0.0	0.0	0	COL		

FIRETYPE1	FIRETYPE2	FIRETYPE3	LOAD100	LOAD50	EXCESSAIRN	EXCESSAIRP	WODBOT	FLYINJECT	ALTFULCAP1	ALTFULCAP2	ALTFULCAP3	ALTDATE
TF			87.1	87.9	1890000	2	D	N	GAS			0
TF			87.1	87.9	1890000	2	D	N	GAS			0
OF			88.4	88.4	2300000	17	D	N	NA			0
OF			88.4	88.4	2300000	17	D	N	NA			0

ALTDAYS	MAXALTFLOW	CANALTFLOW	LOWNOXCON1	LOWNOXCON2	LOWNOXCON3	LOWNOXMAN	BOILMAN	EC
0	5451	Y	NA				CE	1
0	5451	Y	NA				CE	2
0	0		NA				BW	1
0	0		NA				BW	2

PLANT_ID Plant Code
YEAR Data Year
BOILCODE Boiler Identification
INSRVDATE Boiler Actual or Projected Inservice Date
RETDATE Boiler Actual or Projected Retirement Date
MAXFLOW Maximum Continuous Steam Flow at 100% (thousand lbs/hour)
FRMCOAL Design Firing Rate - Coal (short tons/hour) (nearest 0.1 unit)
FRMPETRO Design Firing Rate - Petroleum (barrels/hour) (nearest 0.1 unit)
FRMGAS Design Firing Rate - Gas (thousand cubic feet/hour) (nearest 0.1)
FRMOTHER Design Firing Rate - Other (specify fuel and unit on footnote)
WASTEHEAT Design Waste Heat Input Rate (million btu/hour)
PRIMEFUEL1 Primary Fuels used in Order of Predominance (1st)
PRIMEFUEL2 Primary Fuels used in Order of Predominance (2nd)
PRIMEFUEL3 Primary Fuels used in Order of Predominance (3rd)
FIRETYPE1 Type of Firing Used with Primary Fuels (1st)
FIRETYPE2 Type of Firing Used with Primary Fuels (2nd)
FIRETYPE3 Type of Firing Used with Primary Fuels (3rd)
LOAD100 Boiler Efficiency at 100% Load (nearest 0.1%)
LOAD50 Boiler Efficiency at 50% Load (nearest 0.1%)
EXCESSAIRN Total Air Flow Including Excess Air at 100% Load (cubic feet/minute)
EXCESSAIRP Excess Air at 100% Load (%)
WODBOT Wet or Dry Bottom (for coal-capable boilers only)
FLYINJECT Fly Ash Reinjection
ALTFULCAP1 Alternate Fuels Capability - Fuels other than primary fuel (1st)
ALTFULCAP2 Fuels other than primary fuel (2nd)
ALTFULCAP3 Fuels other than primary fuel (3rd)
ALTDATE Year Alternate Fuel Last Burned
ALTDAYS Number of Days Required to Switch
MAXALTFLOW Max Cont Steam Flow - Alternate Fuels (thousand lbs/hour)
CANALTFLOW Can Alternate Fuels be Burned Continuously for 30 Days Longer
LOWNOXCON1 Low N0x Control Process (1st)
LOWNOXCON2 Low N0x Control Process (2nd)
LOWNOXCON3 Low N0x Control Process (3rd)
LOWNOXMAN Manufacturer of Low N0x Burners
BOILMAN Boiler Manufacturer
EC Equipment Count (by plant)

Table A.5: Form EIA – 767 (Bfuel.dbf – Boiler Information: Fuel Consumption and Quality)

PLANT_ID	BOILCODE	YEAR	STATUS	HULOAD	JANCO	FEBCO	MARCO	APRCO	MAYCO	JUNCO	JULCO	AUGCO	SEPCO	OCTCO	NOVCO	DECCO	TOTCO	JANPE	FEBPE
2341	1	1996	OP	7239	182.5	190.2	187.5	0.0	111.3	198.8	221.3	216.0	219.6	218.7	205.9	240.2	2190.2	0.0	0.0
2341	2	1996	OP	7694	77.4	213.4	199.3	216.1	210.1	204.9	195.3	189.6	196.0	260.6	220.9	222.3	2405.8	0.0	0.0
8102	1	1996	OP	6851	311.0	368.1	317.1	255.5	0.0	140.2	330.9	355.4	340.8	204.9	367.2	364.0	3355.1	1.0	0.6
8102	2	1996	OP	8007	317.4	350.8	368.4	169.8	321.1	324.9	348.9	336.7	364.5	316.5	374.1	335.0	3928.1	1.6	1.7

MARPE	APRPE	MAYPE	JUNPE	JULPE	AUGPE	SEPPE	OCTPE	NOVPE	DECPE	TOTPE	JANGA	FEBGA	MARGA	APRGA	MAYGA	JUNGA	JULGA	AUGGA	SEPGA	OCTGA
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.2	39.7	41.5	0.0	35.0	42.7	21.9	39.2	28.5	22.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.6	44.5	44.2	31.5	66.1	44.1	19.3	34.4	25.5	26.5
1.6	1.6	0.0	8.7	2.7	0.9	2.0	3.2	1.1	1.2	24.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.6	3.2	3.8	3.0	1.3	0.5	0.7	1.9	1.4	0.5	21.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PLANT_ID Plant Code
BOILCODE Boiler Identification
YEAR Data Year
STATUS Boiler Status
HULOAD Hours Under Load (nearest hour)
JANCO Monthly Coal Consumption–Jan (thousand short tons) (nearest 0.1unit)
FEBCO Feb (thousand short tons) (nearest 0.1 unit)
MARCO Mar (thousand short tons) (nearest 0.1 unit)
APRCO Apr (thousand short tons) (nearest 0.1 unit)
MAYCO May (thousand short tons) (nearest 0.1 unit)
JUNCO Jun (thousand short tons) (nearest 0.1 unit)
JULCO Jul (thousand short tons) (nearest 0.1 unit)
AUGCO Aug (thousand short tons) (nearest 0.1 unit)
SEPCO Sep (thousand short tons) (nearest 0.1 unit)
OCTCO Oct (thousand short tons) (nearest 0.1 unit)
NOVCO Nov (thousand short tons) (nearest 0.1 unit)
DECCO Dec (thousand short tons) (nearest 0.1 unit)
TOTCO Annual Coal Consumption Total (thousand short tons) (nearest 0.1 unit)
JANPE Monthly Petroleum Consumption-Jan (thousand barrels) (nearest 0.1unit)
FEBPE Feb (thousand barrels) (nearest 0.1 unit)
MARPE Mar (thousand barrels) (nearest 0.1 unit)
APRPE Apr (thousand barrels) (nearest 0.1 unit)
MAYPE May (thousand barrels) (nearest 0.1 unit)
JUNPE Jun (thousand barrels) (nearest 0.1 unit)
JULPE Jul (thousand barrels) (nearest 0.1 unit)
AUGPE Aug (thousand barrels) (nearest 0.1 unit)
SEPPE Sep (thousand barrels) (nearest 0.1 unit)
OCTPE Oct (thousand barrels) (nearest 0.1 unit)
NOVPE Nov (thousand barrels) (nearest 0.1 unit)
DECPE Dec (thousand barrels) (nearest 0.1 unit)
TOTPE Annual Petroleum Consumption-Total (thousand barrels) (nearest 0.1 unit)
JANGA Monthly Gas Consumption - Jan (million cubic feet) (nearest 0.1 unit)
FEBGA Feb (million cubic feet) (nearest 0.1 unit)
MARGA Mar (million cubic feet) (nearest 0.1 unit)
APRGA Apr (million cubic feet) (nearest 0.1 unit)
MAYGA May (million cubic feet) (nearest 0.1 unit)
JUNGA Jun (million cubic feet) (nearest 0.1 unit)
JULGA Jul (million cubic feet) (nearest 0.1 unit)
AUGGA Aug (million cubic feet) (nearest 0.1 unit)
SEPGA Sep (million cubic feet) (nearest 0.1 unit)
OCTGA Oct (million cubic feet) (nearest 0.1 unit)

Table A.5 continued

NOVGA	DECGA	TOTGA	JANOT	FEBOT	MAROT	APROT	MAYOT	JUNOT	JULOT	AUGOT	SEPOT	OCTOT	NOVOT	DECOT	TOTOT	JANQU	FEBQU	MARQU	APRQU	MAYQU
25.1	19.4	387.6														0.0	0.0	0.0	0.0	0.0
27.0	17.9	411.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0														0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0

JUNQU	JULQU	AUGQU	SEPQU	OCTQU	NOVQU	DECQU	TOTQU	JANHC	FEBHC	MARHC	APRHC	MAYHC	JUNHC	JULHC	AUGHC	SEPHC	OCTHC	NOVHC	DECHC	JANSC
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12303	12227	12241	0	12309	12208	12189	12236	12151	12257	12223	12304	0.54
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12303	12227	12241	10026	12309	12208	12189	12236	12151	12257	12223	12304	0.54
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11245	11165	11317	11362	0	11236	11319	11170	11127	11307	11176	11143	3.40
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11307	11173	11302	11393	11196	11204	11291	11203	11182	11262	11232	11201	3.30

NOVGA Monthly Gas Consumption - Nov (million cubic feet) (nearest 0.1 unit)
DECGA Monthly Gas Consumption - Dec (million cubic feet) (nearest 0.1 unit)
TOTGA Annual Gas Consumption - Total (million cubic feet) (nearest 0.1 unit)
JANOT Monthly Other Fuel (Code) - January
FEBOT Monthly Other Fuel (Code) - February
MAROT Monthly Other Fuel (Code) - March
APROT Monthly Other Fuel (Code) - April
MAYOT Monthly Other Fuel (Code) - May
JUNOT Monthly Other Fuel (Code) - June
JULOT Monthly Other Fuel (Code) - July
AUGOT Monthly Other Fuel (Code) - August
SEPOT Monthly Other Fuel (Code) - September
OCTOT Monthly Other Fuel (Code) - October
NOVOT Monthly Other Fuel (Code) - November
DECOT Monthly Other Fuel (Code) - December
TOTOT Annual Other Fuel (Code)
JANQU Monthly Other Fuel Consumption-Jan (Specify fuel and unit in footnote)
FEBQU Feb (Specify fuel and unit in footnote)
MARQU Mar (Specify fuel and unit in footnote)
APRQU Apr (Specify fuel and unit in footnote)
MAYQU May (Specify fuel and unit in footnote)
JUNQU Jun (Specify fuel and unit in footnote)
JULQU Jul (Specify fuel and unit in footnote)
AUGQU Aug (Specify fuel and unit in footnote)
SEPQU Sep (Specify fuel and unit in footnote)
OCTQU Oct (Specify fuel and unit in footnote)
NOVQU Nov (Specify fuel and unit in footnote)
DECQU Dec (Specify fuel and unit in footnote)
TOTQU Annual Other Fuel Consumption-Total (Specify fuel and unit in footnote)
JANHC Monthly Coal Heat Content - January (btu/pound)
FEBHC Monthly Coal Heat Content - February (btu/pound)
MARHC Monthly Coal Heat Content - March (btu/pound)
APRHC Monthly Coal Heat Content - April (btu/pound)
MAYHC Monthly Coal Heat Content - May (btu/pound)
JUNHC Monthly Coal Heat Content - June (btu/pound)
JULHC Monthly Coal Heat Content - July (btu/pound)
AUGHC Monthly Coal Heat Content - August (btu/pound)
SEPHC Monthly Coal Heat Content - September (btu/pound)
OCTHC Monthly Coal Heat Content - October (btu/pound)
NOVHC Monthly Coal Heat Content - November (btu/pound)
DECHC Monthly Coal Heat Content - December (btu/pound)
JANSC Monthly Coal Sulfur Content - Jan (nearest 0.01% by weight)

Table A.5 continued

FEBSC	MARSC	APRSC	MAYSC	JUNSC	JULSC	AUGSC	SEPSC	OCTSC	NOVSC	DECSC	JANAC	FEBAC	MARAC	APRAC	MAYAC	JUNAC	JULAC	AUGAC	SEPAC
0.52	0.49	0.00	0.51	0.43	0.53	0.51	0.49	0.48	0.48	0.51	10.13	10.52	10.39	0.00	10.18	10.70	10.79	10.48	10.84
0.52	0.49	0.48	0.51	0.43	0.53	0.51	0.49	0.48	0.48	0.51	10.13	10.52	10.39	9.78	10.18	10.70	10.79	10.48	10.84
3.70	3.10	2.90	0.00	3.00	3.10	3.40	3.10	3.20	3.10	3.30	12.30	12.10	11.10	11.20	0.00	12.00	12.20	12.50	11.80
3.60	3.10	2.90	2.80	2.90	3.10	3.30	3.10	3.10	3.00	3.20	12.00	12.00	10.90	11.10	11.50	11.90	11.90	12.30	11.60

OCTAC	NOVAC	DECAC	JANHP	FEBHP	MARHP	APRHP	MAYHP	JUNHP	JULHP	AUGHP	SEPHP	OCTHP	NOVHP	DECHP	JANSP	FEBSP	MARSP	APRSP	MAYSP
10.35	10.53	9.93	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00
10.35	10.53	9.93	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00
11.60	12.30	12.20	137769	137863	137654	137617	0	137724	137759	137995	139416	139468	139409	139666	0.36	0.42	0.42	0.42	0.00
11.70	11.90	11.70	137875	137856	137701	137614	137961	137745	137759	137995	138434	139468	139406	139646	0.36	0.42	0.42	0.42	0.37

FEBSC Monthly Coal Sulfur Content - Feb (nearest 0.01% by weight)
MARSC Monthly Coal Sulfur Content - Mar (nearest 0.01% by weight)
APRSC Monthly Coal Sulfur Content - Apr (nearest 0.01% by weight)
MAYSC Monthly Coal Sulfur Content - May (nearest 0.01% by weight)
JUNSC Monthly Coal Sulfur Content - Jun (nearest 0.01% by weight)
JULSC Monthly Coal Sulfur Content - Jul (nearest 0.01% by weight)
AUGSC Monthly Coal Sulfur Content - Aug (nearest 0.01% by weight)
SEPSC Monthly Coal Sulfur Content - Sep (nearest 0.01% by weight)
OCTSC Monthly Coal Sulfur Content - Oct (nearest 0.01% by weight)
NOVSC Monthly Coal Sulfur Content - Nov (nearest 0.01% by weight)
DECSC Monthly Coal Sulfur Content - Dec (nearest 0.01% by weight)

JANAC Monthly Coal Ash Content - January (nearest 0.01% by weight)
FEBAC Monthly Coal Ash Content - February (nearest 0.01% by weight)
MARAC Monthly Coal Ash Content - March (nearest 0.01% by weight)
APRAC Monthly Coal Ash Content - April (nearest 0.01% by weight)
MAYAC Monthly Coal Ash Content - May (nearest 0.01% by weight)
JUNAC Monthly Coal Ash Content - June (nearest 0.01% by weight)
JULAC Monthly Coal Ash Content - July (nearest 0.01% by weight)
AUGAC Monthly Coal Ash Content - August (nearest 0.01% by weight)
SEPAC Monthly Coal Ash Content - September (nearest 0.01% by weight)
OCTAC Monthly Coal Ash Content - October (nearest 0.01% by weight)
NOVAC Monthly Coal Ash Content - November (nearest 0.01% by weight)
DECAC Monthly Coal Ash Content - December (nearest 0.01% by weight)

JANHP Monthly Petroleum Heat Content - January (btu/U.S. gallon)
FEBHP Monthly Petroleum Heat Content - February (btu/U.S. gallon)
MARHP Monthly Petroleum Heat Content - March (btu/U.S. gallon)
APRHP Monthly Petroleum Heat Content - April (btu/U.S. gallon)
MAYHP Monthly Petroleum Heat Content - May (btu/U.S. gallon)
JUNHP Monthly Petroleum Heat Content - June (btu/U.S. gallon)
JULHP Monthly Petroleum Heat Content - July (btu/U.S. gallon)
AUGHP Monthly Petroleum Heat Content - August (btu/U.S. gallon)
SEPHP Monthly Petroleum Heat Content - September (btu/U.S.gallon)
OCTHP Monthly Petroleum Heat Content - October (btu/U.S. gallon)
NOVHP Monthly Petroleum Heat Content - November (btu/U.S. gallon)
DECHP Monthly Petroleum Heat Content - December (btu/U.S. gallon)

JANSP Monthly Petroleum Sulfur Content - January (nearest 0.01% by weight)
FEBSP Monthly Petroleum Sulfur Content - February (nearest 0.01% by weight)
MARSP Monthly Petroleum Sulfur Content - March (nearest 0.01% by weight)
APRSP Monthly Petroleum Sulfur Content - April (nearest 0.01% by weight)
MAYSP Monthly Petroleum Sulfur Content - May (nearest 0.01% by weight)

Table A.5 continued

JUNSP	JULSP	AUGSP	SEPSP	OCTSP	NOVSP	DECSP	JANHG	FEBHG	MARHG	APRHG	MAYHG	JUNHG	JULHG	AUGHG	SEPHG	OCTHG	NOVHG	DECHG	JANHO	FEBHO
0.00	0.00	0.00	0.00	0.00	0.00	0.00	1025	1027	1024	0	1022	1021	1018	1015	1014	1015	1014	1019	0	0
0.00	0.00	0.00	0.00	0.00	0.00	0.00	1025	1027	1024	1022	1022	1021	1018	1015	1014	1015	1014	1019	0	0
0.35	0.37	0.41	0.44	0.45	0.44	0.46	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.35	0.37	0.41	0.44	0.45	0.44	0.46	0	0	0	0	0	0	0	0	0	0	0	0	0	0

MARHO	APRHO	MAYHO	JUNHO	JULHO	AUGHO	SEPHO	OCTHO	NOVHO	DECHO	COALNITRO	COALCARBON	EC
0	0	0	0	0	0	0	0	0	0	0.0	0.0	1
0	0	0	0	0	0	0	0	0	0	0.0	0.0	2
0	0	0	0	0	0	0	0	0	0	0.0	0.0	1
0	0	0	0	0	0	0	0	0	0	0.0	0.0	2

JUNSP Monthly Petroleum Sulfur Content - June (nearest 0.01% by weight)
JULSP Monthly Petroleum Sulfur Content - July (nearest 0.01% by weight)
AUGSP Monthly Petroleum Sulfur Content - August (nearest 0.01% by weight)
SEPSP Monthly Petroleum Sulfur Content-September (nearest 0.01% by weight)
OCTSP Monthly Petroleum Sulfur Content - October (nearest 0.01% by weight)
NOVSP Monthly Petroleum Sulfur Content-November (nearest 0.01% by weight)
DECSP Monthly Petroleum Sulfur Content-December (nearest 0.01% by weight)
JANHG Monthly Gas Heat Content - January (btu/cubic foot)
FEBHG Monthly Gas Heat Content - February (btu/cubic foot)
MARHG Monthly Gas Heat Content - March (btu/cubic foot)
APRHG Monthly Gas Heat Content - April (btu/cubic foot)
MAYHG Monthly Gas Heat Content - May (btu/cubic foot)
JUNHG Monthly Gas Heat Content - June (btu/cubic foot)
JULHG Monthly Gas Heat Content - July (btu/cubic foot)
AUGHG Monthly Gas Heat Content - August (btu/cubic foot)
SEPHG Monthly Gas Heat Content - September (btu/cubic foot)
OCTHG Monthly Gas Heat Content - October (btu/cubic foot)
NOVHG Monthly Gas Heat Content - November (btu/cubic foot)
DECHG Monthly Gas Heat Content - December (btu/cubic foot)
JANHO Monthly Other Fuel Heat Content - January (btu/pound or U.S. gallon)
FEBHO Monthly Other Fuel Heat Content - February (btu/pound or U.S. gallon)
MARHO Monthly Other Fuel Heat Content - March (btu/pound or U.S. gallon)
APRHO Monthly Other Fuel Heat Content - April (btu/pound or U.S. gallon)
MAYHO Monthly Other Fuel Heat Content - May (btu/pound or U.S. gallon)
JUNHO Monthly Other Fuel Heat Content - June (btu/pound or U.S. gallon)
JULHO Monthly Other Fuel Heat Content - July (btu/pound or U.S. gallon)
AUGHO Monthly Other Fuel Heat Content - August (btu/pound or U.S. gallon)
SEPHO Monthly Other Fuel Heat Content- September (btu/pound or U.S. gallon)
OCTHO Monthly Other Fuel Heat Content - October (btu/pound or U.S. gallon)
NOVHO Monthly Other Fuel Heat Content - November (btu/pound or U.S. gallon)
DECHO Monthly Other Fuel Heat Content-December (btu/pound or U.S. gallon)

COALNITRO Average Coal Nitrogen Content (nearest 0.1% by weight)
COALCARBON Average Coal Fixed Carbon Content (nearest 0.1% by weight)

Table A.6: Form EIA – 767 (Cannual.dbf – Cooling System Information: Annual Operations)

PLANT_ID	COOLCODE	YEAR	STATUS	AARWITH	AARDISC	AARCONS	ITEMPW	ITEMPS	OTEMPW	OTEMPS	CHLORINE	STRATS1	STRATS2	STRATS3	STRATS4	EC
2341	1	1996	OP	32.5	0.0	32.5	82	101	120	133	1880	NC				1
8102	1	1996	OP	25.4	3.3	22.1	46	82	0	0	0	NC				1
8102	2	1996	OP	25.4	3.3	22.1	46	82	0	0	0	NC				2

PLANT_ID	Plant Code
COOLCODE	Cooling System Identification
YEAR	Data Year
STATUS	Cooling System Status
AARWITH	Avg Annual Rate of Cooling Water - Withdrawal (nearest 0.1 cubic ft/sec)
AARDISC	Avg Annual Rate of Cooling Water - Discharge (nearest 0.1 cubic ft/sec)
AARCONS	Avg Annual Rate of Cooling Water - Consumption (nearest 0.1 cubic ft/sec)
ITEMPW	Max Cooling Water Temp -Intake (Winter Peak Load Month) (degrees F)
ITEMPS	Max Cooling Water Temp -Intake (Summer Peak Load Month) (degrees F)
OTEMPW	Max Cooling Water Temp - Discharge Outlet (Win Peak Load Month) (degr F)
OTEMPS	Max Cooling Water Temp - Discharge Outlet (Sum Peak Load Month) (degr F)
CHLORINE	Annual Amount of Chlorine Added to Cooling Water (thousand pounds)
STRATS1	Strategy Employed to Comply W/ Chlorine Discharge Standards (1st)
STRATS2	Strategy Employed to Comply W/ Chlorine Discharge Standards (2nd)
STRATS3	Strategy Employed to Comply W/ Chlorine Discharge Standards (3rd)
STRATS4	Strategy Employed to Comply W/ Chlorine Discharge Standards (4th)
EC	Equipment Count (by plant)

Table A.7: Form EIA – 767 (Cdesign.dbf – Cooling System Information: Design Parameters)

PLANT_ID	COOLCODE	YEAR	INSRVDATE	TYPECOOL1	TYPECOOL2	TYPECOOL3	TYPECOOL4	WATERSOURC	INTLATDEG	INTLATMIN	INTLONDEG	INTLONMIN
2341	1	1996	471	RF				COLORADO RIVER	35	10	114	36
8102	1	1996	574	RN				OHIO RIVER	38	56	82	7
8102	2	1996	375	RN				OHIO RIVER	38	56	82	7

INTDIST	INTAVG	OUTLATDEG	OUTLATMIN	OUTLONDEG	OUTLONMIN	OUTDIST	OUTAVG	OUTDIFF	FLOWRATE	PLSRVDATE	PLSURF	PLVOLUME	TWSRVDATE	TWTYPE1
0	10	0	0	0	0	0	0		1200	0	0	0	471	MW
44	10	0	0	0	0	0	0		31	0	0	0	574	NW
44	10	0	0	0	0	0	0		31	0	0	0	375	

TWTYPE2	MAXFLOW	MAXPOWER	CHSRVDATE	CTTOTSYS	CTPONDS	CTTOWERS	CTCHLORINE	EC
	1200	3950	0	12117	0	9140	0	1
	1337	13262	0	8146	0	8146	0	1
	1337	13262	0	8146	0	8146	0	2

PLANT_ID Plant Code
COOLCODE Cooling System Identification
YEAR Data Year
INSRVDAT Cooling System Actual or Projected Inservice Date
TYPECOOL1 Type of Cooling System (1st)
TYPECOOL2 Type of Cooling System (2nd)
TYPECOOL3 Type of Cooling System (3rd)
TYPECOOL4 Type of Cooling System (4th)
WATERSOURC Source of Cooling Water
INTLATDEG Cooling Water Intake Location - Latitude (degrees)
INTLATMIN Cooling Water Intake Location - Latitude (minutes)
INTLONDEG Cooling Water Intake Location - Longitude (degrees)
INTLONMIN Cooling Water Intake Location - Longitude (minutes)
INTDIST Maximum Distance from Shore - Intake (feet)
INTAVG Average Distance Below Water Surface - Intake (feet)
OUTLATDEG Cooling Water Outlet Location - Latitude (degrees)
OUTLATMIN Cooling Water Outlet Location - Latitude (minutes)
OUTLONDEG Cooling Water Outlet Location - Longitude (degrees)
OUTLONMIN Cooling Water Outlet Location - Longitude (minutes)
OUTDIST Maximum Distance from Shore - Outlet (feet)
OUTAVG Average Distance Below Water Surface - Outlet (feet)
OUTDIFF Are Diffusers Used
FLOWRATE Design Cooling Water Flow Rate at 100% Load at Intake (cubic ft/sec)
PLSRVDATE Cooling Ponds - Actual or Projected Inservice Date
PLSURF Cooling Ponds - Total Surface Area (acres)
PLVOLUME Cooling Ponds - Total Volume (acre-feet)
TWSRVDATE Cooling Towers - Actual or Projected Inservice Date
TWTYPE1 Cooling Towers - Type of Towers (1st)
TWTYPE2 Cooling Towers - Type of Towers (2nd)
MAXFLOW Cooling Towers - Max Design Rate of Water Flow @ 100% Load (cubic ft/sec)
MAXPOWER Maximum Power Requirement at 100% Load (kilowatts)
CHSRVDATE Actual/Proj Insrvce Date Chlorine Disch Control Structrs & Equip
CTTOTSYS Installed Cost of Cooling System - Total System (thousand dollars)
CTPONDS Installed Cost of Cooling Ponds (thousand dollars)
CTTOWERS Installed Cost of Cooling Towers (thousand dollars)
CTCHLORINE Installed Cost of Chlorine Disch Control Structrs and Equip (thousand $)
EC Equipment Count (by plant)

Table A.8: Form EIA – 767 (Ginfo.dbf – Generator Information)

PLANT_ID	GENCODE	YEAR	MAXRATING	MAXFLOW	TEMPRISE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY
2341	1	1996	818100	600	25	393820000	410855000	408860000	-2340000	240555000	422665000	467000000
2341	2	1996	818100	600	25	166920000	460855000	434560000	454460000	454155000	435665000	412000000
8102	1	1996	1300000	1125	20	692930000	828672000	725088000	596252000	0	309251000	747578000
8102	2	1996	1300000	1125	20	725116000	811546000	856751000	399014000	752143000	744626000	788155000

AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL	EC
452845000	459975000	461650000	441965000	515050000	4672900000	1
397345000	410475000	550150000	474165000	476650000	5127400000	2
868872000	777842000	475122000	851127000	851422000	7724156000	1
865113000	826967000	734592000	868054000	791777000	9163854000	2

PLANT_ID Plant Code
GENCODE Generator Identification
YEAR Data Year
MAXRATING Maximum Generator Nameplate Rating (KiloWatt)
MAXFLOW Condenser's Cooling Water: Design Flow Rate at 100% Load (cubic ft/sec)
TEMPRISE Condenser's Cooling Water: Design Temp Rise at 100% Load (degrees F)

JANUARY Monthly Net Electrical Generation - Jan (Kilowatthours)
FEBRUARY Monthly Net Electrical Generation - Feb (Kilowatthours)
MARCH Monthly Net Electrical Generation - Mar (Kilowatthours)
APRIL Monthly Net Electrical Generation - Apr (Kilowatthours)
MAY Monthly Net Electrical Generation - May (Kilowatthours)
JUNE Monthly Net Electrical Generation - Jun (Kilowatthours)
JULY Monthly Net Electrical Generation - Jul (Kilowatthours)
AUGUST Monthly Net Electrical Generation - Aug (Kilowatthours)
SEPTEMBER Monthly Net Electrical Generation - Sep (Kilowatthours)
OCTOBER Monthly Net Electrical Generation - Oct (Kilowatthours)
NOVEMBER Monthly Net Electrical Generation - Nov (Kilowatthours)
DECEMBER Monthly Net Electrical Generation - Dec (Kilowatthours)
TOTAL Annual Net Electrical Generation - Total Year (Kilowatthours)
EC Equipment Count (by plant)

Table A.9: Form EIA – 767 (Odesign.dbf – Flu Gas Particulate Collector Information)

PLANT_ID	COLLCODE	YEAR	STATUS	ERANNUAL	ER100	ETDATE	TPER	INSERVHR	INSRVDATE	TC1	TC2	TC3	AC1	AC2	AP1	AP2	SC1	SC2	SP1	SP2
2341	1	1996	OP	98.0	0.0	1196	0.09	7239	471	EK			10.0	10.0	0.0	0.0	0.5	0.5	0.0	0.0
2341	2	1996	OP	98.0	0.0	1196	0.09	7694	1071	EK			10.0	10.0	0.0	0.0	0.5	0.5	0.0	0.0
8102	1	1996	OP	99.5	99.8	692	0.02	6851	474	EK			0.0	15.0	0.0	0.0	1.0	6.0	0.0	0.0
8102	2	1996	OP	99.5	99.7	392	0.01	8007	375	EK			0.0	15.0	0.0	0.0	1.0	6.0	0.0	0.0

GROSSAIR	TOTCOLL	CYCLONEDIA	SPECCOLL	SPECPER	SPECEXIT	SPECTEMP	COST	EC
0	220.0	0.0	97.0	1130	2420000	260	2317	1
0	220.0	0.0	97.0	1130	2420000	268	2317	2
0	246.4	0.0	99.7	434	4400000	300	6947	1
0	246.4	0.0	99.7	434	4400000	300	6947	2

PLANT_ID Plant Code
COLLCODE Flue Gas Particulate Collector Identification
YEAR Data Year
STATUS Collector Status
ERANNUAL Est Removal Efficiency - At Annual Operating Factor (nearest 0.1%)
ER100 Est Removal Efficiency - At 100% Load or Tested (nearest 0.1%)
ETDATE Date of Most Recent Efficiency Test
TPER Typical Particulate Emission Rate @ Annual Op Rate (nearest 0.01lb./mil btu)
INSERVHR Hours Inservice During Year
INSRVDATE Collector Actual or Projected Inservice Date
TC1 Type of Collector (1st)
TC2 Type of Collector (2nd)
TC3 Type of Collector (3rd)
AC1 Design Fuel Specs of Ash -Coal (as burned nearest 0.1% by weight)
AC2 Design Fuel Specs of Ash -Coal (as burned nearest 0.1% by weight)
AP1 Design Fuel Specs of Ash -Petroleum (as burned nearest 0.1% by weight)
AP2 Design Fuel Specs of Ash -Petroleum (nearest 0.1% by weight)
SC1 Design Fuel Specs of Sulfur -Coal (as burned nearest 0.1% by weight)
SC2 Design Fuel Specs of Sulfur -Coal (as burned nearest 0.1% by weight)
SP1 Design Fuel Specs of Sulfur -Petroleum (as burned nearest 0.1% by weight)
SP2 Design Fuel Specs of Sulfur -Petroleum (as burned nearest 0.1% by weight)
GROSSAIR Gross Air to Fabric Ratio Fabric Collectors Only (cubic ft/minute/sq foot)
TOTCOLL Total Collection Surf Area Electrostatic Precipitation Only (near 0.1 thousand sq ft)
CYCLONEDIA Cyclone Diameter Cyclones Only (nearest 0.1 foot)
SPECCOLL Design Specs at 100% Ld - Collection Efficiency (nearest 0.1%)
SPECPER Design Specs at 100% Ld - Particulate Emission Rate (lbs/hour))
SPECEXIT Design Specs at 100% Ld - Particulate Collector Gas Exit Rate (actual cu.ft/min)
SPECTEMP Design Specs at 100% Ld - Particulate Collector Gas Exit Temp (degr F)
COST Installed Cost of Flue Gas Particulate Collector (thousand dollars)
EC Equipment Count (by plant)

Table A.10: Form EIA – 767 (Pbyprodu.dbf – Plant Information: Annual Byproduct Disposition and Steam Sales)

PLANT_ID	YEAR	FLYTOT	FLYLAN	FLYDIS	FLYONS	FLYSOL	FLYOFF	BOTTOT	BOTLAN	BOTDIS	BOTONS	BOTSOL	BOTOFF	FLUTOT	FLULAN	FLUDIS	FLUONS
2341	1996	360.3	158.7	0.0	0.0	201.6	0.0	211.6	211.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8102	1996	688.7	688.7	0.0	0.0	0.0	0.0	172.5	0.0	74.9	89.2	8.4	0.0	1525.6	1474.2	0.0	51.4

