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Office of Air and Radiation

FINAL REPORT

PERFORMANCE OF SELECTIVE CATALYTIC REDUCTION ON COAL-FIRED STEAM GENERATING UNITS

ACID RAIN PROGRAM

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CHAPTER 1
INTRODUCTION

Emissions of nitrogen oxides (NO_x) contribute to adverse health and environmental impacts resulting from formation of tropospheric ozone, acid rain, and fine particulates. According to a report by the State and Territorial Air Pollution Program Administrators (STAPPA) and the Association of Local Air Pollution Control Officials (ALAPCO), coal-fired electric utility boiler units in the United States accounted for 5.7 million tons of NO_x in 1992 (24 percent of the total national emissions). The report notes that the greatest opportunity for NO_x reduction (75 - 90 percent) may come from selective catalytic reduction (SCR) technology.[1]

Selective catalytic reduction is a NO_x control technology that utilizes a catalyst to reduce NO_x to nitrogen and water. Although SCR technology was developed in the United States, other countries such as Japan and Germany have aggressively implemented SCR on coal-fired utility units over the past fifteen years and have achieved substantially reduced NO_x emission levels. An Institute of Clean Air Companies (ICAC) report listed the following SCR installations: 72 coal-fired plants (137 units) in Germany, 28 plants (40 units) in Japan, 9 plants (29 units) in Italy, and 8 plants (10 units) in other European countries.[2] The cumulative SCR experience of these installations amounts to more than 1700 years.

In light of the broad international experience with use of SCR technology and the health and environmental concerns surrounding NO_x emissions, EPA initiated a study to document the application and performance of SCR technology on coal-burning boilers. EPA has spent more than a year in collecting and evaluating data to develop a comprehensive assessment of this technology. This assessment includes information provided by SCR installations on: boilers and SCR systems, coal characteristics, NO_x control performance, operational experience, and costs.

In all, data have been obtained from SCR installations on coal-fired boilers in the U.S., Germany, Sweden, Austria, Denmark, and Finland. Several of the European utilities requested that the names of their plants be kept confidential. To accommodate this request, each of the units in this study is identified by a letter and a number. The letter identifiers relate to the countries in which plants are located and are: US (United States), A (Austria), D (Denmark), F (Finland), G (Germany), and S (Sweden). The number identifiers relate to the numerical order in which data was received from units in a country. Detailed data for each plant are included in Appendix A.

A Draft Report of findings to date was completed on October 23, 1996 and distributed for review and comment to a broad cross-section of persons and organizations with expertise and interest in the subject area. Summaries of comments on the October 23, 1996 draft of the report as well as EPA's responses are shown in Appendix B. The comments acknowledged the validity of findings related to NO_x control performance being achieved at the SCR installations examined and recommended that further analysis of operational issues and costs be conducted.

In response to these comments, EPA expanded its data collection and analysis efforts. As a result, additional information on NO_x control performance, operational experience, and costs

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[1] "Controlling Nitrogen Oxides under the Clean Air Act: A Menu of Options," State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA&ALAPCO). July 1994.

[2] "White Paper, Selective Catalytic Reduction (SCR) Controls to Abate NO_x Emissions," Institute of Clean Air Companies, Inc. (ICAC). October 1994.

associated with SCR applications was included in an Interim Report titled, "Performance of Selective Catalytic Reduction on Coal-Fired Steam Generating Units," dated April 17, 1997. Since the release of the Interim Report, additional data have become available and have been incorporated into this report. This Final Report dated June 25, 1997 is issued to make this additional data available.

The structure of the report has been modified to its present form to improve readability and to condense the discussion of the factors affecting SCR application and performance into single sections. In Chapter 2, there is a brief discussion of the basis and components of SCR technology. This is followed by a presentation and discussion of the data collected in Chapter 3. Chapter 4 reviews the pertinent foreign and domestic regulations. In order to facilitate the comparison of foreign and U.S. NO_x emissions data, F-factors were needed in some cases to conduct the necessary data conversion; the data normalization procedures used are described in Chapter 5. A detailed discussion of the NO_x control performance of SCR is presented in Chapter 6. Operational experience with SCR is summarized in Chapter 7 and cost information obtained from some of these installations is discussed in Chapter 8. Finally, summary observations are presented in Chapter 9.

The findings indicate that all coal-fired units using SCR have achieved targeted NO_x emission levels. Many units reported average NO_x emission levels at or below 0.15 lbs/mmBtu. Those units reporting emission levels higher than 0.15 lbs/mmBtu are generally meeting emission limits set at these higher levels. In general, the operational histories of SCR installations indicate that NO_x reductions are being achieved in a reliable manner. The results of this study reflect that SCR is an effective and reliable NO_x control technology for coal-fired utility boilers.

CHAPTER 2
TECHNOLOGY

Selective catalytic reduction is a post-combustion NO_x control technology capable of providing NO_x reductions in excess of 90 percent. This technology is widely used in commercial applications overseas and is experiencing expanded use in U.S. facilities. The SCR process uses a catalyst at approximately 300-450 ^{o}C to facilitate a heterogeneous reaction between NO_x and an injected reagent, ammonia (NH_3), to produce nitrogen and water. Within this temperature range, the dominant reactions in the presence of oxygen are:

$$4NO + 4NH_3 + O_2 \quad \text{------------>} \quad 4N_2 + 6H_2O + \text{heat} \qquad (2.1)$$

$$NO + NO_2 + 2NH_3 \quad \text{------------>} \quad 2N_2 + 3H_2O + \text{heat} \qquad (2.2)$$

In the SCR process, NH_3 chemisorbs onto the active sites on the catalyst. The NO_x in the flue gas reacts with adsorbed NH_3 to produce nitrogen (N_2) and water (H_2O).

A typical SCR system is comprised of: the storage, delivery, vaporization and injection system for the reagent; the SCR reactor and catalyst; soot blowers; and additional instrumentation. Anhydrous or aqueous ammonia are the commonly used reagents. The catalyst is the critical component of an SCR system. The catalyst NO_x reduction performance and resistance to deactivation affects the cost effectiveness of the SCR system. Many proprietary catalyst formulations exist for coal-fueled service. These formulations use oxides of vanadium as the active catalyst, titanium as a catalyst dispersing and supporting agent, and tungsten to improve mechanical stability and reduce sulfur oxidation. The concentrations of vanadium pentoxide, titanium dioxide, and tungsten oxide in a catalyst are customized to meet specific installation requirements. Recently, poison-resistant catalyst formulations have also been developed. In these formulations, molybdenum oxide is used to capture and localize the poisons (e.g., arsenic) and thus prevent deactivation of active sites. Structurally, catalysts are manufactured in the form of either supported extrudates (homogenous catalysts) or catalyst coatings (non-homogenous catalysts). The most common type of homogenous catalyst is honeycomb, whereas the most common type of non-homogenous catalyst is plate.

There are three SCR system configurations for coal-fired sources. These configurations are: high dust, low dust, or tail end, as shown schematically in Fig. 2.1. In a high dust configuration, the SCR reactor is placed between the economizer and the air preheater. In this configuration, the catalyst is exposed to flyash and chemical compounds present in the flue gas that have the potential to degrade the catalyst mechanically and chemically. However, as evidenced by the extensive use of this configuration, proper design of a high-dust SCR system can mitigate the mechanical and chemical impacts on the catalyst. In the low dust configuration, the SCR reactor is located downstream of the electrostatic precipitator (ESP). This configuration reduces the degrading effect of flyash on the catalyst. In the tail end configuration, the SCR reactor is installed downstream of the flue gas desulfurization (FGD) unit. The tail end configuration is implicitly low dust. However, this configuration is typically more expensive than the high dust configuration due to associated flue gas reheating requirements. The type of SCR configuration employed at a unit is dependent upon site-specific parameters (e.g., flue gas dust loading or flue gas sulfur dioxide concentration), and the type of SCR application (new installation vs. retrofit).

Some of the critical parameters that need to be considered when designing and operating a SCR installation are: injection, distribution, and mixing of NH_3 in the flue gas; SO_2 and SO_3 concentration in the flue gas; and trace metal species and ash content in the coal. By optimizing the injection, distribution, and mixing of NH_3 in the flue gas, the amount of ammonia slip (i.e., unreacted ammonia that passes through the SCR reactor) can be minimized. Low levels of ammonia slip minimize the potential for air preheater pluggage and flyash contamination with ammonia. European operational experience indicates that ammonia slip of less than 5 ppm minimizes air preheater plugging due to the formation of ammonium bisulfates and, depending on ash characteristics, generally assures the marketability of the flyash. Appropriate catalyst selection can limit the formation of SO_3 and thus mitigate undesired effects on the downstream plant equipment. Finally, careful consideration of trace metal species and ash content in coal can minimize poisoning of active sites as well as plugging and erosion caused by impingement of flyash on catalyst surface. The operational experience of the surveyed units is discussed in Chapter 7.

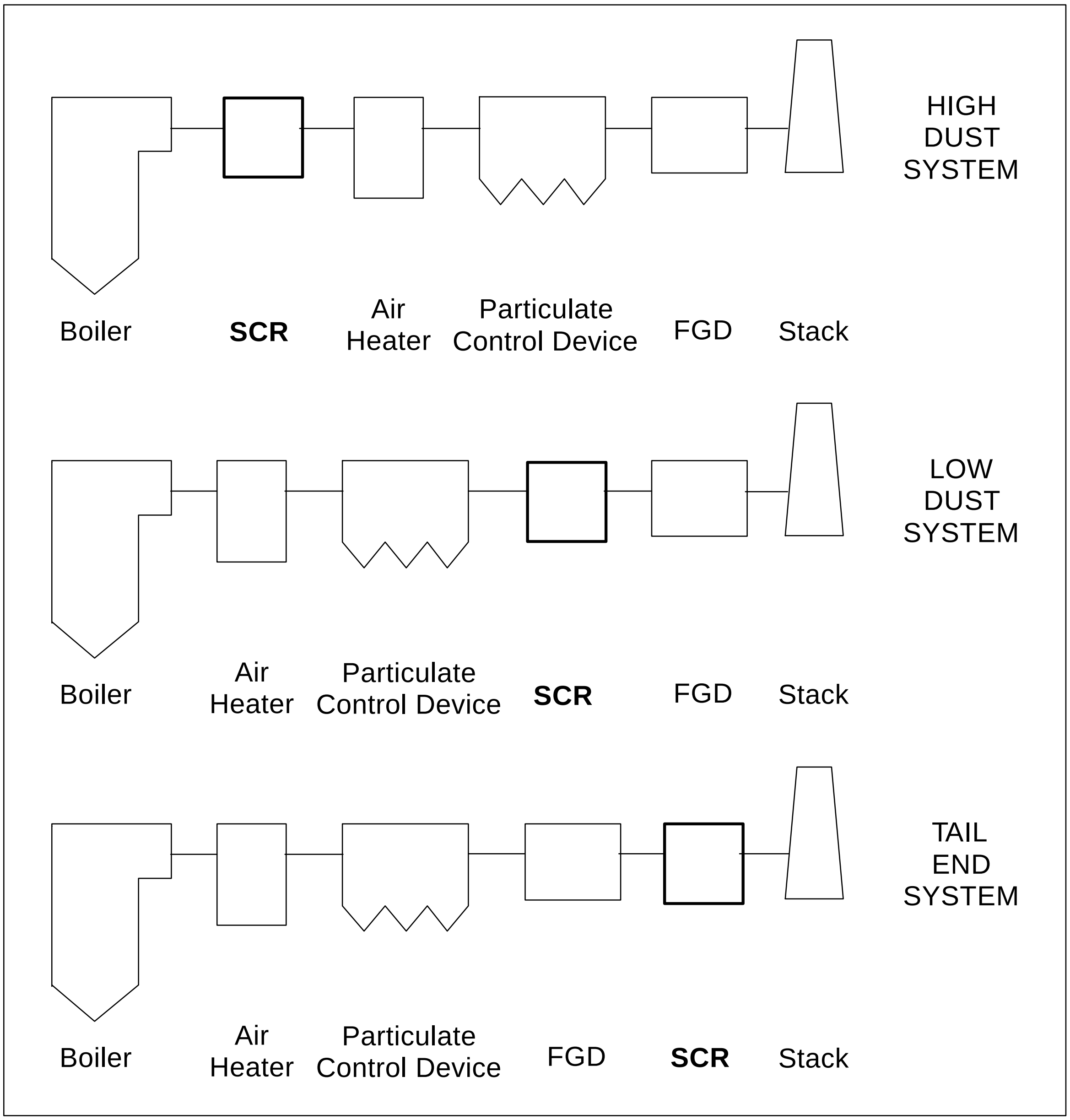

Figure 2.1. SCR Configurations

CHAPTER 3
CURRENT DATABASE

To conduct a comprehensive assessment of SCR performance on coal-fired boilers, information on the following data categories was needed: boiler and SCR system characteristics, coal, emissions, experience with SCR, and cost. Therefore, U.S. and European utilities were contacted and requested to provide data on these data categories. Detailed information provided by each plant is found in Appendix A.

A summary presenting the number of units providing information on these data categories is given in Table 3.1. The following sections contain discussions on each of the data categories.

Table 3.1. NUMBER OF UNITS RESPONDING TO THE REQUEST FOR INFORMATION

Country	Boiler Information	SCR Characteristics	Emissions Data	Operational Experience	Capital Cost
United States	6	6	6	6	1
Austria	4	4	3	3	2
Denmark	1	1	1	1	0
Finland	1	1	1	1	0
Germany	18	18	18	13	4
Sweden	3	3	3	3	0

3.1 INFORMATION ON UNITS AND ASSOCIATED SCR SYSTEMS

The information collected on boilers and their associated SCR systems represents a broad variety of SCR applications on a spectrum of boiler types. Since SCR installations are generally customized to fit the needs and emission goals of a specific facility each SCR system may be slightly different. The unit and SCR characteristics summarized in Table 3.2 indicate that the boilers represent a broad range of operating conditions.

Information was obtained from 21 coal-fired plants for 33 units with SCR systems. NO_x emissions data have been acquired for six units at five plants in the United States, 18 units at 10 plants in Germany, three units at one plant in Sweden, four units at three plants in Austria, one unit in Denmark, and one unit in Finland. As indicated in Table 3.2, the boiler size for units examined in this report ranges from 40 MWe to 740 MWe. Thirteen units were constructed with SCR systems and are designated as "new", while 20 units were retrofitted with SCR systems. The database represents 29 high dust configured units, two low dust configured systems, and two tail-end configured systems. Of the plants reporting boiler information, thirteen units are tangentially fired, four are cyclone, five are wall fired, and 12 indicated the use of NO_x combustion controls. Sixteen units have dry bottom boilers, whereas 15 are wet bottom, six of which are known to perform flyash recirculation. This information is pertinent to a discussion of SCR performance because units that recirculate flyash have the greatest likelihood of experiencing catalyst poisoning.

Information available on startup dates indicates that many SCR systems have been in operation for six or more years, which contributes a significant level of SCR operating experience to this report. Table 3.2 also indicates catalyst type, catalyst volume, and number of catalyst layers filled, for plants that provided this information. The applicable NO_x emission limit for each unit is also displayed in Table 3.2.

Note that plant A-3 has two boilers that exhaust through a common stack. Each of these boilers is equipped an SCR system. While analyzing emissions data from this plant, the two boilers with associated SCR systems are treated as one unit. However, in the discussion of unit and SCR characteristics and operational experiences, the two SCR units are treated separately.

Table 3.2. SUMMARY OF UNIT AND SCR CHARACTERISTICS

Plant: Unit	Boiler Information	MWe Rating	SCR Information							Emission Limit	Combustion Controls?	Flyash Recirculation
			SCR Began Operating	Retrofit/ New	SCR Type	Catalyst Type	Catalyst Volume	Catalyst Layers	Reagent Ammonia			
G-1	Pulverized Coal; Dry Bottom; Base Load	420 MWe	1985	New	High Dust	Honeycomb	440 m^3	3 layers filled	Anhydrous	200 mg/m^3	Yes	No
G-2	Box Fired; Dry Bottom; Base Load	510 MWe	1993	New	High Dust	Honeycomb	878.4 m^3	4 layers; 3 filled	Anhydrous	200 mg/m^3	Yes	No
G-3	Tangentially Fired Dry Bottom 2 SCR Systems	700 MWe	1986	New	High Dust	Honeycomb	826 m^3 (413 m^3 each SCR)	4 layers; 3 filled	Anhydrous	200 mg/m^3	Yes	Not Available
G-4: A	Tangentially Fired Dry Bottom	480 MWe	1992	New	High Dust	Honeycomb	581 m^3	4 layers; 3 filled	Aqueous	100 mg/m^3	Yes	No
G-4: B	Cyclone; Wet Bottom	220 MWe	1988	Retrofit	Tail End	Honeycomb	268 m^3	3 layers filled	Aqueous	200 mg/m^3	No	No
G-5: A	Wet Bottom	350 MWe	1989	Retrofit	Low Dust	Honeycomb	282 m^3 each layer	3 layers filled	Anhydrous	200 mg/m^3	Yes	Yes
G-5: B	Tangentially Fired Dry Bottom	710 MWe	1989	Retrofit	High Dust	Honeycomb	89.1 m^3 each layer	3 layers filled	Anhydrous	200 mg/m^3	Yes	No
G-6: A	Box Fired; Dry Bottom	680 MWe	1990	Retrofit	High Dust	Honeycomb	926 m^3	Not Available	Anhydrous	200 mg/m^3	Yes	No
G-6: B	Jet Burners; 2 units use one SCR system; Wet Bottom	142 MWe each	1991-2	Retrofit	Tail End	Honeycomb	98 m^3 each layer	3 layers; 2 filled	Anhydrous	200 mg/m^3	No	Yes

(cont.)

Table 3.2. SUMMARY OF UNIT AND SCR CHARACTERISTICS (Continued)

Plant: Unit	Boiler Information	MWe Rating	SCR Information							Emission Limit	Combustion Controls?	Flyash Recirculation
			SCR Began Operating	Retrofit/ New	SCR Type	Catalyst Type	Catalyst Volume	Catalyst Layers	Reagent Ammonia			
G-6: C	Wet Bottom	158 MWe	1993	Retrofit	Low Dust	Not Available	Not Available	Not Available	Not Available	200 mg/m^3	No	Yes
G-6: D	Box Fired; Dry Bottom	230 MWe	1989	New	High Dust	Not Available	Not Available	Not Available	Not Available	200 mg/m^3	Yes	No
G-6: E	Tangentially Fired	750 MWe	1989	Retrofit	High Dust	Not Available	Not Available	Not Available	Not Available	200 mg/m^3	No	No
G-7	Benson-Type; Dry Bottom	550 MWe	1989	Retrofit	High Dust	Not Available	521 m^3	Not Available	Anhydrous	200 mg/m^3	Yes	Not Available
G-8	Wall Fired; Pulverized Coal	450 MWe	1985	New	High Dust	Plate	325 m^3	2 SCRs; 1 layer each	Anhydrous	200 mg/m^3	Yes	No
G-9: A	Wet Bottom	345 MWe	1986	Retrofit	High Dust	3 SCRs: 1 Honeycomb; 2 Plate	Not Available	Not Available	Not Available	200 mg/m^3	Yes	Not Available
G-9: B	Tangentially Fired Dry Bottom	740 MWe	1990	Retrofit	High Dust	Not Available	Not Available	2 SCRs	Not Available	200 mg/m^3	No	Not Available
G-10: A	Cyclone; Wet Bottom	220 MWe	1989	Retrofit	High Dust	Plate	381 m^3 initial; 163 m^3 added	5 double layers	Anhydrous	200 mg/m^3	No	Yes
G-10: B	Cyclone; Wet Bottom	220 MWe	1989	Retrofit	High Dust	Plate	381 m^3 initial; 163 m^3 added	5 double layers	Anhydrous	200 mg/m^3	No	Yes

(cont.)

Table 3.2. SUMMARY OF UNIT AND SCR CHARACTERISTICS (Continued)

Plant: Unit	Boiler Information	MWe Rating	SCR Information							Emission Limit	Combustion Controls?	Flyash Recirculation
			SCR Began Operating	Retrofit/ New	SCR Type	Catalyst Type	Catalyst Volume	Catalyst Layers	Reagent Ammonia			
S-1: A[3]	Tangentially Fired Wet Bottom 2 SCRs	155 MWe	1992	Retrofit	High Dust	Plate	325 m^3	3 layers; 2 filled	Anhydrous	80 mg/MJ	Yes	No
S-1: B	Tangentially Fired Wet Bottom	40 MWe	1991	Retrofit	High Dust	Plate	90 m^3	4 layers; 3 filled	Anhydrous	80 mg/MJ	Yes	No
S-1: C	Tangentially Fired Wet Bottom	40 MWe	1991	Retrofit	High Dust	Plate	90 m^3	4 layers; 3 filled	Anhydrous	80 mg/MJ	Yes	No
US-1: A	Wall Fired; Pulverized Coal; Dry Bottom	140 MWe	1993	New	High Dust	Honeycomb	120 m^3	3 layers; 2 filled	Aqueous	0.17 lbs/ mmBtu	Yes	No
US-1: B	Wall Fired; Pulverized Coal; Dry Bottom	140 MWe	1993	New	High Dust	Honeycomb	120 m^3[4]	3 layers; 2 filled	Aqueous	0.17 lbs/ mmBtu	Yes	No
US-2	Wall Fired; Pulverized Coal; Dry Bottom	200 MWe	1994	New	High Dust	Plate[4]	141.3 m^3 initially; 188.4 m^3 currently;	3 layers; 2 filled	Aqueous	0.17 lbs/ mmBtu	Yes	No

(cont.)

[3] The S-1 units can burn either coal or oil. Oil use is restricted to startups or coal mill malfunctions. See Appendix A for further discussion.

[4] "Multiple Coal Plant SCR experience - A U.S. Generating Company Experience," P.A. Wagner, et. al., ICAC Forum ‘96, Baltimore, Maryland, March 1996.

Table 3.2. SUMMARY OF UNIT AND SCR CHARACTERISTICS (Continued)

Plant: Unit	**Boiler Information**	**MWe Rating**	**SCR Information**							**Emission Limit**	**Combustion Controls?**	**Flyash Recirculation**
			SCR Began Operating	**Retrofit/ New**	**SCR Type**	**Catalyst Type**	**Catalyst Volume**	**Catalyst Layers**	**Reagent Ammonia**			
US-4	Wall Fired; Dry Bottom	465 MWe	1996	New	High Dust	Plate	Not Available	4 layers; 2 filled	Anhydrous	0.17 lbs/ mmBtu	Yes	No
US-5	Tangentially Fired Wet Bottom; Cyclic	240 MWe	1996	New	High Dust	Plate	172.5 m^3	3 layers; 1.5 filled	Anhydrous	0.10 lbs/ mmBtu	Yes	No
US-6	Cyclone; Wet Bottom	375 MWe	1995	Retrofit	High Dust	Plate	400 m^3; 100 m^3 added	4 layers; 1.5 filled	Anhydrous	1.4 lbs/ mmBtu; 34.5 tons/day	No	Yes
A-1	Tangentially Fired Dry Bottom	234 - 246 MWe	1986	New	High Dust	Honeycomb	378 m^3	4 layers; 3 filled	Anhydrous	200 mg/m^3	Yes	No
A-2	Tangentially Fired Dry Bottom	330 MWe	1990	Retrofit	High Dust	Plate	405 m^3	3 layers filled	Aqueous	200 mg/m^3	Yes	No
A-3: A	Tangentially Fired Wet Bottom	405 MWe	1987	Retrofit	High Dust	Plate	653 m^3	2 layers filled	Anhydrous	200 mg/m^3	Yes	No
A-3: B	Tangentially Fired Wet Bottom	352 MWe	1987	Retrofit	High Dust	Plate	602 m^3	2 layers filled	Anhydrous	200 mg/m^3	Yes	No
D-1	Boxer-fired; Wet Bottom	250 MWe	1993	Retrofit	High Dust	Plate	313 m^3	3 layers filled	Anhydrous	400 mg/MJ	Yes	No
F-1	Benson-type; Dry Bottom	565 MWe	1994	New	High Dust	Plate	300 m^3	4 layers filled	Anhydrous	70 mg/MJ	Yes	No

3.2 INFORMATION ON COAL CHARACTERISTICS

Varying degrees of information on coal composition and properties were submitted by the participating utilities. In some cases, complete proximate or ultimate coal analyses were supplied. In other cases, only partial information was obtained. The coal data were used to: (1) calculate F-factors that were used to convert NO_x emissions data to units of lbs/mmBtu, and (2) characterize the coal properties relevant to SCR application. The coal parameters that may have the greatest influence on the unit and SCR performance are ash, sulfur, and trace metals. The SCR operational impacts associated with these properties are catalyst abrasion, flyash contamination, operational problems with the air preheater, and poisoning of the catalyst.

3.2.1 Reported Sulfur and Ash Content

As seen in Table 3-3, the reported coal sulfur content ranged from 0.5 to 1.5 percent (plant G-7 reported 0 percent sulfur) and the reported ash content ranged from 4.1 to 31.2 percent. The upper end of the coal sulfur range seen in the applications surveyed in this report is consistent with published literature on German SCR experience. According to Rummenhohl, et. al., SCR systems in Germany are typically operating on units using coals with up to 1.5 percent sulfur[5]. U.S. coals can have sulfur in excess of 4.0 percent . However, coals with sulfur in excess of 1.5 percent account for less than 15 percent of coals burned in the U.S.[5]

As seen in Table 3-3, the reported ash content ranged from 4.1 to 31.2 percent. This range is also consistent with the German SCR experience which covers a wide range of flyash loadings (coal used with up to 40 percent ash).[5] It is noted that most of the coal fired in U.S. electric utility boilers contains less than 15 percent of ash.

3.2.2 F-factors Computed Using Reported Data

To convert NO_x emission concentrations measured in units of mg/m^3 or ppm to a mass emission rate in units of lbs/mmBtu, it is necessary to use a factor that takes into account the amount of combustion gas produced per unit of heat input. This factor, known as the F-factor, is in units of dry standard cubic feet per mmBtu, and can be calculated using the Equation 19-13 given in EPA Reference Method 19 (40 CFR Part 60, Appendix A). This equation is as follows:

$$F_d = \frac{10^6(3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O))}{GCV} \qquad (3.1)$$

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[5] V. Rummenhohl, et al. "Relating the German Denox Experience to U.S. Power Plants: Lessons Learned From More Than 30,000 MW of Denox Retrofits," ASME Joint International Power Generation Conference, Phoenix, AZ, October 1994.

Where:

F_d	=	F-factor (dscf/mmBtu)
%H	=	Hydrogen content of coal
%C	=	Carbon content of coal
%S	=	Sulfur content of coal
%N	=	Nitrogen content of coal
%O	=	Oxygen content of coal
GCV	=	Gross Calorific Value of coal (Btu/lb)

See Appendix A for a discussion on the coal data analysis and the type of coal data obtained from each unit.

As seen in Equation 3.1, information on coal properties is necessary to calculate F-factors. Several plants provided complete information for the coal used during the period(s) for which emissions data were provided. In these cases, the information was used to calculate an F-factor for the correlating emissions period. Other plants provided the characteristics for all coals used at the plant without specifically identifying the unit where the coal was burned or which coal was used during the reported emissions period(s). In these circumstances, the coal data that were provided were used to assign a single F-factor for each plant. Wherever possible, the highest of the computed F-factors was assigned.

Table 3.3 depicts the F-factors computed using plant-specific coal data. The calculated F-factors range from 9,619 to 11,171 dscf/mmBtu with a mean F-factor value of 10,208 dscf/mmBtu and a standard deviation of 399 dscf/mmBtu. These results provide a relative error (standard deviation/mean) of about 3.9 percent for the computed F-factors.

Note that four German units at three plants, two units at the Swedish plant, two U.S. plants, and the Finnish and Danish plants did not provide adequate coal data for F-factor computation. The German plants that did not provide sufficient coal data identified the type of coal as either bituminous or "hard German coal." Such coals were considered to be equivalent to U.S. bituminous coal with the associated standard F-factor of 9780 dscf/mmBtu given in EPA Reference Method 19 (40 CFR Part 60, Appendix A). This standard F-factor was used in converting data from these plants. The standard F-factor was also utilized in converting data from plants in Finland and Denmark.

Note that the higher the F-factor, the higher the calculated NO_x emission rate in lbs/mmBtu. Thus, to avoid underestimation of the controlled NO_x levels achieved with SCR, wherever possible, the highest calculated F-factor has been used to determine emission rates in lbs/mmBtu. As mentioned above, where insufficient data were provided to calculate F-factors, the standard bituminous F-factor of 9780 dscf/mmBtu was used in data conversions.

Table 3.3. COAL CHARACTERISTICS AND COMPUTED F-FACTORS

Plant/Unit/Coal	GCV (kJ/kg)	%Ash	%H	%C	%S	%N	%O	F-Factor (dscf/mmBtu)
G-1: F. Leopold	29500	4.1	4.8	75.7	0.9	1.4	6.8	10308
G-1: Saar	30000	5.0	4.8	72.6	0.7	0.8	6.6	9768
G-3: Ruhrkohle	27500	9.0	3.9	69.6	1.0	1.4	4.2	10101
G-4: A & B Steinkohle	27000	6.3	4.7	74.8	0.7	1.2	5.6	11171
G-6: A	27200	11.3	4.5	67.5	0.9	1.2	8.8	9945
G-6: B	20500	23.5	3.3	51.6	1.2	1.1	6.2	10090
G-6: C & D	19300	25.2	3.3	50.0	1.1	0.9	6.4	10409
G-6: E	26500	10.3	4.4	67.3	0.9	1.7	7.7	10198
G-7: Median	27100	8.8	4.3	72.5	0.0	1.1	4.8	10686
G-9: A	21845	25.1	3.2	56.5	1.0	1.5	2.8	10395
G-9: B	27732	7.7	4.5	70.1	1.0	1.8	5.1	10241
G-10: A & B Median	27900	7.5	5.0	70.0	1.0	1.4	6.0	10278
S-1: A Oct 1-10	27170	7.4	4.2	65.8	0.7	1.2	9.1	9619
S-1: A Oct 11-31	27870	8.9	4.2	68.4	0.7	1.2	8.0	9749
S-1: A Jan 1-9, 21-31	30380	6.7	4.5	73.6	0.6	1.3	6.3	9680
S-1: A Jan 10-20	27200	8.6	4.1	66.9	0.7	1.2	8.3	9763
US-1: A May, 1996	30127	N/A	4.4	75.8	1.5	1.2	2.7	10193
US-1: A June, 1996	29936	N/A	4.4	75.8	1.5	1.2	2.7	10258
US-1: B May, 1996	30238	N/A	4.4	75.8	1.5	1.2	2.7	10155
US-1: B June, 1996	30096	N/A	4.4	75.8	1.5	1.2	2.7	10203
US-1: B July, 1996	30252	N/A	4.4	74.8	1.5	1.2	2.7	10151

(cont.)

Table 3.3. COAL CHARACTERISTICS AND COMPUTED F-FACTORS (Concluded)

Plant/Unit/Coal	GCV (kJ/kg)	%Ash	%H	%C	%S	%N	%O	F-Factor (dscf/mmBtu)
US-2 May, 1996	32043	N/A	4.5	77.2	1.5	1.3	4.2	9690
US-2 June, 1996	30789	N/A	4.5	77.2	1.5	1.3	4.2	10085
US-2 July, 1996	30389	N/A	4.7	76.6	1.25	1.4	0.3	10339
US-6	30669	6.2	4.7	74.3	1.5	1.3	5.8	9790
A-1	26179	9.9	4.6	70.0	0.53	1.2	5.1	10838
A-2	17096	31.2	3.9	44.4	1.3	0.5	16.8	10273
A-3	24300	13.0	4.3	67.4	0.65	1.3	8.7	11042

3.2.3 F-factors for Typical U.S. Coals

Since the values of F-factors can influence the conversion of NO_x concentrations to emission rates expressed in lbs/mmBtu, it was desirable to compare the F-factors of typical U.S. coals with those of coals being burned at overseas SCR applications. Therefore, data were obtained from the DOE/Energy Information publication, "Coal Data: A Reference", Feb. 1995 (DOE-EIA-0064(93)) for "typical" U.S. bituminous and subbituminous coals. These coal data and the corresponding F-factors (calculated using the tabulated U.S. coal data and Equation 3.1) are presented in Table 3.4. As seen in this table, the F-factors for the typical U.S. bituminous coals range from 9,635 dscf/mmBtu to 9,897 dscf/mmBtu with a mean value of 9,761 dscf/mmBtu and a standard deviation of 99 dscf/mmBtu. As expected, the mean of the F-factor values is close to the Method 19 bituminous F-factor of 9780 dscf/mmBtu. Further, the F-factors for subbituminous coals are lower than those for bituminous coals.

A comparison of Table 3.3 and Table 3.4 indicates that the F-factors for bituminous U.S. coals are generally lower than those calculated for coals being fired at overseas SCR applications. Thus by using the highest computed F-factor for the plants that provided adequate coal data, EPA has avoided underestimating NO_x emission rates expressed in lbs/mmBtu.

Table 3.4. U.S. BITUMINOUS COAL CHARACTERISTICS AND CORRESPONDING F-FACTORS[6]

Coal Classification by Rank	Gross Calorific Value, kJ/kg	Ultimate Analysis, percent					Percent Ash	F-factor,[7] dscf/ mmBtu
		Hydrogen	Carbon	Sulfur	Nitrogen	Oxygen		
Low-volatile Bituminous	33467	4.6	83.2	0.8	1.3	4.7	5.4	9897
Medium-volatile Bituminous	33258	5.0	81.6	1.0	1.4	4.9	6.1	9892
High-volatile A Bituminous	32630	5.5	78.4	0.8	1.6	8.5	5.2	9740
High-volatile B Bituminous	27145	5.4	65.1	2.8	1.3	14.6	10.8	9788
High-volatile C Bituminous	25123	5.8	59.7	3.8	1.0	20.1	9.6	9761
Subbituminous A	24751	6.0	60.4	1.4	1.2	27.4	3.6	9635
Subbituminous B	22334	6.9	53.9	0.5	1.0	33.4	4.3	9640
Subbituminous C	20057	6.5	50.0	0.6	0.9	36.2	5.8	9731

3.3 EMISSIONS DATA

In total, continuous emissions data were obtained for 19 units at 16 plants. Plants G-2, G-4, G-6B, G-9A, US-1, US-2, US-4, US-6, A-1, A-2, A-3, D-1, and F-1 provided more than one month of continuous data, while plants G-1 and G-5 provided continuous data for one month (744 hours). Plant S-1 provided continuous data for two non-consecutive months (October 1995 and January 1996) as well as monthly summaries for one unit (Unit A), but only monthly summaries for the other two units (Units B and C). The data reduction methodology employed in converting overseas emissions data to rates expressed in lbs/mmBtu is detailed in Chapter 5. Continuous emissions graphs for these units are presented in Appendix A.

In addition to the continuous emissions data described above, emission summaries were provided by many plants. Annual summaries were received for nine units at five plants and a daily summary of half-hour averages (in 20 mg/m^3 increments) covering more than a month was received from one unit at one plant. One other plant provided a similar overall summary of half-hour averages, along with a bar chart of daily averages, both covering a two month period. One U.S. plant provided daily values for 30-day rolling averages for a three month period. Table 3.5 presents the types of data received and the associated time periods for each unit.

[6] Data from DOE/EIA, “Coal Data: A Reference”

[7] Calculated according to Equation 3.1

Table 3.5. SUMMARY OF EMISSIONS DATA RECEIVED

Plant: Unit	Data Type	Time Period
G-1	Continuous Half-hourly Averages	March, 1995
G-2	Continuous Half-hourly Averages	January 25 - March 25, 1996
G-3	Annual Average	1995
G-4: A	Continuous Hourly Averages	January 1 - March 31, 1996
G-4: B	Continuous Hourly Averages	January 1 - March 31, 1996
G-5: A	Continuous Half-hourly Averages	March 1996
G-5: B	Continuous Half-hourly Averages	March 1996
G-6: A	Daily Summary of Half-hourly Averages	February 24 - April 12, 1996
G-6: B	Continuous Half-hourly Averages	October 1 - 21, 1994 November 1 - December 31, 1994
G-6: C	Annual Average	1995
G-6: D	Annual Average	1995
G-6: E	Annual Average	1995
G-7	Annual Average	1995
G-8	59 Day Summary of Half-hourly Averages and Bar Chart of Daily Averages	January 2 - March 1, 1996
G-9: A	Annual Average and Annual Summary of Half-hourly Averages	1995
	Continuous Half-hourly Averages	August 5 - October 11, 1996
G-9: B	Annual Average and Annual Summary of Half-hourly Averages	1995
G-10: A	Annual Average and Annual Summary of Half-hourly Averages	1995
G-10: B	Annual Average and Annual Summary of Half-hourly Averages	1995
S-1: A	Continuous Half-hourly Averages Monthly Averages	October 1995 and January 1996 1995
S-1: B	Monthly Averages	1995
S-1: C	Monthly Averages	1995
US-1: A	Continuous Hourly Averages	May-June, 1996

(cont.)

Table 3.5. SUMMARY OF EMISSIONS DATA RECEIVED (Concluded)

Plant: Unit	Data Type	Time Period
US-1: B	Continuous Hourly Averages	May 1 - July 30, 1996
US-2	Continuous Hourly Averages	May 1 - July 31, 1996
US-4	Continuous Hourly Averages	October 1 - December 31, 1996
US-5	30-Day Rolling Averages	January 1 - March 31, 1997
US-6	Continuous Hourly Averages	July 1 - September 30, 1996
A-1	Continuous Half-hourly Averages	November 6, 1995 - March 3, 1996
A-2	Continuous Half-hourly Averages	January 1 - March 31, 1996
A-3	Strip Chart of Continuous Half-hourly Averages	February - March, 1996
D-1	Continuous Half-hourly Averages	January 1 - March 31, 1996
F-1	Continuous Hourly Averages	July 24 - September 26, 1996

All of the emissions data included in this report served as the basis for reports submitted by utilities to their respective regulatory agencies to verify their compliance with applicable emission limits. However, to further assess the quality of the reported emissions data from Germany, the opinion of continuous emissions monitoring (CEM) experts at Emissions Monitoring, Inc. (EMI) was sought. In a letter report,[8] dated July 6, 1996, EMI noted that the German government licenses an independent agency, TÜV, to certify and test monitors prior to sale, at installation, and every three to five years after installation. According to EMI, the monitoring equipment in a German utility meets very stringent certification and calibration standards. Table 3.6 compares CEM quality assurance requirements for the German and Swedish plants discussed in this report to the United States requirements included in 40 CFR Part 75.

[8] Letter to Mr. Perrin Quarles, Perrin Quarles Associates, Inc., from Jim Peeler, Emission Monitoring Inc. July 6, 1996.

Table 3.6. SUMMARY OF CEM CERTIFICATION, TESTING AND MAINTENANCE REQUIREMENTS FOR THE COUNTRIES SURVEYED

Requirement	United States (Part 75)	Other Countries
Initial Certification	Certification tests performed on installed CEMS. Reference method testing: 10% relative accuracy; Calibration drift test: 7-days, ±2.5% of span; System response time: <15 minutes; Linearity test: 3 points, <5% of calibration gas.	Germany: Prior to installation: Independent authorized testing of instrument model including analytical function. Regression analyses; detection limit: 2% over most sensitive range; reproducibility: R ≥ 30; zero and calibration drift: ±2% over interval; interference from other species: ±4% of full scale. At installation: Check mounting and leaks; perform calibration with standard gases; check for interference from other species, drift stability, response time, sampling procedures and representativeness, comparing results against independent laboratory test methods; verify reporting procedures. Sweden: Similar to German requirements.
Short-term QA Checks	Daily calibration at zero and high ranges. Maintain as necessary.	Germany: Every seven days for extractive systems: Check zero and reference points (record drift); perform standard maintenance and operating checks. Sweden: Twice a week to once every two weeks, depending on the type of monitor; Check zero and reference points; if drift is greater than ± 2% of full scale, data from the tested period is invalid.
Intermediate Checks	Quarterly 3-point linearity tests.	Germany: Every 1 - 3 months for non-extractive systems: Check zero and reference points (record drift); perform standard maintenance and operating checks. Sweden: No comparable requirement.
Annual Checks	Annual or semiannual Relative Accuracy Test Audits (RATAs)	Germany: Check operational status; review zero and reference point records; perform drift tests; checks for interferences; calibration error test; compare monitor performance against independent laboratory test methods; data processing checks. Sweden: Annual testing by independent, government-accredited laboratory; facility's testing data is compared against independent laboratory test results.
Long-term Checks	None	Germany: Every 3 - 5 years, depending on system: Repeat installation QA. Sweden: No comparable requirement.

3.4 INFORMATION ON OPERATIONAL EXPERIENCE

The information received on SCR operational experience varied in the level of detail. A summary of information related to operational experience is presented in Table 3.7. This information is grouped into the following categories: ammonia slip, air preheater washing experience, operating experience, catalyst replacement experience, catalyst volume, and flyash disposal. Nine German plants responded with operational information for thirteen units. The plant in Sweden provided some information for the three units. Information was also obtained from the plants in Denmark and Finland. Two Austrian plants responded with information about three SCR units. Plant A-3 has two boilers that each are equipped with SCR but that emit through a common stack; therefore, operational experience is reported for each SCR, but emissions data are reported for the entire plant. Five plants in the United States provided information on their operational experiences for six units. Note that the description of “No Problems” under the category “Operating Experience” in Table 3.7 indicates that the SCR systems at these plants were operating as expected. Details on operating experiences for each plant can be found in Appendix A.

Table 3.7. SUMMARY OF OPERATING EXPERIENCE INFORMATION RECEIVED

Plant: Unit	Ammonia Slip	Air Preheater Washing Experience	Operating Experience	Catalyst Replacement Experience	Volume	Flyash Disposal
G-1	20-100 mg/ kg (in flyash)	Washed approximately every fifth year	No Problems	Level 1 replaced after 25,000 operating hours; Level 2 replaced after 36,000 operating hours; Level 3 replaced after 34,000 operating hours.	440 m^3	Sold
G-2	<3.5 mg/m^3; <2 ppm (actual)	Washed twice since operation began (1993) Washing needed when coal used with >2% S.	No Problems	At SCR startup, layers 2 and 3 filled. Layer 4 filled in 1994. Layer 2 replaced in 1996.	878.4 m^3, 4 layers; 3 filled	Sold
G-3	≤5 ppm	Washing unnecessary.	Cleaned first catalyst layer-decreased slip to <0.5 ppm.	After 18,500 operating hours, catalyst activity 77%. Replacement schedule in Appendix A.	826 m^3, 4 layers; 3 filled	Sold/ Disposed
G-4:A	<0.5 ppm (actual)	No need to wash air preheater.	No Problems	Stated that there have been no problems after 30,000 operating hours.	581 m^3, 4 layers; 3 filled	Sold
G-4:B	<0.1 ppm (actual)	Washed only in unusual circumstances Cleaning is related to pollution from FGD.	No Problems	Stated that there have been no problems after 55,000 operating hours.	268 m^3, 3 layers filled	Sold
G-5:A	<0.1 ppm (actual)	No Problems	No Problems	No problems after 45,000 operating hours	3 layers filled, 282 m^3 each	Not Available
G-5:B	<0.2 ppm (actual)	Washed 3 times -- once at catalyst layer replacement	No Problems	One layer replaced after 40,000 operating hours.	3 layers filled, 89.1 m^3 each	Not Available
G-6:A	<0.02 ppm (actual)	High dust -- washed once every 6-7 years	No Problems	One layer recharged after 27,000 hours.	926 m^3	Not Available

(cont.)

Table 3.7. SUMMARY OF OPERATING EXPERIENCE INFORMATION RECEIVED (Continued)

Plant: Unit	Ammonia Slip	Air Preheater Washing Experience	Operating Experience	Catalyst Replacement Experience	Volume	Flyash Disposal
G-6:B	<0.02 ppm (actual)	Low dust -- no washing needed	No Problems	No problems after 36,000 operating hours.	98 m^3 each, 3 layers; 2 filled	Sold depending on market situation, or melted down for building material.
G-7[9]	Not Available	Washed in 1991, two years after SCR, then 1x/ year. No washings needed after enameled metal installed in 1994.	No Problems	Not Available	521 m^3	Sold
G-8	0.5 ppm (actual)	Cleaned each time plant shut down.	Have resolved initial problems with corrosion.	Catalyst life above expectations; Planning to replace with design with lower SO_2 to SO_3 conversion rate.	325 m^3, 1 layer each, 2 SCRs	Sold
G-10: A and B	<5 ppm	No modifications required for SCR. Never has been practice to wash.	No problems after 30,000 operating hours	Has not been replaced; designed with spare layers for addition.	381 m^3 initial volume; 163 m^3 added 5 dble layers	Only slag is sold
S-1:A	<5 ppm (guaranteed)	Not Available	No Problems	Not Available	325 m^3, 3 layers; 2 filled, 2 SCRs	20% sold
S-1:B	<5 ppm (guaranteed)	Not Available	Same as for S-1:A	Not Available	90 m^3, 4 layers; 3 filled	20% sold
S-1:C	<5 ppm (guaranteed)	Not Available	Same as for S-1:A	Not Available	90 m^3, 4 layers; 3 filled	20% sold

(cont.)

9 Plant G-7 was only able to provide limited information because of the plant's confidentiality policy.

Table 3.7. SUMMARY OF OPERATING EXPERIENCE INFORMATION RECEIVED (Continued)

Plant: Unit	Ammonia Slip	Air Preheater Washing Experience	Operating Experience	Catalyst Replacement Experience	Volume	Flyash Disposal
US-1:A	<5 ppm (guaranteed)	Washed once per year	No Problems	Additional layer to be installed after 7 years (56,000 hours) of operation.	120 m^3, 3 layers; 2 filled	100% beneficial use; Used in reclamation.
US-1:B	<5 ppm (guaranteed)	Washed once per year	No Problems	Additional layer to be installed after 7 years (56,000 hours) of operation.	120 m^3, 3 layers; 2 filled	Used in reclamation.
US-2	<5 ppm (guaranteed)	Washed every 1-2 months before catalyst added in 10/96; stopped excessive washes.	APH fouling before catalyst addition	Additional layer to be installed every 3 years (24,000 hours) of operation.	141.3 m^3, 188.4 m^3 currently; 3 layers, 2 filled	80% reclaim; 20% mixed with sewage and used as landfill caps.
US-4	<2 ppm (guaranteed)	Washed since operation began in 1996	No Problems	No Problems	4 layers; 2 filled	Sold / landfill
US-5	<5 ppm (design and actual)	Originally supplied with ceramic coated plates.	No Problems	5 year replacement and maintenance schedule. Expected life 5+ years.	172.5 m^3, 3 layers; 1.5 filled	Taken away by railcar.
US-6	<5 ppm (guaranteed)	Washed several times since SCR installation in 1995. Washed annually before SCR installation.	Initially NH_3 slip problems due to bypass damper seals.	Additional layer (100 m^3) to be installed in April 1997.	400 m^3, 4 layers; 1.5 filled	Not Available
A-1	1 mg/m^3 in stack; 5 ppm (guaranteed)	Washed 2 times since installation, every 50,000 operating hours	No Problems	Layer 1 replaced after 40,000 hours; layer 2 after 60,000 hours; layer 3 after 66,000 hours.	378 m^3, 4 layers; 3 filled	Sold to cement industry

(cont.)

Table 3.7. SUMMARY OF OPERATING EXPERIENCE INFORMATION RECEIVED (Concluded)

Plant: Unit	Ammonia Slip	Air Preheater Washing Experience	Operating Experience	Catalyst Replacement Experience	Volume	Flyash Disposal
A-2	<5 ppm (guaranteed)	Washed once before SCR installation in 1990 and once since	No Problems	Localized erosion because of ash; catalyst replaced in those places.	405 m^3, 3 layers filled	Not Available
A-3:A	Approx. 1.5 ppm (actual)	Washed approximately every 5000 - 6000 operating hours; has been washed approximately 5 -7 times since SCR installation.	No Problems	Additional layer (109 m^3) installed after approximately 15,000 operating hours.	653 m^3, 2 layers filled	Sold
A-3:B	Approx. 1.5 ppm (actual)	Washed approximately every 5000 - 6000 operating hours; has been washed approximately 5 -7 times since SCR installation.	No Problems	Additional layer (100 m^3) installed after approximately 48,000 operating hours.	602 m^3, 2 layers filled	Sold
D-1	<4 ppm in SCR; <0.05 in chimney (actual)	Never washed (plant startup 1990)	No Problems	Plan to add third layer after 30,000 operating hours. Plan to replace a layer every third year.	313 m^3, 3 layers filled	Used for concrete, cement, asphalt, and landfill.
F-1	<1 ppm (actual)	Washed annually	No Problems	One layer added two years after beginning operation. First replacement estimated to be in 1999 or 2000.	300 m^3, 4 layers filled	Sold

3.5 COST

Cost information associated with SCR application is considered to be confidential by many utilities. Accordingly, only limited cost information was provided by utilities. Several European units (German and Austrian) provided cost data in their currencies. To examine costs in the terms of U.S. dollars, German and Austrian currencies were converted to dollars using rates reported in the June 30 issue of the *Wall Street Journal* of the year an SCR installation began its operation. The resulting dollar costs were next escalated to 1995 dollars using Chemical Engineering Plant Annual Cost Indices. The cost data provided by participating utilities is discussed in Chapter 8.

CHAPTER 4
REGULATIONS PERTINENT TO THE UNITS SURVEYED

The regulations pertinent to the U.S. and the European units that provided data for this report are discussed in this chapter. In addition, general overseas regulations[10] affecting the European plants are reviewed. Table 4.1 is a summary of specific NO_x emission limits for all participating units.

Table 4.1. NO_x EMISSION LIMITS FOR THE UNITS EXAMINED IN THIS STUDY

Country	Size, MWt	NO_x Emission Limit
United States	-	0.17 lbs/mmBtu, 0.10 lbs/mmBtu, 1.4 lbs/mmBtu
Austria	>500	200 mg/m^3 (~0.16 lbs/mmBtu)
Denmark	-	400 mg/MJ (~0.93 lbs/mmBtu) Production-based limit
Finland	>150	70 mg/MJ (~0.16 lbs/mmBtu)
Germany	>300	200 mg/m^3 (~0.16 lbs/mmBtu) 100 mg/m^3 (~0.08 lbs/mmBtu)
Sweden	-	80 mg/MJ (~0.19 lbs/mmBtu) + Economic Incentive

4.1 UNITED STATES

The survey of U.S. coal-fired utility boilers includes three new units located in New Jersey, one new unit located in Florida, one new unit in Virginia, and a retrofit unit located in New Hampshire.

The New Jersey units are subject to interim Prevention of Significant Deterioration (PSD) permit limits of 0.17 lbs NO_x/mmBtu calculated each hour, based on a rolling three hour average. These interim limits apply for five years during which each unit is required to optimize its control system to maximize NO_x reductions. Exemptions are provided in the permits for periods of startup (5 hours for US-1 and 6 hours for US-2), shutdown (30 minutes) and malfunction; emissions during these periods are excluded from emission rate calculations done for determining compliance. Monitoring certification and ongoing quality assurance requirements are those required under 40 CFR Part 60, Appendix B and Appendix F (the NSPS requirements).

The Florida unit is subject to a PSD NO_x limit of 0.17 lbs/mmBtu (30-day rolling average) and the NSPS quality assurance requirements. NSPS exemptions are provided in the permit for periods of startup, shutdown, and malfunction.

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[10] H.N. Soud, K. Fukasawa, "Developments in NO_x Abatement and Control", IEA Control Research, London, UK, August 1996.

The Virginia unit is currently subject to a NO_x emission limit of 0.10 lbs/mmBtu (30-day rolling average), as well as a "backup limit" of 0.15 lbs/mmBtu. The secondary limit was established as a backup while SCR system performance was evaluated. The unit is also subject to the NSPS quality assurance requirements and exemptions.

The New Hampshire unit is currently subject to a NO_x limit of 1.4 lbs/mmBtu (24-hour average) as well as 34.5 tons/day. No exemptions are provided in the permit for periods of startup, shutdown, and malfunction. The current limits are RACT limits and are scheduled to be changed to as yet undesignated limits by 1999.

4.2 AUSTRIA

The Austrian coal-fired electric utility plants included in this study are subject to a NO_x emission limit of 200 mg/m^3 (dry volume at 6 percent oxygen dilution). Emission measurements are to be conducted during typical operating hours; periods of startup, shutdown and malfunction are disregarded. For every three operating hours, six half-hourly mean values must be obtained. For coal-fired plants, compliance with the emission limit is considered to be achieved if no more than one of six half-hourly mean values exceeds the limit. The general Austrian emission limit for existing utility plants > 500 MW_t and new utility plants >300 MW_t is 200mg/m^3. This is the most stringent limit for coal-fired utility plants in Austria. Existing plants are defined as being in operation or approved for construction prior to January 1, 1989, and new plants are defined as being approved for construction after January 1, 1989. Plant operators have a duty to remedy malfunctions that cause exceedances of the emission limit. The requirements of this duty are considered to be met if for a calendar year no daily average (the arithmetical average of all values recorded on that day) exceeds the limit; no more than 3 percent of the recorded values exceed the limit by more that 20 percent; and no half-hourly mean value is greater than two times the emission limit. Austrian emission standards are expressed at STP[11] and 6 percent oxygen, on a dry basis. An emission limit of 200 mg/m^3 corresponds to approximately 0.16 lbs/mmBtu, in the units of the existing U.S. NO_x limits.

4.3 DENMARK

Under Danish regulations, Plant D-1 must meet an average annual emission limit of 400 mg NO_x/MJ (1080 mg/m^3)at 6 percent O_2 and STP, on a dry basis, which is the general Danish emission limit for existing utility plants. Expressed in the units of the existing U.S. limits, the Danish limit for Plant D-1 corresponds to 0.93 lbs/mmBtu. From January 1, 1992, new utility plants approved for construction after July 1, 1987 have an average annual emission limit of 200 mg/m^3 (at 6 percent O_2 and STP, on a dry basis). In addition to the individual plant limit, a national program initiated in 1995 to reduce SO_2, NO_x and CO_2 emissions nationwide has resulted in production-based limits for the utility industry. The production-based NO_x limit for the Eastern Denmark region is 1.23 g/kWh.[12] This limit applies to both electricity production and cogenerated heat production.

4.4 FINLAND

Plant F-1 is subject to a specific annual average emission limit of 70 mg NO_x/MJ of coal energy. Expressed in the units of the existing U.S. NO_x limits, this limit corresponds to 0.16 lbs/mmBtu. The Finnish NO_x emission limits vary according to plant size (expressed as MW_t input)

[11] STP is defined as 0°C and 101.3 kPa.

[12] 1995 Annual Report for Plant D-1.

and construction date. The general emission limit in Finland for new, "hard coal fired boilers" > 150 MW_t is 50 mg/MJ (135 mg/m^3) and for new plants ranging between 50 to 150 MW_t the limit is 150 mg NO_x/MJ (405 mg/m^3). The general Finnish limits for existing plants vary depending upon the boiler size and the type of firing. All limits are expressed with 6 percent O_2 and STP, on a dry basis.

4.5 GERMANY

The German NO_x limit for the coal-fired electric utility plants included in this study is 200 mg NO_x/m^3 (dry volume at either 5 percent or 6 percent oxygen dilution) except for one new plant which must meet a 100 mg/m^3 limit. Expressed in units of lbs/mmBtu, the German limit of 200 mg/m^3 corresponds to approximately 0.16 lbs/mmBtu. The 200 mg NO_x/m^3 (at 6 percent O_2 and STP) limit is applicable to both existing and new utility plants larger than 300 MW_t. German regulations require the daily average of half-hour mean values to be below the applicable emission limit, 97 percent of the daily half-hour mean values to be below 1.2 times the applicable emission limit, and all of the daily half-hour mean values to be below two times the applicable emission limit. The German regulations allow utilities to exclude some half-hour mean values, i.e. those that occur during SCR system startup and shutdown and SCR system maintenance or downtime.

4.6 SWEDEN

The Swedish regulations require Plant S-1 to meet an annual average of 80 mg NO_x /MJ of coal energy. Expressed in the units of the existing U.S. NO_x limits, the Swedish limit for the plant in this report corresponds to 0.19 lbs/mmBtu. The general limit in Sweden allows annual average NO_x emissions of up to 100-200 mg NO_x/MJ for existing plants emitting less than 300 ton NO_x/year, and 50-100 mg NO_x/MJ for existing plants emitting more than 300 ton NO_x/year. Additionally, the Swedish regulations also prescribe a fee on NO_x emissions (on a per kg basis) that encourages the plants to minimize emissions. In Sweden, all electric utility units with more than 10 MWe of capacity, that produce more than 50 GWe per year, pay this fee. After a one percent administrative fee is deducted, all remaining revenues are redistributed to the utilities based upon the fraction of total national electrical power output generated by each utility. Personnel at Plant S-1 stated that this approach provides an incentive to achieve a low kg NO_x per MWe rate.

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CHAPTER 5
EMISSIONS DATA ANALYSIS

The goal of the emission analysis was to allow a detailed assessment of SCR performance for a variety of boiler and SCR types over a broad range of operating conditions. As noted previously, data provided by the participating utilities was reported in various units and time increments. In order to compare SCR performance between data sets, it was necessary to normalize the emissions data to a standard basis. The F-factor approach discussed in Chapter 3 was used to convert all concentration data to a mass emission rate expressed in lbs/mmBtu. This chapter details the steps followed in converting the emissions data.

5.1 METHODOLOGY

5.1.1 European Emissions Data

Emissions data reported by European utilities were in measurement units prescribed by the regulations of the appropriate country, corrected to International Standards Organization (ISO) standard conditions of 0°C (273 K), 1013 mbar (1 atm), and no moisture.

Concentrations of NO_x emissions were usually corrected by the utility to a constant five percent or six percent oxygen basis, which was specified in the data received. To provide further standardization, all concentration data received from various countries were corrected to a zero percent oxygen basis. Also, some utilities only measured the nitric oxide (NO) concentration, rather than all oxides of nitrogen, and obtained values for NO_x by assuming a ratio of NO_2 to NO of five percent, or by conducting actual NO_2 concentration measurements on an annual or semi-annual basis. These approaches were accepted without adjustments.

To permit a comparison to the U.S. data and standards, all European emissions data were converted, using the F-factors discussed previously, to units of lbs/mmBtu commonly used in the United States. Three German plants (G-2, G-5, and G-8), as well as the Danish plant (D-1) and the Finnish plant (F-1) did not provide sufficient coal data to calculate F-factors and were assigned the standard F-factor of 9,780 dscf/mmBtu for bituminous coal given in Reference Method 19 (40 CFR Part 60, Appendix A). Plant S-1, Units B and C, provided summary emissions data stated in mg NO_x/MJ. Conversion of these data to lbs/mmBtu did not require the application of an F-factor since the data were already expressed in terms of heat input.

<u>Austrian Data Conversion</u>

To convert the data expressed in mg/m^3, obtained from Austrian electric utilities, to values in units of lbs/mmBtu [at 293 K, 1 atm, and 0 percent O_2], the following conversion formula was applied to the NO_x data:

$$E = K_1 C_1 F_d \left(\frac{20.9}{(20.9 - \%O_2)} \right) \left(\frac{273}{293} \right) \qquad (5.1)$$

Where:

E	=	Emission rate (lbs NO_x/mmBtu)
K_1	=	Conversion factor (1 lb/453.6 g)(1 m^3/35.31 ft^3)(1 g/10^3 mg)
C_1	=	NO_x concentration (mg/m^3 @ a given %O_2, 273K, and 1 atm)
F_d	=	F-factor (dscf/mmBtu)
%O_2	=	Oxygen concentration in flue gas (usually 6 percent)

Danish Data Conversion

Data received from the Danish plant were reported in concentration units (ppm) under dry conditions and did not have to be corrected for moisture. Using the appropriate F-factor, the continuous stack NO_x concentration measurements in ppm were converted to units of lbs/mmBtu. The following formula was used in data conversion:

$$E = K_2 C_2 F \left(\frac{20.9}{20.9 - \%O_2} \right) \qquad (5.2)$$

Where:

E	=	Emission rate (lbs NO_x/mmBtu)
K_2	=	Conversion factor (Molecular wt. NO_2/22.4 l)(10^3)(1 g/10^6 μg) (1 lb/453.6 g)(1 m^3/35.31 ft^3)
C_2	=	NO_x concentration (ppm)
F	=	F-factor (dscf/mmBtu)
%O_2	=	Oxygen concentration in flue gas (6 percent)

The standard bituminous coal F-factor of 9780 dscf/mmBtu was used in data conversion since the coal data provided were insufficient to calculate an F-factor.

Finnish Data Conversion

Data received from the Finnish plant were reported in concentration units (ppm) and had not been corrected for moisture. The moisture content of the flue gases was not measured continuously, but was reported by the plant as 6 to 7 percent; therefore, a value of 6.5 percent was used in the moisture correction procedure. To convert to units of lbs/mmBtu under dry standard conditions at 293K, 1 atm and 0 percent O_2, the following formula was used:

$$E = K_2 C_2 F \left(\frac{20.9}{20.9(1 - \frac{\%H_2O}{100}) - \%O_2} \right) \quad (5.3)$$

Where:

E	=	Emission rate (lbs NO_x/mmBtu)
K_2	=	Conversion factor (Molecular wt. NO_2/22.4 l)(10^3)(1 g/10^6 μg) (1 lb/453.6 g)(1 m^3/35.31 ft^3)
C_2	=	NO_x Concentration (ppm)
F	=	F-factor (dscf/mmBtu)
$\%O_2$	=	Oxygen concentration in flue gas
$\%H_2O$	=	Moisture concentration in flue gas (6.5 percent as reported by the plant)

<u>German Data Conversion</u>

Data received from German plants were expressed in mg/m^3 and were converted in the same manner as the Austrian data.

<u>Swedish Data Conversion</u>

Plant S-1: Unit A supplied continuous half-hour emissions data (expressed in mg NO_x/MJ) as well as stack NO_x concentration (expressed in ppm). Using a calculated F-factor, the continuous stack NO_x concentration measurements in ppm were converted to values in units of lbs/mmBtu according to equation 5.2.

Plant S-1: Units B and C supplied only monthly emissions data in mg NO_x/MJ. These monthly averages were converted to values in units of lbs/mmBtu using the following formula:

$$E = K_3 E_s \quad (5.4)$$

Where:

E	=	Emission rate (lbs NO_x/mmBtu)
K_3	=	Conversion factor (1 lb/453.6g)(1055 MJ/mmBtu)(1g/10^3mg)
E_s	=	Emission rate (mg NO_x/MJ)

5.1.2 United States Data

Data received from United States plants were already stated in units of lbs/mmBtu and required no conversion.

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CHAPTER 6
SCR PERFORMANCE

To assess SCR NO_x removal performance, overall averages, daily averages, and 30-day rolling averages of emissions were examined. Table 6.1 summarizes the overall averages, highest 24-hour averages, and highest 30-day rolling averages for the units that provided continuous data. Further, shown in Table 6.2 are the overall averages and highest 24-hour averages for the units that provided summary data. Note that the averages in Tables 6.1 and 6.2 were computed using data that may include exempt emissions and using the highest calculated F-factor wherever possible. Hence, the averages in these tables are conservative. The following sections discuss the average emissions being achieved at the SCR installations.

6.1 OVERALL AVERAGES

As seen in Table 6.1, all of the plants surveyed (except for US-6 that is regulated with an emission limit of 1.4 lbs/mmBtu) achieved 0.17 lbs/mmBtu or lower for their overall hourly or half-hourly mean and 14 of the 20 units achieved 0.15 lbs/mmBtu or lower. In some instances, units providing continuous data had higher emissions for specific time periods, particularly following unit startup or preceding unit shutdown. In many cases, these emissions are exempt under applicable regulations; however, an explanation of the reasons for NO_x increases or decreases in these instances was not provided by most plants.

The German plants, all coal-fired with more than 140 MW_e capacity, achieved overall hourly and half-hourly averages ranging from 0.08 to 0.17 lbs/mmBtu, and, therefore, are consistently able to achieve NO_x emissions levels at or below the applicable German standard. For all of the retrofit units and one of the new units the German emission limit is 200 mg/m^3 (daily average), which corresponds to 0.16 ±0.01 lbs/mmBtu. One additional new German unit (G-4:A) meets a stricter limit of 100 mg/m^3 (0.08 ±0.01 lbs/mmBtu). Note that the approximate range of numbers expressed in lbs/mmBtu corresponding to German concentration standards results from variation in F-factors (see Section 3.2.1).

The Swedish utility, a cogeneration plant supplying both heat and electrical power to the city of Stockholm, achieved overall half-hourly averages of 0.04 and 0.07 lbs/mmBtu during two separate months of the year (see Table 6.1). The lower value was achieved during variable load conditions experienced in October 1995, and the higher value during maximum load conditions experienced in January 1996. For both months these emissions were dramatically below the Swedish standard of 80 mg/MJ (0.19 lbs/mmBtu).

Four United States units, operating at three plants (US-1, US-2, US-4), were able to achieve overall average hourly NO_x emission levels ranging from 0.13 lbs/mmBtu to 0.16 lbs/mmBtu, below the applicable 0.17 lbs/mmBtu emission limits in their Prevention of Significant Deterioration (PSD) permits. Plant US-6 achieved an overall hourly NO_x emission average of 0.91 lbs/mmBtu, which is below the applicable 1.4 lbs/mmBtu 24-hour average PSD emission limit.

The three Austrian plants achieved overall NO_x emission averages ranging from 0.10 to 0.16 lbs/mmBtu. The lower value is approximate, since for one plant, A-3, the reported daily average values were calculated as an average of each day's highest and lowest half-hour measurement read from a strip chart supplied by the plant. The emission values from all the Austrian plants are below the Austrian emission limit of 200 mg/m^3 (0.16 ±0.01 lbs/mmBtu).

The Danish plant achieved an overall average half-hourly NO_x emission rate of 0.15 lbs/mmBtu. Two periods of uncontrolled emissions during an excusable SCR malfunction (resulting in an SCR system shutdown) and a period of erroneous measurements during a monitoring system malfunction were identified by the plant and were omitted from calculations of emission averages.
The Finnish plant achieved an overall hourly NO_x emission level of 0.16 lbs/mmBtu which complies with the Finnish standard of 70 mg/MJ (0.16 lbs/mmBtu).

The average emissions for plants submitting continuous hourly or half-hourly data are presented separately from the average emissions for plants submitting summary data because in the former case the averages may include exempt data, i.e., data related to startup, shutdown, or some other excusable event. These exempt data would have been excluded by plants in their compliance determinations. Because exempt events for most of the units were not specifically identified in the continuous hourly and half-hourly data that were received, all reported data were included in the calculations. The only plants providing continuous data that identified exempt emissions were US-4 (there was none for the reported period) and D-1 (three periods were identified). The three periods reported by D-1, and described above, were removed from calculations of an overall average emission rate, 24-hour averages and 30-day rolling averages. Plants G-1 and G-4:B indicated that the spikes in their emissions data were related to startup, shutdown, or problems with NH_3 injection. Complete explanations for the higher emission values for these units may be found in Appendix A.