FLUSOL	FLUOFF	GYPTOT	GYPLAN	GYPDIS	GYPONS	GYPSOL	GYPOFF	OTHTOT	OTHLAN	OTHDIS	OTHONS	OTHSOL	OTHOFF	QUATOT
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PLANT_ID	Plant Code
YEAR	Data Year
FLYTOT	Fly Ash - Total (nearest 0.1 thousand short tons)
FLYLAN	Fly Ash - Utility Landfill (dry) (nearest 0.1 thousand short tons)
FLYDIS	Fly Ash - Utility Disposal Ponds (wet) (nearest 0.1 thousand short tons)
FLYONS	Fly Ash - On Site Use and Storage (nearest 0.1 thousand short tons)
FLYSOL	Fly Ash - Sold (nearest 0.1 thousand short tons)
FLYOFF	Fly Ash - Off Site Disposal (nearest 0.1 thousand short tons)
BOTTOT	Bottom Ash - Total (nearest 0.1 thousand short tons)
BOTLAN	Bottom Ash - Utility Landfill (dry) (nearest 0.1 thousand short tons)
BOTDIS	Bottom Ash - Utility Disposal Ponds (wet) (nearest 0.1 thousand short tons)
BOTONS	Bottom Ash - On Site Use and Storage (nearest 0.1 thousand short tons)
BOTSOL	Bottom Ash - Sold (nearest 0.1 thousand short tons)
BOTOFF	Bottom Ash - Off Site Disposal (nearest 0.1 thousand short tons)
FLUTOT	FGD (Sludge) Incl Stabilizers - Total (nearest 0.1 t.s.t.)
FLULAN	FGD (Sludge) Incl Stabilizers - Utility Landfill (dry) (nearest 0.1 t.s.t.)
FLUDIS	FGD (Sludge) Incl Stabilizers-Utility Disposal Ponds (wet)
FLUONS	FGD (Sludge) Incl Stabilizers - On Site Use/Storage (nearest 0.1 t.s.t.)
FLUSOL	FGD (Sludge) Incl Stabilizers – Sold (nearest 0.1 t.s.t.)
FLUOFF	FGD (Sludge) Incl Stabilizers - Off Site Disposal (nearest 0.1 t.s.t.)
GYPTOT	Gypsum (salable) - Total (nearest 0.1 t.s.t.)
GYPLAN	Gypsum (salable) - Utility Landfill (dry) (nearest 0.1 t.s.t.)
GYPDIS	Gypsum (salable) - Utility Disposal Ponds (wet) (nearest 0.1 t.s.t.)
GYPONS	Gypsum (salable) - On Site Use and Storage (nearest 0.1 t.s.t.)
GYPSOL	Gypsum (salable) - Sold (nearest 0.1 t.s.t.)
GYPOFF	Gypsum (salable) - Off Site Disposal (nearest 0.1 t.s.t.)
OTHTOT	Other Byproducts - Total (nearest 0.1 t.s.t.)
OTHLAN	Other Byproducts - Utility Landfill (dry) (nearest 0.1 t.s.t.)
OTHDIS	Other Byproducts - Utility Disposal Ponds (wet) (nearest 0.1 t.s.t.)
OTHONS	Other Byproducts - On Site Use and Storage (nearest 0.1 t.s.t.)
OTHSOL	Other Byproducts - Sold (nearest 0.1 t.s.t.)
OTHOFF	Other Byproducts - Off Site Disposal (nearest 0.1 t.s.t.)
QUATOT	Quantity of Steam Sold During Year (million pounds of steam)

Table A.11: Form EIA – 767 (Pconfig.dbf – Plant Configuration)

PLANT_ID	EC	YEAR	BOILCODE	GEN1	GEN2	GEN3	GEN4	GEN5	COOL1	COOL2	COOL3	COOL4	COOL5	COLL1	COLL2	COLL3	COLL4	COLL5	SCRB1	SCRB2	SCRB3	SCRB4	SCRB5	STCK1	STCK2	STCK3	STCK4	STCK5	FLUE1	FLUE2	FLUE3	FLUE4	FLUE5
2341	1	1996	1	1					1					1										1					1				
2341	2	1996	2	2					1					2										1					2				
8102	1	1996	1	1					1					1					1					11					11				
8102	2	1996	2	2					2					2					2					12					12				

PLANT_ID	Plant Code
EC	Equipment Count (by plant)
YEAR	Data Year
BOILCODE	Equipment Identification - Boiler
GEN1	Equipment Identification - Associated Generator 1
GEN2	Equipment Identification - Associated Generator 2
GEN3	Equipment Identification - Associated Generator 3
GEN4	Equipment Identification - Associated Generator 4
GEN5	Equipment Identification - Associated Generator 5
COOL1	Equipment Identification - Associated Cooling System 1
COOL2	Equipment Identification - Associated Cooling System 2
COOL3	Equipment Identification - Associated Cooling System 3
COOL4	Equipment Identification - Associated Cooling System 4
COOL5	Equipment Identification - Associated Cooling System 5
COLL1	Equipment Identification - Assoc Flue Gas Particulate Collector 1
COLL2	Equipment Identification - Assoc Flue Gas Particulate Collector 2
COLL3	Equipment Identification - Assoc Flue Gas Particulate Collector 3
COLL4	Equipment Identification - Assoc Flue Gas Particulate Collector 4
COLL5	Equipment Identification - Assoc Flue Gas Particulate Collector 5
SCRB1	Equipment Identification -Assoc Flue Gas Desulfurization (FGD) Unit 1
SCRB2	Equipment Identification -Assoc Flue Gas Desulfurization (FGD) Unit 2
SCRB3	Equipment Identification -Assoc Flue Gas Desulfurization (FGD) Unit 3
SCRB4	Equipment Identification -Assoc Flue Gas Desulfurization (FGD) Unit 4
SCRB5	Equipment Identification -Assoc Flue Gas Desulfurization (FGD) Unit 5
STCK1	Equipment Identification - Associated Stack 1
STCK2	Equipment Identification - Associated Stack 2
STCK3	Equipment Identification - Associated Stack 3
STCK4	Equipment Identification - Associated Stack 4
STCK5	Equipment Identification - Associated Stack 5
FLUE1	Equipment Identification - Associated Flue 1
FLUE2	Equipment Identification - Associated Flue 2
FLUE3	Equipment Identification - Associated Flue 3
FLUE4	Equipment Identification - Associated Flue 4
FLUE5	Equipment Identification - Associated Flue 5

Table A.12: Form EIA – 767 (Pfin.dbf – Plant Information: Financial Information)

PLANT_ID	YEAR	FLYCOL	FLYDIS	BOTCOL	BOTDIS	FGDCOL	FGDDIS	WATCOL	WATDIS	OTHCOL	OTHDIS	OTHOTH	TOTCOL	TOTDIS	TOTOTH	AIRPOL	WATPOL
2341	1996	707	565	1126	676	0	0	866	0	0	0	0	2699	1241	0	0	90
8102	1996	783	0	0	0	26336	0	329	0	0	0	0	27448	0	0	109	29

SOLPOL	OTHPOL	FLYSALE	BOTSALE	FABSALE	GASSALE	OTHSALE	TOTSALE
0	0	662	0	0	0	18	680
28	0	0	9	0	0	0	9

PLANT_ID Plant Code
YEAR Data Year
FLYCOL O&M Expenditures - Fly Ash Collection (thousand dollars)
FLYDIS O&M Expenditures - Fly Ash Disposal (thousand dollars)
BOTCOL O&M Expenditures - Bottom Ash Collection (thousand dollars)
BOTDIS O&M Expenditures - Bottom Ash Disposal (thousand dollars)
FGDCOL O&M Expenditures - FGD Collection (thousand dollars)
FGDDIS O&M Expenditures - FGD Disposal (thousand dollars)
WATCOL O&M Expenditures - Water Pollution Collection (thousand dollars)
WATDIS O&M Expenditures - Water Pollution Disposal (thousand dollars)
OTHCOL O&M Expenditures - Other Pollution Collection (thousand dollars)
OTHDIS O&M Expenditures - Other Pollution Disposal (thousand dollars)
OTHOTH O&M Expenditures - Other (thousand dollars)
TOTCOL O&M Expenditures - Total Collection (thousand dollars)
TOTDIS O&M Expenditures - Total Disposal (thousand dollars)
TOTOTH O&M Expenditures - Total Other (thousand dollars)
AIRPOL Capital Expenditures - Air Pollution Abatement (thousand dollars)
WATPOL Capital Expenditures - Water Pollution Abatement (thousand dollars)
SOLPOL Capital Expenditures - Solid/Contained Waste Polltn Abatement (thousand $)
OTHPOL Capital Expenditures - Other Pollution Abatement (thousand dollars)
FLYSALE Byproduct Sales Revenue - Fly Ash (thousand dollars)
BOTSALE Byproduct Sales Rev - Bottom Ash (thousand dollars)
FABSALE Byproduct Sales Rev - Fly and Bottom Ash Sold Intermingled (thousand dollars)
GASSALE Byproduct Sales Rev - Flue Gas Desulfurization Byproducts (thousand dollars)
OTHSALE Byproduct Sales Rev - Other Byproduct (thousand dollars)
TOTSALE Byproduct Sales Rev - Total (thousand dollars)

Table A.13: Form EIA – 767 (Pfuel.dbf – Plant Information: Projected Annual Fuel Consumption)

PLANT_ID	YEAR	CCOAL5	CPETROL5	CGASUFC5	CGASUIC5	CTOTALG5	HCOAL5	HPETROL5	HGAS5	SCOAL5	SPETROL5	CCOAL10	CPETROL10	CGASUFC10	CGASUIC10
2341	1996	4320	0	0	0	2680	10950	0	1040	0.55	0.00	4450	0	0	0
8102	1996	7503	41	0	0	0	11364	137067	0	3.07	0.40	7559	41	0	0

CTOTALG10	HCOAL10	HPETROL10	HGAS10	SCOAL10	SPETROL10	QSA	QUANA5	QUANA10	QSB	QUANB5	QUANB10	QSC	QUANC5	QUANC10	QSD	QUAND5	QUAND10
2750	10950	0	1040	0.55	0.00	AZ	5000	5000		0	0		0	0		0	0
0	12000	137067	0	4.25	0.40	OH	7569	0		0	0		0	0		0	0

PLANT_ID	Plant Code
YEAR	Data Year
CCOAL5	Projected Coal - 5 years (thousand short tons)
CPETROL5	Projected Petroleum - 5 years (thousand barrels)
CGASUFC5	Projected Gas Under Firm Contract - 5 years (million cubic feet)
CGASSUIC5	Projected Gas Under Interruptible Contract - 5 years (million cubic feet)
CTOTALG5	Projected Gas Total - 5 years (million cubic feet)
HCOAL5	Projected Average Heat Content (Coal) - 5 years (btu/pound)
HPETROL5	Projected Average Heat Content (Petroleum) - 5 years (thousand barrels)
HGAS5	Projected Average Heat Content (Gas) - 5 years (million cubic feet)
SCOAL5	Projected Average Sulfur Content (Coal) - 5 years (nearest 0.01%)
SPETROL5	Projected Average Sulfur Content (Petroleum) - 5 years (nearest 0.01%)
CCOAL10	Projected Coal - 10 years (thousand short tons)
CPETROL10	Projected Petroleum - 10 years (thousand barrels)
CGASUFC10	Projected Gas Under Firm Contract - 10 years (million cubic feet)
CGASSUIC10	Projected Gas Under Interruptible Contract - 10 years (million cubic feet)
CTOTALG10	Projected Gas Total - 10 years (million cubic feet)
HCOAL10	Projected Average Heat Content (Coal) - 10 years (btu/pound)
HPETROL10	Projected Average Heat Content (Petroleum) - 10 years (thousand barrels)
HGAS10	Projected Average Heat Content (Gas) - 10 years (million cubic feet)
SCOAL10	Projected Average Sulfur Content (Coal) - 10 years (nearest 0.01%)
SPETROL10	Projected Average Sulfur Content (Petroleum) - 10 years (nearest 0.01%)
QSA	Coal Under Firm Contract by State - State Code
QUANA5	Coal Quantity - 5 years (thousand short tons)
QUANA10	Coal Quantity - 10 years (thousand short tons)
QSB	Coal Under Firm Contract by State - State Code
QUANB5	Coal Quantity - 5 years (thousand short tons)
QUANB10	Coal Quantity - 10 years (thousand short tons)
QSC	Coal Under Firm Contract by State - State Code
QUANC5	Coal Quantity - 5 years (thousand short tons)
QUANC10	Coal Quantity - 10 years (thousand short tons)
QSD	Coal Under Firm Contract by State - State Code
QUAND5	Coal Quantity - 5 years (thousand short tons)
QUAND10	Coal Quantity - 10 years (thousand short tons)

Table A.14: Form EIA – 767 (Rannual.dbf – Flue Gas Desulfurization Unit Information: Annual Operations)

PLANT_ID	SCRBCODE	YEAR	STATUS	EFSULFUR	EF100	TESTDATE	INSRVHOURS	FGDSORB	EEC	CTFEED	CTLABOR	CTDISP	CTMAIN	CTTOT	EC
8102	1	1996	OP	87.8	98.0	0	6949	185.8	220451000	0	61	0	0	12193	1
8102	2	1996	OP	85.3	98.0	895	8060	215.0	246479000	0	72	0	0	14143	2

PLANT_ID	Plant Code
SCRBCODE	Flue Gas Desulfurization (FGD) Unit Identification
YEAR	Data Year
STATUS	FGD Unit Status
EFSULFUR	Removal Efficiency of S02 at Annual Op Factor (nearest 0.1% by weight)
EF100	Removal Efficiency of S02 at 100% Load or Tested (nearest 0.1% by weight)
TESTDATE	Date of Most Recent Efficiency Test
INSRVHOURS	Total Hours Inservice During Year (nearest hour)
FGDSORB	Quantity of FGD Sorbent Used During Year (nearest 0.1 thousand short tons)
EEC	Electrical Energy Consumption During Year (kilowathours)
CTFEED	FGD O&M Expenditures - Feed Materials and Chemicals (thousand dollars)
CTLABOR	FGD O&M Expenditures - Labor and Supervision (thousand dollars)
CTDISP	FGD O&M Expenditures - Waste Disposal (thousand dollars)
CTMAIN	FGD O&M Expenditures - Maintenance Materials/ All Other Costs (thousand $)
CTTOT	Total Cost (thousand dollars)
EC	Equipment Count (by plant)

Table A.15: Form EIA – 767 (Rdesign.dbf - Flue Gas Desulfurization Unit Information: Design)

PLANT_ID	SCRBCODE	YEAR	INSRVDATE	TYPEFGD1	TYPEFGD2	TYPEFGD3	TYPEFGD4	TYPESORB1	TYPESORB2	TYPESORB3	TYPESORB4	SALABLE	MANCODE
8102	1	1996	1294	SP	TR			LI	MO			N	BW
8102	2	1996	395	SP	TR			LI	MO			N	BW

SPECASH	SPECSULFUR	TRAINTOT	TRAINLOAD	WASTESALE	PONDLAND	LINED	SPECRE	SPECER	SPECEXRATE	SPECEXTEMP	SPECENT	SPECLIQUID	SPECPOWER
12.3	3.5	6	5	873	681	NA	95.0	3860	4000000	128	100	21	30000
12.3	3.5	6	5	873	681	NA	95.0	3860	4000000	128	100	21	30000

SPECWATER	SPECHEAT	SPECGTEMP	SPECBY	CTSTRUCT	CTDISP	CTOTHER	CTTOT	EC
4.40	0	0	N	0	0	0	0	1
4.40	0	0	N	0	0	0	0	2

PLANT_ID	Plant Code
SCRBCODE	Flue Gas Desulfurization (FGD) Unit Identification
YEAR	Data Year
INSRVDATE	FGD Unit Actual or Projected Inservice Date
TYPEFGD1	Type of FGD Unit (1st)
TYPEFGD2	Type of FGD Unit (2nd)
TYPEFGD3	Type of FGD Unit (3rd)
TYPEFGD4	Type of FGD Unit (4th)
TYPESORB1	Type of Sorbent (1st)
TYPESORB2	Type of Sorbent (2nd)
TYPESORB3	Type of Sorbent (3rd)
TYPESORB4	Type of Sorbent (4th)
SALABLE	Salable Byproduct Recovery
MANCODE	FGD Unit Manufacturer
SPECASH	Design Fuel Specs/Coal - Ash (nearest 0.1% by weight)
SPECSULFUR	Design Fuel Specs/Coal - Sulfur (nearest 0.1% by weight)
TRAINTOT	Number of FGD Scrubber Trains (or modules) - Total
TRAINLOAD	Number of FGD Scrubber Trains (or modules) - Operated at 100% Load
WASTESALE	Estimated FGD Waste and Salable Byproducts (thousand short tons)
PONDLAND	Annual Pond and Land Fill Requirements (nearest acre-foot/year)
LINED	Sludge Pond Lined
SPECRE	Unit at 100% Gen Load - Removal Efficiency of S02 (nearest 0.1% by weight)
SPECER	Unit at 100% Gen Load - Sulfur Dioxide Emission Rate (pounds/hour)
SPECEXRATE	Unit at 100% Gen Load - Gas Exit Rate (actual cubic feet/minute)
SPECEXTEMP	Unit at 100% Gen Load - Gas Exit Temperature (degrees F)
SPECENT	Unit at 100% Gen Load - Flue Gas Entering FGD Unit (percent of total)
SPECLIQUID	Unit at 100% Gen Load - Liquid/Gas Ratio (US gallons/thousand cu.ft.)
SPECPOWER	Unit at 100% Gen Load - Electrical Power Requirement (kilowatts)
SPECWATER	Unit at 100% Gen Load - Feedwater Consumption Rate (nearest 0.01 cu.ft./second)
SPECHEAT	Unit at 100% Gen Load - FGD Reheater Energy Consumption Rate (1,000 btu/hour)
SPECGTEMP	Unit at 100% Gen Load - Increase in Flue Gas Temp by Reheater (degrees F)
SPECBY	Flue Gas Bypass FGD Unit
CTSTRUCT	Installed Cost of FGD Unit - Structures and Equipment (thousand dollars)
CTDISP	Installed Cost of FGD Unit - Sludge Transportation & Disposal System (thousand $)
CTOTHER	Installed Cost of FGD Unit - Other (thousand dollars)
CTTOT	Installed Cost of FGD Unit - Total (thousand dollars)
EC	Equipment Count (by plant)

Table A.16: Form EIA – 767 (Sdesign.dbf – Stack and Flue Information: Design Parameters)

PLANT_ID	FLUECODE	STACKCODE	YEAR	STATUS	INSRVDATE	LATDEG	LATMIN	LATSEC	LONDEG	LONMIN	LONSEC	HEIGHT	CROSSSECT	RATE100	RATE50
2341	1	1	1996	OP	471	35	10	0	114	36	0	500	830	4840000	2420000
2341	2	1	1996	OP	471	35	10	0	114	36	0	500	830	3800000	190000
8102	11	11	1996	OP	1294	38	56	5	82	6	57	830	1385	4000000	2400000
8102	12	12	1996	OP	395	38	56	9	82	6	56	830	1385	4000000	2400000

TEMP100	TEMP50	VEL100	VEL50	EC
260	130	90	45	1
260	130	90	45	2
125	125	48	29	1
125	125	48	29	2

PLANT_ID	Plant Code
FLUECODE	Flue Identification
STCKCODE	Stack Identification
YEAR	Data Year
STATUS	Stack (or Flue) Status
INSRVDATE	Stack (or Flue) Actual or Projected Inservice Date
LATDEG	Stack Location - Latitude (degrees)
LATMIN	Stack Location - Latitude (minutes)
LATSEC	Stack Location - Latitude (seconds)
LONDEG	Stack Location - Longitude (degrees)
LONMIN	Stack Location - Longitude (minutes)
LONSEC	Stack Location - Longitude (seconds)
HEIGHT	Flue Height at Top from Ground Level (feet)
CROSSSECT	Cross-Sectional Area at Top of Flue (nearest square foot)
RATE100	Design Flue Gas Exit - Rate at 100% Load (actual cubic feet/minute)
RATE50	Design Flue Gas Exit - Rate at 50% Load (actual cubic feet/minute)
TEMP100	Design Flue Gas Exit - Temperature at 100% Load (degrees F)
TEMP50	Design Flue Gas Exit - Temperature at 50% Load (degrees F)
VEL100	Velocity at 100% Load (feet/second)
VEL50	Velocity at 50% Load (feet/second)
EC	Equipment Count (by plant)

Table A.17: Form EIA – 906 (Yearly - Utility Power Plant)

CENSUS	FIPST	OWNER	PMOVER	FUELTYP	COCODE	PLTCODE	UTILNAME	PLTNAME	CAPACITY	FUELNM	UCODE	FILLER	FREQUENCYF	EFFDATE
88	32	1	2	6	152	5	SOUTHERN CALIF EDISON CO	MOHAVE	0	BIT COAL	52721	0	M	1295
88	32	1	2	9	152	5	SOUTHERN CALIF EDISON CO	MOHAVE	0	NAT GAS	52721	0	M	1295
31	39	1	2	2	141	30	OHIO POWER CO	GAVIN	0	LIGHT OIL	54028	0	M	1295
31	39	1	2	6	141	30	OHIO POWER CO	GAVIN	0	BIT COAL	54028	0	M	1295

STATUS	MULTIST	YEAR	NETGENERAT	CONSUMPTIO	STOCKS	PCODE	NERC	UTILCODE	FUELDESC	PMDESC
	480	96	9722202	4596901	521628	2341	9	17609	BIT	ST
	480	96	78098	798930	0	2341	9	17609	NG	ST
	364	96	26827	45809	40730	8102	1	14006	FO2	ST
	364	96	16861183	7367778	778581	8102	1	14006	BIT	ST

CENSUS Census Region Code
FIPST FIPS State Code
OWNER Ownership Code
PMOVER Prime Mover Code
FUELTYP Kind of Fuel Code
COCODE Company Code
PLTCODE Plant Code
UTILNAME Company Name
PLTNAME Plant Name
CAPACITY Current Capacity
FUELNM Fuel Name
UCODE NAD Utility ID
FILLER Filler
FREQUENCYF Frequency
EFFDATE Effective Date (Month, Year)
STATUS Status - R = Retired, S = Cold Standby, A = Addition (New Plant)
MULTIST Multistate Code
YEAR Current Year
NETGENERAT Net Generation (MWh)
CONSUMPTIO Fuel Consumption (short ton, 42 gal. bbl, Mcf.)
STOCKS Fuel Stocks (short ton, 42 gal. bbl)
PCODE Electric Plant Code
NERC NERC Code
01 – ECAR: East Central Area Reliability Coordination Agreement
02 – ERCOT: Electric Reliability Council of Texas
03 – MAAC: Mid-Atlantic Area Council
04 – MAIN: Mid-American Interpool Network
05 – MAPP: Mid-Continent Area Power Pool
06 – NPCC: Northeast Power Coordinating Council
07 – SERC: Southeastern Electric Reliability Council
08 – SPP: Southwest Power Pool
09 – WSCC: Western Systems Coordinating Council
10 – ASCC: Alaska Systems Coordinating Council
11 – HICC: Hawaii Coordinating Council
UTILCODE Company Number
FUELDESC Fuel Description
PMDESC Prime Mover Description
ST - Steam Turbine, including nuclear, geothermal and solar steam
CA - Combined Cycle Steam Part (includes steam part of integrated coal gasification combined cycle)
GT - Combustion (Gas) Turbine (includes Jet Engine Design)
CT - Combined Cycle Combustion Turbine Part (includes combustion turbine part of integrated coal gasification combined cycle)
CS - Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
IC - Internal Combustion (diesel, piston) Engine
HY - Hydraulic Turbine (includes turbines associated with delivery of water by pipeline)
PS - Hydraulic Turbine – Reversible (Pumped Storage)
PV – Photovoltaic WT - Wind Turbine
CC - Combined Cycle Total Unit – (Use only for plants/generators that are in planning stage.) CE - Compressed Air Energy Storage, FC - Fuel Cell, OT – Other NA - Unknown

Table A.18: Form EIA – 906 (Monthly - Utility Power Plant)

CENSUS	FIPST	OWNER	PMOVER	FUELTYP	COCODE	PLTCODE	UTILNAME	PLTNAME	CAPACITY	FUELNM	UCODE	FILLER	FREQUENCYF	EFFDATE
88	32	1	2	6	152	5	SOUTHERN CALIF EDISON CO	MOHAVE	0	BIT COAL	52721	0	M	1295
88	32	1	2	9	152	5	SOUTHERN CALIF EDISON CO	MOHAVE	0	NAT GAS	52721	0	M	1295
31	39	1	2	2	141	30	OHIO POWER CO	GAVIN	0	LIGHT OIL	54028	0	M	1295
31	39	1	2	6	141	30	OHIO POWER CO	GAVIN	0	BIT COAL	54028	0	M	1295

STATUS	MULTIST	YEAR	GEN01	CON01	STK01	GEN02	CON02	STK02	GEN03	CON03	STK03	GEN04	CON04	STK04	GEN05	CON05	STK05	GEN06
	480	96	551720	259847	575204	863220	403600	600356	834791	386881	683158	449044	214956	538516	684626	321421	686682	849635
	480	96	9020	102842	0	8490	84264	0	8629	85701	0	3076	31303	0	10084	101038	0	8695
	364	96	1474	2543	31205	1313	2256	28949	1871	3149	25800	2919	4825	20975	2275	3844	30694	6638
	364	96	1416572	628392	1239834	1638905	718952	1013710	1579968	685457	743557	992347	425300	1059063	749868	321051	1537866	1047239

CON06	STK06	GEN07	CON07	STK07	GEN08	CON08	STK08	GEN09	CON09	STK09	GEN10	CON10	STK10	GEN11	CON11	STK11	GEN12
403734	533573	874968	416570	597794	843020	405592	674023	865189	415631	655267	1007048	479365	481740	910933	426823	513289	988008
86800	0	4032	41283	0	7170	73635	0	5261	54023	0	4752	48681	0	5197	52096	0	3692
11693	19001	2304	4013	23258	817	1398	21860	1631	2791	29037	3043	5067	44940	1547	2532	42428	995
465065	1641693	1533429	679836	1632613	1733168	759305	1483610	1603178	705293	1001303	1206671	521364	962164	1717634	741353	958366	1642204

CON12	STK12	PCODE	NERC	UTILCODE	FUELDESC	PMDESC
462481	521628	2341	9	17609	BIT	ST
37264	0	2341	9	17609	NG	ST
1698	40730	8102	1	14006	FO2	ST
716410	778581	8102	1	14006	BIT	ST

* See the yearly data description

Table A.19: The Clean Air Act Database Browser (CAADB) - Emissions

STATE	COUNTY	UTILITY	PLANT	ID	BOILER	1985 SO2 (tons)	1990 SO2 (tons)	1994 SO2 (tons)	1995 SO2 (tons)
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	2341	1	11840	20071	21072	22982
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	2341	2	11376	23163	23364	19991
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	2	181558	203498	169276	11533
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	1	173966	161811	156888	11945

Table A.20: The Clean Air Act Database Browser (CAADB) – SO2 Compliance

STATE	UTILITY	PLANT	BOILER ID	COUNTY	PHASE I	PHASE I COMPLIANCE METHOD	PHASE II COMPLIANCE METHOD	SOURCE	DATE
NEVADA	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	1	CLARK	NO		No action reported	Trac	
NEVADA	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	2	CLARK	NO		No action reported	Trac	
OHIO	OHIO POWER CO	GEN J M GAVIN	2	GALLIA	YES	Wet lime/limestone FGD	Unknown	Fieldston	1994 Guide
OHIO	OHIO POWER CO	GEN J M GAVIN	1	GALLIA	YES	Wet lime/limestone FGD	Unknown	Fieldston	1994 Guide

Table A.21: The Clean Air Act Database Browser (CAADB) – Scrubbers

STATE	COUNTY	UTILITY	PLANT	PLANT CODE	FGD STATUS	FGD TYPE	SUPPLIER	FGD REMOVAL EFFICIENCY	ON-LINE DATE	FGD ID
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	OPERATING	SPRAY TYPE	BABCOCK AND WILCOX	90.6	12/94	1
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	OPERATING	SPRAY TYPE	BABCOCK AND WILCOX	92.3	03/95	2

Table A.22: The Clean Air Act Database Browser (CAADB) – Fuel Shifts

STATE	COUNTY	UTILITY	PLANT	1985 FUEL TYPE	1996 FUEL TYPE	1985 AVG BTU	1996 AVG BTU	1985 AVG SULFUR (% by weight)	1996 AVG SULFUR (% by weight)
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE		BIT		10,922.00		50.00
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	NG	NG	1,071.00	1,021.00	0.00	0.00
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	BIT	BIT	11,232.00	11,327.00	337.00	316.00
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	FO2	FO2	136,783.00	138,671.00	0.00	0.00

1985 RECEIPTS (tons, barrels, cubic feet)	1996 RECEIPTS (tons, barrels, cubic feet)	1985 AVG COST (cents per million Btus in nominal dollars)	1996 AVG COST (cents per million Btus in nominal dollars)	1985 PRIMARY SOURCE	1985 SOURCE #2	1985 SOURCE #3	1985 SOURCE #4	1985 SOURCE #5
	4,470,000.00		1314					
1,753,400.00	799,000.00	4198	2777					
5,631,400.00	6,903,700.00	2018	1539	OH				
30,300.00	52,900.00	6014	4938					

1996 PRIMARY SOURCE	1996 SOURCE #2	1996 SOURCE #3	1996 SOURCE #4	1996 SOURCE #5
AZ				
OH				

Table A.23: The Clean Air Act Database Browser (CAADB) – Phase I

STATE	PLANT	BOILER ID	UTILITY	COUNTY	PLANT CODE	SUM OF TABLE A AND MIDWEST	FINAL PHASE I	AUCTION RESERVE	TABLE A ALLOCATION	MIDWEST ALLOCATION
OHIO	GEN J M GAVIN	1	OHIO POWER CO	GALLIA	8102	89033	86690	2343	79080	9953
OHIO	GEN J M GAVIN	2	OHIO POWER CO	GALLIA	8102	90699	88312	2387	80560	10139

* Mohave plant was excluded from Phase I regulation.
* Units: Tons

RACHETED PHASE II	BASIC PHASE II	FINAL PHASE II	CONSERVATION/REPOWERING	HARD-HIT UNITS	BONUS	TOTAL BASIC PHASE II
34203	37957	33817	1271	885	0	32932
34844	38668	34450	1295	901	0	33549

* Units: Tons

Table A.24: The Clean Air Act Database Browser (CAADB) – Phase II

STATE	COUNTY	UTILITY	PLANT	PL ANT CODE	BOILER ID	BASIC PHASE II	RATCHETED PHASE II	CONSERVATION REPOWERING	BONUS	HARD-HIT UNITS	FINAL PHASE II
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	2341	1	29849	26897	1001	541	0	26437
NEVADA	CLARK	SOUTHERN CALIFORNIA EDISON CO	MOHAVE	2341	2	29728	26788	995	543	0	26336
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	1	37957	34203	1271	0	885	33817
OHIO	GALLIA	OHIO POWER CO	GEN J M GAVIN	8102	2	38668	34844	1295	0	901	34450

* Units: Tons

Table A.25: The Clean Air Act Database Browser (CAADB) – Acid Rain

SEQNUM	PSTATABB	PNAME	ORISPL	BLRID	NUMGEN	UTILNAME	UCODE	EPARGN	CNTYNAME	STATNAM	TOTALPH1 (tons)
1997	NV	MOHAVE	2341	1	1	SOUTHERN CALIFORNIA EDISON CO	17609	9	CLARK	NEVADA	0
2192	OH	GEN J M GAVIN	8102	1	1	OHIO POWER CO	14006	5	GALLIA	OHIO	89033

TOTHT (10^12 Btu)	SO2 (tons)	SO2CATEG	SCRUBBER	FELIM85 (lbs\MMBtu)	ANNFACT	AVGPD	NAMEPCAP (MW)	SUMNDCAP (MW)	GENMNONL	GENYRONL	BLRMNONL	BLRYRONL	BASE8587 (10^12 Btu)
28.4169	12219	1	0	1.2	0.89	1	818.1	790	12	1970	12	1970	48.338328
58.942248	177338	1	0	7.41	0.96	9	1300	1300	7	1974	7	1974	63.261039

BLROUTGE (hours)	PRIMFUEL	GAS8089 (%)	HEATRATE (Btu/kWh)	GENER (GWh)	UCAPFSST (MW)	MXBS8089 (10^12 Btu)	RY_ER (lbs\MMBtu)	FLAGMUNI	SO2RTE (lbs\MMBtu)	ANNLIM85 (lbs\MMBtu)	HT60 (1012 Btu)	HT60SHR (10^12 Btu)	BLRSEQ
4320	1	0	10217	2309.75	10470	0	0	0	0.86	1.068	42.423436	42.423436	1641
0	1	0	9566	6019.83	6475	0	0	0	6.0173	7.1136	65.362565	65.362565	2020

SEQNUM	ARDB95 boiler sequence number
PSTATABB	State postal code
PNAME	Plant name
ORISPL	DOE 4-digit plant code (if utility) or 5-digit facility code (if nonutility)
BLRID	Boiler identification code
NUMGEN	Number of associated generators
UTILNAME	Operating utility name
UCODE	Operating utility code
EPARGN	EPA Region
CNTYNAME	County name
STATNAM	State name
TOTALPH1	Total basic Phase I allowances (tons) from Table A of the CAA
TOTHT	1985 boiler total heat input (1012 Btu)
SO2	1985 boiler SO2 emissions (tons)
SO2CATEG	Boiler SO2 regulatory category (0=no information, 1=SIP, 2=NSPS D, 3=NSPS Da, 4=NSPS GG, 6=SIP for existing gas turbine, combined cycle with auxiliary firing, 9=NSPS GG for existing gas turbine, combined cycle with auxiliary firing)
SCRUBBER	Boiler SO2 scrubber flag (1=yes, 0=no, 9=no information)
FELIM85	1985 boiler SO2 emission limit (lbs/MMBtu)
ANNFACT	1985 SO2 emission limit annualization factor
AVGPD	1985 SO2 emission limit averaging period
NAMEPCAP	First generator 1989 nameplate capacity (MW)
SUMNDCAP	First generator 1989 summer net dependable capability (MW)
GENMNONL	First generator month on-line
GENYRONL	First generator year on-line
BLRMNONL	Boiler month on-line
BLRYRONL	Boiler year on-line
BASE8587	1985-1987 boiler average total heat input, "baseline" (1012 Btu)
BLROUTGE	Boiler consecutive planned and forced outage time during 1985-1987
PRIMFUEL	Primary fuel indicator based on greatest fuel heat share during 1985-1987 (1=coal>50%, 2=oil/gas)
GAS8089	1980-1989 gas share for non-coal boilers (%)
HEATRATE	First generator 1989 full load heat rate (Btu/kWh)
GENER	First generator 1985 generation (GWh)
UCAPFSST	Total capacity of the fossil-steam units (MW)
MXBS8089	Maximum of the average heat inputs for any combination of three consecutive years, 1980-1989, for selected units (1012 Btu)
RY_ER	Representative year SO2 emission rate (lbs/MMBtu)
FLAGMUNI	Municipally operated flag (1=yes, 0=no)
SO2RTE	1985 boiler SO2 emission rate (lbs/MMBtu)
ANNLIM85	1985 annualized boiler SO2 emission limit (lbs/MMBtu)
HT60	First generator heat input at 60 percent capacity (1012 Btu)
HT60SHR	Boiler share of generator heat input at 60 percent capacity (1012 Btu)
BLRSEQ	Boiler sequence number (If the boiler is in the NADBV311, BLRSEQ=1 - 2913; if not in the NADBV311, then BLRSEQ>=3001)

Table A.26: The Clean Air Act Database Browser (CAADB) – Generator/Boiler Linkage

SEQNUM	PSTATABB	PNAME	ORISPL	BLRID	STRGEN	STRNMP	STRSMC	STRGMN	STRGYR	STROTG	STRHTR	STRGNR	STRH60	STRRET	STRSEQ	BLRSEQ
1997	NV	MOHAVE	2341	1	1	818.10	790.00	12	1970	4320	10217	2309.75	42.423436	0	2229	1641
1998	NV	MOHAVE	2341	2	2	818.10	790.00	7	1971	4853	10452	2317.95	43.399212	0	2230	1642
2192	OH	GEN J M GAVIN	8102	1	1	1300.00	1300.00	7	1974	0	9566	6019.83	65.362565	0	2735	2020
2193	OH	GEN J M GAVIN	8102	2	2	1300.00	1300.00	4	1975	0	9566	6221.54	65.362565	0	2736	2021

SEQNUM	ARDB95 boiler sequence number, after data base sorted by PSTATABB-PNAME-BLRID
PSTATABB	State postal code
PNAME	Plant name
ORISPL	DOE 4-digit ORIS plant code (if utility) or 5-digit facility code (if nonutility)
BLRID	Boiler identification code
STRGEN	Generator identification code multi-generator string
STRNMP	Generator nameplate capacity multi-generator string (MW)
STRSMC	Generator summer net dependable capability multi-generator string (MW)
STRGMN	Generator month on-line multi-generator string
STRGYR	Generator year on-line multi-generator string
STROTG	Generator outage hours multi-generator string
STRHTR	Generator heat rate multi-generator string (Btu/kWh)
STRGNR	Generator generation multi-generator string (GWh)
STRH60	Generator heat input at 60 percent capacity multi-generator string (1012 Btu)
STRRET	Generator retirement year multi-generator string
STRSEQ	Boiler-generator NADBV211 sequence number multi-generator string
BLRSEQ	Boiler sequence number (If the boiler is in the NADBV311, BLRSEQ=1 - 2913; if not in the NADBV311, then BLRSEQ>=3001)

Table A.27: Continuous Emission Monitoring System (CEMS) - SO_2 Mass Emissions – 1 Day, Mohave Plant

ORIS	STACK	YEAR	MONTH	DAY	HOUR	EMIS	ADJEMIS	FORMID	TEMIS
002341	1	96	1	1	0	6009	6393.6	101	
002341	1	96	1	1	1	6010.9	6395.6	101	
002341	1	96	1	1	2	6021.2	6406.6	101	
002341	1	96	1	1	3	6010.8	6395.5	101	
002341	1	96	1	1	4	6016.8	6401.9	101	
002341	1	96	1	1	5	6080.7	6469.9	101	
002341	1	96	1	1	6		6084.2	101	
002341	1	96	1	1	7	6096.5	6486.7	101	
002341	1	96	1	1	8	6124.3	6516.3	101	
002341	1	96	1	1	9	6102.1	6492.6	101	
002341	1	96	1	1	10	6140.8	6533.8	101	
002341	1	96	1	1	11	6138.2	6531	101	
002341	1	96	1	1	12	6144.8	6538.1	101	
002341	1	96	1	1	13	6164.7	6559.2	101	
002341	1	96	1	1	14	6142.1	6535.2	101	
002341	1	96	1	1	15	6138.9	6531.8	101	
002341	1	96	1	1	16	6121.8	6513.6	101	
002341	1	96	1	1	17	6107.8	6498.7	101	
002341	1	96	1	1	18	6083.1	6472.4	101	
002341	1	96	1	1	19	6096.7	6486.9	101	
002341	1	96	1	1	20	6065.5	6453.7	101	
002341	1	96	1	1	21	6082.7	6472	101	
002341	1	96	1	1	22	6056.7	6444.3	101	
002341	1	96	1	1	23	6072.8	6461.5	101	

ORIS	Plant ID
STACK	Unit/Stack/Pipe ID
EMIS	SO_2 mass emission rate for the hour (lb/hr)
ADJEMIS	SO_2 mass emission rate during unit operation based on adjusted values (lb/hr)
FORMID	Formula ID from monitoring plan for hourly SO_2 emissions
TEMIS	Total SO_2 mass emissions for the hour (lb)

Table A.28: Continuous Emission Monitoring System (CEMS) - SO_2 Mass Emissions – 1 Day, Gavin Plant

ORIS	STACK	YEAR	MONTH	DAY	HOUR	EMIS	ADHEMIS	FORMID	TEMIS
008102	1	96	1	1	0	914.3	914.3	401	
008102	1	96	1	1	1	897.6	897.6	401	
008102	1	96	1	1	2	907.1	907.1	401	
008102	1	96	1	1	3	913.7	913.7	401	
008102	1	96	1	1	4	942	942	401	
008102	1	96	1	1	5	911.1	911.1	401	
008102	1	96	1	1	6	875.4	875.4	401	
008102	1	96	1	1	7	834.2	834.2	401	
008102	1	96	1	1	8	824.8	824.8	401	
008102	1	96	1	1	9	821.8	821.8	401	
008102	1	96	1	1	10	862.1	862.1	401	
008102	1	96	1	1	11	860.2	860.2	401	
008102	1	96	1	1	12	864.5	864.5	401	
008102	1	96	1	1	13	810.3	810.3	401	
008102	1	96	1	1	14	760.1	760.1	401	
008102	1	96	1	1	15	785.5	785.5	401	
008102	1	96	1	1	16	801.7	801.7	401	
008102	1	96	1	1	17	826.9	826.9	401	
008102	1	96	1	1	18	781.4	781.4	401	
008102	1	96	1	1	19	770.6	770.6	401	
008102	1	96	1	1	20	806.3	806.3	401	
008102	1	96	1	1	21	804.8	804.8	401	
008102	1	96	1	1	22	802	802	401	
008102	1	96	1	1	23	776.2	776.2	401	

Table A.29: CEMUOP.dbf - Unit Operating and Cumulative Emissions Data – 1 Day, Mohave Plant

ORIS	STACK	YEAR	MONTH	DAY	HOUR	OPTIME	GLOAD	SLOAD	OPLOADRG	HEATINP	FORMID	FFACTOR	DILCAP	THEATINP
002341	1	96	1	1	0	1	767		10	6939.6				
002341	1	96	1	1	1	1	767		10	6941.1				
002341	1	96	1	1	2	1	765		10	6922.6				
002341	1	96	1	1	3	1	768		10	6925.3				
002341	1	96	1	1	4	1	769		10	6926.3				
002341	1	96	1	1	5	1	770		10	6969.4				
002341	1	96	1	1	6	1	770		10	6969.7				
002341	1	96	1	1	7	1	769		10	6979.9				
002341	1	96	1	1	8	1	765		10	6988.8				
002341	1	96	1	1	9	1	765		10	6991.7				
002341	1	96	1	1	10	1	766		10	7009.6				
002341	1	96	1	1	11	1	760		9	6995.2				
002341	1	96	1	1	12	1	758		9	6974.6				
002341	1	96	1	1	13	1	760		9	6998.6				
002341	1	96	1	1	14	1	759		9	6984.2				
002341	1	96	1	1	15	1	760		9	6987.8				
002341	1	96	1	1	16	1	756		9	6966				
002341	1	96	1	1	17	1	765		9	6980.1				
002341	1	96	1	1	18	1	762		9	6949.3				
002341	1	96	1	1	19	1	767		10	6964.5				
002341	1	96	1	1	20	1	767		10	6967.7				
002341	1	96	1	1	21	1	767		10	6973.1				
002341	1	96	1	1	22	1	762		9	6941.9				
002341	1	96	1	1	23	1	769		10	6965.5				

ORIS	Plant ID
STACK	Unit/Stack/Pipe ID
OPTIME	Unit operating time (0.00-1.00)
GLOAD	Gross unit load during unit operation (MW)
SLOAD	Steam load during unit operation (1000 lb/hr)
OPLOADRG	Operating load range corresponding to gross load during unit operation (01-20)
HEATINP	Hourly heat input rate during unit operation for all fuels (mmBtu/hr)
FORMID	Heat input formula ID
FFACTOR	F-factor for heat input calculation
DILCAP	Use of diluent cap for heat input calculation for this hour (Y-cap used)
THEATINP	Total heat input for the hour (mmBtu)

Table A.30: CEMUOP.dbf - Unit Operating and Cumulative Emissions Data – 1 Day, Gavin Plant

ORIS	STACK	YEAR	MONTH	DAY	HOUR	OPTIME	GLOAD	SLOAD	OPLOADRG	HEATINP	FORMID	FFACTOR	DILCAP	THEATINP
008102	1	96	1	1	0	1	601	0	5	7292.4				
008102	1	96	1	1	1	1	601	0	5	7316				
008102	1	96	1	1	2	1	601	0	5	7388				
008102	1	96	1	1	3	1	601	0	5	7337.1				
008102	1	96	1	1	4	1	601	0	5	7180.3				
008102	1	96	1	1	5	1	601	0	5	7329.5				
008102	1	96	1	1	6	1	601	0	5	7295.2				
008102	1	96	1	1	7	1	601	0	5	7240.2				
008102	1	96	1	1	8	1	601	0	5	7190.2				
008102	1	96	1	1	9	1	601	0	5	7180.1				
008102	1	96	1	1	10	1	601	0	5	7245.6				
008102	1	96	1	1	11	1	601	0	5	7235.6				
008102	1	96	1	1	12	1	600	0	5	7279.9				
008102	1	96	1	1	13	1	600	0	5	7271.5				
008102	1	96	1	1	14	1	601	0	5	7177.9				
008102	1	96	1	1	15	1	600	0	5	7177.9				
008102	1	96	1	1	16	1	601	0	5	7195				
008102	1	96	1	1	17	1	600	0	4	7267.4				
008102	1	96	1	1	18	1	600	0	4	7189.7				
008102	1	96	1	1	19	1	601	0	5	7091.6				
008102	1	96	1	1	20	1	601	0	5	7206.5				
008102	1	96	1	1	21	1	601	0	5	7253.9				
008102	1	96	1	1	22	1	601	0	5	7231.4				
008102	1	96	1	1	23	1	601	0	5	7282.9				

Table A.31: SO_2 Emissions Trading (AUCTIONPROCEEDS.dbf)

YEAR OF AUCTION	USE YEAR	DESCRIPTION	ORISPL	PLANT NAME	STATE	REPRESENTATIVE	PAYEE	ACCOUNT	PROCEEDS
1996	1996	March 1996 auction of year 1996 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000001	$159,660.42
1996	1996	March 1996 auction of year 1996 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000002	$162,658.73
1996	2002	March 1996 auction of year 2002 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000001	$6,287.57
1996	2002	March 1996 auction of year 2002 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000002	$6,405.21
1996	2003	March 1996 auction of year 2003 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000001	$24,708.96
1996	2003	March 1996 auction of year 2003 allowances	8102	Gen J M Gavin	OH	McManus, John	Ohio Power Co	008102000002	$25,171.29
1996	2002	March 1996 auction of year 2002 allowances	2341	Mohave	NV	Fielder, John	Queen City Investments,Inc.	002341000001	$4,947.70
1996	2002	March 1996 auction of year 2002 allowances	2341	Mohave	NV	Fielder, John	Queen City Investments,Inc.	002341000002	$4,921.56
1996	2003	March 1996 auction of year 2003 allowances	2341	Mohave	NV	Fielder, John	Queen City Investments,Inc.	002341000001	$19,443.54
1996	2003	March 1996 auction of year 2003 allowances	2341	Mohave	NV	Fielder, John	Queen City Investments,Inc.	002341000002	$19,340.80

Table A.32: SO_2 Emissions Trading Types (TR-TYPE.dbf)

Type	Tran	BUYACC	BUYNAME	BUYTY	BUYUTNME	SELLACC	SELLNAME	SELLTY	SELLUTNAME	Full_Amt
Intra	28030	2828000001	Cardinal			8102000001	Gen J M Gavin			578
Inter	2160	999900000016		GA		008102000002	Gen J M Gavin	UA	OHIO POWER CO	80000
Intra - oc	2166	008102000001	Gen J M Gavin	UA	OHIO POWER CO	008102000002	Gen J M Gavin	UA	OHIO POWER CO	56000
Intra - hc	6128	002828000001	Cardinal	UA	CARDINAL CO	008102000001	Gen J M Gavin	UA	OHIO POWER CO	38056
Realloc	10063	999900000261	Appalachian Power Company	GA		008102000001	Gen J M Gavin	UA	OHIO POWER CO	40105
Realloc	4588	999900000005		GA		008102000002	Gen J M Gavin	UA	OHIO POWER CO	279986
R	37672	999900000262	Columbus Southern Power Co.	GA		008102000002	Gen J M Gavin	UA	OHIO POWER CO	20266
B to U	27061	008102000001	Gen J M Gavin		OHIO POWER CO	999900000362	CONSOL Inc.			45063
R	42552	999900000246	SRP GENERAL			2341000001	Mohave			635

Table A.33: Meteorological Data (METEOROLOGY.dbf)

STN	YEAR	MODA	TEMP	DEWP	SLP	STP	VISIB	WDSP	MXSPD	GUST	MAX	MIN	PRCP	SNDP	FRSHTT
10010	1996	101	27	24.3	1022.4	1021.2	8.3	5.4	12	999.9	32.9	19	0.02	999.9	1000
10010	1996	102	25	19.6	1020.7	1019.4	25.9	6.1	27	999.9	32.4	20.1	0	999.9	0
10010	1996	103	24	19.4	1017.1	1015.9	20.6	4.7	19	999.9	34	18.9	0	999.9	100000
10010	1996	104	22.7	16.7	1018.3	1017	45.1	4.6	12	999.9	29.1	16.5	0	999.9	0
10010	1996	105	25.2	21.4	1014.2	1013	7.2	14.1	28	999.9	30.6	15.8	0	999.9	1000

STN Station number (WMO/DATSAV3 number)For the location.

YEAR The year.

MODA The month and day.

TEMP Mean temperature for the day in degrees Fahrenheit to tenths. Missing = 9999.9 (Celsius to tenths for metric version.)

DEWP Mean dew point for the day in degrees Fahrenheit to tenths. Missing = 9999.9 (Celsius to tenths for metric version.)

SLP Mean sea level pressure for the day in millibars to tenths. Missing = 9999.9

STP Mean station pressure for the day In millibars to tenths. Missing = 9999.9

VISIB Mean visibility for the day in miles to tenths. Missing = 999.9 (Kilometers to tenths for metric version.)

WDSP Mean wind speed for the day in knots to tenths. Missing = 999.9 (Meters/second to tenths for metric version.)

MXSPD Maximum sustained wind speed reported for the day in knots to tenths. Missing = 999.9 (Meters/second to tenths for metric version.)

GUST Maximum wind gust reported for the day in knots to tenths. Missing = 999.9 (Meters/second to tenths for metric version.)

MAX Maximum temperature reported during the day in Fahrenheit to tenths--time of max temp report varies by country and region, so this will sometimes not be the max for the calendar day. Missing = 9999.9 (Celsius to tenths for metric version.)

MIN Minimum temperature reported during the day in Fahrenheit to tenths--time of min temp report varies by country and region, so this will sometimes not be the min for the calendar day. Missing = 9999.9 (Celsius to tenths for metric version.)

PRCP total precipitation (rain and/or melted snow) reported during the day in inches and hundredths; will usually not end with the midnight observation--i.e., may include latter part of previous day. .00 indicates no measurable Precipitation (includes a trace). Missing = 99.99 (For metric version, units = millimeters to tenths & missing = 999.9.) Note: Many stations do not report '0' on days with no precipitation--therefore, '99.99' will often appear on these days. Also, for example, a station may only report a 6-hour amount for the period during which rain fell. See Flag field for source of data.

SNDP Snow depth in inches to tenths—last report for the day if reported more than once. Missing = 999.9 (Centimeters to tenths for metric version.) Note: Most stations do not report '0' on days with no snow on the ground--therefore, '999.9' will often appear on these days.

FRSHTT Indicators (1 = yes, 0 = no/not reported) for the occurrence during the day of:
Fog ('F' - 1st digit).
Rain or Drizzle ('R' - 2nd digit).
Snow or Ice Pellets ('S' - 3rd digit).
Hail ('H' - 4th digit).
Thunder ('T' - 5th digit).
Tornado or Funnel Cloud ('T' - 6th digit).

APPENDIX B

SAS PROGRAMMING FOR DATA PREPARATION

Program B.1: SAS Program for FERC Form-423

```
*-------------------
DATA BASE FERC-423
-------------------
-----------------------------------------------------------------------------------
PROGRAM NAME: FERC423.SA2. THIS PROGRAM READS THE DATA FILE FERC423.DA1 CREATED BY
PROGRAM FERC423.SA1. THIS FILE INCLUDES MONTHLY FUEL SHIPMENTS BY POWER PLANTS OVER THE
PERIOD 1996-2000, IN PHYSICAL QUANTITIES, BTU CONTENTS, SULFUR CONTENTS, AND COSTS.
*-----------------------------------------------------------------------------------;
DATA SHIP; INFILE 'C:\TK_KIM\423\F423_SA1\FERC423.DA1' MISSOVER;
       INPUT  CCODE 1-6 /*COMPANY CODE*/
              PCODE 7-10 /*PLANT CODE*/
              YEAR 11-14 /*YEAR*/
              MONTH 15-16 /*MONTH*/
              ORST 17-18 /*STATE OF ORIGIN*/
              PLREG 19-20 /*LOCATION OF PLANT-REGION*/
              PLST 21-22 /*LOCATION OF PLANT-STATE*/
              GFUEL 23 /*GENERIC FUEL-1: SOLID, 2: LIQUID, 3: GAS*/
              SFUEL $ 24-26 /*SPECIFIC FUEL-BIT/SUB/FO2/FO6 ETC.*/
              QTY 27-34 /*QUANTITY-COAL: TONS, OIL: BARRELS, GAS: 1000 CUBIC FEET*/
              BTU 35-41 /*BTU CONTENT-PER LB/GALLON/CUBIC FEET*/
              SULF 42-45 2 /*SULFUR CONTENT-PERCENT BY WEIGHT*/
              ASH 46-50 2 /*ASH CONTENT-PERCENT BY WEIGHT*/
              COST 51-56 2 /*CENTS/MMBTU*/
              UNIT 57 /*UNIT TYPE-1: STEAM*/;

*-----
 COAL
-----;
       IF GFUEL=1 THEN DO;
              CQTY=QTY; /* COAL, QUANTITY - SHORT TON */
              CBTU=BTU*QTY*2/1000; /* COAL, QUANTITY - MMBTU */
              CSULFT=(SULF/100)*QTY; /* COAL, SULFUR QUANTITY - SHORT TON */
              CSULFP=(SULF/100)*QTY*2000; /* COAL, SULFUR QUANTITY - POUNDS */
              CCOST=COST*CBTU; /* COAL, COSTS (CENTS) */
       END;
*----------
 PETROLEUM
----------;
       IF GFUEL=2 THEN DO;
              PQTY=QTY; /* PETROLEUM, QUANTITY - BARREL */
              PBTU=BTU*QTY*(42/1000)/1000; /* PETROLEUM, QUANTITY - MMBTU */
              PSULFT=(SULF/100)*QTY; /* PETROLEUM, SULFUR QUANTITY - BARRELS */
              PSULFP=(SULF/100)*QTY*0.226*2000; /* PET, SULFUR QUANTITY- POUNDS */
              PCOST=COST*PBTU; /* PETROLEUM, COSTS (CENTS) */
       END;
*------------
 NATURAL GAS
------------;
       IF GFUEL=3 THEN DO;
              GQTY=QTY; /* NATURAL GAS, QUANTITY - 1000 CUBIC FT. */
              GBTU=BTU*QTY/1000; /* NATURAL GAS, QUANTITY - MMBTU */
```

```
                GCOST=GBTU*COST; /* NATURAL GAS, COSTS (CENTS) */
        END;

        PROC SORT; BY PCODE YEAR MONTH;
        PROC MEANS NOPRINT SUM;
                VAR CQTY PQTY GQTY CBTU PBTU GBTU
                        CSULFT CSULFP PSULFT PSULFP
                        CCOST PCSOT GCOST;
                BY PCODE YEAR MONTH;
        OUTPUT OUT=SHIPSUM
                SUM=CQTY_S PQTY_S GQTY_S CBTU_S PBTU_S GBTU_S
                        CSULFT_S CSULFP_S PSULFT_S PSULFP_S
                        CCOST_S PCOST_S GCOST_S;

*-------------------
UNIT SHIPMENT DATA
-------------------;
DATA UNIT_S; SET SHIPSUM;
        IF CQTY_S>0 THEN DO;
                UCBTU_S=CBTU_S*1000/(CQTY_S*2); /* COAL-UNIT BTU (PER POUND) */
                UCST_S=(CSULFT_S*100)/CQTY_S; /* COAL-UNIT SULFUR CONTENT (% BY WEIGHT) */
        END;

        IF CBTU_S>0 THEN DO;
                UCSP_S=CSULFP_S/CBTU_S; /*COAL-UNIT SULFUR (POUND/MMBTU)*/
                UCSO2_S=CSULFP_S*2/CBTU_S; /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
                UCCOST_S=CCOST_S/CBTU_S; /* COAL - UNIT COSTS (CENTS/MMBTU) */
        END;

        IF PQTY_S>0 THEN DO;
                UPBTU_S=(PBTU_S*1000*1000)/(PQTY_S*42); /* PET-UNIT BTU (PER GALLON) */
                UPST_S=(PSULFT_S*100)/PQTY_S; /* PET-UNIT SULFUR CONTENT (% BY WEIGHT) */
        END;

        IF PBTU_S>0 THEN DO;
                UPSP_S=PSULFP_S/PBTU_S; /*PET-UNIT SULFUR (POUND/MMBTU)*/
                UPSO2_S=PSULFP_S*2/PBTU_S; /*PET-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
                UPCOST_S=PCOST_S/PBTU_S; /* PET - UNIT COSTS (CENTS/MMBTU) */
        END;

        IF GQTY_S>0 THEN DO;
                UGBTU_S=GBTU_S*1000/GQTY_S; /* NG - UNIT BTU (PER CUBIC FT.) */
        END;

        IF GBTU_S>0 THEN DO;
                UGCOST_S=GCOST_S/GBTU_S; /* NG - UNIT COSTS (CENTS/MMBTU) */
        END;

*----------------------------------
TOTAL AND UNIT VARIABLES ARE MERGED
----------------------------------;
DATA MERSHIP; MERGE SHIPSUM UNIT_S; BY PCODE YEAR MONTH;

/*
```

```
*----------------
VARIABLE LENGTHS
----------------;
        PROC MEANS N MIN MAX;
                VAR PCODE YEAR MONTH
                CQTY_S PQTY_S GQTY_S
                CBTU_S PBTU_S GBTU_S
                CSULFT_S CSULFP_S PSULFT_S PSULFP_S
                CCOST_S PCOST_S GCOST_S
                UCBTU_S UPBTU_S UGBTU_S
                UCST_S UCSP_S UPST_S UPSP_S UCSO2_S UPSO2_S
                UCCOST_S UPCOST_S UGCOST_S;
*/

*------------------------------
CREATED DATA BASE: FERC423.DA2.
------------------------------;
DATA _NULL_; SET MERSHIP; FILE 'C:\TK_KIM\423\F423_SA2\FERC423.DA2';
        INPUT   PCODE 1-4
                YEAR 5-8
                MONTH 9-10
                CQTY_S 11-20 2 /*COAL-QUANTITY (SHORT TON)*/
                PQTY_S 21-30 2 /*PETROLEUM-QUANTITY (BARREL)*/
                GQTY_S 31-41 2 /*NATURAL GAS-QUANTITY (1000 CUBIC FT.)*/
                CBTU_S 42-52 2 /*COAL-QUANTITY (MMBTU)*/
                PBTU_S 53-63 2 /*PETROLEUM-QUANTITY (MMBTU)*/
                GBTU_S 64-74 2 /*NATURAL GAS-QUANTITY (MMBTU)*/
                CSULFT_S 75-82 2 /*COAL-SULFUR QUANTITY (SHORT TON)*/
                CSULFP_S 83-93 2 /*COAL-SULFUR QUANTITY (POUNDS)*/
                PSULFT_S 94-101 2 /*PETROLEUM-SULFUR QUANTITY (BARRELS)*/
                PSULFP_S 102-112 2 /*PETROLEUM-SULFUR QUANTITY (POUNDS)*/
                CCOST_S 113-125 2 /*COAL-COSTS (CENTS)*/
                PCOST_S 126-138 2 /*PETROLEUM-COSTS (CENTS)*/
                GCOST_S 139-151 2 /*NATURAL GAS-COSTS (CENTS)*/
                UCBTU_S 152-160 2 /*COAL-UNIT BTU (PER POUND)*/
                UPBTU_S 161-169 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
                UGBTU_S 170-177 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
                UCST_S 178-181 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
                UCSP_S 182-185 2 /*COAL-UNIT SULFUR (POUND/MMBTU)*/
                UPST_S 186-189 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
                UPSP_S 190-194 2 /*PETROLEUM-UNIT SULFUR (POUND/MMBTU)*/
                UCSO2_S 195-199 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
                UPSO2_S 200-204 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
                UCCOST_S 205-210 2 /*COAL-UNIT COSTS (CENTS/MMBTU)*/
                UPCOST_S 211-217 2 /*PETROLEUM-UNIT COSTS (CENTS/MMBTU) */
                UGCOST_S 218-225 2 /*NATURAL GAS-UNIT COSTS (CENTS/MMBTU)*/;

RUN;
```