In contrast to exempt emissions, periods of no reported emissions could be identified in the continuous emissions data and were excluded from the analysis in Table 6.1. In many cases it was possible to identify periods where the unit was down because the MW_e data indicated zero, i.e. no electricity being produced. In computing 24-hour averages where continuous data were available, only days for which at least 18 hours (75 percent of the day) were available were included. In computing 30-day rolling averages, any day where at least one hour of data was available was included. Data obtained for periods during which boilers were burning supplemental fuel, such as gas or oil, were excluded from all averages calculated in this report. This was the case only for plants S-1 and A-3.

In general, it was not possible to exclude from calculated averages the data exempt from compliance. The only plant submitting summary data that identified exempt emissions as a part of its summary was G-10, which appears to have excluded these emissions from data used to calculate an average emission rate. Emissions from plants submitting only summary data are reported in Table 6.2. For these plants, the overall average NO_x emissions ranged from 0.10 to 0.17 lbs/mmBtu (see Table 6.2). Overall average emissions for the German units were between 0.13 and 0.17 lbs/mmBtu. The two Swedish units (Plant S-1: Units B and C) achieved 0.10 lbs/mmBtu. These emission levels are significantly below the applicable emission limit (0.19 lbs/mmBtu) due to the economic incentive provided in the Swedish regulation to achieve lower emission levels.

Table 6.1. NO_x EMISSIONS FROM PLANTS PROVIDING CONTINUOUS DATA

Plant/Unit	NO_x Emissions (lbs/mmBtu)		
	Overall Average	**Highest 24-Hour Average**	**Highest 30-Day Rolling Average**
G-1	0.16	0.18	--
G-2	0.15	0.17	0.15
G-4: A	0.08	0.10	0.08
G-4: B	0.16	0.24	0.16
G-5: A	0.14	0.15	--
G-5: B	0.15	0.18	--
G-6: B (10/1 - 10/21)	0.13	0.14	--
G-6: B (11/1 - 12/31)	0.12	0.13	0.12
G-9: A (8/5 - 10/11)	0.17	0.19	0.17
S-1: A, October[13]	0.04	0.08	--
S-1: A, January[13]	0.07	0.08	--
US-1: A	0.14	0.18	0.14
US-1: B	0.13	0.15	0.14
US-2	0.16	0.18	0.16
US-4	0.14	0.19	0.15
US-6	0.91	1.13	0.95
A-1	0.16	0.16	0.16
A-2	0.12	0.15	0.13
A-3[14]	daily high: 0.11 daily low: 0.08	0.14	0.11
D-1	0.15	0.25	0.18
F-1	0.16	0.22	0.18

[13] January represents a month of continuously high demand, while October represents a month of variable demand. This plant periodically burns oil as supplementary fuel; however, periods where oil was burned were excluded from all calculations included in this report.

[14] High and low values were read from a strip chart of continuous half-hour data. The overall average for daily highs and lows is the calculated overall average of each extreme, and the highest 24-hour average is the highest of these values. The highest 30-day rolling average, on the other hand, is based on the average of each day's extremes, averaged again over a 30-day period.

Table 6.2. NO_x EMISSIONS FROM PLANTS PROVIDING SUMMARY DATA

Plant/Unit	NO_x Emissions (lbs/mmBtu)		
	Overall Average	**Highest 24-Hour Average**	**Data Provided**
G-3	0.13	No Data Provided	Annual (1995)[15]
G-6: A	0.16	0.17	Daily Summary of Half-Hour Averages - 48 days (1996)[16]
G-6: C	0.17	No Data Provided	Annual (1995)[15]
G-6: D	0.17	No Data Provided	Annual (1995)[15]
G-6: E	0.17	No Data Provided	Annual (1995)[15]
G-7	0.17	No Data Provided	Annual (1995)[15]
G-8	0.14	0.15	Daily Averages - 59 days (1996)[17]
G-9: A	0.13	No Data Provided	Annual (1995)[18]
G-9: B	0.16	No Data Provided	Annual (1995)[18]
G-10: A	0.15	No Data Provided	Annual (1995)[19]
G-10: B	0.16	No Data Provided	Annual (1995)[19]
S-1: B	0.10	No Data Provided	Monthly (1995)[20]
S-1: C	0.10	No Data Provided	Monthly (1995)[20]
US-5	--	0.07 (Highest 30-day rolling average)	30-Day Rolling Averages - 3 months (1997)

15 An overall average emission rate was provided by each plant either with no supporting data or with insufficient data to corroborate the reported average rate.

16 A daily summary of half-hourly averages in 20 mg/m^3 increments was provided. This permitted the calculation of daily and overall half-hourly averages for the period reported. The high end of each 20 mg increment was used in all calculations.

17 A bar graph of 59 daily average half-hourly means was provided in mg/m^3 and converted to the equivalent lbs/mmBtu. The overall average is an average of the daily half-hourly means for 55 operating days during this period. Thirty-day rolling averages were also calculated for this unit and are shown in Figure 2. The highest 30-day rolling average during this period was 0.15 lbs/mmBtu.

18 These annual averages were reported by the plants, along with an annual summary of half-hourly averages that indicate a lower level may have actually been achieved.

19 These annual averages were reported by the plants, along with an annual summary of half-hourly averages that are consistent with the annual average reported by the plant. Exempt emissions were identified in data provided by the plant and appear to have been excluded from the reported annual average for each unit.

20 A combined monthly average was provided for both Units B and C. The overall average shown is the average of the monthly averages for the ten months these units operated.

In summary, all German plants achieve overall average NO_x emission levels at or below the applicable German emission limits (expressed in mg/m^3). As shown in the figures in Appendix A that depict the continuous emissions from these plants, the German plants seem to operate their SCR controls to comply with the applicable emission limits. The United States, Austrian, Finnish, and Danish plants also achieve overall average NO_x emissions below the applicable emission limits.

The Swedish retrofitted unit (Plant S-1), in contrast, demonstrates that NO_x levels well below the Swedish standard (and also well below the German or United States standards) are achievable during both the variable load conditions experienced in October 1995 and the maximum load conditions experienced in January 1996. The Swedish regulatory system incorporating an economic incentive, described in Section 4.3, clearly motivates Plant S-1 to achieve minimal NO_x rates rather than just comply with the applicable emission standard.

Overall average emissions for plants providing continuous data are also presented in Figure 6.1. The solid lines in Figure 6.1 represent regulatory emission limits for each of the plants participating in this study (for Germany and Austria a range of limits based on the applicable plant F-factor is provided). Note that a single bar representing the overall average of the longest emissions period for G-6:B is used in Figure 6.1. As seen in this figure, in all cases the overall average emissions were lower than the applicable regulatory emission limits.

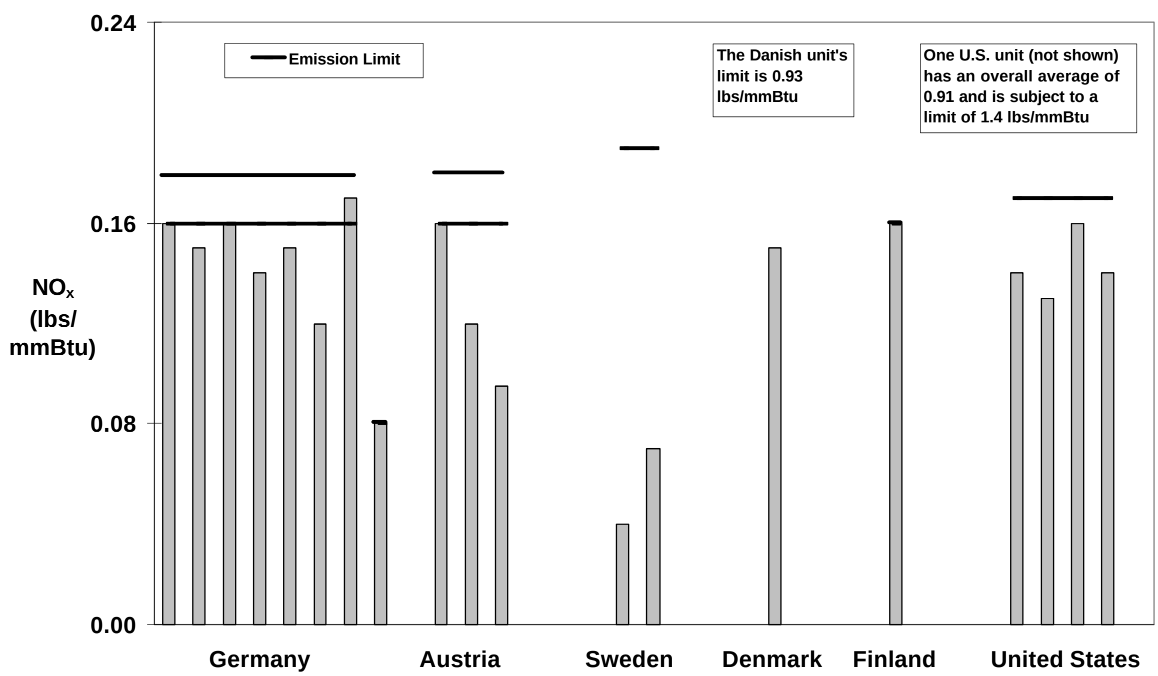

Figure 6.1. Overall Average Emissions

6.2 DAILY AVERAGES

The average NO_x emissions (expressed in 24-hour averages) are shown in Figure 6.2 for the German units that provided continuous half-hourly, hourly, or daily data. Plant G-4: Unit A is a non-retrofit (new) plant that is required to meet a 100 mg/m^3 German standard. Plant G-1 reported using two types of coal, and the higher of the two calculated F-factors was used in emission rate calculations.

Although the data for each German unit covered different time periods within the overall time range of October 1994 to October 1996, data have been plotted on the same time axis in Figure 6.2 to facilitate comparison. Thus, Figure 6.3 shows only the first 30 days of each unit's reported data, regardless of the particular date on which the first data point falls and regardless of whether the continuous data extended beyond 30 days. For example, Figure 6.2 shows Plant G-1 averages for March 1 - 30, 1995, along with Plant G-4: Unit A averages for January 1 - 30, 1996. Complete 24-hour average graphs covering all of the data provided by these plants are included in Appendix A.

As previously discussed, these data show a fairly consistent pattern of NO_x emissions below the German emission limit of 200 mg/m^3 (approximately 0.16 ±0.01 lbs/mmBtu). Notably, the one German unit with a lower emission limit of 100 mg/m^3 (approximately 0.08 lbs/mmBtu) showed sustained daily averages below 0.09 lbs/mmBtu (the upper end of the range).

Figure 6.3 shows the 24-hour averages recalculated for the German units using the Method 19 9780 dscf/mmBtu F-factor, which can be used under U.S. regulations when bituminous coal is burned. The results show that 24-hour averages are consistently below 0.16 lbs/mmBtu and at or below 0.15 lbs/mmBtu for most of the units. For plants G-2, G-5 and G-8, the emissions values are the same in both figures, as these units did not supply enough coal information to calculate specific F-factors. As expected, a comparison of Figures 6.2 and 6.3 reveals that emission rates (lbs/mmBtu) decrease when the standard bituminous F-factor of 9780 dscf/mmBtu is used (see section 3.2.3).

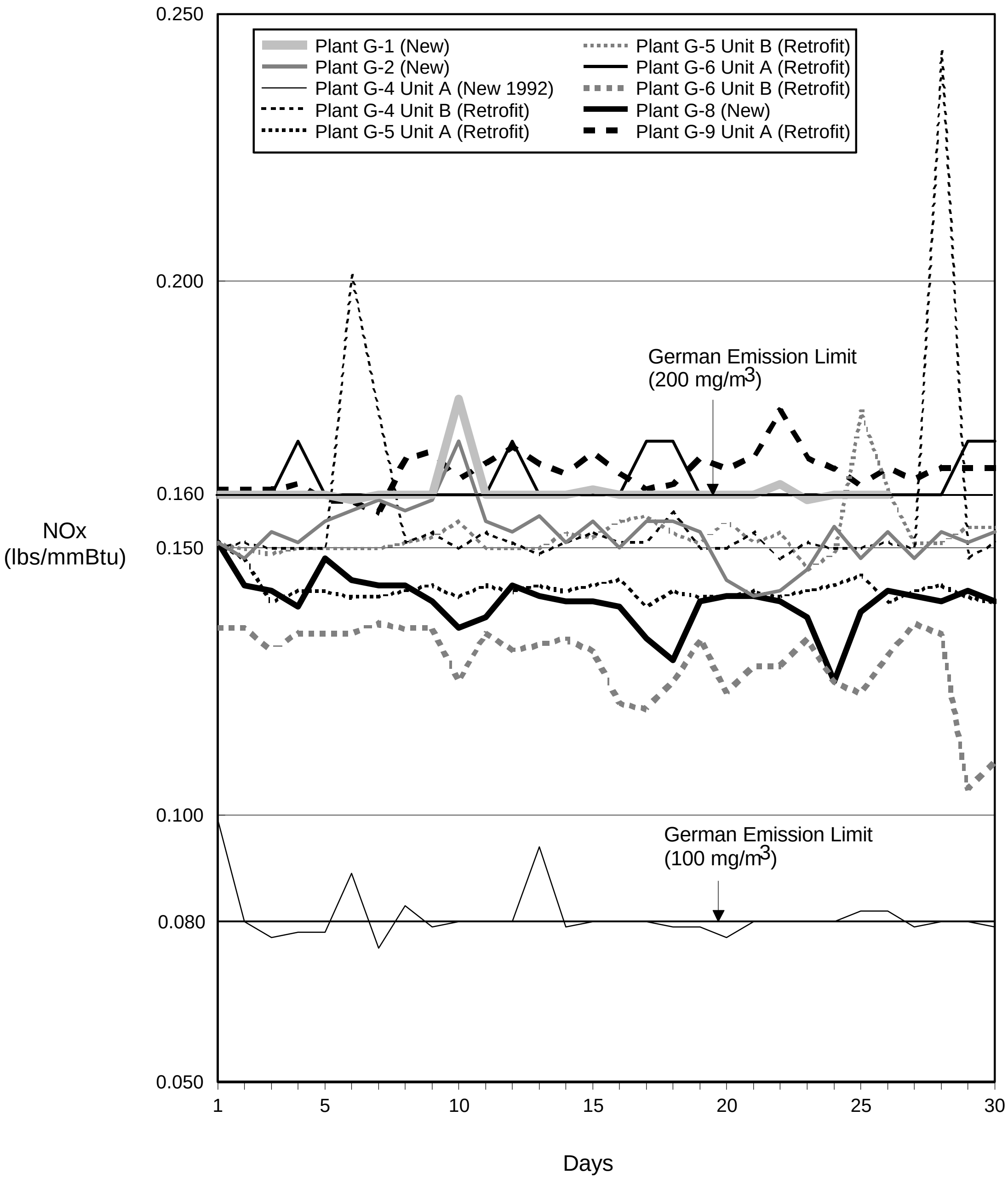

Figure 6.2. NO_x Emissions (24-Hour Averages) for
German Plants G-1, G-2, G-4, G-5, G-6, G-8, and G-9

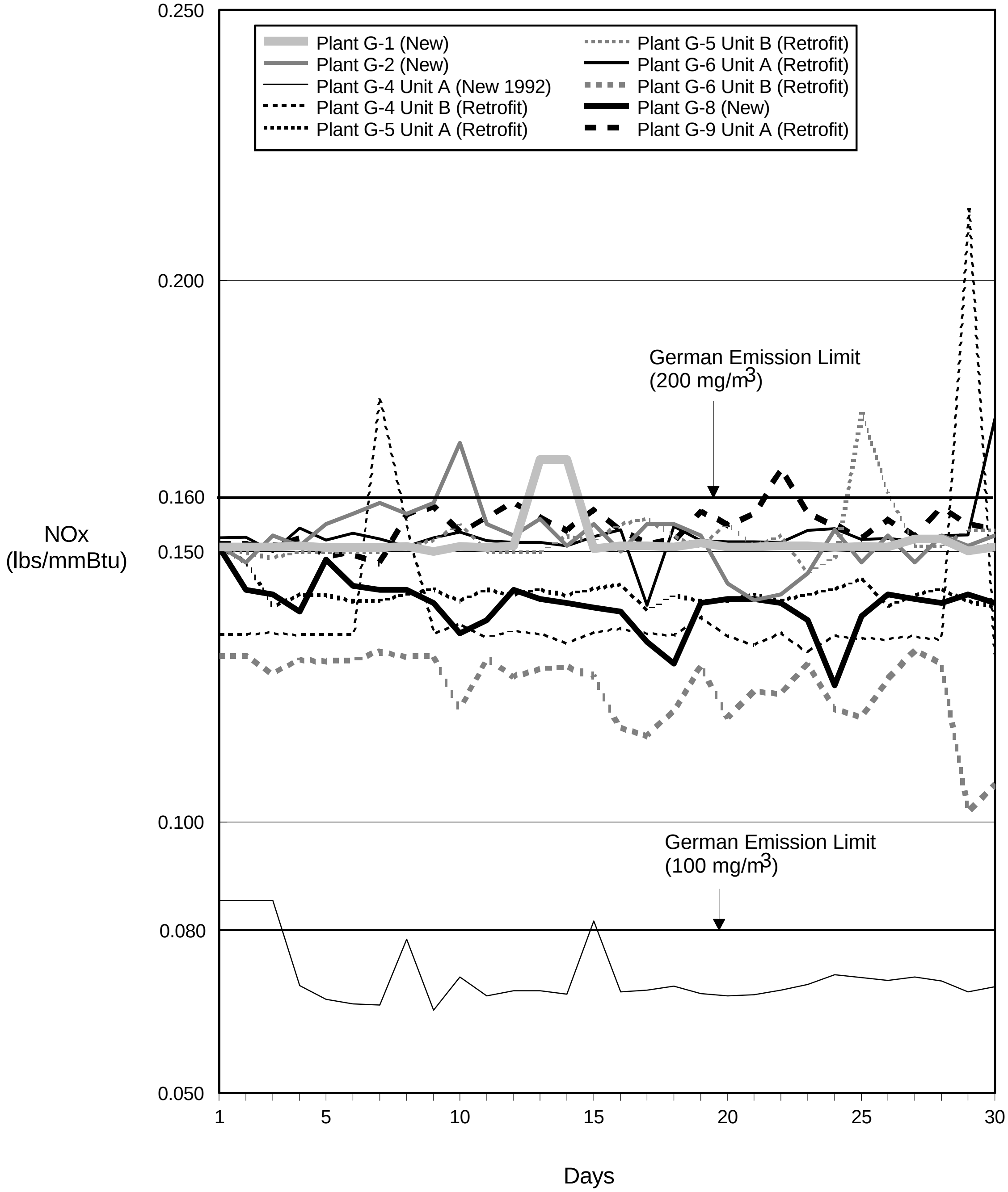

Figure 6.3. NO_x Emissions (24-Hour Averages) for German Plants Using 9780 F-Factor

Figure 6.4 shows the average NO_x emissions expressed in 24-hour averages for the Swedish Plant S-1: Unit A. January and October were selected by the utility as two months that would provide a representative range of NO_x emissions for the year. January represents a month of continuously high combined electricity and steam heat demand, while October represents a month of variable demand. Plant S-1 did not provide continuous data for Units B and C. As a result, 24-hour averages could not be calculated for these additional units. The figure indicates that Plant S-1: Unit A is able to achieve very low NO_x emission rates, substantially below the annual average emission limit of 0.19 lbs/mmBtu, in periods of high and variable demand.

After reviewing the October 23, 1996, draft report, some commenters raised questions about whether the combustion of oil at Plant S-1, Unit A, would impact the effectiveness of the SCR system. In response to EPA's request for additional information on this issue, the plant stated that Unit A burns coal the majority of the time and combusts oil only during startup or when the plant is having trouble with its coal mills. The plant noted that oil was burned approximately four percent of the operating time in October 1995 and approximately one percent of the operating time during January 1996. The plant stated that, in general, oil use does not exceed "a couple of percent" of operating time in a month, and that there are months when oil is not used at all. The plant also reported that analysis of a test piece of catalyst from Unit A showed catalyst activity decreasing at the expected rate and showed no impact from oil burning. As stated earlier, all data acquired while burning supplemental fuels were excluded from the calculated averages.

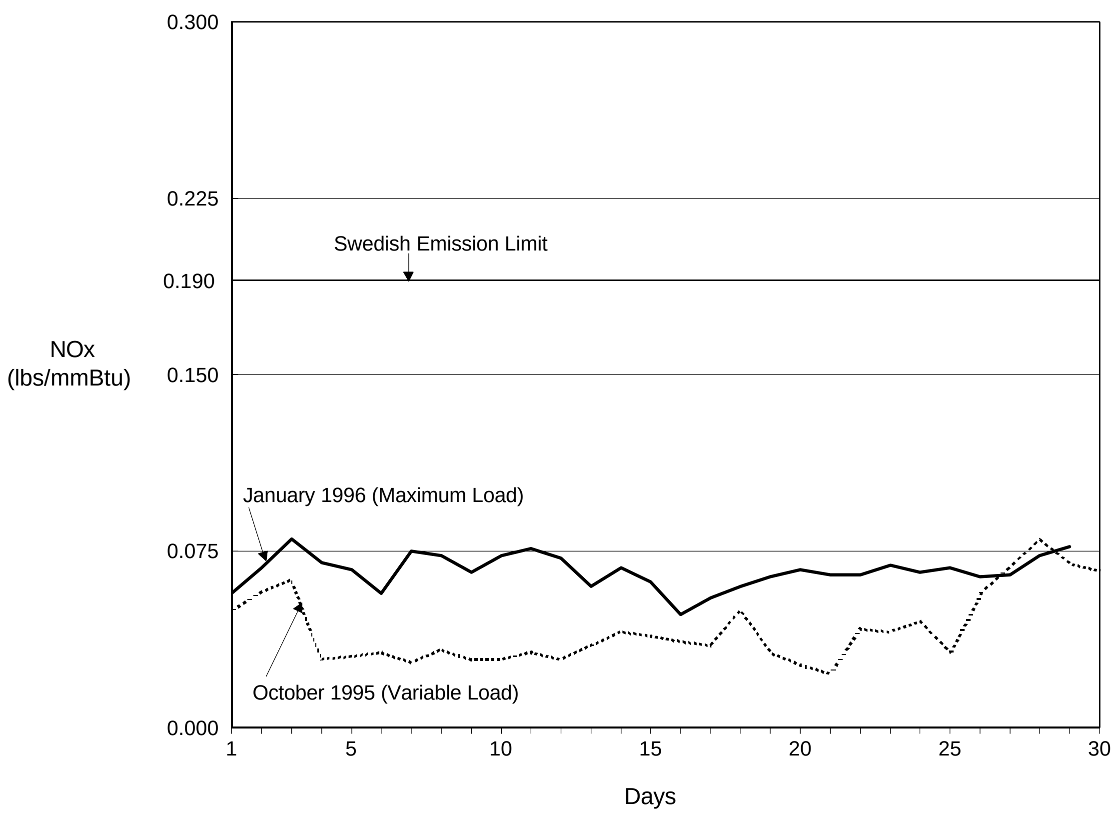

Figure 6.4. NO_x Emissions (24-Hour Averages) for Swedish Plant S-1: Unit A

Figure 6.5 shows the average NO_x emissions (expressed in 24-hour averages) for the four United States units subject to 0.17 lbs/mmBtu emission limit (US-1A, US-1B, US-2, US-4), all of which provided continuous hourly data. The four units achieve 24-hour averages consistently below 0.17 lbs/mmBtu, and three of the four units consistently achieved emission levels of 0.15 lbs/mmBtu or lower.

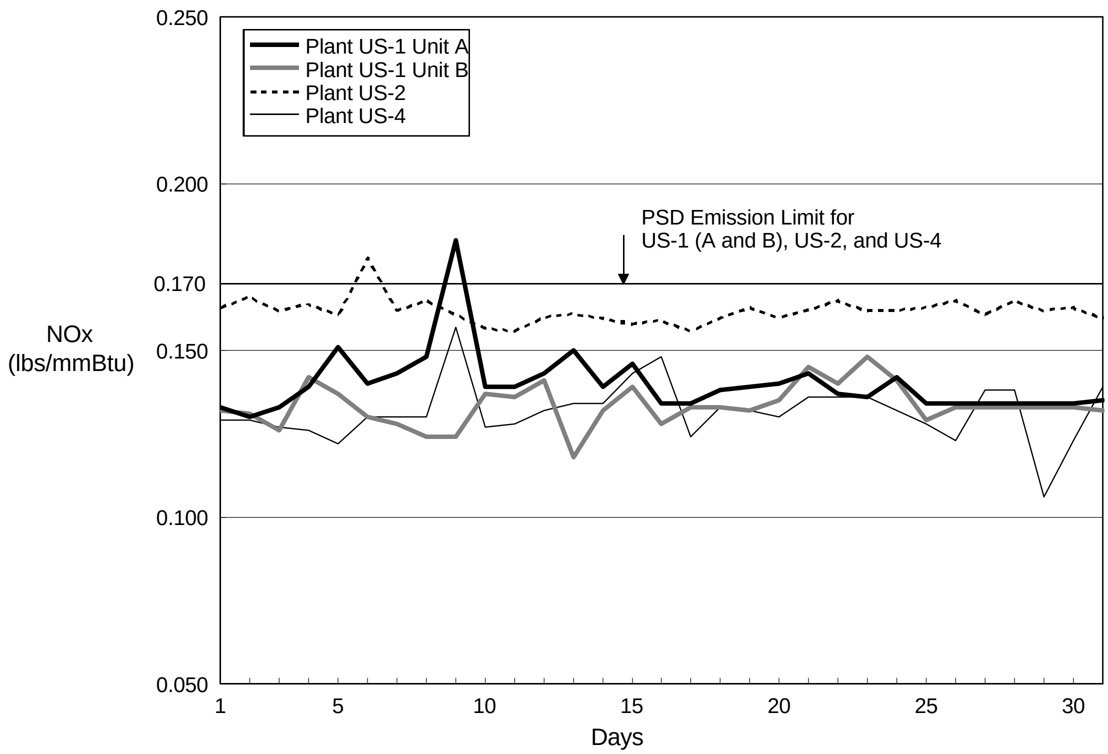

Figure 6.5. NO_x Emissions (24-Hour Averages) for
United States Plants US-1 (Units A and B), US-2, and US-4

Figure 6.6 shows the average NO_x emissions expressed in 24-hour averages for Plant US-6, which is subject to a 1.4 lbs/mmBtu emission limit. The cyclone boiler achieves 24-hour averages consistently below the 1.4 lbs/mmBtu limit.

Figure 6.7 shows the 24-hour average NO_x emissions for the Austrian plants A-1, A-2 and A-3. The curve representing Plant A-3 is plotted using values that are calculated as an average of the daily high and daily low values read from a strip chart of continuous half-hourly NO_x data. The Austrian plants achieved 24-hour average NO_x rates at or below the operating permit limit of 200 mg/m^3 (0.16 ±0.01 lbs/mmBtu). Further, two of the units consistently achieved 24-hour averages below 0.13 lb/mmBtu.

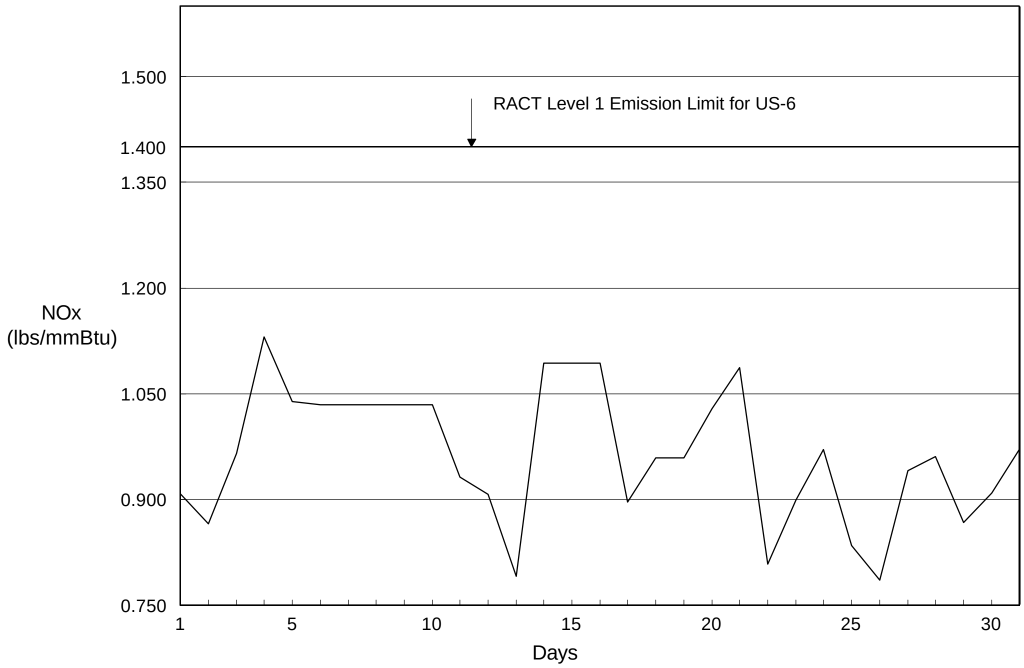

Figure 6.6. NO_x Emissions (24-Hour Averages) for United States Plant US-6

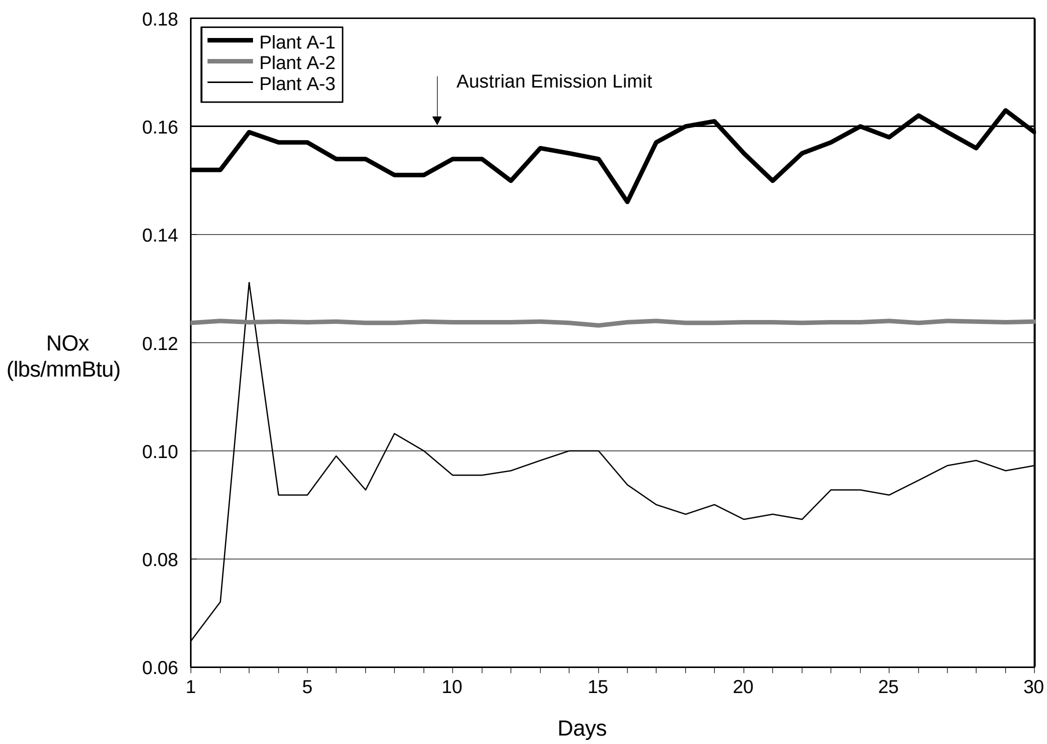

Figure 6.7. NO_x Emissions (24-Hour Averages) for Austrian Plants A-1, A-2 and A-3

Figure 6.8 presents 24-hour averages for the plant from Denmark. As previously stated, two periods in which the SCR system was identified by the plant as being inoperable and one period where the monitoring system malfunctioned were classified as exempt and have been removed from the calculations of 24-hour and 30-day rolling averages. As shown in Figure 6.8, Plant D-1 consistently achieved NO_x emissions levels well below the Danish emission limit of 0.93 lbs/mmBtu. In fact, for approximately eight days, the plant emitted at levels below 0.12 lbs/mmBtu. Continuous emissions data without the exempt emissions removed are displayed in Appendix A.

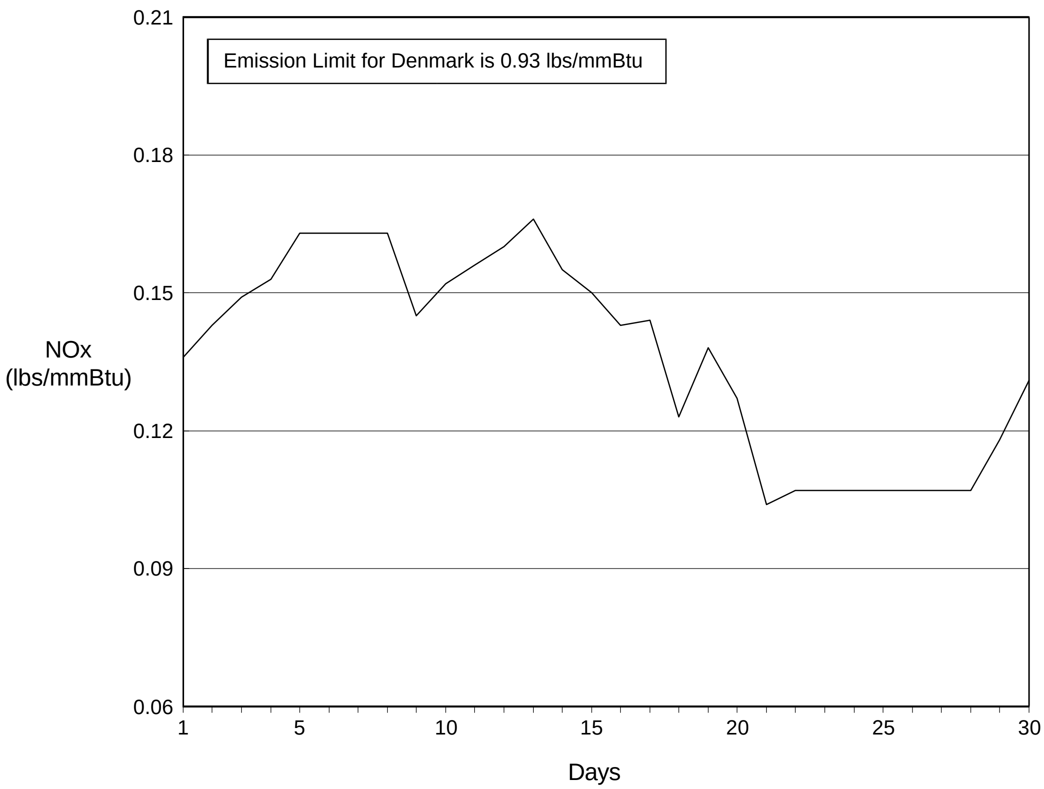

Figure 6.8. NO_x Emissions (24-Hour Averages) for Danish Plant D-1

Figure 6.9 shows the 24-hour average NO_x emission rates for the Finnish plant. Periods of possible exemption were not identified and therefore may have been included in the calculation of 24-hour averages. Even so, 80 percent of the reported daily averages are below the plant's limit of 70 mg/MJ (0.16 lbs/mmBtu).

The summary of 24-hour average data in this report is compiled in Figure 6.10. Figure 6.10 shows the mean value and the range of the 24-hour averages for each unit for which daily averages were calculated. Most of the German plants (except for one plant) did not exhibit much variability of NO_x emissions. The largest degree of variability of NO_x emissions was observed for plants in Denmark and Finland. A very low level of variability was experienced for new German plants (G-1 and G-2). New German unit G-4:A was consistently operated to comply with the limit of 100 mg/m3 (~0.08 lbs/mmBtu). Swedish plant S-1 was able to achieve very low NO_x emission rates, substantially below the annual average emission limit of 80 mg/MJ (~0.19 lbs/mmBtu).

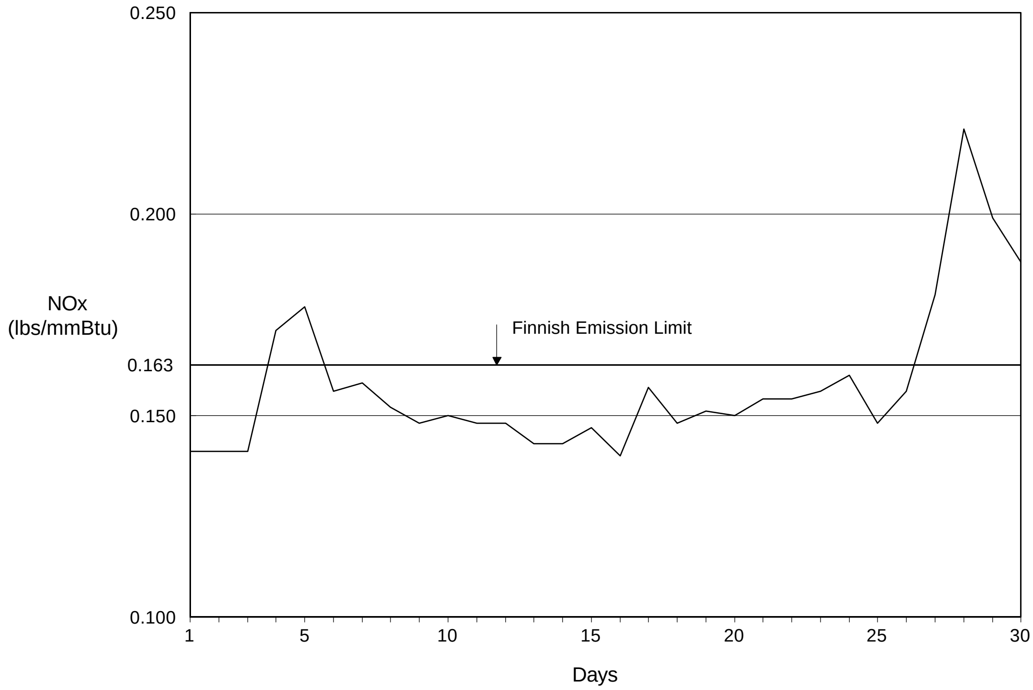

Figure 6.9. NO_x Emissions (24-Hour Averages) for Finnish Plant F-1

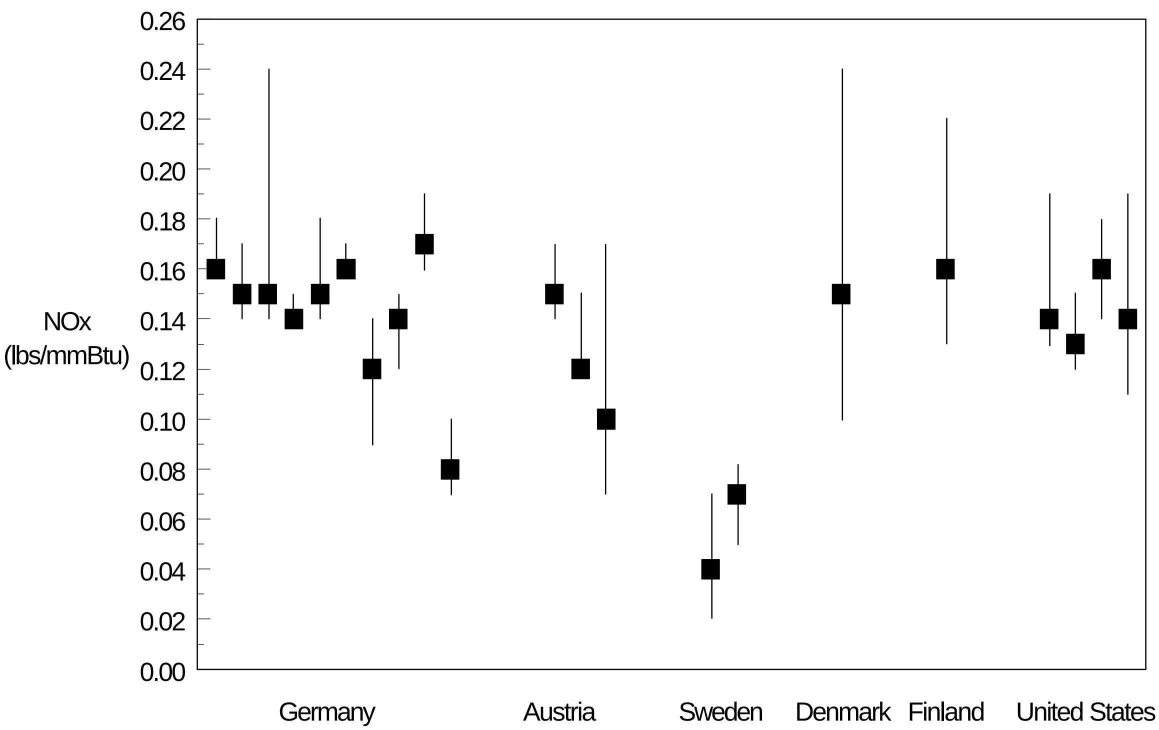

Figure 6.10. NO_x Emissions (24-hour Rolling Averages) for Plants

6.3 THIRTY-DAY ROLLING AVERAGES

For Plants G-2, G-4, G-6, G-9, US-1, US-2, US-4, US-6, A-1, A-2, D-1 and F-1 (14 units), where more than 30 days of continuous data were available, 30-day rolling averages of NO_x emissions could also be calculated. Another plant, G-8, provided a graph of 24-hour averages for a two month period. These data were also used to calculate 30-day rolling averages by converting the graph to numerical data. To achieve this, the scale on the graph was converted from mg/m^3 to lbs/mmBtu, by correcting for temperature and dilution and using an F-factor (in this case, 9780 dscf/mmBtu). Similarly, the average daily high and low NO_x emission values read from a strip chart for plant A-3 were used to calculate 30-day rolling averages. Plant US-5 provided 30-day rolling averages for a three month period. The 30-day rolling averages for all plants (excluding US-5 and US-6) are shown in Figure 6.11. The 30-day rolling averages for Plant US-5 are not shown in Figure 6.11 because the plant exhibited averages that were lower than the scale shown on the graph, ranging from 0.056 lbs/mmBtu to 0.067 lbs/mmBtu. The graph of 30-day rolling averages for Plant US-5 may be seen in Appendix A. The 30-day rolling averages for US-6 are shown in a separate figure (Figure 6.12) because the emissions from this unit are substantially higher. In computing the 30-day rolling averages, the highest F-factor was used where alternatives were available.

The 30-day rolling averages for all the plants excluding Plant US-6 ranged from 0.06 to 0.18 lbs/mmBtu with the new German unit (G-4:A) emitting at 0.08 lbs/mmBtu, and Plant US-5 achieving 0.06 lbs/mmBtu. The averages for the five new U.S. units (US-1: A and B, US-2, US-4, and US-5) ranged between 0.06 to 0.16 lbs/mmBtu. The 30-day rolling averages show relatively stable or declining NO_x emissions over time for 12 of the 16 units.

Figure 6.13 presents the median value and the range for the 30-day rolling averages for each of the units. The Danish plant exhibits a large range in the calculated 30-day rolling averages. As expected, a comparison of Figure 6.13 with Figure 6.10 reveals that variability in emission ranges is reduced when averages are computed over a longer period of time (thirty-days compared to 24-hours).

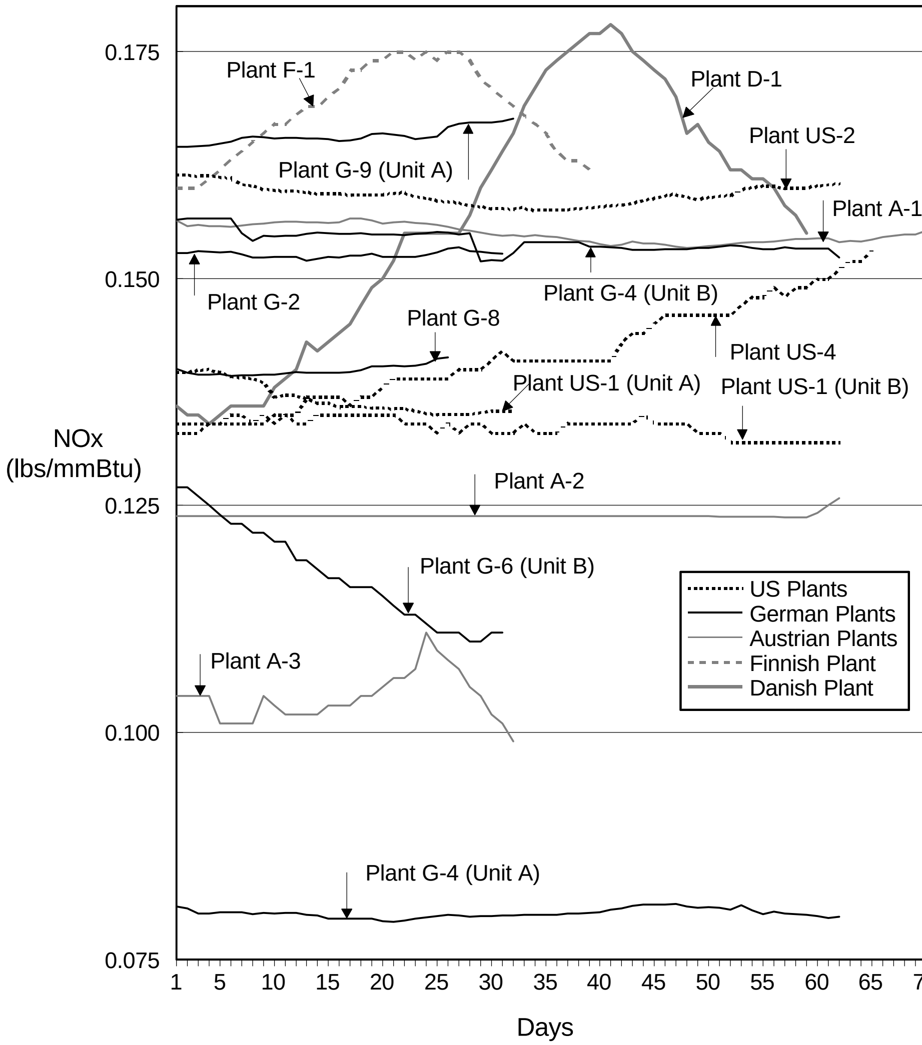

Figure 6.11. NO_x Emissions (30-Day Rolling Averages)[21] for
Plants G-2, G-4[22], G-6, G-8[23], G-9, US-1, US-2, US-4, A-1, A-2, A-3, D-1, and F-1

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21 To allow for maximum consideration of all valid data, calculations of 30-day rolling averages followed 40 CFR Part 60 Subpart Db specifications. Thus, calendar days with at least one hour of data were considered valid days.

22 Plant G-4: Unit A is required to meet a lower standard of 100 mg NO_x/m^3.

23 All plants other than G-8 provided more than 30-days of continuous data. Plant G-8 provided a graph of 24-hour averages which was converted to numerical data. Since Plant G-8 did not provide continuous hourly or half-hourly data, the 24-hour average data provided by the plant were used to calculate the 30-day rolling average. Similarly, the averages of the daily extremes from Plant A-3 were used to calculate the 30-day rolling averages.

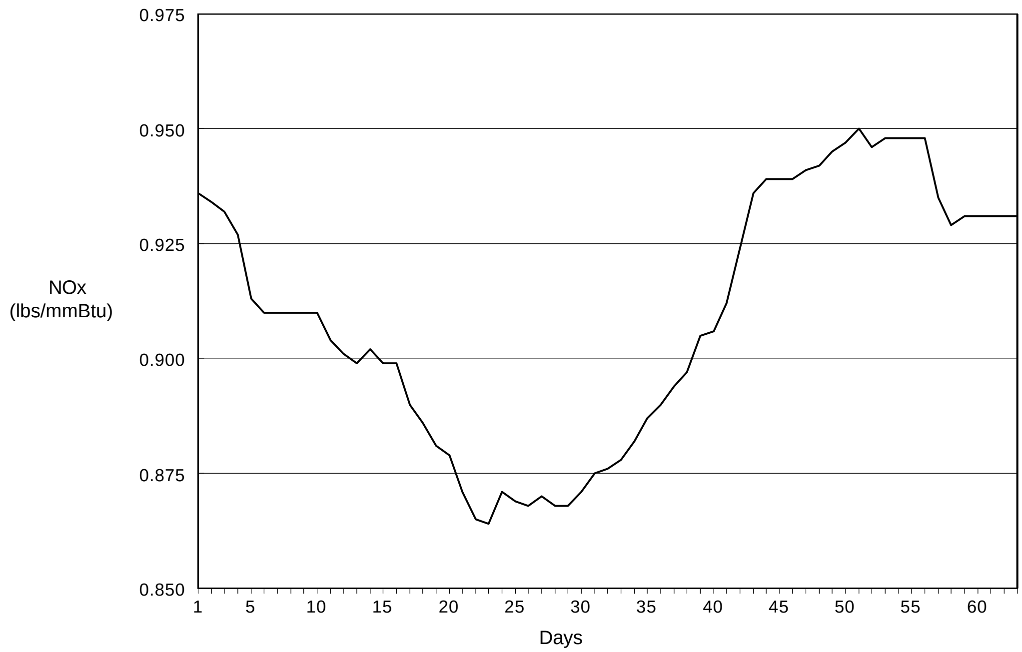

Figure 6.12. NO_x Emissions (30-Day Rolling Averages) for United States Plant US-6

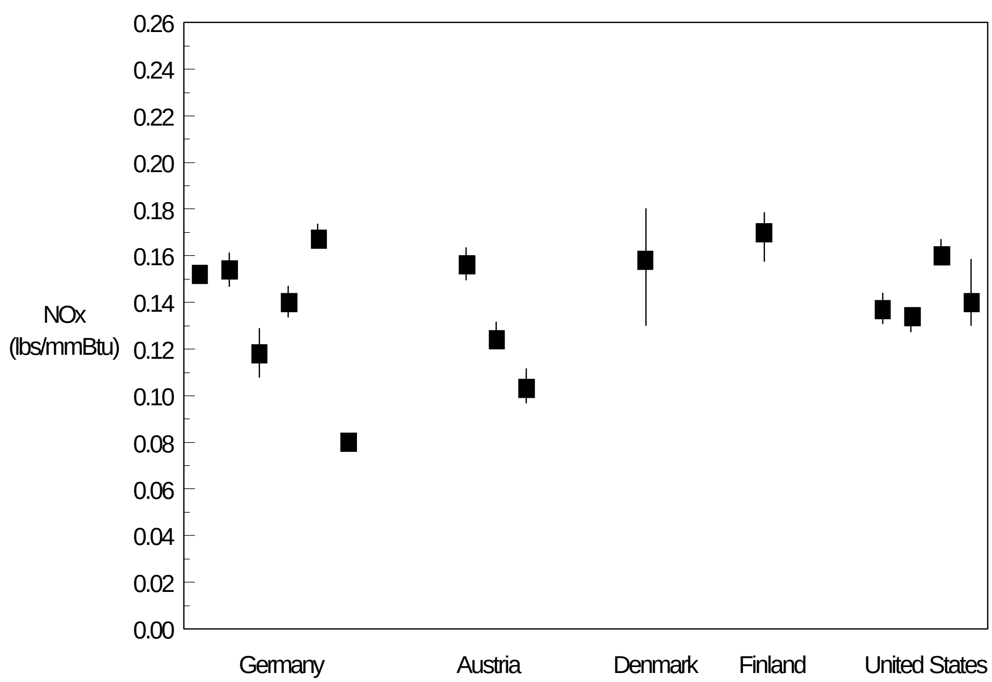

Figure 6.13. NO_x Emissions (30-day Rolling Averages) for Plants

6.4 EMISSION AVERAGES USING U.S. BITUMINOUS COAL F-FACTORS

U.S. utilities are allowed to calculate emission rates using an F-factor based on their actual coal composition or on a general F-factor based on their coal classification as found in EPA Method 19 (40 CFR Part 60, Appendix A). In order to assess the impact of using calculated F-factors in the analysis of emission rates, a comparison of calculated versus standard F-factors was performed. Figure 6.14 illustrates the average NO_x emission rate determined from the calculated F-factor for 20 units that provided sufficient coal data (see Table 3.3) compared to the average NO_x emission rate determined from the Method 19 F-factor for bituminous coal. Note that some facilities that reported emissions data did not supply sufficient coal data to calculate an F-factor.

It should be noted that except for Plants G-1 and S-1, the Method 19 F-factor for bituminous coal was always lower than the calculated F-factor. Plant G-1 provided coal data for two coal types: for one coal the calculated F-factor was higher than the Method 19 F-factor for bituminous coal; for the other coal it was lower. Because the plant did not indicate how much of each coal was actually used, the higher coal F-factor was used in all calculations. The emissions at Plant S-1: Unit A in January 1996 have been used in Figure 6.14. Although the F-factor calculated for Plant S-1 (a weighted average of the F-factors listed in Table 3.3) is below the standard F-factor for bituminous coal, the two values are very close, and when used in the emissions calculation, the difference in emission rates is less than 0.001 lbs/mmBtu and cannot be distinguished in Figure 6.14. It should also be noted that the F-factor for Plant US-2 in May (9690 dscf/mmBtu) is lower than the standard F-factor, but the weighted average for both months (10037 dscf/mmBtu) is higher, and Figure 6.14 depicts the weighted average.

As seen in Figure 6.14, the use of calculated F-factors has yielded higher NO_x emission rates. Thus by using calculated F-factors, wherever possible, EPA has been conservative in its conversion of NO_x concentration measurements to mass rates in lbs/mmBtu.

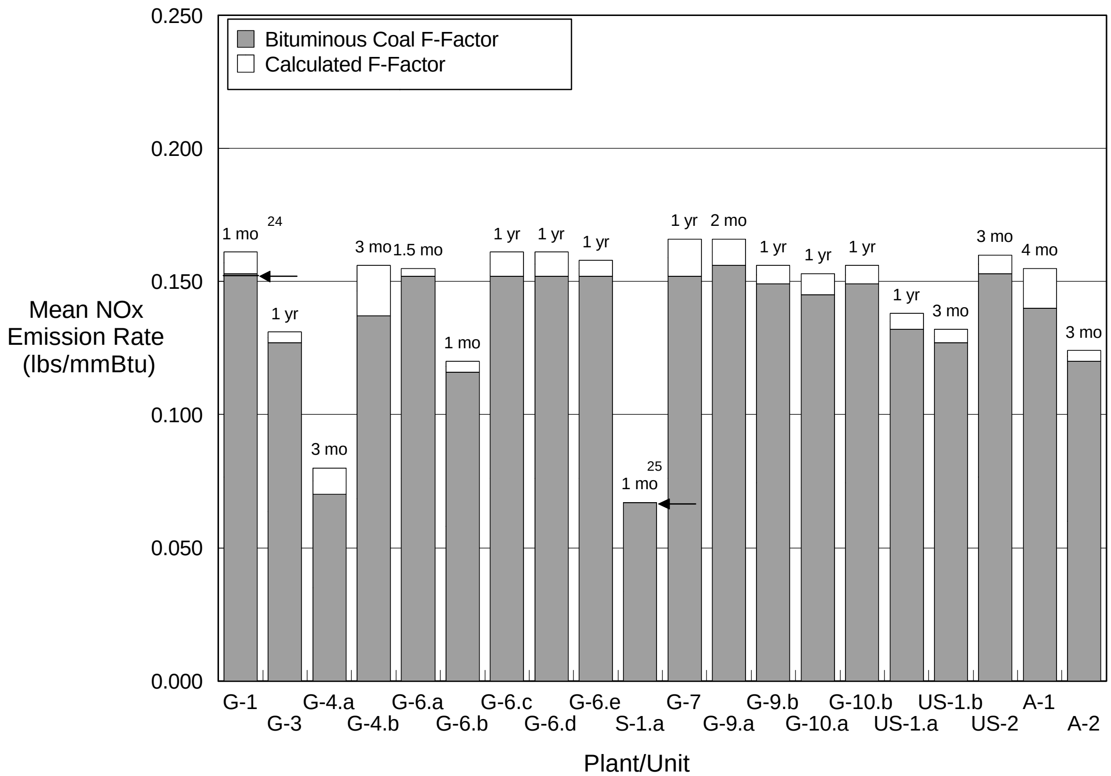

Figure 6.14. A Comparison of NO_x Emissions Calculated Using Alternative F-Factors

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[24] Plant G-1 reported using two types of coal, each with a different calculated F-factor (10308 dscf/mmBtu for F. Leopold and 9768 dscf/mmBtu for Saar). The F-factor for bituminous coal (9780 dscf/mmBtu) falls between these two. A separate line bisecting the bar and marked with an arrow represents the emissions that would be calculated using the lowest F-factor at Plant G-1. Note, however, that EPA used the highest F-factor in its calculations.

[25] An arrow marks the lower emissions calculated for Plant S-1: Unit A, using the weighted average F-factor for January 1996 (9709). In this case, the difference in emissions using the weighted average F-factor and the Reference Method 19 bituminous coal F-factor is negligible.

6.5 NO_x REMOVAL EFFICIENCY

Plants G-1, G-4, G-6 (Unit B), G-9 (Unit A), S-1 (Unit A), A-2, D-1 and F-1 provided continuous pre-SCR readings for the same time period as the NO_x emissions data. Other plants provided pre-SCR NO_x averages. Pre-SCR data were not available for Plant US-4. In calculating the average values and SCR efficiencies for the units, any data points where either pre- or post-SCR readings were zero were discarded. Data points were also discarded where the pre-SCR emission rate was lower than the contemporaneous post-SCR emission rate. All other emissions, including those occurring during possible exempt periods, were included in the SCR efficiency calculation (except for Plant D-1 for which exempt periods of SCR in operation were removed). The pre- and post-SCR levels for all units are shown in Table 6.3. Where a range of pre-SCR values was provided, the mean was used to calculate the corresponding NO_x removal efficiency.

According to a recent STAPPA & ALAPCO report, SCR is capable of reducing by 75-90 percent NO_x emissions from coal-fired electric utilities, which typically range between 0.5 and 1.5 lbs/mmBtu.[26]

The units with lower removal efficiencies (62-79 percent) were German and United States plants with lower pre-SCR levels (0.32-0.8 lbs/mmBtu), which appear to have been seeking to achieve the applicable emissions limit rather than to minimize NO_x emissions. Where pre-SCR levels were higher (greater than 0.8 lbs/mmBtu), the plants achieved better than 80 percent removal efficiency.

Four units (G-4: Unit A and the three units at Plant S-1) achieved high NO_x removal efficiencies (85-89 percent) despite low pre-SCR levels (0.40-0.81 lbs/mmBtu), demonstrating the ability of SCR to reduce low levels of uncontrolled emissions effectively. In the case of Plant G-4: Unit A, the unit is required to meet a lower emission limit than the other plants. Plant S-1 appears to be minimizing NO_x emissions below the applicable standard to take advantage of the economic incentive provided in the Swedish regulation (see discussion in Section 4.3). Also of interest is Plant G-9: Unit A, which has a very high pre-SCR NO_x level (2.03 lbs/mmBtu). The retrofit SCR controls reduce NO_x levels at this unit by 93.6 percent to meet the applicable emission limit.

Based on data presented in this report, SCR applications can be designed to provide the required NO_x removal efficiencies to comply with applicable regulatory requirements. Figure 6.15 plots SCR NO_x removal efficiency as a function of uncontrolled NO_x emissions (pre-SCR NO_x levels) for the units surveyed in this report. As expected, for a given regulatory limit, higher NO_x removal efficiencies are needed to be achieved by units with higher uncontrolled NO_x emissions. This behavior, however, is not exhibited by the Swedish units which, in the presence of the economic incentive, appear to be maximizing their NO_x reductions. The range in pre-SCR NO_x levels reported in Table 6.3 suggests that SCR technology is capable of reducing a wide range of uncontrolled emissions (including NO_x emissions in excess of 2.00 lbs/mmBtu) to 0.17 lbs/mmBtu or lower.

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[26] Controlling Nitrogen Oxides under the Clean Air Act: A Menu of Options," State and Territorial Air Pollution Program Administrators and the Association of Local Air Pollution Control Officials (STAPPA&ALAPCO). July 1994.

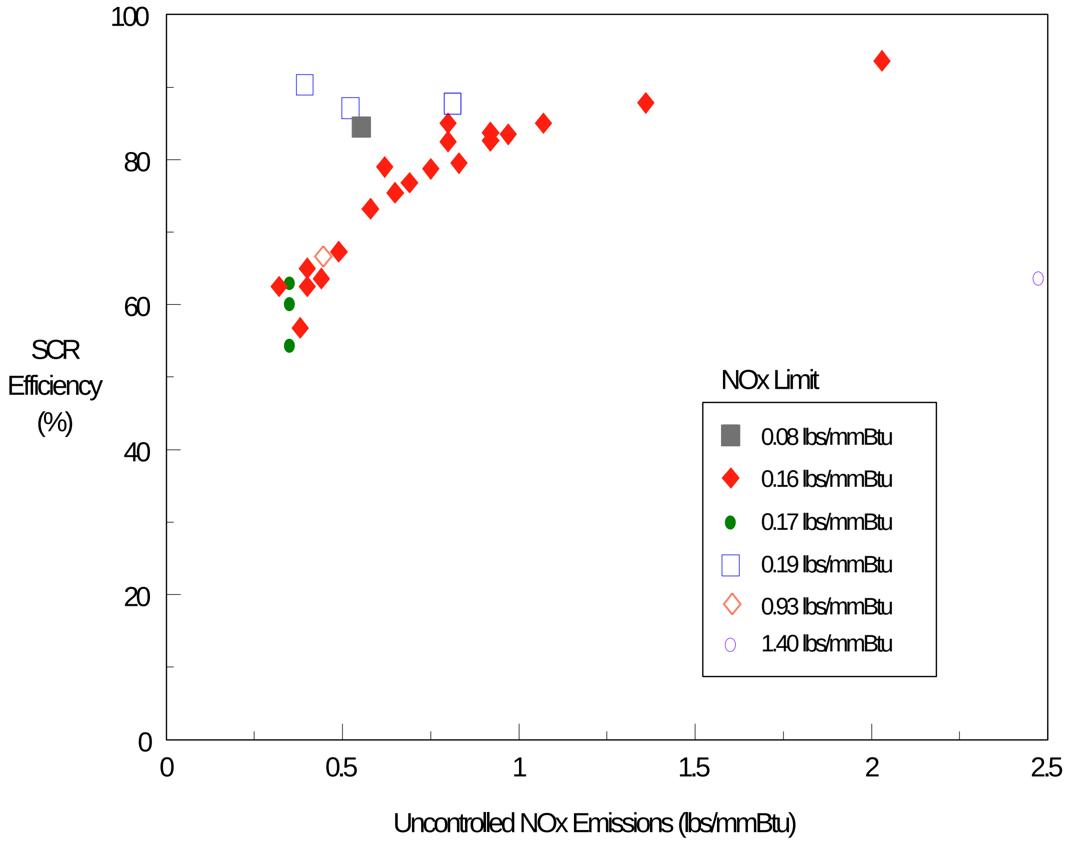

Figure 6.15. NO_x Removal Efficiency

Table 6.3. SCR EFFICIENCY CALCULATIONS

Plant: Unit	**NO_x Emissions (lbs/mmBtu)**		**SCR Efficiency**
	Pre-SCR (Average or Range)[27]	**Post SCR (Average)[27]**	
G-1	0.49[28]	0.16	67.3%
G-2	0.40	0.15	62.5%
G-3	0.62	0.13	79.0%
G-4: A	0.53[28]	0.080	84.9%
G-4: B	1.07[28]	0.16	85.0%
G-5: A	0.76	0.14	81.6%
G-5: B	0.76	0.15	80.3%
G-6: A	0.69	0.16	76.8%
G-6: B (10/1/94 - 10/21/94)	0.80[28]	0.14	82.5%
G-6: B (11/1/94 - 12/31/94)	0.80[28]	0.12	85.0%
G-6: C	0.44	0.16	63.6%
G-6: D	0.97	0.16	83.5%
G-6: E	0.65	0.16	75.4%
G-7	0.83	0.17	79.5%
G-8	0.40	0.14	65.0%
G-9: A	2.03	0.13	93.6%
G-9: A (8/5/96 - 10/11/96)	1.36[28]	0.17	87.8%
G-9: B	0.75	0.16	78.7%
G-10: A	0.92	0.15	83.7%
G-10: B	0.92	0.16	82.6%
S-1: A, October	0.39[28]	0.038	90.3%
S-1: A, January	0.52[28]	0.067	87.1%
S-1: B	0.81	0.10	87.7%
S-1: C	0.81	0.10	87.7%

(cont.)

27 Overall average emissions, see Tables 6.1 and 6.2.

28 Pre-SCR level is documented by continuous half-hourly NO_x data provided to EPA. Other units provided pre-SCR NO_x averages.

Table 6.3. SCR EFFICIENCY CALCULATIONS (Concluded)

Plant: Unit	**NO_x Emissions (lbs/mmBtu)**		**SCR Efficiency**
	Pre-SCR (Average or Range)[27]	**Post SCR (Average)[27]**	
US-1: A	0.32-0.38	0.14	60.0%
US-1: B	0.32-0.38	0.13	62.9%
US-2	0.32-0.38	0.16	54.3%
US-4	Not Available	0.14	--
US-6	2.4 - 2.66	0.91	64.0%
A-1	0.579	0.155	73.2%
A-2	0.32 [28]	0.12	62.5%
D-1	0.46 [28]	0.154	66.5%
F-1	0.38 [28]	0.16	56.8%[29]

29 SCR efficiency calculated directly from plant-provided emissions values in ppm is 52.6%. The higher reduction efficiency in the table results from the conversion of ppm to mg/MJ.

CHAPTER 7
OPERATIONAL EXPERIENCE

Plants with SCR installations were requested to provide information on their SCR systems and SCR related operational experience. Many of the SCR systems surveyed have been in operation for six or more years and, thus, have accumulated significant operating experience. Although some plants experienced problems related to SCR, most have not, and all of the plants that reported problems have successfully resolved them. Operational experience was presented in Table 3.7. The following paragraphs discuss the data contained in Table 3.7.

7.1 AMMONIA SLIP AND BALANCE-OF-PLANT IMPACTS

At SCR installations, ammonia slip results from the reagent that does not participate in NO_x reduction and instead "slips by" the catalyst. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia in to flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with the SO_3 present to form ammonium salts. In high-dust applications, these ammonium salts can increase the potential for air preheater pluggage. Further, excessive ammonia slip can cause flyash contamination and adversely impact flyash marketing. Generally, with the available advanced catalysts and the capability to design for low (5 ppm or less) ammonia slip, operational problems resulting from undesirable levels of ammonia slip and SO_3 can be avoided.

As shown in Table 3.7, ammonia slip levels were provided by some plants. The data reflect ammonia slip levels measured at Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1 and US-5, and vendor guarantees for Plants G-2, S-1, US-4, US-6, A-1 and A-2. Guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and seven units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

7.1.1 Air Preheater Impacts

Plants were requested to provide information on air preheater washings related to SCR operation. Many of the plants responded by providing historical information on air preheater washings. Table 3.7 contains information related to air preheater washing experienced at the responding SCR installations. Of the 24 units reporting the impact of SCR on air preheaters, only those with high dust configurations reported the need to conduct washing. The frequency of air preheater washing varied from once in a six-to-seven-year period to once each year, except for the Plant US-6 which has reported many washings of its air preheater since SCR retrofit in 1995. However, Plant US-6 noted that ammonia slip occurring due to insufficient bypass damper closing was believed to have caused much of the air preheater fouling that required washing. Plant US-2 also initially conducted washings once or twice a month after SCR installation until an additional layer of catalyst was added which stopped the necessity for excessive washings. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that all of the responding plants did not experience notable increases in air preheater washings resulting from normal SCR operation.

7.1.2 Flyash Contamination

Flyash absorption of any excess, unreacted ammonia (NH_3) released by an SCR system into the treated flue gas is a function of the ammonia slip rate, quantity of flyash, and specific ash characteristics (namely pH, alkali mineral content, and volatile sulfur and chlorine content). At an elevated pH, ammonia in the ash will be released, possibly leading to odorous emissions. SCR ammonia slip is a function of controllable design parameters, (i.e., NH_3/ NO_x ratio, SCR reactor space velocity, reaction temperature, inlet NO_x concentration, and NO_x reduction level). Because controlling ammonia slip limits ammonia absorption by the flyash, the system can be designed and operated to limit ash contamination to allow either landfill disposal or the sale of the flyash. Several references document that ammonia slip levels of 5 ppm or less will not affect ash disposal or marketability. [30,31] A large portion of eastern and midwestern U.S. bituminous coal flyash is acidic, and as a result the spontaneous NH_3 release from flyash of these coals may not be of much concern. However, some eastern and most western coal flyash is alkaline and disposal problems could occur if NH_3 slip is not controlled adequately.

Plants were requested to provide information related to flyash disposal at their SCR installations. The information received from the plants is shown in Table 3.7. Most of the responding plants sell their flyash. This indicates that flyash contamination is not an issue at these SCR installations. In light of the low ammonia slip levels being maintained at SCR installations, this result is not unexpected.

7.2 CATALYST REPLACEMENT

A need for catalyst replacement arises when catalyst becomes deactivated. Five primary causes of deactivation are: poisoning by arsenic and other chemical poisons, fouling of the surface by flyash or sulfur-related compounds, plugging of flow channels, erosion, and thermal degradation. In general, these deactivation mechanisms are countered by using poison-resistant catalysts, selecting proper catalyst pitches, using appropriate soot blowing cycles, and selecting thermally stable catalyst formulations with tungsten.

Plants were requested to provide information related to catalyst replacement at their SCR installations. Several plants responded by providing historical information on their catalyst replacement cycles. As shown in Table 3.7, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. two to seven years) of operation. At Plant G-4B, no problems with catalyst performance were noted after 55,000 operating hours (or approximately six years). These results suggest that catalysts are performing satisfactorily over relatively long periods of time at all of the responding SCR installations.

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[30] Report, Evaluation of NO_x Removal Technologies Volume 1 Selective Catalytic Reduction Revision 2, prepared for U.S. Department of Energy, prepared by S.N. Rao, H.G. McIlvried, and A. Mann, Contract NO. DE-AC22-94PC92100, Burns and Roe Services Corporation, September 1994.

[31] J. Philbrick & B. Owens, Public Service of New Hampshire, F. Ghoreshi, Noell, Inc., SCR System at Merrimack Unit 2, presented at the ICAC Forum, March 19-20, 1996.

CHAPTER 8
COSTS

In addition to the request for information on operational experiences, plants were asked to provide information on the capital and operating costs associated with SCR. Several plants that provided operational information stated that they were unable to provide cost information because they considered it to be confidential. The capital cost information received from high dust SCR installations is summarized in Table 8.1 below. Units with other types of SCR installations were omitted because the cost information received was very limited (one unit with a tail-end SCR and two units with low-dust SCRs). As explained in Section 3.5, German and Austrian currencies were converted to dollars using rates reported in the *Wall Street Journal* for the year the SCR began operation and then escalated to 1995 dollars using the *Chemical Engineering Indices.* In addition to the costs described above, five plants also submitted information on operating costs; this information is discussed in the Appendix entry for each of those plants. Further, some capital costs were provided that were not included in Table 8.1 as it was unclear whether they pertained exclusively to the SCR system.

The capital costs, shown in Table 8.1, ranged between 51-77 $/kW for the boiler size range of 352-710 MWe. In general, the capital costs for German and Austrian installations are higher than expected costs for similar SCR installations in the U.S. for the following reasons:

1. Labor rates in Germany and Austria are higher than labor rates in the U.S.
2. Raw material (steel) costs are higher in Germany and Austria than in the U.S.
3. Plant space limitations in Germany and Austria force the utilities to retrofit the SCR system “on top of” the coal-fired boiler (tower boiler arrangement with retrofit SCR installation at elevated height). Such arrangements require more structural reinforcement materials for both the SCR reactor and boiler than convective backpasses in the U.S. Therefore, lower structural steel and ducting costs are expected for U.S. installations.
4. All but one German and Austrian installations were completed 7 or more years ago. It is a fair assumption that since then competition and operational experience associated with SCR have lowered the costs associated with this technology.

Table 8.1. SUMMARY OF CAPITAL COST INFORMATION RECEIVED FOR HIGH DUST SCR INSTALLATIONS.

Unit/MWe	Retrofit or New Installation	Year SCR Began Operation	SCR Capital Costs[32] (as reported)	SCR Capital Costs (in 1995 $)[33]	SCR Capital Costs (in 1995 $/kW)
G-4:A / 480	New	1992	53,000,000 DM ($34,774,621)	36,997,789	77
G-5:B / 710	Retrofit	1989	$33,600,000	36,029,713	51
G-6:A / 680	Retrofit	1990	71,600,000 DM ($43,114,349)	45,947,647	68
US-6 / 375	Retrofit	1995	Not Available	Not Available	56
A-3:A / 405	Retrofit	1987	270,000,000 Austrian Schillings ($17,453,135)	20,890,043	52
A-3:B / 352	Retrofit	1987	270,000,000 Austrian Schillings ($17,453,135)	20,890,043	59

[32] Currencies were converted using the rates reported in the Wall Street Journal for June 30th of the year SCR began operation. Capital costs that appear only as dollars were reported as dollars by the plants.

[33] Escalated using Chemical Engineering Plant Annual Cost Indices

CHAPTER 9
FINDINGS

The following general observations relate to all responding plants with the exception of Plant US-6. Plant US-6 is excluded because this plant had an unusually high uncontrolled NO_x emission rate (2.4 - 2.66 lbs/mmBtu) and is at an interim stage of NO_x emission reductions. Thus the controlled NO_x emission level for this plant, when compared to all the other plants in this report, is an outlier.

Using SCR, coal-fired power plants in the United States and Western Europe are achieving average NO_x emission levels between 0.04 lbs/mmBtu and 0.17 lbs/mmBtu. Of the 20 units submitting continuous hourly or half-hourly emissions data, 14 had overall averages at or below 0.15 lbs/mmBtu. Further, Germany, Sweden, and Austria have units that are achieving daily averages consistently below 0.10 lbs/mmBtu. The highest thirty-day rolling averages for the units surveyed ranged from 0.07 lbs/mmBtu to 0.18 lbs/mmBtu. Nine of the 15 units for which thirty-day rolling averages were calculated had highest thirty-day rolling averages at or below 0.15 lbs/mmBtu.

SCR NO_x removal efficiency for plants included in this study varied from 54 percent to 94 percent. For the plants in Germany, the efficiencies actually achieved appear to be closely related to the emission limits that apply. The efficiencies achieved at the U.S. plants appear to be somewhat greater than those required to meet the applicable emission limits.

The Swedish plants are emitting NO_x emission rates that are significantly below the applicable regulatory limit. This suggests that the economic incentives provided in the Swedish regulatory system have resulted in NO_x reductions in excess of those that would be available through compliance with the regulatory limit.

Many of the SCR systems surveyed have been in operation for six or more years and, thus, have accumulated a significant level of operating experience. More than 200 installations of SCR systems operating on coal-fired boilers worldwide have accumulated an experience base of more than 1700 years.[34]

Guaranteed ammonia slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range from <0.1 ppm to <5 ppm and seven units reported levels of less than 1 ppm. These data show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels, even after significant periods of operation.

Of the 23 units reporting the impact of SCR on air preheaters, only those with high dust configurations reported the need to conduct washing on a regular basis. At these units, the frequency of washing varied from once in a six-to-seven-year period to once each year. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that no notable impacts on air preheaters resulted from normal SCR operation.

Most of the SCR installations that provided information on flyash disposal reported that they sell their flyash. This indicates that flyash contamination with ammonia is not an issue at these SCR installations. In light of the low ammonia slip levels being maintained at SCR installations, this result is not unexpected.

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[34] "White Paper, Selective Catalytic Reduction (SCR) Controls to Abate NO_x Emissions," Institute of Clean Air Companies, Inc. (ICAC). October 1994.

Several plants provided historical information on their catalyst replacement cycles. This information indicates that, in general, a catalyst layer was replaced/added after 15,000-56,000 hours (or approximately two to seven years) of operation. At one plant no problems with catalyst performance were noted after 55,000 operating hours (or approximately seven years). These results suggest that catalysts are performing satisfactorily over relatively long periods of time at all of the responding SCR installations.

The capital costs for high-dust installations surveyed in this report ranged between 51-77 $/kW for the boiler size range 352-710 MWe.

June 25, 1997

FINAL REPORT

PERFORMANCE OF SELECTIVE CATALYTIC REDUCTION ON COAL-FIRED STEAM GENERATING UNITS

APPENDICES

June 25, 1997

FINAL REPORT

APPENDIX A

A SUMMARY OF SCR RELATED RESEARCH ON INDIVIDUAL UTILITY PLANTS

Contents

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FINAL REPORT

Introduction

The following emissions data and other information relating to NO_x emissions from coal-fired utility boilers using SCR were gathered during a series of surveys and follow up data requests that began in January 1996 and that are still ongoing. Plant names have been coded to ensure confidentiality of the emissions data. These codes include G: Germany, S: Sweden, US: United States, A: Austria, F: Finland and D: Denmark. Notes relating to each plant are included in the individual plant discussions. The following are general notes applicable to more than one plant.

Coal Analysis and F-Factor Calculations

Plants were asked to provide data on the chemical composition of the coals used in their boilers. The elemental percentages and gross calorific values (GCV) provided by the plants were used to compute F-factors for each coal type. The uncorrected, "as-received" values for the coal components were used in the F-factor calculations.[35] Plants submitted data in which the elemental percentages totaled 100% ("dry"), the elemental percentages plus the ash component totaled 100% ("dry + ash"), or the elemental percentages plus the ash and moisture components totaled 100% ("as-received"). The data were examined to determine the form in which the values were reported, and corrected to the "as-received" values. Plants for which the coal components did not total exactly 100% did not provide information on additional elements that may be found in coal (e.g., Cl and F).

Operational and Cost Related Information

Plants that provided emissions data were recontacted and asked to provide information on operational experiences and costs associated with SCR. As of the date of this interim report, information had been received from nine German plants, five U.S. plants, two Austrian plants, one plant in Sweden, two plants in Denmark and one plant in Finland. However, some plants were still gathering information as of the date of this interim report. Plants were asked about the impact of SCR on air preheaters, operational experiences and costs associated with the type of ammonia used, and any other operational, cost, and emissions-related impacts of the SCR. Plants were also asked to report the capital costs and operating expenses associated with SCR. Several plants described operational experience, but stated that the cost information could not be provided.

For the plants included in this report, this information is displayed in Tables titled "Summary of Data Submitted" in this appendix.

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[35] Jahnke, Continuous Emissions Monitoring ; Shigehara et al., "Summary of F-Factor Methods for Determining Emissions from Combustion Sources," Jim Peeler, personal communication.

Plant G-1

Plant/Unit Information:

The German Plant G-1 provided continuous half-hour data for one 420 MWe unit with SCR for March 1995. The boiler was described as accommodating both base and center fuel loading and is dry bottom. The boiler was under construction when the utility decided to install SCR; therefore the SCR system is a new installation. This boiler was originally designed to run as a partial flow system (80% of the effluent was sent to the SCR and 20% bypassed the SCR). However, in 1988, another SCR system was installed on the bypass converting the partial flow system into a full flow system.
The unit's control equipment includes an SCR system, followed by an electrostatic precipitator, followed by a flue gas desulfurization system. The SCR system began operation in 1985. The design NO_x reduction efficiency of the SCR system was reported as approximately 70%. All NO_x measurements were reported under dry, standard International Standards Organization (ISO) conditions (0 °C, 1 atm) and were corrected by the plant to a 6% oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted by Plant G-1 is provided in Table G-1.1 below.

Table G-1.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly Data	Half-hourly
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	Yes

(cont.)

Table G-1.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	Yes

Coal Information:

Plant G-1 provided coal characteristics data with which to calculate F-factors. Data for two types of coal, Furst Leopold and Saar, were provided; however, it is unknown which coal was used for what period of time during March 1995. The coal data are presented in Table G-1.2 below. Please refer to Table 3 in the text of the main report for a summary of these coal data in comparison to other plants. Plant G-1 provided %H, %C, %S, %N, and %O values corrected for moisture and ash. Each value was re-corrected using the moisture and ash data for use in the F-factor calculation.

Table G-1.2

Coal Characteristics Data for Plant G-1

Coal Analysis		
	Furst Leopold	**Saar**
Moisture (%)	6.5	5.0
Ash (%)	4.5	5.5
Nitrogen (%N)	1.6 dry	0.87 dry
Oxygen (%O)	7.5 dry	7.3 dry
Carbon (%C)	84.0 dry	80.2 dry
Hydrogen (%H)	5.3 dry	5.3 dry
Sulfur (%S)	0.95 dry	0.8 dry
GCV (kJ/kg)	29,500	30,000
F-Factor (dscf/mmBtu)	10,308	9,767

Emissions Data Analysis:

The average NO_x emissions during March were 0.15 - 0.16 lbs/mmBtu, depending upon whether F. Leopold or Saar Coal F-factors are used. Figure G-1.1 shows the continuous NO_x emissions data for Plant G-1 from March 1 to March 31, 1995 using the F-factors for both types of coal. Figure G-1.2 provides the same results expressed in 24-hour averages. All NO_x readings of zero were discarded from the 24-hour calculations and mean calculations. However, non-zero data were included even if the data were possibly related to a period of startup or shutting down. Please refer to the text of the main report for a discussion of computing 24-hour averages.

Information accompanying the data indicated that the unit was shut down regularly over some weekends during the data period. Therefore, startup and shutdown patterns are evident in Figure G-1.1. Plant G-1 provided explanations for the 6 spikes seen in Figure G-1.1 as follows: 1) Start-up after weekend standstill; i.e., temperature before, in and after the catalyst < 320 °C; 2) Same as 1); 3) Shut off of unit; 4) Same as 1); 5) Same as 1); 6) Problems by NH_3 injection. Plant G-1 indicated that according to the German regulatory permit, no limits were exceeded. Therefore, all values were included in calculations of 24-hour and 30-day rolling averages.

Figure G-1.1

Plant G-1: NO_x Emissions

March 1 - March 31, 1995

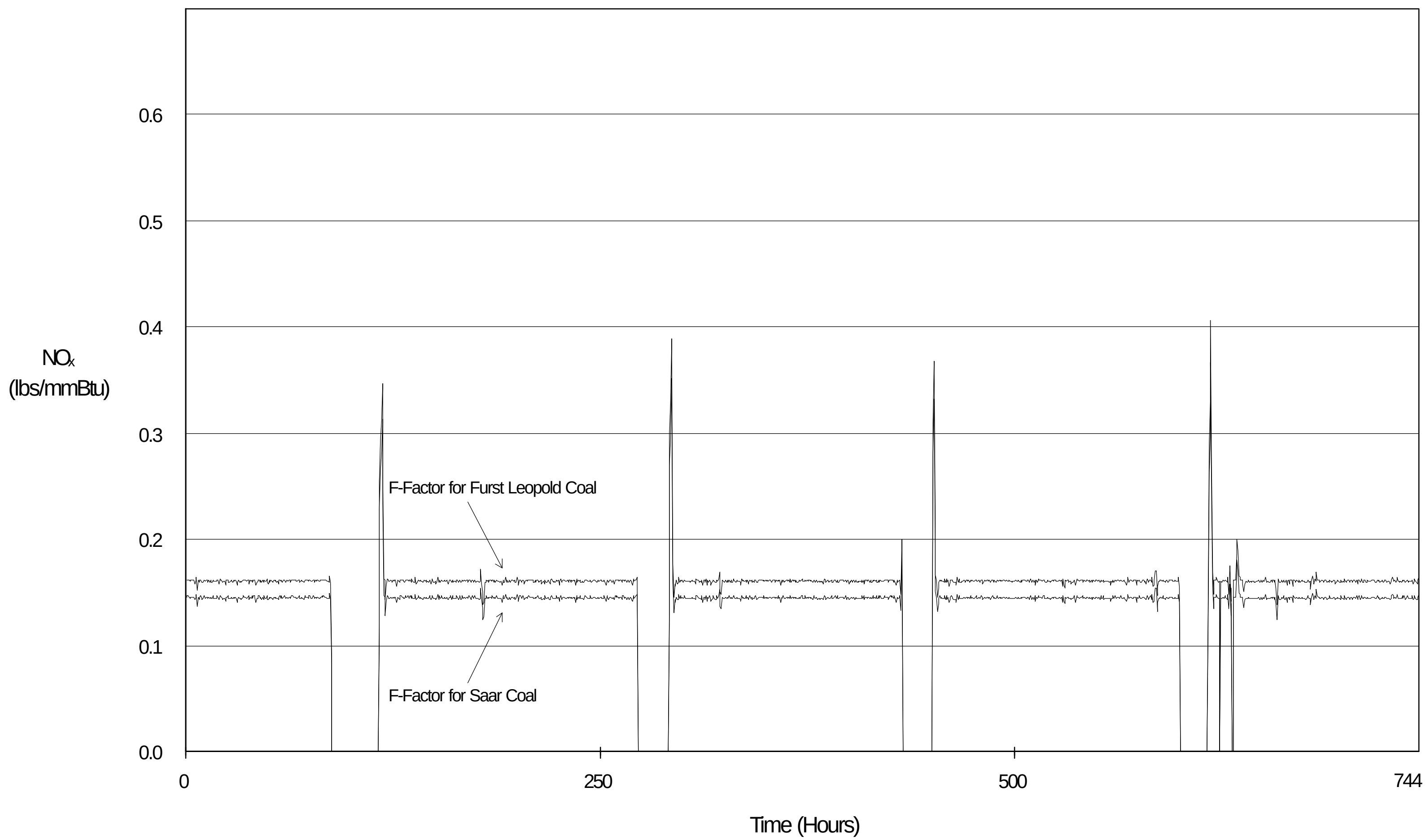
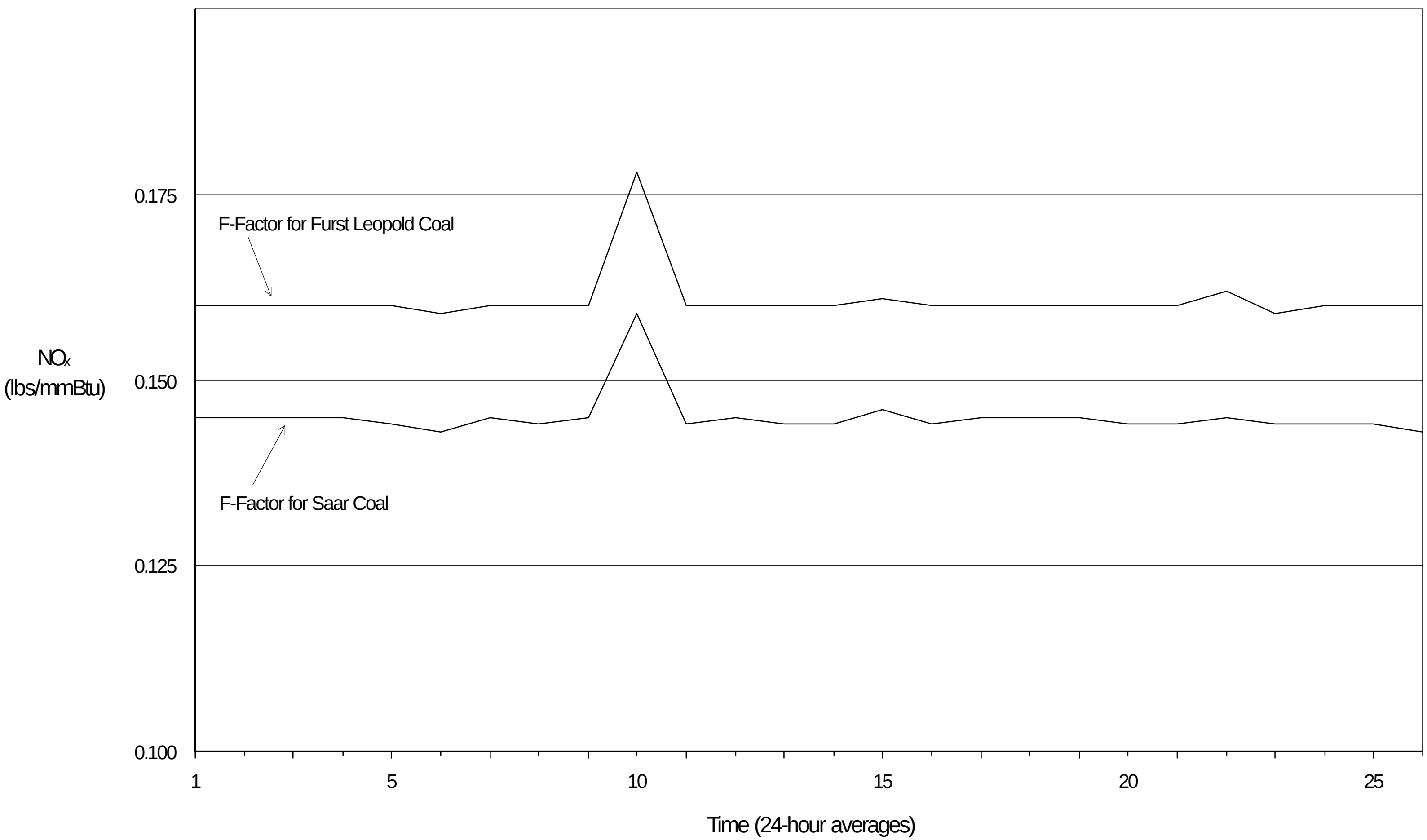


Figure G-1.2

Plant G-1: NO_x Emissions (24 Hour Averages)

March 1 - March 31, 1995



Operation, Maintenance and Cost Related Information:

Plant G-1 has a regenerative air preheater. The plant reported that the air preheater is washed about every fifth year, but did not report the cost impact. The SCR system uses anhydrous ammonia; no problems were reported. The plant reported ammonia in the flyash at levels ranging from 20 - 100 mg/kg. The plant stated that flyash is analyzed each day. Flyash from the plant is sold for use as an additive to concrete. The boiler does not recirculate flyash. Plant G-1 has a honeycomb catalyst with a total volume of 440 cubic meters. The plant reported that layer 1 was replaced after 25,000 operating hours, layer 2 was replaced after 36,000 operating hours and layer 3 was replaced after 34,000 operating hours. Costs of replacing catalyst layers were not reported. The plant stated that they have had no problems related to coal type. The plant reported that it had observed German standard QA procedures and had achieved greater than 95% data availability from its NO_x and O_2 monitors. The plant reported capital costs of approximately 17,000,000 Deutsche Marks in 1985. The plant reported operating costs for use of ammonia at 0.023 Pf/kWh, power consumption (in-house) at 0.048 Pf/kWh and SCR operating costs at 0.093 pf/kWh (for 30,000 hours of operation). No breakdown of specific cost components was provided. The plant reported that it had not experienced any operational problems as a result of its SCR system.

Table G-1.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	None
Costs	Capital: DM 17,000,000 (1985)
	Operating: 0.163 Pf/kWh

Plant G-2

Plant/Unit Information:

The German Plant G-2 provided continuous half-hour data for January 15 through March 25, 1996 from one 510 MWe boiler unit equipped with SCR. The boiler is described as box-fired and is dry bottom. The control equipment for this unit includes an SCR system followed by an electrostatic precipitator followed by flue gas desulfurization (FGD). This unit was originally constructed with the SCR system; the boiler and SCR commenced operation in 1993. All data are corrected to ISO standards of 0 ^oC (273K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6% oxygen dilution basis. In addition, the analyzer only measures NO; the plant applies an assumed 5% NO_2/NO ratio to obtain a NO_x value. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data provided is shown in Table G-2.1 below.

Table G-2.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Half-hourly
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Partial
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table G-2.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	No
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant G-2 has not provided sufficient coal characteristics data to calculate F-factors, but did indicate that bituminous coal was used. Therefore, the Method 19 F-factor of 9,780 dscf/mmBtu for bituminous coal was used in the analysis.

Emissions Data Analysis:

Plant G-2 achieved an average NO_x emission level of 0.15 lbs/mmBtu. Figure G-2.1 shows the continuous half-hourly readings. Although it is not known why the peaks occur, one may surmise that they are the result of startup operations, since they follow periods of zero emissions. The plant indicated that the first large break at 250 hours is a shutdown event. However, the reasons for the remaining missing data or zero data periods are unknown. Figure G-2.2 shows the same data expressed in 24-hour averages. Figure G-3.3 shows the data expressed as a 30-day rolling average. All NO_x readings of zero were discarded from the mean, 24-hour, and 30-day rolling average calculations. However, non-zero data were included even if the data were possibly related to a period of start up or shutting down. Please refer to the text of the main report for a discussion of computing 24-hour averages.

Figure G-2.1

Plant G-2: NO_x Emissions (1/2 Hour Averages)

January 25 - March 25, 1996

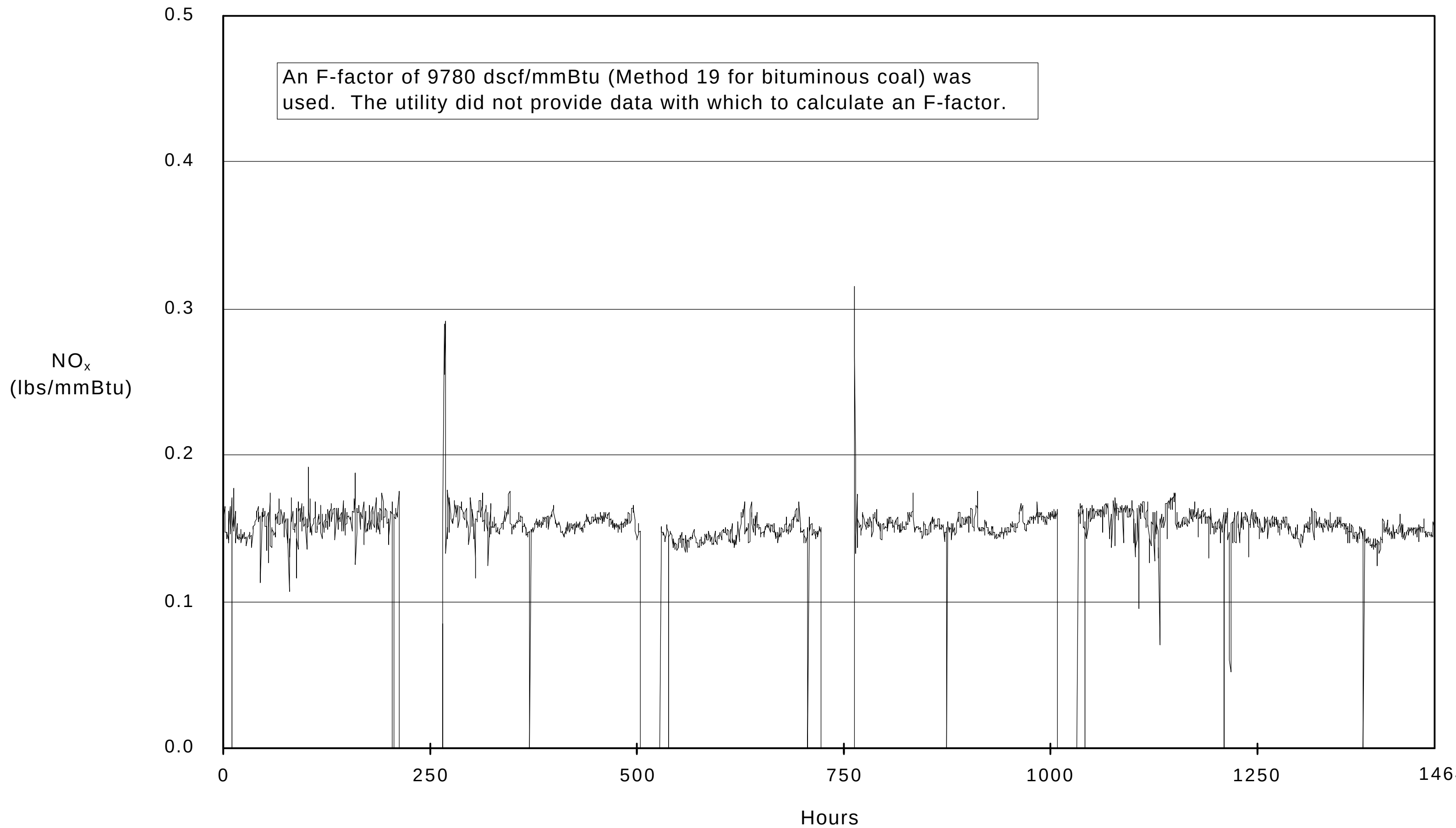


Figure G-2.2

Plant G-2: NO_x Emissions (24 Hour Averages)

January 25 - March 25, 1996

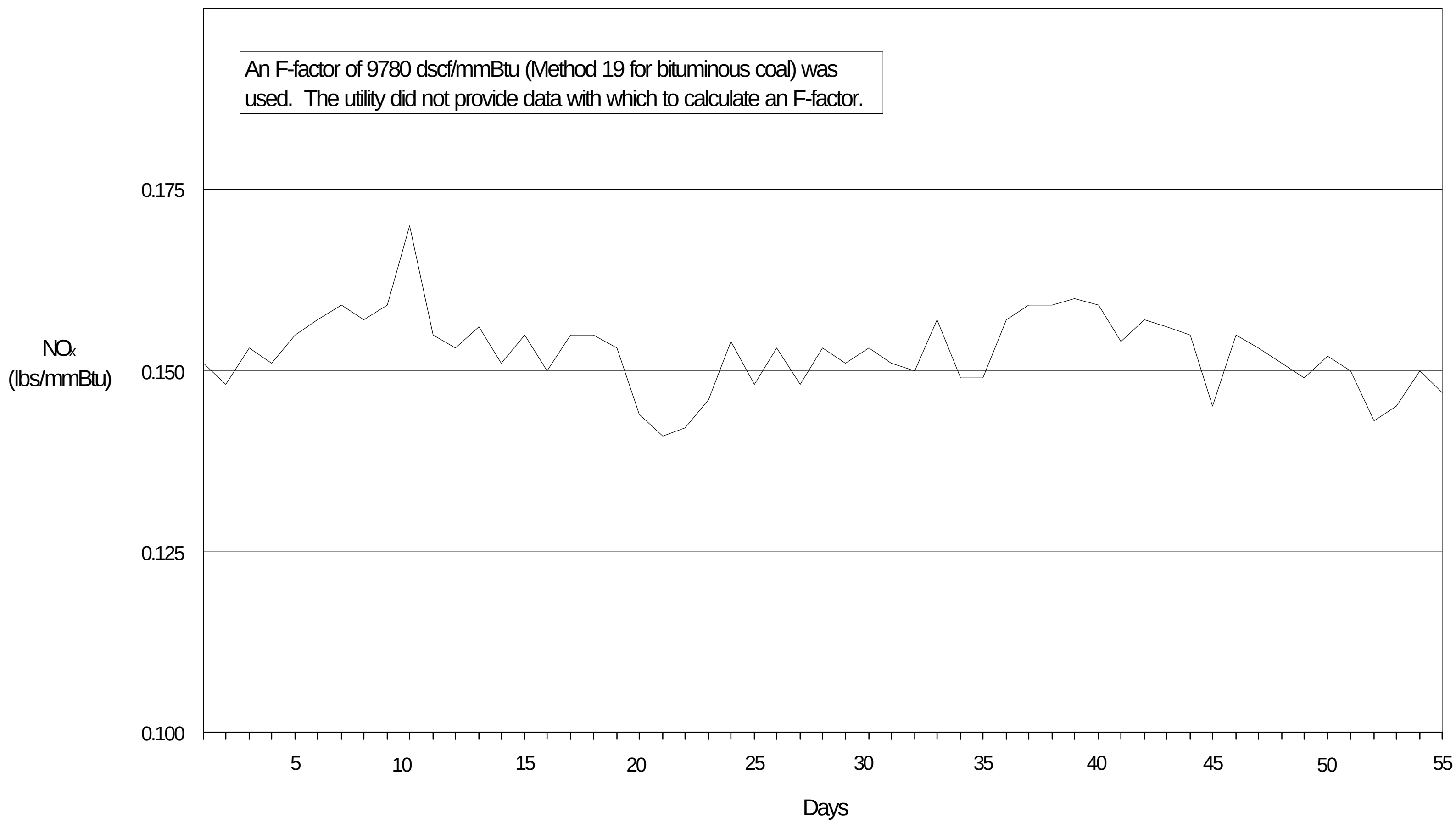
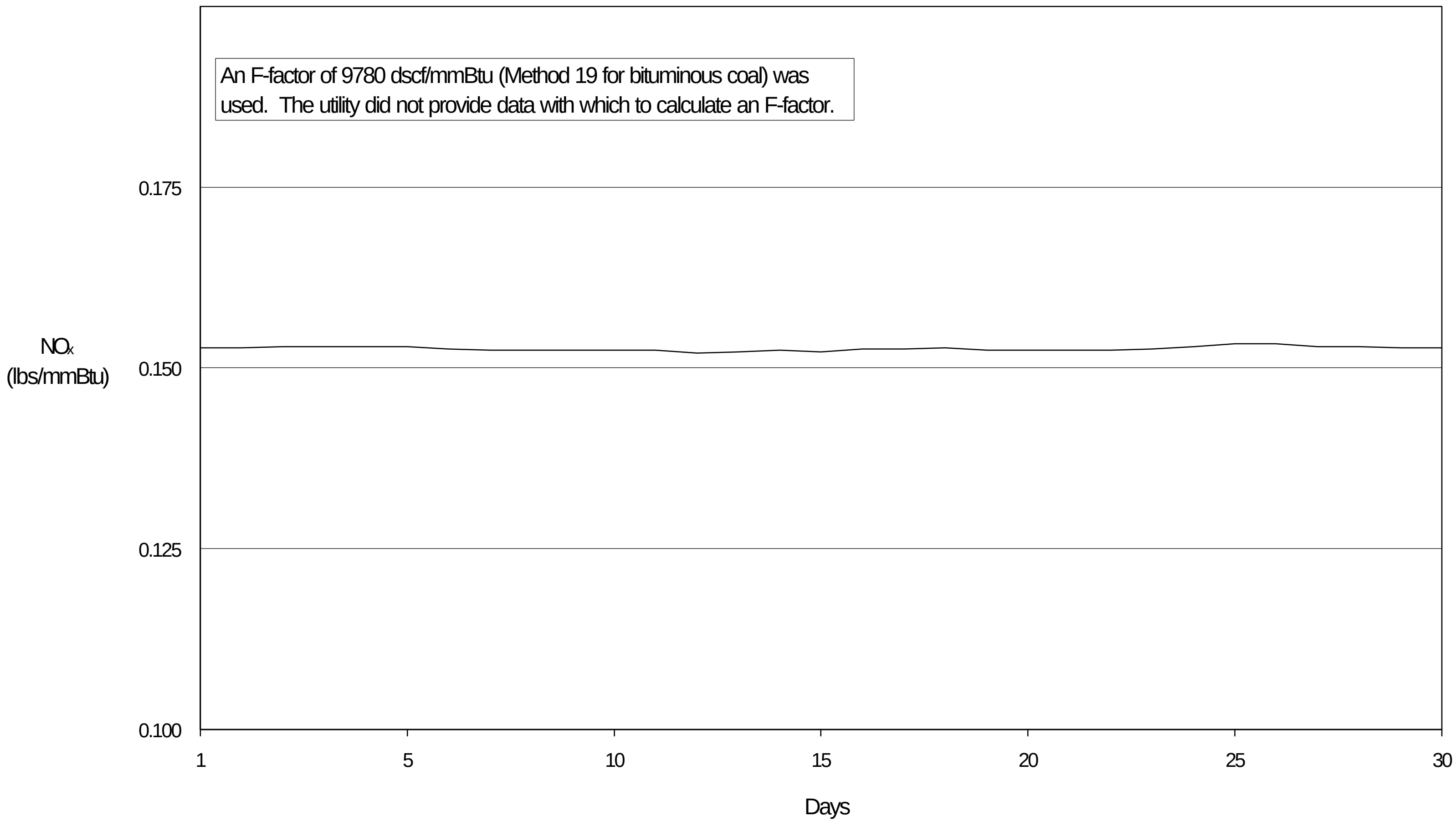


Figure G-2.3

Plant G-2: NO_x Emissions (30 Day Rolling Averages)

January 25 - March 25, 1996



Operation, Maintenance and Cost Related Information:

Plant G-2 uses regenerative air preheaters. The air preheater for the unit discussed in this report has been washed twice since the SCR system began operation in 1993. The plant stated that when coal with a sulfur content greater than 2% is burned at this unit, ammonium sulfate forms in the air preheater. The plant reported that this problem has been addressed by washing the air preheater. The plant did not report costs associated with air preheater washing. Ammonia slip at the plant is less than 3.5 mg/m^3; in a later response, the plant indicated that the ammonia slip after the SCR reactor is less than or equal to 2 ppmv. The plant reported that anhydrous ammonia was used, and did not report any problems associated with the ammonia type. Flyash is sold to be used in the construction industry; the boiler does not use flyash recirculation. Plant G-2 uses a honeycomb catalyst with a total volume of 878.4 m^3. The catalyst consists of packages, each 1960mm x 1300mm x 960mm. There are packages per layers (10 x 12). The reactor has room for 4 layers; layers 2 through 4 are currently filled. The pitch in layer 2 is 10.1 mm; in layer 3 the pitch is 7.1 mm, and is 10.1 mm in layer 4. At the SCR startup, layers 2 and 3 were filled. Layer 4 was filled in 1994, and layer 2 was replaced in 1996. Plant G-2 also reported that at 100% load, NO_x levels before the SCR reactor are 650 mg/m^3. After the SCR reactor, NO_x levels are 158 mg/m^3. From these values, the SCR efficiency is calculated as 75.7%. The plant stated that its NO_x and O_2 monitors are low maintenance and that the plant's control room is automatically informed in the event of a malfunction. The plant was unable to provide cost information.

Table G-2.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Combusting coal with sulfur content over 2% has caused ammonium sulfite to form on the air preheater. This problem has been addressed by washing the air preheater, which has been done twice since SCR installation in 1993. Cost not specified.
Costs	Requested but Not Received

Plant G-3

Plant/Unit Information:

The German Plant G-3 provided an annual average of NO_x emissions for one 700 MWe unit with two SCR systems. The tangentially-fired, dry bottom boiler was under construction when the utility decided to install SCR; therefore, the SCR system is a new installation which started operation in 1985. Plant G-3 also provided two strip charts depicting the NO_x emissions for 1995 and the pre-SCR NO_x levels for December. All data are corrected to ISO standards of 0 ^oC (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6% oxygen dilution basis. This allows conversion of the scale on the strip charts into lbs/mmBtu, and this scale has been added to Figures G-3.1 and 3.2 for comparison. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted is provided in Table G-3.1 below.

Table G-3.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	No
Hourly data	No
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table G-3.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	No
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

The coal data provided was sufficient to calculate F-factors. A summary of the coal data provided is shown in Table G-3.2.

Table G-3.2

Coal Characteristics Data for Plant G-3

Coal Analysis	
	Unit A
Moisture (%)	11.0
Ash (%)	9

(cont.)

Table G-3.2 (cont.)

Coal Characteristics Data for Plant G-3

Coal Analysis	
	Unit A
Nitrogen (%N)	1.35
Oxygen (%O)	4.17
Carbon (%C)	69.61
Hydrogen (%H)	3.87
Sulfur (%S)	1.0
GCV (kJ/kg)	27,500
F-Factor (dscf/mmBtu)	10,101

Emissions Data Analysis:

Plant G-3 provided the mean for 1995 as 0.13 lbs/mmBtu. Figures G-3.1 and G-3.2 show utility-provided strip charts depicting the NO_x emissions for 1995 and the pre-SCR NO_x levels for December 1995.

Figure G-3.1

Plant G-3: NO_x Emissions Data

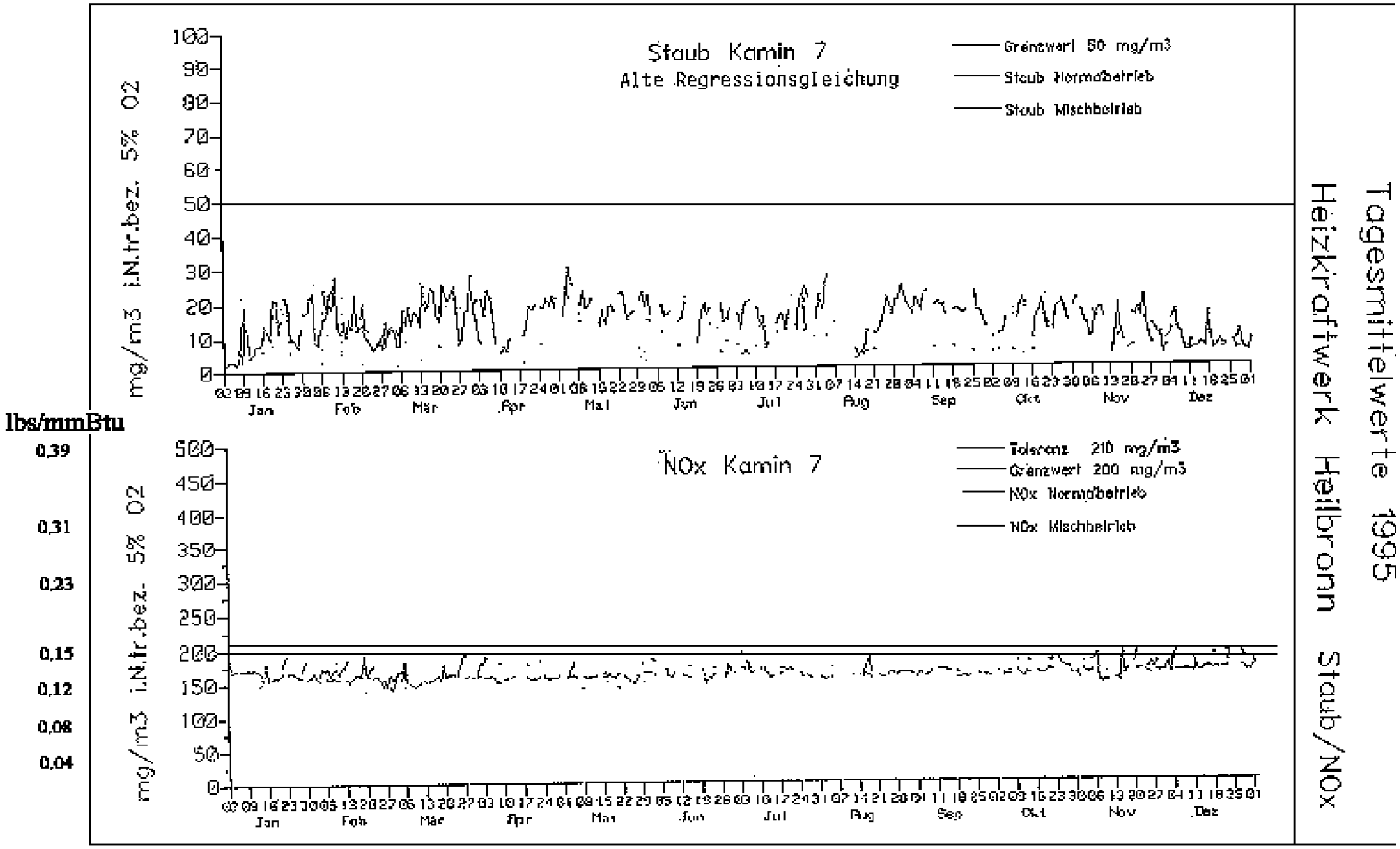
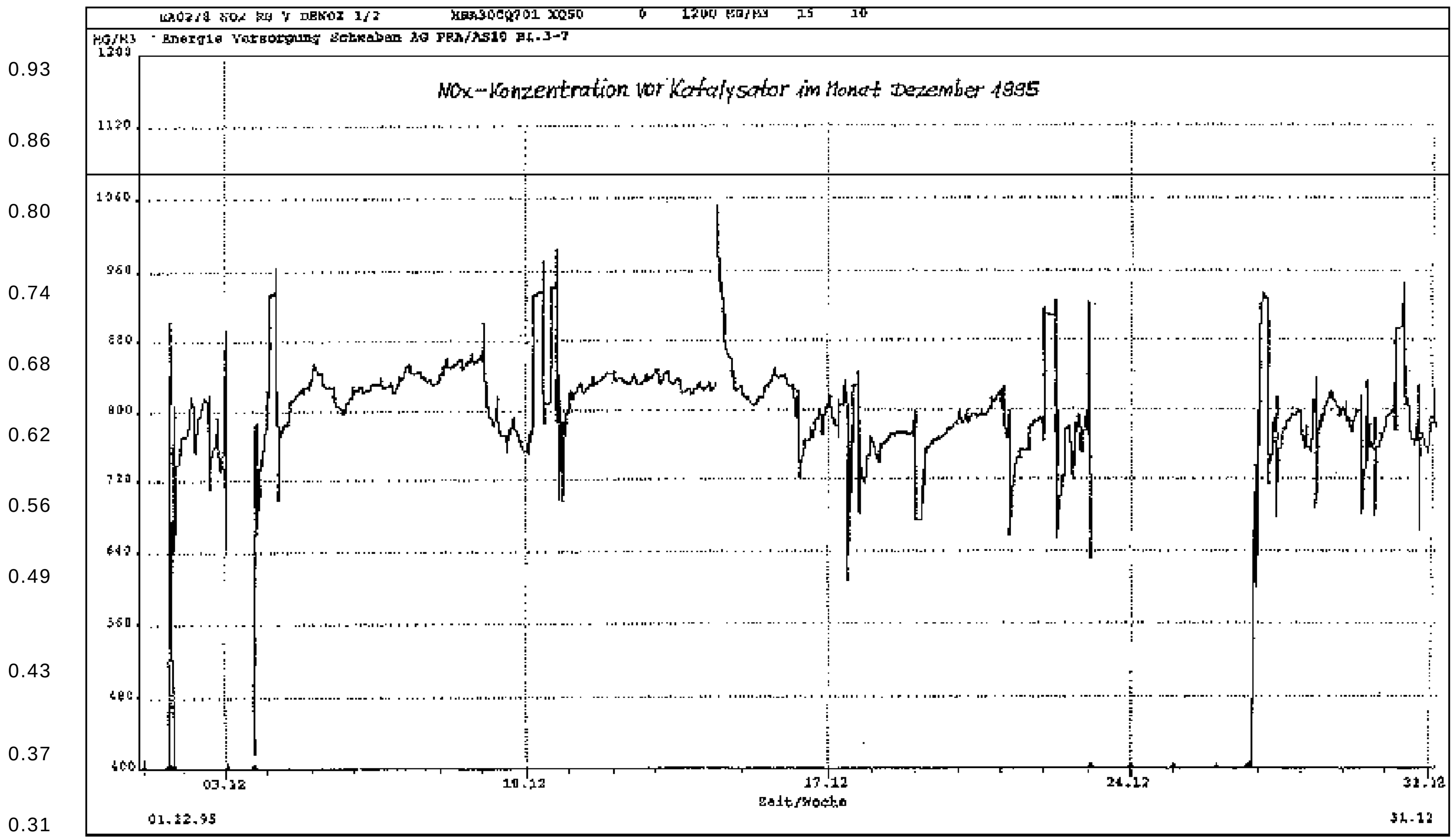


Figure G-3.2

Plant G-3: Pre-SCR NO_x Levels (December 1995)



Operation, Maintenance and Cost Related Information:

Plant G-3 has two SCR systems for one unit. Anhydrous ammonia is used as the reagent for the SCR systems. Ammonia slip at the plant is less than 5 ppm. Plant G-3 provided extensive information on operation and maintenance of the SCR systems. After approximately 18,000 hours of operation, the facility noticed an increase in the ammonia content in the flyash and assumed that loss of catalyst activity had taken place. However, after testing the activity, it was found to be 77%. Therefore, plant G-3 decided to clean the first layer of catalyst from flyash deposits, after which the ammonia slip was less than 0.5 ppm, and the catalyst activity increased. They installed additional soot blowers in each layer of the catalyst in order to avoid fouling by flyash in the future. Plant G-3 also reported that air preheater washings were unnecessary at the plant due to the very low ammonia slip that is obtained at the plant. A honeycomb catalyst is employed with a total volume of 826 m^3 (413 m^3 in each system). The catalyst was designed with 3 layers to be utilized at one time. After 18,500 operating hours, the plant tested the catalyst activity and found it to be 77%. Plant G-3, however, has an explicit replacement schedule for the SCR systems. After 20,000 operating hours, one layer (1) is to be removed for storage, and a new layer (4) will be added. After 39,000 operating hours, layer 1 will be added back to the SCR, and a new layer (5) will be added. Therefore, layers 2 and 3 will be stored for disposal. After 53,000 operating hours, layer 6 will be added and layer 1 will be removed and stored for disposal. After 73,000 operating hours, layer 7 will be added and layer 4 will be removed and stored for disposal. At the time of the information request, Plant G-3 had not added any catalyst layers.

Plant G-4

Plant/Unit Information:

The German Plant G-4 provided continuous hourly NO_x data for two coal-fired boilers (Units A and B). The plant has five SCR systems; one of these is shared by two boilers. Unit A is a dry bottom, tangentially fired boiler and is equipped with an SCR system followed by electrostatic precipitator and flue gas desulfurization systems. Unit A also is equipped with low NO_x burners. Unit A is a newer boiler, originally constructed with SCR systems in 1992, and is regulated at 100 mg/m^3; whereas Unit B, an older boiler, must achieve 200 mg/m^3. Unit B commenced operation in 1965, and the SCR system began operation in 1988. Unit B is a wet bottom, cyclone boiler with the SCR system in a tail-end configuration. Unit A generates 480 MWe and Unit B generates 220 MWe when operating at full capacity. All measurements for Unit A were corrected to ISO conditions and 6% oxygen. Measurements for Unit B were corrected to ISO conditions and 5% oxygen. A summary of data provided by Plant G-4 is shown in Table G-4.1 below.

Table G-4.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Yes
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table G-4.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	Yes

Coal Information:

Plant G-4 provided sufficient coal characteristics data to calculate F-factors. These are shown in Table G-4.2. All dry chemical characteristics were corrected for ash and moisture content for use in the F-factor calculation. The median values for each parameter were used in the calculation.

Table G-4.2

Coal Characteristics Data for Plant G-4

Coal Analysis		
	Range	**Median**
Moisture (%)	7.0 - 11.0	9.0
Ash (%)	5.8 - 8.8	7.3
Nitrogen (%N)	1.1 - 1.7 dry	1.2 wet
Oxygen (%O)	3 - 10 dry	6.0 wet
Carbon (%C)	83 - 91 dry	74.8 wet
Hydrogen (%H)	5.3 - 5.7 dry	4.7 wet
Sulfur (%S)	0.6 - 1.1 dry	0.73 wet
GCV (kJ/kg)	22,000 - 32000	27,000
F-Factor (dscf/mmBtu)		11,171

Emissions Data Analysis:

Average NO_x emissions for the period January 1 through March 31, 1996 were 0.08 lbs/mmBtu for Unit A, which is required to meet the 100 mg/m^3 standard, and 0.16 lbs/mmBtu for Unit B which is required to meet the 200 mg/m^3 standard. Figure G-4.1 shows the continuous hourly data for Unit A using the calculated F-factor. Figure G-4.2 shows the continuous hourly data for Unit B, the older unit, using the calculated F-factor. Figures G-4.3 and G-4.4 provide the same information expressed in 24-hour averages. Figures G-4.5 and G-4.6 express these results as 30-day rolling averages. All NO_x readings of zero were discarded from the mean, 24-hour and 30-day rolling average calculations. However, non-zero data were included even if the data were possibly related to a period of start up or shutting down. Please refer to the text of the main report for a discussion of computing 24-hour averages.

Plant G-4 provided explanations for the five emissions spikes in the continuous data for Unit B seen in Figure G-4.2. The reasons are as follows: 1) Problems with the burners used to reheat the flue gas before the SCR repeatedly resulted in a temperature drop of the catalyst. Therefore, for security reasons the NH_3 had to be shut off. 2) Same reason as 1). 3) While changing the burner used to reheat the flue gas from gas fuel over to oil fuel, a burner failure occurred. Therefore, for security reasons the NH_3 had to be shut off. 4) SCR was shut down owing to standstill of REA. 5) Following a unit standstill, SCR was started to heat up the catalyst. NH_3 is released after first reaching a minimum temperature.

Figure G-4.1

Plant G-4: NO_x Emissions (Unit A: Hourly Averages)

January 1 - March 31, 1996

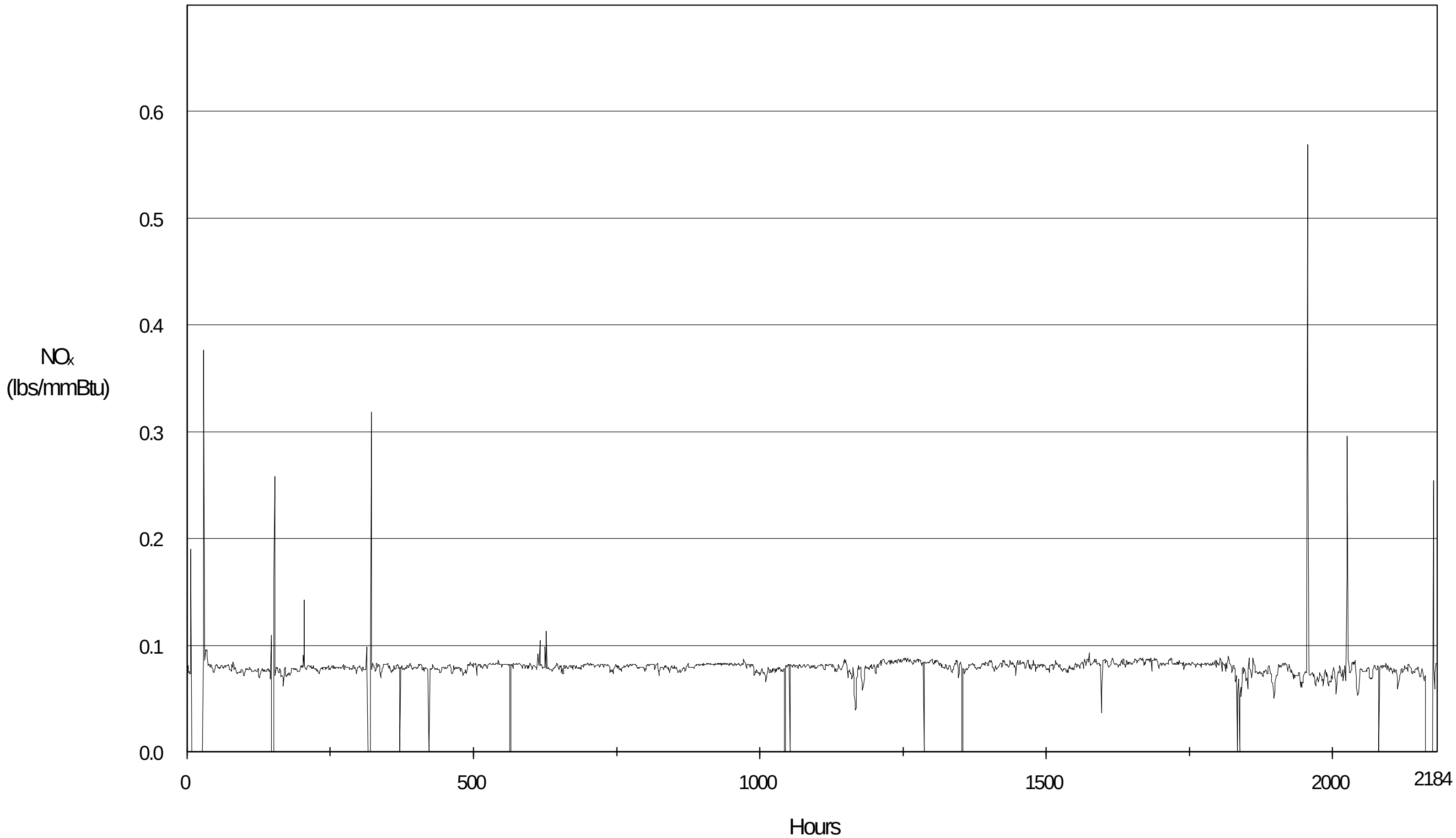


Figure G-4.2

Plant G-4: NO_x Emissions (Unit B: Hourly Averages)

January 1 - March 31, 1996

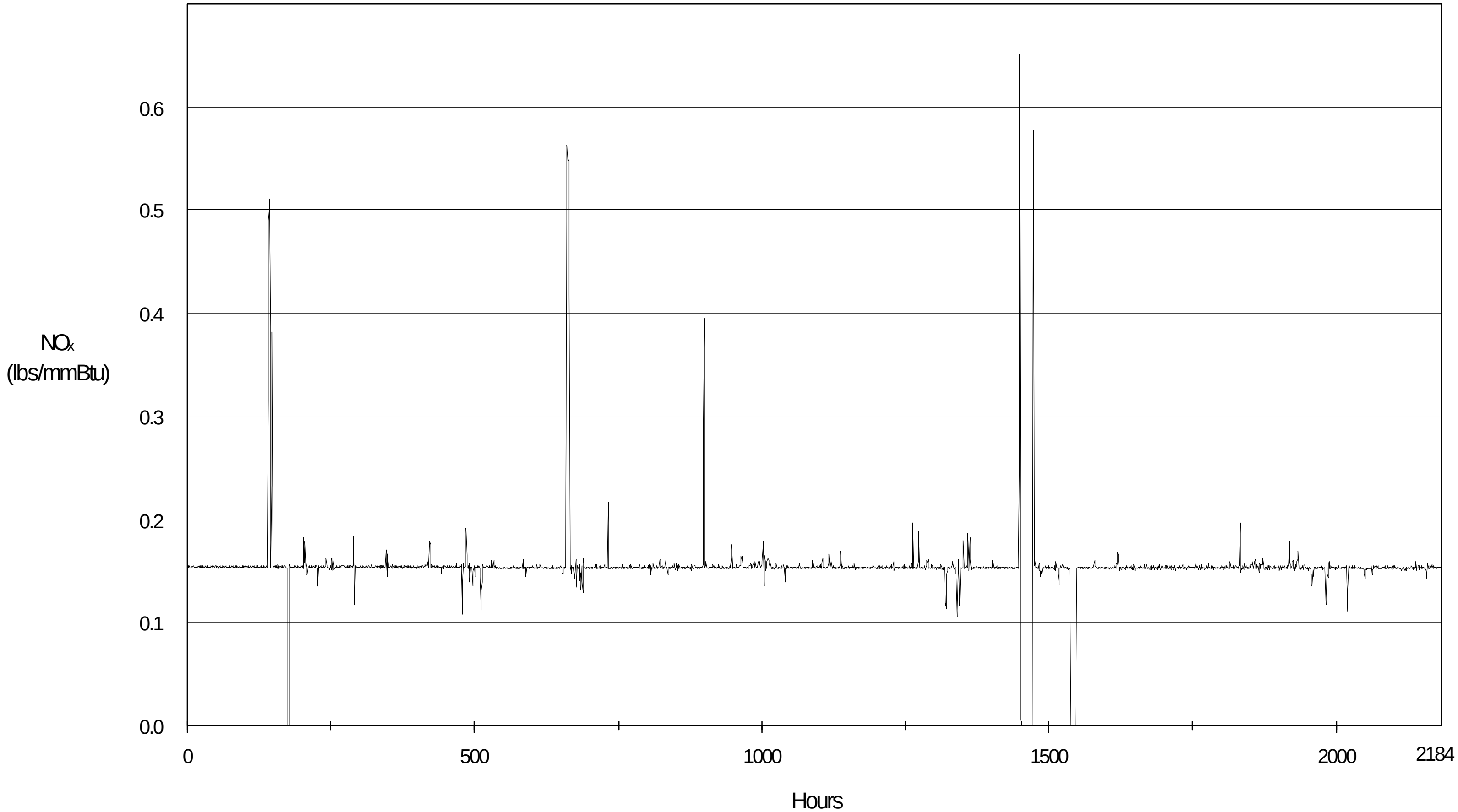


Figure G-4.3

Plant G-4: NO_x Emissions (Unit A: 24 Hour Averages)

January 1 - March 30, 1996

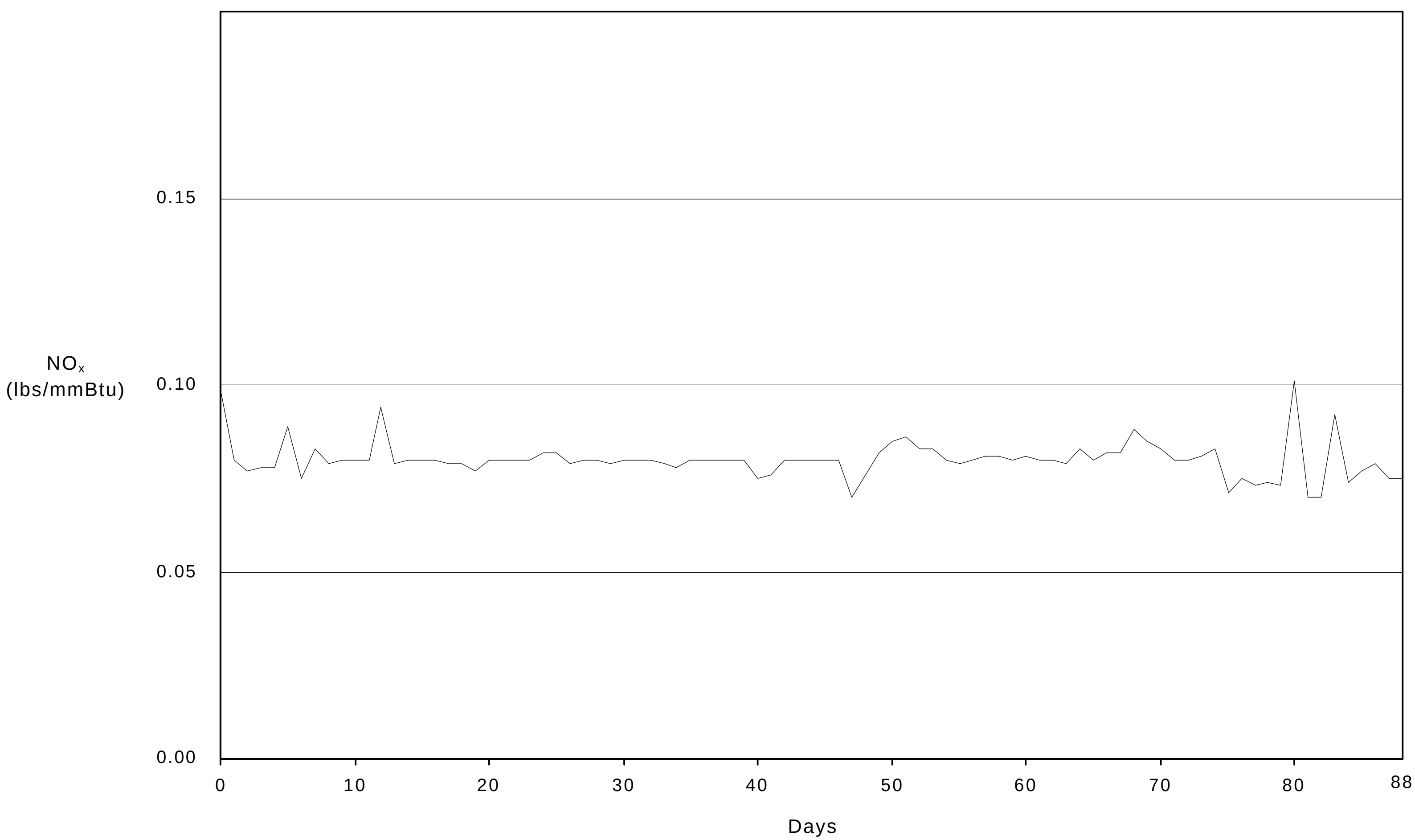


Figure G-4.4

Plant G-4: NO_x Emissions (Unit B: 24 Hour Averages)

January 1 - March 31, 1996

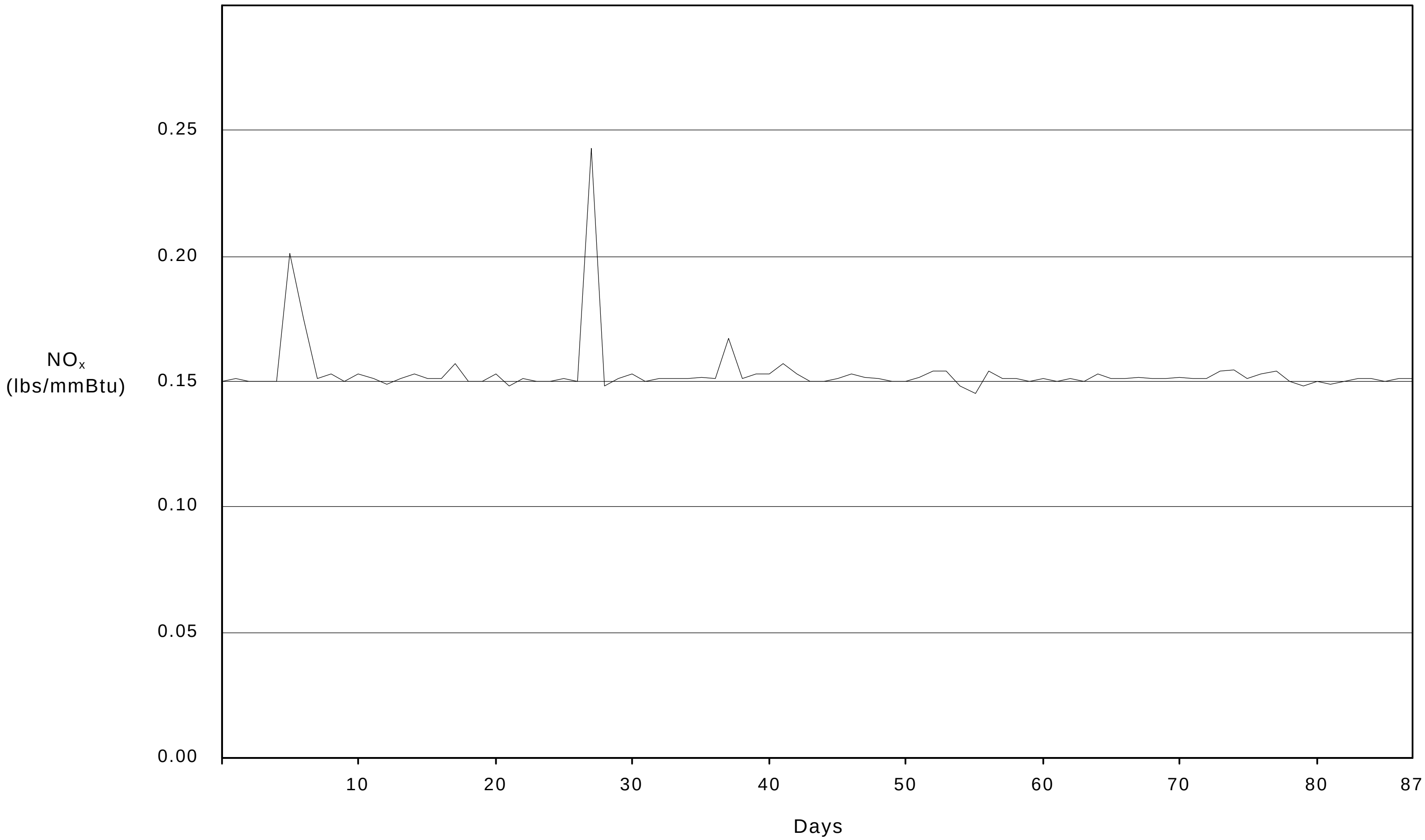


Figure G-4.5

Plant G-4: NO_x Emissions (Unit A: 30 Day Rolling Averages)