Program B.2: SAS Programs for Form EIA-767

```
*------------------------
DATA BASE EIA-767 (BAIR)
-------------------------
------------------------------------------------------------------------------------------
PROGRAM NAME: BAIR767.SA1. THIS PROGRAM READS THE DATA FILE BAIR.TXT CREATED BY AN
ACCESS PROGRAM (BAIR.MDB). THIS FILE INCLUDES ANNUAL SO2 EMISSION STANDARDS.
------------------------------------------------------------------------------------------;
DATA BAIR; INFILE 'G:\TK_KIM\767\BAIR\BAIR.TXT';
       INPUT  PCODE 1-4
              BOIL $ 5-14
              YEAR 15-18
              SO2ST1 19-26 2 /*SULFUR DIOXIDES EMISSION STANDARD PART 1*/
              SO2ST2 27-33 2 /*SULFUR DIOXIDES EMISSION STANDARD PART 2*/
              STYEAR 34-37; /*Year Boiler was to be in Compliance-Sulfur Dioxide*/

              SO2ST=SO2ST1+SO2ST2;

DATA BAIR2; SET BAIR;
       PROC SORT; BY PCODE YEAR;
       PROC MEANS NOPRINT SUM; VAR SO2ST; BY PCODE YEAR;
       OUTPUT OUT=BAIROUT SUM=SO2ST;

/*
DATA LENGTH; SET BAIROUT;
       PROC MEANS N MIN MAX;
*/

DATA _NULL_; SET BAIROUT; FILE 'G:\TK_KIM\767\BAIR\BAIR767.DA1';
       PUT    PCODE 1-4
              YEAR 5-8
              SO2ST 9-17 2 /*ANNUAL SO2 EMISSION STANDARD*/;

RUN;


*------------------------
DATA BASE EIA-767 (BFUEL)
-------------------------
------------------------------------------------------------------------------------------
PROGRAM NAME: BFUEL767.SA1. THIS PROGRAM READS THE DATA FILE BFUEL767.TXT CREATED BY AN
ACCESS PROGRAM (BFUEL.MDB). THIS FILE INCLUDES MONTHLY FUEL CONSUMPTIONS BY POWER PLANTS
OVER THE PERIOD 1996-2000, IN BOTH PHYSICAL TERMS AND BTU CONTENTS AS WELL AS THE SULFUR
CONTENTS OF COAL AND PETROLEUM.
------------------------------------------------------------------------------------------;
DATA BOILER; INFILE 'C:\TK_KIM\767\BFUEL\BFUEL767.TXT' MISSOVER LRECL=1000;
       INPUT  PCODE 1-4
              YEAR 5-8
       /* COAL QUANTITIES - 1000 SHORT TONS */
              CO1 9-13 1 CO2 14-18 1 CO3 19-23 1 CO4 24-28 1
              CO5 29-33 1 CO6 34-38 1 CO7 39-43 1 CO8 44-48 1
              CO9 49-53 1 CO10 54-58 1 CO11 59-63 1 CO12 64-68 1
       /* PETROLEUM QUANTITIES - 1000 BARRELS */
```

```
            PE1 69-73 1 PE2 74-78 1 PE3 79-83 1 PE4 84-88 1
            PE5 89-93 1 PE6 94-98 1 PE7 99-103 1 PE8 104-108 1
            PE9 109-113 1 PE10 114-118 1 PE11 119-123 1 PE12 124-128 1
        /* NATURAL GAS QUANTITIES - MMCF */
            GA1 129-135 1 GA2 136-141 1 GA3 142-147 1 GA4 148-153 1
            GA5 154-159 1 GA6 160-165 1 GA7 166-171 1 GA8 172-177 1
            GA9 178-183 1 GA10 184-189 1 GA11 190-195 1 GA12 196-202 1
        /* COAL HEAT CONTENT - BTU/POUND */
            HC1 203-207 HC2 208-212 HC3 213-217 HC4 218-222
            HC5 223-227 HC6 228-232 HC7 233-237 HC8 238-242
            HC9 243-247 HC10 248-252 HC11 253-257 HC12 258-262
        /* COAL SULFUR CONTENT - % BY WEIGHT */
            SC1 263-266 2 SC2 267-270 2 SC3 271-274 2 SC4 275-278 2
            SC5 279-282 2 SC6 283-286 2 SC7 287-290 2 SC8 291-294 2
            SC9 295-298 2 SC10 299-302 2 SC11 303-306 2 SC12 307-310 2
        /* PETROLEUM HEAT CONTENT - BTU/US GALLON */
            HP1 311-316 HP2 317-322 HP3 323-328 HP4 329-334
            HP5 335-340 HP6 341-346 HP7 347-352 HP8 353-358
            HP9 359-364 HP10 365-370 HP11 371-376 HP12 377-382
        /* PETROLEUM SULFUR CONTENT - % BY WEIGHT */
            SP1 383-386 2 SP2 387-390 2 SP3 391-394 2 SP4 395-398 2
            SP5 399-402 2 SP6 403-406 2 SP7 407-410 2 SP8 411-414 2
            SP9 415-418 2 SP10 419-422 2 SP11 423-426 2 SP12 427-430 2
        /* NATURAL GAS HEAT CONTENT - BTU/CUBIC FT. */
            HG1 431-434 HG2 435-438 HG3 439-442 HG4 443-446
            HG5 447-450 HG6 451-454 HG7 455-458 HG8 459-462
            HG9 463-466 HG10 467-470 HG11 471-474 HG12 475-478;
            IX=1;

/*
*--------------------
MISSING VALUE COUNTS
--------------------;
        PROC MEANS DATA=BOILER N NMISS;
            VAR CO1-CO12 PE1-PE12 GA1-GA12
                HC1-HC12 SC1-SC12 HP1-HP12 SP1-SP12 HG1-HG12;
*/

DATA CONV; SET BOILER;
        /* ARRAY FOR FUEL QUANTITIES - 1000 SHORT TONS/1000 BARRELS/MMCF) */
            ARRAY ACO CO1-CO12;
            ARRAY APE PE1-PE12;
            ARRAY AGA GA1-GA12;
        /* ARRAY FOR HEAT CONTENT - BTUS PER POUND/GALLON/CUBIC FT. */
            ARRAY AHC HC1-HC12;
            ARRAY AHP HP1-HP12;
            ARRAY AHG HG1-HG12;
        /* ARRAY FOR SULFUR CONTENT - % BY WEIGHT */
            ARRAY ASC SC1-SC12;
            ARRAY ASP SP1-SP12;
        /* RESERVED SPACES FOR COAL/PET/NG QUANTITIES-SHORT TONS/BARRELS/1000 CUBIC FT.*/
            ARRAY QCTY QCO1-QCO12;
            ARRAY QPTY QPE1-QPE12;
            ARRAY QGTY QGA1-QGA12;
```

```
        /* RESERVED SPACES FOR MMBTUS */
               ARRAY AMBCO MBCO1-MBCO12;
               ARRAY AMBPE MBPE1-MBPE12;
               ARRAY AMBGA MBGA1-MBGA12;
        /* RESERVED SPACES FOR AMOUNTS OF SULFUR - COAL/PET (SHORT TONS/BARRELS) */
               ARRAY SCO SCO1-SCO12;
               ARRAY SPE SPE1-SPE12;
        /* RESERVED SPACE FOR SO2 GROSS EMISSIONS - POUND (1 BARREL=0.226 SHORT TON) */
               ARRAY S2CO S2CO1-S2CO12;
               ARRAY S2PE S2PE1-S2PE12;

        DO OVER ACO;
               QCTY=ACO*1000; /*SHORT TON*/
               QPTY=APE*1000; /*BARRELS*/
               QGTY=AGA*1000; /*MCF*/

               AMBCO=QCTY*AHC*2/1000; /*COAL QUANTITY IN MMBTU*/
               AMBPE=QPTY*AHP*(42/1000)/1000; /*PETROLEUM QUANTITY IN MMBTU*/
               AMBGA=QGTY*AHG/1000; /*NATURAL GAS QUANTITY IN MMBTU*/

               SCO=(ASC/100)*QCTY; /*COAL SULFUR QUANTITY - SHORT TON*/
               SPE=(ASP/100)*QPTY; /*PETROLEUM SULFUR QUANTITY - BARRELS*/

               S2CO=2*(ASC/100)*QCTY*2000; /*COAL-POUNDS OF SO2*/
               S2PE=2*(ASP/100)*QPTY*0.226*2000; /*PETROLEUM-POUNDS OF SO2*/
        END;

*------------------------------------------------
DATA STRUCTURE CHANGE - HORIZONTAL TO VERTICAL.
-----------------------------------------------;
DATA LOOP; SET CONV;
        MONTH=0;
        DROP QCO1-QCO12 QPE1-QPE12 QGA1-QGA12
               MBCO1-MBCO12 MBPE1-MBPE12 MBGA1-MBGA12
               SCO1-SCO12 SPE1-SPE12 S2CO1-S2CO12 S2PE1-S2PE12;
        ARRAY XCTY QCO1-QCO12;
        ARRAY XPTY QPE1-QPE12;
        ARRAY XGTY QGA1-QGA12;
        ARRAY XMBCO MBCO1-MBCO12;
        ARRAY XMBPE MBPE1-MBPE12;
        ARRAY XMBGA MBGA1-MBGA12;
        ARRAY XSCO SCO1-SCO12;
        ARRAY XSPE SPE1-SPE12;
        ARRAY XS2CO S2CO1-S2CO12;
        ARRAY XS2PE S2PE1-S2PE12;

        DO OVER XCTY;
               MONTH=MONTH+1;
        /* COAL/PET/NG QUANTITIES - SHORT TONS/BARRELS/1000 CUBIC FT. */
               CQTY_C=XCTY;
               PQTY_C=XPTY;
               GQTY_C=XGTY;
        /* MMBTUS (COAL/PETROLEUM/NATURAL GAS) */
               CMBTU_C=XMBCO;
```

```
                PMBTU_C=XMBPE;
                GMBTU_C=XMBGA;
        /* AMOUNTS OF SULFUR - COAL/PET (SHORT TONS/BARRELS) */
                CSULF_C=XSCO;
                PSULF_C=XSPE;
        /* SO2 GROSS EMISSIONS - POUND */
                CSO2_C=XS2CO;
                PSO2_C=XS2PE;
        OUTPUT;
        END;

        PROC SORT; BY PCODE YEAR MONTH;
        PROC MEANS NOPRINT SUM;
                VAR CQTY_C PQTY_C GQTY_C CMBTU_C PMBTU_C GMBTU_C
                        CSULF_C PSULF_C CSO2_C PSO2_C;
                BY PCODE YEAR MONTH;
        OUTPUT OUT=SUMS
                SUM=CQTY_C PQTY_C GQTY_C CMBTU_C PMBTU_C GMBTU_C
                        CSULF_C PSULF_C CSO2_C PSO2_C;

*-------------------------
UNIT FUEL CONSUMPTION DATA
-------------------------;
DATA UNIT_C; SET SUMS;
        IF CQTY_C>0 THEN DO;
                UCBTU_C=CMBTU_C*1000/(CQTY_C*2); /*COAL-UNIT BTU (PER POUND)*/
                UCSULF_C=(CSULF_C*100)/CQTY_C; /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
        END;

        IF PQTY_C>0 THEN DO;
                UPBTU_C=(PMBTU_C*1000*1000)/(PQTY_C*42); /*PET-UNIT BTU (PER GALLON)*/
                UPSULF_C=(PSULF_C*100)/PQTY_C; /*PET-UNIT SULFUR CONTENT (% BY WEIGHT)*/
        END;

        IF GQTY_C>0 THEN DO;
                UGBTU_C=GMBTU_C*1000/GQTY_C; /* NG - UNIT BTU (PER CUBIC FT.) */
        END;

        IF CMBTU_C>0 THEN DO;
                UCSO2_C=CSO2_C/CMBTU_C; /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
        END;

        IF PMBTU_C>0 THEN DO;
                UPSO2_C=PSO2_C/PMBTU_C; /*PET-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
        END;

        PROC SORT; BY PCODE YEAR MONTH;

DATA MER; MERGE SUMS UNIT_C; BY PCODE YEAR MONTH;

/*
*--------------------
VARIABLE LENGTHS
--------------------;
```

```
PROC MEANS N MIN MAX;
       VAR PCODE YEAR MONTH CQTY_C PQTY_C GQTY_C CMBTU_C PMBTU_C GMBTU_C CSULF_C PSULF_C
              CSO2_C PSO2_C UCBTU_C UPBTU_C UGBTU_C UCSULF_C UPSULF_C UCSO2_C UPSO2_C;
*/

*-------------------------------
CREATED DATA BASE: BFUEL767.DA3
-------------------------------;
DATA _NULL_; SET MER; FILE 'C:\TK_KIM\767\BFUEL\BFUEL767.DA1';
       PUT    PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              CQTY_C 11-20 2 /*COAL QUANTITIES-SHORT TONS*/
              PQTY_C 21-30 2 /*PETOLEUM QUANTITIES-BARRELS*/
              GQTY_C 31-41 2 /*NATURAL GAS QUANTITIES-1000 CUBIC FT.*/
              CMBTU_C 42-52 2 /*COAL QUANTITY IN MMBTU*/
              PMBTU_C 53-62 2 /*PETROLEUM QUANTITY IN MMBTU*/
              GMBTU_C 63-73 2 /*NATURAL GAS QUANTITY IN MMBTU*/
              CSULF_C 74-81 2 /*COAL SULFUR QUANTITY - SHORT TON*/
              PSULF_C 82-89 2 /*PETROLEUM SULFUR QUANTITY - BARRELS*/
              CSO2_C 90-101 2 /*COAL-POUNDS OF SO2*/
              PSO2_C 102-112 2 /*PETROLEUM-POUNDS OF SO2*/
              UCBTU_C 113-120 2 /*COAL-UNIT BTU (PER POUND)*/
              UPBTU_C 121-129 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
              UGBTU_C 130-136 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
              UCSULF_C 137-140 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
              UPSULF_C 141-144 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
              UCSO2_C 145-148 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
              UPSO2_C 149-152 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/;

RUN;


*-------------------------
DATA BASE EIA-767 (GINFO)
-------------------------
-------------------------------------------------------------------------------------
PROGRAM NAME: GINFO767.SA1. THIS PROGRAM READS THE DATA FILE GINFO767.TXT CREATED BY
ACCESS PROGRAM (GINFO.MDB). THIS FILE INCLUDES MONTHLY NET ELECTRICITY GENERATION (KW) BY
POWER PLANTS OVER THE PERIOD 1996-2000.
-------------------------------------------------------------------------------------;
DATA GEN; INFILE 'C:\TK_KIM\767\GINFO\GINFO767.TXT' MISSOVER;
       INPUT  PCODE 1-4
              GENCODE $ 5-10
              YEAR 11-14
       /* MONTHLY NET ELECTRICITY GENERATION, JAN-DEC */
              GE1 15-23 GE2 24-32 GE3 33-41 GE4 42-50 GE5 51-59 GE6 60-68
              GE7 69-77 GE8 78-86 GE9 87-95 GE10 96-104 GE11 105-113 GE12 114-122; IX=1;

*--------------------------------------------
DATA STRUCTURE CHANGE - HORIZONTAL TO VERTICAL.
--------------------------------------------;
       MONTH=0;
       DROP GE1-GE12;
```

```
        ARRAY XGE GE1-GE12;
        DO OVER XGE;
                MONTH=MONTH+1;
                GEN=XGE/1000; /*CHANGE TO MW FROM KW*/
        OUTPUT;
        END;

        PROC SORT; BY PCODE YEAR MONTH;
        PROC MEANS NOPRINT SUM; VAR GEN; BY PCODE YEAR MONTH;
        OUTPUT OUT=GENOUT SUM=GEN_C;

/*
*----------------
VARIABLE LENGTHS
----------------;
        PROC MEANS N MIN MAX; VAR PCODE YEAR MONTH GEN_C;
*/

*------------------------------
CREATED DATA BASE: GINFO767.DA1
-------------------------------;
DATA _NULL_; SET GENOUT; FILE 'C:\TK_KIM\767\GINFO\GINFO767.DA1';
        PUT     PCODE 1-4
                YEAR 5-8
                MONTH 9-10
                GEN_C 11-17; /*MONTHLY NET ELECTRICITY GENERATION (kWh)-VERTICAL*/

RUN;


*---------------
DATABASE - FGD
----------------
-----------------------------------------------------------------------------------------
PROGRAM NAME: RDES.SA1. THIS PROGRAM READS DATA FILES RAN767 AND RDE767 TO CREATE DATA
FOR FGD INFORMATION.
-----------------------------------------------------------------------------------------;
DATA RAN767; INFILE "G:\TK_KIM\767\RAN.TXT";
        INPUT   PCODE 1-4
                SCRUB $ 5-10
                YEAR 11-14
                EFSULFUR 15-19 1 /*REMOVAL EFFICIENCY AT ANNUAL OP FACTOR-% BY WEIGHT*/
                EF100 20-24 1 /*REMOVAL EFFICIENCY AT 100% LOAD OR TESTED-% BY WEIGHT*/
                TESTDATE 25-28 /*DATE OF MOST RECENT EFFICIENCY TEST*/
                INSRVHR 29-32 /*TOTAL HOURS INSEREVICE DURING YEAR-HOUR*/
                FGDSORB 33-38 1 /*QUANTITY FGD SORBENT USED DURING YEAR-1000 SHORT TON*/
                EEC 39-47 /*ELECTRICAL ENERGY CONSUMPTION DURING YEAR -KWHOURS*/
                CTFEED 48-52 /*FGD O&M EXPENDITURES-FEED MATERIALS AND CHEMICALS-$1000*/
                CTLABOR 53-56 /*FGD O&M EXPENDITURES-LABOR AND SUPERVISION-$1000*/
                CTDISP 57-60 /*FGD O&M EXPENDITURES-WASTE DISPOSAL-$1000*/
                CTMAIN 61-65 /*FGD O&M EXPENDITURES-MAINTENANCE MATERIALS/OTHERS-$1000*/
                CTTOT 66-70 /*TOTAL COST-$1000*/
                EC 71 /*EQUIPMENT COUNT*/;
```

```
        PROC SORT; BY PCODE YEAR;

DATA RAN767Q; SET RAN767;
        PROC MEANS NOPRINT SUM;
                VAR INSRVHR FGDSORB EEC CTFEED CTLABOR CTDISP CTMAIN CTTOT;
                BY PCODE YEAR;
        OUTPUT OUT=QQ1
                SUM=INSRVHR FGDSORB EEC CTFEED CTLABOR CTDISP CTMAIN CTTOT;

DATA RAN767A; SET RAN767;
        PROC MEANS NOPRINT MEAN;
                VAR EFSULFUR EF100;
                BY PCODE YEAR;
        OUTPUT OUT=AA1
                MEAN=EFSULFUR EF100;

DATA RDE767; INFILE "G:\TK_KIM\767\RDE.TXT";
        INPUT   PCODE 1-4
                SCRUB $ 5-10
                YEAR 11-14
                INSRVDD 15-18 /*FGD UNIT ACTUAL OR PROJECTED INSERVICE DATE*/
                SPECASH 19-22 1 /*DESIGN FUEL SPECS/COAL-ASH-% BY WEIGHT*/
                SPECSULF 23-25 1 /*DESIGN FUEL SPECS/COAL-SULFUR-% BY WEIGHT*/
                TRAINTOT 26-27 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-TOTAL*/
                TRAIN100 28-30 /* " -OPERATED AT 100% LOAD*/
                WASTESAL 31-34 /*EST. FGD WASTE AND SALABLE BYPRODUCTS-1000 SHORT TONS*/
                PONDLAND 35-38 /*ANNUAL POND AND LAND FILL REQUIREMENTS-ACRE-FOOT/YEAR*/
                SPECRE 39-42 1 /*REMOVAL EFFICIENCY-UNIT AT 100% GEN LOAD-% BY WEIGHT*/
                SPECER 43-46 /*SO2 EMISSION RATE-UNIT AT 100% GEN LOAD-POUNDS/HOUR*/
                SPECEXRA 47-53 /*GAS EXIT RATE-AT 100% GEN LOAD-ACTUAL CUBIC FEET/MIN*/
                SPECEXTE 54-56 /*GAS EXIT TEMPERATURE-UNIT AT 100% GEN LOAD-DEGREES F*/
                SPECENT 57-59 /*FLUE GAS ENTERING FGD UNIT-AT 100% GEN LOAD-% OF TOTAL*/
                SPECLIQI 60-62 /*LIQUID/GAS RATIO-AT 100% GEN LOAD-US GAL./1000 CU.FT.*/
                SPECPOWE 63-67 /*ELECTRICAL POWER REQUIREMENT-UNIT AT 100% GEN LOAD-KW*/
                SPECWATE 68-72 2 /*FEEDWATER CONS. RATE-AT 100% GEN LOAD-0.01 CU.FT/SEC*/
                SPECHEAT 73-78 /*FGD REHEATER ENERGY CONS. 100% GEN LOAD-1000 BTU/HR*/
                SPECGTEM 79-81 /*INCREASE IN FLUE GAS TEMP BY REHEATER-100%, DEGREES F*/
                CTSTRUCT 82-87 /*INSTALLED COST OF FGD-STRUCTURES AND EQUIPMENT-$1000*/
                CTDISPD 88-92 /* COST OF FGD-SLUDGE TRANSP. & DISPOSAL SYSTEM-$1000*/
                CTOTHER 93 /*INSTALLED COST OF FGD UNIT-OTHER-$1000*/
                CTTOTD 94-99 /*INSTALLED COST OF FGD UNIT-TOTAL-$1000*/
                ECD 100 /*EQUIPMENT COUNT*/;

        PROC SORT; BY PCODE YEAR;

DATA RDE767Q; SET RDE767;
        PROC MEANS NOPRINT SUM;
                VAR INSRVDD TRAINTOT TRAIN100 WASTESAL PONDLAND
                        SPECPOWE CTSTRUCT CTDISPD CTOTHER CTTOTD;
                BY PCODE YEAR;
        OUTPUT OUT=QQ2
                SUM=INSRVDD TRAINTOT TRAIN100 WASTESAL PONDLAND
                        SPECPOWE CTSTRUCT CTDISPD CTOTHER CTTOTD;
```

```
DATA RDE767A; SET RDE767;
        PROC MEANS NOPRINT MEAN;
                VAR SPECRE SPECER SPECENT SPECHEAT;
                BY PCODE YEAR;
        OUTPUT OUT=AA2
                MEAN=SPECRE SPECER SPECENT SPECHEAT;

DATA RDES767; MERGE QQ1 AA1 QQ2 AA2; BY PCODE YEAR;

DATA _NULL_; SET RDES767; FILE 'G:\TK_KIM\767\RDES1\RDES.DA1';
        PUT     PCODE 1-4
                YEAR 5-8
                INSRVHR 9-12 /*TOTAL HOURS INSEREVICE DURING YEAR-HOUR*/
                FGDSORB 13-18 1 /*QTY OF FGD SORBENT USED DURING YEAR-1000 SHORT TON*/
                EEC 19-27 /*ELECTRICAL ENERGY CONSUMPTION DURING YEAR -KWHOURS*/
                CTFEED 28-32 /*FGD O&M EXPENDITURES-FEED MATERIALS AND CHEMICALS-$1000*/
                CTLABOR 33-36 /*FGD O&M EXPENDITURES-LABOR AND SUPERVISION-$1000*/
                CTDISP 37-40 /*FGD O&M EXPENDITURES-WASTE DISPOSAL-$1000*/
                CTMAIN 41-45 /*FGD O&M EXPENDITURES-MAINTENANCE MATERIALS/OTHERS-$1000*/
                CTTOT 46-50 /*TOTAL COST-$1000*/
                EFSULFUR 51-55 1 /*REMOVAL EFFICIENCY AT ANNUAL OP FACTOR-% BY WEIGHT*/
                EF100 56-60 1 /*REMOVAL EFFICIENCY AT 100% LOAD OR TESTED-% BY WEIGHT*/
                INSRVDD 61-64 /*FGD UNIT ACTUAL OR PROJECTED INSERVICE DATE*/
                TRAINTOT 65-66 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-TOTAL*/
                TRAIN100 67-69 /*NUMBER OF FGD SCRUBBER TRAINS -OP AT 100% LOAD*/
                WASTESAL 70-73 /*ESTIMATED FGD WASTE/SALABLE BYPRODUCTS-1000 SHORT TONS*/
                PONDLAND 74-77 /*ANNUAL POND AND LAND FILL REQUIREMENTS-ACRE-FOOT/YEAR*/
                SPECPOWE 78-82 /*ELECTRICAL POWER REQUIREMENT-UNIT AT 100% GEN LOAD-KW*/
                CTSTRUCT 83-88 /*INSTALLED COST, FGD UNIT-STRUCTURES AND EQUIPMENT-$1000*/
                CTDISPD 89-93 /*INSTALLED COST, FGD UNIT-SLUDGE TRANS & DISPOSAL-$1000*/
                CTOTHER 94 /*INSTALLED COST OF FGD UNIT-OTHER-$1000*/
                CTTOTD 95-100 /*INSTALLED COST OF FGD UNIT-TOTAL-$1000*/
                SPECRE 101-104 1 /*REMOVAL EFFICIENCY-UNIT AT 100% GEN LOAD-% WEIGHT*/
                SPECER 105-108 /*SO2 EMISSION RATE-UNIT AT 100% GEN LOAD-POUNDS/HOUR*/
                SPECENT 109-111 /*FLUE GAS ENTERING FGD UNIT-UNIT, 100% GEN LOAD-% TOTAL*/
                SPECHEAT 112-117/*FGD REHEAT ENERGY CONS RATE-100% GEN LOAD-1000 BTU/HR*/;

RUN;
```

Program B.3: SAS Programs for Form EIA-906

```
*-------------------
DATA BASE EIA-906M
--------------------
-----------------------------------------------------------------------------------
PROGRAM NAME: EIA906.SA2. THIS PROGRAM READS THE DATA FILE EIA906.TXT CREATED BY ACCESS
PROGRAM (906.MDB). THIS FILE INCLUDES NET ELECTRICITY GENERATION, FUEL CONSUMPTION,
AND FUEL STOCKS BY POWER PLANTS OVER THE PERIOD 1996-2000, IN PHYSICAL UNITS. THE
VARIABLES ARE SUMMARIZED BY YEAR ONLY.
------------------------------------------------------------------------------------;
DATA E906; INFILE 'C:\TK_KIM\906\EIA_PROCESSED_FILES_906\EIA906.TXT' MISSOVER LRECL=500;
       INPUT  PCODE 1-4
              YEAR 5-8
              NERC 9-10
              FTYPE 11
       /* NET ELECTRICITY GENERATION (MWH) */
              GEN1 12-18 GEN2 19-25 GEN3 26-32 GEN4 33-39
              GEN5 40-46 GEN6 47-53 GEN7 54-60 GEN8 61-67
              GEN9 68-74 GEN10 75-81 GEN11 82-88 GEN12 89-95
       /* FUEL CONSUMPTION (SHORT TON/42 GAL.BBL/MCF.) */
              CON1 96-102 CON2 103-109 CON3 110-117 CON4 118-125
              CON5 126-133 CON6 134-141 CON7 142-149 CON8 150-157
              CON9 158-165 CON10 166-172 CON11 173-179 CON12 180-186
       /* FUEL STOCKS (SHORT TON, 42 GAL.BBL) */
              STK1 187-194 STK2 195-202 STK3 203-210 STK4 211-218 STK5 219-226
              STK6 227-234 STK7 235-242 STK8 243-250 STK9 251-258 STK10 259-266
              STK11 267-274 STK12 275-282; IX=1;

       /* ARRAY FOR NET ELECTRICITY GENERATION */
              ARRAY GEN GEN1-GEN12;
       /* ARRAY FOR FUEL CONSUMPTION */
              ARRAY CON CON1-CON12;
       /* ARRAY FOR FUEL STOCKS */
              ARRAY STK STK1-STK12;
       /* RESERVED SPACES FOR NET ELECTRICITY GENERATIONS BY COAL/PET/NG - MWH */
              ARRAY COAL_GEN CGEN1-CGEN12;
              ARRAY PET_GEN PGEN1-PGEN12;
              ARRAY GAS_GEN GGEN1-GGEN12;
       /* RESERVED SPACES FOR COAL/PET/NG CONSUMPTIONS - SHORT
       TON/BARREL(42GAL=1BARREL)/MCF.*/
              ARRAY COAL_CON CCON1-CCON12;
              ARRAY PET_CON PCON1-PCON12;
              ARRAY GAS_CON GCON1-GCON12;
       /* RESERVED SPACES FOR COAL/PET CONSUMPTIONS - SHORT TON/BARREL(42GAL=1BARREL) */
              ARRAY COAL_STK CSTK1-CSTK12;
              ARRAY PET_STK PSTK1-PSTK12;

       DO OVER GEN;
       /* GENERATIONS/CONSUMPTIONS/STOCKS BY COAL, PETOLEUM AND NATURAL GAS */
       IF FTYPE=4 OR FTYPE=5 OR FTYPE=6 OR FTYPE=7 THEN DO;
              COAL_GEN=GEN; COAL_CON=CON; COAL_STK=STK; END;
       IF FTYPE=2 OR FTYPE=3 THEN DO;
              PET_GEN=GEN; PET_CON=CON; PET_STK=STK; END;
```

```
        IF FTYPE=9 THEN DO;
               GAS_GEN=GEN; GAS_CON=CON; END;

        /* REPLACE MISSING TO ZERO */
         IF COAL_GEN=. THEN COAL_GEN=0;
         IF COAL_CON=. THEN COAL_CON=0;
         IF COAL_STK=. THEN COAL_STK=0;
         IF PET_GEN=. THEN PET_GEN=0;
         IF PET_CON=. THEN PET_CON=0;
         IF PET_STK=. THEN PET_STK=0;
         IF GAS_GEN=. THEN GAS_GEN=0;
         IF GAS_CON=. THEN GAS_CON=0;

        /* MISSING VALUES (1999 AND 2000 STOCKS) */
         IF YEAR=1999 OR YEAR=2000 THEN DO;
               COAL_STK=.; PET_STK=.; END;

        END;

*-----------------------------------------------
DATA STRUCTURE CHANGE - HORIZONTAL TO VERTICAL
-----------------------------------------------;
DATA VERT; SET E906;
        MONTH=0;
        DROP CGEN1-CGEN12 PGEN1-PGEN12 GGEN1-GGEN12
               CCON1-CCON12 PCON1-PCON12 GCON1-GCON12
               CSTK1-CSTK12 PSTK1-PSTK12;
        /* NET ELECTRICITY GENERATIONS BY COAL/PET/NG - MWH */
        ARRAY XCGEN CGEN1-CGEN12;
        ARRAY XPGEN PGEN1-PGEN12;
        ARRAY XGGEN GGEN1-GGEN12;
        /* COAL/PET/NG CONSUMPTIONS - SHORT TON/BARREL/MCF. */
        ARRAY XCOAL_CON CCON1-CCON12;
        ARRAY XPET_CON PCON1-PCON12;
        ARRAY XGAS_CON GCON1-GCON12;
        /* COAL/PET/NG STOCKS - SHORT TON/BARREL/MCF. */
        ARRAY XCOAL_STK CSTK1-CSTK12;
        ARRAY XPET_STK PSTK1-PSTK12;

        DO OVER XCGEN;
               MONTH=MONTH+1;
               CGEN=XCGEN;
               PGEN=XPGEN;
               GGEN=XGGEN;
               CCON=XCOAL_CON;
               PCON=XPET_CON;
               GCON=XGAS_CON;
               CSTK=XCOAL_STK;
               PSTK=XPET_STK;
        OUTPUT;
        END;

DATA FINAL; SET VERT;
        TGEN=CGEN+PGEN+GGEN; /* TOTAL NET ELECTRICITY GENERATIONS (MWH) */
```

```
        PROC SORT; BY YEAR;
        PROC MEANS NOPRINT SUM;
                VAR CGEN PGEN GGEN TGEN CCON PCON GCON CSTK PSTK;
                BY YEAR;
        OUTPUT OUT=FSUM
                SUM=CGEN_906 PGEN_906 GGEN_906 TGEN_906
                        CCON_906 PCON_906 GCON_906 CSTK_906 PSTK_906;

/*
*-----------------
VARIABLE LENGTHS
-----------------;
        PROC MEANS N MIN MAX;
                VAR PCODE YEAR MONTH
                        CGEN_906 PGEN_906 GGEN_906 TGEN_906
                        CCON_906 PCON_906 GCON_906
                        CSTK_906 PSTK_906;
*/

*------------------------------
CREATED DATA BASE: EIA906.DA1
------------------------------;
DATA _NULL_; SET FSUM; FILE 'C:\TK_KIM\906\F906_SA1\EIA906.DA1';
        PUT     PCODE 1-4
                YEAR 5-8
                MONTH 9-10
                CGEN_906 11-17 /*NET ELECTRICITY GENERATIONS BY COAL-MWh*/
                PGEN_906 18-23 /*NET ELECTRICITY GENERATIONS BY PETROLEUM-MWh*/
                GGEN_906 24-30 /*NET ELECTRICITY GENERATIONS BY NATURAL GAS-MWh*/
                TGEN_906 31-37 /*NET ELECTRICITY GENERATIONS TOTAL-MWh*/
                CCON_906 38-44 /*COAL CONSUMPTIONS-SHORT TON*/
                PCON_906 45-51 /*PETROLEUM CONSUMPTIONS-BARREL*/
                GCON_906 52-59 /*NATURAL GAS CONSUMPTIONS-MCF.*/
                CSTK_906 60-66 /*COAL STOCKS-SHORT TON*/
                PSTK_906 67-73 /*PETROLEUM STOCKS-BARREL*/;

RUN;
```