January 1 - March 31, 1996

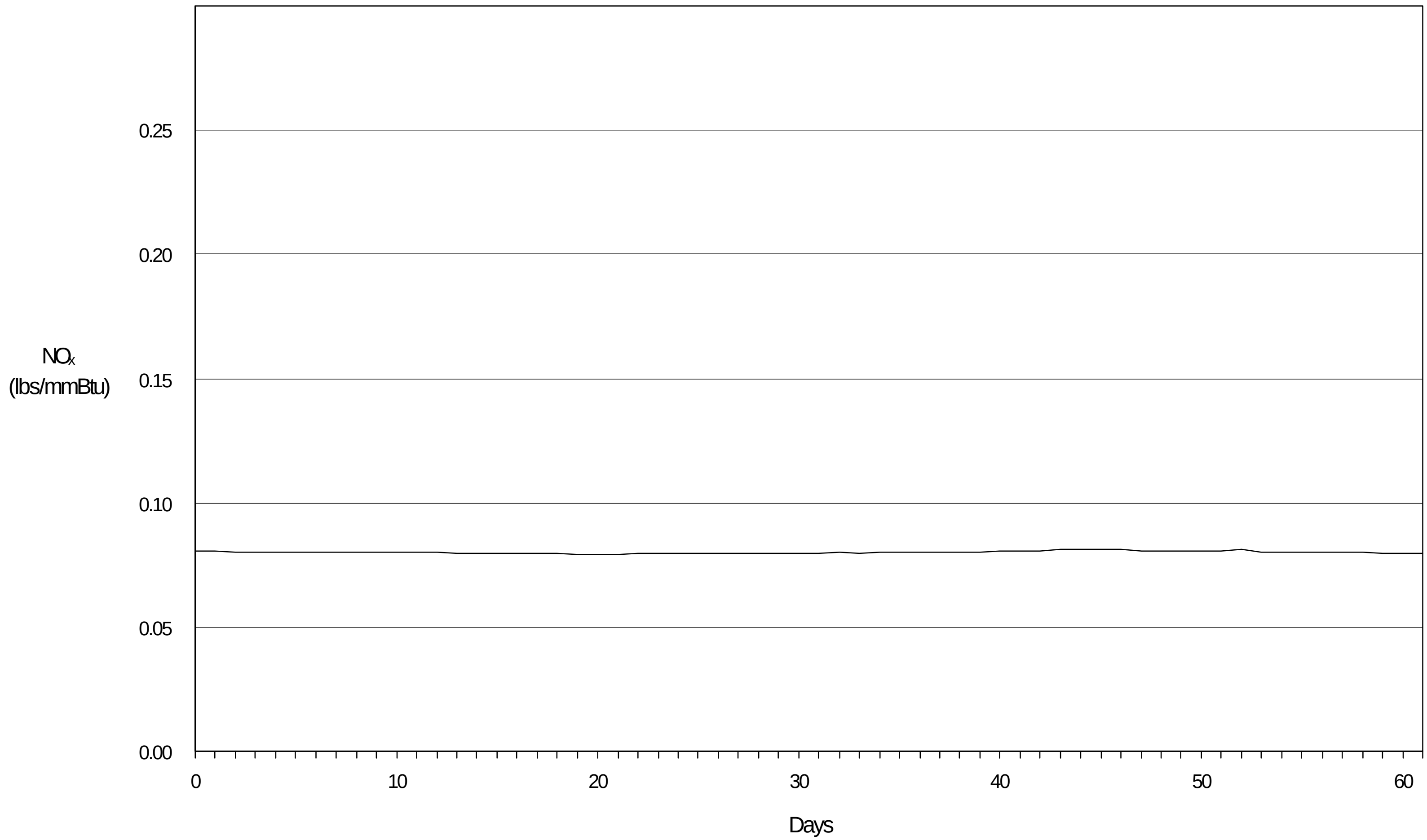
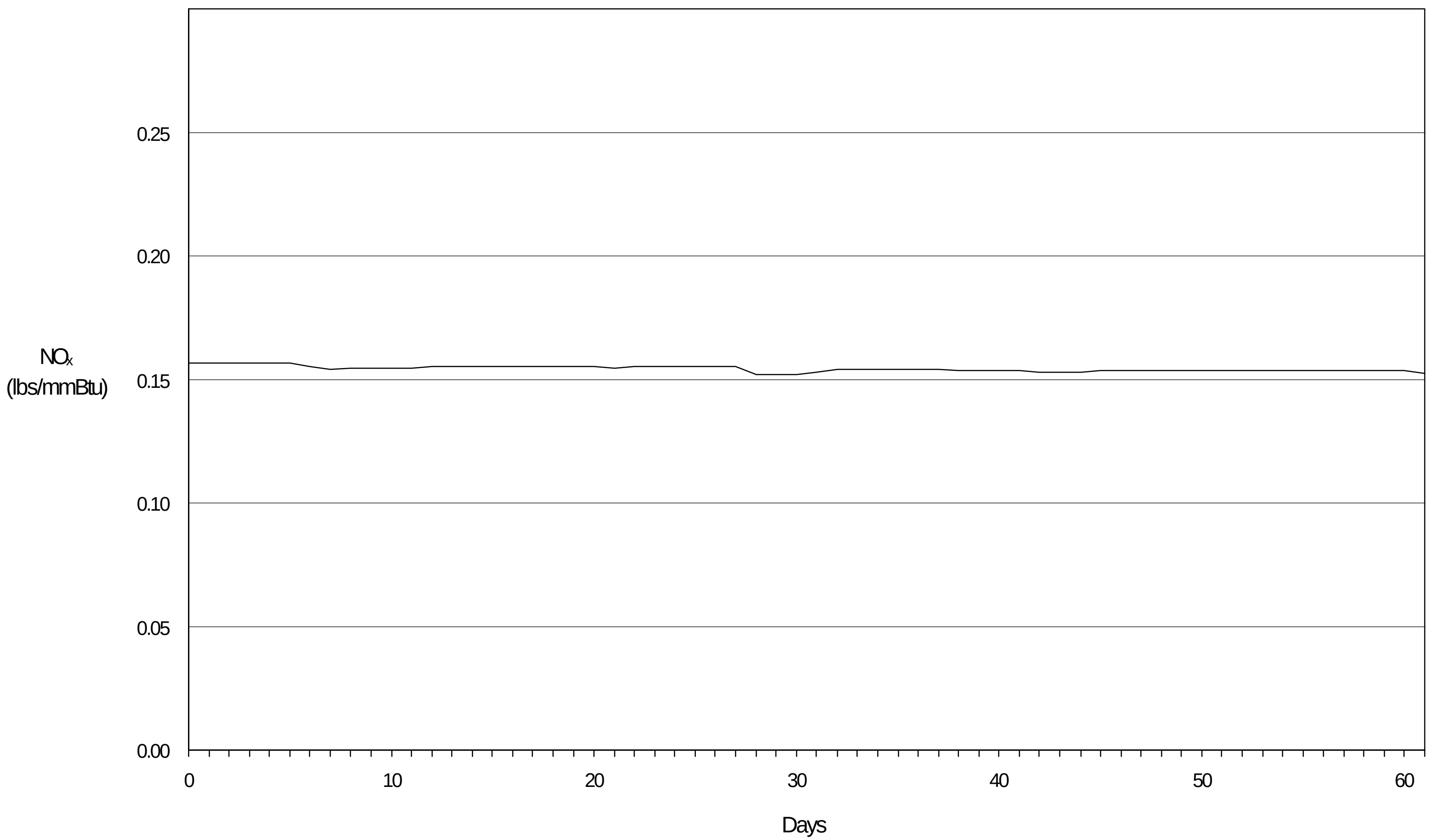


Figure G-4.6

Plant G-4: NO_x Emissions (Unit B: 30 Day Rolling Averages)

January 1 - March 31, 1996



Operation, Maintenance and Cost Related Information:

Plant G-4 uses regenerative air preheaters. The plant reported that with unit A, there was no need to wash the air preheater. With unit B, air preheaters are washed only as an exception, as a result of the SCR being placed in a "tail-end" configuration. Therefore, the cleaning of the flue gas preheaters is related to pollution from the flue gas desulfurization unit. Plant G-4 did not report costs involved. The SCR systems use aqueous ammonia, and the plant stated that there have been no ammonia-related problems. Plant G-4 reported ammonia slip at Unit A as less than 0.5 ppm and less than 0.1 ppm at Unit B, and stated that the standard is 11.25 ppm. Flyash from the plant is sold to be used in the construction material industry; the boiler does not use flyash recirculation.

Unit A has a honeycomb catalyst of three out of four possible layers filled with a total volume of 581 cubic meters. The plant reported that after 30,000 operating hours they have had no problems with the catalyst. The catalyst is cleaned annually by suctioning off deposits, and erosion damage of baffles and deflection plates before the SCR is also repaired annually. Unit B has a honeycomb catalyst of three layers with a total volume of 268 cubic meters. The plant reported that after 55,000 operating hours they have had no noticeable loss of effectiveness, and stated that the catalyst durability has exceeded their expectations. The plant also reported no problems associated with coal type, and noted that they combust coal with a maximum sulfur content of 1.15%. Equal success was reported in the operation of the plant's monitoring system. Zero point and test gas checks are performed on the NO_x and O_2 monitors once each week. The plant stated that downtime related to maintenance and malfunctions is less than 2% of operating time.

For Unit A, the plant reported capital costs of approximately 53,000,000 Deutsche Marks (1995). The plant reported operating costs, including materials used, maintenance and financing costs, at approximately 3 Deutsche Marks (1995). For Unit B, the plant reported capital costs of approximately 115,000,000 Deutsche Marks (1995). The plant reported operating costs, including materials used, maintenance and financing costs, of approximately 9 Deutsche Marks/kWh (1995). No breakdown of specific cost components was provided.

Table G-4 .3

Summary of Reported Operational Problems and Costs

Category	Summary	
Operational Problems	Unit A: None. Unit B: None	
Costs	Unit	Data Provided
	Unit A	Capital: DM 53,000,000
		Operating: DM 3/kWh (1995)
	Unit B	Capital: DM 115,000,000
		Operating: DM 9/kWh (1995)

Plant G-5

Plant/Unit Information:

The German Plant G-5 provided continuous half-hour NO_x data for March 1996 for two units (A and B) retrofitted with a low dust SCR system and a high dust SCR system, respectively. Unit A is a 350 MWe wet bottom boiler and Unit B is a 710 MWe tangentially fired, dry bottom boiler. Unit B also is equipped with low NO_x burners. The Unit A boiler began operation in 1970 and the SCR system began operation in 1989. At Unit B, the boiler began operation in 1985 and the SCR system began operation in 1989. All data were corrected to ISO standards of 0 °C (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6% oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted is provided in Table G-5.1.

Table G-5.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Half-hourly
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Partial
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table G-5.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	No
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	Yes
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	Yes

Coal Information:

Plant G-5 provided coal data (GCV, ash, moisture and sulfur); however, Plant G-5 has not provided a complete ultimate analysis with which to calculate F-factors. Therefore, a standard F-factor for bituminous coal (9780 dscf/mmBtu) was used.

Emissions Data Analysis:

The average of NO_x emissions for Unit A over the March 1996 period was 0.14 lbs/mmBtu. Figure G-5.1 shows the continuous hourly emissions for Unit A. The average of NO_x emissions for Unit B was 0.15 lbs/mmBtu. Figure G-5.2 shows the continuous data for Unit B. Figures G-5.3 and G-5.4 provide the same results expressed as 24-hour averages. All NO_x readings of zero were discarded from the 24-hour and mean calculations. However, non-zero data were included even if the data were possibly related to a period of start up or shutting down. Please refer to the text of the main report for a discussion of computing 24-hour averages.

Figure G-5.1

Plant G-5: NO_x Emissions (Unit A)

March 1-30, 1996

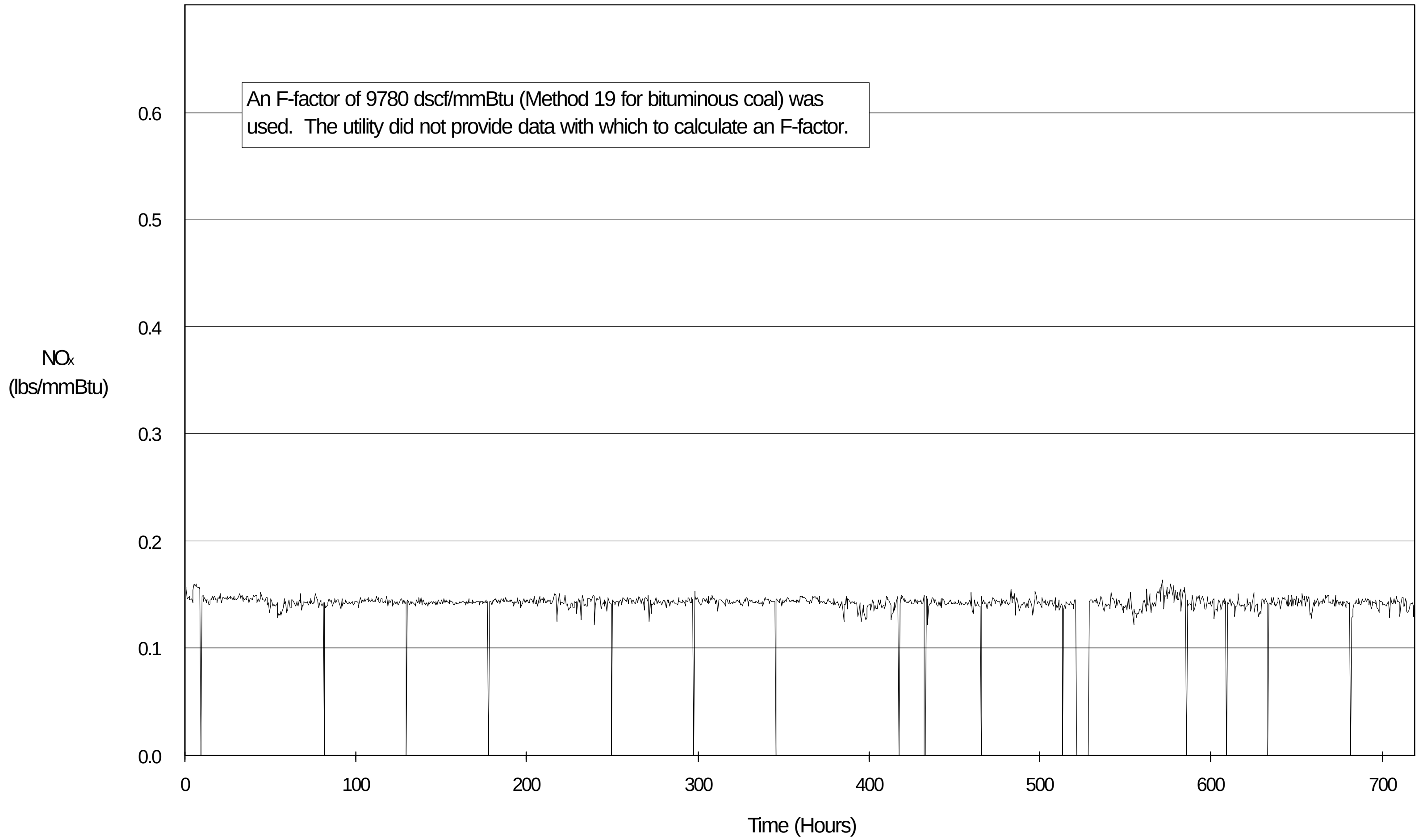


Figure G-5.2

Plant G-5: NO_x Emissions (Unit B)

March 1-31, 1996

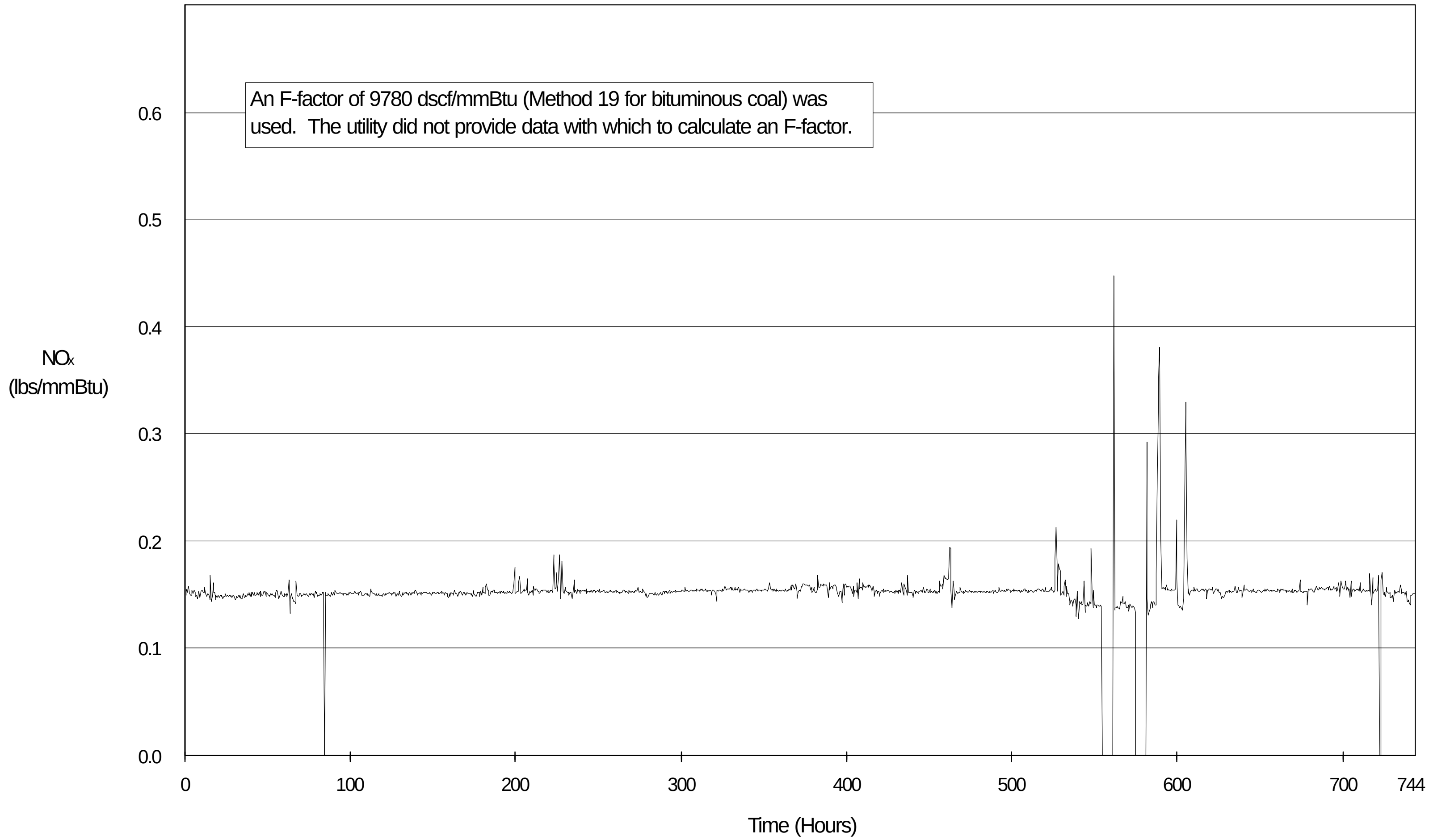


Figure G-5.3

Plant G-5: NO_x Emissions (Unit A: 24 Hour Averages)

March 1-30, 1996

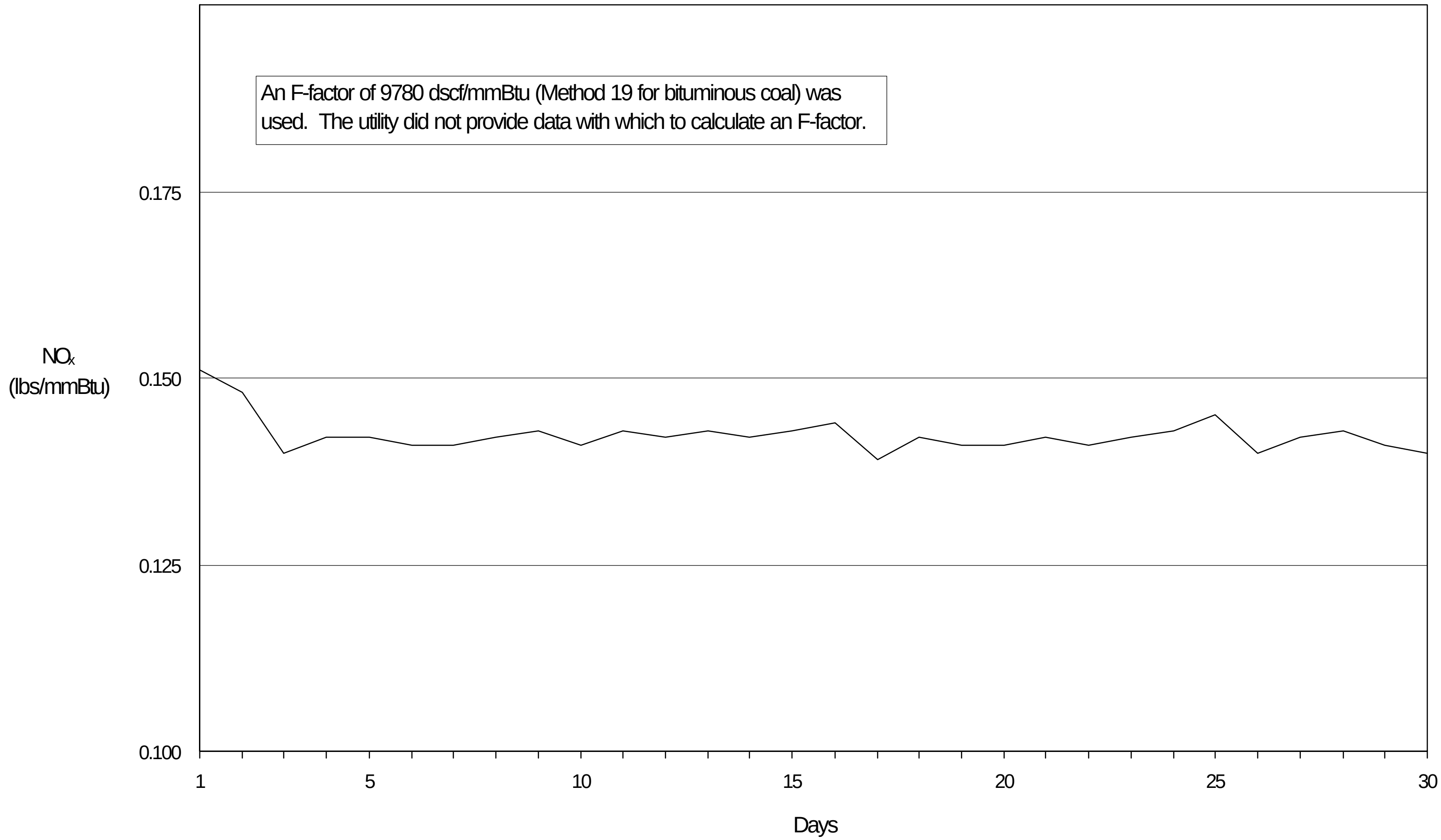
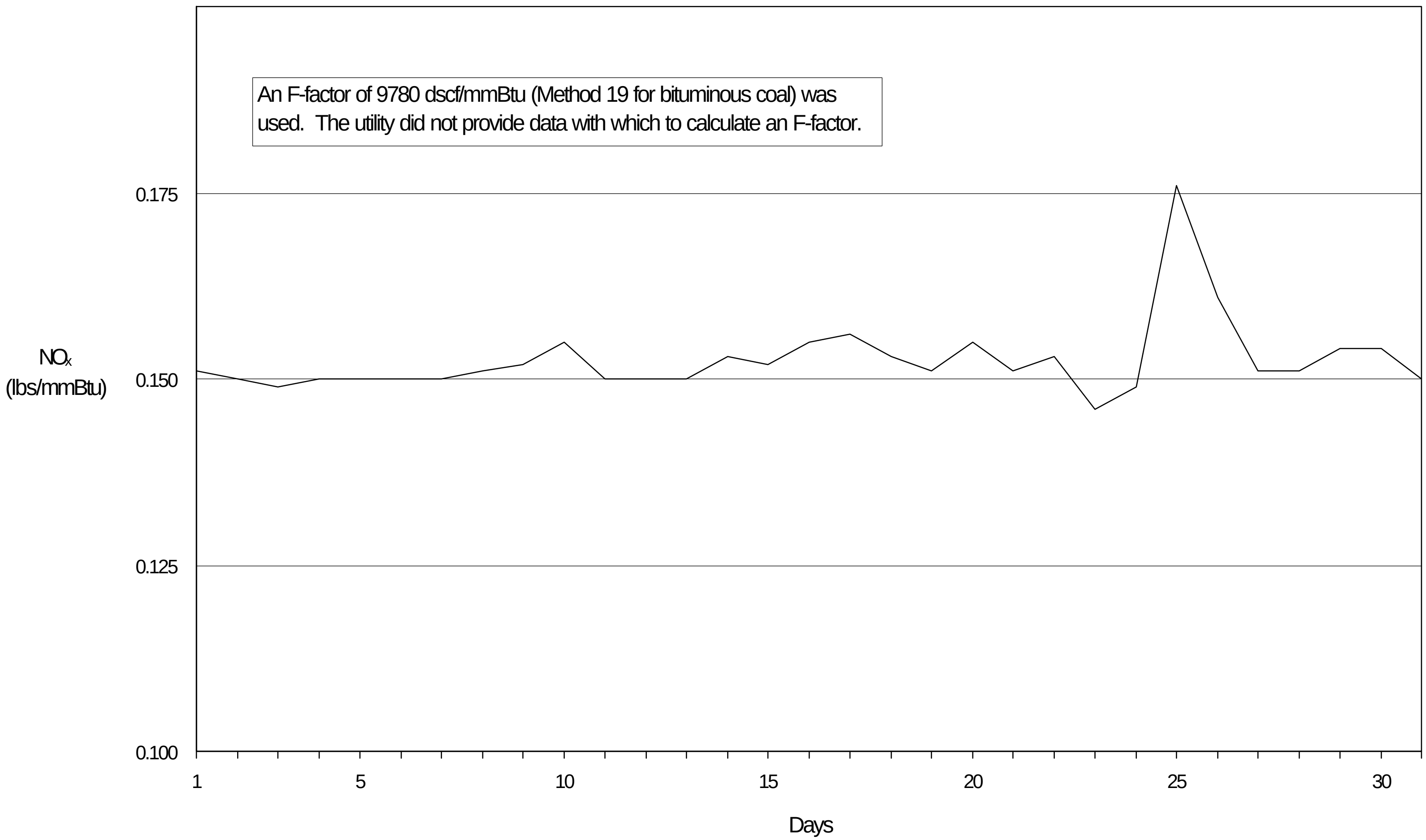


Figure G-5.4

Plant G-5: NO_x Emissions (Unit B: 24 Hour Averages)

March 1-31, 1996



Operation, Maintenance and Cost Related Information:

Unit A has a regenerative air preheater. The plant reported that the SCR has not affected the air preheater, but has not provided specific information on air preheater washing. Unit A uses anhydrous ammonia, and the plant stated that there have been no ammonia-related problems. The maximum allowable ammonia slip is 2 ppm; actual slip is less than 0.1 ppm. The plant recirculates 100% of the flyash. Unit A has a honeycomb catalyst with three layers, which have a volume of 282 cubic meters each. The plant reported that after 45,000 operating hours there have been no problems with the catalyst. Unit A reported no problems related to coal type. The NO_x and O_2 monitors are calibrated every three days; data availability information was not provided. The plant reported capital costs of approximately $ 40,000,000 to retrofit a low-dust SCR system. Replacing a layer of catalyst would cost approximately $ 1,080,000. Operating costs were estimated at $5,000,000 per year, and NO_x removal costs were estimated at $1,470 per ton. No breakdown of specific cost components was provided.

Unit B has a regenerative air preheater, which has been washed three times since the plant began operation in 1985. The air preheater was washed once because of a catalyst at the end of its lifetime; no cost information was provided. Unit B uses anhydrous ammonia, and the plant stated that there have been no ammonia-related problems. The maximum ammonia slip is 1 ppm; actual slip is less than 0.2 ppm. Unit B boiler does not use flyash recirculation. Unit B has a honeycomb catalyst with three layers of 89.10 cubic meters each. One layer of the catalyst was replaced after 40,000 hours of operation; the plant estimated the cost of replacing one layer at $ 3,700,000. The plant reported slight plugging of the catalyst caused by the low-NO_x burners, and stated that the catalyst was cleaned successfully at a cost of approximately $ 1,500 per cubic meter. The plant reported one problem related to coal type: strong corrosion in the boiler, caused by the low-NO_x burners, which produced "pop-corn-ash" that slightly plugs the catalyst. The plant did not further discuss operational impacts associated with this problem and did not discuss the costs involved. The NO_x and O_2 monitors are calibrated every three days; data availability information was not provided. The plant reported capital costs of approximately $ 33,600,000 to retrofit a high-dust SCR system. Operating costs were estimated at $1,500,000 per year, and NO_x removal costs were estimated at $ 820 per ton of NO_x removed. No breakdown of specific cost components was provided. A summary of the operational problems and costs reported for both units is provided in the table below.

Table G-5.3

Summary of Reported Operational Problems and Costs

Category	Summary		
Operational Problems	Unit A:	Problem with FGD accelerated catalyst deactivation in first years. Solved with little difficulty; cost not specified.	
	Unit B:	Slight plugging of catalyst. Catalyst cleaned at approximate cost of $ 1,500 per cubic meter.	
Costs	Unit	Data Provided	
	Unit A	Capital:	$ 40,000,000
		Operating: $ 5,000,000/year	
	Unit B	Capital:	$ 33,600,000
		Operating: $ 1,500,000/year	

Plant G-6

Plant/Unit Information:

The German Plant G-6 provided annual data summaries for five units (A, B, C, D, and E) for 1995. Four of these units have been retrofitted with SCR; Unit D was built with SCR. The Unit A boiler began operating in 1976, and the SCR system began operating in 1990. For Unit B, the utility reported boiler startup in 1963-64 and SCR system startup in 1991-92. The Unit C boiler began operating in 1967 and the SCR system began operating in 1993. Both the boiler and the SCR system at Unit D commenced operation in 1989. At Unit E, the boiler began operating in 1983 and the SCR system began operating in 1989. An average emission rate for each unit was provided in both mg/m^3 and ηg /J. For two of these units (A with a high dust SCR system and B with a low dust or tail-end SCR system), Plant G-6 provided both an overall daily average and a daily summary of half-hour averages covering the period from February 24 - April 12, 1996, for Unit A and from March 2 - April 12, 1996, for Unit B. Each day's summary gave the number of readings in 20 mg/m^3 NO_x emission intervals along with the 24-hour average for that day. All data were corrected to ISO standards of 0 °C (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6 % oxygen dilution basis. Unit A is described as a box-fired, dry bottom boiler with a high dust SCR. Unit B is actually two units using one SCR system and is described as a jet burner with wet bottom ash removal and tail-end SCR configuration. Unit C is a wet bottom boiler with low dust SCR. Unit D is box- fired, dry bottom with a high dust SCR, while Unit E is tangentially-fired and high dust. The capacities of A, B, C, D and E are 680, 2X150, 158, 230 and 750 MWe, respectively. The plant is required to meet a NO_x standard of 200 mg/m^3.

The utility also provided continuous half-hourly NO_x data for Unit B for the period October 1 - 21, 1994 as well as for November 1 - December 31, 1994. The 142 MWe coal-fired boiler is described as a forced circulation steam generator with "low dust" SCR. A summary of data submitted is provided in Table G-6.1.

The daily emissions data for Unit A are graphed below with the highest and lowest 20 mg/m^3 increment range (converted to lbs/mmBtu) shown for each day (the highest end of the 20 mg/m^3 range was selected for this purpose). Similar data for Unit B are not graphed, because continuous one-half hour averages were available, which were graphed instead.

Table G-6.1

Summary of Data Submitted

Requested	**Submitted?**
Continuous NO_x Emissions	Yes (Unit B only)
Hourly data	Half-hourly (Unit B)
O_2 diluent	No
Moisture	No
Temperature	No

(cont.)

Table G-6.1 (cont.)

Summary of Data Submitted

Requested	**Submitted?**
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes (Unit B)
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes (Unit B)
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	No

Coal Information:

The coal data provided by Plant G-6 had been corrected for moisture content. These data are shown in Table G-6.2. Each value was recorrected using the moisture values for use in the F-factor calculation.

Table G-6.2

Coal Data for Plant G-6

Coal Analysis				
Property	**Unit A**	**Unit B**	**Units C & D**	**Unit E**
Moisture (%)	6.0	15.0	15.0	8.5
Ash (%)	12.0	27.0	29.0	11.2
Nitrogen (%N)	1.3	1.3	1.0	1.8
Oxygen (%O)	9.3	7.1	7.3	8.4
Carbon (%C)	71.5	59.5	57.5	73.5
Hydrogen (%H)	4.8	3.8	3.8	4.8
Sulfur (%S)	0.9	1.4	1.3	0.92
GCV (kJ/kg)	27,200	20,500	19,300	26,500
F-Factor (dscf/mmBtu)	9,945	10,090	10,408	10,198

Emissions Data Analysis:

Average NO_x emissions for Unit A were calculated using the data on daily averages provided by the plant. The average of NO_x emissions was 0.16 lbs/mmBtu for Unit A. Figure G-6.1 shows the daily NO_x averages for Unit A along with a plot of the maximum and minimum readings for each day. For Units C, D and E the reported average emissions in mg/m^3 did not match the reported average in ηg/J when both were converted to lbs/mmBtu. To resolve this difference the reported emissions in ηg/J were used. In each case the average of emissions in ηg/J corresponded to 0.17 lbs/mmBtu. Unit B achieved an average NO_x emission level of 0.13 lbs/mmBtu during the period October 1 - 21, 1994 and 0.12 lbs/mmBtu for November 1 - December 31, 1994. Figures G-6.2 and G-6.3 show the continuous half-hourly NO_x emissions readings for these two periods. Figures G-6.4 and G-6.5 show emissions data for the two periods expressed in 24-hour averages. Figure G-6.6 shows the data from November 1 - December 31, 1994 expressed as a 30-day rolling average. All NO_x readings of zero were discarded from the graph of continuous emissions, as well as from the mean and 24-hour average calculations. However, non-zero data were included even if the data were possibly related to a period of startup or shutdown.

Figure G-6.1

Plant G-6: NO_x Emissions (Unit A: 24 Hour Averages)

February 2-April 12, 1996

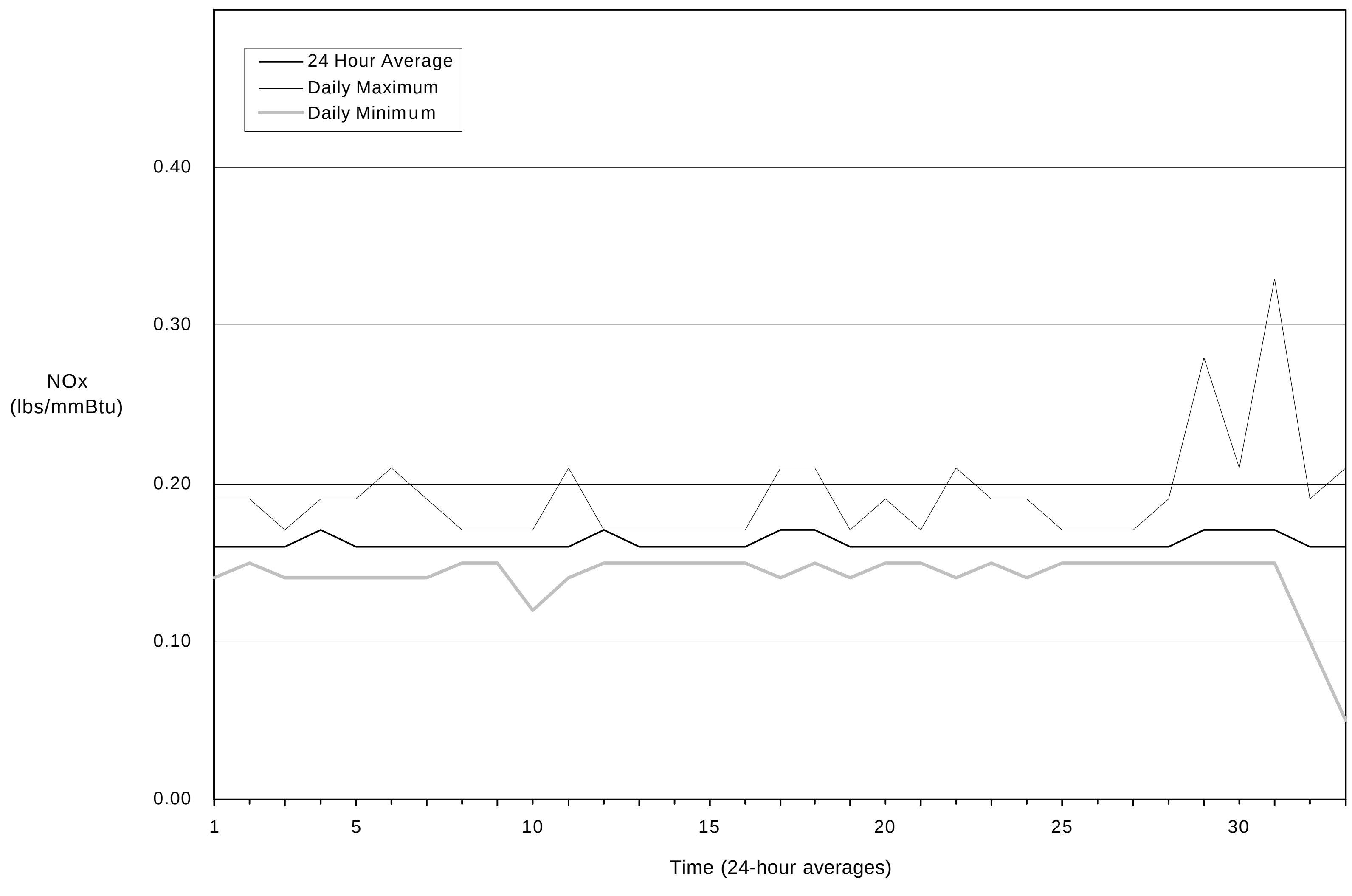


Figure G-6.2

Plant G-6: NO_x Emissions (Unit B: 1/2 Hour Averages)

October 1 - October 21, 1994

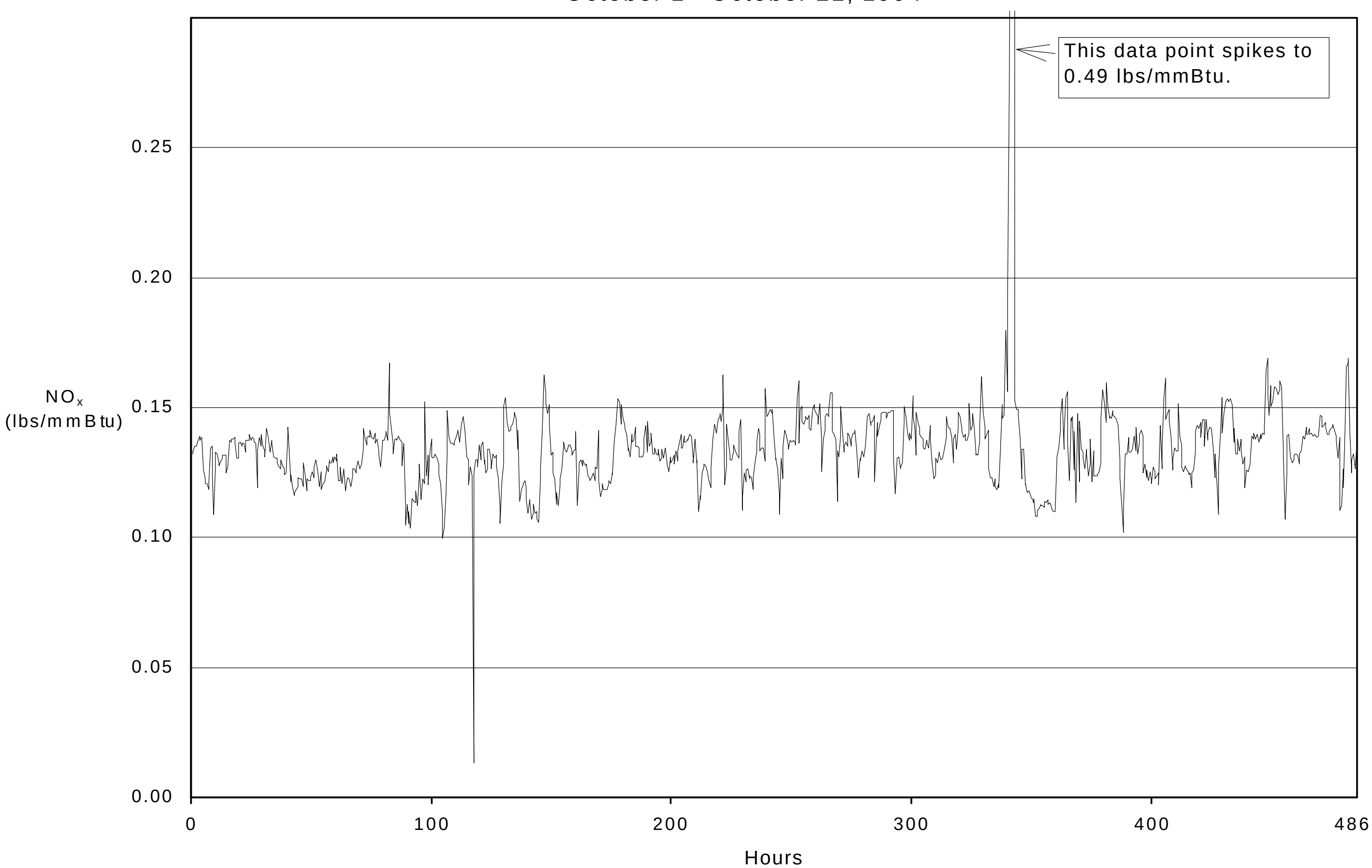


Figure G-6.3

Plant G-6: NO_x Emissions (Unit B: 1/2 Hour Averages)

November 1 - December 31, 1994

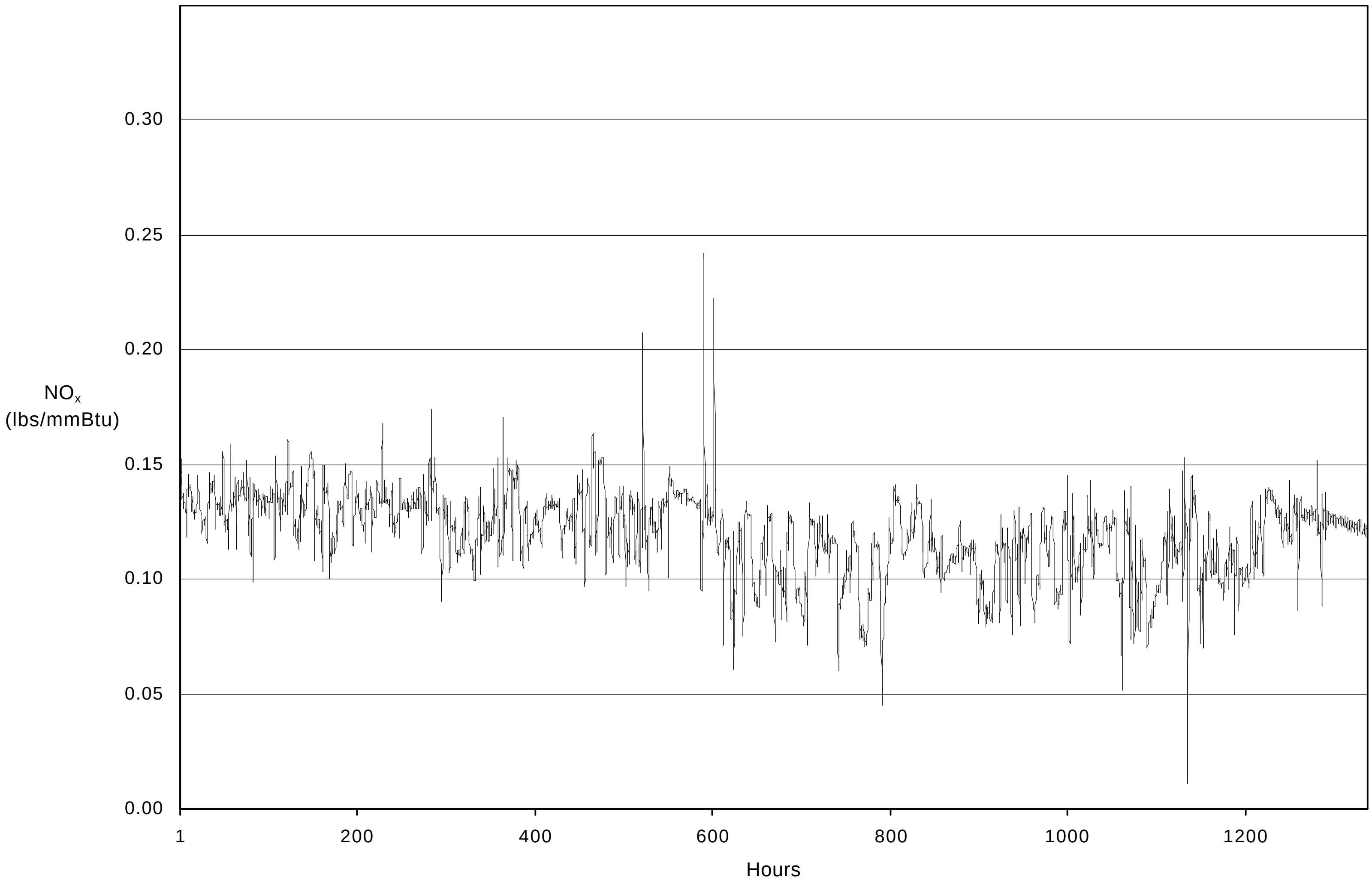


Figure G-6.4

Plant G-6: NO_x Emissions (Unit B: 24-Hour Averages)

October 1 - October 21, 1994

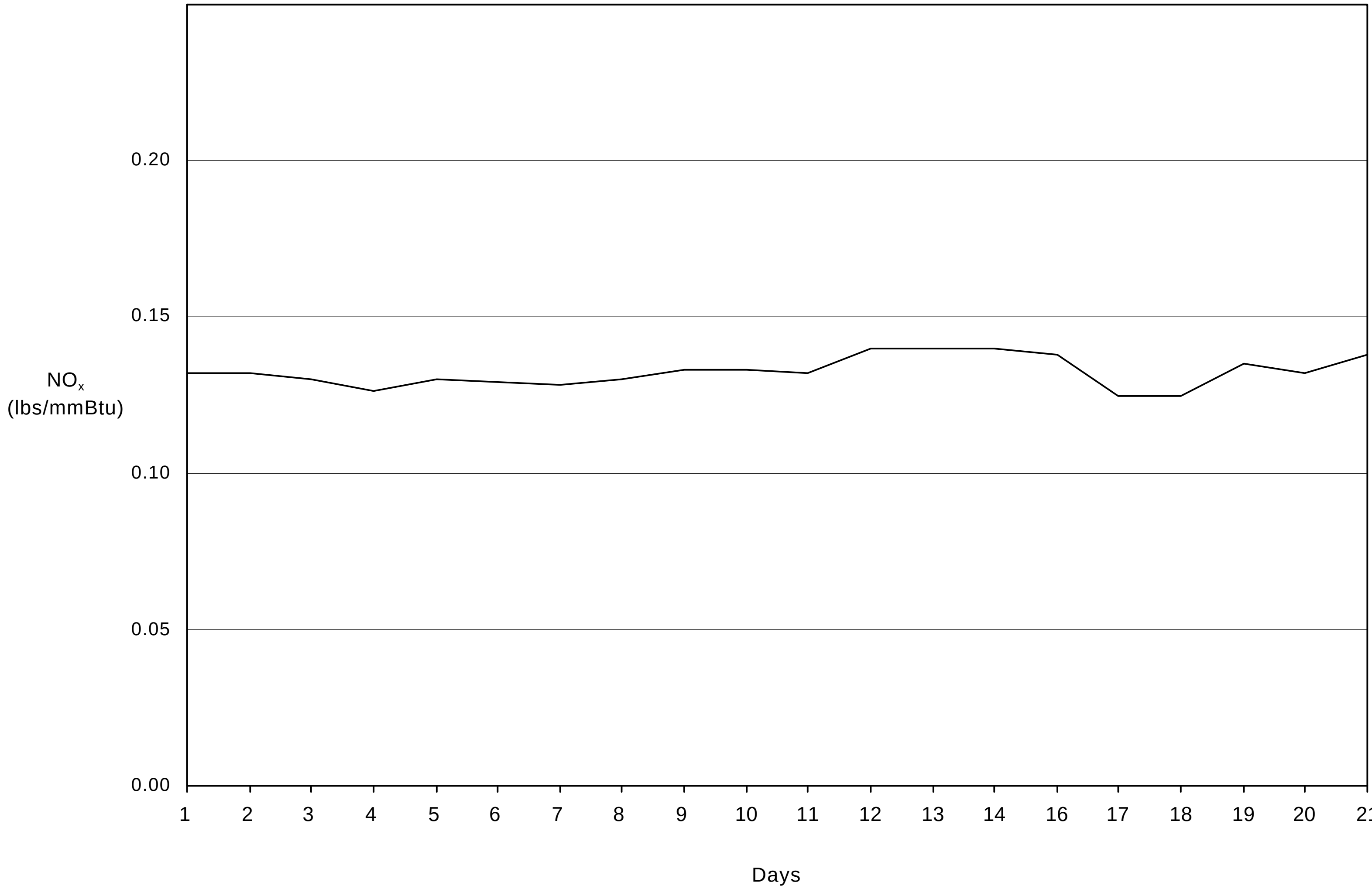


Figure G-6.5

Plant G-6: NO_x Emissions (Unit B: 24 Hour Averages)

November 1 - December 31, 1994

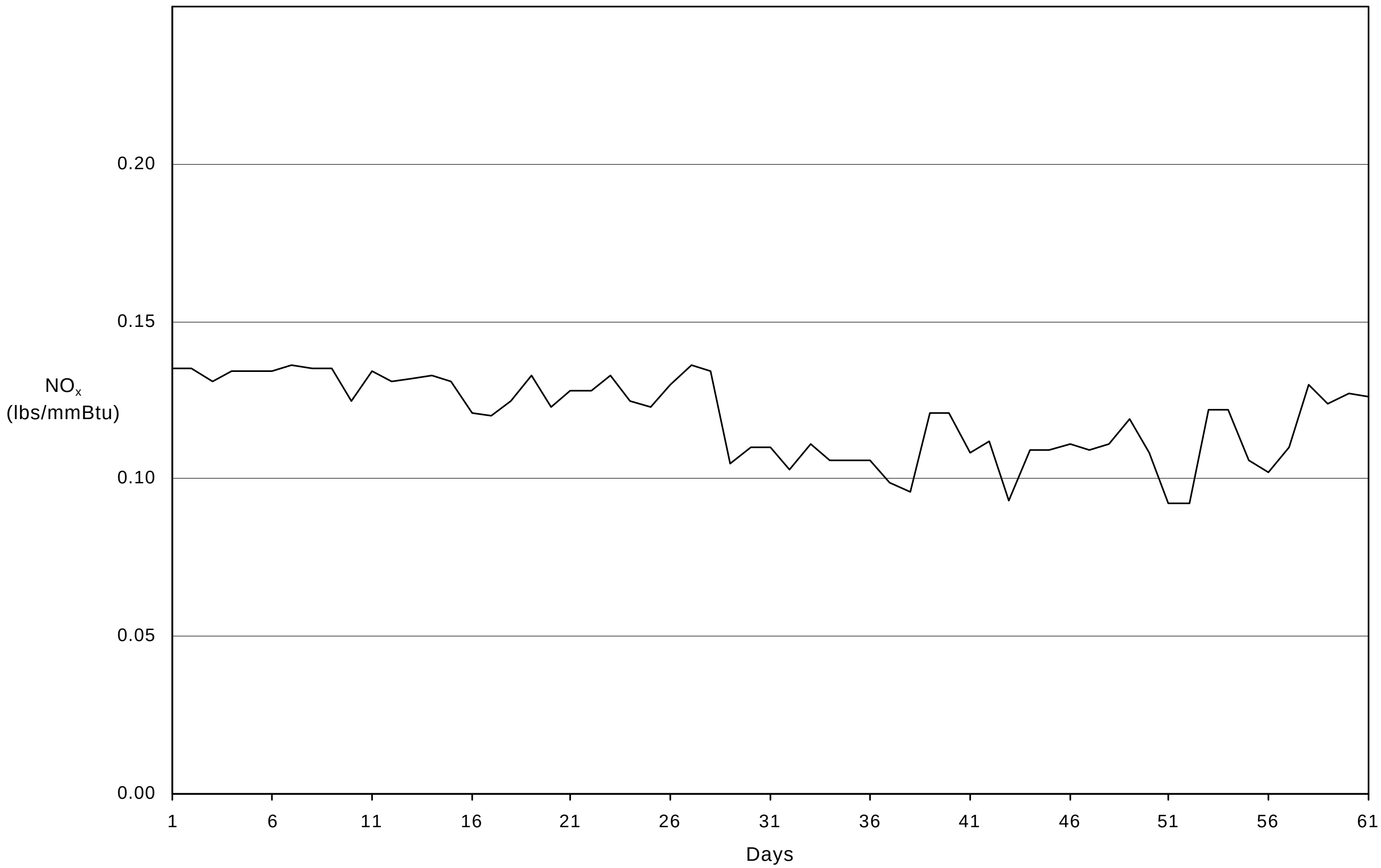
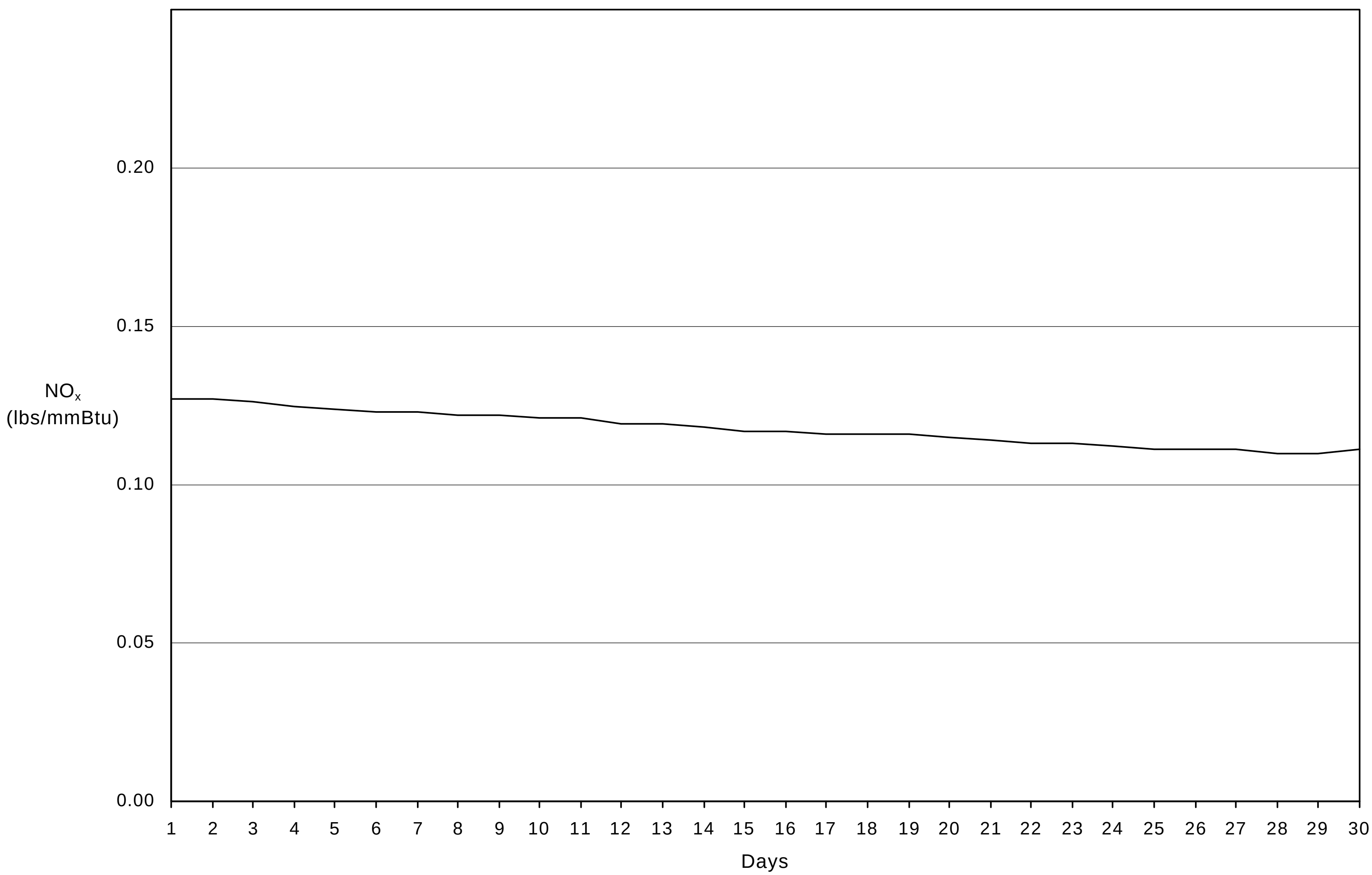


Figure G-6.6

Plant G-6: NO_x Emissions (Unit B: 30 Day Rolling Averages)

November 1 - December 31, 1994



Operation, Maintenance and Cost Related Information:

Plant G-6 provided information on operation and maintenance and costs for Unit A and Unit B, but was unable to provide information on Units C, D or E. Units A and B use regenerative air preheaters. The utility reported that in its experience, air preheaters at units with high-dust SCR systems need to be washed after six to seven years of SCR system operation, but that air preheaters at low-dust SCR systems do not need to be washed. The utility stated that it did not wash air preheaters before SCR system installation. Cost information associated with washing air preheaters was not provided. At both Units A and B, the SCR systems use anhydrous ammonia. At Unit A, the allowable ammonia slip is below 3 ppm, and the actual ammonia slip is less than 0.02 ppm. Unit B has an allowable ammonia slip of less than 5 ppm, and actual slip is less than 0.02 ppm. The utility stated that there have been no ammonia-related problems. The utility stated that two of the five boilers are equipped for flyash recirculation; Units B and C are wet bottom boilers. The plant reported that unit B uses a smelting chamber heating system for firing and that the sale of flyash depends on the market situation. If the flyash cannot be sold due to market reasons, or if it does not meet specifications, (especially because it contains too much combustible material), it is returned to the heating system and melted down together with the boiler ash. The melted down boiler ash is granulated in a water bath. The ash granulate obtained in this manner is a much sought-after building material.

Unit A has a honeycomb catalyst with a total volume of 926 cubic meters. After 27,000 hours of operation, one catalyst layer was recharged (not exchanged). The utility did not specify what this cost. Unit B has a honeycomb catalyst with two out of three possible layers filled, each layer having a volume of 98 cubic meters. There has been no reduction in effectiveness after 36,000 operating hours. The utility stated that they have had no problems related to coal type. They do not often obtain coal with a sulfur content greater than 2%. When the utility has coal with a sulfur content greater than 2%, it is burned only after it has been mixed with coal having a sulfur content of 1.1%.

The NO_x and O_2 monitors are calibrated with test gas once each week. The utility reported capital costs of approximately 59,800,000 Deutsche Marks (1991) to retrofit a high-dust SCR system at Unit A. To retrofit a high-dust SCR system at Unit B, capital costs were approximately 68,300,000 Deutsche Marks (1991). The utility also reported capital costs for ammonia storage, which were 11,800,000 Deutsche Marks (1991) for Unit A and 6,400,000 Deutsche Marks (1991). The utility noted these costs were high because of a difficult storage location. Adding the two elements of capital costs resulted in a total of 71,600,000 Deutsche Marks (1991) for Unit A and a total of 74,400,000 Deutsche Marks (1991) for Unit B. Other than specifying capital cost for ammonia storage, no breakdown of specific cost components was provided. The utility has not provided operating costs for either unit. A summary of the operational problems and costs reported by the utility is provided in the table below.

Table G-6.3

Summary of Reported Operational Problems and Costs

<table>
<tr><th>Category</th><th colspan="2">Summary</th></tr>
<tr><td>Operational Problems</td><td colspan="2">False alarms at ammonia storage interrupted ammonia input to SCR. Solved by replacing gas detector at ammonia storage. Cost not specified. Did not indicate which unit.</td></tr>
<tr><td rowspan="5">Costs</td><td>Unit</td><td>Data Provided</td></tr>
<tr><td rowspan="2">Unit A</td><td>Capital: DM 71,600,000 (1991)</td></tr>
<tr><td>Operating: Not Provided</td></tr>
<tr><td rowspan="2">Unit B</td><td>Capital: DM 74,700,000 (1991)</td></tr>
<tr><td>Operating: Not Provided</td></tr>
</table>

Plant S-1

Plant/Unit Information:

Plant S-1 is the only Swedish plant surveyed in this report. It is required to meet an annual average of 80 mg NO_x per MJ of coal energy. Plant S-1 provided continuous hourly data for October 1995 and January 1996 for one boiler (Unit A) retrofitted in 1992 with SCR. Unit A is a tangentially fired, wet bottom coal boiler with two effluent pathways. The boiler was constructed as an oil fired unit, but was converted to use pulverized coal and was retrofitted with SCR technology. Each effluent stream passes through a separate SCR system; then, the effluent streams rejoin to pass through an SO_2 absorber, an electrostatic precipitator and finally the stack. Oil is sometimes burned along with the pulverized coal. Plant S-1 also provided monthly and annual summaries of NO_x emissions for Unit A from January 1994 to December 1996, expressed in mg/MJ. In addition, Plant S-1 provided monthly summaries for two other units (Units B and C) with SCR for 1995. Units B and C emit through a common stack and were retrofitted in 1991 with high dust SCR systems. Both units have 40 MW electrical capacity and 110 MW heat capacity. A summary of the data provided by Plant S-1 is shown in Table S-1.1 below.

Plant S-1: Unit A provided NO_x stack concentration in parts per million (ppm) by volume. These measurements are on a dry basis corrected to a 6% oxygen dilution level. In applying the conversion calculation methodology (discussed above in the methods section as Formula 1) the temperature correction factor (273/293) is not needed because the data are in a volumetric ratio (ppm) rather than a weight per volume. In Unit A, the analyzer measures NO concentration rather than NO and NO_2. The regulations for this plant require continuous measuring of NO_x only if the amount of NO_2 exceeds 5% of the NO amount. This is determined by an annual measurement of NO and NO_2. Plant S-1 used a 1.4% NO_2 factor (1.014 times the NO reading) to convert NO to NO_x.

Table S-1.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Yes
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No

(cont.)

Table S-1.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	No
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	No
Other Operational Experience	No
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant S-1: Unit A provided extensive coal analysis with which to calculate F-factors. Chemical characteristics data were provided for specific periods during the data period. These coal data are shown in Table S-1.2.

Table S-1.2

Coal Data for Plant S-1: Unit A

Coal Analysis				
Property	**Oct 1 - 10**	**Oct. 11 - 31**	**Jan 1 - 9, & 21 - 31**	**Jan 10 - 20**
Moisture (%)	11.5	8.5	6.9	10.0
Ash (%)	7.4	8.9	6.7	8.6
Nitrogen (%N)	1.24	1.21	1.28	1.24
Oxygen (%O)	9.12	8.00	6.30	8.29
Carbon (%C)	65.8	68.4	73.6	66.9
Hydrogen (%H)	4.2	4.2	4.45	4.14
Sulfur (%S)	0.74	0.68	0.62	0.68
GCV (kJ/kg)	27,170	27,870	30,380	27,200
F-Factor (dscf/mmBtu)	9,619	9,749	9,680	9,763

Emissions Data Analysis:

The average of emissions for Unit A in October 1995 was 0.039 lbs/mmBtu. Figure S-1.1 shows the continuous emissions over this period. When hours in which oil was burned along with the coal are excluded, the average of emissions is 0.038 lbs/mmBtu. The continuous measurements excluding oil hours are shown in Figure S-1.2. This period's emissions rates, including and excluding oil hours and expressed in 24-hour averages, are shown in Figures S-1.5 and S-1.6.

In January 1996 the average was 0.067 lbs/mmBtu for both cases-including and excluding oil hours. Continuous readings for this period are shown in Figure S-1.3. The same results excluding oil hours are shown in Figure S-1.4. This period's emissions rates, including and excluding oil hours and expressed in 24-hour averages, are shown in Figures S-1.7 and S-1.8.

A calculation of the monthly average for the ten months in 1995 when Units B and C were in operation indicates average NO_x emissions of 0.10 lbs/mmBtu for each of these units.

Figure S-1.1

Plant S-1: NO_x Emissions Including Oil Hours

October 1-31, 1995

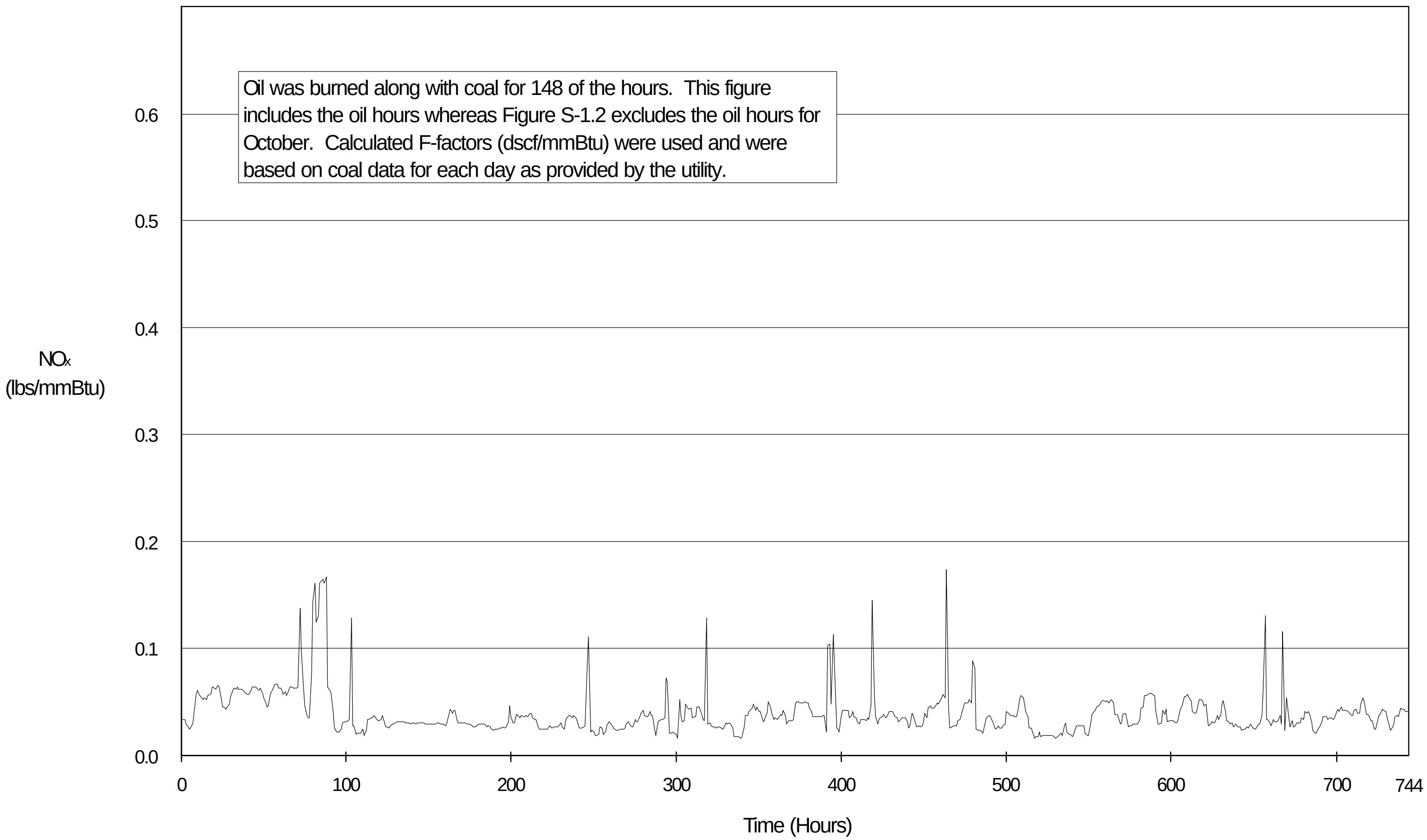


Figure S-1.2

Plant S-1: NO_x Emissions Excluding Oil Hours

October 1-31, 1995

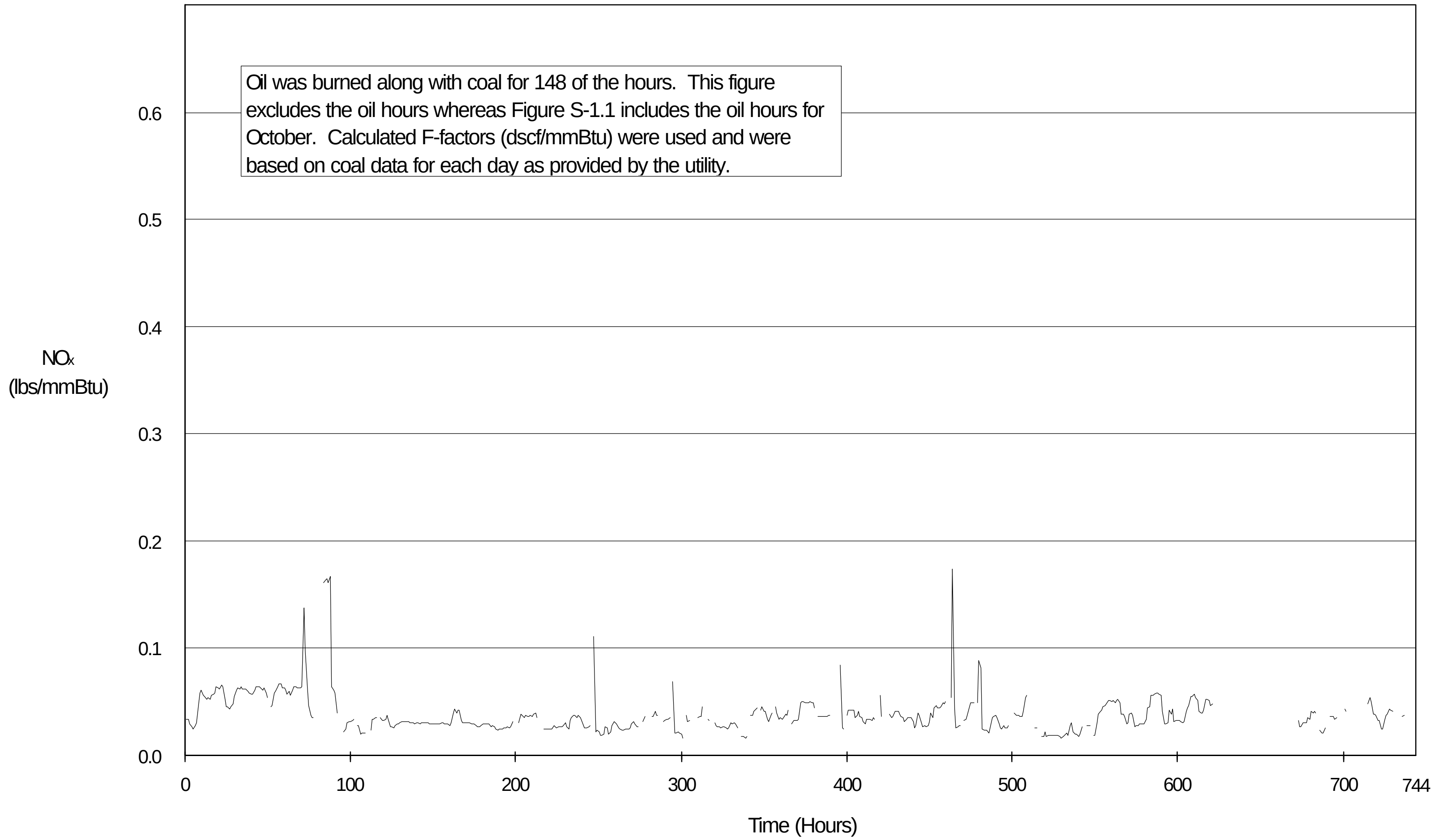


Figure S-1.3

Plant S-1: NO_x Emissions Including Oil Hours

January 1-31, 1996

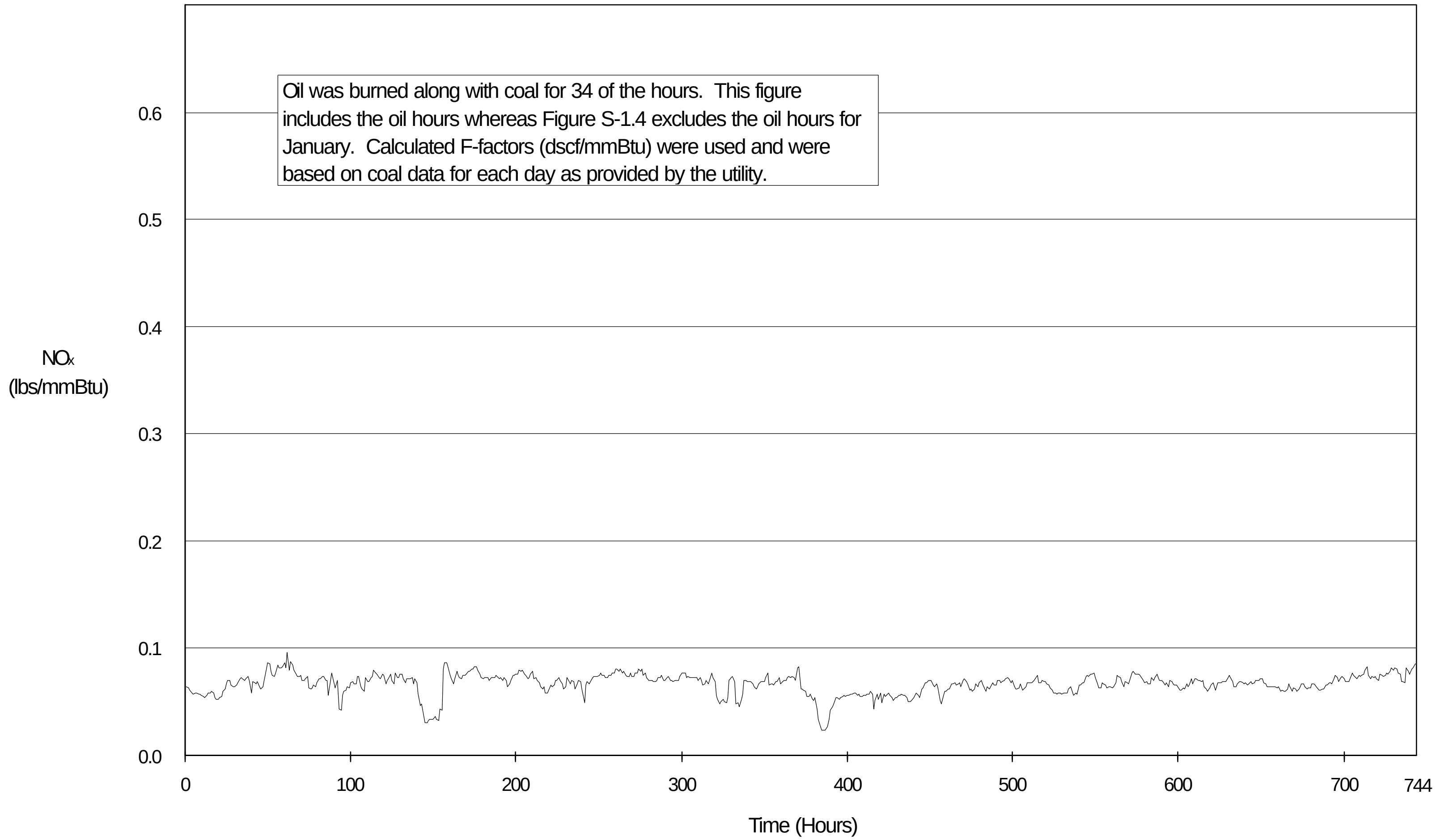


Figure S-1.4

Plant S-1: NO_x Emissions Excluding Oil Hours

January 1-31, 1996

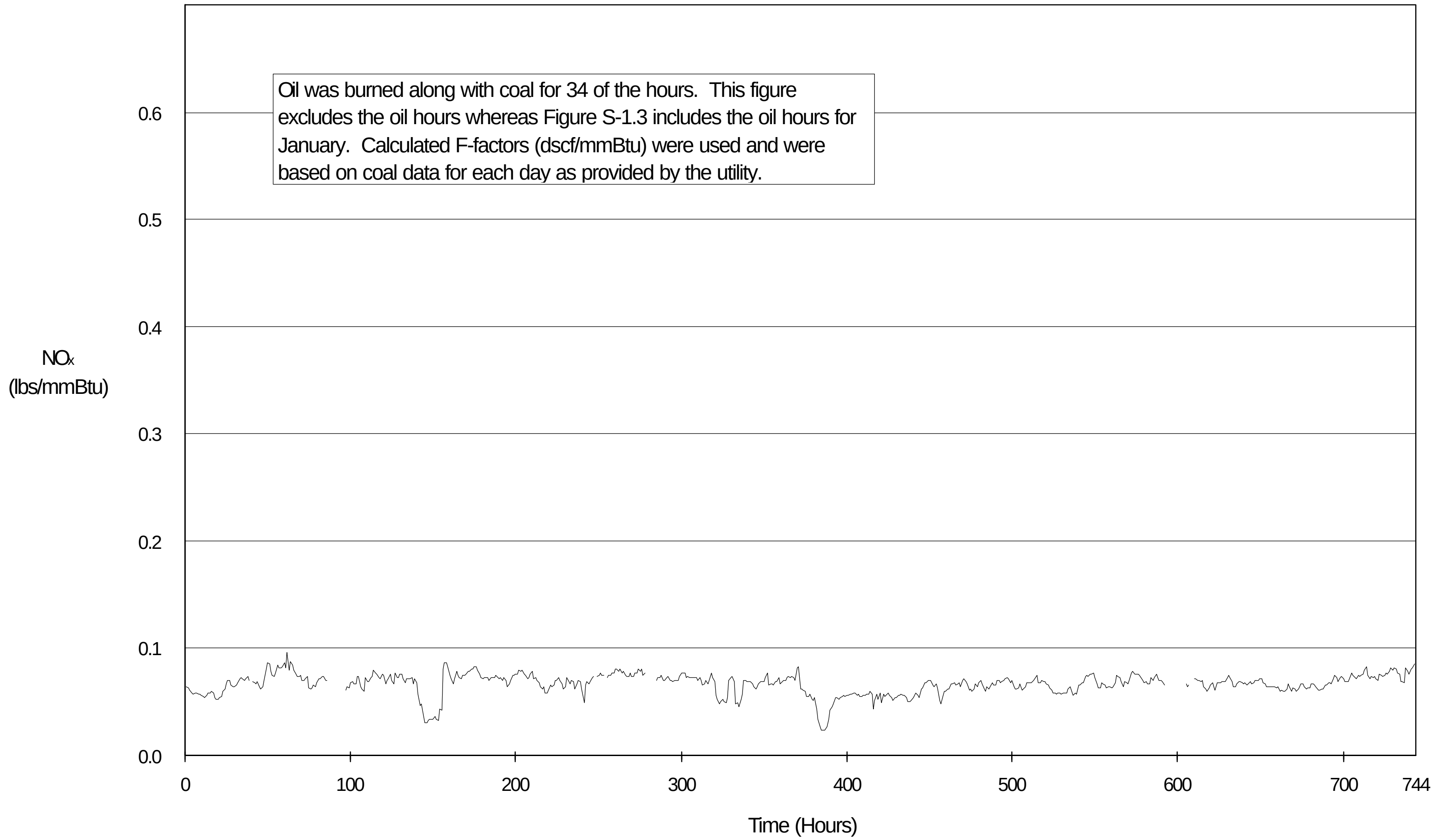


Figure S-1.5

Plant S-1: NO_x Emissions Including Oil Hours (24 Hour Averages)

October 1-31, 1995

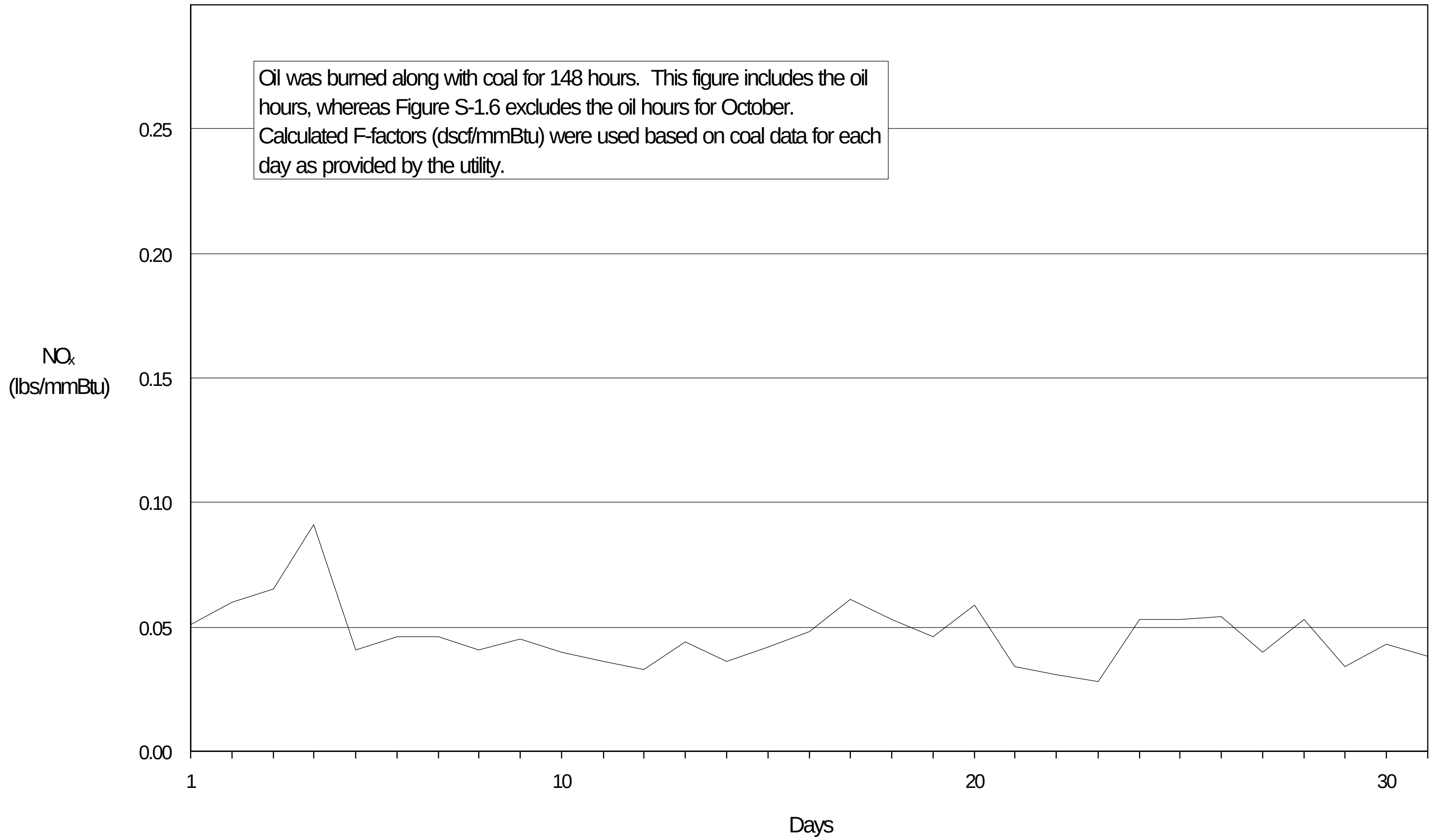


Figure S-1.6

Plant S-1: NO_x Emissions Excluding Oil Hours (24 Hour Averages)

October 1-31, 1995

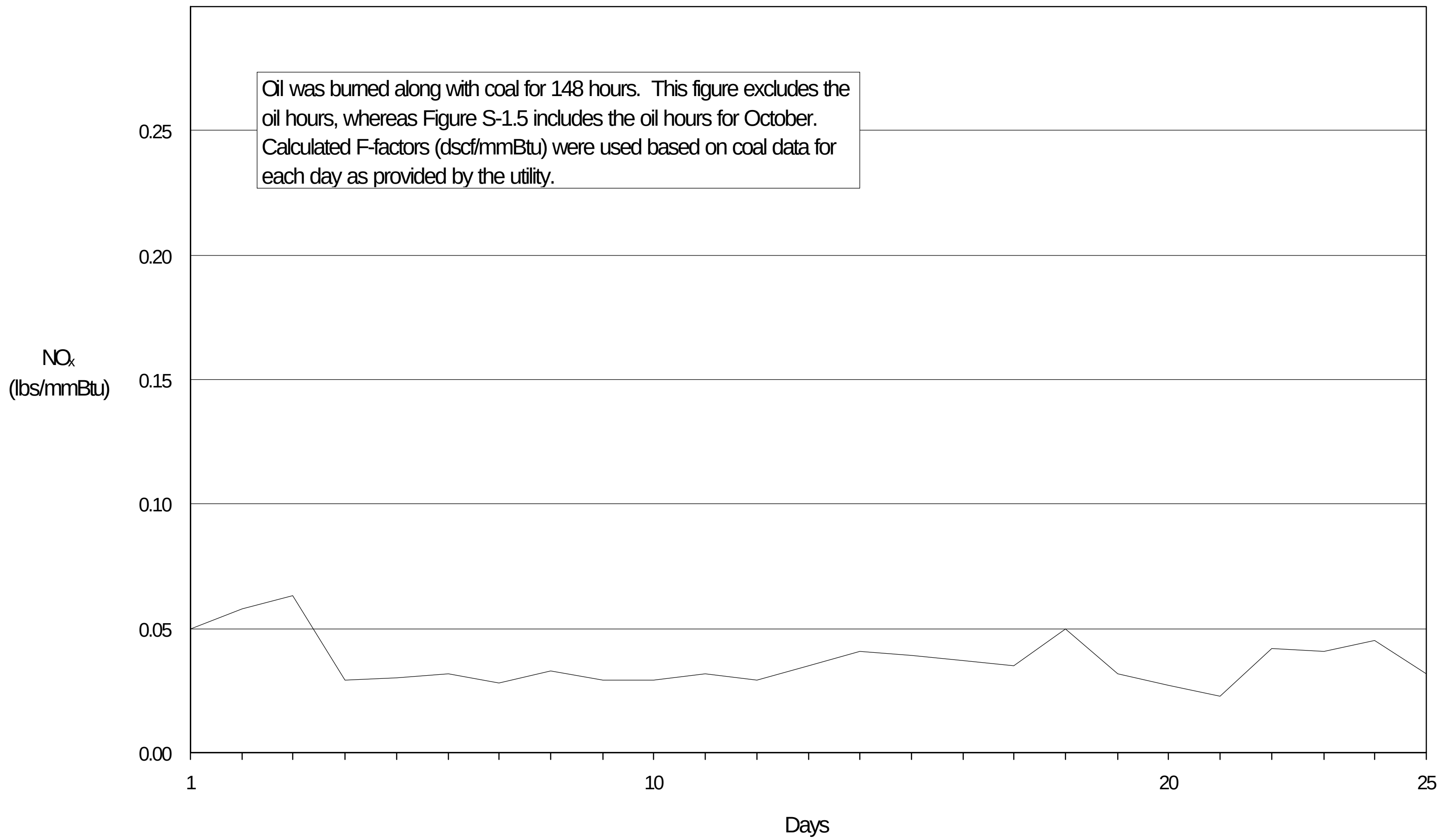


Figure S-1.7

Plant S-1: NO_x Emissions Including Oil Hours (24 Hour Averages)

January 1-31, 1996

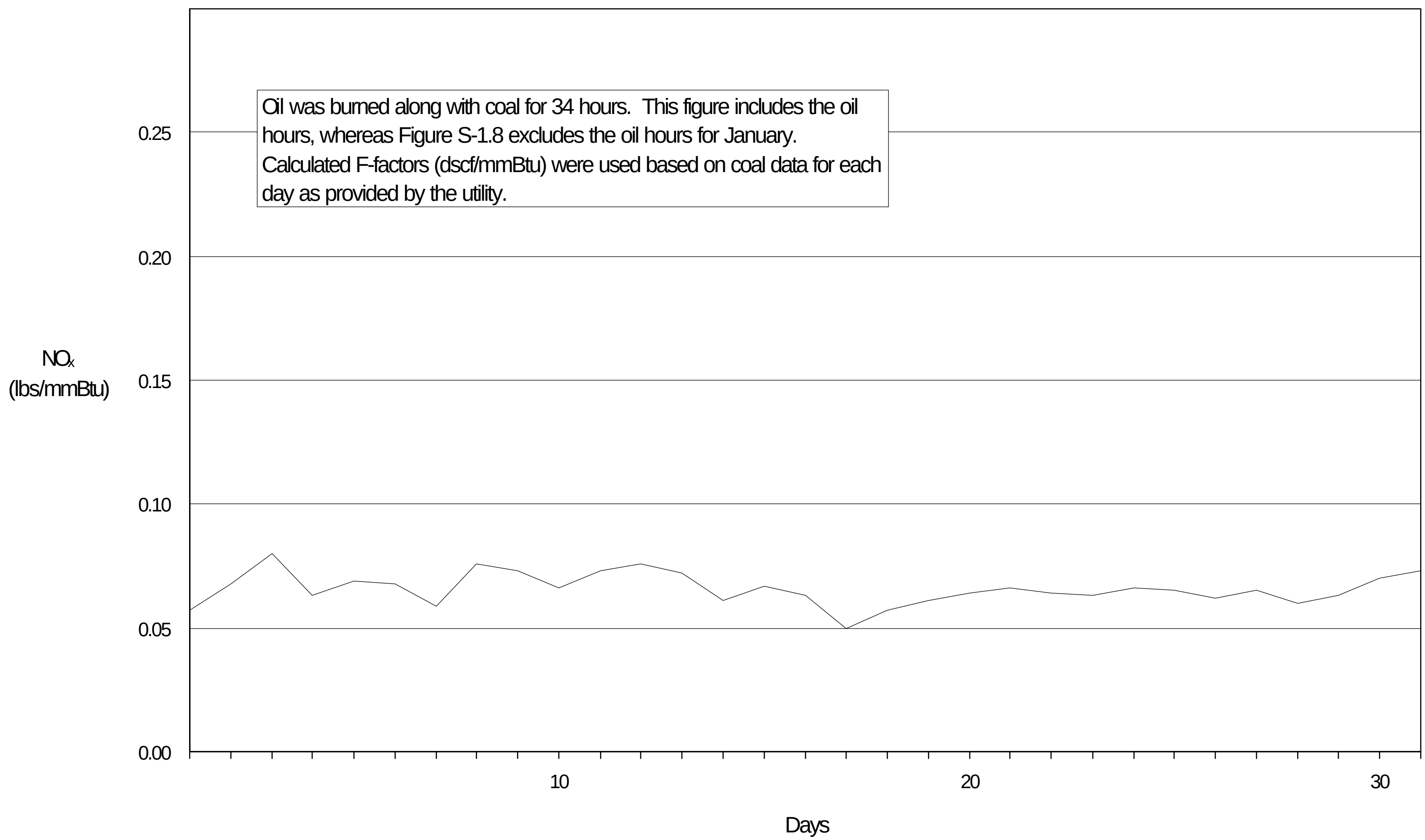
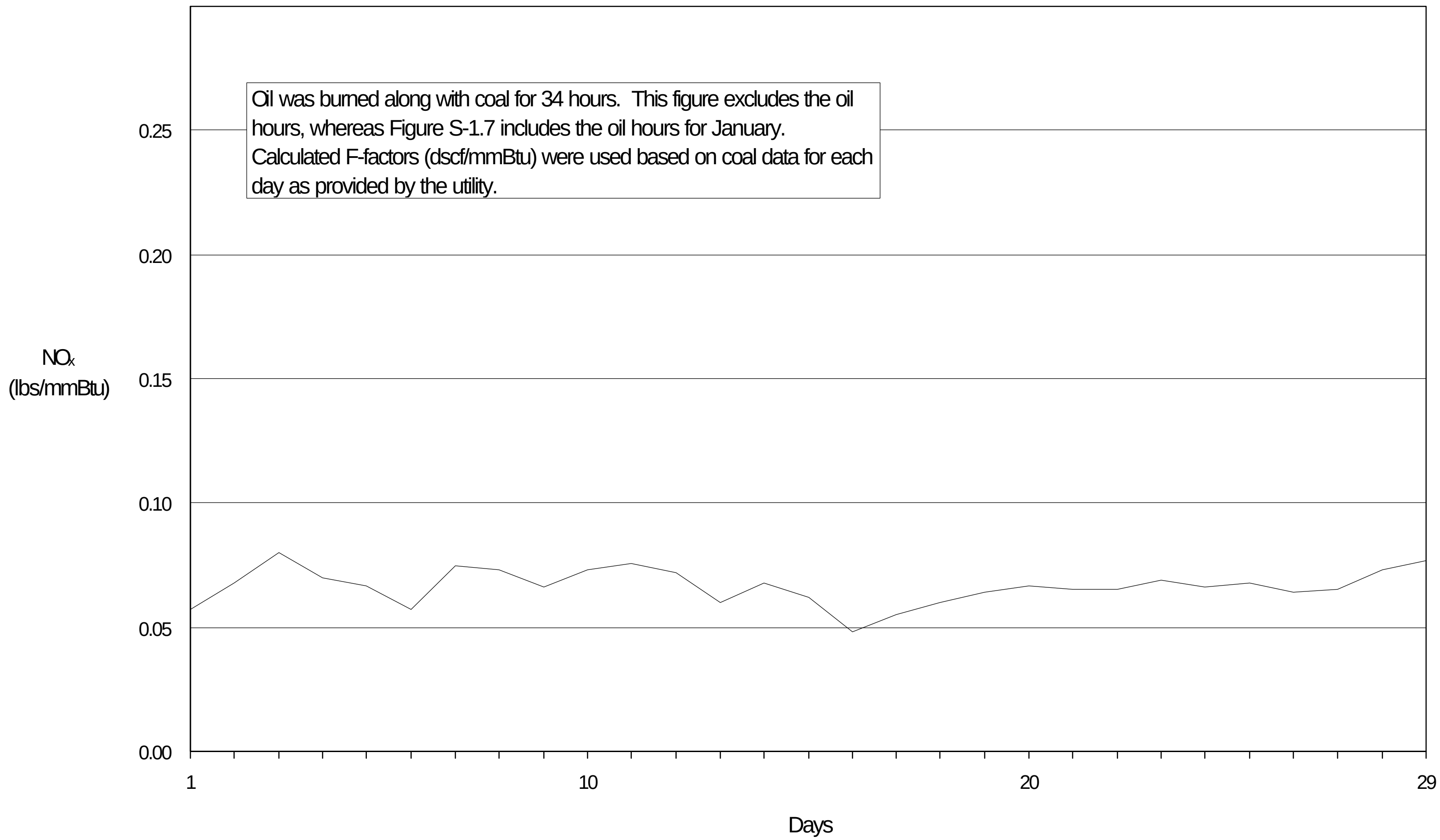


Figure S-1.8

Plant S-1: NO_x Emissions Excluding Oil Hours (24 Hour Averages)

January 1-31, 1996



Operation, Maintenance and Cost Related Information:

Plant S-1 reported that it uses anhydrous ammonia; the ammonia slip is less than 5 ppm. The plate catalyst for unit A has a volume of 325 cubic meters, with two layers and one reserve layer. The catalyst for units B and C is also plate with three layers and one reserve layer and a total volume of 90 cubic meters.

After reviewing the October 23, 1996, draft report, some commenters raised questions about whether the combustion of oil at Plant S-1, Unit A, would impact the effectiveness of the SCR system. In response to EPA's request for additional information on this issue, the plant stated in a telephone interview that Unit A burns coal the majority of the time and combusts oil only during startup or when the plant is having trouble with its coal mills. The plant noted that oil was burned approximately 4% of the operating time in October 1995 and approximately 1% of the operating time during January 1996. The plant stated that oil use never exceeds "a couple of percents" of operating time in a month, and that there are months when oil is not used at all. The plant also stated that burning oil has a negative effect on the catalyst, because ash builds on the catalyst and the plant has to steam clean the catalyst. However, when coal is burned, the ash causes friction with the catalyst and cleans the catalyst material itself. The plant also reported that analysis of a test piece of catalyst from Unit A showed catalyst activity decreasing at the expected rate and showed no impact from oil burning.

The plant also reported that it uses a regenerative air preheater. Flyash is not reinjected in to the boilers. Approximately 20% of the flyash at the plant is sold for use in the construction industry.

In response to a request for information on why the hourly emissions data showed lower NO_x emissions in October than in January, the plant explained that it was because of the weather. Because October is not so cold, Unit A was fired at 70% of capacity, while in January, the boiler was operating at its maximum the entire month. The plant stated that when the boiler is operating at maximum capacity, the SCR system may operate less efficiently. The plant explained that the SCR system regulates the amount of NH_3 injected into the flue gas stream based on the boiler load. When the boiler is operating at maximum capacity, the amount of NO_x in the flue gas may exceed the amount for which the maximum amount of NH_3 injected into the flue gas would be effective.

The plant has not yet provided information in response to the request for operation and maintenance cost data.

Plant G-7

Plant/Unit Information:

The German Plant G-7 provided an annual summary for 1995 for one unit retrofitted with SCR. The boiler commenced operation in 1985 and the SCR system began operating in 1989. The unit is a Benson-type supercritical boiler with dry bottom ash removal. The unit is equipped with low NO_x burners in addition to SCR in a high dust configuration. All data were corrected to ISO standards of 0 ^oC (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6 % oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. Plant G-7 is also subject to an emission exemption for start-up and load less than 40% providing for allowable NO_x emissions of 800 mg/m^3. A summary of the data submitted is provided in Table G-7.1.

Table G-7.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	No
Hourly data	No
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	No
Flyash Disposal	Yes

(cont.)

Table G-7.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	No
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	No
Catalyst Volume	Yes
Catalyst Replacement Cycle	No
Other Operational Experience	No
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant G-7 provided coal data that was sufficient to calculate F-factors for the coal. A range of values was given that had been corrected for moisture and ash content. The average value for each component was corrected back to "as received" values for use in the F-factor calculation. The coal data are shown in Table G-7.2.

Table G-7.2

Coal Characteristics Data for Plant G-7

Coal Analysis		
	Range	Median
Moisture (%)	6 - 11	8.5
Ash (%)	6 - 15	10.5
Nitrogen (%N)	0.9 - 1.7 dry	1.1 wet
Oxygen (%O)	3.9 - 7.5 dry	4.8 wet

(cont.)

Table G-7.2 (cont.)

Coal Characteristics Data for Plant G-7

Coal Analysis		
	Range	Median
Carbon (%C)	83.5 - 89 dry	72.5 wet
Hydrogen (%H)	4.9 - 5.3 dry	4.3 wet
Sulfur (%S)	-	-
GCV (kJ/kg)	24,700 - 29,500	27,100 wet
F-Factor (dscf/mmBtu)		10,686

Emissions Data Analysis:

Plant G-7 provided the mean for 1995 as 0.17 lbs/mmBtu.

Operation, Maintenance and Cost Related Information:

Plant G-7 uses a regenerative air preheater. The plant stated that the air preheater was washed for the first time in 1991. The plant reported that when deposits on the air preheater were analyzed, they found ammonium compounds resulting from SCR system operation. For three years, the plant washed the air preheaters each year. The plant reported that no air preheater washings have been needed since it installed enameled sheet metal in 1994. The plant noted that the remaining contaminations can be removed during operation by using steam blowers. The plant did not report any costs associated with washing the air preheaters or with installing the enameled sheet metal.

Flyash from the plant is sold for use as an additive to concrete. Plant G-7 uses anhydrous ammonia, and stated that there have been no problems associated with that type of ammonia. The plant did not specify the catalyst type, but did state that it has a volume of 521 cubic meters. The plant did not report any problems associated with the catalyst. The plant has not yet provided any further information on operational impacts associated with SCR. No cost information was reported.

Table G-7.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Ammonium deposits on air preheater. Washed air preheater annually for three years, then installed enameled sheet metal, which made preheater washing unnecessary. Costs not specified.
Costs	Not Provided

Plant G-8

Plant/Unit Information:

The German Plant G-8 provided a bar graph of daily mean half-hour averages of pre- and post-SCR NO_x levels for the period January 2 through March 1, 1996 for one wall-fired unit with SCR. This 450 MWe unit is equipped with low NO_x burners with overfire air in addition to a high dust SCR. To arrive at 24-hour emission rates for the plant, the values were converted from mg/m^3 to lbs/mmBtu. The measurements were converted from German and ISO standards of 0 °C (273 K), and 6% oxygen to 20 °C (293 K) and 0% oxygen dilution. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted is provided in Table G-8.1.

Table G-8.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	No
Hourly data	No
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	No
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	No
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes

(cont.)

Table G-8.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant G-8 indicated that "Ruhr (Blumenthal)", "Ruhr (Westfallen)", and "Saar" coal were used; however, the coal data provided were not sufficient to calculate F-factors for the coal. However, the plant also indicated that "German bituminous coal" having low ash content and about 1% sulfur was used in firing. Therefore, the standard F-factor for bituminous coal (9780 dscf/mmBtu) was used.

Emissions Data Analysis:

The average of NO_x emissions over the January 2 - March 1, 1996, time period was 0.14 lbs/mmBtu. This was calculated using the 24-hour emission averages for the period from January 2 - March 1, 1996, which are displayed in the graph provided by Plant G-8, shown here as Figure G-8.1. Figure G-8.1 shows emissions expressed in terms of 24-hour averages for the period January 2 - March 1, 1996. Figure G-8.2 indicates the 30-day rolling averages for the same time period.

Figure G-8.1

Plant G-8: NO_x Emissions

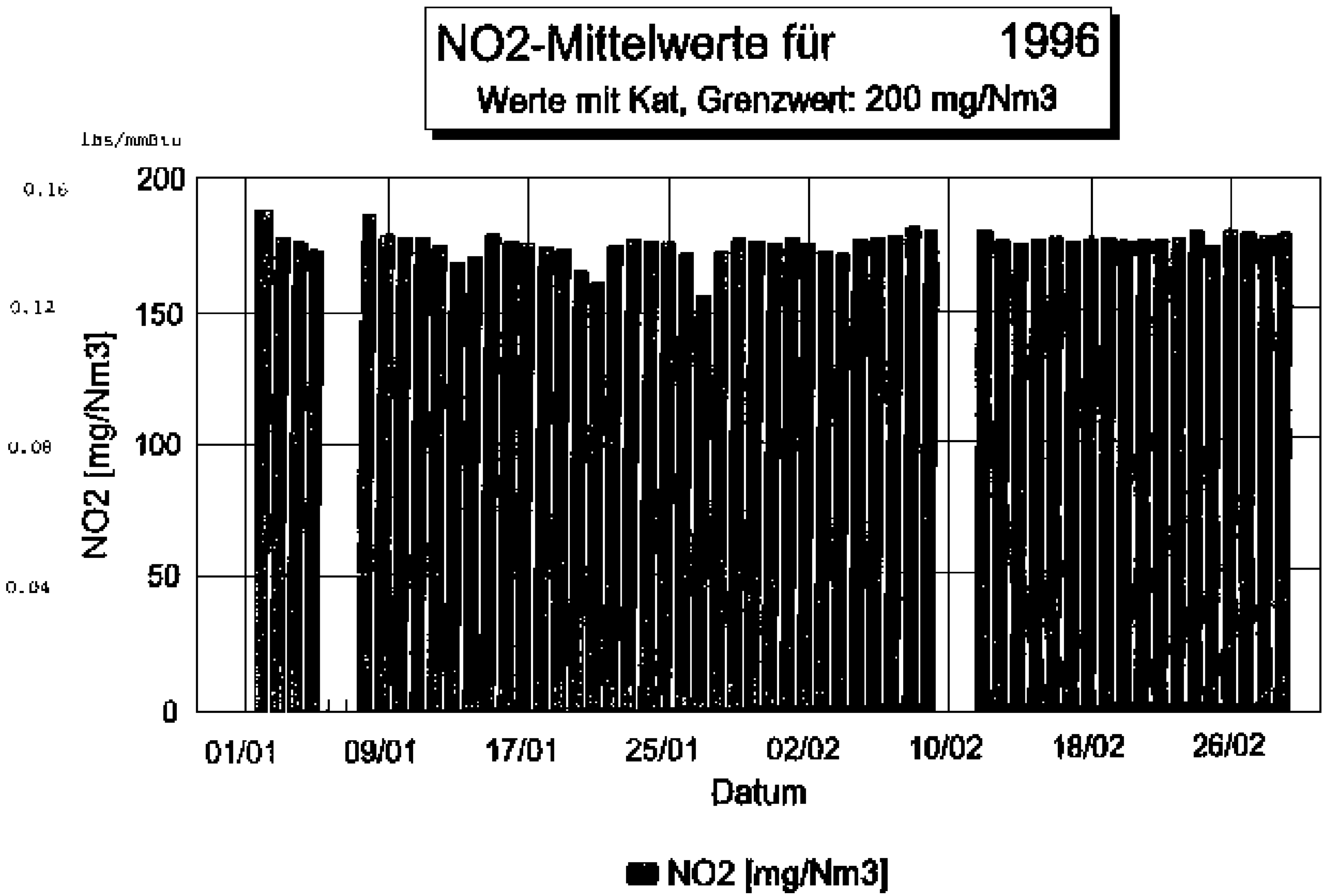


Figure G-8.2

Plant G-8: NO_x Emissions (24 Hour Averages)

January 2 - March 1, 1996

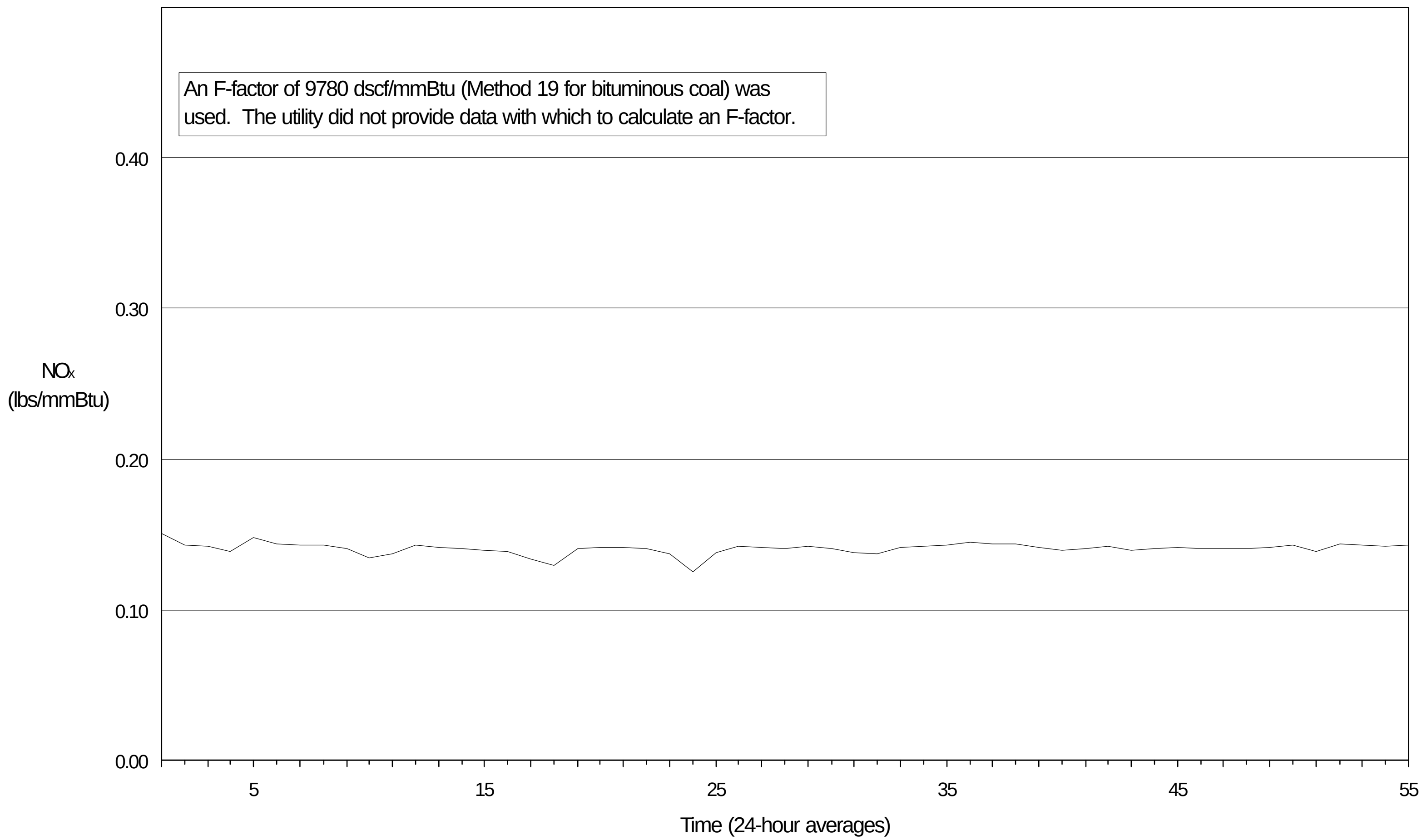
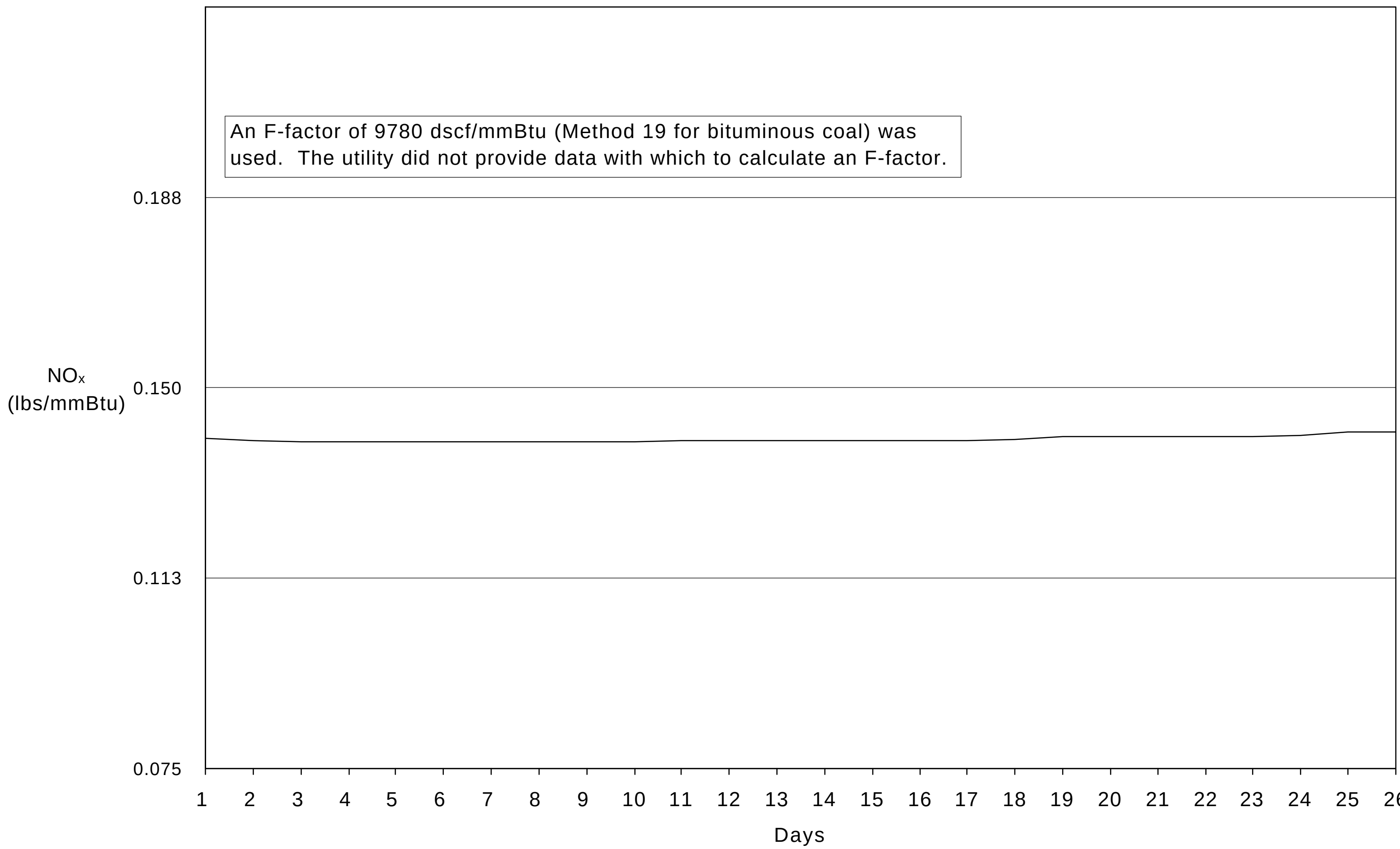


Figure G-8.3

Plant G-8: NO_x Emissions (30 Day Rolling Averages)

January 2 - March 1, 1996



Operation, Maintenance and Cost Related Information:

Plant G-8 uses a regenerative air preheater. The plant reported that the preheater is cleaned each time the plant is shut down. Plant G-8 uses anhydrous ammonia; the ammonia slip is less than 5 ppm. The plate-type catalyst has a volume of 325 cubic meters. The usual catalyst life was reported to have been "above expectations", but the plant is planning to replace the catalyst with a design featuring a lower SO_2 to SO_3 conversion rate. Flyash from the plant is used in the construction industry and is not recirculated. In response to the request for operational experience, the plant reported that problems with corrosion of equipment and emission of acidic particles were counteracted by modifications to the system and to the facility. The plant was unable to provide cost information.

Plant G-9

Plant/Unit Information:

The German Plant G-9 reported an overall annual average emission rate and provided an annual summary of half-hour averages in 20 mg/m^3 increments for two units retrofitted with SCR for 1995. Unit A was retrofitted for high dust SCR in 1986, and unit B was retrofitted for high dust SCR in 1990. Plant G-9 also provided continuous half-hourly NO_x data for the period August 5 - October 11, 1996 for unit A. Unit A is a wet bottom boiler with 345 MWe capacity. Unit B is a tangentially fired, dry bottom boiler with 740 MWe capacity. All data are corrected to ISO standards of 0ºC (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6% oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted is provided in Table G-9.1.

Table G-9.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes (Unit A)
Hourly data	Half-hourly
O_2 diluent	Yes
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes (Unit A)
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	No
Retrofit/New	Yes
Flyash Recirculation	No
Flyash Disposal	No

(cont.)

Table G-9.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Air Preheater System	
Type	No
Operational Experience	No
Ammonia Information	
Type	No
Slip Experience	No
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes (Unit A)
Catalyst Volume	No
Catalyst Replacement Cycle	No
Other Operational Experience	No
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

The coal data provided was sufficient to calculate F-factors for the coal. These data are provided in Table G-9.2.

Table G-9.2

Coal Characteristics Data for Plant G-9

Coal Analysis		
	Unit A	Unit B
Moisture (%)	9.7	9.6
Ash (%)	25.1	7.7
Nitrogen (%N)	1.51	1.84
Oxygen (%O)	2.82	5.06

(cont.)

Table G-9.2 (cont.)

Coal Characteristics Data for Plant G-9

Coal Analysis		
	Unit A	**Unit B**
Carbon (%C)	56.5	70.1
Hydrogen (%H)	3.22	4.49
Sulfur (%S)	0.97	1.01
GCV (kJ/kg)	21,845	27,732
F-Factor (dscf/mmBtu)	10,395	10,241

Emissions Data Analysis:

The annual NO_x emission averages reported by Plant G-9, after conversion to United States equivalents, were 0.13 lbs/mmBtu and 0.16 lbs/mmBtu for units A and B, respectively. A calculation produced slightly different results. Using plant-provided data, annual NO_x emission averages of 0.11 lbs/mmBtu for Unit A and 0.15 lbs/mmBtu for Unit B were calculated. These noted discrepancies are unexplained in the plant's report. The annual averages reported by the plant were used for purposes of this report. Unit A had an average NO_x emission rate of 0.17 lbs/mmBtu during the period August 5 - October 11, 1996. All NO_x readings of zero were discarded from the graph of continuous emissions as well as from the calculations of overall mean, and 24-hour and 30-day rolling averages. Figure G-9.1 shows the continuous half-hourly emissions for Unit A using the calculated F-factor. Figure G-9.2 shows the emissions data for the same time period expressed in 24-hour averages. Figure G-9.3 indicates the 30-day rolling averages for Unit A.

Figure G-9.1

Plant G-9: NO_x Emissions (Unit A: 1/2-Hour Averages)

August 5 - October 11, 1996

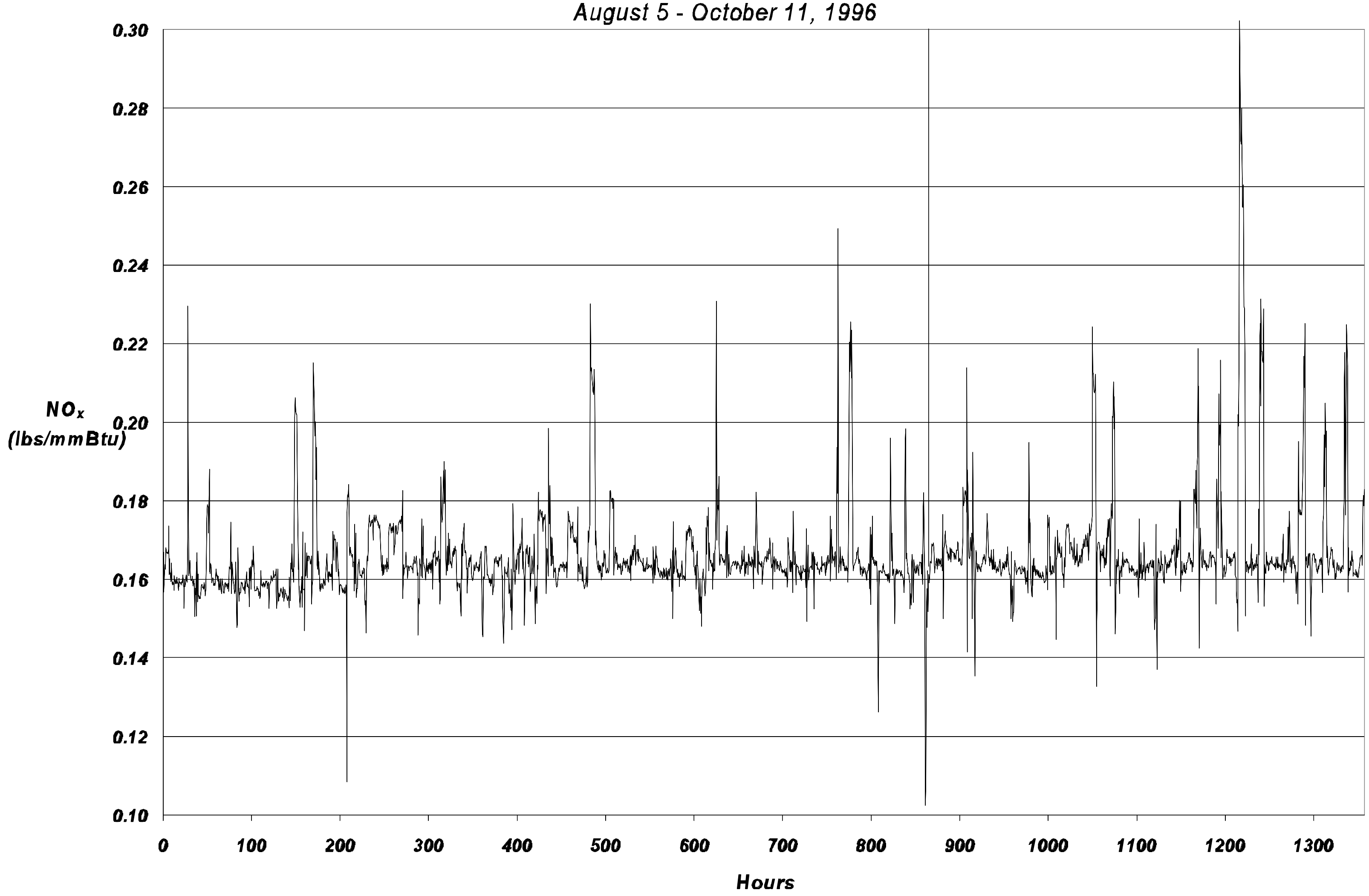


Figure G-9.2

Plant G-9: NO_x Emissions (Unit A: 24-Hour Averages)

August 5 - October 11, 1996

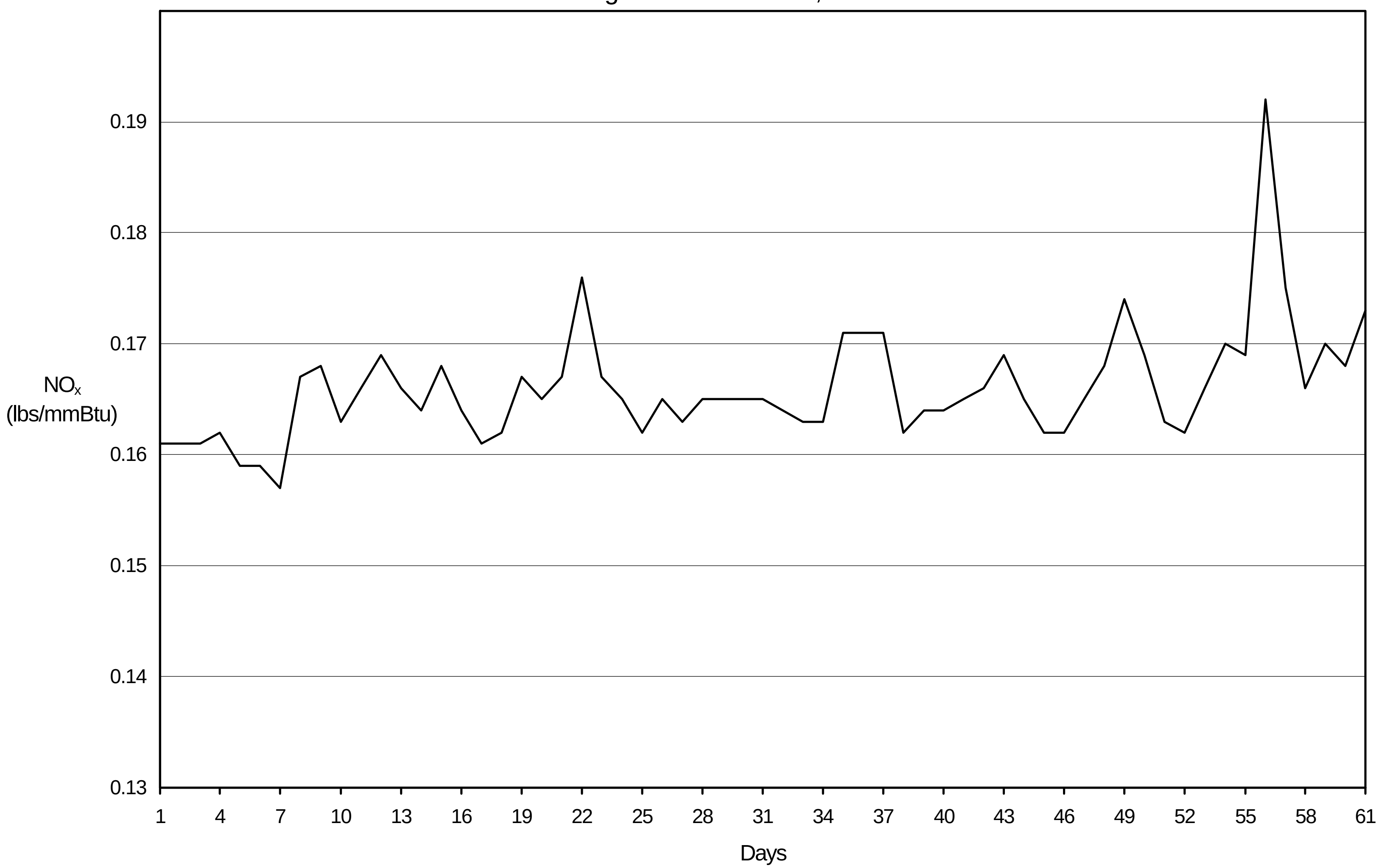
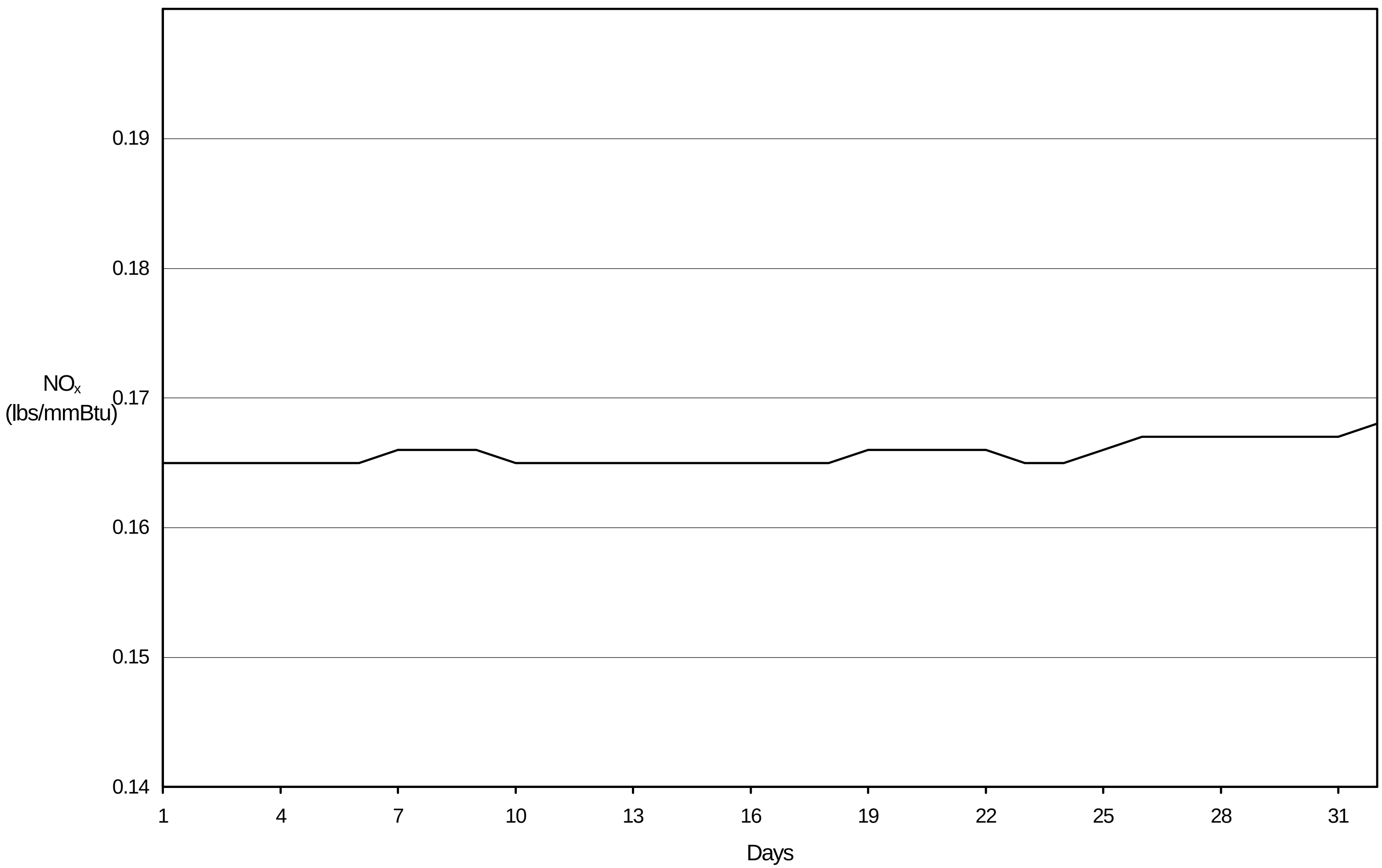


Figure G-9.3

Plant G-9: NO_x Emissions (Unit A: 30 Day Rolling Averages)

August 5 - October 11, 1996



Operation, Maintenance and Cost Related Information:

Plant G-9, unit A, contains three separate SCR systems for one boiler. Two of the catalyst components are plate-type, and one is honeycomb. Plant G-9 did not provide any further information in response to the request for information on operation and maintenance and cost.

Plant G-10

Plant/Unit Information:

The German Plant G-10 reported an overall annual average emission rate and provided an annual summary of half-hour averages in 20 mg/m^3 increments for two 220 MWe retrofit units for 1995. The annual summary also identified the number of exempt half-hour averages (without indicating their emission ranges) in 20 mg/m^3 increments. Exempt periods appear to have been excluded from the statistical summary of half-hour averages. This may be inferred by comparing the reported operating time for each unit with the total reported half-hour averages. By adding the number of half-hours in the statistical summary to the number of half hours reported as exempt, there is a near (but not exact) match to the reported operating time.

Both units (A and B) are cyclone, wet bottom, 220 MWe boilers. The units were retrofit with SCR in the high dust configuration in 1989. All data were corrected to ISO standards of 0 ^oC (273 K), 1013 mbar (1 atm), and no moisture. The readings are corrected by the plant to a 6% oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data submitted is provided in Table G-10.1.

Table G-10.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	No
Hourly data	No
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes

(cont.)

Table G-10.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	No
Slip Experience	No
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	No
Catalyst Volume	No
Catalyst Replacement Cycle	No
Other Operational Experience	No
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

The coal data provided was sufficient to calculate F-factors for the coal. The coal was described as Ruhr and Saar coal. These data are provided in Table G-10.2.

Table G-10.2

Coal Characteristics Data for Plant G-10

Coal Analysis		
	Range	**Median**
Moisture (%)	7 - 14	10.5
Ash (%)	5 - 10	7.5
Nitrogen (%N)	1.0 - 1.7	1.35
Oxygen (%O)	3 - 9	6
Carbon (%C)	65 - 75	70
Hydrogen (%H)	4 - 6	5
Sulfur (%S)	0.4 - 1.6	1.0
GCV (kJ/kg)	24,300 - 31,500	27,900
F-Factor (dscf/mmBtu)		10,279

Emissions Data Analysis:

The annual NO_x emission averages reported by Plant G-10, after conversion to United States equivalents, were 0.15 lbs/mmBtu and 0.16 lbs/mmBtu for Units A and B, respectively. A calculation produced slightly different results. Using the plant-provided statistical summary of half-hour averages in 20 mg/m^3 increments, annual NO_x emission averages of 0.16 lbs/mmBtu for Unit A and 0.17 lbs/mmBtu for Unit B were calculated. These discrepancies appear to be related to the conservative calculation procedure that was used. When calculating the annual average, the upper end of each 20 mg/m^3 increment was used. The annual averages reported by the plant were used in this report.

Operation, Maintenance and Cost Related Information:

Plant G-10 uses a regenerative air preheater. The plant reported that no modifications were required for SCR, and that it has never been the practice to wash the air preheaters. Anhydrous ammonia is used as the reagent and the ammonia slip is less than 5 ppm. The catalyst is a plate-type, and has five double layers. The catalyst volume was initially 381 m^3, and 163 m^3 was added at a later time. The catalyst has not been replaced, and was designed with spare layers for additional catalyst. The plant recirculates the flyash, and only slag is sold. Plant G-10 reported that there have been no problems after 30,000 operating hours. They were unable to provide cost information.