Program B.4: SAS Programs for CEMS (Final program only)

```
*---------------------
DATA BASE CEMSO2
---------------------
*---------------------
DATA BASE CEMUOP
---------------------
*---------------------
DATA BASE EIA-767
---------------------
*---------------------
DATA BASE EIA-906
---------------------
-----------------------------------------------------------------------------------------
PROGRAM NAME: CEMSO2.S81. THIS PROGRAM READS THE DATA FILE BFUEL767.DA1, SO2467M.D55,
GINFO767.DA1, UOP467M.D55, RAN.TXT, RDE.TXT, AND MER467.D36. DIVIDING THE PLANTS INTO
TWO GROUPS (W/ AND W/O FGD), THE RATIO DISTRIBUTIONS OF SO2 EMISSIONS AND ELECTRICITY
GENERATIONS ARE RESTRICTED USING 95% QUANTILE. AFTER THE PROCESS, FINAL SAMPLE CANDIDATES
ARE GENERATED.
-----------------------------------------------------------------------------------------;
DATA BFUEL; INFILE 'G:\TK_KIM\767\BFUEL\BFUEL767.DA1';
       INPUT  PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              CQTY_C 11-20 2
              PQTY_C 21-30 2
              GQTY_C 31-41 2
              CMBTU_C 42-52 2
              PMBTU_C 53-62 2
              GMBTU_C 63-73 2
              CSULF_C 74-81 2
              PSULF_C 82-89 2
              CSO2_C 90-101 2
              PSO2_C 102-112 2
              UCBTU_C 113-120 2
              UPBTU_C 121-129 2
              UGBTU_C 130-136 2
              UCSULF_C 137-140 2
              UPSULF_C 141-144 2
              UCSO2_C 145-148 2
              UPSO2_C 149-152 2;

       PROC SORT; BY PCODE YEAR MONTH;

DATA SO2467; INFILE 'G:\TK_KIM\CEM\SO2\55\SO2467M.D55';
       INPUT  PCODE 1-6
              YEAR 7-8
              MONTH 9-10
              NETSO2 11-25 2; IX=1;

       IF YEAR=96 THEN YEAR=1996;
       IF YEAR=97 THEN YEAR=1997;
       IF YEAR=98 THEN YEAR=1998;
```

```
        IF YEAR=99 THEN YEAR=1999;
        IF YEAR=0 THEN YEAR=2000;

        IF PCODE=201 OR PCODE=202 OR PCODE=203 OR PCODE=1007 OR PCODE=1058 OR
               PCODE=1073 OR PCODE=1077 OR PCODE=1004 OR PCODE=1175 OR PCODE=1595 OR
               PCODE=1732 OR PCODE=2502 OR PCODE=2682 OR PCODE=2824 OR PCODE=2864 OR
               PCODE=4042 OR PCODE=6250 OR PCODE=7253 OR PCODE=562 OR PCODE=2364 OR
               PCODE=2367 OR PCODE=2861 OR PCODE=302 OR PCODE=377 OR PCODE=420 OR
               PCODE=609 OR PCODE=612 OR PCODE=619 OR PCODE=621 OR PCODE=399 OR
               PCODE=400 OR PCODE=404 OR PCODE=6013 OR PCODE=2079 OR PCODE=2336 OR
               PCODE=3160 OR PCODE=3169 OR PCODE=3396 OR PCODE=6094 OR PCODE=6768 OR
               PCODE=141 OR PCODE=2491 OR PCODE=2535 OR PCODE=2732 OR PCODE=647 OR
               PCODE=1613 OR PCODE=4125 OR PCODE=1897 OR PCODE=2490 OR PCODE=2504 OR
               PCODE=3152 OR PCODE=375 OR PCODE=992 OR PCODE=1294 OR PCODE=1726 OR
               PCODE=2226 OR PCODE=2640 OR PCODE=3145 OR PCODE=7537 OR PCODE=50202 OR
               PCODE=408 OR PCODE=50611
        THEN DELETE;

        PROC SORT; BY PCODE YEAR MONTH;

DATA MER1; MERGE BFUEL SO2467 (IN=A); BY PCODE YEAR MONTH;
        IF A;
        IF CSO2_C>0 OR PSO2_C>0 THEN DO;
               RATSO2=NETSO2/(CSO2_C+PSO2_C);
        END;

DATA GINFO; INFILE 'G:\TK_KIM\767\GINFO\GINFO767.DA1';
        INPUT  PCODE 1-4
               YEAR 5-8
               MONTH 9-10
               GEN_C 11-17; /*NET GENERATION*/

        PROC SORT; BY PCODE YEAR MONTH;

DATA CEMUOPM; INFILE 'G:\TK_KIM\CEM\SO2\55\UOP467M.D55';
        INPUT  PCODE 1-6
               YEAR 7-8
               MONTH 9-10
               MGLOAD 11-25
               MHEATINP 26-40 1;IX=1;

        IF YEAR=96 THEN YEAR=1996;
        IF YEAR=97 THEN YEAR=1997;
        IF YEAR=98 THEN YEAR=1998;
        IF YEAR=99 THEN YEAR=1999;
        IF YEAR=0 THEN YEAR=2000;

        IF PCODE=201 OR PCODE=202 OR PCODE=203 OR PCODE=1007 OR PCODE=1058 OR
               PCODE=1073 OR PCODE=1077 OR PCODE=1004 OR PCODE=1175 OR PCODE=1595 OR
               PCODE=1732 OR PCODE=2502 OR PCODE=2682 OR PCODE=2824 OR PCODE=2864 OR
               PCODE=4042 OR PCODE=6250 OR PCODE=7253 OR PCODE=562 OR PCODE=2364 OR
               PCODE=2367 OR PCODE=2861 OR PCODE=302 OR PCODE=377 OR PCODE=420 OR
               PCODE=609 OR PCODE=612 OR PCODE=619 OR PCODE=621 OR PCODE=399 OR
```

```
            PCODE=400 OR PCODE=404 OR PCODE=6013 OR PCODE=2079 OR PCODE=2336 OR
            PCODE=3160 OR PCODE=3169 OR PCODE=3396 OR PCODE=6094 OR
            PCODE=6768 OR PCODE=141 OR PCODE=2491 OR PCODE=2535 OR PCODE=2732 OR
            PCODE=647 OR PCODE=1613 OR PCODE=4125 OR PCODE=1897 OR PCODE=2490 OR
            PCODE=2504 OR PCODE=3152 OR PCODE=375 OR PCODE=992 OR PCODE=1294 OR
            PCODE=1726 OR PCODE=2226 OR PCODE=2640 OR PCODE=3145 OR PCODE=7537 OR
            PCODE=50202 OR PCODE=408 OR PCODE=50611
       THEN DELETE;
       PROC SORT; BY PCODE YEAR MONTH;

DATA MER2; MERGE GINFO CEMUOPM (IN=A); BY PCODE YEAR MONTH;
       IF A;
       IF MGLOAD>0 THEN DO;
              RAT767=GEN_C/MGLOAD;
       END;

DATA MER12; MERGE MER1 MER2; BY PCODE YEAR MONTH; IX467=1;
       PROC SORT; BY PCODE YEAR MONTH;

DATA E767RAN; INFILE 'G:\TK_KIM\767\RAN.TXT';
       INPUT  PCODE 1-4
              SCRUB $ 5-10
              YEAR 11-14
              EFSULFUR 15-19 1
              EF100 20-24 1
              TESTDATE 25-28
              INSRVHR 29-32
              FGDSORB 33-38 1
              EEC 39-47
              CTFEED 48-52
              CTLABOR 53-56
              CTDISP 57-60
              CTMAIN 61-65
              CTTOT 66-70
              EC 71;

       PROC SORT; BY PCODE YEAR;

DATA E767RDE; INFILE 'G:\TK_KIM\767\RDE.TXT';
       INPUT  PCODE 1-4
              SCRUB $ 5-10
              YEAR 11-14
              INSRVDD 15-18
              SPECASH 19-22 1
              SPECSULF 23-25 1
              TRAINTOT 26-27
              TRAINLOA 28-30
              WASTESAL 31-34
              PONDLAND 35-38
              SPECRE 39-42 1
              SPECER 43-46
              SPECEXRA 47-53
              SPECEXTE 54-56
              SPECENT 57-59
```

```
            SPECLIQI 60-62
            SPECPOWE 63-67
            SPECWATE 68-72 2
            SPECHEAT 73-78
            SPECGTEM 79-81
            CTSTRUCT 82-87
            CTDISPD 88-92
            CTOTHER 93
            CTTOTD 94-99
            EC;

      PROC SORT; BY PCODE YEAR;

DATA E767; MERGE E767RAN E767RDE; BY PCODE YEAR;

DATA E767Q; SET E767;
      PROC MEANS NOPRINT SUM;
            VAR INSRVHR EEC CTTOT INSRVDD SPECER SPECPOWE CTTOTD FGDSORB;
            BY PCODE YEAR;
      OUTPUT OUT=SUM767
            SUM=INSRVHRQ EECQ CTTOTQ INSRVDDQ SPECERQ SPECPOWEQ CTTOTDQ FGDSORBQ;

DATA E767A; SET E767;
      PROC MEANS NOPRINT MEAN; VAR EFSULFUR EF100 SPECRE; BY PCODE YEAR;
            OUTPUT OUT=MEAN767 MEAN=EFSULFURA EF100A SPECREA;

DATA F767; MERGE MER12 SUM767 MEAN767; BY PCODE YEAR;

DATA F; SET F767;
      IF IX467=1 THEN IXG=467;
      IF IX467=. THEN DELETE;
      PROC SORT; BY PCODE YEAR;

DATA FGD; SET F;
      IF INSRVHRQ=. OR INSRVHRQ=0 THEN IXFGD=0;
      IF INSRVHRQ>0 THEN IXFGD=1;

DATA FGDNO; SET FGD;
      IF IXFGD=0;
      PROC MEANS NOPRINT MEAN MAX MIN; VAR RATSO2 RAT767; BY PCODE;
      OUTPUT OUT=FGDNOOUT MEAN=MEANRATSO2 MEANRAT767
            MIN=MINRATSO2 MINRAT767 MAX=MAXRATSO2 MAXRAT767;
            /*FGD_NO_MEAN MAX MIN*/

DATA NOFGD95_1; SET FGDNOOUT;
      IF MINRATSO2<0 OR MAXRATSO2>1.3 THEN DELETE;
      /*SO2 95% QUANTILE W/ NO FGD*/

DATA NOFGD95_2; SET FGDNOOUT;
      IF MINRAT767<0 OR MAXRAT767>1.1 THEN DELETE;
      /*UOP 95% QUANTILE W/ NO FGD*/

DATA NOFGD95_3; SET FGDNOOUT;
      IF MINRATSO2<0 OR MAXRATSO2>1.3 THEN DELETE;
```

```
        IF MINRAT767<0 OR MAXRAT767>1.1 THEN DELETE;
        /*SO2 AND UOP 95% QUANTILE W/ NO FGD*/

DATA NOFGD95_4; SET FGDNOOUT;
        IF MINRATSO2<0 OR MEANRATSO2>1.3 THEN DELETE;
        IF MINRAT767<0 OR MEANRAT767>1.1 THEN DELETE;
        /*USING MEAN SO2 AND UOP 95% QUANTILE W/ NO FGD*/

DATA NOFGD95_5; SET FGDNOOUT;
        IF MINRATSO2<0 OR MEANRATSO2>1.3 OR MAXRATSO2>2.0 THEN DELETE;
        IF MINRAT767<0 OR MEANRAT767>1.1 OR MAXRAT767>2.0 THEN DELETE;
        /*USING MEAN AND MAX SO2 AND UOP 95% QUANTILE W/ NO FGD*/

DATA NOFGD95_6; SET NOFGD95_5;
        IF MEANRATSO2<0.8 THEN DELETE;
        /*REMOVE IF MEAN RATIO IS LOWER THAN 0.8 W/ NO FGD*/

DATA FGDYES; SET FGD;
        IF IXFGD=1;
        PROC MEANS NOPRINT MEAN MAX MIN; VAR RATSO2 RAT767; BY PCODE;
        OUTPUT OUT=FGDYESOUT MEAN=MEANRATSO2 MEANRAT767
                MIN=MINRATSO2 MINRAT767 MAX=MAXRATSO2 MAXRAT767;
                /*FGD_YES_MEAN MAX MIN*/

DATA YESFGD95_1; SET FGDYESOUT;
        IF MINRATSO2<0 OR MAXRATSO2>1.0 THEN DELETE;
        /*TITLE 'SO2 95% QUANTILE W/ FGD*/

DATA YESFGD95_2; SET FGDYESOUT;
        IF MINRAT767<0 OR MAXRAT767>1.0 THEN DELETE;
        /*UOP 95% QUANTILE W/ FGD*/

DATA YESFGD95_3; SET FGDYESOUT;
        IF MINRATSO2<0 OR MAXRATSO2>1.0 THEN DELETE;
        IF MINRAT767<0 OR MAXRAT767>1.0 THEN DELETE;
        /*SO2 AND UOP 95% QUANTILE W/ FGD*/

DATA YESFGD95_4; SET FGDYESOUT;
        IF MINRATSO2<0 OR MEANRATSO2>1.0 THEN DELETE;
        IF MINRAT767<0 OR MEANRAT767>1.0 THEN DELETE;
        /*USING MEAN SO2 AND UOP 95% QUANTILE W/ FGD*/

DATA YESFGD95_5; SET FGDYESOUT;
        IF MINRATSO2<0 OR MEANRATSO2>1.0 OR MAXRATSO2>2.0 THEN DELETE;
        IF MINRAT767<0 OR MEANRAT767>1.0 OR MAXRAT767>2.0 THEN DELETE;
        /*USING MEAN AND MAX SO2 AND UOP 95% QUANTILE W/ FGD*/

DATA YESFGD95_6; SET YESFGD95_5;
        IF MEANRATSO2>0.8 THEN DELETE;
        /*REMOVE IF MEAN RATIO IS HIGHER THAN 0.8 W/ FGD*/

DATA FINAL; SET NOFGD95_6 YESFGD95_6; BY PCODE; IS=1;
        /*MERGE AFTER REMOVING INAPPROPRIATE VALUES*/
```

```
DATA SAM; MERGE FINAL FGD; BY PCODE;
       PROC SORT; BY IXFGD PCODE YEAR MONTH;

DATA NOSAMPLE; SET SAM;
       IF IS=.;
       IF PCODE=147 OR PCODE=589 OR PCODE=603 OR PCODE=664 OR PCODE=673 OR PCODE=2132 OR
              PCODE=2169 OR PCODE=2411 OR PCODE=2712 OR PCODE=2838 OR PCODE=2847 OR
              PCODE=2857 OR PCODE=2917 OR PCODE=3236 OR PCODE=3251 OR PCODE=4057 OR
              PCODE=4140 OR PCODE=4146 OR PCODE=6025 OR PCODE=6035 OR PCODE=6043 OR
              PCODE=7242 OR PCODE=7314
       THEN DELETE;

DATA SAMPLE; SET SAM;
       IF IS=1;

DATA FSAMPLE; SET NOSAMPLE SAMPLE;
       IF IS=1 THEN ISAM=1; /*PRE-SELECTED 250 SAMPLES*/
       IF IS=. THEN ISAM=0; /*PRE ELIMINATED SAMPLES*/
       IF PCODE=527 OR PCODE=2790 OR PCODE=6089 OR PCODE=7030 THEN IA=1; ELSE IA=0;
              /*NO FGD BUT TOO SMALL NUMBERS*/
       IF PCODE=469 OR PCODE=728 OR PCODE=4040 OR PCODE=4158 OR PCODE=6068 OR
              PCODE=6147 OR PCODE=6177 THEN IB=1; ELSE IB=0;
              /*FGD BUT TOO BIG NUMBERS*/
       IF RATSO2 GT 2 OR RAT767 GT 2 THEN IC=1; ELSE IC=0;
              /*TOO HIGH RATIOS OF NET TO GROSS SO2 EMISSIONS AND ELECTRICITY
              GENERATIONS-ALL VARIABLES IN THIS RECORD SHOULD BE TREATED AS MISSING
              VALUES*/
       IF GEN_C LT 0 OR MGLOAD=0 OR MGLOAD=. THEN ID=1; ELSE ID=0;
              /*IN THIS CASE, ALL OTHER VARIABLES, OR AT LEAST GENERATION PARTS SHOULD
              BE ZERO*/
       IF GEN_C=. OR GEN_C=0 THEN IE=1; ELSE IE=0;
              /*NO NET TO GROSS NET ELECTRICITY GENERATION*/
       IF (CSO2_C=0 OR CSO2_C=.) AND (PSO2_C=0 OR PSO2_C=.) THEN IF=1; ELSE IF=0;
              /*AT LEAST SO2 EMISSION PART SHOULD BE ZERO*/
       IF NETSO2=. OR NETSO2=0 THEN IG=1; ELSE IG=0;
              /*NO NET TO GROSS SO2 EMISSIONS*/
       IF RATSO2=. AND RAT767=. THEN IH=1; ELSE IH=0;
              /*IN THIS CASE, ALL OTHER SHOULD BE ZERO*/

/*
*--------------------
VARIABLE LENGTHS
--------------------;
DATA LENGTH; SET FSAMPLE;
       PROC SORT; BY PCODE YEAR MONTH;
       PROC MEANS N MIN MAX;
              VAR PCODE YEAR MONTH RATSO2 NETSO2 CSO2_C PSO2_C RAT767 GEN_C
              MGLOAD IXFGD ISAM ICASE;
*/
DATA _NULL_; SET FSAMPLE; FILE 'G:\TK_KIM\CEM\SO2\82\SAMPLE.DAT';
       PUT    PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              RATSO2 11-20 4 /*NET TO GROSS SO2 EMISSION RATIO*/
```

```
                    NETSO2 21-31 2 /*NET SO2 EMISSIONS*/
                    RAT767 32-40 4 /*NET TO GROSS ELECTRICITY GENERATION RATIO*/
                    GEN_C 41-47 /*NET ELECTRICITY GENERATION*/
                    MGLOAD 48-55 /*GROSS ELECTRICITY GENERATION*/
                    IXFGD 56 /*FGD=1, NOFGD=0*/
                    ISAM 57 /*PRE-SELECTED SAMPLE=1, PRE-ELIMINATED SAMPLE=0*/
                    IA 58 /*CASE1-NO FGD BUT TOO SMALL NUMBERS*/
                    IB 59 /*CASE2-FGD BUT TOO BIG NUMBERS*/
                    IC 60 /*CASE3-TOO HIGH RATIOS OF NET TO GROSS SO2 EMISSIONS AND
                           ELECTRICITY GENERATIONS-ALL VARIABLES IN THIS RECORD SHOULD BE
                           TREATED AS MISSING VALUES*/
                    ID 61   /*CASE4-GEN_C LT 0 OR MGLOAD=0 OR MGLOAD=.-ALL OTHER VARIABLES, OR
                           AT LEAST GENERATION PARTS SHOULD BE ZERO*/
                    IE 62   /*CASE5-NO NET TO GROSS NET ELECTRICITY GENERATION*/
                    IF 63   /*CASE6-(CSO2_C=0 OR CSO2_C=.) AND (PSO2_C=0 OR PSO2_C=.)-AT LEAST
                           SO2 EMISSION PART SHOULD BE ZERO*/
                    IG 64   /*CASE7-NO NET TO GROSS SO2 EMISSIONS*/
                    IH 65   /*CASE8-RATSO2=. AND RAT767=.-ALL OTHER SHOULD BE ZERO*/
RUN;
```

Program B.5: SAS Program for Final Sample

```
*-----------------------------------------------------------------------------------------
PROGRAM NAME: FINAL.SA1. THIS PROGRAM READS ALL DATA FILES INCLUDING SAMPLE.DAT
(CEMSO2.S81), FERC423.DA2 (FERC423.SA2), BFUEL767.DA1 (BFEUL767.SA1), RDES.DA1 (RDES.SA1),
BAIR767.DA1 (BAIR767.SA1), PFIN.TXT (PFIN767.SAS), NAMECAP.DA1 (NAMECAP.SA1), EIA906.DA1
(EIA906.SA1), NERC.DA1(NERC.SAS), ALLOW.DA1 (ALLOW.SA1), TRADING.DA1 (TRADING.SA1), AND
METEO.DA1 (METEO.SAS). FINAL DATABASE FOR THIS RESEARCH IS CREATED.
-----------------------------------------------------------------------------------------;
DATA SAMPLE; INFILE 'G:\TK_KIM\CEM\SO2\82\SAMPLE.DAT';
       INPUT  PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              RATSO2 11-20 4 /*NET TO GROSS SO2 EMISSION RATIO*/
              NETSO2 21-31 2 /*NET SO2 EMISSIONS*/
              RAT767 32-40 4 /*NET TO GROSS ELECTRICITY GENERATION RATIO*/
              GEN_C 41-47 /*NET ELECTRICITY GENERATION*/
              MGLOAD 48-55 /*GROSS ELECTRICITY GENERATION*/
              IXFGD 56 /*FGD=1, NOFGD=0*/
              ISAM 57 /*PRE-SELECTED SAMPLE=1, PRE-ELIMINATED SAMPLE=0*/
              IA 58 /*CASE1-NO FGD BUT TOO SMALL NUMBERS*/
              IB 59 /*CASE2-FGD BUT TOO BIG NUMBERS*/
              IC 60 /*CASE3-TOO HIGH RATIOS OF NET TO GROSS SO2 EMISSIONS AND
                     ELECTRICITY GENERATIONS-ALL VARIABLES IN THIS RECORD SHOULD BE
                     TREATED AS MISSING VALUES*/
              ID 61  /*CASE4-GEN_C LT 0 OR MGLOAD=0 OR MGLOAD=.-ALL OTHER VARIABLES, OR
                     AT LEAST GENERATION PARTS SHOULD BE ZERO*/
              IE 62  /*CASE5-NO NET TO GROSS NET ELECTRICITY GENERATION*/
              IF 63  /*CASE6-(CSO2_C=0 OR CSO2_C=.) AND (PSO2_C=0 OR PSO2_C=.)-AT LEAST
                     SO2 EMISSION PART SHOULD BE ZERO*/
              IG 64  /*CASE7-NO NET TO GROSS SO2 EMISSIONS*/
              IH 65  /*CASE8-RATSO2=. AND RAT767=.-ALL OTHER SHOULD BE ZERO*/;

       PROC SORT; BY PCODE YEAR MONTH;

DATA FERC423; INFILE 'G:\TK_KIM\423\F423_SA2\FERC423.DA2';
       INPUT  PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              CQTY_S 11-20 2 /*COAL-QUANTITY (SHORT TON)*/
              PQTY_S 21-30 2 /*PETROLEUM-QUANTITY (BARREL)*/
              GQTY_S 31-41 2 /*NATURAL GAS-QUANTITY (1000 CUBIC FT.)*/
              CBTU_S 42-52 2 /*COAL-QUANTITY (MMBTU)*/
              PBTU_S 53-63 2 /*PETROLEUM-QUANTITY (MMBTU)*/
              GBTU_S 64-74 2 /*NATURAL GAS-QUANTITY (MMBTU)*/
              CSULFT_S 75-82 2 /*COAL-SULFUR QUANTITY (SHORT TON)*/
              CSULFP_S 83-93 2 /*COAL-SULFUR QUANTITY (POUNDS)*/
              PSULFT_S 94-101 2 /*PETROLEUM-SULFUR QUANTITY (BARRELS)*/
              PSULFP_S 102-112 2 /*PETROLEUM-SULFUR QUANTITY (POUNDS)*/
              CCOST_S 113-125 2 /*COAL-COSTS (CENTS)*/
              PCOST_S 126-138 2 /*PETROLEUM-COSTS (CENTS)*/
              GCOST_S 139-151 2 /*NATURAL GAS-COSTS (CENTS)*/
              UCBTU_S 152-160 2 /*COAL-UNIT BTU (PER POUND)*/
              UPBTU_S 161-169 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
```

```
            UGBTU_S 170-177 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
            UCST_S 178-181 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
            UCSP_S 182-185 2 /*COAL-UNIT SULFUR (POUND/MMBTU)*/
            UPST_S 186-189 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
            UPSP_S 190-194 2 /*PETROLEUM-UNIT SULFUR (POUND/MMBTU)*/
            UCSO2_S 195-199 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
            UPSO2_S 200-204 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
            UCCOST_S 205-210 2 /*COAL-UNIT COSTS (CENTS/MMBTU)*/
            UPCOST_S 211-217 2 /*PETROLEUM-UNIT COSTS (CENTS/MMBTU) */
            UGCOST_S 218-225 2/*NATURAL GAS-UNIT COSTS (CENTS/MMBTU)*/;

      PROC SORT; BY PCODE YEAR MONTH;

DATA BFUEL767; INFILE 'G:\TK_KIM\767\BFUEL\BFUEL767.DA1';
      INPUT PCODE 1-4
            YEAR 5-8
            MONTH 9-10
            CQTY_C 11-20 2 /*COAL QUANTITIES-SHORT TONS*/
            PQTY_C 21-30 2 /*PETOLEUM QUANTITIES-BARRELS*/
            GQTY_C 31-41 2 /*NATURAL GAS QUANTITIES-1000 CUBIC FT.*/
            CMBTU_C 42-52 2 /*COAL QUANTITY IN MMBTU*/
            PMBTU_C 53-62 2 /*PETROLEUM QUANTITY IN MMBTU*/
            GMBTU_C 63-73 2 /*NATURAL GAS QUANTITY IN MMBTU*/
            CSULF_C 74-81 2 /*COAL SULFUR QUANTITY - SHORT TON*/
            PSULF_C 82-89 2 /*PETROLEUM SULFUR QUANTITY - BARRELS*/
            CSO2_C 90-101 2 /*COAL-POUNDS OF SO2*/
            PSO2_C 102-112 2 /*PETROLEUM-POUNDS OF SO2*/
            UCBTU_C 113-120 2 /*COAL-UNIT BTU (PER POUND)*/
            UPBTU_C 121-129 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
            UGBTU_C 130-136 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
            UCSULF_C 137-140 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
            UPSULF_C 141-144 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
            UCSO2_C 145-148 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
            UPSO2_C 149-152 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/;
      PROC SORT; BY PCODE YEAR MONTH;

DATA RDES767; INFILE 'G:\TK_KIM\767\RDES1\RDES.DA1';
      INPUT PCODE 1-4
            YEAR 5-8
            INSRVHR 9-12 /*TOTAL HOURS INSEREVICE DURING YEAR-HOUR*/
            FGDSORB 13-18 1 /*QUANTITY OF FGD SORBENT USED DURING YEAR-1000 SHORT
                           TON*/
            EEC    19-27 /*ELECTRICAL ENERGY CONSUMPTION DURING YEAR -KWHOURS*/
            CTFEED 28-32 /*FGD O&M EXPENDITURES-FEED MATERIALS AND CHEMICALS-$1000*/
            CTLABOR 33-36 /*FGD O&M EXPENDITURES-LABOR AND SUPERVISION-$1000*/
            CTDISP 37-40 /*FGD O&M EXPENDITURES-WASTE DISPOSAL-$1000*/
            CTMAIN 41-45 /*FGD O&M EXPENDITURES-MAINTENANCE MATERIALS/ALL
                           OTHERS-$1000*/
            CTTOT 46-50 /*TOTAL COST-$1000*/
            EFSULFUR 51-55 1 /*REMOVAL EFFICIENCY OF SO2 AT ANNUAL OP FACTOR-
                           % BY WEIGHT*/
            EF100 56-60 1 /*REMOVAL EFFICIENCY OF SO2 AT 100% LOAD OR TESTED-
                           % BY WEIGHT*/
            INSRVDD 61-64 /*FGD UNIT ACTUAL OR PROJECTED INSERVICE DATE*/
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            TRAINTOT 65-66 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-TOTAL*/
            TRAIN100 67-69 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-
                           OP AT 100% LOAD*/
            WASTESAL 70-73 /*ESTIMATED FGD WASTE AND SALABLE BYPRODUCTS-
                           1000 SHORT TONS*/
            PONDLAND 74-77 /*ANNUAL POND AND LAND FILL REQUIREMENTS-ACRE-FOOT/YEAR*/
            SPECPOWE 78-82 /*ELECTRICAL POWER REQUIREMENT-UNIT AT 100% GEN LOAD-KW*/
            CTSTRUCT 83-88 /*INSTALLED COST OF FGD UNIT-STRUCTURES AND EQUIPMENT-
                           $1000*/
            CTDISPD 89-93 /*INSTALLED COST OF FGD UNIT-SLUDGE TRANS & DISPOSAL
                           SYS-$1000*/
            CTOTHER 94 /*INSTALLED COST OF FGD UNIT-OTHER-$1000*/
            CTTOTD 95-100 /*INSTALLED COST OF FGD UNIT-TOTAL-$1000*/
            SPECRE 101-104 1 /*REMOVAL EFFICIENCY OF SO2-UNIT AT 100% GEN LOAD-
                           % WEIGHT*/
            SPECER 105-108 /*SO2 EMISSION RATE-UNIT AT 100% GEN LOAD-POUNDS/HOUR*/
            SPECENT 109-111 /*FLUE GAS ENTERING FGD UNIT-UNIT AT 100% GEN LOAD-
                           % OF TOTAL*/
            SPECHEAT 112-117 /*FGD REHEAT ENERGY CONSUM RATE-100% GEN LOAD-
                           1000 BTU/HR*/;

      PROC SORT; BY PCODE YEAR;

DATA BAIR767; INFILE 'G:\TK_KIM\767\BAIR\BAIR767.DA1';
      INPUT PCODE 1-4
            YEAR 5-8
            SO2ST 9-17 2 /*ANNUAL SO2 EMISSION STANDARDS*/;

      PROC SORT; BY PCODE YEAR;

DATA PFIN767; INFILE 'G:\TK_KIM\767\PFIN\PFIN.TXT';
      INPUT PCODE 1-4
            YEAR 5-8
            FLYCOL 9-12 /*O&M EXPENDITURE-FLY ASH COLLECTION-$1000*/
            FLYDIS 13-16 /*O&M EXPENDITURE-FLY ASH DISPOSAL-$1000*/
            BOTCOL 17-21 /*O&M EXPENDITURE-BOTTOM ASH COLLECTION-$1000*/
            BOTDIS 22-25 /*O&M EXPENDITURE-BOTTOM ASH DISPOSAL-$1000*/
            FGDCOL 26-30 /*O&M EXPENDITURE-FGD COLLECTION-$1000*/
            FGDDIS 31-35 /*O&M EXPENDITURE-FGD DISPOSAL-$1000*/
            WATCOL 36-40 /*O&M EXPENDITURE-WATER POLLUTION COLLECTION-$1000*/
            WATDIS 41-45 /*O&M EXPENDITURE-WATER POLLUTION DISPOSAL-$1000*/
            OTHCOL 46-50 /*O&M EXPENDITURE-OTHER POLLUTION COLLECTION-$1000*/
            OTHDIS 51-55 /*O&M EXPENDITURE-OTHER POLLUTION DISPOSAL-$1000*/
            OTHOTH 56-60 /*O&M EXPENDITURE-OTHER-$1000*/
            TOTCOL 61-65 /*O&M EXPENDITURE-TOTAL COLLECTION-$1000*/
            TOTDIS 66-70 /*O&M EXPENDITURE-TOTAL DISPOSAL-$1000*/
            TOTOTH 71-74 /*O&M EXPENDITURE-TOTAL OTHER-$1000*/
            AIRPOL 75-80 /*CAPITAL EXPENDIUTURE-AIR POLLUTION ABATEMENT-$1000*/
            WATPOL 81-86 /*CAPITAL EXPENDIUTURE-WATER POLLUTION ABATEMENT-$1000*/
            SOLPOL 87-91 /*CAPITAL EXPENDIUTURE-SOLID/CONTAINED WASTE POLLUTION
                           ABATEMENT-$1000*/
            OTHPOL 92-96 /*CAPITAL EXPENDIUTURE-OTHER POLLUTION ABATEMENT-$1000*/
            FLYSALE 97-100 /*BYPRODUCT SALES REVENUE-FLY ASH-$1000*/
            BOTSALE 101-104 /*BYPRODUCT SALES REVENUE-BOTTOM ASH-$1000*/
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            FABSALE 105-108 /*BYPRODUCT SALES REVENUE-FLY AND BOTTOM ASH SOLD
                               INTERMINGLED-$1000*/
            GASSALE 109-112 /*BYPRODUCT SALES REVENUE-FLUE GAS DESULFURIZATION
                               BYPRODUCTS-$1000*/
            OTHSALE 113-116 /*BYPRODUCT SALES REVENUE-OTHER BYPRODUCT-$1000*/
            TOTSALE 117-120 /*BYPRODUCT SALES REVENUE-TOTAL-$1000*/;

       PROC SORT; BY PCODE YEAR;

DATA EIA860; INFILE 'G:\TK_KIM\860\NAMECAP_SA1\NAMECAP.DA1';
       INPUT  PCODE 1-4
              YEAR 5-8
              N_CAP 9-15 /*NAMEPLATE CAPACITY-IN KW*/;

       PROC SORT; BY PCODE YEAR;

DATA EIA906; INFILE 'G:\TK_KIM\906\F906_SA1\EIA906.DA1';
       INPUT  PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              CGEN_906 11-17 /*NET ELECTRICITY GENERATIONS BY COAL-MWh*/
              PGEN_906 18-23 /*NET ELECTRICITY GENERATIONS BY PETROLEUM-MWh*/
              GGEN_906 24-30 /*NET ELECTRICITY GENERATIONS BY NATURAL GAS-MWh*/
              TGEN_906 31-37 /*NET ELECTRICITY GENERATIONS TOTAL-MWh*/
              CCON_906 38-44 /*COAL CONSUMPTIONS-SHORT TON*/
              PCON_906 45-51 /*PETROLEUM CONSUMPTIONS-BARREL*/
              GCON_906 52-59 /*NATURAL GAS CONSUMPTIONS-MCF.*/
              CSTK_906 60-66 /*COAL STOCKS-SHORT TON*/
              PSTK_906 67-73 /*PETROLEUM STOCKS-BARREL*/;

       PROC SORT; BY PCODE YEAR MONTH;

DATA NERC; INFILE 'G:\TK_KIM\906\NERC\NERC.DA1';
       INPUT  PCODE 1-4
              NERC 5-6 /*1.ECAR;2.ERCOT;3.MAAC;4.MAIN;5.MAPP;6.NPCCL;7.SERC;8.SPP;9.WSCC
                         10.ASCC;11.HICC*/;

       PROC SORT; BY PCODE;

DATA ALLOWANCE; INFILE 'G:\TK_KIM\BROWSER\ALLOW.DA1';
       INPUT  PCODE 1-4
              PHASE1 5-10 /*FINAL PHASE I-2.5 LB OF SO2 PER MMBTU OF HEAT INPUT*/
              AUCRES 11-14 /*AUCTION RESERVE*/
              PHASE2 15-20 /*FINAL PHASE II-2.5 LB OF SO2 PER MMBTU OF HEAT INPUT*/;

       PROC SORT; BY PCODE;

DATA TRADING; INFILE 'G:\TK_KIM\TRADING\TRADING.DA1';
       INPUT  PCODE 1-4
              YEAR 5-8
              AUCCOST 9-18 2 /*TOTAL AUCTION PRICE ($) BY POWER PLANTS*/;

       PROC SORT; BY PCODE YEAR;
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DATA METEO; INFILE 'G:\TK_KIM\WIND\MSTATION FILE\METEO.DA1';
       INPUT  PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              TEMP 11-16 1 /*MEAN TEMPERATURE FOR THE MONTH IN DEGREES F TO TENTH*/
              WDSP 17-20 1 /*MEAN WIND SPEED FOR THE DAY IN KNOTS TO TENTH*/;

       PROC SORT; BY PCODE YEAR MONTH;

DATA MER1; MERGE SAMPLE (IN=A) FERC423 BFUEL767 EIA906 METEO; BY PCODE YEAR MONTH;
       IF A;

DATA MER2; MERGE RDES767 BAIR767 PFIN767 EIA860 TRADING; BY PCODE YEAR;

DATA MER3; MERGE NERC ALLOWANCE ; BY PCODE;

DATA MER12; MERGE MER1 (IN=A) MER2; BY PCODE YEAR;
       IF A;

DATA MER123; MERGE MER12 (IN=A) MER3; BY PCODE;
       IF A;

DATA _NULL_; SET MER123; FILE 'G:\TK_KIM\FINAL\FINAL.DA1' LRECL=1000;
       PUT    PCODE 1-4
              YEAR 5-8
              MONTH 9-10
              RATSO2 11-20 4 /*NET TO GROSS SO2 EMISSION RATIO*/
              NETSO2 21-31 2 /*NET SO2 EMISSIONS*/
              RAT767 32-40 4 /*NET TO GROSS ELECTRICITY GENERATION RATIO*/
              GEN_C 41-47 /*NET ELECTRICITY GENERATION*/
              MGLOAD 48-55 /*GROSS ELECTRICITY GENERATION*/
              IXFGD 56 /*FGD=1, NOFGD=0*/
              ISAM 57 /*PRE-SELECTED SAMPLE=1, PRE-ELIMINATED SAMPLE=0*/
              IA 58 /*CASE1-NO FGD BUT TOO SMALL NUMBERS*/
              CQTY_S 59-68 2 /*COAL-QUANTITY (SHORT TON)*/
              PQTY_S 69-78 2 /*PETROLEUM-QUANTITY (BARREL)*/
              GQTY_S 79-89 2 /*NATURAL GAS-QUANTITY (1000 CUBIC FT.)*/
              CBTU_S 90-100 2 /*COAL-QUANTITY (MMBTU)*/
              PBTU_S 101-111 2 /*PETROLEUM-QUANTITY (MMBTU)*/
              GBTU_S 112-122 2 /*NATURAL GAS-QUANTITY (MMBTU)*/
              CSULFT_S 123-130 2 /*COAL-SULFUR QUANTITY (SHORT TON)*/
              CSULFP_S 131-141 2 /*COAL-SULFUR QUANTITY (POUNDS)*/
              PSULFT_S 142-149 2 /*PETROLEUM-SULFUR QUANTITY (BARRELS)*/
              PSULFP_S 150-160 2 /*PETROLEUM-SULFUR QUANTITY (POUNDS)*/
              CCOST_S 161-173 2 /*COAL-COSTS (CENTS)*/
              PCOST_S 174-186 2 /*PETROLEUM-COSTS (CENTS)*/
              GCOST_S 187-199 2 /*NATURAL GAS-COSTS (CENTS)*/
              UCBTU_S 200-208 2 /*COAL-UNIT BTU (PER POUND)*/
              UPBTU_S 209-217 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
              UGBTU_S 218-225 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
              UCST_S 226-229 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
              UCSP_S 230-233 2 /*COAL-UNIT SULFUR (POUND/MMBTU)*/
              UPST_S 234-237 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
              UPSP_S 238-242 2 /*PETROLEUM-UNIT SULFUR (POUND/MMBTU)*/
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UCSO2_S 243-247 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
UPSO2_S 248-252 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
UCCOST_S 253-258 2 /*COAL-UNIT COSTS (CENTS/MMBTU)*/
UPCOST_S 259-265 2 /*PETROLEUM-UNIT COSTS (CENTS/MMBTU) */
UGCOST_S 266-273 2/*NATURAL GAS-UNIT COSTS (CENTS/MMBTU)*/
CQTY_C 274-283 2 /*COAL QUANTITIES-SHORT TONS*/
PQTY_C 284-293 2 /*PETOLEUM QUANTITIES-BARRELS*/
GQTY_C 294-304 2 /*NATURAL GAS QUANTITIES-1000 CUBIC FT.*/
CMBTU_C 305-315 2 /*COAL QUANTITY IN MMBTU*/
PMBTU_C 316-325 2 /*PETROLEUM QUANTITY IN MMBTU*/
GMBTU_C 326-336 2 /*NATURAL GAS QUANTITY IN MMBTU*/
CSULF_C 337-344 2 /*COAL SULFUR QUANTITY - SHORT TON*/
PSULF_C 345-352 2 /*PETROLEUM SULFUR QUANTITY - BARRELS*/
CSO2_C 353-364 2 /*COAL-POUNDS OF SO2*/
PSO2_C 365-375 2 /*PETROLEUM-POUNDS OF SO2*/
UCBTU_C 376-383 2 /*COAL-UNIT BTU (PER POUND)*/
UPBTU_C 384-392 2 /*PETROLEUM-UNIT BTU (PER GALLON)*/
UGBTU_C 393-399 2 /*NATURAL GAS-UNIT BTU (PER CUBIC FT.)*/
UCSULF_C 400-403 2 /*COAL-UNIT SULFUR CONTENT (% BY WEIGHT)*/
UPSULF_C 404-407 2 /*PETROLEUM-UNIT SULFUR CONTENT (% BY WEIGHT)*/
UCSO2_C 408-411 2 /*COAL-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
UPSO2_C 412-415 2 /*PETROLEUM-UNIT GROSS SO2 EMISSIONS (POUND/MMBTU)*/
INSRVHR 416-419 /*TOTAL HOURS INSEREVICE DURING YEAR-HOUR*/
FGDSORB 420-425 1 /*QUANTITY OF FGD SORBENT USED DURING YEAR-
                       1000 SHORT TON*/
EEC     426-434 /*ELECTRICAL ENERGY CONSUMPTION DURING YEAR -KWHOURS*/
CTFEED 435-439 /*FGD O&M EXPENDITURES-FEED MATERIALS AND CHEMICALS-$1000*/
CTLABOR 440-443 /*FGD O&M EXPENDITURES-LABOR AND SUPERVISION-$1000*/
CTDISP 444-447 /*FGD O&M EXPENDITURES-WASTE DISPOSAL-$1000*/
CTMAIN 448-452 /*FGD O&M EXPENDITURES-MAINTENANCE MATERIALS/ALL OTHERS-
               $1000*/
CTTOT 453-457 /*TOTAL COST-$1000*/
EFSULFUR 458-462 1 /*REMOVAL EFFICIENCY OF SO2 AT ANNUAL OP FACTOR-
                       % BY WEIGHT*/
EF100 463-467 1 /*REMOVAL EFFICIENCY OF SO2 AT 100% LOAD OR TESTED-
               % BY WEIGHT*/
INSRVDD 468-471 /*FGD UNIT ACTUAL OR PROJECTED INSERVICE DATE*/
TRAINTOT 472-473 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-TOTAL*/
TRAIN100 474-476 /*NUMBER OF FGD SCRUBBER TRAINS (OR MODULES)-OP AT
               100% LOAD*/
WASTESAL 477-480 /*ESTIMATED FGD WASTE AND SALABLE BYPRODUCTS-
               1000 SHORT TONS*/
PONDLAND 481-484 /*ANNUAL POND AND LAND FILL REQUIREMENTS-ACRE-FOOT/YEAR*/
SPECPOWE 485-489 /*ELECTRICAL POWER REQUIREMENT-UNIT AT 100% GEN LOAD-KW*/
CTSTRUCT 490-495 /*INSTALLED COST OF FGD UNIT-STRUCTURES AND EQUIPMENT-
               $1000*/
CTDISPD 496-500 /*INSTALLED COST OF FGD UNIT-SLUDGE TRANS & DISPOSAL SYS-
               $1000*/
CTOTHER 501 /*INSTALLED COST OF FGD UNIT-OTHER-$1000*/
CTTOTD 502-507 /*INSTALLED COST OF FGD UNIT-TOTAL-$1000*/
SPECRE 508-511 1 /*REMOVAL EFFICIENCY OF SO2-UNIT AT 100% GEN LOAD-
               % WEIGHT*/
SPECER 512-515 /*SO2 EMISSION RATE-UNIT AT 100% GEN LOAD-POUNDS/HOUR*/
SPECENT 516-518 /*FLUE GAS ENTERING FGD UNIT-UNIT AT 100% GEN LOAD-
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              % OF TOTAL*/
SPECHEAT 519-524 /*FGD REHEAT ENERGY CONSUM RATE-100% GEN LOAD-
              1000 BTU/HR*/
SO2ST 525-533 2 /*ANNUAL SO2 EMISSION STANDARDS*/
FLYCOL 534-537 /*O&M EXPENDITURE-FLY ASH COLLECTION-$1000*/
FLYDIS 538-541 /*O&M EXPENDITURE-FLY ASH DISPOSAL-$1000*/
BOTCOL 542-546 /*O&M EXPENDITURE-BOTTOM ASH COLLECTION-$1000*/
BOTDIS 547-550 /*O&M EXPENDITURE-BOTTOM ASH DISPOSAL-$1000*/
FGDCOL 551-555 /*O&M EXPENDITURE-FGD COLLECTION-$1000*/
FGDDIS 556-560 /*O&M EXPENDITURE-FGD DISPOSAL-$1000*/
WATCOL 561-565 /*O&M EXPENDITURE-WATER POLLUTION COLLECTION-$1000*/
WATDIS 566-570 /*O&M EXPENDITURE-WATER POLLUTION DISPOSAL-$1000*/
OTHCOL 571-575 /*O&M EXPENDITURE-OTHER POLLUTION COLLECTION-$1000*/
OTHDIS 576-580 /*O&M EXPENDITURE-OTHER POLLUTION DISPOSAL-$1000*/
OTHOTH 581-585 /*O&M EXPENDITURE-OTHER-$1000*/
TOTCOL 586-590 /*O&M EXPENDITURE-TOTAL COLLECTION-$1000*/
TOTDIS 591-595 /*O&M EXPENDITURE-TOTAL DISPOSAL-$1000*/
TOTOTH 596-599 /*O&M EXPENDITURE-TOTAL OTHER-$1000*/
AIRPOL 600-605 /*CAPITAL EXPENDIUTURE-AIR POLLUTION ABATEMENT-$1000*/
WATPOL 606-611 /*CAPITAL EXPENDIUTURE-WATER POLLUTION ABATEMENT-
              $1000*/
SOLPOL 612-616 /*CAPITAL EXPENDIUTURE-SOLID/CONTAINED WASTE POLLUTION
              ABATEMENT-$1000*/
OTHPOL 617-621 /*CAPITAL EXPENDIUTURE-OTHER POLLUTION ABATEMENT-$1000*/
FLYSALE 622-625 /*BYPRODUCT SALES REVENUE-FLY ASH-$1000*/
BOTSALE 626-629 /*BYPRODUCT SALES REVENUE-BOTTOM ASH-$1000*/
FABSALE 630-633 /*BYPRODUCT SALES REVENUE-FLY AND BOTTOM ASH SOLD
               INTERMINGLED-$1000*/
GASSALE 634-637 /*BYPRODUCT SALES REVENUE-FLUE GAS DESULFURIZATION
              BYPRODUCTS-$1000*/
OTHSALE 638-641 /*BYPRODUCT SALES REVENUE-OTHER BYPRODUCT-$1000*/
TOTSALE 642-645 /*BYPRODUCT SALES REVENUE-TOTAL-$1000*/
N_CAP 646-652 /*NAMEPLATE CAPACITY-IN KW*/
CGEN_906 653-659 /*NET ELECTRICITY GENERATIONS BY COAL-MWh*/
PGEN_906 660-665 /*NET ELECTRICITY GENERATIONS BY PETROLEUM-MWh*/
GGEN_906 666-672 /*NET ELECTRICITY GENERATIONS BY NATURAL GAS-MWh*/
TGEN_906 673-679 /*NET ELECTRICITY GENERATIONS TOTAL-MWh*/
CCON_906 680-686 /*COAL CONSUMPTIONS-SHORT TON*/
PCON_906 687-693 /*PETROLEUM CONSUMPTIONS-BARREL*/
GCON_906 694-701 /*NATURAL GAS CONSUMPTIONS-MCF.*/
CSTK_906 702-708 /*COAL STOCKS-SHORT TON*/
PSTK_906 709-715 /*PETROLEUM STOCKS-BARREL*/
NERC 716-717 /*1.ECAR;2.ERCOT;3.MAAC;4.MAIN;5.MAPP;6.NPCCL;7.SERC;8.SPP;
               9.WSCC;10.ASCC;11.HICC*/
PHASE1 718-723 /*FINAL PHASE I-2.5 LB OF SO2 PER MMBTU OF HEAT INPUT*/
AUCRES 724-727 /*AUCTION RESERVE*/
PHASE2 728-733 /*FINAL PHASE II-2.5 LB OF SO2 PER MMBTU OF HEAT INPUT*/
AUCCOST 734-743 2 /*TOTAL AUCTION PRICE ($) BY POWER PLANTS*/
TEMP 744-749 1 /*MEAN TEMPERATURE FOR THE MONTH IN DEGREES F TO TENTH*/
WDSP 750-753 1 /*MEAN WIND SPEED FOR THE DAY IN KNOTS TO TENTH*/
IB 754  /*CASE2-FGD BUT TOO BIG NUMBERS*/
IC 755  /*CASE3-TOO HIGH RATIOS OF NET TO GROSS SO2 EMISSIONS AND
       ELECTRICITY GENERATIONS-ALL VARIABLES IN THIS RECORD SHOULD BE
       TREATED AS MISSING VALUES*/
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                  ID 756  /*CASE4-GEN_C LT 0 OR MGLOAD=0 OR MGLOAD=.-ALL OTHER VARIABLES, OR
                          AT LEAST GENERATION PARTS SHOULD BE ZERO*/
                  IE 757  /*CASE5-NO NET TO GROSS NET ELECTRICITY GENERATION*/
                  IF 758  /*CASE6-(CSO2_C=0 OR CSO2_C=.) AND (PSO2_C=0 OR PSO2_C=.)-AT LEAST
                          SO2 EMISSION PART SHOULD BE ZERO*/
                  IG 759  /*CASE7-NO NET TO GROSS SO2 EMISSIONS*/
                          IH 760  /*CASE8-RATSO2=. AND RAT767=.-ALL OTHER SHOULD BE ZERO*/
;

RUN;
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APPENDIX C

EXPLORATORY ANALYSIS TABLES

Table C.1: Fuel shipments pattern by state of destination during the period of 1996-2000

STATE	YEAR	CBTU	PBTU	GBTU	TOTAL MMBTU	STATE	YEAR	CBTU	PBTU	GBTU	TOTAL MMBTU
Alaska	1996	0.00%	0.00%	100.00%	18452922.30	Illinois	1996	95.77%	1.03%	3.21%	774994313.61
	1997	0.00%	0.00%	100.00%	20989567.08		1997	93.98%	0.65%	5.37%	850090969.79
	1998	0.00%	0.00%	100.00%	18887326.57		1998	92.82%	0.92%	6.26%	845214535.04
	1999	0.00%	0.00%	100.00%	20428537.41		1999	94.55%	0.64%	4.80%	734057049.91
	2000	0.00%	0.00%	100.00%	16792619.80		2000	99.42%	0.16%	0.42%	278786161.97
Alabama	1996	99.64%	0.15%	0.21%	698595531.76	Indiana	1996	99.47%	0.23%	0.30%	1082014578.67
	1997	99.64%	0.18%	0.17%	706320771.83		1997	99.56%	0.20%	0.24%	1132444717.92
	1998	99.66%	0.09%	0.25%	714788344.10		1998	99.40%	0.24%	0.36%	1211559565.38
	1999	99.52%	0.15%	0.33%	665158687.42		1999	99.37%	0.31%	0.32%	1226089007.96
	2000	98.88%	0.13%	0.99%	711010254.82		2000	99.59%	0.19%	0.23%	1101558513.78
Arkansas	1996	88.38%	0.17%	11.44%	290189740.98	Kansas	1996	94.64%	0.23%	5.12%	334829034.26
	1997	91.82%	0.19%	7.99%	225283943.73		1997	92.77%	1.01%	6.22%	315070384.29
	1998	91.24%	0.20%	8.56%	269394525.35		1998	91.07%	0.43%	8.50%	352232625.78
	1999	90.67%	0.22%	9.11%	293956219.63		1999	91.22%	0.60%	8.19%	369894166.60
	2000	90.08%	0.13%	9.79%	280796447.33		2000	91.38%	1.01%	7.61%	365872331.44
Arizona	1996	94.21%	0.29%	5.50%	326421569.59	Kentucky	1996	99.79%	0.14%	0.07%	888482956.66
	1997	93.67%	0.20%	6.13%	364145874.40		1997	99.77%	0.17%	0.06%	917971686.22
	1998	91.15%	0.20%	8.65%	420755490.32		1998	99.38%	0.52%	0.10%	861845552.46
	1999	89.12%	0.16%	10.72%	453754750.67		1999	99.74%	0.16%	0.11%	827907989.04
	2000	83.81%	0.41%	15.79%	463368275.59		2000	99.77%	0.14%	0.09%	750347634.22
California	1996	0.00%	0.00%	100.00%	323660783.50	Louisiana	1996	44.44%	0.40%	55.16%	459840745.66
	1997	0.00%	0.00%	100.00%	382129422.82		1997	43.26%	1.11%	55.63%	493129894.54
	1998	0.00%	0.23%	99.77%	273353843.79		1998	42.31%	1.52%	56.17%	537502142.13
	1999	0.00%	0.04%	99.96%	150161039.01		1999	41.16%	0.75%	58.09%	548678818.79
	2000	0.00%	0.13%	99.87%	123558412.78		2000	33.82%	0.81%	65.38%	461920475.30
Colorado	1996	99.27%	0.01%	0.71%	326028531.42	Massachu-	1996	51.38%	27.06%	21.57%	230795346.20
	1997	99.28%	0.01%	0.71%	332320295.27	setts	1997	40.30%	41.20%	18.50%	283563881.64
	1998	99.01%	0.01%	0.98%	358788711.75		1998	41.83%	47.75%	10.42%	209494957.41
	1999	95.63%	0.02%	4.35%	374918605.81		1999	50.81%	6.34%	42.86%	20410482.14
	2000	91.69%	0.22%	8.09%	363809224.14		2000	55.79%	3.43%	40.78%	15246106.81
Connecticut	1996	25.31%	63.77%	10.92%	96369086.63	Maryland	1996	93.01%	5.18%	1.81%	303226087.11
	1997	19.54%	69.53%	10.93%	127992126.66		1997	93.69%	4.50%	1.81%	279500738.88
	1998	14.55%	76.43%	9.02%	118646969.02		1998	86.63%	11.76%	1.61%	323372906.62
	1999	1.22%	80.22%	18.56%	77807796.66		1999	83.99%	12.33%	3.68%	343426455.38
	2000	N/A	N/A	N/A	N/A		2000	89.48%	3.64%	6.88%	178549252.77
DC	1996	0.00%	100.00%	0.00%	1775022.52	Maine	1996	0.00%	100.00%	0.00%	8989453.44
	1997	0.00%	100.00%	0.00%	844850.43		1997	0.00%	100.00%	0.00%	14815239.60
	1998	0.00%	100.00%	0.00%	2679998.66		1998	0.00%	100.00%	0.00%	20349469.40
	1999	0.00%	100.00%	0.00%	2479299.40		1999	0.00%	100.00%	0.00%	6620941.95
	2000	64.75%	35.25%	0.00%	3110529.51		2000	N/A	N/A	N/A	N/A
Delaware	1996	55.63%	15.05%	29.33%	81687218.35	Michigan	1996	97.61%	1.30%	1.09%	650579710.13
	1997	61.60%	15.21%	23.19%	71348358.30		1997	97.61%	1.14%	1.25%	700028800.19
	1998	65.09%	19.32%	15.59%	69454248.58		1998	95.19%	1.97%	2.84%	778936780.11
	1999	47.35%	19.97%	32.68%	65779093.95		1999	94.47%	1.98%	3.55%	748706471.07
	2000	67.84%	11.29%	20.87%	22036932.40		2000	95.37%	1.30%	3.34%	743739487.13
Florida	1996	56.54%	19.92%	23.54%	1167325480.87	Minnesota	1996	99.00%	0.12%	0.88%	307400937.22
	1997	56.59%	19.97%	23.44%	1230047752.25		1997	99.07%	0.07%	0.86%	322992674.82
	1998	52.94%	28.24%	18.82%	1348517466.95		1998	99.25%	0.08%	0.67%	327430270.09
	1999	50.68%	27.24%	22.08%	1272932260.88		1999	99.17%	0.08%	0.75%	303127249.56
	2000	52.37%	25.42%	22.21%	1191675300.98		2000	99.26%	0.06%	0.67%	324993775.62
Georgia	1996	99.18%	0.43%	0.40%	674420718.02	Montana	1996	99.29%	0.20%	0.51%	617277460.15
	1997	99.29%	0.25%	0.47%	671451586.49		1997	99.32%	0.20%	0.48%	608131952.59
	1998	97.99%	0.56%	1.44%	761569046.86		1998	99.00%	0.14%	0.86%	703374256.84
	1999	98.19%	0.42%	1.38%	796285321.60		1999	98.82%	0.10%	1.08%	687506377.69
	2000	99.16%	0.32%	0.53%	830647944.42		2000	98.79%	0.31%	0.89%	597282908.95
Hawaii	1996	0.00%	100.00%	0.00%	56399799.33	Mississippi	1996	61.38%	5.74%	32.87%	194940909.46
	1997	0.00%	100.00%	0.00%	45333837.57		1997	62.55%	13.27%	24.18%	202624843.14
	1998	0.00%	100.00%	0.00%	43339858.44		1998	52.75%	23.46%	23.79%	236034049.89
	1999	0.00%	100.00%	0.00%	67457747.02		1999	56.75%	13.20%	30.04%	250405369.78
	2000	0.00%	100.00%	0.00%	83867786.44		2000	56.01%	13.71%	30.28%	218268627.77
Iowa	1996	99.03%	0.10%	0.86%	319275140.67	Montana	1996	99.72%	0.15%	0.12%	133307968.76
	1997	98.89%	0.17%	0.94%	294253657.45		1997	99.82%	0.11%	0.07%	154641068.92
	1998	98.98%	0.19%	0.83%	379913425.69		1998	99.81%	0.07%	0.12%	177766847.06
	1999	98.69%	0.25%	1.06%	373450481.75		1999	99.67%	0.10%	0.23%	176322837.45
	2000	98.87%	0.10%	1.03%	375348481.51		2000	99.56%	0.00%	0.44%	4218435.00

CBTU: Shares of coal shipments (MMBtu); PBTU: Shares of petroleum shipments (MMBtu); GBTU: Shares of natural gas shipments (MMBtu)
These values are computed from the source – FERC Form – 423

Table C.1 continued

STATE	YEAR	CBTU	PBTU	GBTU	TOTAL MMBTU	STATE	YEAR	CBTU	PBTU	GBTU	TOTAL MMBTU
North Carolina	1996	99.67%	0.20%	0.13%	614334429.44	Rhode Island	1996	0.00%	1.34%	98.66%	35837345.47
	1997	99.49%	0.31%	0.19%	650149248.81		1997	0.00%	0.00%	100.00%	31364133.53
	1998	99.38%	0.34%	0.28%	694083620.62		1998	0.00%	0.00%	100.00%	16024002.04
	1999	99.23%	0.45%	0.32%	641762443.89		1999	N/A	N/A	N/A	N/A
	2000	99.35%	0.36%	0.29%	560430929.42		2000	N/A	N/A	N/A	N/A
North Dakota	1996	99.72%	0.27%	0.00%	326302984.35	South Carolina	1996	99.78%	0.15%	0.07%	280039780.50
	1997	99.74%	0.26%	0.00%	303694098.95		1997	99.67%	0.26%	0.07%	305272548.69
	1998	99.87%	0.13%	0.00%	318216490.27		1998	99.68%	0.19%	0.13%	332609961.78
	1999	99.91%	0.09%	0.00%	323069689.31		1999	99.73%	0.16%	0.10%	330768877.00
	2000	99.92%	0.08%	0.00%	323168532.55		2000	99.78%	0.18%	0.03%	364325840.96
Nebraska	1996	99.31%	0.05%	0.64%	177924535.68	South Dakota	1996	99.85%	0.15%	0.01%	24587692.24
	1997	99.36%	0.07%	0.57%	184032395.65		1997	100.00%	0.00%	0.00%	34380058.00
	1998	99.01%	0.04%	0.95%	207043414.09		1998	99.98%	0.00%	0.02%	31312006.00
	1999	99.15%	0.04%	0.81%	205205749.33		1999	100.00%	0.00%	0.00%	37067120.00
	2000	99.21%	0.03%	0.76%	187172256.66		2000	100.00%	0.00%	0.00%	35229846.00
New Hampshire	1996	81.52%	18.48%	0.00%	42685461.29	Tennessee	1996	99.64%	0.36%	0.00%	572599506.51
	1997	80.15%	19.27%	0.58%	53019014.84		1997	99.85%	0.15%	0.00%	626454196.69
	1998	70.50%	29.50%	0.00%	52467778.58		1998	99.86%	0.14%	0.00%	634986215.41
	1999	67.32%	32.29%	0.39%	52103700.55		1999	99.68%	0.32%	0.00%	642849672.84
	2000	90.44%	8.70%	0.85%	44032609.31		2000	99.95%	0.05%	0.00%	644915522.51
New Jersey	1996	61.96%	16.23%	21.81%	101484785.19	Texas	1996	56.96%	0.11%	42.93%	2462011260.35
	1997	66.29%	11.37%	22.34%	83185855.63		1997	56.53%	0.12%	43.35%	2430163699.57
	1998	68.12%	12.39%	19.49%	89784297.85		1998	53.70%	0.05%	46.25%	2705247222.34
	1999	65.99%	14.70%	19.31%	103948518.88		1999	55.80%	0.04%	44.16%	2732697345.32
	2000	77.71%	7.89%	14.41%	61840042.22		2000	53.32%	0.15%	46.53%	2633742621.83
New Mexico	1996	90.47%	0.09%	9.44%	302367686.81	Utah	1996	99.31%	0.06%	0.64%	317553020.07
	1997	89.50%	0.08%	10.42%	319696870.74		1997	99.30%	0.04%	0.66%	343509648.74
	1998	87.83%	0.09%	12.08%	327614815.29		1998	98.69%	0.07%	1.24%	341432542.46
	1999	89.16%	0.11%	10.73%	328986454.24		1999	98.55%	0.07%	1.38%	335022393.74
	2000	87.53%	0.09%	12.38%	311026992.84		2000	97.43%	0.06%	2.51%	369898692.70
Nevada	1996	79.25%	0.09%	20.66%	205347481.40	Virginia	1996	94.10%	2.48%	3.42%	295150565.29
	1997	73.95%	0.11%	25.94%	206931556.20		1997	94.43%	2.67%	2.90%	317221083.68
	1998	77.01%	0.07%	22.92%	233689168.40		1998	87.87%	7.86%	4.28%	364749639.13
	1999	74.82%	0.05%	25.13%	242962629.31		1999	87.86%	6.82%	5.31%	373883410.30
	2000	71.90%	0.04%	28.06%	245488382.52		2000	87.63%	8.99%	3.37%	368026783.45
New York	1996	45.33%	23.03%	31.64%	454823343.39	Vermont	1996	97.62%	1.38%	1.00%	2433961.92
	1997	40.98%	17.34%	41.68%	529955687.48		1997	98.36%	0.41%	1.22%	2777841.54
	1998	40.55%	24.26%	35.19%	598468603.74		1998	92.35%	0.82%	6.83%	2783269.45
	1999	25.93%	28.73%	45.34%	406769586.55		1999	92.30%	0.00%	7.70%	3311397.69
	2000	14.57%	45.78%	39.66%	232168791.37		2000	68.69%	8.96%	22.35%	4859863.19
Ohio	1996	99.75%	0.18%	0.07%	1265170538.10	Washington	1996	99.83%	0.12%	0.05%	75723098.60
	1997	99.73%	0.22%	0.06%	1257862221.96		1997	99.87%	0.11%	0.02%	80482632.55
	1998	99.66%	0.22%	0.12%	1280218068.59		1998	99.91%	0.09%	0.00%	101067686.81
	1999	99.39%	0.35%	0.27%	1237409600.41		1999	99.92%	0.08%	0.00%	90310546.00
	2000	99.56%	0.31%	0.13%	1108915298.64		2000	99.91%	0.09%	0.00%	31124168.00
Oklahoma	1996	70.97%	0.09%	28.94%	474304433.94	Wisconsin	1996	99.46%	0.08%	0.46%	425860705.89
	1997	69.70%	0.05%	30.25%	455685690.29		1997	99.17%	0.09%	0.74%	445721090.05
	1998	65.07%	0.01%	34.92%	525060449.48		1998	98.96%	0.05%	0.98%	446183797.33
	1999	68.68%	0.01%	31.30%	527061620.58		1999	98.98%	0.06%	0.96%	447611748.90
	2000	65.64%	0.09%	34.27%	488631852.23		2000	99.06%	0.07%	0.87%	417636827.97
Oregon	1996	49.56%	0.00%	50.44%	29681645.00	West Virginia	1996	99.70%	0.25%	0.05%	780634758.33
	1997	57.79%	0.39%	41.82%	26517440.62		1997	99.70%	0.25%	0.05%	786698140.00
	1998	54.45%	0.05%	45.50%	64252323.37		1998	99.73%	0.23%	0.04%	842222096.39
	1999	63.58%	0.38%	36.05%	65570541.52		1999	99.72%	0.24%	0.04%	911877810.07
	2000	45.80%	0.72%	53.48%	75427647.56		2000	99.68%	0.29%	0.04%	661847908.96
Pennsyl- vania	1996	96.49%	2.87%	0.64%	1048873457.36	Wyoming	1996	99.83%	0.15%	0.02%	412277040.94
	1997	97.96%	1.76%	0.28%	1106205495.56		1997	99.81%	0.17%	0.02%	408693426.27
	1998	95.65%	3.92%	0.43%	1154272910.82		1998	99.88%	0.10%	0.02%	458649603.31
	1999	95.65%	3.24%	1.10%	914624460.38		1999	99.85%	0.11%	0.04%	447054099.19
	2000	94.16%	4.95%	0.89%	272518248.48		2000	99.77%	0.09%	0.14%	440673993.96

Continued

Table C.2: Fuel consumptions pattern by state of destination during the period of 1996-2000

STATE	YEAR	CBTU	PBTU	GBTU	TBTU	STATE	YEAR	CBTU	PBTU	GBTU	TBTU
Alaska	1996	97.35%	2.65%	0.00%	3544038.09	Illinois	1996	95.60%	1.20%	3.20%	783099368.85
	1997	97.33%	2.67%	0.00%	3409357.59		1997	93.84%	0.65%	5.51%	844241942.09
	1998	98.49%	1.51%	0.00%	3251761.33		1998	92.45%	0.80%	6.75%	834961422.66
	1999	99.42%	0.58%	0.00%	4017722.76		1999	93.06%	0.43%	6.51%	826178880.78
	2000	99.91%	0.09%	0.00%	4854942.62		2000	95.60%	0.74%	3.66%	905130919.87
Alabama	1996	99.62%	0.13%	0.25%	736227412.19	Indiana	1996	99.50%	0.20%	0.30%	1144334552.48
	1997	99.65%	0.14%	0.22%	718190665.40		1997	99.57%	0.19%	0.25%	1203795775.95
	1998	99.48%	0.14%	0.38%	723674095.53		1998	99.43%	0.18%	0.39%	1219191658.39
	1999	99.59%	0.10%	0.31%	740196753.17		1999	99.40%	0.23%	0.37%	1248589567.53
	2000	99.65%	0.13%	0.22%	776897529.99		2000	99.12%	0.16%	0.72%	1312322714.31
Arkansas	1996	87.93%	0.28%	11.79%	292181393.72	Kansas	1996	94.32%	0.44%	5.24%	349806927.58
	1997	90.03%	0.23%	9.74%	265203012.05		1997	93.03%	0.31%	6.66%	324155794.19
	1998	84.88%	0.39%	14.73%	286422566.80		1998	90.50%	0.22%	9.28%	336584875.90
	1999	84.14%	1.35%	14.51%	306715821.29		1999	90.56%	0.83%	8.61%	359006201.80
	2000	81.99%	0.73%	17.28%	305180632.24		2000	91.38%	1.23%	7.38%	390932391.66
Arizona	1996	96.43%	0.19%	3.38%	336591924.95	Kentucky	1996	99.79%	0.13%	0.07%	870796958.24
	1997	95.99%	0.16%	3.86%	371258812.65		1997	99.77%	0.16%	0.07%	899650479.32
	1998	94.15%	0.08%	5.77%	397730669.87		1998	99.74%	0.16%	0.10%	897580971.86
	1999	91.97%	0.11%	7.92%	422681338.49		1999	99.74%	0.15%	0.11%	931645293.54
	2000	89.07%	0.26%	10.67%	467764250.38		2000	99.79%	0.14%	0.08%	942887656.51
California	1996	0.00%	1.92%	98.08%	310470763.82	Louisiana	1996	43.68%	0.41%	55.91%	458173345.48
	1997	0.00%	0.08%	99.92%	356116863.02		1997	44.19%	1.38%	54.43%	503933179.87
	1998	0.00%	0.02%	99.98%	364492792.17		1998	41.79%	1.32%	56.89%	533182613.88
	1999	0.00%	0.00%	100.00%	408108522.04		1999	40.12%	1.12%	58.76%	561483998.93
	2000	0.00%	0.08%	99.92%	614512960.84		2000	42.18%	1.11%	56.70%	592125850.79
Colorado	1996	98.29%	0.35%	1.36%	342545476.51	Massachu-	1996	50.05%	28.86%	21.09%	219316679.44
	1997	98.93%	0.02%	1.05%	345564961.16	setts	1997	42.82%	40.49%	16.70%	283832468.63
	1998	98.53%	0.01%	1.46%	352670326.12		1998	37.87%	50.32%	11.81%	283559454.05
	1999	98.41%	0.04%	1.56%	351787570.23		1999	45.41%	45.06%	9.53%	241836181.29
	2000	97.31%	0.03%	2.66%	380614201.14		2000	51.48%	40.53%	7.99%	217217849.86
Connecticut	1996	28.07%	62.06%	9.87%	85799246.49	Maryland	1996	93.26%	4.86%	1.88%	290574717.74
	1997	20.97%	67.57%	11.46%	131777140.31		1997	92.76%	5.25%	1.99%	289165577.28
	1998	13.13%	77.99%	8.87%	117849345.85		1998	87.35%	11.02%	1.63%	324742401.18
	1999	0.00%	87.84%	12.16%	98111217.04		1999	83.77%	12.62%	3.60%	336326164.26
	2000	20.38%	65.48%	14.13%	98841228.59		2000	88.90%	6.28%	4.82%	304657994.56
DC	1996	0.00%	100.00%	0.00%	1456097.28	Maine	1996	0.00%	100.00%	0.00%	7048713.54
	1997	0.00%	100.00%	0.00%	762562.34		1997	0.00%	100.00%	0.00%	15602811.13
	1998	0.00%	100.00%	0.00%	2708601.81		1998	0.00%	100.00%	0.00%	17978812.41
	1999	0.00%	100.00%	0.00%	2652285.90		1999	0.00%	100.00%	0.00%	29492797.46
	2000	0.00%	100.00%	0.00%	1841342.30		2000	0.00%	100.00%	0.00%	20338795.20
Delaware	1996	71.92%	19.38%	8.70%	63299328.84	Michigan	1996	98.16%	1.35%	0.49%	683000109.82
	1997	75.49%	15.53%	8.97%	56744775.84		1997	97.28%	1.06%	1.66%	687199724.78
	1998	74.18%	22.38%	3.44%	56034498.29		1998	95.16%	1.51%	3.32%	745903375.90
	1999	63.12%	24.47%	12.41%	49318424.66		1999	94.41%	1.94%	3.65%	742551996.46
	2000	86.19%	12.03%	1.78%	51194802.58		2000	94.01%	0.52%	5.47%	726499461.21
Florida	1996	62.67%	21.69%	15.65%	1044709236.47	Minnesota	1996	98.45%	0.09%	1.47%	324932649.18
	1997	62.06%	22.38%	15.56%	1076720613.44		1997	98.62%	0.09%	1.29%	327430724.15
	1998	55.91%	32.24%	11.85%	1161506115.75		1998	98.53%	0.09%	1.38%	332922983.41
	1999	55.03%	30.24%	14.73%	1122731390.02		1999	98.63%	0.10%	1.27%	320581848.61
	2000	57.27%	29.00%	13.73%	1136397512.88		2000	98.94%	0.07%	0.99%	345403032.61
Georgia	1996	99.41%	0.19%	0.39%	677127174.31	Montana	1996	99.40%	0.20%	0.41%	603669333.78
	1997	99.40%	0.20%	0.40%	716631692.03		1997	99.53%	0.17%	0.30%	633798096.95
	1998	98.03%	0.44%	1.53%	730430664.42		1998	99.31%	0.18%	0.51%	667448844.36
	1999	98.07%	0.42%	1.51%	752579195.37		1999	99.36%	0.09%	0.54%	652576522.74
	2000	98.43%	0.54%	1.04%	803552231.89		2000	99.44%	0.10%	0.45%	670528930.94
Hawaii	1996	0.00%	100.00%	0.00%	54670956.94	Mississippi	1996	63.84%	5.70%	30.46%	191093605.22
	1997	0.00%	100.00%	0.00%	53907763.90		1997	62.46%	13.14%	24.40%	201552459.25
	1998	0.00%	100.00%	0.00%	53662927.82		1998	49.93%	20.99%	29.08%	242689148.05
	1999	0.00%	100.00%	0.00%	54935317.97		1999	56.03%	12.62%	31.35%	235835183.23
	2000	0.00%	100.00%	0.00%	55834262.49		2000	61.38%	11.89%	26.73%	230482011.93
Iowa	1996	98.89%	0.10%	1.00%	314865543.54	Montana	1996	99.80%	0.10%	0.10%	134001203.30
	1997	98.32%	0.09%	1.59%	327649941.64		1997	99.87%	0.07%	0.06%	157535850.70
	1998	98.99%	0.08%	0.94%	356375640.33		1998	99.81%	0.08%	0.11%	178111331.30
	1999	98.74%	0.13%	1.14%	357600679.56		1999	99.90%	0.05%	0.06%	176938207.80
	2000	98.76%	0.08%	1.16%	380104647.10		2000	99.87%	0.11%	0.02%	165866257.60

CBTU: Shares of coal consumptions (MMBtu); PBTU: Shares of petroleum consumptions (MMBtu); GBTU: Shares of natural gas consumptions (MMBtu)
These values are computed from the source – Form EIA-767

Table C.2 continued

STATE	YEAR	CBTU	PBTU	GBTU	TBTU	STATE	YEAR	CBTU	PBTU	GBTU	TBTU
North Carolina	1996	99.76%	0.24%	0.00%	624722993.10	Rhode Island	1996	N/A	N/A	N/A	N/A
	1997	99.77%	0.23%	0.00%	672581915.34		1997	N/A	N/A	N/A	N/A
	1998	99.78%	0.22%	0.00%	664310455.68		1998	N/A	N/A	N/A	N/A
	1999	99.76%	0.23%	0.00%	660632097.92		1999	N/A	N/A	N/A	N/A
	2000	99.76%	0.22%	0.02%	694839364.94		2000	N/A	N/A	N/A	N/A
North Dakota	1996	99.72%	0.28%	0.00%	311429759.40	South Carolina	1996	99.69%	0.17%	0.14%	303027437.15
	1997	99.72%	0.28%	0.00%	297056396.04		1997	99.64%	0.29%	0.07%	309107268.30
	1998	99.85%	0.15%	0.00%	315223413.38		1998	99.71%	0.14%	0.15%	317654086.63
	1999	99.89%	0.11%	0.00%	318271545.42		1999	99.66%	0.23%	0.10%	345844510.35
	2000	99.87%	0.13%	0.00%	323870830.87		2000	95.21%	4.75%	0.03%	397494981.11
Nebraska	1996	99.30%	0.05%	0.66%	174390331.43	South Dakota	1996	99.63%	0.27%	0.10%	26028979.60
	1997	99.18%	0.11%	0.70%	186491902.02		1997	99.85%	0.10%	0.05%	34740517.80
	1998	98.28%	0.10%	1.61%	200845091.15		1998	99.70%	0.28%	0.02%	32495252.40
	1999	98.38%	0.05%	1.57%	194308919.13		1999	94.94%	0.28%	4.77%	39176051.00
	2000	96.78%	1.40%	1.81%	203558509.52		2000	99.91%	0.09%	0.00%	38410207.10
New Hampshire	1996	78.56%	21.43%	0.01%	44540246.48	Tennessee	1996	99.80%	0.20%	0.00%	548896870.62
	1997	78.19%	20.60%	1.21%	55271200.47		1997	99.85%	0.15%	0.00%	581971341.41
	1998	71.71%	28.29%	0.00%	52904285.38		1998	99.83%	0.17%	0.00%	549154744.76
	1999	67.51%	31.81%	0.69%	51908870.52		1999	99.79%	0.21%	0.00%	549760417.19
	2000	88.50%	9.81%	1.69%	49021450.87		2000	99.81%	0.19%	0.00%	597988843.41
New Jersey	1996	86.27%	4.45%	9.28%	71097559.43	Texas	1996	57.69%	0.26%	42.05%	2429238245.86
	1997	90.68%	2.79%	6.54%	81139841.62		1997	57.95%	0.10%	41.95%	2446715531.69
	1998	82.26%	5.63%	12.12%	72835852.84		1998	53.39%	0.02%	46.59%	2613882844.06
	1999	82.00%	5.37%	12.63%	81522655.92		1999	55.26%	0.06%	44.67%	2559747983.14
	2000	88.05%	4.76%	7.19%	93198256.00		2000	54.75%	0.46%	44.79%	2638856502.66
New Mexico	1996	90.68%	0.08%	9.24%	306302729.04	Utah	1996	99.25%	0.10%	0.65%	312318140.07
	1997	90.24%	0.07%	9.69%	321548157.83		1997	99.23%	0.09%	0.69%	330731172.83
	1998	89.41%	0.08%	10.51%	322122145.31		1998	98.68%	0.09%	1.24%	341180278.77
	1999	90.34%	0.10%	9.56%	322244353.04		1999	98.57%	0.08%	1.35%	343431346.57
	2000	89.43%	0.10%	10.47%	338845702.38		2000	97.27%	0.09%	2.65%	351474639.34
Nevada	1996	86.22%	0.49%	13.28%	204738309.31	Virginia	1996	97.37%	2.09%	0.54%	283462819.70
	1997	86.17%	0.12%	13.71%	200643827.76		1997	96.71%	2.76%	0.53%	303452342.73
	1998	86.80%	0.17%	13.03%	218773487.42		1998	91.96%	7.74%	0.30%	336728924.72
	1999	86.70%	0.12%	13.18%	213932810.49		1999	91.40%	8.34%	0.26%	345426830.64
	2000	83.86%	0.28%	15.86%	243710058.90		2000	93.44%	6.48%	0.08%	362336728.12
New York	1996	45.75%	21.56%	32.70%	446752917.16	Vermont	1996	0.00%	49.75%	50.25%	47377.61
	1997	41.35%	16.27%	42.37%	524931737.86		1997	0.00%	0.00%	100.00%	35006.80
	1998	39.25%	25.01%	35.73%	596312845.15		1998	0.00%	14.81%	85.19%	216237.78
	1999	35.17%	21.16%	43.67%	615537568.55		1999	0.00%	3.63%	96.37%	251918.00
	2000	40.99%	25.33%	33.68%	580156469.79		2000	0.00%	12.86%	87.14%	1212263.20
Ohio	1996	99.72%	0.20%	0.08%	1287591045.77	Washington	1996	99.93%	0.07%	0.01%	84801085.20
	1997	99.73%	0.20%	0.06%	1259796873.56		1997	99.85%	0.07%	0.08%	73443196.10
	1998	99.65%	0.19%	0.16%	1291622566.96		1998	99.95%	0.05%	0.00%	96925900.00
	1999	99.53%	0.25%	0.22%	1250814638.89		1999	99.93%	0.05%	0.02%	90935464.00
	2000	99.71%	0.19%	0.10%	1310430381.39		2000	99.90%	0.08%	0.02%	100055999.80
Oklahoma	1996	73.34%	0.20%	26.46%	457814647.40	Wisconsin	1996	99.31%	0.10%	0.59%	413248427.31
	1997	75.64%	0.01%	24.34%	460431999.58		1997	99.30%	0.05%	0.65%	439762499.74
	1998	67.04%	0.01%	32.95%	486392771.32		1998	98.88%	0.06%	1.06%	434163192.60
	1999	65.59%	0.02%	34.39%	484798784.21		1999	98.83%	0.05%	1.11%	433460821.08
	2000	71.48%	0.19%	28.33%	486652303.48		2000	98.84%	0.16%	1.01%	446973888.84
Oregon	1996	99.79%	0.21%	0.00%	18210119.92	West Virginia	1996	99.70%	0.25%	0.05%	754189982.03
	1997	99.27%	0.73%	0.00%	15905297.36		1997	99.76%	0.20%	0.04%	853824293.84
	1998	99.78%	0.22%	0.00%	34554230.80		1998	99.73%	0.22%	0.05%	868227260.28
	1999	99.83%	0.17%	0.00%	38207483.60		1999	99.75%	0.21%	0.04%	891048637.19
	2000	99.84%	0.16%	0.00%	35455970.00		2000	99.66%	0.28%	0.06%	873932085.97
Pennsyl-vania	1996	96.58%	2.77%	0.65%	1018687286.45	Wyoming	1996	99.83%	0.15%	0.02%	425771906.26
	1997	97.50%	1.80%	0.70%	1079475935.36		1997	99.84%	0.14%	0.02%	424944475.04
	1998	96.06%	3.42%	0.52%	1104379528.22		1998	99.89%	0.10%	0.02%	467952818.72
	1999	95.97%	3.07%	0.96%	1030222080.88		1999	99.85%	0.11%	0.04%	453558449.12
	2000	96.43%	3.18%	0.39%	1088970633.58		2000	99.78%	0.08%	0.13%	462408438.89

Continued

Table C.3: Unit Btu values of fuel shipments by state of destination during the period of 1996-2000

STATE	YEAR	UCBTU	UPBTU	UGBTU	STATE	YEAR	UCBTU	UPBTU	UGBTU
Alaska	1996	.	.	1000.76	Illinois	1996	9887.27	149181.60	1020.19
	1997	.	.	1000.04		1997	9787.42	146913.25	1015.53
	1998	.	.	1000.03		1998	9812.28	148752.75	1019.36
	1999	.	.	999.91		1999	9565.29	145807.10	1022.14
	2000	.	.	1000.05		2000	9698.79	137442.12	1031.15
Alabama	1996	11793.91	139384.98	1024.27	Indiana	1996	10371.46	137321.82	1020.75
	1997	11584.19	139646.30	1030.57		1997	10487.79	137049.49	1020.82
	1998	11518.71	139510.44	1044.39		1998	10524.75	137318.56	1025.47
	1999	10962.79	139142.53	1010.51		1999	10639.10	137245.50	1025.93
	2000	10951.50	137397.01	1033.86		2000	10615.86	137387.52	1023.46
Arkansas	1996	10232.42	142293.72	1015.41	Kansas	1996	8827.24	141942.49	973.25
	1997	10158.80	140336.74	1014.26		1997	8765.95	154117.62	978.04
	1998	10186.49	138850.90	1013.71		1998	8696.04	144688.94	1001.16
	1999	10256.64	138692.07	1010.67		1999	8628.06	147608.67	1009.71
	2000	10229.97	138607.97	1016.45		2000	8671.83	154872.13	1010.03
Arizona	1996	8702.55	139077.73	1023.67	Kentucky	1996	11538.36	137128.93	1021.64
	1997	8707.03	140073.84	1029.18		1997	11571.85	132346.30	1022.83
	1998	8670.67	141228.28	1022.71		1998	11580.02	100928.77	1024.07
	1999	8650.73	140807.29	1022.20		1999	11596.58	136645.91	1025.00
	2000	8680.77	140489.92	1020.16		2000	11604.37	136383.95	1025.00
California	1996	.	.	1020.03	Louisiana	1996	8171.15	147222.74	1043.38
	1997	.	.	1016.39		1997	8101.75	153519.34	1035.65
	1998	.	144857.00	1017.55		1998	8097.28	153401.93	1042.96
	1999	.	144857.00	1006.18		1999	8149.36	154471.16	1039.04
	2000	.	140000.00	1001.60		2000	7933.09	149842.86	1034.25
Colorado	1996	9858.31	91500.00	998.41	Massachu-setts	1996	12633.25	151996.37	1036.72
	1997	9871.67	91500.00	994.95		1997	12570.99	151641.43	1033.48
	1998	9833.80	91500.00	993.82		1998	12616.95	151402.88	1028.88
	1999	9748.55	109989.81	1031.93		1999	13159.60	149853.29	1026.17
	2000	9796.97	107873.29	1021.39		2000	13136.90	143297.88	1036.70
Connecticut	1996	13100.01	153018.41	1018.92	Maryland	1996	12878.89	150176.91	1041.15
	1997	13131.94	152431.95	1018.54		1997	12912.92	150922.20	1041.42
	1998	13137.77	152132.26	1029.54		1998	12914.49	150776.41	1046.51
	1999	13541.00	152336.80	1024.73		1999	12942.54	151072.52	1040.18
	2000	.	.	.		2000	12944.68	150182.29	1043.77
DC	1996	.	143262.51	.	Maine	1996	.	150390.53	.
	1997	.	144404.07	.		1997	.	151068.01	.
	1998	.	143070.61	.		1998	.	151239.60	.
	1999	.	143278.98	.		1999	.	150838.65	.
	2000	13251.16	142642.92	.		2000	.	.	.
Delaware	1996	13020.15	151901.10	1034.20	Michigan	1996	10508.35	147556.82	273.63
	1997	13062.18	151464.74	1034.51		1997	10608.96	147648.46	310.18
	1998	12961.66	150957.27	971.31		1998	10577.64	147899.38	541.73
	1999	12935.35	150998.58	983.49		1999	10589.70	148828.47	607.80
	2000	12995.38	150486.26	1007.91		2000	10860.11	147807.65	709.81
Florida	1996	12213.20	151876.34	1008.15	Minnesota	1996	8972.62	138855.53	1003.00
	1997	12187.65	152640.53	1043.75		1997	8967.15	136689.96	1003.66
	1998	12233.32	151575.68	1052.70		1998	8951.06	137796.94	1008.06
	1999	12346.49	152090.05	1043.96		1999	8950.53	137595.64	1010.78
	2000	12380.68	152420.08	1038.47		2000	8992.49	137649.58	1011.00
Georgia	1996	11579.41	140609.71	1024.11	Montana	1996	9071.16	140709.21	1010.82
	1997	11753.53	140357.17	1024.03		1997	8996.41	143525.56	1006.21
	1998	11748.80	138481.59	1028.07		1998	8995.52	143394.24	1010.88
	1999	11738.48	138487.08	1032.21		1999	9000.05	138006.11	1003.00
	2000	11557.81	138475.44	1031.15		2000	8936.86	137799.87	1006.80
Hawaii	1996	.	148815.59	.	Mississippi	1996	11023.45	154383.09	1038.15
	1997	.	149351.34	.		1997	10486.03	156867.82	1035.74
	1998	.	149204.94	.		1998	10570.73	157346.91	1038.76
	1999	.	149491.51	.		1999	11062.13	157968.35	1027.15
	2000	.	149703.65	.		2000	11548.66	155569.30	1028.15
Iowa	1996	8684.39	138481.67	1002.51	Montana	1996	8438.57	118200.00	1075.33
	1997	8686.42	138236.68	1002.94		1997	8425.77	115037.32	1071.19
	1998	8653.62	139096.91	1003.25		1998	8433.16	121738.71	1072.33
	1999	8581.25	139340.85	1003.93		1999	8435.00	119400.00	1092.41
	2000	8626.03	138731.38	1003.03		2000	6618.08	.	1138.95

UCBTU: Unit Btu of coal shipments (Btu/pound); UPBTU: Unit Btu of petroleum shipments (Btu/gallon); UGBTU: Unit Btu of natural gas shipments (Btu/cu. ft.)
These values are computed from the source – FERC Form – 423

Table C.3 continued

STATE	YEAR	UCBTU	UPBTU	UGBTU	STATE	YEAR	UCBTU	UPBTU	UGBTU
North Carolina	1996	12421.87	138299.99	1036.32	Rhode Island	1996	.	140390.71	1028.00
	1997	12367.68	138266.03	1036.82		1997	.	.	1026.84
	1998	12397.58	138167.96	1047.69		1998	.	.	1028.12
	1999	12450.11	138170.62	1030.97		1999	.	.	.
	2000	12447.82	138360.91	1025.62		2000	.	.	.
North Dakota	1996	6882.48	139313.65	1058.72	South Carolina	1996	12757.48	138371.02	1024.58
	1997	6559.67	139090.85	1066.45		1997	12855.02	138068.05	1024.02
	1998	6566.26	138812.23	1049.53		1998	12805.21	138121.91	1024.00
	1999	6547.28	138876.00	1041.71		1999	12809.26	138150.73	1028.00
	2000	6528.43	138959.59	1045.12		2000	12727.14	138243.06	1028.00
Nebraska	1996	8598.83	137622.37	1004.00	South Dakota	1996	9140.16	140000.00	1014.00
	1997	8594.82	137568.12	997.63		1997	8770.42	.	.
	1998	8584.62	137642.69	989.12		1998	8924.40	.	1000.00
	1999	8498.22	137672.91	994.55		1999	8734.01	.	.
	2000	8632.07	137751.77	1001.20		2000	8563.40	.	.
New Hampshire	1996	13145.51	154516.73	.	Tennessee	1996	12062.05	139792.23	.
	1997	13054.29	152622.06	1017.00		1997	11855.47	139900.00	.
	1998	13132.68	151851.93	.		1998	11732.54	139886.47	.
	1999	13133.37	153221.55	1023.92		1999	11635.07	139900.00	.
	2000	13114.30	153740.81	1068.97		2000	11629.34	139900.00	.
New Jersey	1996	12999.30	147322.60	1020.13	Texas	1996	7440.46	138385.50	1023.26
	1997	13099.91	148489.03	1037.21		1997	7426.46	138472.51	1023.09
	1998	13129.99	148656.39	1045.47		1998	7531.38	138846.89	1023.88
	1999	13158.24	149297.43	1030.87		1999	7523.27	138003.00	1020.54
	2000	13154.72	149559.31	1027.21		2000	7548.98	139674.67	1020.25
New Mexico	1996	9116.17	136000.00	1011.74	Utah	1996	11513.44	139570.68	1021.01
	1997	9068.98	136000.00	1017.09		1997	11330.07	139821.34	1031.64
	1998	9082.28	136000.00	1010.07		1998	11310.40	139757.72	1044.17
	1999	9132.24	136000.00	1012.78		1999	11621.72	139722.08	1043.29
	2000	9205.93	136000.00	1015.83		2000	11678.05	139292.66	1048.98
Nevada	1996	11139.73	136898.67	1029.32	Virginia	1996	12597.32	146896.68	1057.32
	1997	11168.84	138761.31	1028.57		1997	12553.85	148219.07	1068.58
	1998	11199.04	138847.50	1033.55		1998	12602.64	150158.49	1049.51
	1999	11257.17	139110.00	1036.54		1999	12701.51	150483.63	1056.31
	2000	11211.31	139110.00	1022.91		2000	12814.17	150892.68	1033.82
New York	1996	13003.18	149672.40	1029.06	Vermont	1996	5400.00	133376.67	1014.63
	1997	13099.20	150326.28	1025.94		1997	5400.00	136720.00	1011.56
	1998	13050.78	150741.82	1028.87		1998	5400.00	136130.00	1013.87
	1999	13033.89	150570.70	1023.92		1999	5400.00	.	1012.00
	2000	13117.42	151162.24	1018.80		2000	5402.07	134088.91	1012.00
Ohio	1996	12056.78	137759.92	1027.69	Washington	1996	7928.47	139931.75	1050.00
	1997	11891.18	137988.71	1024.32		1997	8049.30	139944.14	1048.42
	1998	11916.51	137773.63	1027.15		1998	8214.10	139908.27	1054.68
	1999	11918.83	138054.35	1027.62		1999	8224.03	140000.00	.
	2000	11823.47	137727.20	1024.87		2000	8309.67	140000.00	.
Oklahoma	1996	8600.15	139661.45	1027.93	Wisconsin	1996	9195.21	139719.70	1010.25
	1997	8641.01	140095.82	1031.70		1997	9349.27	139650.10	1008.02
	1998	8651.23	141968.27	1030.17		1998	9292.94	139978.98	1013.25
	1999	8619.50	142350.00	1027.55		1999	9127.50	139969.64	1009.94
	2000	8727.82	140888.08	1028.79		2000	9185.78	140000.00	1008.01
Oregon	1996	8781.53	.	1009.48	West Virginia	1996	12378.41	138655.40	1000.00
	1997	8757.46	140000.00	1011.00		1997	12397.78	138884.47	1000.00
	1998	8685.26	140000.00	1011.00		1998	12305.47	139186.02	1000.00
	1999	8961.43	140000.00	1012.16		1999	12361.07	139101.85	1000.00
	2000	8636.45	140000.00	1016.05		2000	12280.79	139323.94	1000.00
Pennsyl-vania	1996	12332.78	149581.78	1027.84	Wyoming	1996	8734.40	139173.25	1039.50
	1997	12289.24	151269.14	1033.88		1997	8787.84	138823.27	1041.20
	1998	12346.46	149656.76	1028.62		1998	8795.67	139139.92	1044.02
	1999	12587.11	150039.10	1033.27		1999	8785.05	139102.40	1044.02
	2000	12700.78	150960.11	1032.77		2000	8804.57	139219.76	1044.00

Continued

Table C.4: Unit Btu values of fuel consumptions by state during the period of 1996-2000

STATE	YEAR	UCBTU	UPBTU	UGBTU	STATE	YEAR	UCBTU	UPBTU	UGBTU
Alaska	1996	7794.97	138128.00	.	Illinois	1996	9796.85	148543.66	1019.27
	1997	7752.79	132349.00	.		1997	9658.18	145803.07	1014.36
	1998	7596.30	139349.00	.		1998	9705.73	145307.43	1017.73
	1999	7825.97	132349.00	.		1999	9647.95	143121.04	1021.02
	2000	7534.01	135310.00	.		2000	9441.84	147975.94	1018.58
Alabama	1996	11754.33	138886.54	1034.10	Indiana	1996	10321.50	137498.11	1013.09
	1997	11542.17	138951.04	1043.80		1997	10385.28	137120.97	1009.94
	1998	11471.95	139116.37	1068.26		1998	10467.50	137143.33	1019.88
	1999	11008.73	139110.94	1018.76		1999	10571.06	137201.95	1024.45
	2000	10906.68	138755.68	1020.68		2000	10531.97	137064.45	1024.47
Arkansas	1996	8616.10	146261.37	1025.11	Kansas	1996	8759.70	146995.53	974.83
	1997	8571.75	141918.05	1025.35		1997	8715.35	144846.84	980.76
	1998	8569.99	145966.51	1016.06		1998	8681.87	138272.58	1000.40
	1999	8592.19	148484.35	1017.96		1999	8601.56	147938.52	1009.07
	2000	8541.28	149420.84	1018.88		2000	8652.34	153184.56	1012.30
Arizona	1996	10224.18	141918.54	1015.32	Kentucky	1996	11745.36	138746.18	1021.51
	1997	10176.96	138508.83	1013.47		1997	11726.51	137562.12	1022.94
	1998	10214.03	139153.41	1012.47		1998	11706.53	137855.23	1023.41
	1999	10224.74	139548.65	1010.31		1999	11678.96	138105.67	1021.28
	2000	10230.80	141594.50	1016.74		2000	11703.27	138874.66	1020.07
California	1996	.	144556.87	1024.76	Louisiana	1996	7953.54	145264.46	1038.86
	1997	.	146188.78	1020.57		1997	7940.00	151654.85	1035.69
	1998	.	146226.42	1022.65		1998	7931.99	152100.84	1034.56
	1999	.	145548.00	1019.30		1999	8008.23	150954.29	1030.58
	2000	.	139033.35	1019.26		2000	7953.92	149334.66	1042.44
Colorado	1996	9955.23	137586.21	983.58	Massachu-	1996	12452.90	151475.97	1035.70
	1997	9859.77	135683.75	1010.16	setts	1997	12442.04	151125.68	1033.76
	1998	9840.54	138644.76	1009.20		1998	12453.41	150695.02	1029.37
	1999	9775.62	135178.23	979.94		1999	12526.91	151055.03	1032.38
	2000	9847.37	134345.53	958.81		2000	12464.04	151496.87	1041.53
Connecticut	1996	13015.90	152680.62	1019.71	Maryland	1996	12870.15	150516.04	1041.15
	1997	13063.51	151889.89	1022.04		1997	12893.77	150823.03	1041.29
	1998	13123.26	151220.66	1033.90		1998	12931.38	150633.33	1046.51
	1999	.	151783.39	1027.77		1999	12905.30	150807.81	1041.01
	2000	13070.00	151913.77	1021.85		2000	12859.74	150404.79	1043.60
DC	1996	.	143556.86	.	Maine	1996	.	150991.01	.
	1997	.	144441.10	.		1997	.	151038.99	.
	1998	.	143280.43	.		1998	.	151062.91	.
	1999	.	143521.96	.		1999	.	150653.16	.
	2000	.	143132.50	.		2000	.	151415.49	.
Delaware	1996	12801.35	150287.80	1036.22	Michigan	1996	10388.09	146067.83	1023.47
	1997	12823.19	149928.32	1036.36		1997	10406.86	146809.99	1015.98
	1998	12777.66	149024.25	1043.77		1998	10415.69	147020.19	1016.38
	1999	12661.13	150200.98	1034.56		1999	10391.71	147969.65	1014.81
	2000	12654.51	148690.61	1031.37		2000	10297.22	143196.12	1013.72
Florida	1996	12098.84	152055.03	1011.50	Minnesota	1996	8877.11	138557.56	1005.17
	1997	11976.38	152638.94	1013.56		1997	8920.13	138143.41	1006.02
	1998	11976.62	151587.36	1013.71		1998	8908.31	137482.30	1009.71
	1999	12116.07	151704.66	1019.28		1999	8917.58	137791.94	1013.81
	2000	12140.19	152364.87	1012.28		2000	8934.06	137150.74	1013.37
Georgia	1996	11541.04	142995.91	1024.16	Montana	1996	9052.21	148021.46	1007.59
	1997	11603.27	143556.02	1025.00		1997	8919.54	145725.80	1005.94
	1998	11731.19	146198.61	1023.92		1998	8906.41	141380.70	1010.25
	1999	11631.89	147423.30	1025.06		1999	8875.27	138281.95	1009.04
	2000	11745.51	147302.35	1024.13		2000	8875.45	138365.39	1008.07
Hawaii	1996	.	148910.87	.	Mississippi	1996	10969.31	154130.06	1026.07
	1997	.	149496.62	.		1997	10430.17	149998.25	1023.31
	1998	.	149206.93	.		1998	10579.67	149051.65	1030.50
	1999	.	149456.53	.		1999	10970.90	148129.26	1019.30
	2000	.	149715.88	.		2000	11348.45	142568.98	1020.21
Iowa	1996	8607.58	138334.07	1002.96	Montana	1996	8467.14	141000.00	1078.26
	1997	8578.51	138451.39	1010.24		1997	8471.50	141000.00	1044.24
	1998	8579.32	138381.99	1011.72		1998	8433.27	141000.00	1052.23
	1999	8558.08	138521.70	1013.81		1999	8437.34	141000.00	1095.08
	2000	8635.80	138523.40	1009.26		2000	8390.90	141000.00	1053.81

UCBTU: Unit Btu of coal consumptions (Btu/pound); UPBTU: Unit Btu of petroleum consumptions (Btu/gallon); UGBTU: Unit Btu of natural gas consumptions (Btu/cu. ft.)
These values are computed from the source – Form EIA – 767

Table C.4 continued

STATE	YEAR	UCBTU	UPBTU	UGBTU	STATE	YEAR	UCBTU	UPBTU	UGBTU
North Carolina	1996	12388.53	139334.36	.	Rhode Island	1996	.	.	.
	1997	12334.20	139458.76	.		1997	.	.	.
	1998	12370.22	139459.44	.		1998	.	.	.
	1999	12415.28	139299.25	1032.29		1999	.	.	.
	2000	12420.91	139562.42	1026.20		2000	.	.	.
North Dakota	1996	6593.63	139556.82	1057.50	South Carolina	1996	12704.90	139975.93	1020.93
	1997	6529.54	144063.45	1055.00		1997	12757.91	138094.12	1023.96
	1998	6486.94	142907.80	.		1998	12782.52	139522.28	1036.56
	1999	6481.49	139722.38	.		1999	12774.63	143046.87	1025.30
	2000	6452.08	140742.81	.		2000	12724.04	139842.75	1025.61
Nebraska	1996	8578.62	138577.55	1005.90	South Dakota	1996	8925.02	137458.33	1020.74
	1997	8568.08	139126.07	1000.40		1997	8649.65	139491.53	1022.48
	1998	8547.20	146134.93	998.54		1998	8681.45	139922.58	1003.25
	1999	8500.18	142009.54	1005.01		1999	8614.18	139957.67	1020.64
	2000	8607.73	140534.34	1008.68		2000	8439.55	139896.55	1001.27
New Hampshire	1996	12951.61	153014.80	1020.23	Tennessee	1996	12025.40	138208.62	.
	1997	12997.26	152352.95	1019.00		1997	11890.82	138182.36	.
	1998	12939.18	150918.68	1018.56		1998	11754.96	138104.73	.
	1999	13076.54	150750.72	1010.62		1999	11739.19	138038.57	.
	2000	12971.69	151845.06	1066.48		2000	11715.92	138175.24	.
New Jersey	1996	12887.89	148828.43	1033.71	Texas	1996	7407.02	142703.74	1021.20
	1997	12909.54	148382.52	1034.82		1997	7354.82	139353.75	1020.29
	1998	12861.77	149192.06	1041.61		1998	7435.32	139951.27	1022.33
	1999	12861.56	150209.96	1031.86		1999	7402.74	138038.26	1019.10
	2000	12914.71	148739.77	1029.62		2000	7502.70	140262.04	1021.41
New Mexico	1996	9119.30	134769.09	1011.37	Utah	1996	11586.36	138281.27	1021.23
	1997	9193.21	134751.26	1011.53		1997	11532.03	138593.59	1031.64
	1998	9064.35	134722.00	1012.14		1998	11484.55	139122.52	1042.47
	1999	9087.87	134722.00	1012.24		1999	11642.15	139219.85	1043.26
	2000	9176.20	135998.52	1017.85		2000	11748.78	137186.53	1048.98
Nevada	1996	11896.08	148669.05	1027.28	Virginia	1996	12578.00	147486.09	1165.25
	1997	11972.82	142194.59	1029.50		1997	12581.59	149706.32	1258.64
	1998	11902.96	148935.33	1042.42		1998	12559.48	149853.92	1058.80
	1999	11957.78	144873.63	1043.12		1999	12728.97	151935.06	1080.15
	2000	11788.89	146844.30	1022.98		2000	12752.02	150707.75	1091.47
New York	1996	12862.36	149609.66	1029.28	Vermont	1996	.	136888.00	1013.00
	1997	12934.88	149698.44	1028.32		1997	.	.	1011.76
	1998	12952.17	149935.34	1034.03		1998	.	136130.00	1013.31
	1999	13061.87	149866.76	1027.20		1999	.	136000.00	1012.00
	2000	13023.66	150155.46	1024.80		2000	.	136000.00	1012.00
Ohio	1996	12000.40	137713.82	1030.73	Washington	1996	7693.95	139957.45	1035.27
	1997	11867.69	137819.49	1031.93		1997	7685.36	140000.00	1022.66
	1998	11850.71	137795.85	1030.30		1998	7926.70	140000.00	1036.98
	1999	11899.55	138007.93	1029.33		1999	7934.51	139900.00	1051.88
	2000	11738.87	137844.50	1030.13		2000	7977.44	140000.00	1032.92
Oklahoma	1996	8588.85	141755.06	1030.12	Wisconsin	1996	9170.72	138899.93	1006.96
	1997	8564.63	140586.50	1034.75		1997	9263.45	139683.74	1005.78
	1998	8637.24	138763.09	1030.20		1998	9220.06	140115.82	1011.35
	1999	8614.31	138834.36	1030.46		1999	9074.51	139998.63	1007.43
	2000	8704.86	139130.01	1031.00		2000	9147.80	140361.31	1005.34
Oregon	1996	8708.45	138800.00	.	West Virginia	1996	11475.48	138909.69	1000.00
	1997	8752.05	138804.00	.		1997	12352.47	139032.08	1000.00
	1998	8706.68	138800.00	.		1998	12315.60	139127.51	1000.00
	1999	9025.88	138800.00	.		1999	12361.74	138933.47	1000.00
	2000	8517.25	138800.00	.		2000	12294.85	139340.37	1000.00
Pennsyl-vania	1996	12057.56	149597.88	1030.25	Wyoming	1996	8638.80	139262.40	1039.99
	1997	12419.08	149772.17	1018.98		1997	8711.16	138722.43	1041.24
	1998	12422.01	150831.42	1030.54		1998	8756.96	139301.03	1044.02
	1999	12506.18	149993.24	1031.70		1999	8736.12	139088.45	1044.60
	2000	12531.57	149885.55	1038.20		2000	8765.37	140103.73	1044.00

Continued

Table C.5: Shares of end-of-year fuel stocks by year during the period of 1996-1998

STATE	FUEL	1996	1997	1998	TQ
Alaska	Coal	51.79%	44.90%	3.31%	18150
	Petroleum	35.72%	35.28%	28.99%	47957
Alabama	Coal	29.87%	34.69%	35.43%	114004540
	Petroleum	27.58%	31.12%	41.30%	6443187
Arkansas	Coal	49.94%	29.18%	20.88%	65503215
	Petroleum	29.90%	31.63%	38.47%	7956638
Arizona	Coal	46.31%	25.85%	27.84%	77695873
	Petroleum	34.54%	32.06%	33.40%	10717546
California	Coal	0.00%	0.00%	0.00%	0
	Petroleum	43.08%	34.58%	22.35%	172190610
Colorado	Coal	37.11%	31.88%	31.01%	106282278
	Petroleum	34.49%	29.00%	36.51%	3878279
Connecticut	Coal	33.26%	34.20%	32.54%	4554713
	Petroleum	27.88%	34.98%	37.14%	65091568
DC	Coal	0.00%	0.00%	0.00%	0
	Petroleum	33.70%	34.48%	31.82%	3419109
Delaware	Coal	29.61%	33.48%	36.91%	11521709
	Petroleum	27.97%	34.30%	37.73%	12105329
Florida	Coal	28.92%	32.41%	38.67%	95562279
	Petroleum	31.36%	33.47%	35.18%	233193460
Georgia	Coal	36.46%	33.08%	30.47%	124288049
	Petroleum	33.20%	33.75%	33.05%	14541074
Hawaii	Coal	0.00%	0.00%	0.00%	0
	Petroleum	32.80%	34.82%	32.38%	20126105
Iowa	Coal	41.11%	31.99%	26.90%	119421792
	Petroleum	35.29%	34.92%	29.79%	1270358
Illinois	Coal	31.47%	31.84%	36.69%	192687675
	Petroleum	27.99%	36.97%	35.04%	33519030
Indiana	Coal	38.12%	29.30%	32.58%	268373728
	Petroleum	32.96%	28.49%	38.54%	3622574
Kansas	Coal	39.33%	29.60%	31.08%	104755733
	Petroleum	31.37%	28.43%	40.21%	17071343
Kentucky	Coal	31.50%	32.13%	36.37%	155383172
	Petroleum	31.83%	33.89%	34.28%	4787613
Louisiana	Coal	43.27%	30.18%	26.56%	74887485
	Petroleum	25.90%	29.09%	45.00%	48216689
Massachusetts	Coal	36.79%	36.53%	26.68%	20323386
	Petroleum	40.69%	37.97%	21.34%	47285065
Maryland	Coal	33.16%	34.35%	32.49%	41877775
	Petroleum	38.84%	28.33%	32.83%	51049402
Nebraska	Coal	0.00%	0.00%	0.00%	0
	Petroleum	29.59%	30.64%	39.76%	15061667
Michigan	Coal	29.52%	31.12%	39.36%	192346372
	Petroleum	27.63%	27.01%	45.35%	28486487
Minnesota	Coal	32.73%	31.09%	36.18%	63787819
	Petroleum	37.57%	31.08%	31.35%	1224853
Montana	Coal	35.46%	31.32%	33.22%	161737354
	Petroleum	28.47%	32.29%	39.24%	4873173
Mississippi	Coal	29.09%	34.53%	36.38%	23608263
	Petroleum	20.39%	30.49%	49.11%	32015599
Montana	Coal	36.71%	34.69%	28.60%	16877249
	Petroleum	31.38%	31.55%	37.06%	336292
North Carolina	Coal	29.14%	32.99%	37.87%	97913027
	Petroleum	34.21%	33.01%	32.78%	3693430
North Dakota	Coal	33.52%	35.19%	31.30%	64026816
	Petroleum	29.50%	28.50%	42.00%	1222348
Nebraska	Coal	32.47%	30.97%	36.55%	60608329
	Petroleum	29.99%	29.54%	40.47%	2992956
New Hampshire	Coal	31.88%	37.32%	30.81%	10514579
	Petroleum	36.15%	31.73%	32.13%	15685453
New Jersey	Coal	35.08%	33.93%	30.99%	23782293
	Petroleum	32.00%	32.64%	35.36%	29233780
New Mexico	Coal	34.84%	32.95%	32.21%	29560233
	Petroleum	34.06%	33.88%	32.05%	2523965
Nevada	Coal	41.14%	32.73%	26.13%	40214585
	Petroleum	43.54%	27.98%	28.49%	9598776
New York	Coal	32.01%	32.24%	35.74%	28716530
	Petroleum	30.90%	30.33%	38.77%	145856922
Ohio	Coal	32.53%	35.20%	32.27%	199674823
	Petroleum	30.30%	31.96%	37.73%	10302721
Oklahoma	Coal	38.88%	33.59%	27.53%	118314296
	Petroleum	37.09%	30.13%	32.78%	14888100
Oregon	Coal	42.89%	30.99%	26.13%	9430139
	Petroleum	41.03%	32.43%	26.54%	216119
Pennsylvania	Coal	30.75%	33.40%	35.85%	195767116
	Petroleum	31.12%	31.62%	37.26%	64514177
South Carolina	Coal	27.62%	35.99%	36.39%	72756924
	Petroleum	27.74%	33.38%	38.88%	4213666
South Dakota	Coal	28.99%	32.08%	38.92%	6050653
	Petroleum	30.40%	30.20%	39.40%	726215
Tennessee	Coal	31.61%	26.80%	41.59%	59241559
	Petroleum	30.10%	31.88%	38.02%	16654585
Texas	Coal	41.46%	31.46%	27.08%	325303916
	Petroleum	32.40%	32.91%	34.69%	158635569
Utah	Coal	30.44%	32.24%	37.32%	82213240
	Petroleum	21.72%	24.55%	53.72%	1049482
Virginia	Coal	31.37%	31.66%	36.97%	39079692
	Petroleum	34.02%	33.92%	32.07%	22367197
Vermont	Coal	0.00%	0.00%	0.00%	0
	Petroleum	27.04%	32.77%	40.18%	122567
Washington	Coal	47.38%	25.59%	27.02%	37638847
	Petroleum	23.45%	30.30%	46.25%	94645
Wisconsin	Coal	31.69%	34.11%	34.21%	143445408
	Petroleum	31.48%	33.45%	35.08%	2893348
West Virginia	Coal	33.52%	33.63%	32.85%	153490448
	Petroleum	30.19%	35.06%	34.75%	4578920
Wyoming	Coal	45.14%	32.41%	22.45%	67830373
	Petroleum	28.00%	32.82%	39.18%	1057133

TQ: Total quantities (Coal – Short ton; Petroleum – Barrels)
These values are computed from the source – Form EIA – 767

Table C.6: Unit fuel purchasing costs by year during the period of 1996-2000

STATE	YEAR	UCCOST	UPCOST	UGCOST	STATE	YEAR	UCCOST	UPCOST	UGCOST
Alaska	1996	.	.	144.55	Illinois	1996	162.40	368.08	257.20
	1997	.	.	173.98		1997	155.31	375.00	251.36
	1998	.	.	179.77		1998	155.43	275.19	220.68
	1999	.	.	159.28		1999	143.54	345.05	236.18
	2000	.	.	177.06		2000	115.03	705.65	469.12
Alabama	1996	154.26	445.70	287.63	Indiana	1996	118.86	486.89	341.18
	1997	153.58	405.22	277.17		1997	116.12	453.13	316.26
	1998	157.47	287.62	247.52		1998	112.21	319.39	280.46
	1999	147.60	325.95	295.09		1999	110.67	426.29	289.27
	2000	140.98	651.66	437.49		2000	107.84	669.94	445.34
Arkansas	1996	150.27	452.52	246.64	Kansas	1996	99.17	412.19	231.75
	1997	163.98	470.21	261.91		1997	102.13	282.08	258.36
	1998	147.19	370.79	224.02		1998	98.10	265.52	213.73
	1999	145.60	329.27	253.04		1999	95.42	318.97	234.11
	2000	142.13	465.74	437.52		2000	98.47	400.02	414.16
Arizona	1996	144.38	538.61	298.17	Kentucky	1996	105.84	519.26	341.30
	1997	142.47	531.82	294.44		1997	104.58	483.80	337.34
	1998	133.10	428.96	239.09		1998	105.87	357.95	331.89
	1999	132.66	479.84	264.32		1999	105.36	435.15	340.40
	2000	123.79	859.86	477.89		2000	102.28	679.93	495.83
California	1996	.	.	267.95	Louisiana	1996	151.39	326.76	281.58
	1997	.	.	302.29		1997	147.93	301.80	269.28
	1998	.	274.69	268.88		1998	142.93	222.29	227.36
	1999	.	327.22	272.69		1999	139.82	204.17	249.03
	2000	.	619.36	580.99		2000	131.99	459.17	439.62
Colorado	1996	102.64	590.47	209.76	Massachu-setts	1996	168.76	299.22	296.19
	1997	100.95	610.89	317.48		1997	169.91	260.67	300.98
	1998	98.68	428.34	300.30		1998	167.63	192.57	273.81
	1999	98.49	526.98	256.92		1999	173.39	243.24	265.31
	2000	92.56	762.21	403.09		2000	174.65	553.28	443.75
Connecticut	1996	191.04	324.13	270.73	Maryland	1996	149.44	331.56	298.61
	1997	190.47	292.66	242.11		1997	150.03	296.36	285.28
	1998	181.11	218.73	236.90		1998	145.68	211.46	263.19
	1999	169.29	223.53	267.33		1999	137.89	257.42	307.59
	2000	N/A	N/A	N/A		2000	133.04	400.66	442.30
DC	1996	.	378.18	.	Maine	1996	.	293.58	.
	1997	.	357.68	.		1997	.	278.85	.
	1998	.	252.87	.		1998	.	202.14	.
	1999	.	339.54	.		1999	.	177.89	.
	2000	143.66	543.43	.		2000	N/A	N/A	N/A
Delaware	1996	159.41	321.22	302.52	Michigan	1996	139.59	340.22	269.26
	1997	157.14	277.95	298.34		1997	137.25	345.07	256.33
	1998	156.30	214.67	297.73		1998	133.22	279.44	232.41
	1999	158.94	243.85	303.25		1999	130.92	289.21	252.26
	2000	152.14	445.87	488.49		2000	132.95	414.88	389.92
Florida	1996	172.77	285.40	309.67	Minnesota	1996	105.76	487.36	216.94
	1997	169.90	270.18	304.29		1997	108.49	483.15	243.64
	1998	159.51	205.92	276.17		1998	106.05	352.66	233.78
	1999	156.00	245.62	297.23		1999	108.58	420.93	266.29
	2000	153.92	430.47	433.75		2000	109.57	660.32	448.65
Georgia	1996	157.73	430.63	281.27	Montana	1996	95.39	352.23	255.22
	1997	158.53	420.25	265.46		1997	93.40	367.38	279.41
	1998	154.51	327.62	316.01		1998	92.07	274.96	223.40
	1999	154.55	389.64	248.90		1999	92.39	381.55	265.55
	2000	154.20	690.61	417.64		2000	91.57	648.74	438.96
Hawaii	1996	.	353.55	.	Mississippi	1996	151.07	223.56	267.89
	1997	.	364.26	.		1997	154.68	269.06	262.18
	1998	.	261.47	.		1998	153.83	199.20	222.14
	1999	.	319.88	.		1999	155.23	154.08	242.63
	2000	.	503.91	.		2000	152.24	333.34	390.13
Iowa	1996	93.89	507.50	322.41	Montana	1996	70.50	598.50	269.26
	1997	93.46	445.19	339.80		1997	68.34	528.42	326.83
	1998	87.48	332.87	305.90		1998	67.38	404.23	191.61
	1999	82.12	398.77	313.74		1999	72.68	470.75	184.50
	2000	81.63	643.05	454.74		2000	91.53	.	510.39

UCCOST: Unit coal purchasing costs (cents/MMBtu); UPCOST: Unit petroleum purchasing costs (cents/MMBtu); UGCOST: Unit natural gas purchasing costs (cents/MMBtu)
These values are computed from the source – FERC Form – 423

Table C.6 continued

STATE	YEAR	UCCOST	UPCOST	UGCOST	STATE	YEAR	UCCOST	UPCOST	UGCOST
North Carolina	1996	148.42	468.20	300.54	Rhode Island	1996	.	478.71	222.62
	1997	142.92	427.73	310.66		1997	.	.	326.39
	1998	143.81	310.51	267.87		1998	.	.	328.55
	1999	143.76	398.38	283.31		1999	N/A	N/A	N/A
	2000	142.70	615.59	432.15		2000	N/A	N/A	N/A
North Dakota	1996	72.62	505.12	276.64	South Carolina	1996	147.14	496.55	445.42
	1997	77.81	459.17	321.99		1997	144.73	454.10	397.58
	1998	76.20	311.92	369.27		1998	144.68	327.63	353.41
	1999	73.04	417.23	404.04		1999	141.64	406.74	347.33
	2000	72.40	692.29	639.94		2000	138.96	672.33	556.87
Nebraska	1996	71.94	511.43	204.70	South Dakota	1996	92.46	597.90	233.00
	1997	58.51	450.28	287.11		1997	91.24	.	.
	1998	58.65	354.48	242.75		1998	90.94	.	176.70
	1999	55.44	431.50	281.13		1999	92.17	.	.
	2000	55.97	648.52	459.99		2000	97.74	.	.
New Hampshire	1996	160.61	254.45	.	Tennessee	1996	114.56	484.65	.
	1997	163.23	263.55	266.58		1997	112.47	439.03	.
	1998	161.22	187.21	.		1998	112.49	304.46	.
	1999	151.50	213.63	261.02		1999	113.12	393.30	.
	2000	148.45	345.31	315.09		2000	110.63	635.17	.
New Jersey	1996	174.82	358.71	289.75	Texas	1996	129.46	473.17	245.56
	1997	174.50	298.68	295.14		1997	125.92	453.65	263.30
	1998	158.24	242.17	262.02		1998	123.60	362.09	224.92
	1999	145.07	288.15	298.93		1999	119.64	395.99	245.79
	2000	139.30	484.08	430.37		2000	122.69	655.75	415.53
New Mexico	1996	142.83	586.77	227.89	Utah	1996	107.10	579.16	178.97
	1997	133.59	574.63	259.16		1997	111.28	583.60	202.95
	1998	130.59	439.32	219.95		1998	114.83	439.55	202.49
	1999	132.90	502.33	228.25		1999	103.07	513.62	253.83
	2000	137.83	758.49	387.73		2000	101.31	678.63	383.62
Nevada	1996	136.62	551.53	206.02	Virginia	1996	141.81	290.23	281.63
	1997	139.21	507.65	211.87		1997	139.33	281.85	274.04
	1998	129.81	379.62	230.18		1998	137.80	203.68	295.43
	1999	129.37	452.65	242.28		1999	134.27	230.46	299.65
	2000	126.39	721.57	474.97		2000	133.03	424.27	451.15
New York	1996	142.36	319.22	287.89	Vermont	1996	252.58	523.82	317.47
	1997	142.24	284.12	280.96		1997	252.14	453.50	312.12
	1998	143.43	203.46	249.61		1998	244.02	327.10	286.06
	1999	144.91	236.53	278.55		1999	246.35	.	319.27
	2000	149.06	430.64	459.65		2000	262.90	675.45	485.50
Ohio	1996	134.03	489.59	334.97	Washington	1996	153.24	508.54	474.75
	1997	132.07	436.98	362.93		1997	156.90	499.12	4519.47
	1998	136.31	332.58	308.38		1998	147.93	405.35	325.87
	1999	136.19	391.67	306.36		1999	155.96	478.79	.
	2000	145.69	668.67	485.47		2000	168.79	664.02	.
Oklahoma	1996	97.63	406.70	290.13	Wisconsin	1996	105.69	481.64	300.57
	1997	91.84	409.22	287.81		1997	108.66	462.61	314.74
	1998	90.97	292.18	241.16		1998	106.85	348.95	264.06
	1999	91.24	495.50	271.67		1999	101.70	413.67	290.54
	2000	94.32	586.06	441.62		2000	100.99	626.74	444.48
Oregon	1996	107.07	.	132.23	West Virginia	1996	124.93	528.71	298.97
	1997	113.91	490.18	147.57		1997	123.72	464.01	335.15
	1998	108.91	331.90	154.07		1998	122.15	370.91	351.43
	1999	107.89	414.10	193.61		1999	118.19	463.49	299.80
	2000	106.84	858.58	289.58		2000	120.40	721.34	498.08
Pennsyl-vania	1996	137.70	345.20	276.92	Wyoming	1996	81.99	545.60	753.69
	1997	135.07	284.69	292.52		1997	80.54	517.00	826.66
	1998	134.27	225.74	316.51		1998	78.61	405.50	796.04
	1999	128.56	269.09	293.14		1999	76.19	476.01	372.26
	2000	113.98	384.64	370.68		2000	77.91	724.33	375.77

Continued

APPENDIX D

PROGRAMMING FOR MODEL ESTIMATION

Program D.1: SAS Program for Basic Fuel Shipment Model