Plant US-1

Plant/Unit Information:

The U.S. Plant US-1 provided continuous hourly NO_x data for two 140 MW coal-fired boilers (unit A and unit B). At both units, the SCR was installed on new boilers. The boilers and SCR systems began operation in 1993. Unit A supplied data for May and June, 1996, and unit B supplied data for May 1 - July 30, 1996. Both units are described as front wall fired pulverized coal boilers with SCR used in conjunction with low-NO_x burners and overfire air. Both units have dry bottom ash removal. Data conversion was not required, since emissions were provided in lbs/mmBtu. All NO_x measurements are corrected to dry, standard conditions (20 ^oC, 1 atm, 0 % O_2). Both units are required to meet an operating permit limit of 0.17 lbs/mmBtu (three hour rolling average). In response to EPA's follow-up request for information on periods of exempt emissions, Unit B indicated that there were no reportable exempt NO_x emissions for the period of July 1 - 31. A summary of the data submitted by Plant US-1 is shown in Table US-1.1.

Table US-1.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Yes
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	No
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	No

(cont.)

Table US-1.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant US-1 indicated that bituminous coal was used and that the emissions data provided had been corrected using the Method 19 F-factor of 9,780 dscf/mmBtu. In addition, Plant US-1 provided sufficient coal characteristics data to calculate F-factors for May 1 - July 30, 1996. The coal data are presented in Table US-1.2. Information presented in later figures portrays emissions using the calculated F-factor.

Table US-1.2

Coal Characteristics Data for Plant US-1

Coal Analysis			
		Unit A	**Unit B**
Moisture (%)		N/A	N/A
Ash (%)		N/A	N/A
Nitrogen (%N)		1.24	1.24
Oxygen (%O)		2.66	2.66
Carbon (%C)		75.81	75.81
Hydrogen (%H)		4.42	4.42
Sulfur (%S)		1.5	1.5
GCV (Btu/lb):	May	12,953	13,001
	June	12,871	12,940
	July		13,007
F-Factor:	May	10,193	10,155
(dscf/mmBtu)	June	10,258	10,203
	July		10,151

Emissions Data Analysis:

Unit A had average NO_x emission rate of 0.138 lbs/mmBtu for May through June, 1996. Unit B had average NO_x emission rate of 0.133 lbs/mmBtu for the period from May 1 - July 30, 1996. Figure US-1.1 shows the continuous hourly NO_x emissions data for May and June, 1996, using the calculated F-factor, for Unit A. Figure US-1.2 provides the NO_x emissions for May 1 - July 30, 1996 for Unit B. Figures US-1.3 and US-1.4 indicate emissions data expressed in 24-hour averages, while Figures US-1.5 and US-1.6 express these results using 30-day rolling averages. All NO_x readings of zero were discarded from the mean calculations and the 24-hour and 30-day rolling average calculations.

Figure US-1.1

Plant US-1: NO_x Emissions (Unit A: Hourly Averages)

May 1 - June 30, 1996

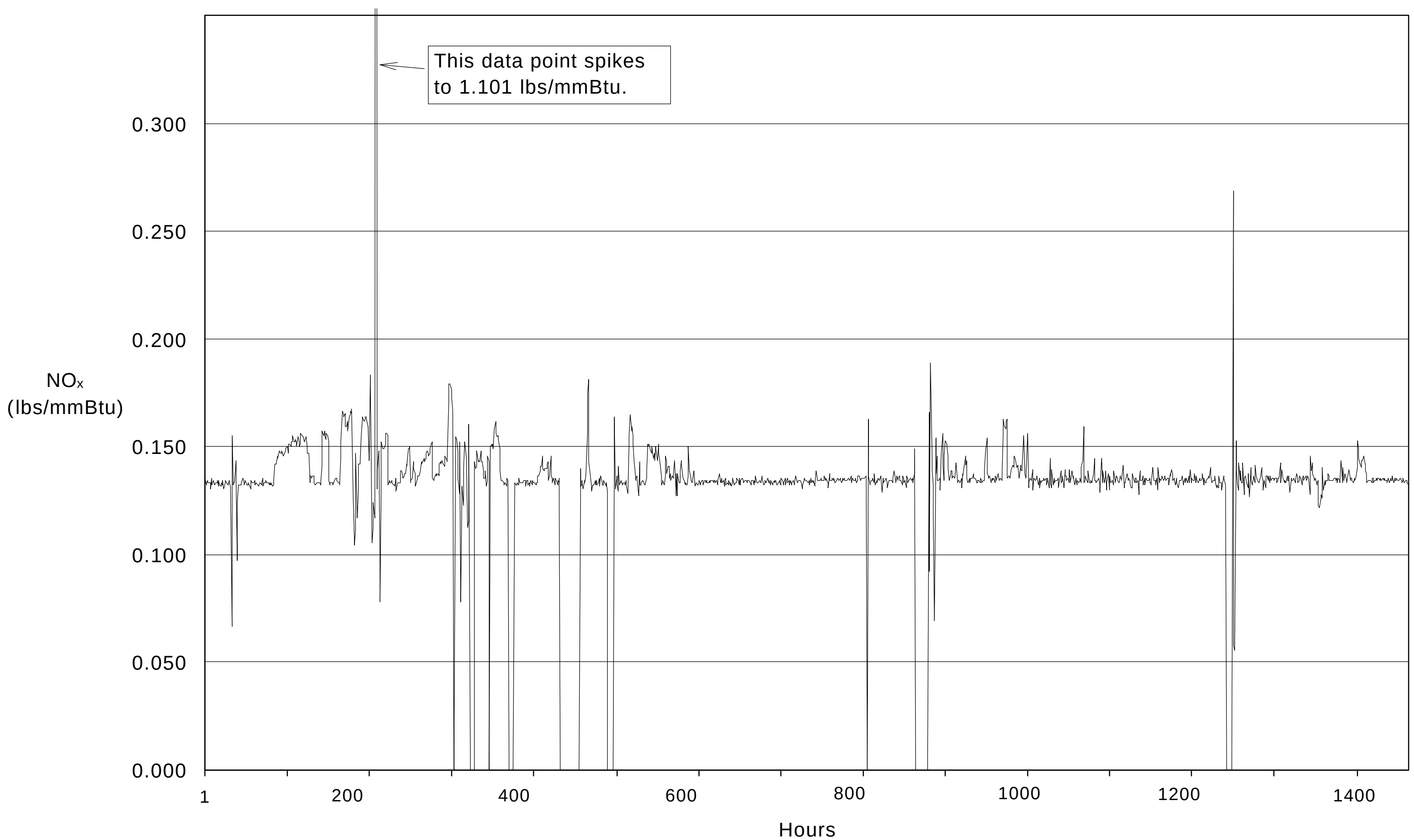


Figure US-1.2

Plant US-1: NO_x Emissions (Unit B: Hourly Averages)

May 1 - July 30, 1996

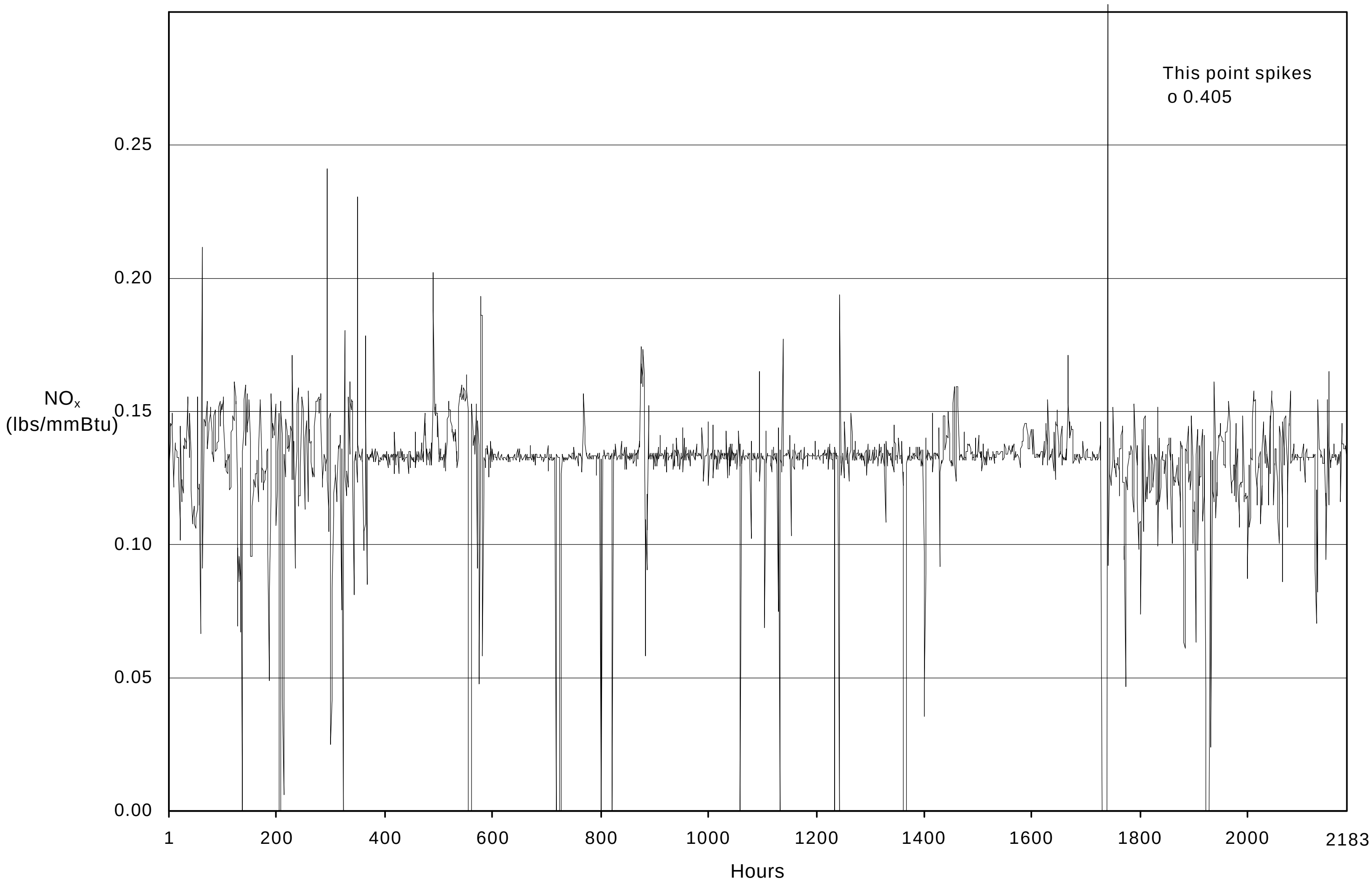


Figure US-1.3

Plant US-1: NO_x Emissions (Unit A: 24 Hour Averages)

May 1 - June 30, 1996

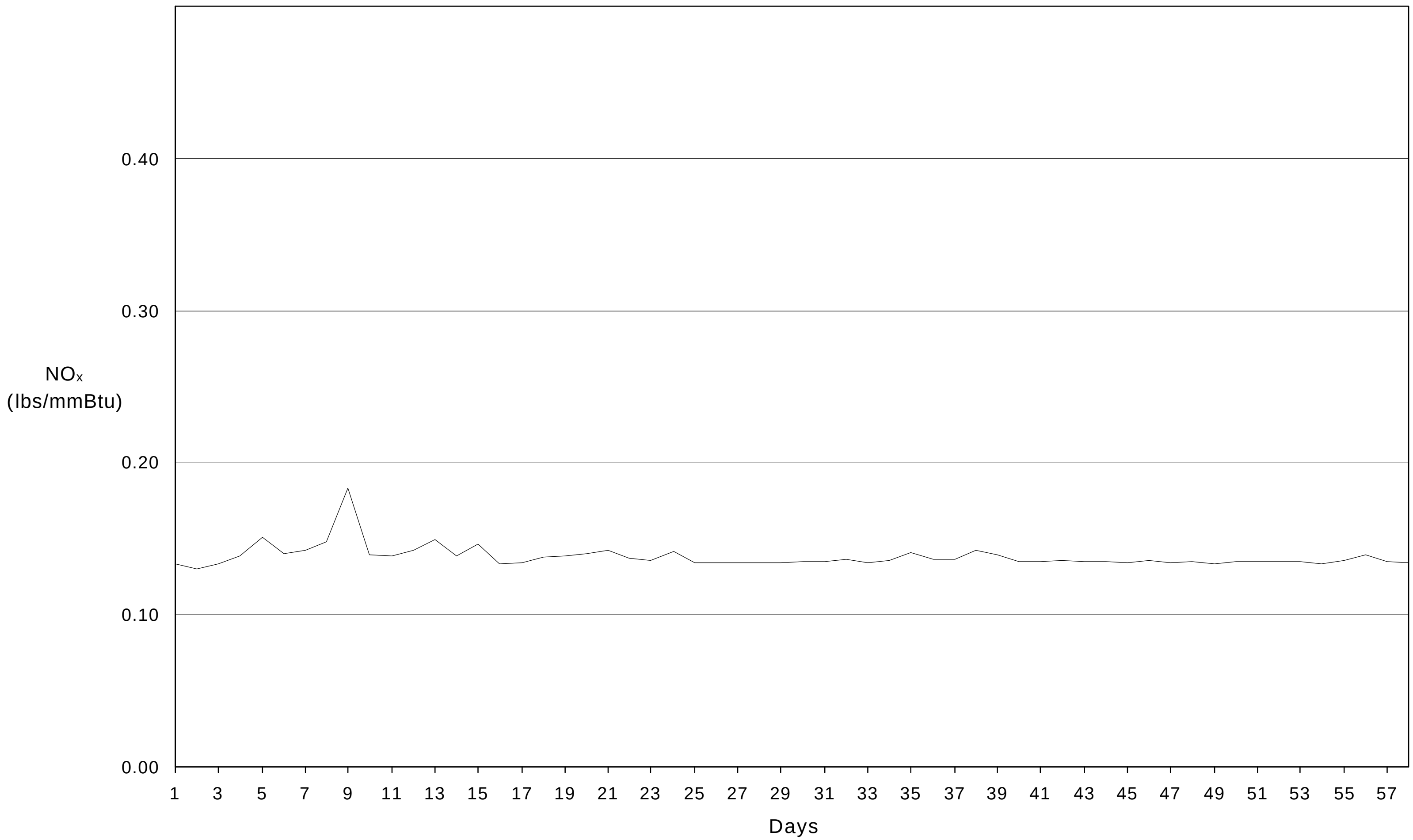


Figure US-1.4

Plant US-1: NO_x Emissions (Unit B: 24 Hour Averages)

May 1 - July 30, 1996

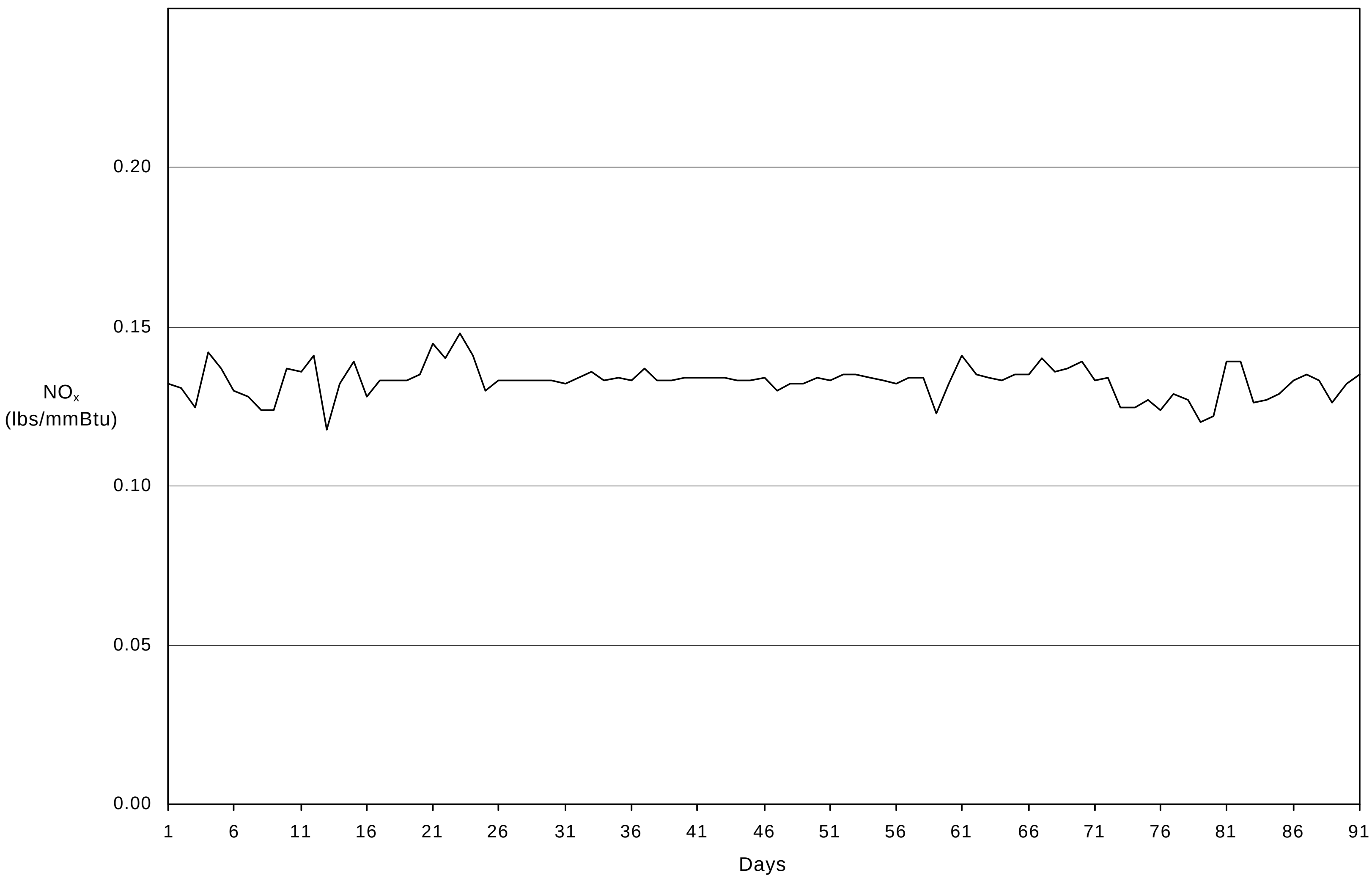


Figure US-1.5

Plant US-1: NO_x Emissions (Unit A: 30 Day Rolling Averages)

May 1 - June 30, 1996

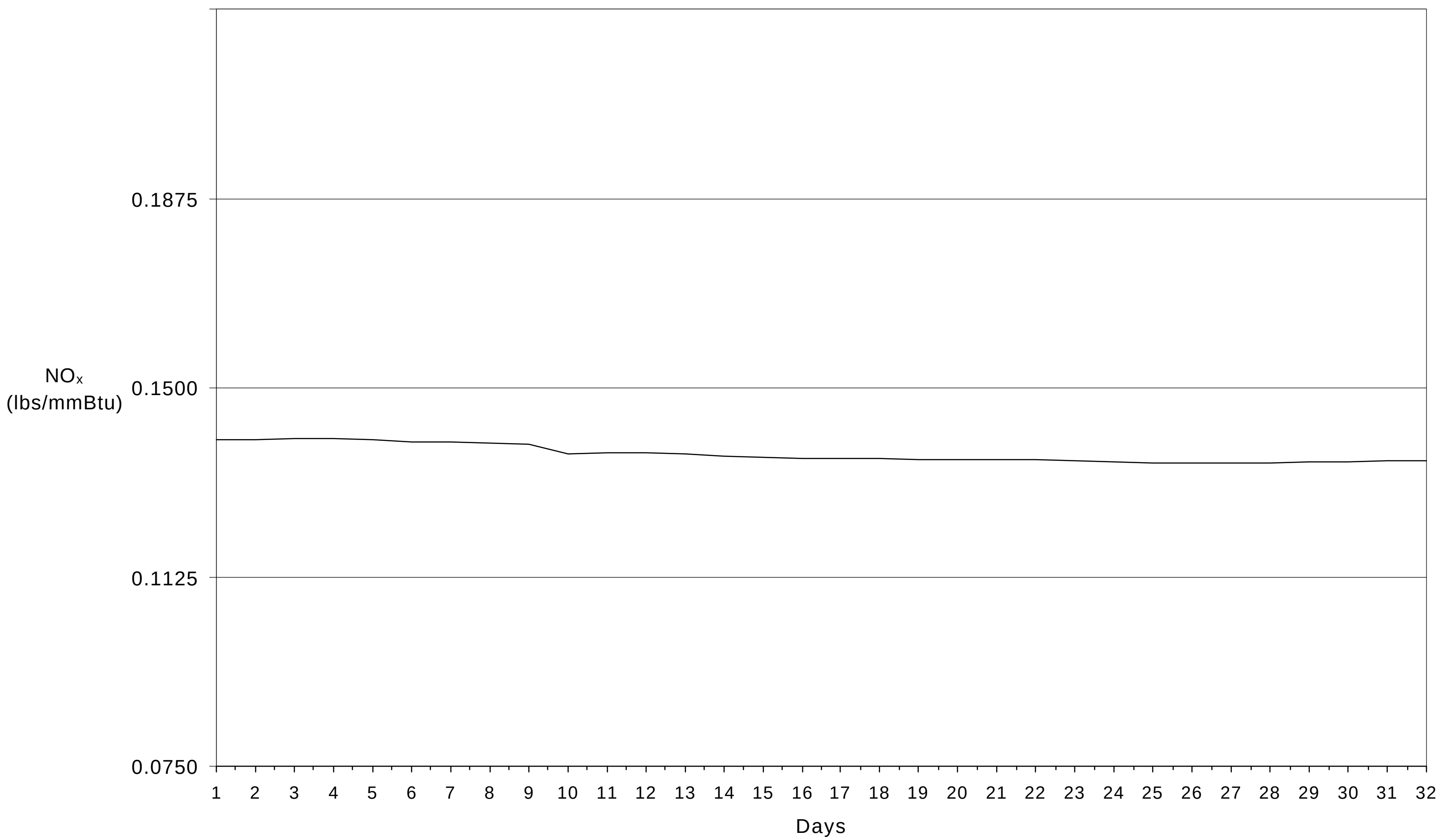
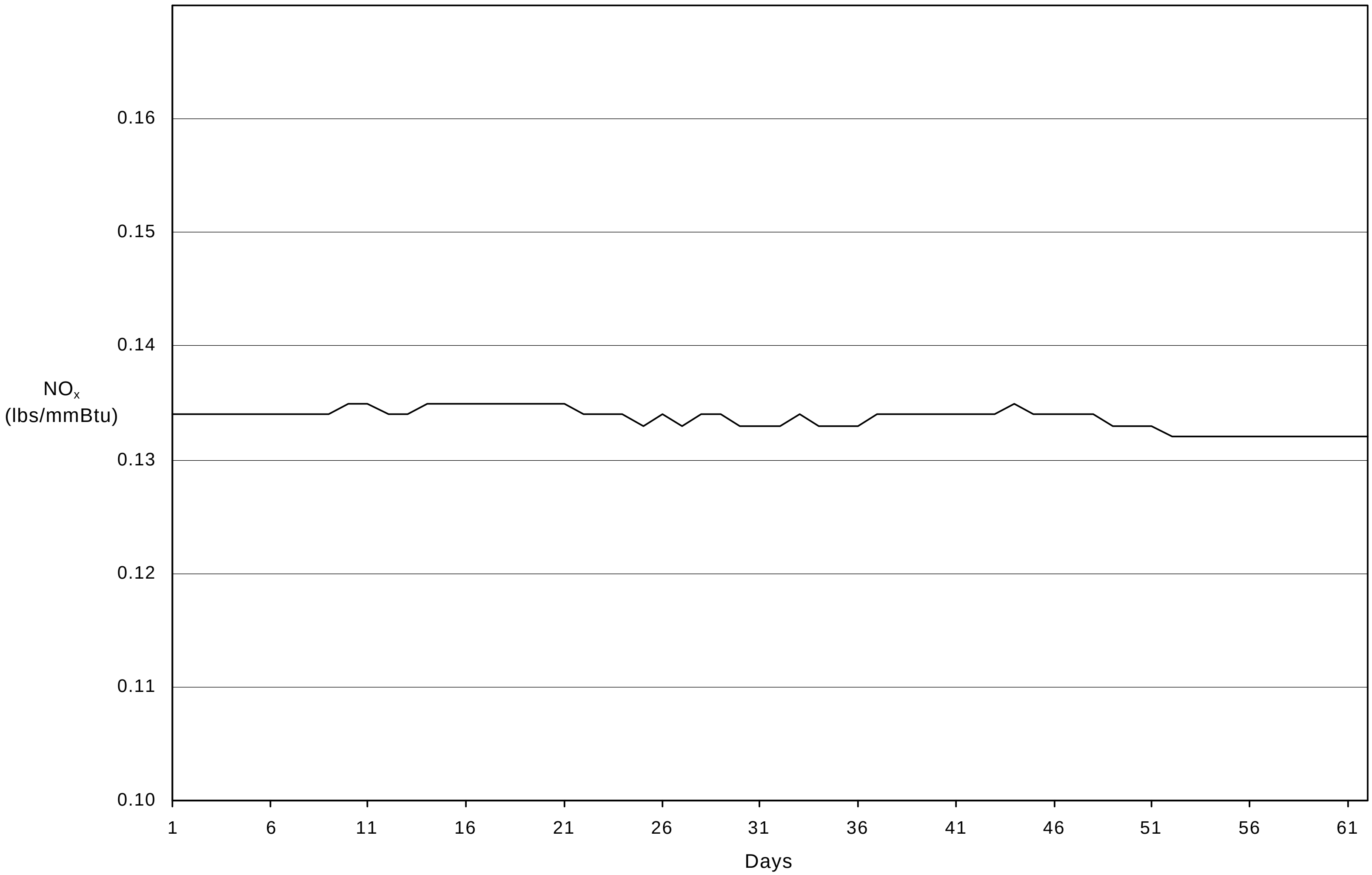


Figure US-1.6

Plant US-1: NO_x Emissions (Unit B: 30 Day Rolling Averages)



Operation, Maintenance and Cost Related Information:

Plant US-1 uses aqueous ammonia at both units, with a guaranteed ammonia slip of less than 5 ppm. The ammonia injection system was described as "capacity limited" and "underdesigned," but did not cause major problems with the operation of the SCR system. Both units have honeycomb-style catalysts, with a volume of 120 m^3 each. There are three catalyst layers with only two layers filled at this time. An additional layer of catalyst is planned to be installed after seven years of operation. The catalyst life expectancy is 56,000 operating hours; this governs the replacement schedule. The NO_x design removal efficiency is 63% for both units. Plant US-1 uses a regenerative air preheater at both units. The scheduled frequency of air preheater washing is once per year; the plant reported that there were no fouling problems at either unit. The plant reported no problems associated with the type of coal fired, and noted that coal with less than 2.0% sulfur was used. The flyash from Plant US-1 is not sold; it goes to "100% beneficial use." Flyash is used in reclamation, while bottom ash is used as structural fill. Flyash is not recirculated back to the boilers, although 10% is recycled for SO_2 removal. Plant US-1 was unable to provide cost information.

Plant US-2

Plant/Unit Information:

The U.S. Plant US-2 provided continuous hourly NO_x data for one 200 MW coal-fired boiler for May 1 - July 31, 1996. The high dust SCR system was included in the construction of a new boiler; both the boiler and the SCR commenced operation in 1994. The boiler is described as a front wall fired pulverized coal boiler with SCR used in conjunction with low NO_x burners and overfire air. Plant US-2 utilizes dry bottom ash removal in the boiler. Data conversion was not required, since emissions were provided in lbs/mmBtu. All NO_x measurements are corrected to dry, standard conditions (20 °C, 1 atm, 0 % O_2). The unit is required to meet an operating permit limit of 0.17 lbs/mmBtu (three-hour rolling average). In response to EPA's followup request for information on periods of exempt emissions, US-2 indicated that there were no reportable exempt NO_x emissions for the period of July 1 - 31. A summary of the data submitted by Plant US-2 is shown in Table US-2.1.

Table US-2.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Yes
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	No
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	No

(cont.)

Table US-2.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant US-2 indicated that bituminous coal was used and that the emissions data provided had been corrected using the Method 19 F-factor of 9,780 dscf/mmBtu. In addition, Plant US-2 provided sufficient coal characteristics data to calculate F-factors for May 1 - July 31, 1996. The coal data are presented in Table US-2.2. Information presented in later figures portrays emissions using the calculated F-factor.

Table US-2.2

Coal Characteristics Data for Plant US-2

Coal Analysis		
	May - June, 1996	**July, 1996**
Moisture (%)	N/A	N/A
Ash (%)	N/A	N/A
Nitrogen (%N)	1.33	1.44
Oxygen (%O)	4.23	0.33
Carbon (%C)	77.19	76.59
Hydrogen (%H)	4.48	4.71
Sulfur (%S)	1.5	1.25
GCV (Btu/lb): May June July	13,777 13,238	 13,066
F-Factor: May (dscf/mmBtu) June July	9,690 10,085	 10,339

Emissions Data Analysis:

The average of NO_x emissions for the period May 1 - July 31, 1996, using the calculated F-factor, was 0.16 lbs/mmBtu. Figure US-2.1 shows the continuous hourly NO_x emissions data, using the calculated F-factor. Figure US-2.2 shows emissions data expressed in 24-hour averages. Figure US-2.3 expresses these same results using 30-day rolling averages. All NO_x readings of zero were discarded from the mean calculations and the 24-hour and 30-day rolling average calculations.

Figure US-2.1

Plant US-2: NO_x Emissions (Hourly Averages)

May 1 - July 31, 1996

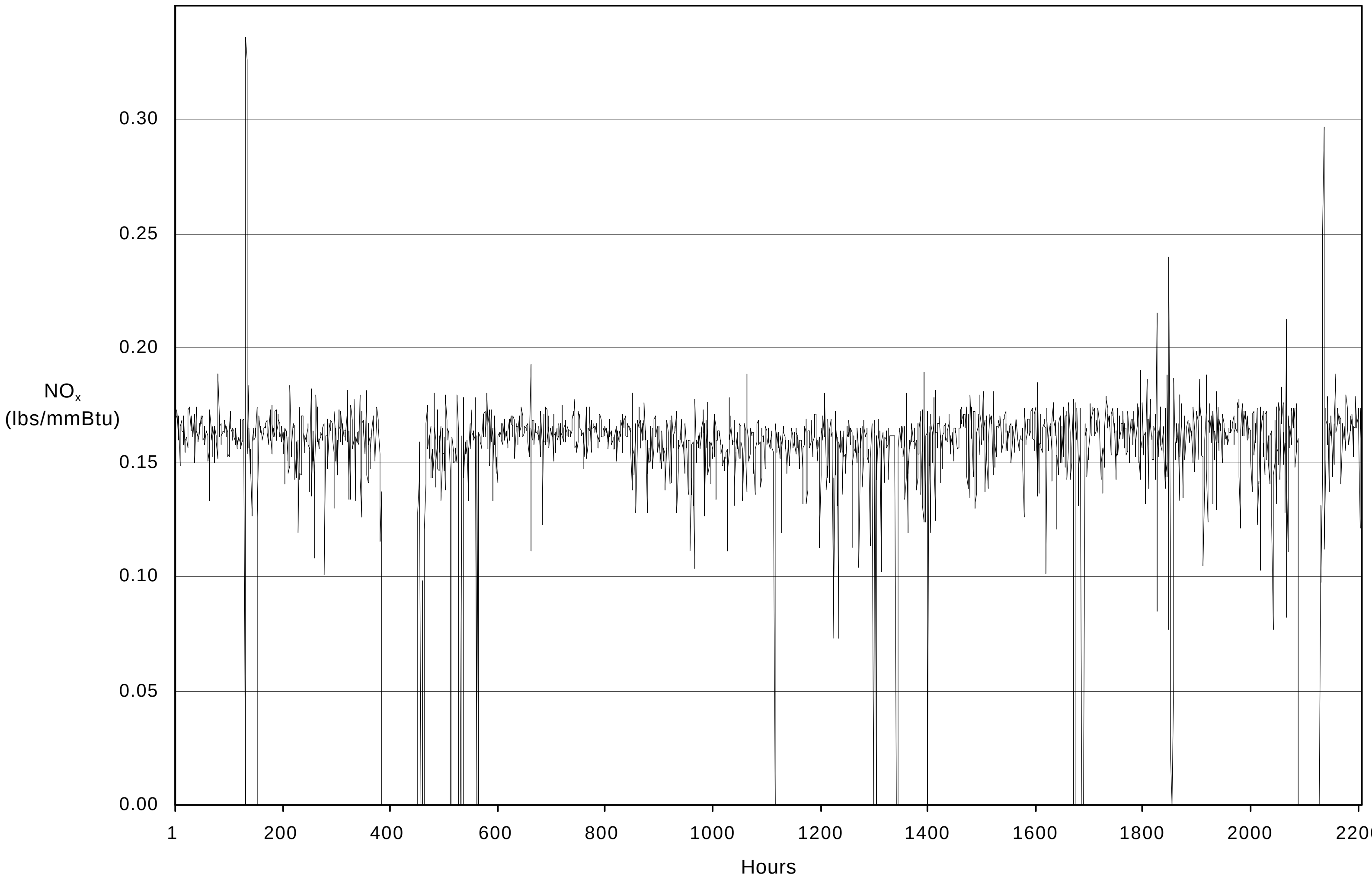


Figure US-2.2

Plant US-2: NO_x Emissions (24 Hour Averages)

May 1 - July 31, 1996

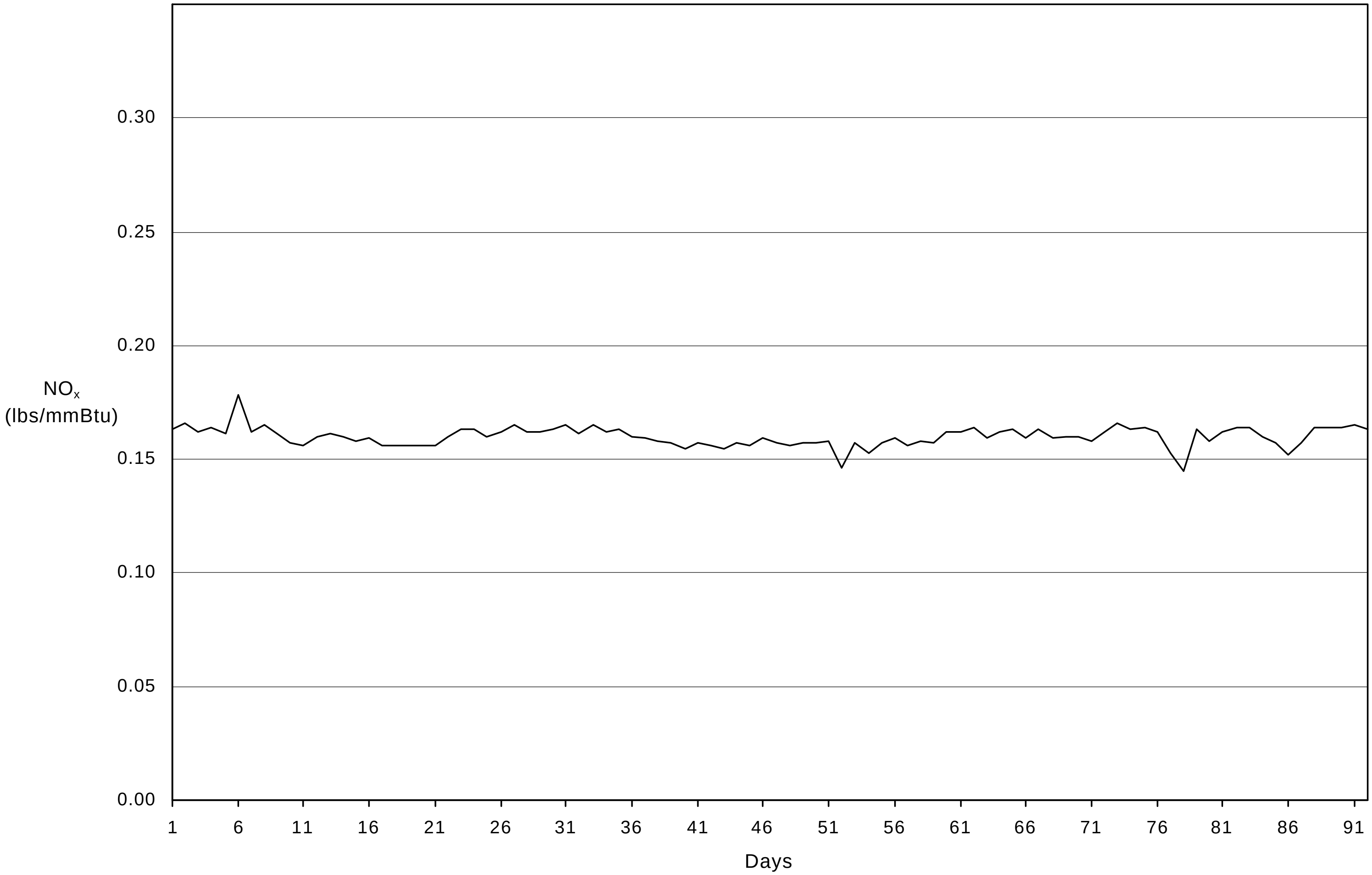
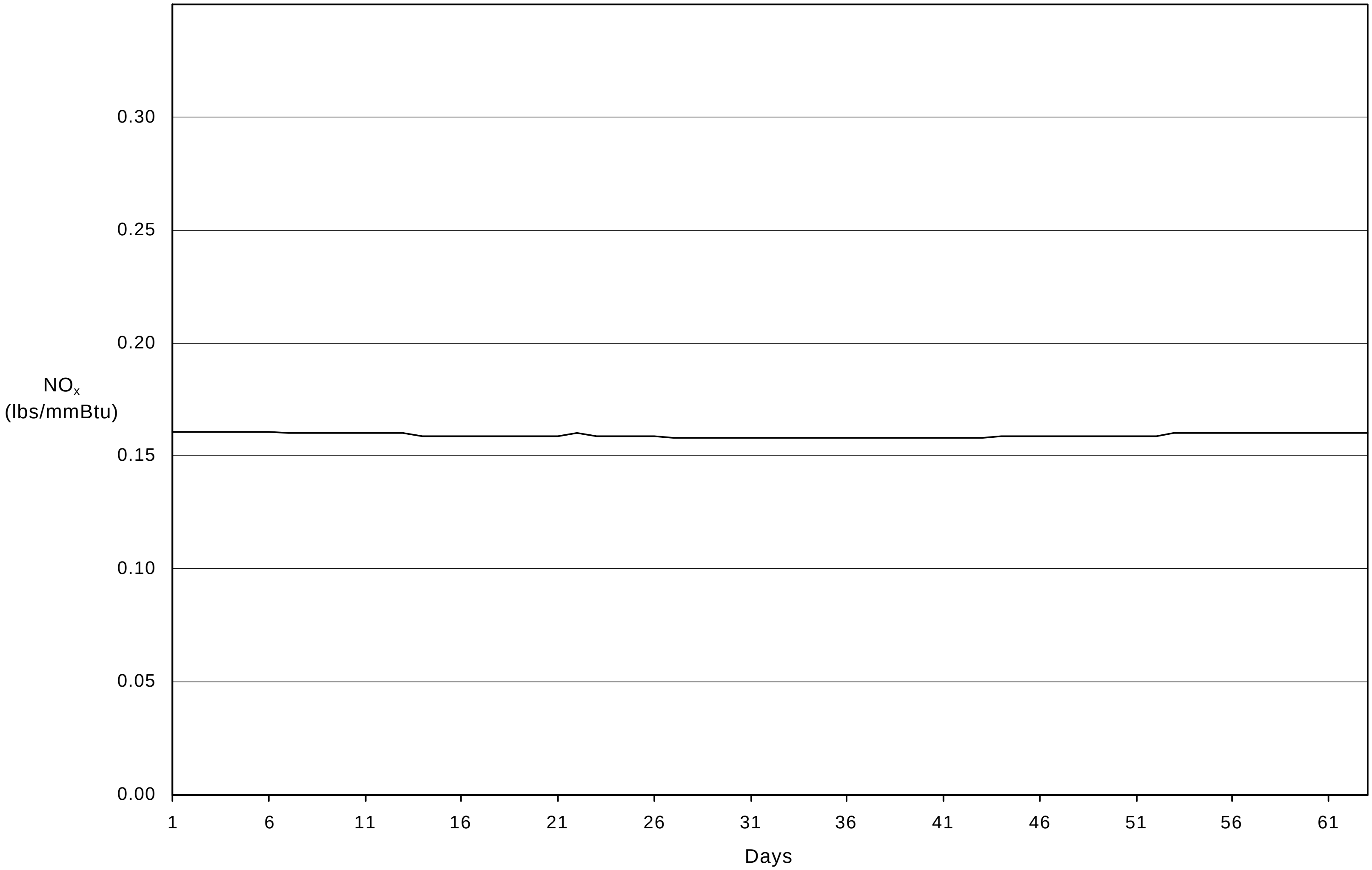


Figure US-2.3

Plant US-2: NO_x Emissions (30 Day Rolling Averages)

May 1 - July 31, 1996



Operation, Maintenance and Cost Related Information:

The SCR system uses aqueous ammonia, and the guaranteed ammonia slip is less than 5 ppm. Plate-type catalysts are used, with an initial volume of 141.3 m^3. Six half-layers (or three full layers) are possible, with four half-layers currently filled. An additional layer of catalyst is planned to be installed after three years of operation. The expected catalyst life is 24,000 hours of operation; this governs the replacement schedule. Plant US-2 uses a regenerative air preheater, which was washed every 1-2 months due to fouling problems. An additional layer of catalyst was added in October 1996 which stopped the excessive washes. The current catalyst volume is 188.4 m^3. Plant US-2 reported problems with SCR operation to be air preheater fouling and popcorn slag accumulation. The preheater fouling was caused by low NO_x burner/overfire air deficiencies which required higher SCR efficiencies. After installing fresh catalyst, the slip problem was minimized. Problems with the ammonia injection system at Plant US-2 were described as: 1) vaporizer pluggage, which was solved by changing the aqueous ammonia quality from city water to demineralized water, and 2) capacity limited, which was resolved by upgrading the dilution fans and heaters. The flyash from Plant US-2 is not sold; it goes to "100% beneficial use." Eighty percent (flyash and bottom ash) goes to reclamation, while 20% is mixed with sewage and used as landfill caps. Flyash is not recirculated back to the boilers, although 10% is recycled for SO_2 removal. The SCR design removal efficiency is reported as 63%. Plant US-2 was unable to provide capital costs, but did report that the cost of scheduled catalyst replacement was $ 86,000 for installation labor, and $ 13,000/cubic meter x 47.1 cubic meters =
$ 612,300 for the catalyst. A summary of operational problems and costs provided by Plant US-2 is shown in the table below.

Table US-2.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Plugging of air preheater resolved by adding catalyst layer. Ammonia injection system vaporizer pluggage resolved by changing water quality of aqueous ammonia. Popcorn slag accumulations.
Costs	Catalyst replacement cost: $86,000 for installation labor $13,000/cubic meter x 47.1 cubic meters = $ 612,300 for layer

Plant US-4

Plant/Unit Information:

The U.S. Plant US-4 provided continuous hourly NO_x data for one 465 MWe coal-fired boiler. The SCR is a new installation. Both the boiler and the SCR commenced operation in 1996. The boiler is described as a dry bottom wall-fired boiler with "high dust" SCR system. Data were obtained electronically for July 31-September 30, 1996 as well as for October 1 - December 31, 1996; however, since the plant provided information on emissions during October - December period, data were used from this time period in the report. Data conversion was not required, since emissions were provided in lbs/mmBtu. All NO_x measurements are corrected to dry, standard conditions (20 °C, 1 atm, 0% O_2). The unit is required to meet an operating permit limit of 0.17 lbs/mmBtu (30-day rolling average). The unit experienced no reportable exempt emissions during this period. A summary of the data submitted by Plant US-4 is shown in Table US-4.1.

Table US-4.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly Data	Yes
O_2 diluent	Yes
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	No
Description of Other Controls	No
Retrofit/New	Yes

(cont.)

Table US-4.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	No
Catalyst Replacement Cycle	Yes
Other Operational Experience	No
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	Yes

Coal Information:

Plant US-4 indicated that Appalachian bituminous coal was used. "As-fired" values for GCV, moisture, ash and sulfur content of the coal were provided; however, this information was insufficient to calculate an F-factor.

Emissions Data Analysis:

Plant US-4 had average NO_x emission rate of 0.14 lbs/mmBtu for October 1 - December 31, 1996. Figure US-4.1 shows the continuous hourly NO_x emissions data during this time period. Figure US-4.2 indicates the emissions data expressed in 24-hour averages, while Figure US-4.3 shows the 30-day rolling averages. All NO_x readings of zero were discarded from the graph of continuous NO_x emissions as well as from the mean calculations and the 24-hour and 30-day rolling average calculations.

Figure US-4.1

Plant US-4: NO_X Emissions (Hour Averages)

October 1 - December 31, 1996

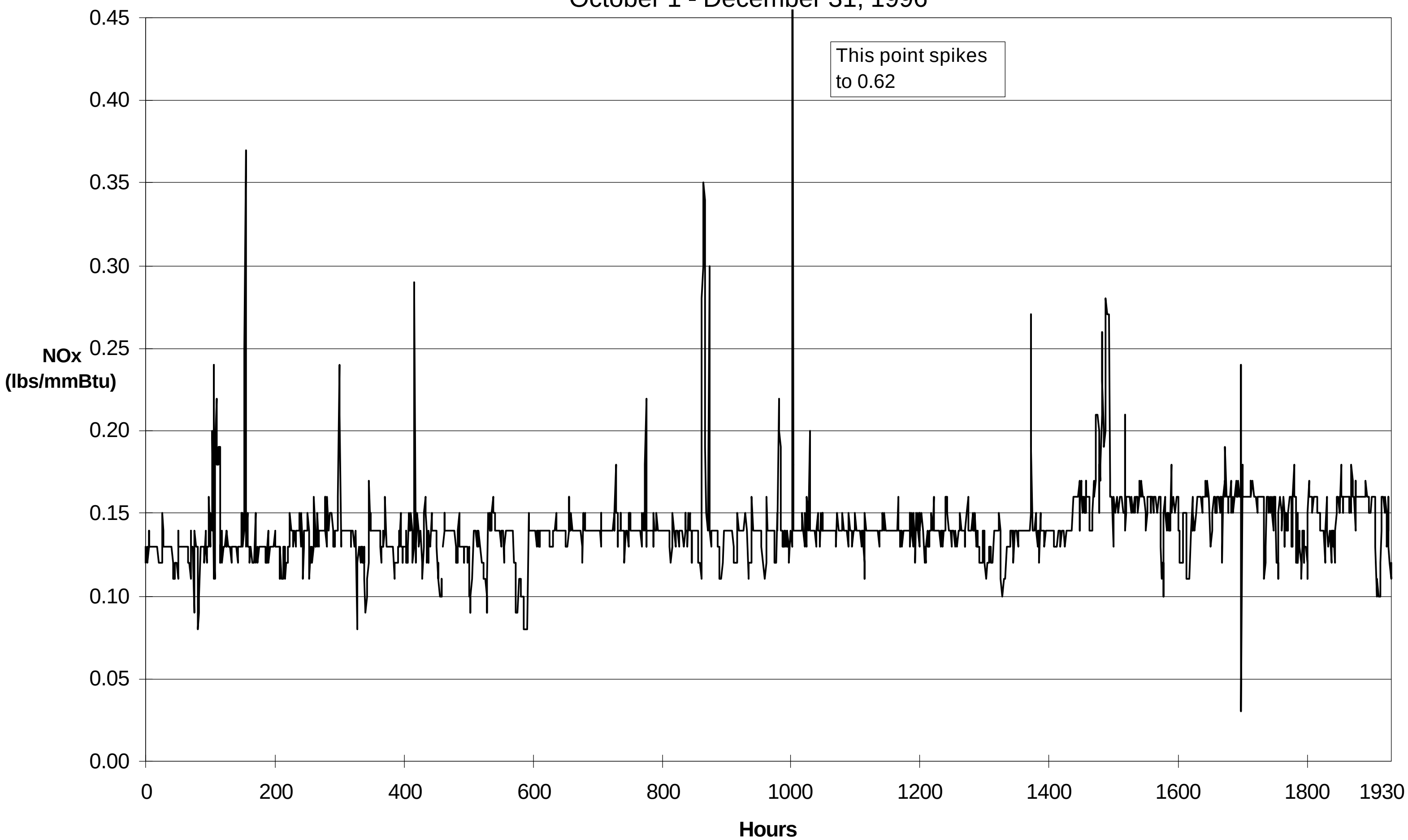


Figure US-4.2

Plant US-4: NO_X Emissions (24-Hour Averages)

October 1 - December 31, 1996

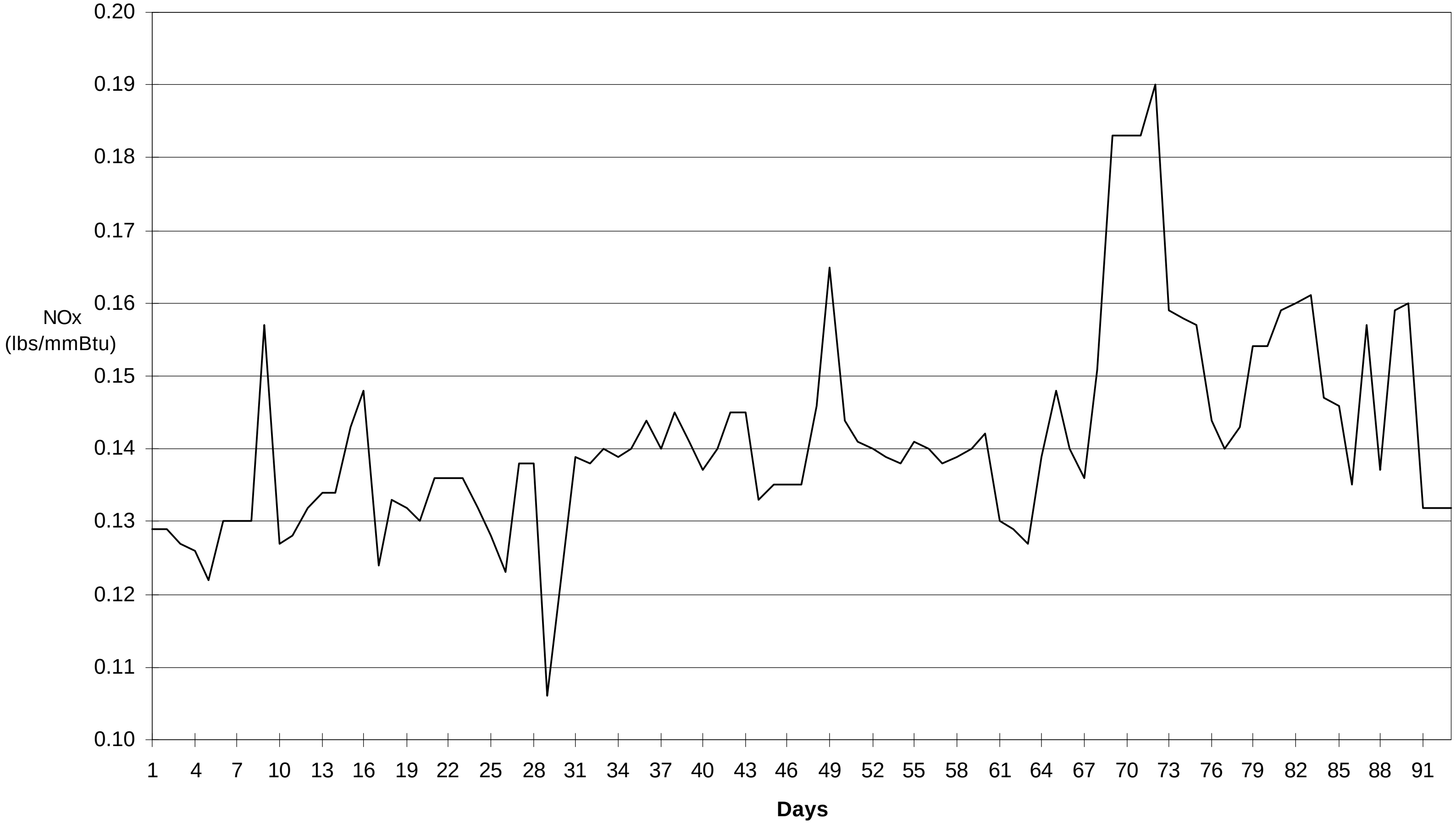
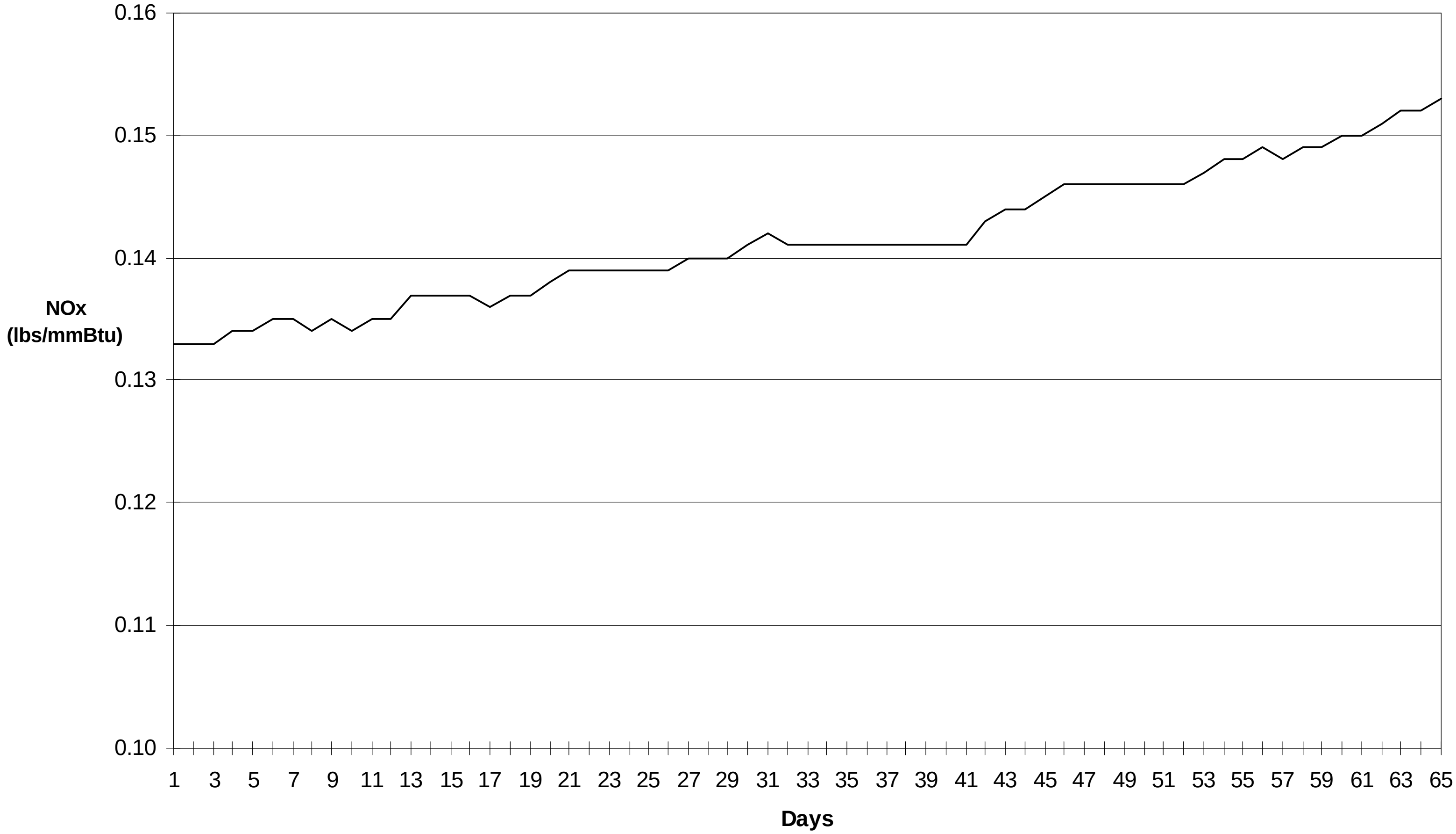


Figure US-4.3

Plant US-4: NO_X Emissions (30-Day Rolling Averages)

October 1 - December 31, 1996



Operation, Maintenance and Cost Related Information:

Plant US-4 uses a regenerative air preheater. The plant reported that because of minor plugging problems, the air preheater had been washed since the boiler and SCR system began operation in 1996. The plant did not discuss the costs or other operational impacts associated with washing the air preheater. Plant US-4 uses anhydrous ammonia; the plant stated that it had experienced no problems with this type of ammonia. The vendor guaranteed ammonia slip is < 2 ppm. The plant reported that some flyash is recycled and some is sent to a landfill. The SCR uses a plate-type catalyst. The plant stated that it has experienced no catalyst-related problems. The plant did not discuss problems associated with the type of coal used. The plant reported total equipment and installation costs of approximately $ 11,438,000. Operating costs, including annual level cost and estimated operation and maintenance, were reported at $ 1,412,264. The plant also stated that the cost of replacing catalyst every three years would be approximately $ 13,100,000. No breakdown of specific cost components was provided. A summary of the operational problems and costs reported by Plant US-4 is shown in the table below.

Table US-4.3

Summary of Reported Operational Problems and Costs

Category	Summary	
Operational Problems	Minor plugging of air preheater; solved by washing preheater. Cost not specified.	
Costs	Capital:	$ 11,438,000.00
	Operating:	$ 1,412,264.00

Plant US-5

Plant/Unit Information:

The U.S. Plant US-5 provided data for one 240 MW coal-fired boiler with a new SCR installation. Both the boiler and the SCR commenced operation in 1996. The boiler is a wet bottom, tangentially-fired boiler and reported to have a "hot end" or high dust SCR configuration. The burner is described as having double separated overfire air and close coupled overfire air. Plant US-5 is also reported to be a peaking unit. Thirty-day rolling averages of NO_x emissions rates were provided for an entire quarter from January 1 through March 31, 1997. Data conversion was not required, since emissions values were provided in lbs/mmBtu. The plant is subject to a NO_x emissions limit of 0.10 lbs/mmBtu with a backup permit limit of 0.15 lbs/mmBtu (30-day rolling average). The backup limit was instated before the SCR performance was evaluated. A summary of the data submitted by Plant US-5 is shown in Table US-5.1.

Table US-5.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	No
Hourly Data	No
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table US-5.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant US-5 indicated that bituminous coal was used and that the standard Method 19 bituminous F-factor of 9780 dscf/mmBtu had been used to calculate emissions data. Both proximate and ultimate coal analyses were provided; however, Plant US-5 did not indicate the percentage of oxygen in the coal from the ultimate analysis. Therefore, an F-factor could not be calculated.
The coal data are presented in Table US-5.2.

Table US-5.2

Coal Characteristics Data for Plant US-5

Coal Analysis	
	Unit A
Moisture (%)	5.65
Ash (%)	9.86
Nitrogen (%N)	1.36
Oxygen (%O)	N/A
Carbon (%C)	75.51
Hydrogen (%H)	4.88
Sulfur (%S)	0.71
GCV (Btu/lb):	12,654
F-Factor: (dscf/mmBtu)	--

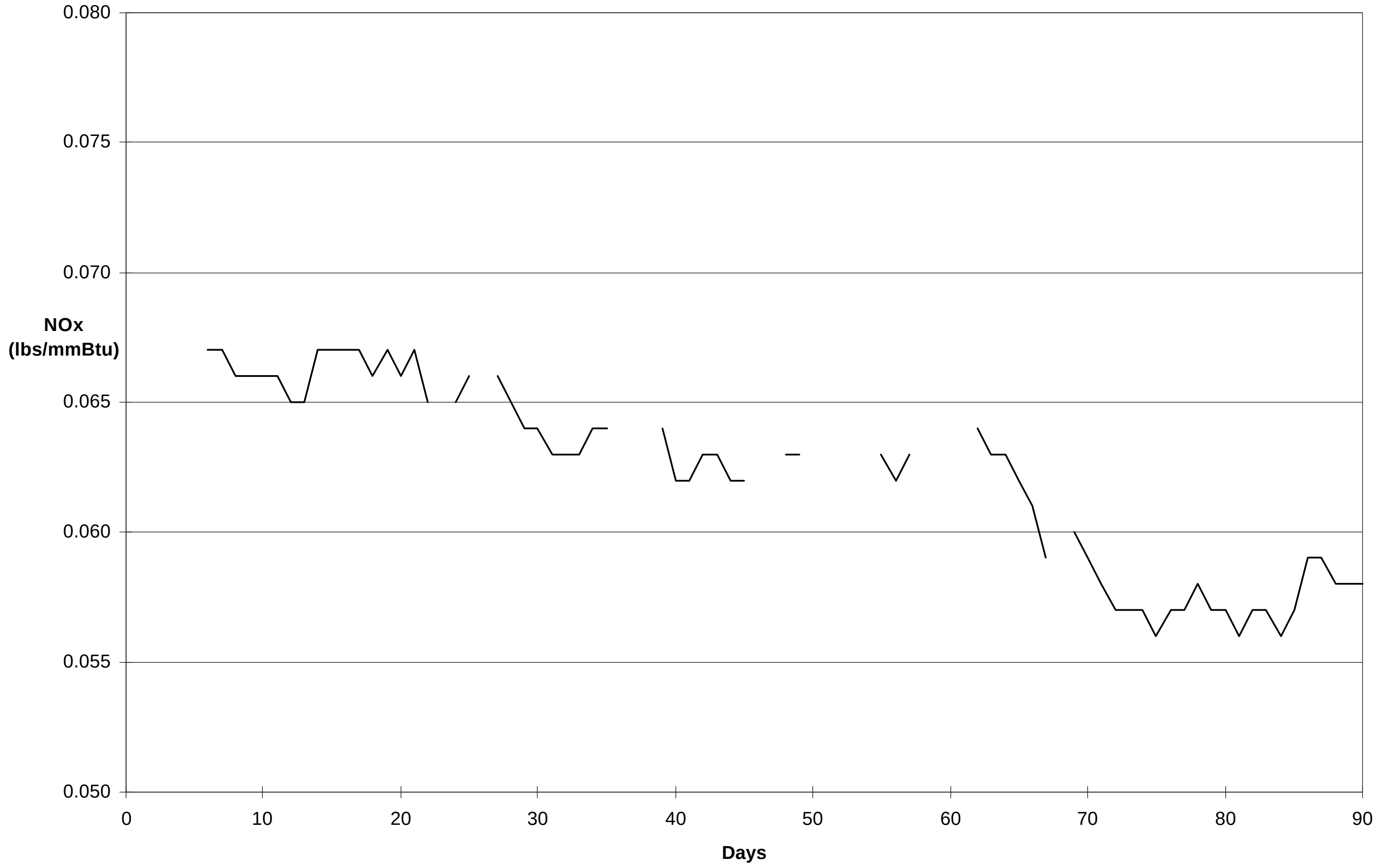
Emissions Data Analysis:

The reported values for 30-day rolling averages for January 1 through March 31, 1997 for Plant US-5 ranged from 0.056 to 0.067 lbs/mmBtu. The mean 30-day rolling average NO_x emission rate for Plant US-5 was 0.062 lbs/mmBtu for this time period.. Figure US-5.1 shows the 30-day rolling averages provided by the plant for this time period. Periods of no reported 30-day averages occurred on days with "no samples" according to the plant-provided data report. However, in the main report, values from the previous day which had a calculated average were filled in for the days with no reported value, as is the procedure for reporting such values.

Figure US-5.1

Plant US-5: 30-Day Rolling Averages

January 1 - March 31, 1997



Operation, Maintenance and Cost Related Information:

Plant US-5 uses a regenerative air preheater. The plant reported that the air preheater was originally supplied with ceramic coasted plates. Plant US-5 uses anhydrous ammonia, and stated that it had experienced no problems with this type of ammonia. The actual and design ammonia slip is < 5 ppm. The plant reported that an outside vendor is used for quality assurance procedures for NH_3 slip measurements. The plant reported that 0% of the flyash is reinjection and the flyash disposal method is by railcar. The SCR uses a plate-type catalyst with 1.5 layers filled out of 3 possible layers. The catalyst volume is 172.5 m^3. Plant US-5 stated that it has experienced no catalyst-related problems. The catalyst maintenance and replacement schedule is 5 years, and the expected life of the catalyst was stated to be 5+ years. The plant also reported that there were no problems associated with the type of coal used. The plant was unable to provide cost information. A summary of the operational problems and costs reported by Plant US-5 is shown in the table below.

Table US-5.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	No problems reported relating to catalyst, ammonia type, coal type, or operation and maintenance of the SCR system.
Costs	Not Provided

Plant US-6

Plant/Unit Information:

Continuous hourly data was obtained electronically as reported under the Acid Rain Program requirements in 40 CFR Part 75 from the U.S. Plant US-6 for the period July 1 - September 30, 1996. The 375 MWe boiler is described as a wet bottom cyclone boiler with retrofit SCR system. The boiler began operation in 1968, and the SCR system started operating in 1995. All NO_x measurements are corrected to dry, standard conditions (20°C, 1 atm, 0% O_2). The unit is required to meet an operating permit limit of 1.4 lbs/mmBtu (24-hour average) and 34.5 tons per day. A summary of the data obtained from Plant US-6 is shown in Table US-6.1.

Table US-6.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly Data	Yes
O_2 diluent	Yes
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	Yes
Description of Other Controls	No
Retrofit/New	Yes
Flyash Recirculation	Yes

(cont.)

Table US-6.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	No

Coal Information:

Plant US-6 indicated that bituminous coal was used and that the emissions data had been corrected using the Reference Method 19 F-factor of 9,780 dscf/mmBtu. Plant US-6 also provided coal data with which to calculate an F-factor; however, the calculated F-factor is almost exactly equal to the standard bituminous F-factor so that no corrections were made to the provided emissions data. The coal data had been corrected for moisture content; therefore, the components were re-corrected for use in the F-factor calculation. The coal data are presented in Table US-6.2

Table US-6.2

Coal Characteristics Data for Plant US-6

Coal Analysis		
	Unit A (dry)	Unit A (wet)
Moisture (%)	6.0	5.7
Ash (%)	6.5	6.2

(cont.)

Table US-6.2 (cont.)

Coal Characteristics Data for US-6

Coal Analysis		
	Unit A (dry)	**Unit A (wet)**
Nitrogen (%N)	1.4	1.3
Oxygen (%O)	6.1	5.8
Carbon (%C)	78.8	74.3
Hydrogen (%H)	4.9	4.7
Sulfur (%S)	1.6	1.5
GCV (Btu/lb):	13,186	
F-Factor: (dscf/mmBtu)		9790

Emissions Data Analysis:

The average of NO_x emissions for the period July 1 - September 30, 1996, was 0.91 lbs/mmBtu. Figure US-6.1 shows the continous hourly NO_x emissions data. Figure US-6.2 shows emissions data expressed in 24-hour averages, and Figure US-6.3 indicates the 30-day rolling averages. All NO_x readings of zero were discarded from the graph of hourly emissions as well as from the mean calculations and the 24-hour and 30-day rolling average calculations.