```
*-------------------------------------------------------------------------------------
PROGRAM NAME: SHIP.SA1. THIS PROGRAM READS DATA FILE SHIPDATA_ADD.DA1 CREATED BY PROGRAM
SHIPDATA_ADD.SA1. THIS PROGRAM RUNS REGRESSION MODELS FOR BTU SHIPMENTS.
-------------------------------------------------------------------------------------;
DATA SHIP; INFILE 'C:\DISSERTATION\052604\SHIPDATA_ADD.DA1' LRECL=1000;
       INPUT  PCODE 1-4
              IM 5-7
              YEAR 8-11
              MONTH 12-13
              LBTU_S 14-20 2
              LUCOST_S 21-26 2
              LBTU_C 27-36 2
              LBTU_C_1F 37-46 2
              LBTU_C_2F 47-56 2
              LBTU_C_3F 57-66 2
              LBTU_C_4F 67-76 2
              LBTU_C_5F 77-86 2
              LBTU_C_6F 87-96 2
              LBTU_C_7F 97-106 2
              LBTU_C_8F 107-116 2
              LBTU_C_9F 117-126 2
              LBTU_C_10F 127-136 2
              LBTU_C_11F 137-146 2
              LBTU_C_12F 147-156 2
              LC112 156-170 2
              LC212 171-185 2
              LC312 186-200 2
              LC412 201-215 2
              LC512 216-230 2
              LC612 231-245 2
              LC712 246-260 2
              LC812 261-275 2
              LC912 276-290 2
              LC1012 291-305 2
              LC1112 306-320 2
              LR111 321-335 2
              LR110 336-350 2
              LR19 351-365 2
              LR18 366-380 2
              LR17 381-395 2
              LR16 396-410 2
              LR15 411-425 2
              LR14 426-440 2
              LR13 441-455 2
              LR12 456-470 2
              LM13 471-485 2
              LM46 486-500 2
              LM79 501-515 2
              LM1012 516-530;
```