Figure US-6.1

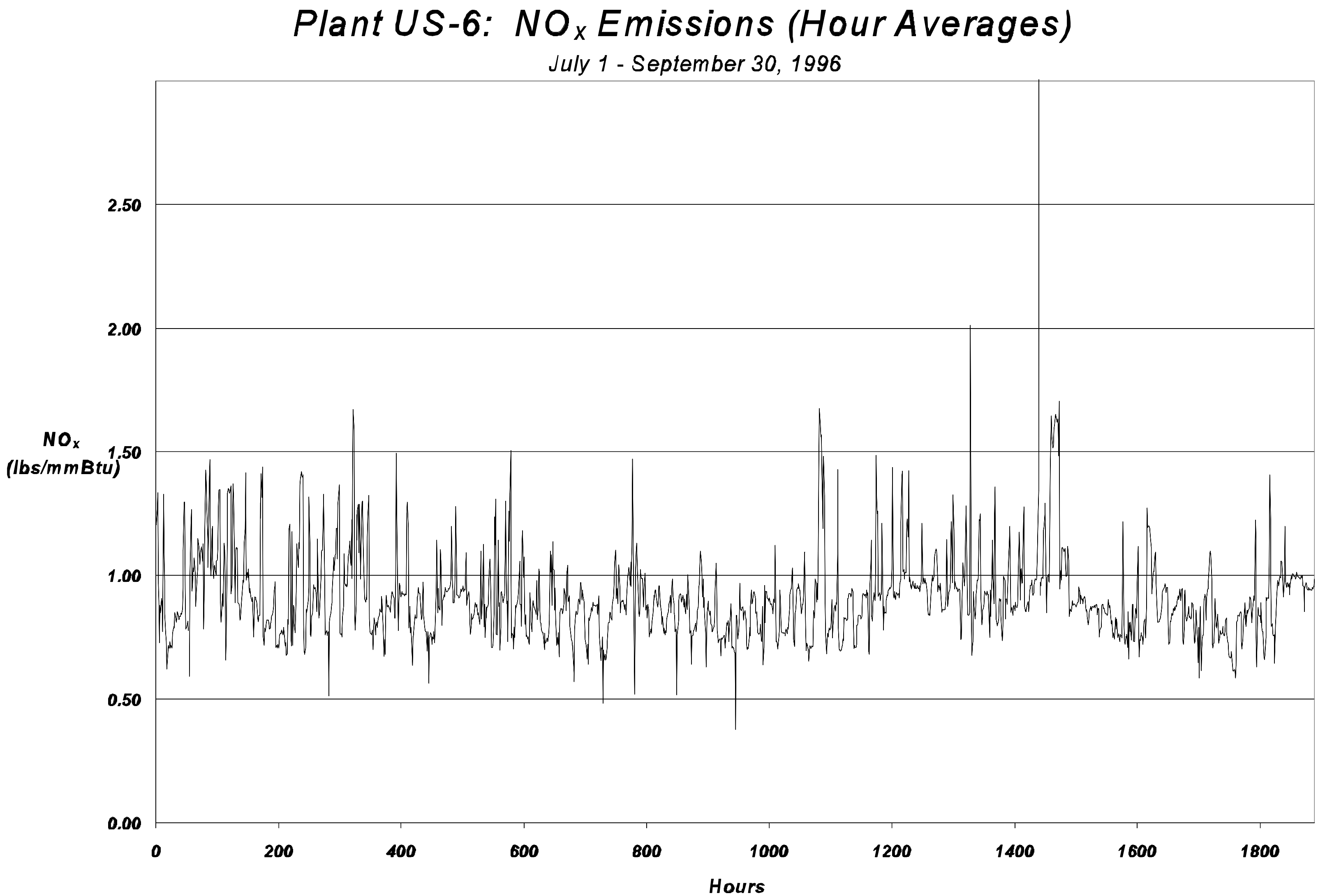

Plant US-6: NOx Emissions (Hour Averages)
July 1 - September 30, 1996
NOx
(lbs/mmBtu)
2.50
2.00
1.50
1.00
0.50
0.00
0
200
400
600
800
1000
1200
1400
1600
1800
Hours

Figure US-6.2

Plant US-6: NO_x Emissions (24-Hour Averages)

July 1 - September 30, 1996

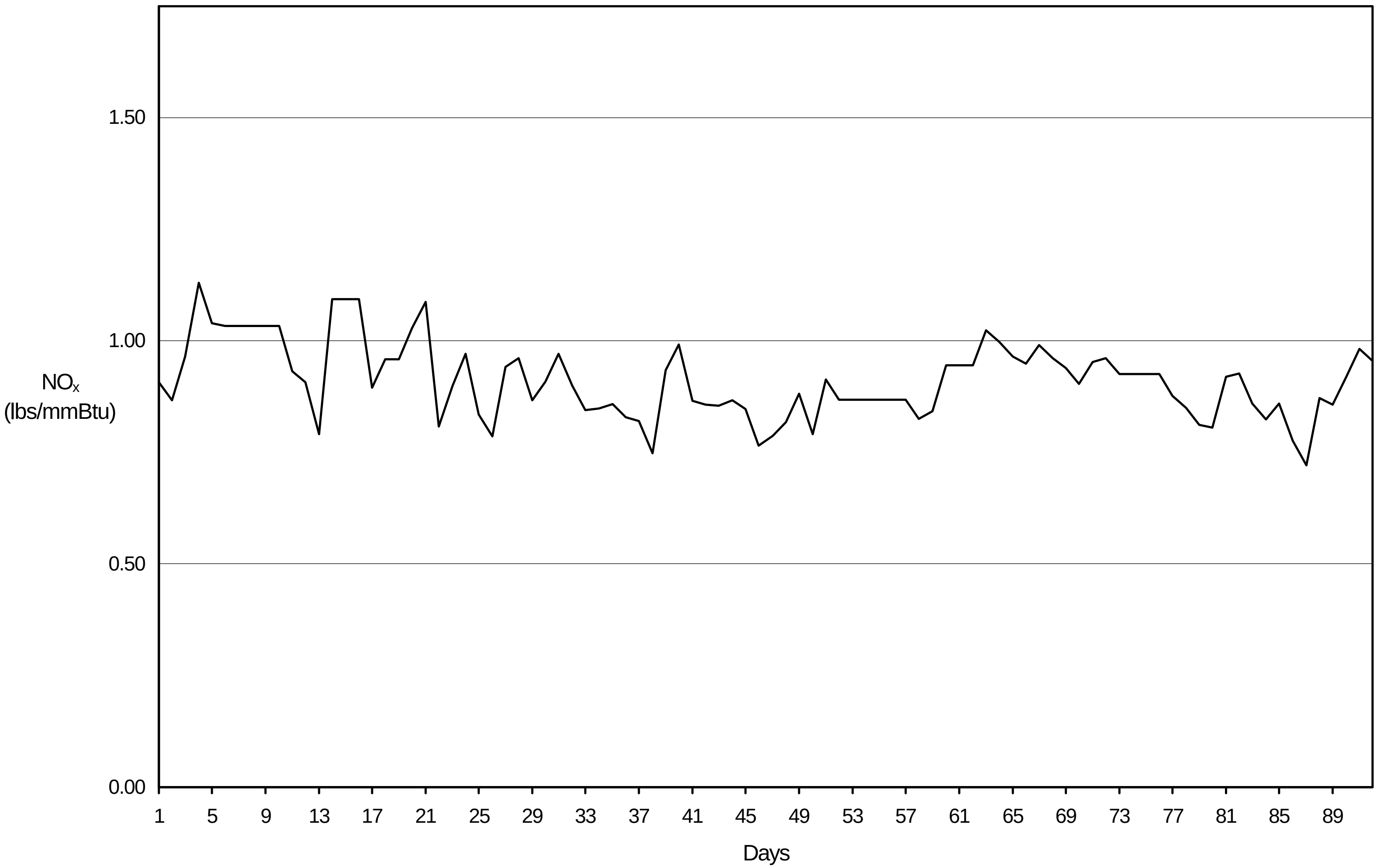
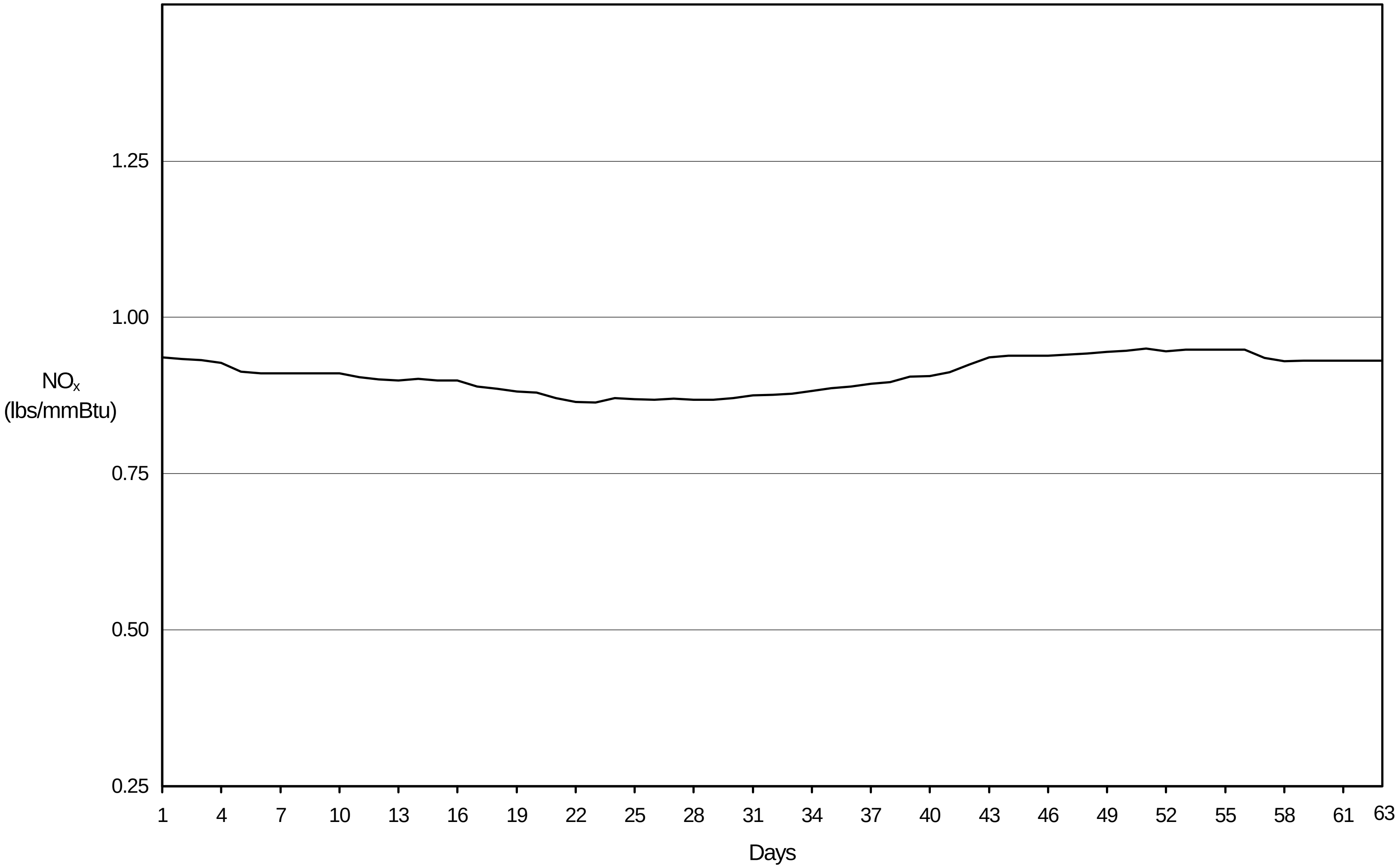


Figure US-6.3

Plant US-6: NO_x Emissions (30-Day Rolling Averages)

July 1 - September 30, 1996



Operation, Maintenance and Cost Related Information:

Plant US-6 uses a tubular air preheater. The plant reported that the air preheater had been washed several times since the SCR system was installed in 1995, due to air preheater pluggage. The plant explained that its SCR system is equipped with a damper arrangement intended to bypass the flow of flue gas around the reactor/catalyst during unit startups and shutdowns. This bypass damper is intended to provide a tight seal to prevent ammonia-laden flue gas from “short circuiting” the reactor during normal operation of the system. The plant stated that damaged bypass damper seals and/or insufficient closing of the bypass damper was believed to have caused periods of significant ammonia slip, which caused the fouling that required washing. Before SCR installation, the air preheater was washed annually. The SCR system uses anhydrous ammonia; the plant did not report any problems associated with the type of ammonia used. The maximum allowable ammonia slip is 10 ppm; the maximum guaranteed ammonia slip is 5 ppm. The plant reinjects 100% of the flyash collected in the electrostatic precipitator back into the cyclones.

In response to the question on impacts of using high-sulfur coal, Plant US-6 stated that the air preheater fouling that made it necessary to wash the air preheater appeared to result from the formation of ammonia salts. The plant added that observations of the location and extent of the fouling indicated that the ammonia salt formation appeared to be limited by the amount of ammonia slip, rather than the amount of SO_3 present. The plant reported that the conversion of SO_2 to SO_3 in the SCR system and the resultant condensation of SO_3 in the air preheater does not appear to have caused significant operational or maintenance impacts to date. The plant also stated that it has found that operating with an air heater average cold-end temperature approximately 20º F higher than normal helps to minimize the effects of the fouling. The plant noted that this measure is used to affect the location of ammonia salt formation more than impact the condensation of SO_3 in the air heater. Costs associated with air preheater washing were not reported.

Plant US-6 has a plate-type catalyst with a total volume of approximately 400 cubic meters. The plant stated that an additional 100 cubic meters are to be installed in April 1997. The plant noted that analysis of catalyst samples indicated that catalyst deactivation was occurring at the expected rate. The plant reported that its SCR system was designed for and operates at a NO_x reduction rate of approximately 65%. The plant reported that, with the exception of the bypass damper problems discussed above, it has encountered no significant problems in operating and maintaining the SCR system and has not experienced SCR-related problems with other plant operations. Plant US-6 reported a total installed capital cost of approximately $56 per kW and levelized costs for the current percentage NO_x reduction of approximately $404 per ton of NO_x removed. No breakdown of specific cost components was provided. A summary of the operational problems and costs reported by Plant US-6 is shown in Table US-6.2 below.

Table US-6.2

Summary of Reported Operational Problems and Cost

Category	Summary
Operational Problems	Reported air preheater washing necessary because of ammonia salt formation caused by insufficient bypass damper seals. Cost not specified.
Costs	Capital: $56/kW (1995)

Plant A-1

Plant/Unit Information:

The Austrian Plant A-1 provided continuous half-hour NO_x emissions data from one 234 - 246 MWe unit for the period November 6, 1995 - March 3, 1996. The SCR system is a new installation; the boiler and SCR system commenced operating in 1986. The unit for which data was provided is described as a dry bottom tangentially fired boiler which was initially constructed with high dust SCR. All data are corrected to ISO standards of 0 °C (273 K), 1013 mbar (1 atm) and no moisture. The readings are corrected by the plant to a 6 % oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data provided by Plant A-1 is shown in Table A-1.1.

Table A-1.1

Summary of Data Submitted

Requested	**Submitted?**
Continuous NO_x Emissions	Yes
Hourly data	Yes
O_2 diluent	No
Moisture	No
Temperature	Yes
NO_x Annual/Daily/Monthly Summary	Yes
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table A-1.1 (cont.)

Summary of Data Submitted

Requested	**Submitted?**
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	No
Monitor Quality Assurance Experience	No
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant A-1 provided sufficient coal characteristics data to calculate F-factors. A summary of the coal data provided is shown in Table A-1.2.

Table A-1.2

Coal Characteristics Data for Plant A-1

Coal Analysis	
	Unit A
Moisture (%)	8.61
Ash (%)	9.91
Nitrogen (%N)	1.22
Oxygen (%O)	5.05
Carbon (%C)	69.99
Hydrogen (%H)	4.61
Sulfur (%S)	0.53
GCV (kJ/kg)	26,179
F-Factor (dscf/mmBtu)	10,838

Emissions Data Analysis:

Plant A-1 achieved an average NO_x emission level of 0.155 lbs/mmBtu for the period November 6, 1995 - March 3, 1996. Figure A-1.1 shows the plant's continuous half-hourly emission readings from this period. Figure A-1.2 shows the same data expressed in 24-hour averages while Figure A-1.3 indicates 30-day rolling averages. All NO_x readings of zero were discarded from the mean, 24-hour and 30-day rolling average calculations.

Figure A-1.1

Plant A-1: NO_x Emissions (1/2 Hour Averages)

November 6, 1995 - March 3, 1996

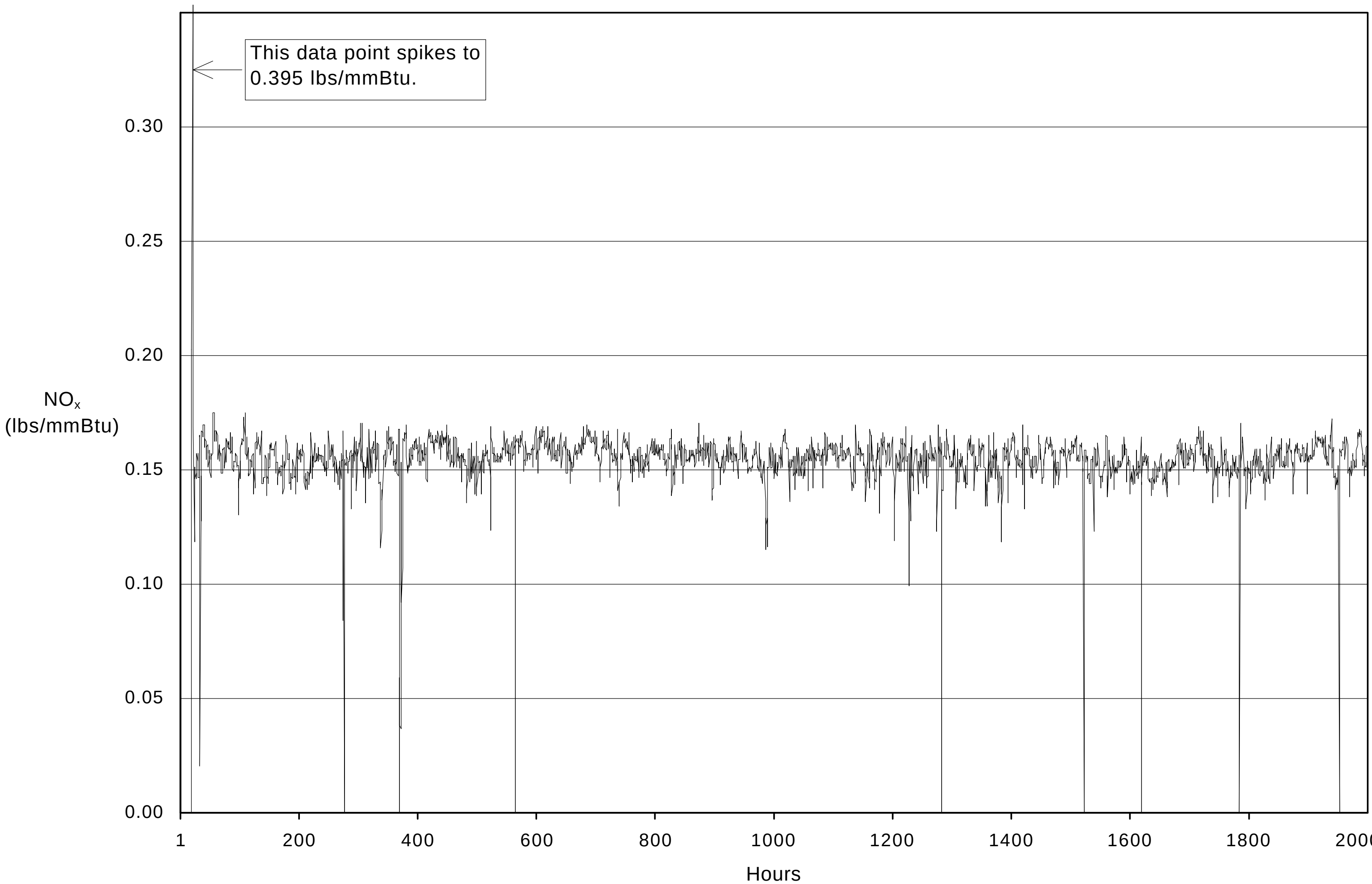


Figure A-1.2

Plant A-1: NO_x Emissions (24 Hour Averages)

November 6, 1995 - March 3, 1996

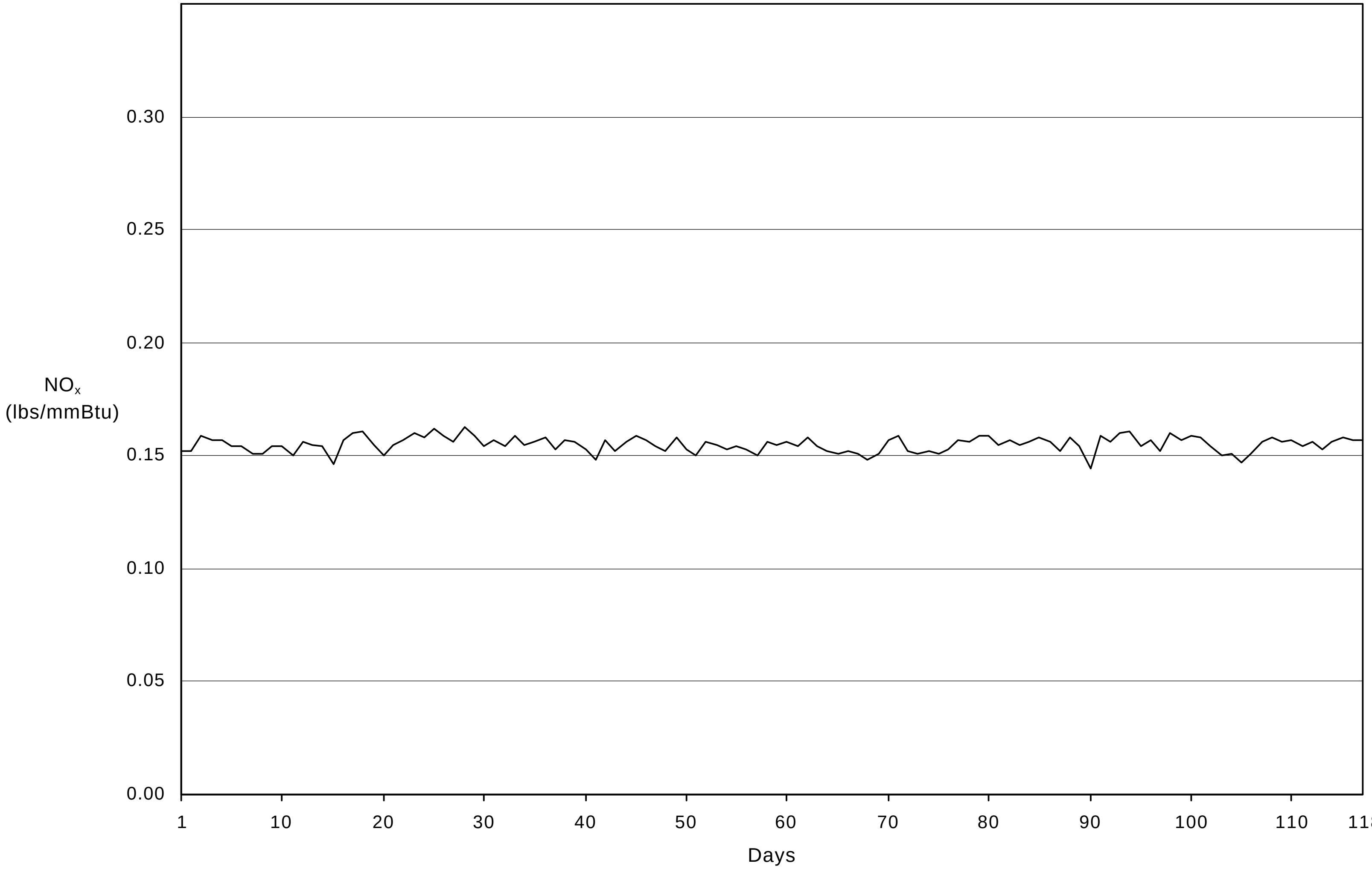
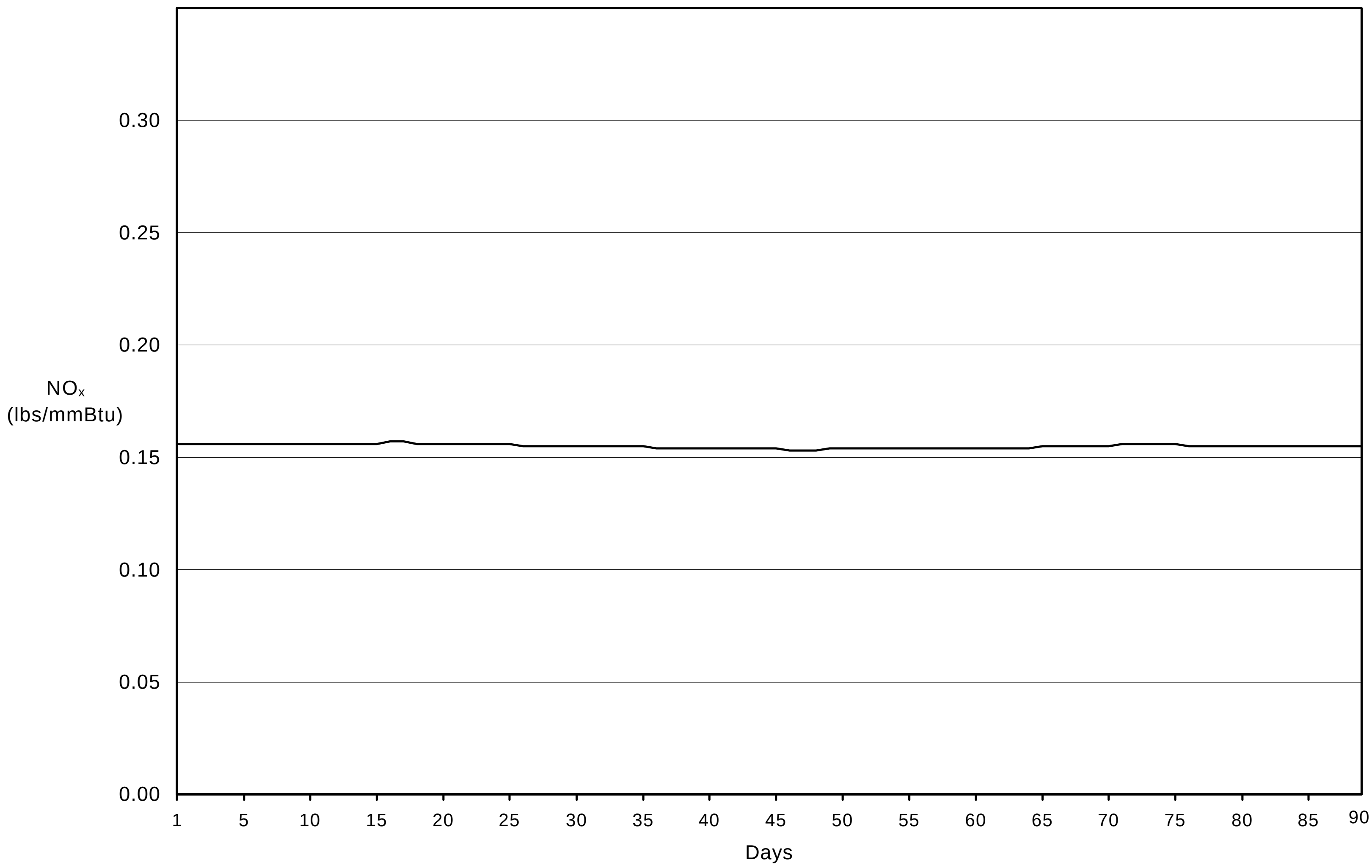


Figure A-1.3

Plant A-1: NO_x Emissions (30 Day Rolling Averages)

November 6, 1995 - March 3, 1996



Operation, Maintenance and Cost Related Information:

Plant A-1 uses a regenerative air preheater. The plant reported that the air preheater has been washed two times since installation, after approximately 50,000 operating hours each time. Anhydrous ammonia is the reagent utilized in the SCR system. The ammonia slip is reported as 1 mg/m^3 in the stack and 5 ppm guaranteed. The SCR system has a honeycomb-type catalyst with a 378 m^3 volume and three of four possible layers filled. The catalyst life is guaranteed for 42,000 operating hours. The plant reported the catalyst replacement schedule to be as follows: Layer 1 replaced after 40,000 operating hours; Layer 2 replaced after 60,000 operating hours; and Layer 3 replaced after 66,000 operating hours. Flyash is not recirculated, but is sold to the cement industry. The plant indicated that there had been no major problems with the operation and maintenance of the SCR system and the unit in general. Plant A-1 was unable to provide further information on cost.

Plant A-2

Plant/Unit Information:

The Austrian Plant A-2 provided continuous half-hour NO_x emissions data from one 330 MWe unit for the period January 1 - March 31, 1996. The SCR system is a retrofit installation; it began operation in 1990. The unit for which data is provided is described as a dry bottom tangentially fired boiler which was retrofitted with high dust SCR system in 1990. All data are corrected to ISO standards of 0 °C (273 K), 1013 mbar (1 atm) and no moisture. The readings are corrected by the plant to a 6 % oxygen dilution basis. The plant is required to meet a NO_x standard of 200 mg/m^3. A summary of the data provided by Plant A-2 is shown in Table A-2.1.

Table A-2.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Half-hourly
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	No
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	No
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table A-2.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	No
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	No
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant A-2 stated that their boilers were fired with "browncoal" or lignite. They also provided sufficient coal characteristics data to calculate F-factors. These are shown in Table A-2.2.

Table A-2.2

Coal Characteristics Data for Plant A-2

Coal Analysis	
	Unit A
Moisture (%)	1.9
Ash (%)	31.2
Nitrogen (%N)	0.5
Oxygen (%O)	16.8
Carbon (%C)	44.4
Hydrogen (%H)	3.9
Sulfur (%S)	1.3
GCV (kJ/kg)	17,096
F-Factor (dscf/mmBtu)	10,273

Emissions Data Analysis:

Plant A-2 achieved an average NO_x emission level of 0.124 lbs/mmBtu for the period January 1 through March 31, 1996. The standard deviation about the mean is 0.0048. Figure A-2.1 shows the plant's continuous half-hourly emission readings from this period. Figure A-2.2 shows the same data expressed in 24-hour averages while Figure A-2.3 indicates 30-day rolling averages. The slight increase at the end of the 24-hour and 30-day average graphs is not reflected in the graph of continuous NO_x emissions due to a limit on the number of data points that can be graphed on one figure. All NO_x readings of zero were discarded from the mean, 24-hour and 30-day rolling average calculations.

Figure A-2.1

Plant A-2: NO_x Emissions (1/2 Hour Averages)

January 1 - March 31, 1996

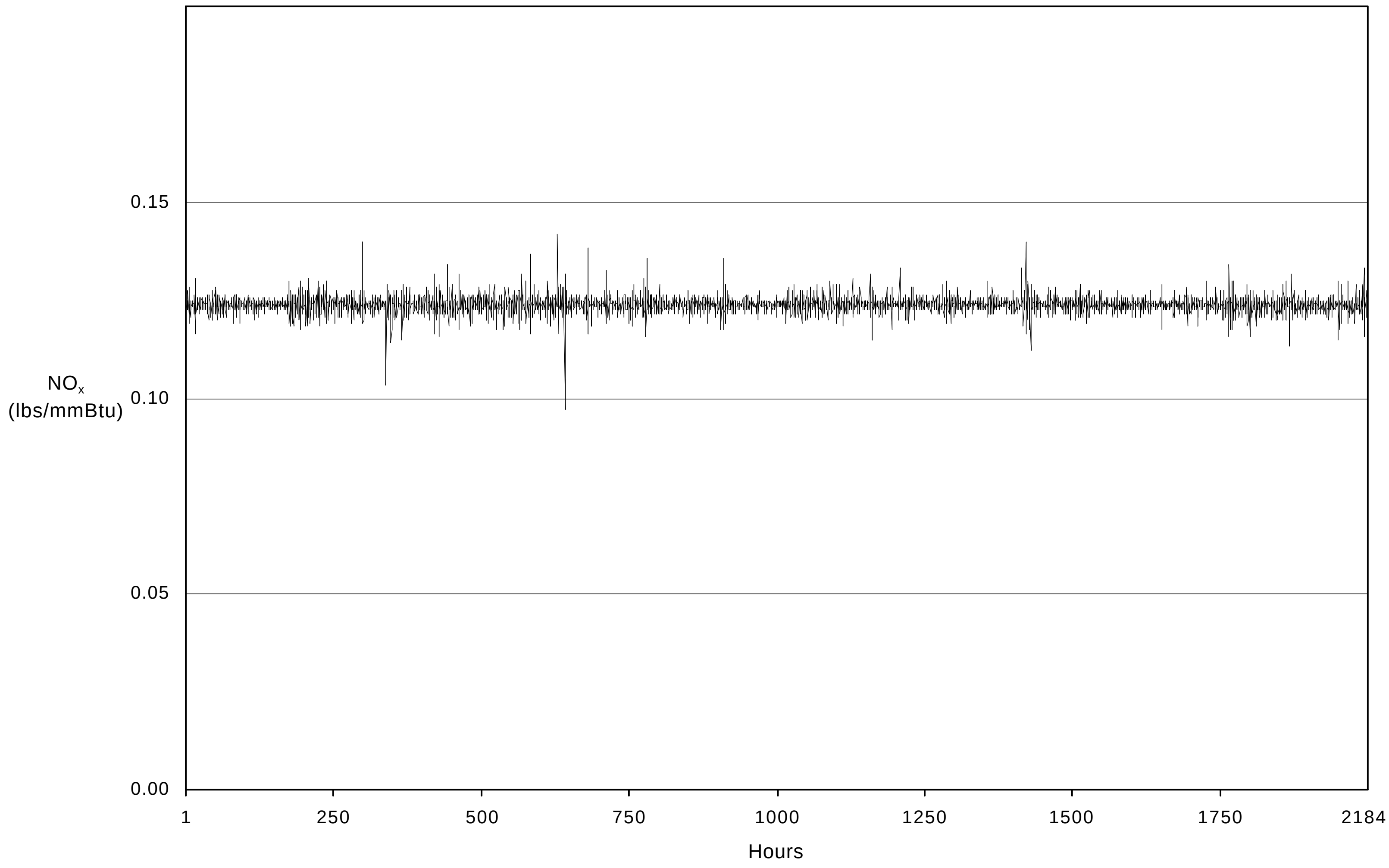


Figure A-2.2

Plant A-2: NO_x Emissions (24 Hour Averages)

January 1 - March 31, 1996

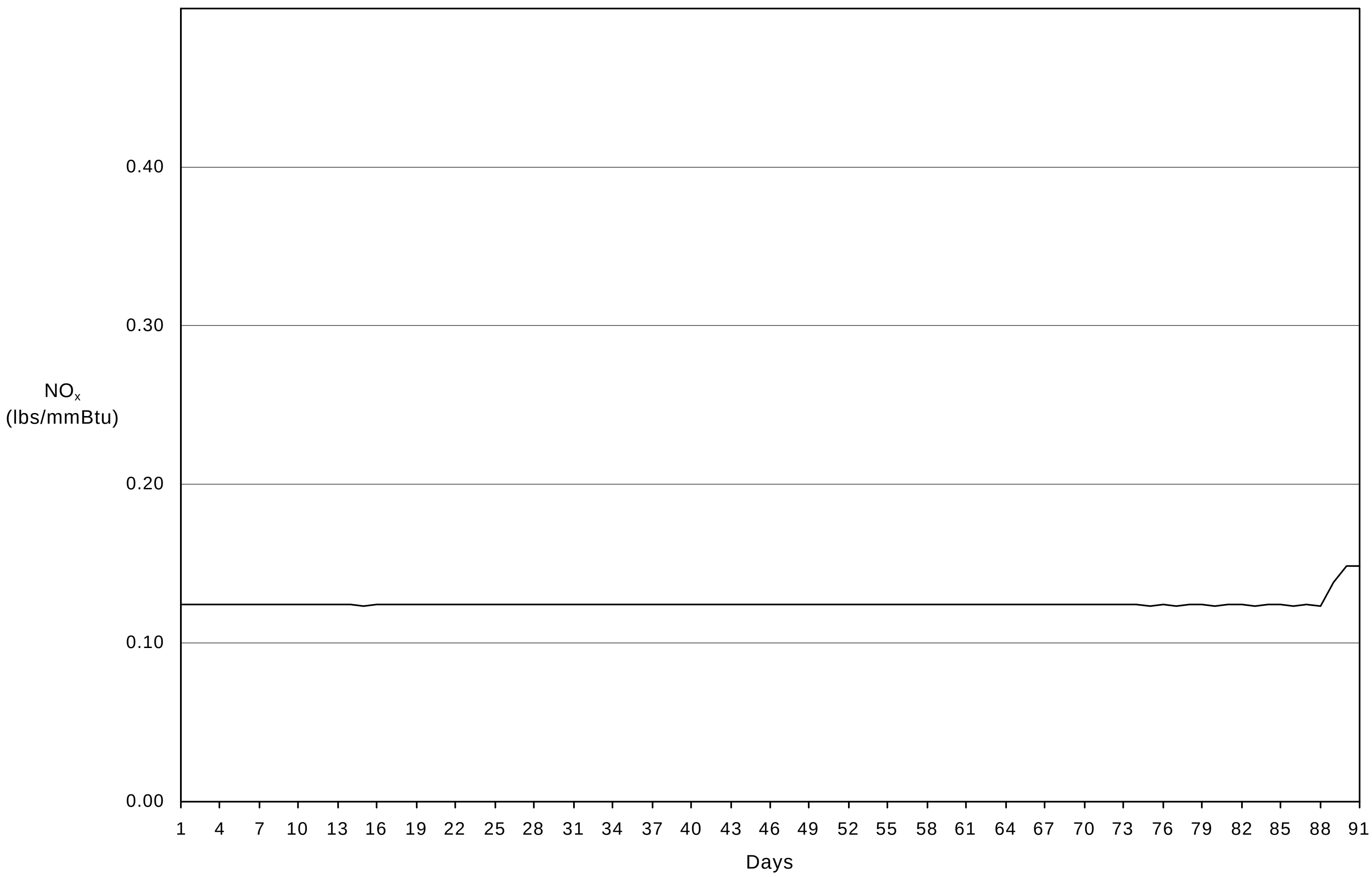
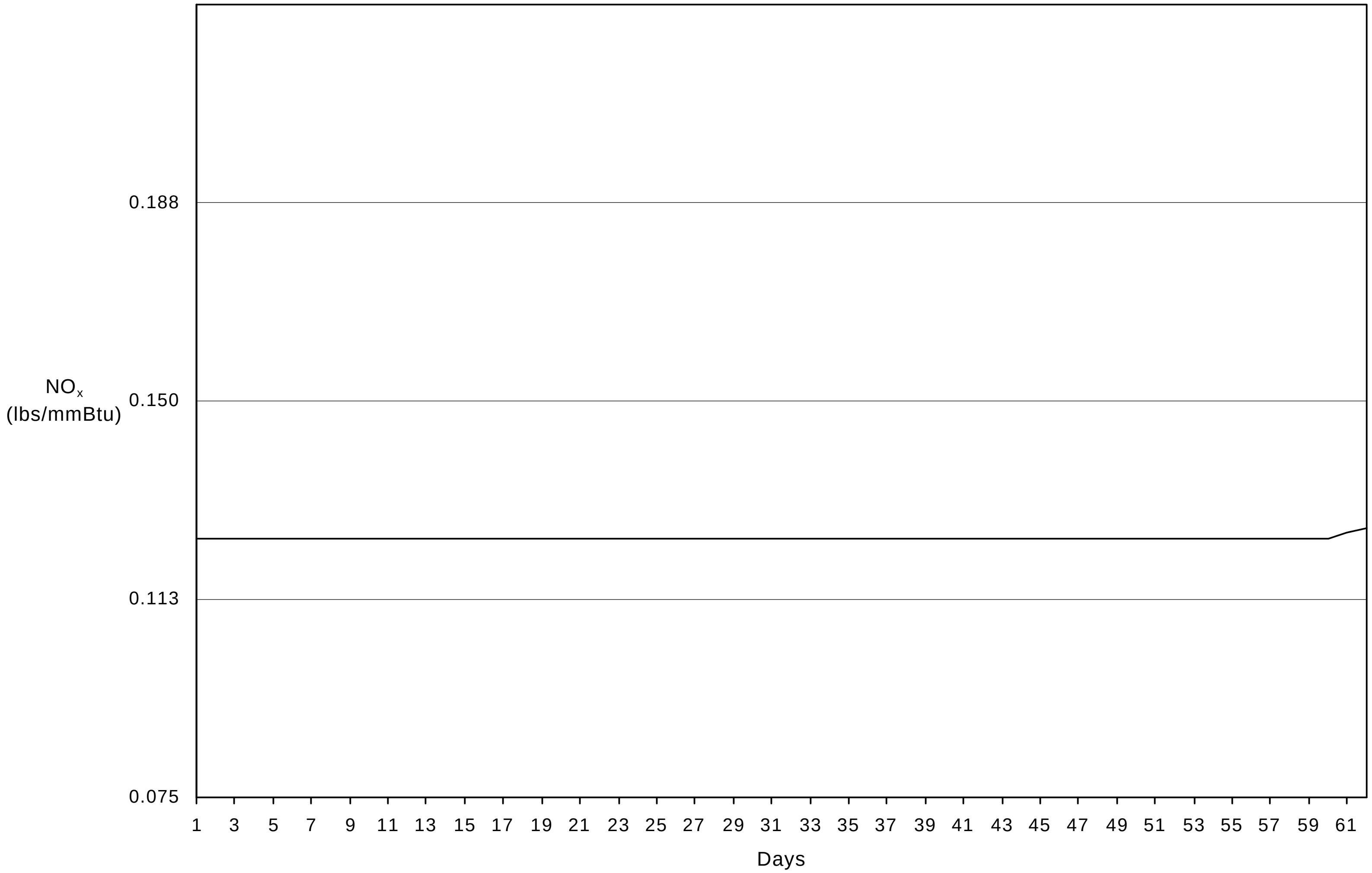


Figure A-2.3

Plant A-2: NO_x Emissions (30 Day Rolling Averages)

January 1 - March 31, 1996



Operation, Maintenance and Cost Related Information:

Plant A-2 has a regenerative air preheater. The plant reported that the preheater was washed once between 1983 and 1990, before the SCR system was installed, and has been washed once since. The plant did not report any costs associated with washing the air preheater. The SCR system uses aqueous ammonia; the plant did not report any problems associated with using this type of ammonia. The maximum ammonia slip is 5 ppm, and flyash from the plant is not recycled. The SCR system uses a plate-type catalyst, which has a volume of 405 square meters. The plant reported ash erosion problems at the edges of the catalysts, and stated that the catalyst in this area has been replaced. The plant has not yet provided additional information about operational impacts associated with this problem; also, the plant did not report the costs associated with replacing the catalyst in the affected areas. The plant stated that it has had no other problems with the SCR. The plant reported no problems related to coal type, and stated that it uses only coal with a sulfur content less than 1%. Zero point and range checks are performed on the NO_x and O_2 monitors once each week, and the plant stated that the monitors have a 90% data availability. Plant A-2 provided no cost information.

Table A-2.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Localized catalyst erosion because of ash; solved by replacing catalyst in affected areas. Cost not specified.
Costs	Not Provided

Plant A-3

Plant/Unit Information:

The Austrian Plant A-3 is comprised of two boiler units (405 MWe and 352 MWe), each retrofitted with a separate SCR system and feeding to a common stack. Both SCR systems are high dust and retrofit installations that commenced operation in 1987. Plant representatives provided line graphs indicating continuous half-hourly NO_x emissions from the common stack for the months of February and March, 1996. From these graphs, the highest and lowest common stack NO_x emission rate was identified for each day. The scale on these graphs was then converted from units of the Austrian standard (mg/m^3) to lbs/mmBtu. The measurements were converted from Austrian and ISO standards of 0 °C (273 K), and 6% oxygen to 20 °C (293 K) and 0% oxygen dilution. The plant is required to meet a NO_x standard of 200 mg/m^3 when burning coal and 150 mg/m^3 when burning natural gas. The time period for which emissions data was provided included a period in which only natural gas was burned. Average high and low plant emission rates were calculated both including and excluding the period when natural gas was burned. A summary of the data submitted is shown in
Table A-3.1.

Table A-3.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly data	Half-hourly
O_2 diluent	No
Moisture	No
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	No
Estimate	Yes

(cont.)

Table A-3.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	Yes
Operating Cost Summary	Yes

Coal Information:

Plant A-3 provided sufficient coal characteristic data to calculate an F-factor. These coal characteristics are shown in Table A-3.2. All dry chemical characteristics were corrected for ash and moisture content for use in the F-factor calculation. The median values for each parameter were used in the calculation.

Table A-3.2

Coal Data for Plant A-3

Coal Analysis		
	Range	**Median**
Moisture (%)	7.0 - 12.0	9.5
Ash (%)	8.0 - 18.0	13.0
Nitrogen (%N)	1.6 dry	1.31 wet
Oxygen (%O)	10.6 dry	8.65 wet
Carbon (%C)	82.5 dry	67.35 wet
Hydrogen (%H)	5.3 dry	4.33 wet
Sulfur (%S)	0.6 - 1.0 dry	0.65 wet
GCV (kJ/kg)	24300	24300
F-Factor (dscf/mmBtu)		11,042

Emissions Data Analysis:

The average daily high and low emission rates, including natural gas hours, for February and March, 1996 were 0.101 lbs/mmBtu and 0.080 lbs/mmBtu. Figure A-3.1 shows the daily median, high and low emissions over this period. When hours in which natural gas was burned are excluded, the average daily high and low emission rates are 0.106 lbs/mmBtu and 0.088 lbs/mmBtu. The median, high and low measurements excluding natural gas hours are shown in Figure A-3.2.

Figure A-3.1

Plant A-3: NO_x Emissions Including Natural Gas Hours

(Daily Maximum, Minimum and Median)

February 1 - March 31, 1996

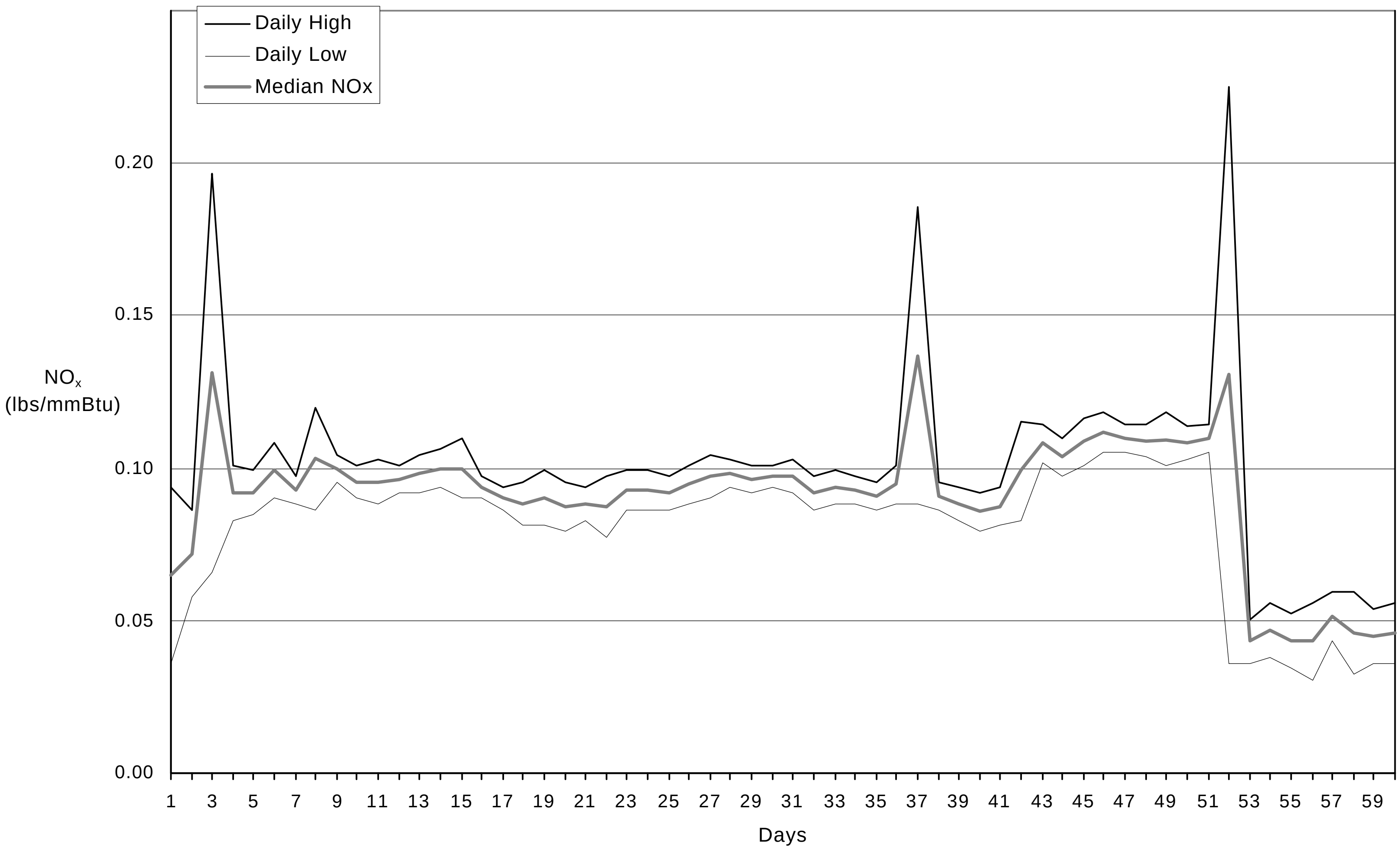
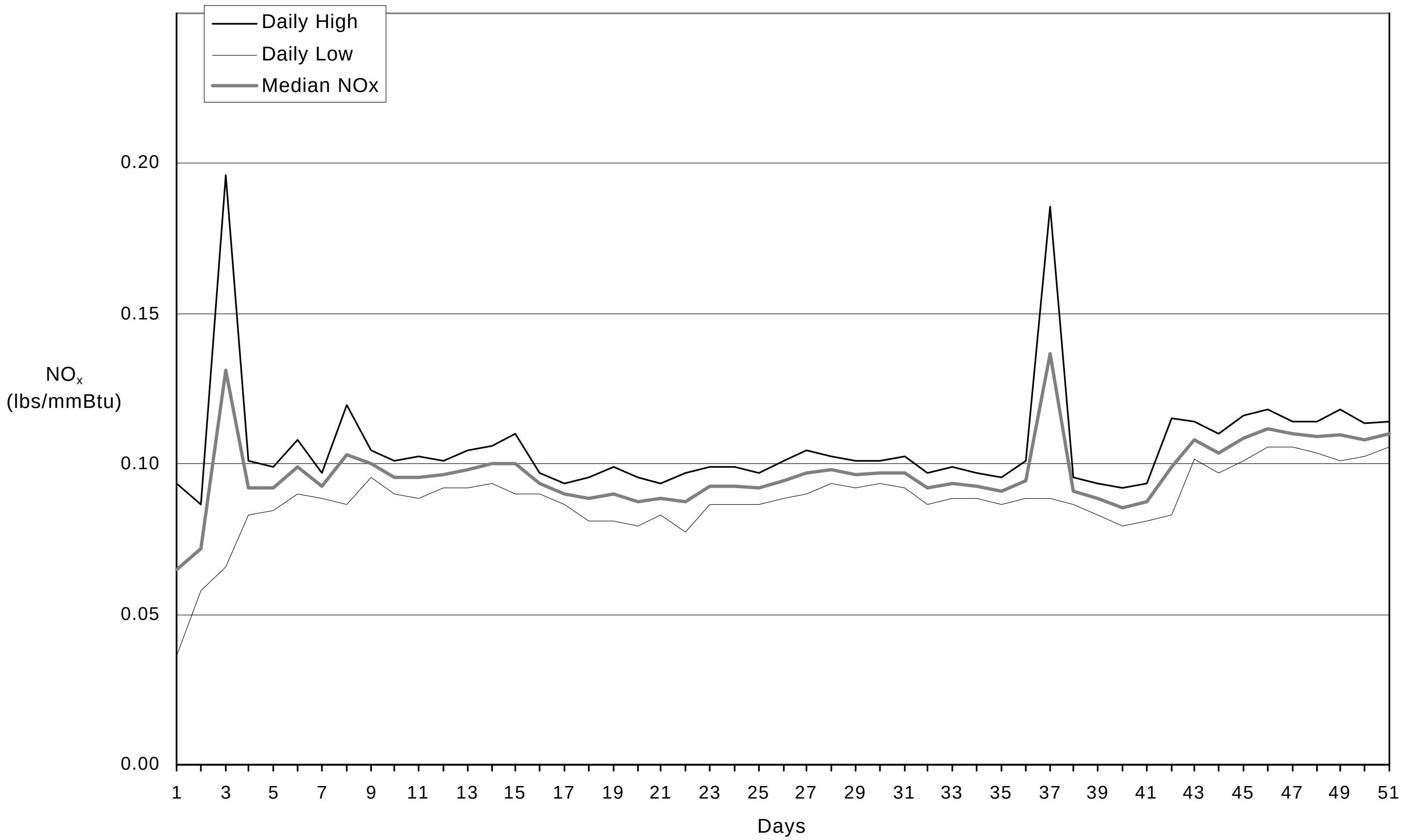


Figure A-3.2

Plant A-3: NO_x Emissions Excluding Natural Gas Hours

(Daily Maximum, Minimum and Median)

February 1 - March 31, 1996



Operation, Maintenance and Cost Related Information:

Plant A-3 uses regenerative air preheaters. The plant reported that preheater washing depends on slagging of the air preheater. In a supplementary interview, the plant reported that the air preheaters are washed approximately every 5000-6000 operating hours. Since SCR system operation began in 1987, the air preheaters have been washed approximately 5-7 times. The plant reported that air preheaters are washed when pressure loss over the air preheater increases to undesirable levels; this depends on the quality of coal burned and the amount of ammonia leakage. No cost information associated with washing air preheaters was provided. The SCR system uses anhydrous ammonia, which the plant stated has caused no problems. The maximum allowed ammonia slip is 3.75 ppm; actual ammonia slip is approximately 1.5 ppm for both units. Flyash from the plant is not recycled. The SCR system uses plate-type catalysts. The initial volume of the catalyst in Unit A was 544 square meters; an additional layer of 109 square meters was installed after approximately 15,000 operating hours. The initial volume of the catalyst in the other unit was 502 square meters, and a second layer of 100 square meters was installed after approximately 45,000 operating hours. The plant stated that installing additional catalyst layers cost approximately 20,000,000 Austrian Schillings per layer. The plant also stated that there have been no problems associated with the catalysts, such as slagging of ash or erosion of the catalysts' surface. The plant also stated that it has had no problems related to coal type, and added that it only uses coal with approximately 0.8% sulfur. The NO_x and O_2 monitors are calibrated automatically each day, and there is a manual calibration once a week. The plant reported capital costs of 270,000,000 Austrian Schillings per unit (catalyst and catalyst box). The plant reported operating expenses of 2500 to 3000 Austrian Schillings per ton of ammonia. No breakdown of specific cost components was provided. A summary of the operational problems and costs reported by Plant A-3 is shown in the table below.

Table A-3.3

Summary of Reported Operational Problems and Costs

Category	Summary	
Operational Problems	Unit A:	Air preheater slagging affected catalyst activity. Solved by installing additional catalyst layer.
Costs	For Each Unit (approximate):	
	Capital:	ATS 270,000,000
	Operating:	ATS 2500 to 3000/ton NH_3

Plant D-1

Plant/Unit Information:

The Danish Plant D-1 provided continuous half-hourly NO_x emissions rates for January 1 - March 31, 1996 for one 250 MWe unit retrofitted with SCR technology. The boiler began operation in 1990, and the SCR began operation in 1993. The boiler is described as a wet-bottom, boxer-fired boiler with "high dust" SCR system. The unit is equipped with low NO_x burners and an electrostatic precipitator. The data readings were corrected to ISO standards and 6% O_2 dilution basis. The plant is required to meet a NO_x standard of 400 mg/MJ, which converts to 0.93 lbs/mmBtu. Plant D-1 reported that there is an incentive to operate the plant at a low level, due to an emissions limit for all the power stations together in Denmark. In addition to the individual plant limit, a national program initiated in 1995 to reduce SO_2, NO_x and CO_2 emissions nationwide has resulted in production-based limits for the utility industry. The production-based NO_x limit for the Eastern Denmark region is 1.23 g/kWh. This limit applies to both electricity production and cogenerated heat production. A summary of the data provided by Plant D-1 is shown in Table D-1.1.

Table D-1.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly Data	Half-hourly
O_2 diluent	Yes
Moisture	Yes
Temperature	No
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	No
Calorific Value	Yes
Ultimate Analysis	Yes
Additional Elements (As, Ca, Na, K)	Yes
Electrical Output (MWe)	
Hourly Load	No
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	No

(cont.)

Table D-1.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	No
Description of Other Controls	Yes
Retrofit/New	Yes
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant D-1 provided coal data, but did not provide an oxygen percentage amount. The unit reported burning "hard coal" (bituminous); therefore, the standard F-factor of 9780 dscf/mmBtu was used in computing emissions rates. Table D-1.2 shows the coal data submitted by Plant D-1.

Table D-1.2

Coal Characteristics Data for Plant D-1

Coal Analysis	
	Unit A
Moisture (%)	8.5
Ash (%)	16.6
Nitrogen (%N)	1.25
Oxygen (%O)	N/A
Carbon (%C)	67.0
Hydrogen (%H)	4.6
Sulfur (%S)	1.5
GCV (kJ/kg)	23,740
F-Factor (dscf/mmBtu)	N/A
Arsenic (%AS)	0.0010%
Potassium (%K)	0.35%
Sodium (%Na)	0.07%
Calcium (%Ca)	0.65%

Emissions Data Analysis:

The average NO_x emission rate for January 1 - March 31, 1996 was 0.15 lbs/mmBtu. Figure D-1.1 shows the continuous half-hourly NO_x emissions for this time period. Three periods of exempt emissions were removed from the graph of continuous half-hourly averages and from the calculations of 24-hour and 30-day rolling averages. These exempt periods, identified by plant personnel, occurred on January 7, from January 22-27, and on March 27, 1996 and were related to malfunctioning ammonia injection nozzles that resulted in shutdown of the SCR (the January incidents) and a malfunctioning monitor (the March incident). Figure D-1.2 shows the 24-hour averages, and Figure D-1.3 expresses these results in 30-day rolling averages. Figure D-1.4 shows the continuous half-hourly NO_x emissions without the exempt periods removed.