```
*-------------------------------------------
MODELS FOR AGGREGATED BTU SHIPMENTS UP TO M+6
--------------------------------------------;
DATA SHIPM6; SET SHIP;
       PROC REG; MODEL LBTU_S
                      =LUCOST_S /*UNIT FUEL PURCHASING COSTS AT MONTH M*/
                      LBTU_C /*BTU CONSUMPTIONS AT MONTH M+1*/
                      LBTU_C_1F /*BTU CONSUMPTIONS AT MONTH M+1*/
                      LBTU_C_2F /*BTU CONSUMPTIONS AT MONTH M+2*/
                      LBTU_C_3F /*BTU CONSUMPTIONS AT MONTH M+3*/
                      LBTU_C_4F /*BTU CONSUMPTIONS AT MONTH M+4*/
                      LBTU_C_5F /*BTU CONSUMPTIONS AT MONTH M+5*/
                      LBTU_C_6F /*BTU CONSUMPTIONS AT MONTH M+6*/
                      ;
       TITLE 'AGGREGATED BTU SHIPMENTS UP TO M+6';

RUN;
```

Program D.2: SAS Program for Basic Fuel Consumption Model

```
*------------------------------------------------------------------------------------------
PROGRAM NAME: CONS.SA1. THIS PROGRAM READS DATA FILE CONDATA.DA1 CREATED BY PROGRAM
CONDATA.SA1. THIS PROGRAM ESTIMATES A BASIC REGRESSION MODEL FOR BTU CONSUMPTIONS.
-----------------------------------------------------------------------------------------;
DATA CONS; INFILE 'C:\DISSERTATION\FINAL MODELS_042304\CONDATA.DA1' ;
        INPUT   PCODE 1-4
                IM 5-6
                IX 7
                BTU_C 8-18 2
                CBTU_C 19-29 2
                PBTU_C 30-39 2
                GBTU_C 40-50 2
                GEN_C 51-60 2
                CGEN_906 61-70 2
                PGEN_906 71-79 2
                GGEN_906 80-88 2
                GEN2_C 89-108
                CGEN2_906 109-128
                PGEN2_906 129-148
                GGEN2_906 149-168;

*-----------------------------
MODELS FOR BTU CONSUMPTIONS
----------------------------;
DATA CON_A; SET CONS;
        PROC REG; MODEL BTU_C
                =GEN_C /*AGGREGATED NET ELECTRICITY GENERATION*/
                GEN2_C /*SQUARES OF AGGREGATED NET ELECTRICITY GENERATION*/
                               ;
        TITLE 'BASIC BTU CONSUMPTION MODEL';

RUN;
```

Program D.3: SAS Program for Simultaneous Equation (3SLS) Model

```
*-------------------------------------------------------------------------------------------
PROGRAM NAME: 3SLS_052504.SAS. THIS PROGRAM READS DATA FILE 3SLSDATA.DAT CREATED BY
PROGRAM 3SLSDATA_052504.SAS. THIS PROGRAM EXAMINES THE SIMULTANEITY AMONG SULFUR
SHIPMENTS, GROSS SO2 EMISSIONS AND NET SO2 EMISSIONS.
-------------------------------------------------------------------------------------------;
DATA SO; INFILE 'C:\DISSERTATION\052504\3SLS\3SLSDATA.DAT' LRECL=1000;
       INPUT PCODE 1-4
              IM 5-8 2
              YEAR 9-12
              MONTH 13-14
              LUCOST_S 15-22 4
              LUGE 23-29 4
              LUGE_1B 30-36 4
              LUGE_2B 37-43 4
              LUGE_3B 44-50 4
              LUGE_1F 51-57 4
              LUGE_2F 58-64 4
              LUGE_3F 65-71 4
              LSBR 72-78 4
              LSBR_1B 79-85 4
              LSBR_2B 86-92 4
              LSBR_3B 93-99 4
              LSBR_1F 100-106 4
              LSBR_2F 107-113 4
              LSBR_3F 114-120 4
              LUSULF_S 121-127 4
              LUSULF_S_1B 128-134 4
              LUSULF_S_2B 135-141 4
              LUSULF_S_3B 142-148 4
              LUSULF_S_1F 149-155 4
              LUSULF_S_2F 156-162 4
              LUSULF_S_3F 163-169 4
              LAVESB 170-176 4
              LAVESF 177-183 4
              LAVECB 184-190 4
              LAVECF 191-197 4
              LAVENB 198-204 4
              LAVENF 205-211 4
              LALLOW 212-230 4
              LAUCCOST 231-241 4
              LWDSP 242-252 4
              IXFGD 253
              LCUMALL 254-264 4;

       IM1=(YEAR-1996)*12+MONTH;
       IS=0;
       IF MONTH LE 4 OR MONTH GE 11 THEN IS=1;

*-------------------------------------
MODELS FOR AGGREGATED SO2 EMISSIONS
-------------------------------------;
DATA SO2_1; SET SO;
```

```
        PROC REG; MODEL LUSULF_S
                              =LUGE /*UNIT GROSS SO2 EMISSIONS AT MONTH M*/
                              LUCOST_S /*UNIT FUEL PURCHASING COSTS AT MONTH M*/
                              LUSULF_S_1B /*UNIT SULFUR SHIPMENTS AT MONTH M-1*/
                              LUSULF_S_2B /*UNIT SULFUR SHIPMENTS AT MONTH M-2*/
                              LUSULF_S_3B /*UNIT SULFUR SHIPMENTS AT MONTH M-3*/
                              LALLOW /*ANNUAL SO2 EMISSION ALLOWANCES-ACTUAL SO2*/
                              IS IM1
                              ;
        TITLE 'AGGREGATED SULFUR SHIPMENTS';

        PROC REG; MODEL LUGE
                              =LSBR /*NET SO2 EMISSIONS TO BTU CONSUMPTIONS RATIO*/
                              LUSULF_S /*UNIT SULFUR SHIPMENTS AT MONTH M*/
                              LUSULF_S_1B /*UNIT SULFUR SHIPMENTS AT MONTH M-1*/
                              LUSULF_S_2B /*UNIT SULFUR SHIPMENTS AT MONTH M-2*/
                              LUSULF_S_3B /*UNIT SULFUR SHIPMENTS AT MONTH M-3*/
                              IXFGD  /*FGD=1, NOFGD=0*/
                              IS IM1
                              ;
        TITLE 'AGGREGATED GROSS SO2 EMISSIONS';

        PROC REG; MODEL LSBR
                              =LUGE /*UNIT GROSS SO2 EMISSIONS - LB*/
                              LALLOW /*ANNUAL SO2 EMISSION ALLOWANCES-ACTUAL SO2*/
                              IXFGD /*=1 IF FGD IS EQUIPED;=0 OTHERWISE*/
                              IS IM1
                              ;
        TITLE 'AGGREGATED NET SO2 EMISSIONS';

        PROC SYSLIN IT3SLS REDUCED DATA=SO2_1;
        ENDOGENOUS LSBR LUGE LUSULF_S;
        INSTRUMENTS LUCOST_S LUSULF_S_1B LUSULF_S_2B LUSULF_S_3B LALLOW IXFGD
                              IS IM1;
        SHIP: MODEL LUSULF_S=LUGE LUCOST_S LUSULF_S_1B LUSULF_S_2B LUSULF_S_3B
                                             LALLOW IS IM1/COVB;
        GROSS: MODEL LUGE=LSBR LUSULF_S LUSULF_S_1B LUSULF_S_2B LUSULF_S_3B
                                             IXFGD IS IM1/COVB;
        NET: MODEL LSBR=LUGE LALLOW IXFGD IS IM1/COVB;

        TITLE '3 STAGE LEAST SQUARES MODEL';


RUN;
```

Program D.4: FORTRAN Program for Simulation Analysis

```
*     FILE NAME: Sim_sens5.FPP - Tae-Kyung Kim'S Dissertation
*     Sensitivity analysis
*     VERSION ON 5/26/2004
*     Includes the new basic shipment model, with consumption in month m
*     Includes new allowance variable


      DIMENSION UPC(69),GEN(69),BTUC(69),BTUS(69)
      DIMENSION USO2S(69),USO2C(69),UNE(69),ALLOWB(69)
      DIMENSION RBTUS(69),RBTUC(69),RUSO2S(69),RUSO2C(69),RUNE(69)
      DIMENSION ALLOW(69),FGD(69),SEASON(69),IMONTH(69)
      DIMENSION XALLOW(10),XFGD(2), WIND(69)

      INTEGER IFGD(69),IALLOW(69)

*     -------------------------------------------------------
*     SETTING SENSITIVITY PARAMETERS:
*     XALLOW: MULTIPLIER OF ALLOW
*     XFGD: 1 WITH FGD, 0 WITHOUT
*     -------------------------------------------------------

      XALLOW(1)=0.1
      XALLOW(2)=0.5
      XALLOW(3)=1.0
      XALLOW(4)=2.0
      XALLOW(5)=3.0
      XALLOW(6)=4.0
      XALLOW(7)=5.0
      XALLOW(8)=6.0
      XALLOW(9)=0.3
      XALLOW(10)=0.7

      XFGD(1)=1.0
      XFGD(2)=0.0



*     -------------------------------------------------------
*     READ INPUT DATA FILE
*     -------------------------------------------------------
      OPEN(UNIT=1, FILE='NP2341_4.DAT', STATUS='OLD')

      DO 1 IM=1,69
      READ(1,2) IMONTH(IM),RBTUS(IM),RBTUC(IM),UPC(IM),RUSO2S(IM),RUSO2C(IM),
     1RUNE(IM),GEN(IM),IALLOW(IM),IFGD(IM),WIND(IM)
  2   FORMAT(8X,I2,2X,F15.2,F14.2,F10.2,F10.4,F10.4,F10.4,F15.2,I16,I2,10X,F6.2)
      ALLOWB(IM)=REAL(IALLOW(IM))
      FGD(IM)=REAL(IFGD(IM))

      WRITE(6,4) IMONTH(IM),RBTUS(IM),RBTUC(IM),UPC(IM),RUSO2S(IM),RUSO2C(IM),
     1RUNE(IM),GEN(IM),ALLOWB(IM),FGD(IM)
```

```
  4   FORMAT(8X,I2,2X,F15.2,F14.2,F10.2,F10.4,F10.4,F10.4,F15.2,F16.0,
     15X,F2.0)

  1   CONTINUE

      CLOSE(UNIT=1)

*     ----------------------------------------------------------
*     COMPUTATION OF ENERGY CONSUMPTIONS AND SHIPMENTS
*     ----------------------------------------------------------
      IM=4
      BTUC(IM)=110940.0 + 10.24579*GEN(IM) - 0.0000004*(GEN(IM)**2.0)

      DO 5 IM=4,63
      BTUC(IM+1)=110940.0 + 10.24579*GEN(IM+1) - 0.0000004*(GEN(IM+1)**2.0)
      BTUC(IM+2)=110940.0 + 10.24579*GEN(IM+2) - 0.0000004*(GEN(IM+2)**2.0)
      BTUC(IM+3)=110940.0 + 10.24579*GEN(IM+3) - 0.0000004*(GEN(IM+3)**2.0)
      BTUC(IM+4)=110940.0 + 10.24579*GEN(IM+4) - 0.0000004*(GEN(IM+4)**2.0)
      BTUC(IM+5)=110940.0 + 10.24579*GEN(IM+5) - 0.0000004*(GEN(IM+5)**2.0)
      BTUC(IM+6)=110940.0 + 10.24579*GEN(IM+6) - 0.0000004*(GEN(IM+6)**2.0)



      A=3.52014 - 0.72107*LOG(UPC(IM)) + 0.49194*LOG(BTUC(IM))
     1  + 0.14711*LOG(BTUC(IM+1)) + 0.09912*LOG(BTUC(IM+2))
     2  + 0.08395*LOG(BTUC(IM+3)) + 0.07752*LOG(BTUC(IM+4)) + 0.04206*LOG(BTUC(IM+5))
     3  + 0.05129*LOG(BTUC(IM+6))
      BTUS(IM)=EXP(A)

      WRITE(6,6) IM, (GEN(IM+IK),IK=1,6), (BTUC(IM+IK),IK=1,6),A, BTUS(IM)
  6   FORMAT(I2,1X,6F10.2,3X,6F10.2,3X,F10.5,1X,F12.2)

  5   CONTINUE

*     ------------------------------------------------------------------
*     COMPUTATION OF UNIT SULFUR SHIPMENTS, GROSS EMISSIONS, AND NET EMISSIONS
*     ------------------------------------------------------------------
      OPEN(UNIT=3, FILE='SIM_SENS5_2341_OUT.TXT', STATUS='NEW')

      USO2S(1)=RUSO2S(1)
      USO2S(2)=RUSO2S(2)
      USO2S(3)=RUSO2S(3)

      DO 100 IA=1,10
      DO 100 IG=1,2


      DO 7 IM=4,63

      ALLOW(IM)=XALLOW(IA)*ALLOWB(IM)
      FGD(IM)=XFGD(IG)


*     WRITE(6,10) ALLOWB(IM),XALLOW(IA),ALLOW(IM),FGD(IM)
```

```
* 10  FORMAT(4F12.1)

      IM1=IM-3
      SEASON(IM)=0.0
      IF (IMONTH(IM).LE.4) SEASON(IM)=1.0
      IF (IMONTH(IM).GE.11) SEASON(IM)=1.0


       A=-1.11149 + 0.106563*LOG(UPC(IM)) + 0.316293*LOG(USO2S(IM-1)) +
     1  0.206488*LOG(USO2S(IM-2)) + 0.211609*LOG(USO2S(IM-3)) + 0.071122*LOG(ALLOW(IM))
     2  - 0.00103*IM1 -0.02252*SEASON(IM) -1.28736*FGD(IM)


       B=0.075975 + 0.129099*LOG(UPC(IM)) + 0.383183*LOG(USO2S(IM-1)) +
     1  0.250156*LOG(USO2S(IM-2)) + 0.25636*LOG(USO2S(IM-3)) - 0.00084*LOG(ALLOW(IM))
     2  - 0.00023*IM1 -0.00947*SEASON(IM) + 0.058632*FGD(IM)


       C=0.216434 - 0.07492*LOG(UPC(IM)) + 0.498032*LOG(USO2S(IM-1)) +
     1  0.262405*LOG(USO2S(IM-2)) + 0.204101*LOG(USO2S(IM-3)) + 0.008253*LOG(ALLOW(IM))
     2  - 0.00034*IM1 -0.00663*SEASON(IM) + 0.013793*FGD(IM)


      UNE(IM)=EXP(A)
      USO2C(IM)=EXP(B)
      USO2S(IM)=EXP(C)

      WRITE(3,9) IM,IMONTH(IM),SEASON(IM),XALLOW(IA),XFGD(IG),
     1           BTUC(IM),BTUS(IM),USO2S(IM),USO2C(IM),UNE(IM)
  9   FORMAT(1X,2I3,1X,F4.1,2X,2F4.1,5X,2F12.0,2X,3F8.4)

  7   CONTINUE

 100  CONTINUE

*     THE OUTPUT FILE ON DISK INCLUDES 20(5X2) . 60(IM=4,63)= 1200 RECORDS

      CLOSE(UNIT=3)


      WRITE(6,101)
  101 FORMAT(2X,'----- END OF PROGRAM -----')

      STOP
      END
```

Program D.5: SAS Program for Simulation Output Analysis

```
*---------------------------------------------------------------------------------------
PROGRAM NAME: SIMREG5.TXT. THIS PROGRAM READS DATA FILE SIM_SENS5_2341_OUT.TXT
CREATED BY A FORTRAN PROGRAM SIM_SENS5.FPP. THIS PROGRAM TESTS LINEAR RELATIONSHIPS
BETWEEN DECISION VARIABLES AND PARAMETERS TO ESTIMATE SENSITIVITY.
---------------------------------------------------------------------------------------;
DATA SIM2341; INFILE 'D:\TK_KIM\DISSERTATION\New Simulation\SIM_SENS5_2341_OUT.TXT' ;
       INPUT  IM 1-4
              IMONTH 5-7
              SEASON 8-12 1
              XALLOW 13-18 1
              XFGD 19-22 1
              BTUC 23-40 1
              BTUS 41-52 1
              USO2S 53-61 4
              USO2C 62-69 4
              UNE 70-77 4;

       NSO2=UNE*BTUC;
       GSO2=USO2C*BTUC;
       SHIP=USO2S*BTUS;

       PROC SORT; BY XALLOW XFGD;
       PROC MEANS NOPRINT SUM; VAR NSO2 GSO2 SHIP; BY XALLOW XFGD;
       OUTPUT OUT=S2341 SUM=NSO2 GSO2 SHIP;

DATA S2341; SET S2341;
       NSO2=NSO2/5;
       GSO2=GSO2/5;
       SHIP=SHIP/5;

       PROC PRINT DATA=S2341;

DATA S2341; SET S2341;
       LALLOW=LOG(XALLOW);
       LNSO2=LOG(NSO2);
       LGSO2=LOG(GSO2);
       LSHIP=LOG(SHIP);

       PROC REG;
       MODEL LNSO2=LALLOW XFGD;
       MODEL LGSO2=LALLOW XFGD;
       MODEL LSHIP=LALLOW XFGD;

RUN;
```