Figure D-1.1

Plant D-1: NO_x Emissions (Half-Hourly Averages)

January 1 - March 31, 1996

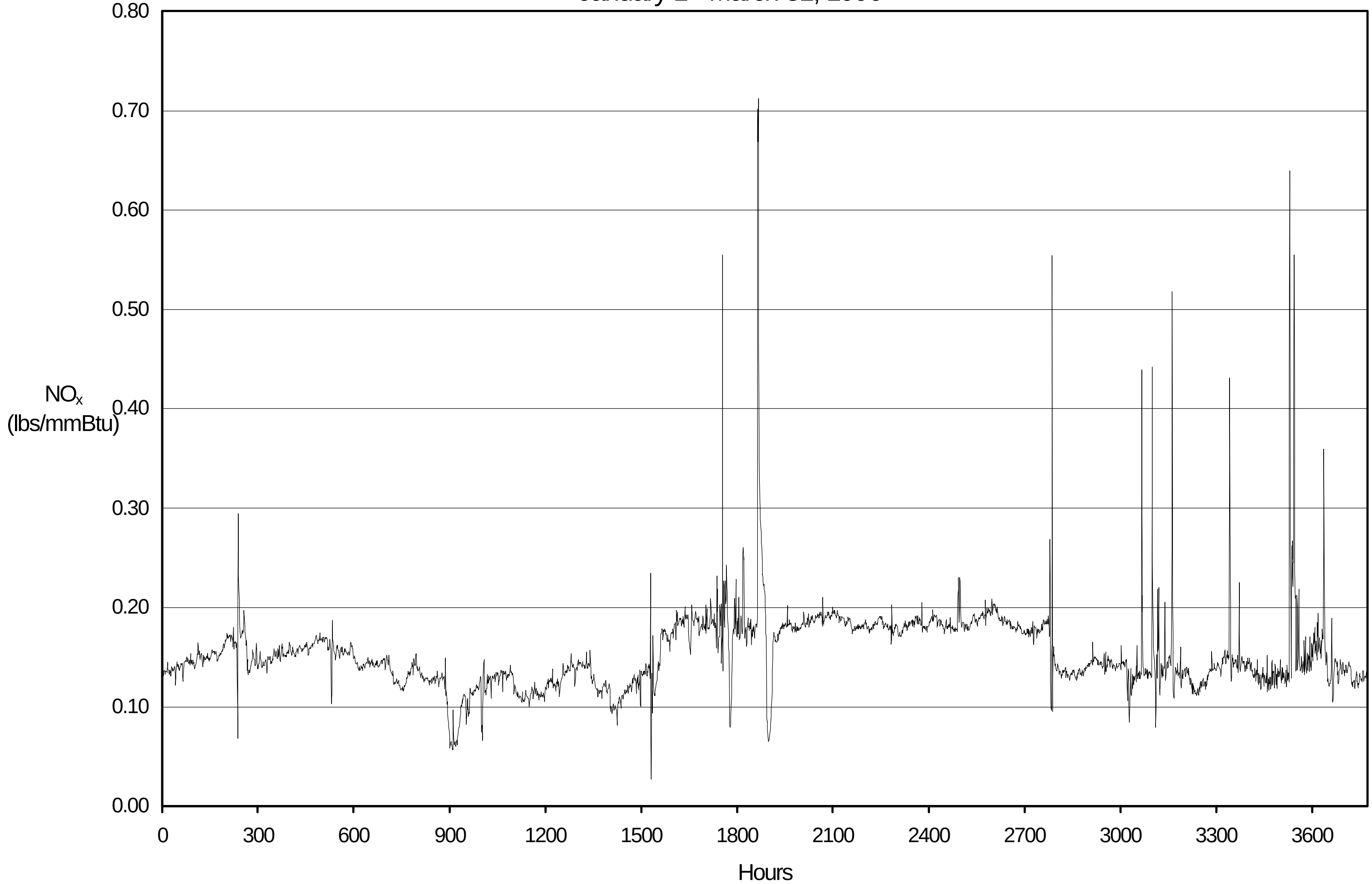


Figure D-1.2

Plant D-1: NO_x Emissions (24-Hour Averages)

January 1 - March 31, 1996

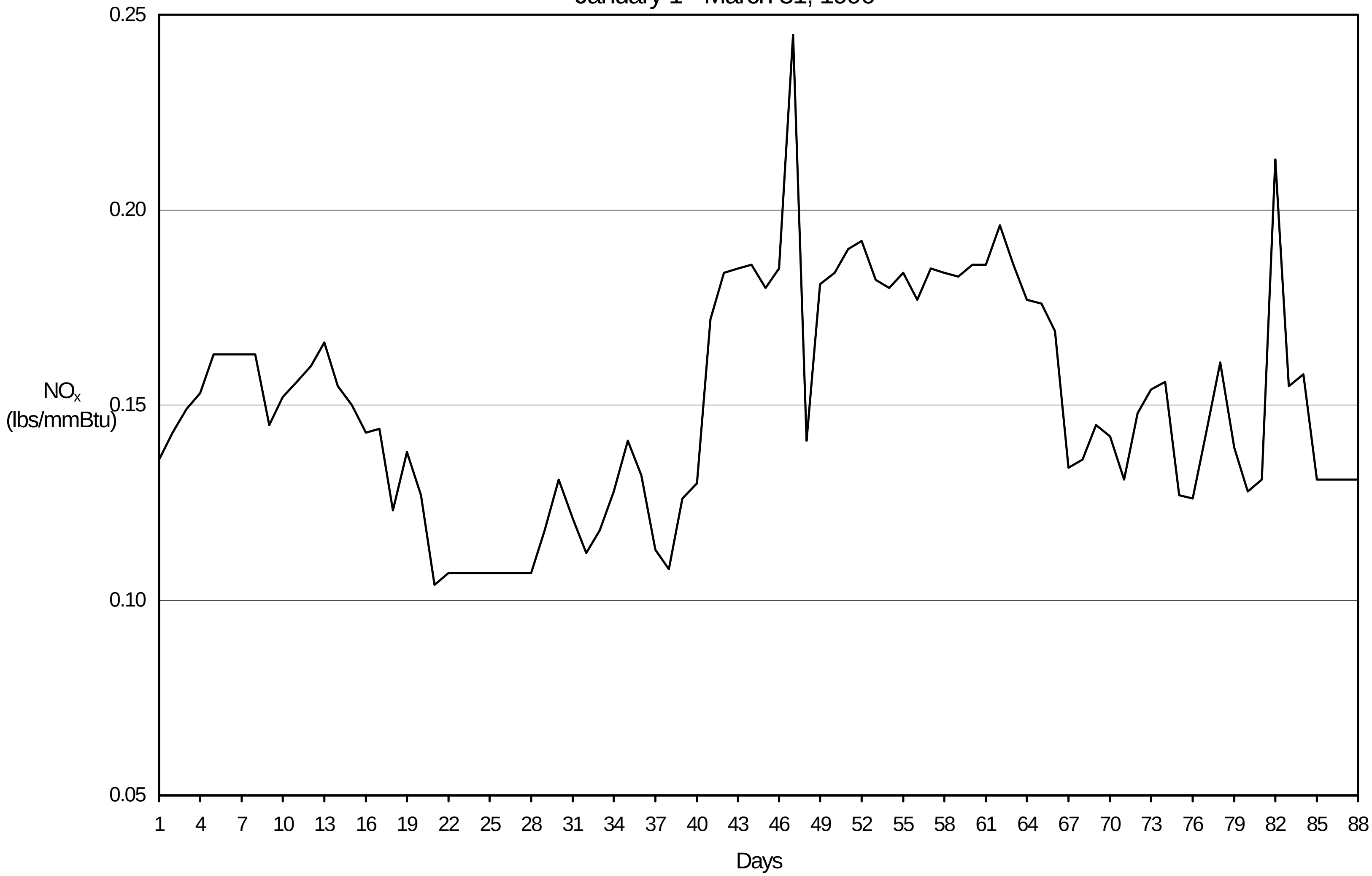


Figure D-1.3

Plant D-1: NO_x Emissions (30-Day Rolling Averages)

January 1 - March 31, 1996

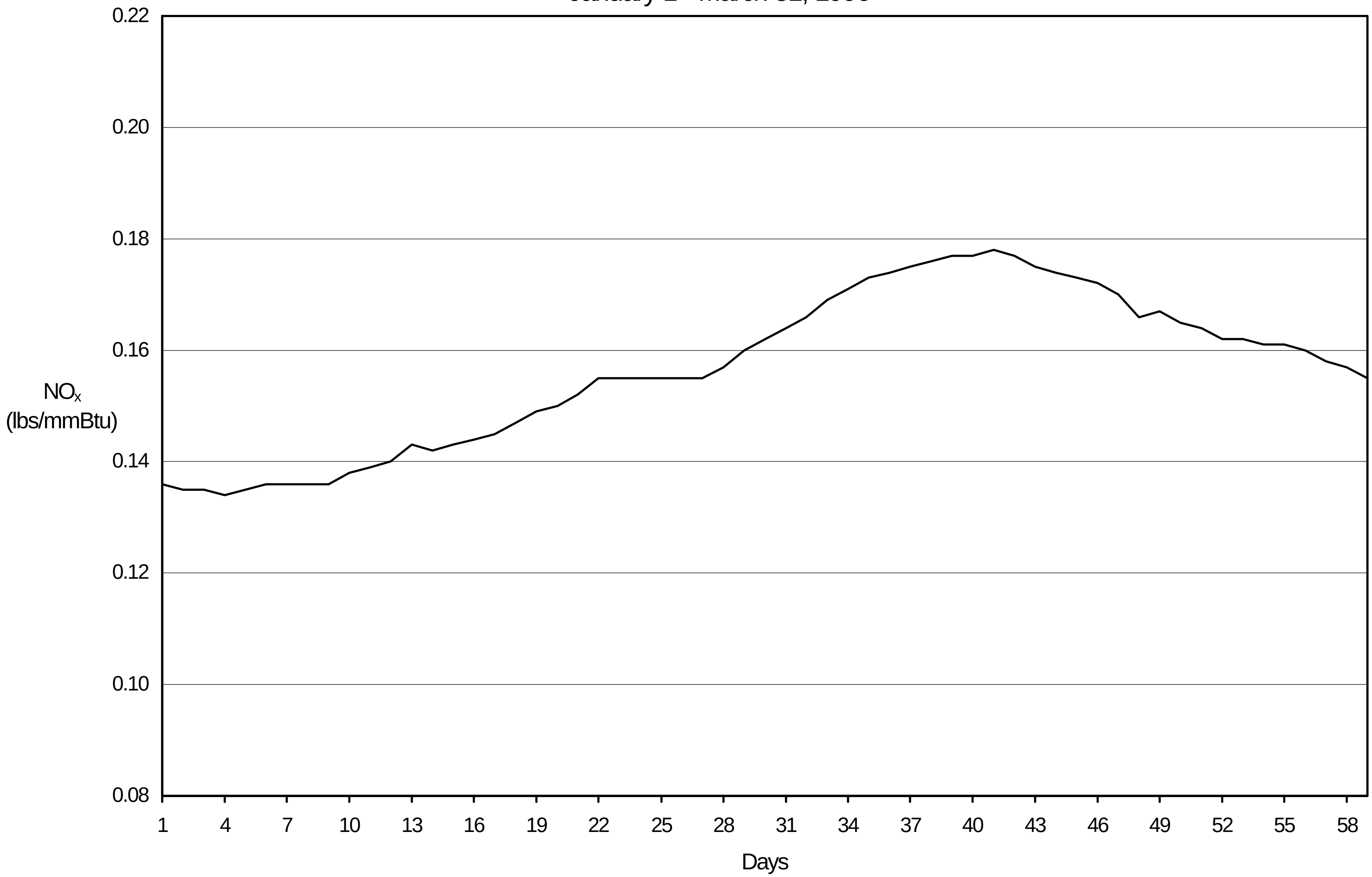
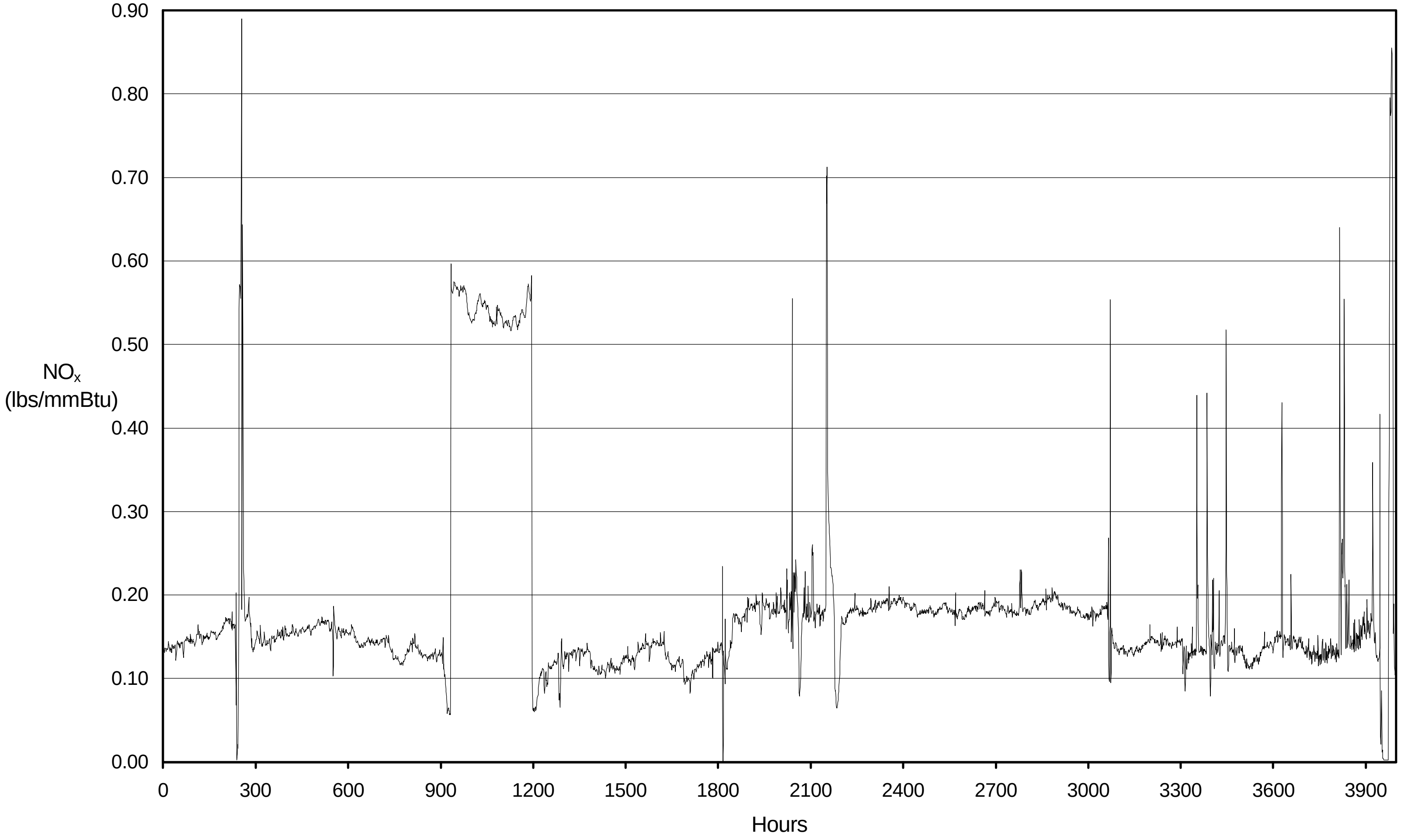


Figure D-1.4
Plant D-1: NO_x Emissions (Half-Hour) with Exempt Periods
January 1 - March 31, 1996



Operation, Maintenance and Cost Related Information:

Plant D-1 has a regenerative air preheater that has never been washed. The plant did not report any problems associated with the air preheater. The SCR system uses anhydrous ammonia, which the plant stated has caused no problems. The maximum ammonia slip from the SCR is 5 ppm and the maximum ammonia slip in the stack is 0.1 ppm. The plant stated that actual ammonia slip from the SCR is less than 4 ppm and in the stack is approximately 0.05 ppm. The plant stated that there have been no problems associated with the type of ammonia used. Flyash from the plant is not reinjected in to the boiler. The flyash generated at Plant D-1 is used for concrete, cement, asphalt, and landfill. Plant D-1 uses a plate-type catalyst with a total volume of 313 cubic meters. The maximum number of layers in the SCR reactor is three, all of which are currently filled. The plant stated that they are planning to add another catalyst layer after 30,000 operating hours. The replacement schedule is one layer every third year. However, no cost information was provided, and the plant did not specify any problems that may have led to this decision. The plant stated that there have been only minor problems maintaining the SCR system. They stated that there has been some wear on the catalyst and the ammonia injection nozzles caused by combusting very abrasive coals. The type of coal that caused this problem was not specified, and the plant did not state how the problem was solved or list any costs associated with the problem. Also, the plant did not describe the seriousness of this problem. No other operational impacts associated with the SCR were specified. The NO_x and O_2 monitors are calibrated with a certified standard once a week. The plant was unable to provide cost information. A summary of the operational problems and costs reported by the plant is shown in the table below.

Table D-1.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Combusting very abrasive coal caused wear on catalyst and ammonia injection nozzles. Operational impacts not specified. Degree of seriousness not specified. Solution not specified. Cost impact not specified.
Costs	Not Provided

Plant F-1

Plant/Unit Information:

Plant F-1 is the only plant located in Finland surveyed in this report. Plant F-1 provided continuous hourly operating data for one boiler for the period from July 24 - September 26, 1996. The high dust SCR system is a new installation. Both the boiler and the SCR system began operating in 1994. The boiler is described as an overcritical Benson-type once-through boiler. The unit is equipped with low NO_X burners in addition to SCR. Data was provided that had not been adjusted in any way. The plant is required to meet a NO_X standard of 70 mg/MJ (0.17 lbs/mmBtu). Further information has been requested on possibly exempt emissions during the reporting period. A summary of the data submitted by Plant F-1 is shown in Table F-1.1.

Table F-1.1

Summary of Data Submitted

Requested	Submitted?
Continuous NO_x Emissions	Yes
Hourly Data	Yes
O_2 diluent	Yes
Moisture	No
Temperature	Yes
NO_x Annual/Daily/Monthly Summary	No
Coal Characteristics	
Moisture	Yes
Volatile Matter	Yes
Fixed Carbon	Yes
Calorific Value	Yes
Ultimate Analysis	No
Additional Elements (As, Ca, Na, K)	No
Electrical Output (MWe)	
Hourly Load	Yes
Capacity	Yes
Pre-SCR	
Hourly	Yes
Estimate	No
Basic Plant Data	
Boiler Type	Yes
Ash Removal Technique	Yes
Burner Configuration	Yes
Schematic of Unit	Yes
Description of Other Controls	Yes
Retrofit/New	Yes

(cont.)

Table F-1.1 (cont.)

Summary of Data Submitted

Requested	Submitted?
Flyash Recirculation	Yes
Flyash Disposal	Yes
Air Preheater System	
Type	Yes
Operational Experience	Yes
Ammonia Information	
Type	Yes
Slip Experience	Yes
Other Operational Experience	Yes
Monitoring Data (if available)	No
SCR System Information	
Catalyst Type	Yes
Catalyst Volume	Yes
Catalyst Replacement Cycle	Yes
Other Operational Experience	Yes
Operational Experience Related to Coal Type	Yes
Monitor Quality Assurance Experience	Yes
Cost Information	
Capital Cost Summary	No
Operating Cost Summary	No

Coal Information:

Plant F-1 did not provide sufficient coal data with which to calculate F-factors. Therefore, a standard F-factor for bituminous coal (9780 dscf/mmBtu) was used.

Emissions Data Analysis:

The average of NO_x emissions for July 23 - September 27 period was 0.16 lbs/mmBtu. All NO_x readings of zero were removed from the graph of continuous emissions as well as from the calculations of the overall mean and 24-hour and 30-day rolling averages. Figure F-1.1 shows the continuous hourly emissions for the unit during this time period. Figure F-1.2 shows the emissions over the same period expressed in 24-hour averages, and Figure F-1.3 indicates the 30-day rolling averages.

Figure F-1.1

Plant F-1: NO_X Emissions

July 23 - Sept 27, 1996

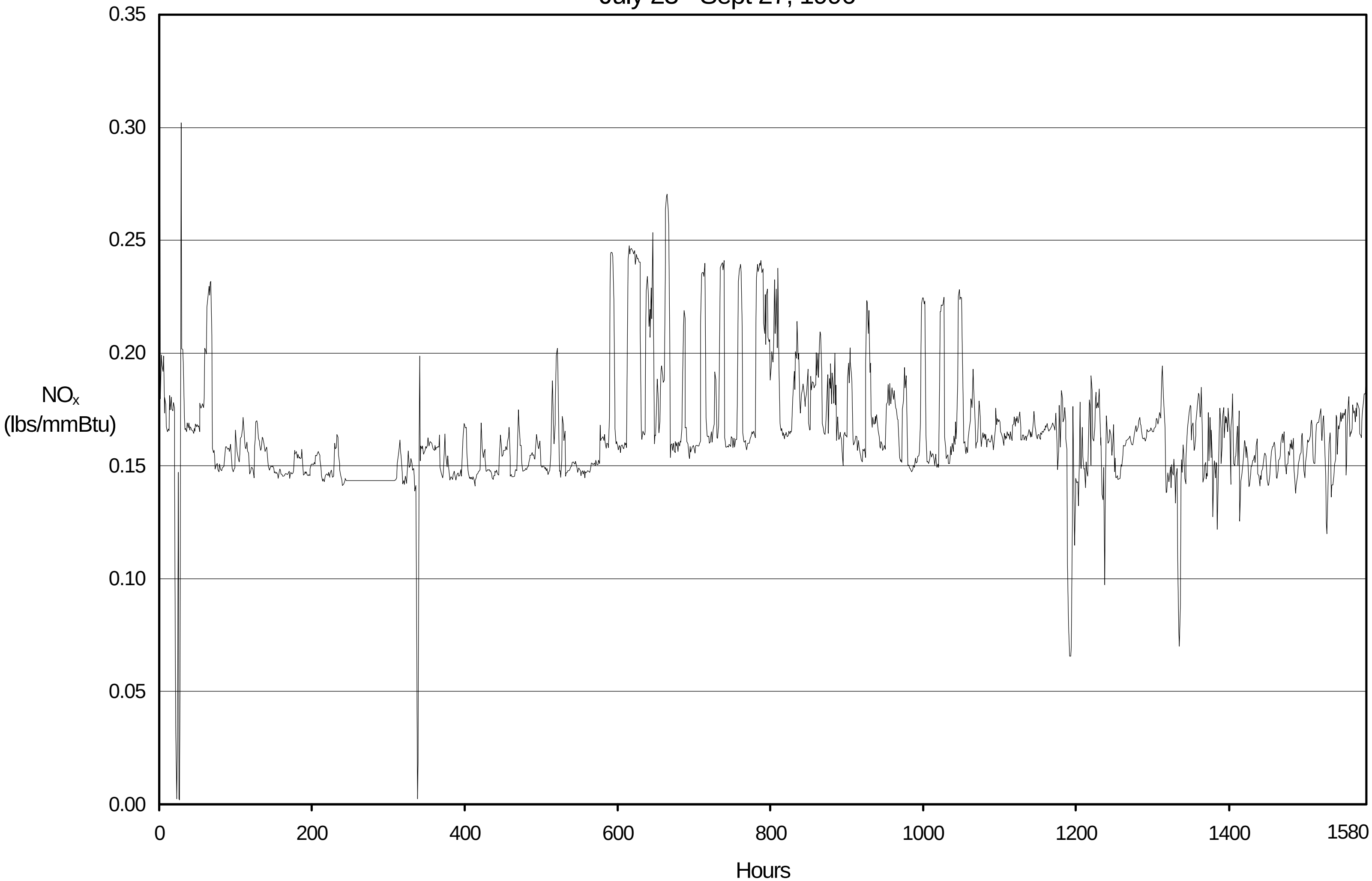


Figure F-1.2

Plant F-1: NO_x Emissions (24-Hour Averages)

July 23 - Sept 27, 1996

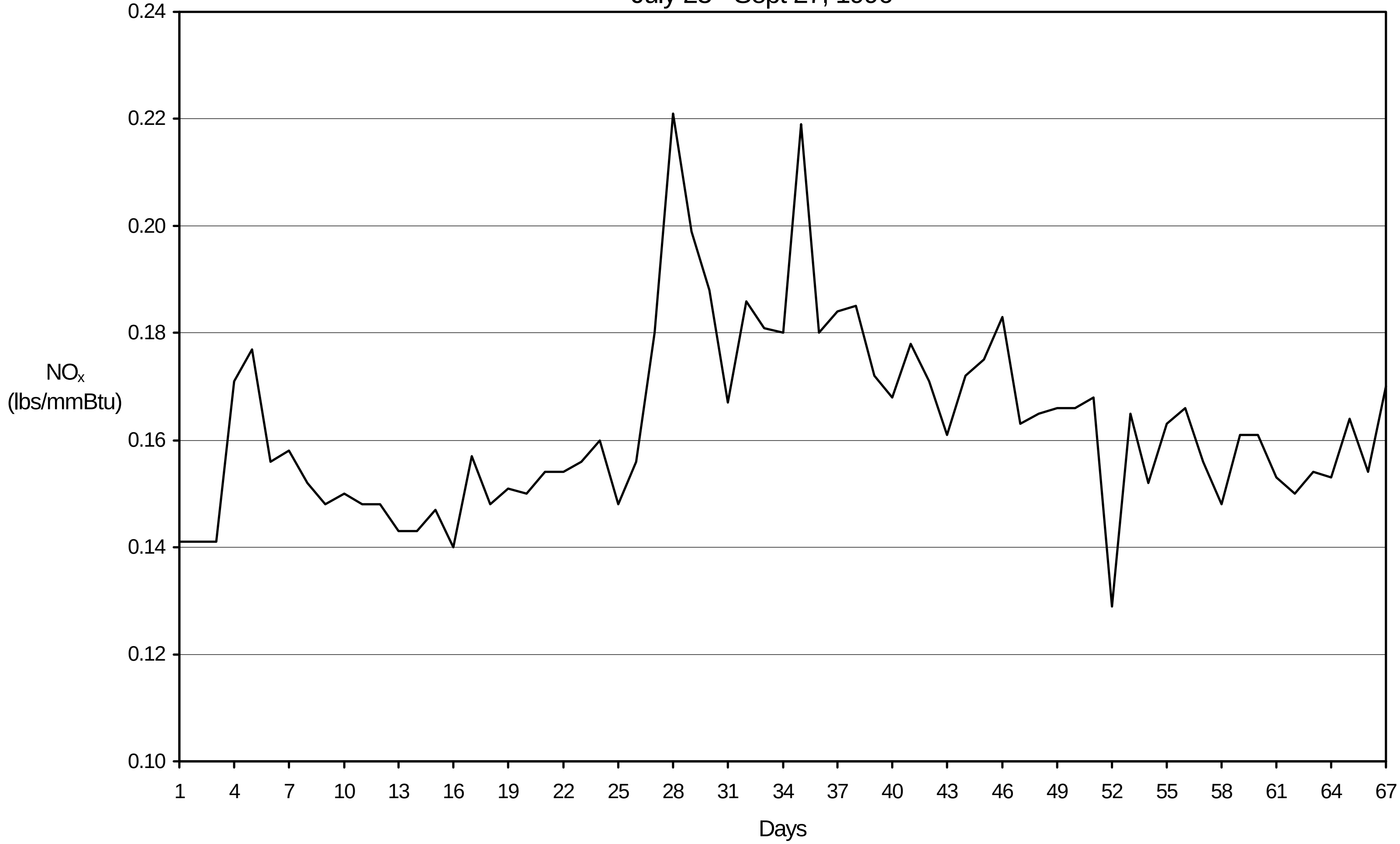
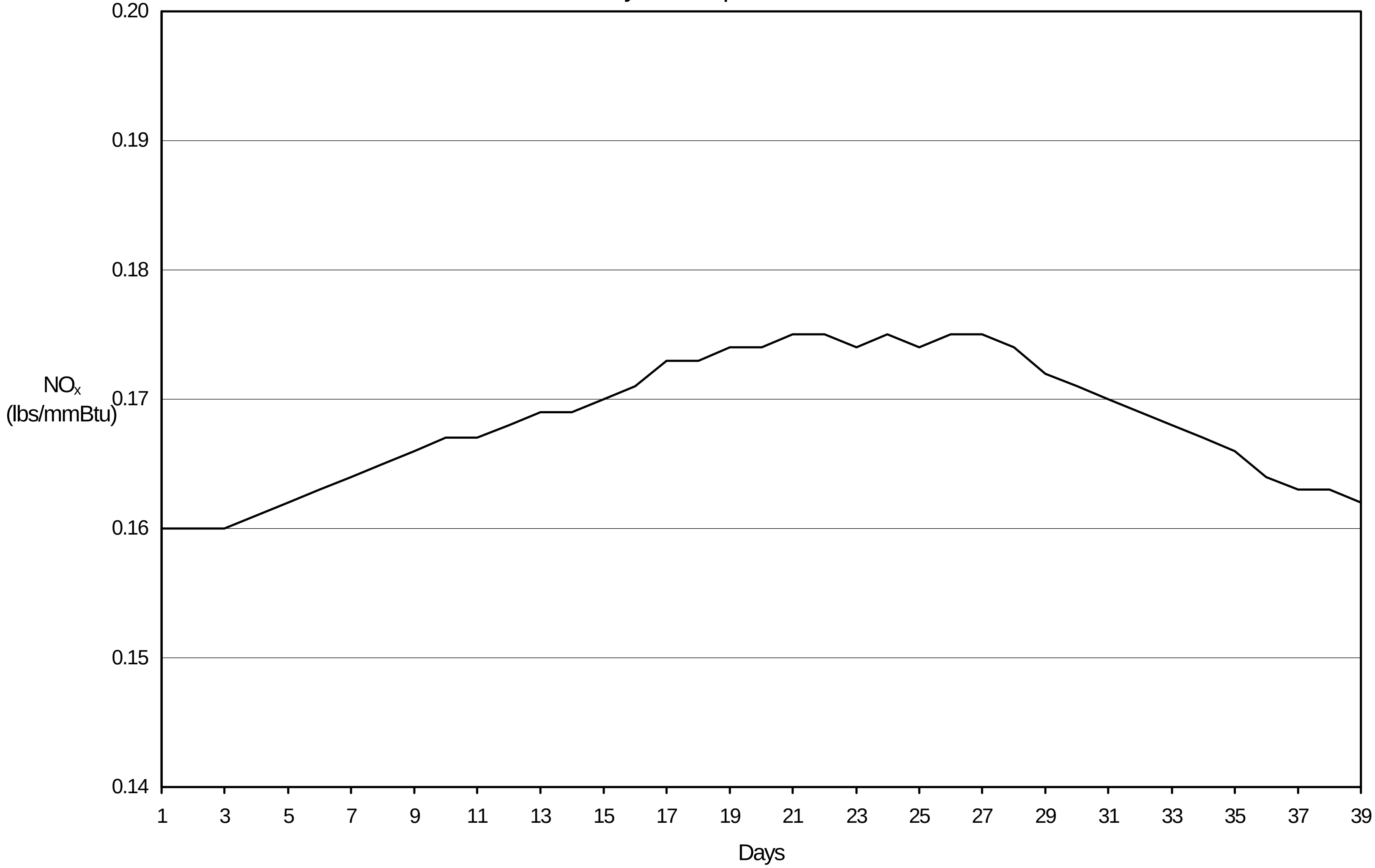


Figure F-1.3

Plant F-1: NO_x Emissions (30-Day Rolling Averages)

July 23 - Sept 27, 1996



Operation, Maintenance and Cost Related Information:

Plant F-1 has a regenerative air preheater that is washed once a year. The plant did not identify any problems associated with the air preheater and has not yet provided the costs of washing the preheater. Anhydrous ammonia is used. The plant stated that NH_3 leakages are a possible problem, and described precautions that they have taken to detect NH_3 leakages and mitigate damage. The ammonia storage tank and evaporating system are located approximately 500 meters from the plant, and the plant has installed ammonia monitors and camera monitoring. The plant also has a water spraying system to dissolve leaking ammonia. The plant did not indicate the ammonia leak had actually occurred, and did not describe costs or operational problems associated with the type of ammonia used. Ammonia slip at the plant has been less than 1 ppm. The plant reported that the ammonia concentration of the flyash is measured weekly. Flyash is not reinjected to the boiler; flyash from the plant is recycled for use in the construction industry.

The plant uses a plate-type catalyst with a total volume of approximately 300 cubic meters. No catalyst has been replaced since the facility began commercial operation in 1994, but one layer of catalyst was added in 1996. The plant added that once a year they test the catalyst reactor to estimate a catalyst replacement schedule. They have not replaced catalyst since SCR installation, but estimate that the first replacement will be done in 1999 or 2000. The cost of adding a layer of catalyst was not reported. The plant stated that before adding the additional layer, ammonia content of the flyash reached 150 ppm, but since the additional layer was added, it is approximately 50 ppm. The plant stated that they have had no notable problems operating and maintaining the SCR. They reported that pressure drop of the air preheater increased in 1995, but the plant could not determine that the pressure drop was caused by ammonia slip. The air preheater was washed during the annual overhaul. The plant did not specify whether washing the air preheater solved the problem, and did not describe any operational impacts associated with this problem.

Coal burned at the plant has a maximum sulfur content of 1.7%; the plant reported no problems related to coal type. The NO_x and O_2 monitors are calibrated every four weeks and tested more extensively once each year. The plant was unable to provide cost information. A summary of operational problems and costs reported by Plant F-1 is shown in the table below.

Table F-1.3

Summary of Reported Operational Problems and Costs

Category	Summary
Operational Problems	Increased pressure drop of air preheater; not certain whether SCR-related. Air preheater washed on regular schedule. Not specified whether this solved the problem. Cost impacts not specified.
Costs	Not Provided

APPENDIX B

RESPONSES TO COMMENTS ON THE 10/23/96 DRAFT SCR REPORT

An earlier draft of this report titled, "Performance of Selective Catalytic Reduction Technology at Electric Utility Units in the United States, Germany, and Sweden," dated October 23, 1996, was distributed to a broad cross-section of persons and organizations with possible interest in the subject area. Subsequently, comments were received from the reviewers of the draft report. The comments that EPA considered to be editorial in nature have been addressed by appropriately revising the text of the report, wherever necessary. Other comments are addressed in this Appendix. Individual commenters are identified by name and organization.

Mr. Reda Iskandar
Senior Vice President
Cormetech, Inc. Environmental Technologies

Comment Recommends including additional data from U.S. sources, specifically the cyclone boiler with high-dust SCR at PSNH-Merrimack02.

Response This report includes information on U.S. boilers US-4 and US-6 in addition to the U.S. boilers presented in the October 23, 1997 draft of the report.

Comment Recommends finding out the type of SCR installation at the plant G-6, Units C, D, and E.

Response The type of SCR installation (high dust, low dust, tail end) for all of the units included in the report is shown in Table 3.2 of this report. Twenty nine of the 33 SCR installations examined are of the high dust type.

Mr. Kent D. Zammit
Manager, NO_x Emission Control
Electric Power Research Institute

Comment States that report findings should not be used to draw broad conclusions regarding SCR performance that can be achieved in the U.S. since U.S. boilers fire a wide variety of coals and byproduct tolerance constraints may inhibit SCR performance.

Response In coal-fired boilers, a small fraction of the sulfur in coal converts to sulfur trioxide (SO_3). In units using SCR, this conversion occurs through direct oxidation of sulfur dioxide (SO_2) and catalytic conversion of SO_2. Sulfur trioxide in the presence of ammonia slip can form ammonium salts. These salts can, in turn, increase air heater pluggage potential. As shown in Table 3.3 of this report, the units examined so far are firing coal sulfur up to 1.5%; however SCR installations exist on high-sulfur fuel oil of as much as 5.4% sulfur [1, 2]. It is to be noted that SO_3 levels with oil-firing are generally substantially higher compared to coals with similar sulfur contents. At least one coal-fired plant in Japan and another in Austria are firing coals with sulfur contents of 2.5% and higher [1].

SCR feasibility on high-sulfur coals has also been shown at a demonstration project sponsored by DOE at Gulf Power's 75-MWe Crist Unit 5 [3]. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. These catalysts were evaluated while achieving NO_x reduction as high as 98%.

Criteria for successful catalyst performance at this demonstration required that 80% NO_x reduction be achieved while maintaining ammonia slip less than 5 ppm and SO_2 oxidation less than 0.75% through the end of the test program. The project experience shows that all catalyst suppliers would likely be able to meet a customer's specific SO_2 oxidation requirements.

In view of the experience both in the U.S. and abroad, the commenter's concern over the use of SCR for high-sulfur coal applications is unsupported. In general for such installations, design features such as a low ammonia slip, a catalyst that minimizes SO_3 conversion, and an economizer bypass to maintain proper flue gas temperatures at low loads are provided.

Comment Recommends more detailed evaluation of the Swedish multi-fuel unit with respect to possibility of oversize SCR, increase in catalyst activity due to oil-based vanadium, and byproduct tolerance.

Response In response to EPA's request for additional information, the plant stated in a telephone interview that Unit A burns coal the majority of the time and combusts oil only during startup or when the plant is having trouble with its coal mills. The plant stated that oil use never exceeds "a couple of percents" of operating time in a month, and that there are months when oil is not used at all. The plant noted that oil was burned approximately 4% of the operating time in October 1995 and approximately 1% of the operating time during January 1996 (period of high load). In light of these findings, the unit is essentially a coal-fired boiler and is not derated in operation. The plant also reported that analysis of a test piece of catalyst from Unit A showed catalyst activity decreasing at the expected rate and showed no impact from oil burning.

Comment Recommends that information related to boiler type, SO_3 concentration, NH3 slip, the presence of FGD with restricted water discharge, flue gas conditions, and capacity factor be presented to assess the key factors that allow SCR NO_x reduction above the conventional 80%.

Response SCR is a post-combustion NO_x control technology in which the reactor containing the catalyst is located downstream of the economizer, completely outside of the boiler combustion and heat transfer zones. The boiler type, therefore, has an insignificant impact on the SCR process. Consequently, experience with SCR on one boiler type can be applied to confirm feasibility of SCR application on other boiler types.

At SCR installations, ammonia slip is caused by the incomplete reaction of injected ammonia. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia into flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with SO_3 present to form ammonium salts which, in high-dust applications, can increase air preheater pluggage potential. Generally, with the available advanced catalysts and capability to design for low (5 ppm or less) ammonia slip, operational problems (resulting from undesirable levels of ammonia slip and SO_3) can be avoided.

Shown in Table 3.7 of this report are the ammonia slip levels provided by some plants. Actual ammonia slip levels being achieved have been provided for Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1, and US-5 while vendor guaranteed ammonia slip has been provided for Plants G-2, S-1, US-4, US-6, A-1, and A-2. As seen in Table 3.7, guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and 7 units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

Blowdown of flue gas desulfurization system can potentially contain ammonia in case both SCR and FGD are installed at a plant. However, this occurrence is expected to be rare for the following reasons:

- Presence of ammonia compounds at locations downstream of SCR system would be minimized by designing the SCR system for a low ammonia slip. It is therefore expected that only minimal quantities of such compounds may end up in any effluent from the downstream equipment.

- A wet FGD system would be preceded by a particulate control device, such as a precipitator or a baghouse. Experience shows that a significant amount of ammonia present in the flue gas ends up in the ash collected with these devices. It is therefore expected that the possibility of any ammonia showing up in an FGD bleed stream are remote.

In light of the above information, treatment of FGD blowdown for ammonia does not appear to be a problem. EPA requests information on SCR installations where this treatment is being done.

Annual capacity factor reflects annual usage of a boiler and would influence levelized costs associated with SCR at the specific boiler. Costs associated with SCR have been examined in detail in recent documents [4, 5].

Ms. Mary A. Gade
Director
Illinois Environmental Protection Agency

Comment Recommends including information on the performance of SCR on cyclone boilers.

Response This report includes information on one U.S. cyclone boiler, US-6, in addition to the two cyclone boilers at Plant G-10.

SCR is a post-combustion NO_x control technology. For the SCR process, the reactor containing the catalyst is located downstream of the economizer, completely outside of the boiler combustion and heat transfer zones. The boiler type, therefore, has an insignificant impact on the SCR process. Consequently, experience with SCR on one boiler type can be applied to confirm feasibility of SCR application on other boiler types.

Comment Recommends including information on the efficiency of SCR on high-sulfur coal.

Response In coal-fired boilers, a small fraction of the sulfur in coal converts to sulfur trioxide (SO_3). In units using SCR, this conversion occurs through direct oxidation of sulfur dioxide (SO_2) and catalytic conversion of SO_2. Sulfur trioxide in the presence of ammonia slip can form ammonium salts. These salts can, in turn, increase air heater pluggage potential. As shown in Table 3.3 of this report, the units examined so far are firing coal sulfur up to 1.5%; however SCR installations exist on high-sulfur fuel oil of as much as 5.4% sulfur [1, 2]. It is to be noted that SO_3 levels with oil-firing are generally substantially higher compared to coals with similar sulfur contents. At least one coal-fired plant in Japan and another in Austria are firing coals with sulfur contents of 2.5% and higher [1].

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SCR feasibility on high-sulfur coals has also been shown at a demonstration project [3] sponsored by DOE at Gulf Power's 75-MWe Crist Unit 5. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. These catalysts were evaluated while achieving NO_x reduction as high as 98%. Criteria for successful catalyst performance at this demonstration required that 80% NO_x reduction be achieved while maintaining ammonia slip less than 5 ppm and SO_2 oxidation less than 0.75% through the end of the test program. The project experience shows that all catalyst suppliers would likely be able to meet a customer's specific SO_2 oxidation requirements.

In view of the experience both in the U.S. and abroad, the commenter's concern over the use of SCR for high-sulfur coal applications is unsupported. In general for these installations, design features such as a low ammonia slip, a catalyst that minimizes SO_3 conversion, and an economizer bypass to maintain proper flue gas temperatures at low loads are provided.

Comment Recommends addressing secondary impacts of SCR such as decreased operational flexibility, ammonia slip, increased ammonium sulfate and bisulfate formation, or increased sulfur trioxide.

Response For some plants, flue gas temperature at lower loads may fall below the operating range of an SCR catalyst. However, the SCR system can be equipped with an economizer bypass that mixes a portion of the hotter flue gas from upstream of the economizer with the flue gas at the SCR reactor inlet. This bypass ensures that gas temperatures stay within the desired temperature range.

At SCR installations, ammonia slip is caused by the incomplete reaction of injected ammonia. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia into flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with SO_3 present to form ammonium salts which, in high-dust applications, can increase air preheater pluggage potential. Generally, with the available advanced catalysts and capability to design for low (5 ppm or less) ammonia slip, operational problems (resulting from undesirable levels of ammonia slip and SO_3) can be avoided.

Shown in Table 3.7 of this report are the ammonia slip levels provided by some plants. Actual ammonia slip levels being achieved have been provided for Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1, and US-5 while vendor guaranteed ammonia slip has been provided for Plants G-2, S-1, US-4, US-6, A-1, and A-2. As seen in Table 3.7, guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and 7 units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

Plants were requested to provide information on air preheater washings related to SCR operation. Many of the plants responded by providing historical information on air preheater washings. Shown in Table 3.7 of this report is information related to air preheater washing experienced at the responding SCR installations. Of the 24 units reporting the impact of SCR on air preheaters, only those with high dust configurations reported the need to conduct washing. The frequency of air preheater washing varied from once in a 6-7 year period to once each year, except for the Plant US-6 which has reported many washings of its air preheater since SCR retrofit in 1995. However, Plant US-6 noted that ammonia slip occurring due to insufficient bypass damper closing was believed to have caused much of the air preheater fouling that required washing. Plant US-2 also initially conducted washings once or twice a month after SCR installation until an additional layer of catalyst was added. This addition of catalyst eliminated the necessity for conducting excessive washings. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that all of the responding plants did not experience notable increases in air preheater washings resulting from normal SCR operation.

Comment Recommends including technical information on SCR catalysts.

Response Catalyst volume and type (plate or honeycomb) being used at many of the SCR installations are shown in the Table 3.2 of this report. These parameters are taken into consideration while designing an SCR system to provide the required NO_x reduction with acceptable levels of ammonia slip.

Comment Recommends including information on cost data for NO_x control effectiveness being achieved using SCR.

Response In addition to the request for information on operational experiences, plants were asked to provide information on the capital and operating costs associated with SCR. Several plants that provided operational information stated that they were unable to provide cost information because they considered it to be confidential. The information received on capital costs of high dust SCR installations is summarized in Chapter 8 of this report. Units with other types of SCR installations were omitted because the cost information received was very limited (1 unit with tail-end SCR and two units with low-dust SCR). Further, the costs of tail-end and low-dust SCRs can be significantly higher than the costs of high-dust SCRs since they involve reheating the flue gas. Five plants also submitted information on operating costs; this information is discussed in the Appendix entry for each of these plants. The capital costs, shown in Chapter 8 of this report, range between 51-77 $/kW for the boiler size range 352-710 MWe. Note that the cost projections for SCR applications on U.S. boilers have been presented in two recent reports [4, 5].

Dr. Michael J. Wax
Deputy Director
Institute of Clean Air Companies

Comment Recommends including data from additional plants using SCR.

Response The database in the study has been expanded to include information on U.S. boilers US-4, US-5, and US-6 and boilers in Austria, Denmark, and Finland. SCR performance at these plants is examined in this report.

Comment Recommends clarifying that SCR systems usually do not operate during startup and shutdown. Recommends excluding startup and shutdown periods from SCR efficiency calculations.

Response In this report, some emissions from Plant D-1 were excluded from analysis because the plant confirmed that these emissions occurred during exempt periods. The unit US-4 provided data that showed no exempt emissions. In any case, since exempt emissions may be included in most of the data analyzed by EPA, the NO_x reduction performance results in the report may be conservative.

Ms. Kim C. Walden
Environmental Policy Manager
Nebraska Public Power District

Comment Concerned that boilers firing low sulfur Powder River Basin (PRB) coal (with reflective ash) have exit temperatures exceeding 750 °F. For such boilers, application of SCR would cause oxidation of NH3 leading to additional NO_x production.

Response EPA rejects the commenters' claim of an SCR operating temperature limitation of 750°F. A review of the vendor literature and published information [6, 7, 8] shows the higher end of an acceptable temperature range to be around 850°F. There should therefore be no difficulty in applying SCR to a boiler with an economizer outlet temperature below 850 °F.

Comment Suggests that NO_x removal be tabulated with catalyst age.

Response In SCR applications, as the catalyst ages, ammonia injection rate is adjusted to satisfy the NO_x removal requirements. It is for this reason that ammonia slip guarantees are based on the slip occurring at the end of catalyst life. Since NO_x reduction is maintained through catalyst life, tabulation of NO_x removal with catalyst age is not pertinent.

As shown in Table 3.7 of this report, SCR installations have been operating with various catalyst management plans to achieve the required NO_x reductions.

Comment Concerned that SCR operation causes pluggage, which requires additional soot-blowing, which in turn leads to erosion.

Response Catalyst erosion is caused by the impingement of flyash on the catalyst surface and depends on gas velocity, ash properties, angle of impingement and catalyst properties. Significant erosion can be prevented by properly designing the SCR system and hardening the leading edge of the catalyst. Experience with flyash loadings as high as 30 g/Nm3 and flue gas velocities up to 6.2 m/s has been noted [2].

Sootblowing systems have been extensively used within boilers and air heaters. These systems can be designed with proper steam conditions to minimize erosion. Further, EPA is not aware of any erosion of SCR catalyst, resulting from sootblowing, that has been cited in the published literature.

Only one unit (A-2) out of the 33 units examined in this report reported localized erosion at the edges of the catalyst. The unit replaced the catalyst at the eroded locations and continued operation. SCR operation at this unit commenced in 1990. Thus the data in the report indicate that with proper design of SCR system, catalyst erosion is avoided.

Comment Concerned that because of catalyst material being a hazardous waste, recycling would be preferred over disposal and this would incur higher O&M costs.

Response Based on information on actual operating experience obtained from plants, SCR catalysts last for long periods of time. This can be inferred from Table 3.7 in this report which shows that, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. 2-7 years) of operation. Many catalyst manufacturers offer a disposal service for spent catalyst which involves either reactivating and reusing the catalyst or recycling the catalyst. Alternatively, the spent catalyst can be disposed of in an approved landfill. In light of the relatively long life of SCR catalysts, the volume of spent catalysts has been small and the cost of disposal has been negligible in Germany and Japan [1]. In the U.S., EPA has determined that spent catalyst is not a hazardous waste under RCRA Subtitle C [4].

Comment Concerned over SCR cost, especially retrofit.

Response In addition to the request for information on operational experiences, plants were asked to provide information on the capital and operating costs associated with SCR. Several plants that provided operational information stated that they were unable to provide cost information because they considered it to be confidential. The information received on capital costs of high dust SCR installations is summarized in Chapter 8 of this report. Units with other types of SCR installations were omitted because the cost information received was very limited (1 unit with tail-end SCR and two units with low-dust SCR). Further, the costs of tail-end and low-dust SCRs can be significantly higher than the costs of high-dust SCRs since they involve reheating the flue gas. Five plants also submitted information on operating costs; this information is discussed in the Appendix entry for each of these plants. The capital costs, shown in Chapter 8 of this report, range between 51-77 $/kW for the boiler size range 352-710 MWe. Note that the cost projections for SCR applications on U.S. boilers have been presented in two recent reports [4, 5].

Comment Concerned that adequate space for retrofitting SCR may not be available at power plants.

Response This concern is speculative because the commenter failed to cite any specific examples of units where the stated space limitations exist. Further, moving of existing equipment can be avoided by locating the SCR reactor in available space and using appropriate ducting to connect it to economizer and air preheater. This was done at the SCR retrofit at Merrimack Unit 2.

Comment Concerned over poisoning of catalyst leading to shorter catalyst life.

Response Metal compounds in flue gas, generated from trace metals in coal, can react with catalyst and cause deactivation or poisoning. However, the German wet bottom boiler experience has led to catalysts that resist poisoning. Several measures can be applied to prevent or to reduce catalyst poisoning. These measures can be classified as: 1) measures to prevent metal concentration enrichment in flue gas, and 2) measures to improve catalyst composition to increase resistance to poisoning [2]. A catalyst resistant to arsenic poisoning is being used at Merrimack Unit 2 SCR retrofit.

Plants were requested to provide information related to catalyst replacement at their SCR installations. Several plants responded by providing historical information on their catalyst replacement cycles. As shown in Table 3.7, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. 2-7 years) of operation. At one plant, no problems with catalyst performance were noted after 55,000 operating hours (or approx. 6 years). These results suggest that catalysts are performing satisfactorily over relatively long periods of operation at all of the responding SCR installations.

Catalyst poisoning has also been examined at a demonstration project sponsored by DOE at Gulf Power's 75-MWe Crist Unit 5 [3]. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. In the project, nine small-scale reactors were operated and catalysts were exposed to flue gas from combustion of high sulfur U.S. coal. The results showed that catalyst deactivation was similar to that experienced in Europe and Japan.

Mr. Charles F. Carlin, Jr.
Principal Engineer
Environmental Affairs
Northeast Utilities

Comment Recommends including information from the SCR installation at Merrimack Station Unit 2.

Response This report includes information on U.S. boilers US-4, US-5, and US-6 in addition to the U.S. boilers presented in the October 23, 1997 draft of the report.

Comment In discussion of data conversions, recommends clarifying that all NO_x concentration data have been converted to the same O_2 basis. Requests that report include the U.S. standard for O_2 basis for use with NO_x emissions from coal-fired boilers.

Response The NO_x concentration data received from SCR installations have all been corrected for dilution to correspond 0% O_2 basis. This dilution correction is required in the procedure for converting NO_x concentrations to units of lb/mmBtu [9].

Comment Recommends including discussion of catalyst age and NO_x reduction performance.

Response In SCR applications, as the catalyst ages, ammonia injection rate is adjusted to satisfy the NO_x removal requirements. It is for this reason that ammonia slip guarantees are based on the slip occurring at the end of catalyst life. Since NO_x reduction is maintained through catalyst life, tabulation of NO_x removal with catalyst age is not pertinent.

Plants were requested to provide information related to catalyst replacement at their SCR installations. Several plants responded by providing historical information on their catalyst replacement cycles. As shown in Table 3.7, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. 2-7 years) of operation. At one plant, no problems with catalyst performance were noted after 55,000 operating hours (or approx. 6 years).

Comment Recommends addressing ammonia slip and its impacts (air preheater pluggage, acid formation on downstream equipment, and ammonia stack emissions in the U.S.).

Response At SCR installations, ammonia slip is caused by the incomplete reaction of injected ammonia. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia in to flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with SO_3 present to form ammonium salts which, in high-dust applications, can increase air preheater pluggage potential.

Generally, with the available advanced catalysts and capability to design for low (5 ppm or less) ammonia slip, operational problems (resulting from undesirable levels of ammonia slip and SO_3) can be avoided.

Shown in Table 3.7 of this report are the ammonia slip levels provided by some plants. Actual ammonia slip levels being achieved have been provided for Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1, and US-5 while vendor guaranteed ammonia slip has been provided for Plants G-2, S-1, US-4, US-6, A-1, and A-2. As seen in Table 3.7, guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and 7 units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

Plants were requested to provide information on air preheater washings related to SCR operation. Many of the plants responded by providing historical information on air preheater washings. Shown in Table 3.7 of this report is information related to air preheater washing experienced at the responding SCR installations. Of the 24 units reporting the impact of SCR on air preheaters, only those with high dust configurations reported the need to conduct washing. The frequency of air preheater washing varied from once in a 6-7 year period to once each year, except for the Plant US-6 which has reported many washings of its air preheater since SCR retrofit in 1995. However, Plant US-6 noted that ammonia slip occurring due to insufficient bypass damper closing was believed to have caused much of the air preheater fouling that required washing. Plant US-2 also initially conducted washings once or twice a month after SCR installation until an additional layer of catalyst was added. This addition of catalyst eliminated the necessity for conducting excessive washings. Considering that annual washing of air preheaters at coal-fired plants is commonly conducted, the results suggest that all of the responding plants did not experience notable increases in air preheater washings resulting from normal SCR operation.

Minimizing ammonia slip also limits ambient air impacts. If ammonia slip in the flue gas is maintained below 30 ppmv, it will have minimal effect on the ammonia concentration in the ambient air [10].

According to the commenter, high acid dew point temperatures may result from additional SO_3 generated by the SCR catalyst. The power plants operate with sufficiently high air heater exit gas temperatures to avoid flue gas acid condensation. As an example, consider a plant firing a bituminous high sulfur coal [11] with chemical composition of 71.2% carbon, 4.9% hydrogen, 3.0% sulfur, 1.5% nitrogen, 7.7% oxygen, and 11.3% ash. For the coal, combustion calculations using 15% excess air would predict an SO_2 concentration of approximately 2,511 ppm. As a general industry practice, boiler systems are designed for a conversion rate of one percent from SO_2 to SO_3, which results in an SO_3 concentration of 25 ppm for this plant.

The acid dew point corresponding to 25 ppm of SO_3 is approximately 286°F [12]. The air heater design exit gas temperature would be selected above the acid dew point, preferably at 310°F or higher. Based on the comment, the SO_3 concentration would increase by another 0.5 to 0.75% of flue gas SO_2 concentration to account for the conversion by the catalyst. Thus, the maximum SO_3 concentration for this case would be about 43 ppm.

The acid dew point for a 43 ppm SO_3 concentration is estimated at approximately 295°F. Thus, the maximum potential for an increase in the acid dew point temperature is only 9°F. Repeating similar calculations for a very high sulfur (5% by weight) bituminous coal (with chemical composition of 78.6% carbon, 5.6% hydrogen, 5.0% sulfur, 1.3% nitrogen, and 9.5% oxygen) yields an acid dew point of approximately 300 F. This dew point is within the design air heater exit temperature of 310 F or higher. Thus, a properly designed boiler would have sufficient margins to cover any dew point increases associated with SCR applications.

Comment Recommends including information regarding precipitator position with respect to SCR (European installations may be equipped with hot precipitator upstream of SCR).

Response EPA understands that installations of SCR with a hot precipitator upstream of the reactor are not commonly found; only one plant in Germany is equipped with a hot precipitator upstream of SCR. It is worth noting that a hot precipitator would remove particulates and would permit selection of a catalyst with a smaller pitch in an SCR application, thereby lowering installation costs.

Comment Recommends including information on fuel constituent content because poisonous metals content in the coal fly ash is a design consideration for SCR.

Response Metal compounds in flue gas, generated from trace metals in coal, can react with catalyst and cause deactivation or poisoning. However, the German wet bottom boiler experience has led to catalysts that resist poisoning. Several measures can be applied to prevent or to reduce catalyst poisoning. These measures can be classified as: 1) measures to prevent metal concentration enrichment in flue gas, and 2) measures to improve catalyst composition to increase resistance to poisoning [2]. A catalyst resistant to arsenic poisoning is being used at Merrimack Unit 2 SCR retrofit.

Plants were requested to provide information related to catalyst replacement at their SCR installations. Several plants responded by providing historical information on their catalyst replacement cycles. As shown in Table 3.7, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. 2-7 years) of operation. At one plant, no problems with catalyst performance were noted after 55,000 operating hours (or approx. 6 years). These results suggest that catalysts are performing satisfactorily over relatively long periods of operation at all of the responding SCR installations.

Catalyst poisoning has also been examined at a demonstration project sponsored by DOE at Gulf Power's 75-MWe Crist Unit 5 [3]. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. In the project, nine small-scale reactors were operated and catalysts were exposed to flue gas from combustion of high sulfur U.S. coal. The results showed that catalyst deactivation was similar to that experienced in Europe and Japan.

Comment Recommends including discussion of hazardous waste disposal concerns regarding catalyst materials.

Response Based on information on actual operating experience obtained from plants, SCR catalysts last for long periods of time. This can be inferred from Table 3.7 in this report which shows that, in general, a layer was replaced/added after 15,000-48,000 hours (or approx. 2-6 years) of operation. Many catalyst manufacturers offer a disposal service for spent catalyst which involves either reactivating and reusing the catalyst or recycling the catalyst. Alternatively, the spent catalyst can be disposed of in an approved landfill. In light of the relatively long life of SCR catalysts, the volume of spent catalysts has been small and the cost of disposal has been negligible in Germany and Japan [1]. In the U.S., EPA has determined that spent catalyst is not a hazardous waste under RCRA Subtitle C [4].

Mr. Alex Huhmann
Public Service Electric and Gas Company

Comment States that the use of flow monitoring and F-factor data for the actual operating mmBtus from coal-fired plants has historically been high, 10-15%. Suggests that an alternative, more accurate, method to calculate mmBtus should be allowable, such as calculating mmBtus from fuel burned or from more accurate performance data.

Response Not within the scope of this report.

Mr. Craig Harrison
Counsel
Utility Air Regulatory Group

Comment Recommends including information on the SCR installation at Merrimack Unit 2.

Response This report includes information on U.S. boilers US-4, US-5, and US-6 in addition to the U.S. boilers presented in the October 23, 1997 draft of the report.

Comment Recommends segregating analyses of new and retrofit applications of SCR.

Response The NO_x reduction performance of an SCR system depends on the volume of the catalyst employed and the amount of NH3 injected into the flue gas and is independent of whether the system is retrofit onto a boiler or is installed with a new boiler. Further, as shown in this report, low ammonia slip levels (below 5 ppm) are being maintained at the SCR installations, including new or retrofit systems, that provided this information. This suggests that byproduct tolerance requirements at new applications and retrofits are quite similar. Therefore, for purposes of evaluating NO_x reduction capability of SCR, EPA sees no reason to segregate analyses of new and retrofit applications.

Comment Recommends grouping units according to boiler types as much as possible equivalent to the boiler types defined in the 1990 Clean Air Act Amendments, and comparing SCR performance within these categories.

Response SCR is a post-combustion NO_x control technology in which the reactor containing the catalyst is located downstream of the economizer, completely outside of the boiler combustion and heat transfer zones. The boiler type, therefore, has an insignificant impact on the SCR process. Consequently, experience with SCR on one boiler type can be applied to confirm feasibility of SCR application on other boiler types.

Comment Recommends including additional information on coal/oil cofiring units, plant S-1 in particular, to account for plant conditions when the unit is firing fuel oil. Recommends confirming that the boiler is not derated while firing coal.

Response In response to EPA's request for additional information, the plant stated in a telephone interview that Unit A burns coal the majority of the time and combusts oil only during startup or when the plant is having trouble with its coal mills. The plant stated that oil use never exceeds "a couple of percents" of operating time in a month, and that there are months when oil is not used at all. The plant noted that oil was burned approximately 4% of the operating time in October 1995 and approximately 1% of the operating time during January 1996 (period of high load). In light of these findings, the unit is essentially a coal-fired boiler and is not derated in operation. The plant also reported that analysis of a test piece of catalyst from Unit A showed catalyst activity decreasing at the expected rate and showed no impact from oil burning.

Comment Recommends explaining how data extracted by various methods can be compared.

Response The data conversions were explicitly described in the October 23, 1996 draft of the report. Data was analyzed only after converting it to units of lb/mmBtu.

Comment Requests that for continuous data, operating load and excess air level be evaluated in parallel with NO_x emissions. This would clarify the potential for low load operation (with the SCR reactor operating in an "oversized" mode) for the periods during which the data was obtained.

Response The intent of the report is to analyze the performance of SCR being achieved at coal-fired electric utility units for possible compliance periods and not to examine the impact of potential operating variables such as load or excess air on the SCR process. The findings of the report reflect that, over sustained periods of time, units surveyed are operating their SCR systems to meet their regulatory requirements. Generally, during operation of an SCR system, ammonia injection is varied to maintain the required controlled NO_x rate and the ammonia slip level. Since ammonia injection incurs operating cost, SCR systems are not operated in "oversized" mode.

Comment Requests information on the criteria used by EPA/PQA or the utility in selecting the periods over which unit operation was judged representative.

Response As described in footnote 5 of the October 23, 1996 draft report, "...Calculations excluded periods of no reported emissions (MW=0) but included all other data, including potentially exempt emissions (which were not identified in the data that was received)." Thus in its analyses of emissions data, EPA/PQA did not choose any periods but rather used all of the data received. This same data analysis methodology has been followed in this report. Again, as shown in Table 4 of the October 23, 1996 draft report, a month or more of data pertinent to actual operation was received from each unit. Thus the data used in EPA analysis is not short term test data.

Comment Requests SCR design information (esp. for low uncontrolled NO_x and high reduction units), such as catalyst volume, volume of flue gas treated (space velocity), residual NH_3 concentration allowed in flue gas, average NH_3 content in collected fly ash, and the fate of the fly ash.

Response Catalyst volume and type (plate or honeycomb) are shown in the Table 3.7 of this report. In an SCR system, these parameters will be taken in to consideration while designing an SCR system to provide the required NO_x reduction with acceptable levels of ammonia slip.

At SCR installations, ammonia slip is caused by the incomplete reaction of injected ammonia. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia into flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with SO_3 present to form ammonium salts which, in high-dust applications, can increase air preheater pluggage potential. Further, relatively high levels of ammonia slip can potentially contaminate flyash and impact its marketability. Generally, with the available advanced catalysts and capability to design for low (5 ppm or less) ammonia slip, potential operational problems (resulting from undesirable levels of ammonia slip and SO_3) can be avoided.

Shown in Table 3.7 of this report are the ammonia slip levels provided by some plants. Actual ammonia slip levels being achieved have been provided for Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1, and US-5 while vendor guaranteed ammonia slip has been provided for Plants G-2, S-1, US-4, US-6, A-1, and A-2. As seen in Table 3.7, guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and 7 units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

Fly ash absorption of any excess, unreacted ammonia (NH_3) released by an SCR system into the treated flue gas is a function of the ammonia slip rate, quantity of fly ash, and specific ash characteristics (namely pH, alkali mineral content, and volatile sulfur and chlorine content). SCR ammonia slip is a function of controllable design parameters, (i.e., NH_3/ NO_x ratio, SCR reactor space velocity, reaction temperature, inlet NO_x concentration, and NO_x reduction level). Because controlling ammonia slip limits absorption by fly ash, the system can be designed and operated to limit ash contamination to the extent that allows either landfill disposal or the sale of the fly ash as a byproduct.

Plants were requested to provide information related to flyash disposal at their SCR installations. The information received from some of the plants is shown in Table 3.7 of this report. Most of the responding plants sell their flyash. This indicates that flyash contamination is not an issue at these SCR installations. In light of the low ammonia slip levels being maintained at SCR installations, this result is not unexpected.

Comment Recommends addressing costs associated with use of SCR.

Response In addition to the request for information on operational experiences, plants were asked to provide information on the capital and operating costs associated with SCR. Several plants that provided operational information stated that they were unable to provide cost information because they considered it to be confidential. The information received on capital costs of high dust SCR installations is summarized in Chapter 8 of this report. Units with other types of SCR installations were omitted because the cost information received was very limited (1 unit with tail-end SCR and two units with low-dust SCR). Further, the costs of tail-end and low-dust SCRs can be significantly higher than the costs of high-dust SCRs since they involve reheating the flue gas. Five plants also submitted information on operating costs; this information is discussed in the Appendix entry for each of these plants. The capital costs, shown in Chapter 8 of this report, range between 51-77 $/kW for the boiler size range 352-710 MWe. Note that the cost projections for SCR applications on U.S. boilers have been presented in two recent reports [4, 5].

Mr. Arthur L. Baldwin, Program Coordinator, NO_x Control Technology
Mr. Dennis N. Smith, Program Coordinator, System Analysis Division
U.S. Department of Energy
Federal Energy Technology Center

Comment Recommends including information from additional SCR installations especially those in the U.S., Japan, Austria, and Denmark.

Response The database in the study has been expanded to include information on U.S. boilers US-4, US-5, and US-6 and boilers in Austria, Denmark, and Finland. SCR performance at these plants is examined in this report.

Comment Recommends that SCR effectiveness be analyzed in light of boiler type, coal sulfur content, space availability, ammonia slip, and catalyst poisoning due to coal trace metal content.

Response Information on the boiler type on which SCR is installed is shown in Table 3.2 of this report. However, SCR is a post-combustion NO_x control technology in which the reactor containing the catalyst is located downstream of the economizer, completely outside of the boiler combustion and heat transfer zones. The boiler type, therefore, has an insignificant impact on the SCR process. Consequently, experience with SCR on one boiler type can be applied to confirm feasibility of SCR application on other boiler types.

In coal-fired boilers, a small fraction of the sulfur in coal converts to sulfur trioxide (SO_3). In units using SCR, this conversion occurs through direct oxidation of sulfur dioxide (SO_2) and catalytic conversion of SO_2. Sulfur trioxide in the presence of ammonia slip can form ammonium salts. These salts can, in turn, increase air heater pluggage potential. As shown in Table 3.3 of this report, the units examined so far are firing coal sulfur up to 1.5%; however SCR installations exist on high-sulfur fuel oil of as much as 5.4% sulfur [1, 2]. It is to be noted that SO_3 levels with oil-firing are generally substantially higher compared to coals with similar sulfur contents. At least one coal-fired plant in Japan and another in Austria are firing coals with sulfur contents of 2.5% and higher [1].

SCR feasibility on high-sulfur coals has also been shown at a demonstration project [3] sponsored by DOE at Gulf Power’s 75-MWe Crist Unit 5. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. These catalysts were evaluated while achieving NO_x reduction as high as 98%. Criteria for successful catalyst performance at this demonstration required that 80% NO_x reduction be achieved while maintaining ammonia slip less than 5 ppm and SO_2 oxidation less than 0.75% through the end of the test program. The project experience shows that all catalyst suppliers would likely be able to meet a customer's specific SO_2 oxidation requirements.

In view of the experience both in the U.S. and abroad, the commenter’s concern over the use of SCR for high-sulfur coal applications is unsupported. In general for such installations, design features such as a low ammonia slip, a catalyst that minimizes SO_3 conversion, and an economizer bypass to maintain proper flue gas temperatures at low loads are provided.

Adequate space for retrofitting of SCR is generally available at power plants. This is evidenced by the existence of numerous SCR retrofits overseas. See Table 3.2 in this report. Moreover, in most cases, moving of existing equipment can be avoided by locating the SCR reactor in available space and using appropriate ducting to connect it to economizer and air preheater. This was done at the SCR retrofit at Merrimack Unit 2.

At SCR installations, ammonia slip is caused by the incomplete reaction of injected ammonia. This slip may be minimized by designing SCR systems such that good distribution and mixing of injected ammonia in to flue gas is ensured. In practice, the catalyst for a specific application will be sized with respect to NO_x reduction required and ammonia slip permitted. During SCR system operation, ammonia slip can react with SO_3 present to form ammonium salts which, in high-dust applications, can increase air preheater pluggage potential. Generally, with the available advanced catalysts and capability to design for low (5 ppm or less) ammonia slip, operational problems (resulting from undesirable levels of ammonia slip and SO_3) can be avoided.

Shown in Table 3.7 of this report are the ammonia slip levels provided by some plants. Actual ammonia slip levels being achieved have been provided for Plants G-1, G-2, G-3, G-4, G-5, G-6, G-8, G-10, A-3, D-1, F-1, and US-5 while vendor guaranteed ammonia slip has been provided for Plants G-2, S-1, US-4, US-6, A-1, and A-2. As seen in Table 3.7, guaranteed slip levels are below 5 ppm (at the end of catalyst lifetime) for the units that reported this information. Fourteen units reported actual slip levels being achieved; these levels range between <0.1 ppm to 5 ppm and 7 units reported levels of less than 1 ppm. Thus the data in Table 3.7 show that ammonia slip levels are being controlled to levels below 5 ppm and many units are achieving much lower ammonia slip levels after significant periods of operation.

Metal compounds in flue gas, generated from trace metals in coal, can react with catalyst and cause deactivation or poisoning. However, the German wet bottom boiler experience has led to catalysts that resist poisoning. Several measures can be applied to prevent or to reduce catalyst poisoning. These measures can be classified as: 1) measures to prevent metal concentration enrichment in flue gas, and 2) measures to improve catalyst composition to increase resistance to poisoning [2]. A catalyst resistant to arsenic poisoning is being used at Merrimack Unit 2 SCR retrofit.

Plants were requested provide information related to catalyst replacement at their SCR installations. Several plants responded by providing historical information on their catalyst replacement cycles. As shown in Table 3.7, in general, a layer was replaced/added after 15,000-56,000 hours (or approx. 2-7 years) of operation. At one plant, no problems with catalyst performance were noted after 55,000 operating hours (or approx. 6 years). These results suggest that catalysts are performing satisfactorily over relatively long periods of operation at all of the responding SCR installations.

Catalyst poisoning has also been examined at a demonstration project sponsored by DOE at Gulf Power's 75-MWe Crist Unit 5 [3]. At this demonstration, the performance of eight commercially available SCR catalysts was evaluated from various suppliers. In the project, nine small-scale reactors were operated and catalysts were exposed to flue gas from combustion of high sulfur U.S. coal. The results showed that catalyst deactivation was similar to that experienced in Europe and Japan.

Comment Recommends including information on costs associated with SCR use.

Response In addition to the request for information on operational experiences, plants were asked to provide information on the capital and operating costs associated with SCR. Several plants that provided operational information stated that they were unable to provide cost information because they considered it to be confidential. The information received on capital costs of high dust SCR installations is summarized in Chapter 8 of this report. Units with other types of SCR installations were omitted because the cost information received was very limited (1 unit with tail-end SCR and two units with low-dust SCR). Further, the costs of tail-end and low-dust SCRs can be significantly higher than the costs of high-dust SCRs since they involve reheating the flue gas. Five plants also submitted information on operating costs; this information is discussed in the Appendix entry for each of these plants. The capital costs, shown in Chapter 8 of this report, range between 51-77 $/kW for the boiler size range 352-710 MWe. Note that the cost projections for SCR applications on U.S. boilers have been presented in two recent reports [4, 5].

Dr. Brian Gullett
U.S. Environmental Protection Agency
National Risk Management Research Laboratory,
Air Pollution Prevention and Control Division

Comment Suggests further discussion of the technical basis for comparing Swedish and German units.

Response In response to EPA's request for additional information, the Swedish plant stated in a telephone interview that Unit A burns coal the majority of the time and combusts oil only during startup or when the plant is having trouble with its coal mills. The plant stated that oil use never exceeds "a couple of percents" of operating time in a month, and that there are months when oil is not used at all. The plant noted that oil was burned approximately 4% of the operating time in October 1995 and approximately 1% of the operating time during January 1996 (period of high load). In light of these findings, the Swedish Unit A is essentially a coal-fired boiler and can be analyzed with coal-fired German boilers.

Comment Questions whether the impact of pre-SCR NO_x levels on SCR performance may be worthy of further elaboration.

Response The data in the report indicate that using SCR, a boiler population with a large range of uncontrolled NO_x emissions can comply with the applicable NO_x emission limit. This is consistent with the fact that for a boiler with a wide range of uncontrolled NO_x emissions, an SCR system can be designed to provide the requisite NO_x reductions while maintaining acceptable levels of ammonia slip.

List of Commenters:

Black & Veatch
Cormetech, Inc. Environmental Technologies
Electric Power Research Institute (EPRI)
Illinois Environmental Protection Agency
Institute of Clean Air Companies (ICAC)
Nebraska Public Power District
Northeast Utilities
Public Service Electric and Gas Company
U.S. Generating Company
Utility Air Regulatory Group (UARG)
U.S. Department of Energy, Federal Energy Technology Center
U.S. Environmental Protection Agency, National Risk Management Research Laboratory

References

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2. "Optimizing SCR Catalyst Design and Performance for Coal-Fired Boilers," Scot Pritchard and Chris DiFrancesco, Cormetech, Inc.; and Shozo Kaneko and Norihisa Kobayashi, Kohei Suyama, and Kozo Iida, Mitsubishi Heavy Industries, Ltd., presented at EPRI/EPA 1995 Joint Symposium on Stationary Combustion NO_x Control, May 16-19, 1995.

3. “Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NO_x) Emissions from High-Sulfur Coal-Fired Boilers,” Final Report, Southern Company Services, Inc., Birmingham, Alabama, October 1996.

4. Revised Draft Report, “Investigation of Performance and Cost of NOx Controls as Applied to Group 2 Boilers,” prepared for EPA by The Cadmus Group, Inc., August, 1996.

5. Draft Report, “Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers,” prepared for EPA by The Cadmus Group, Inc., March, 1996.

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7. Brochures, "SCR Catalyst for Gas Turbines," "SCR Catalyst for Utility and Industrial Boilers," “Mitsubishi Dry Selective Catalytic NOx Removal System and Field Experience,” July 10, 1990, Letter from R. Iskandar of Cormetech to S. Khan of Bechtel.

8. B. Speronello, et. al., "Application of Composite NO_x SCR Catalysts in Commercial Systems," 1991 Joint Symposium on Stationary Combustion NO_x Control, Washington, D.C.

9. 40 CFR Part 60, Reference Method 19.

10. American Lung Association, “Why NO_x?” April 1989, p. 12.

11. "Coal Data: A Reference," Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels, U.S. Department of Energy, February 1995, p. 108.

12. Lisle and J. Sensenbaugh, "The Determination of Sulfur Trioxide and Acid Dew Point in Flue Gases,” *Combustion*, **36**, 12, January 1965.