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Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for Sulfur Dioxide (SO_2) Emission Standards for Small Steam Generating Units

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OVERVIEW OF THE REGULATORY BASELINE, TECHNICAL BASIS, AND ALTERNATIVE CONTROL LEVELS FOR SULFUR DIOXIDE (SO_2) EMISSION STANDARDS FOR SMALL STEAM GENERATING UNITS

Emission Standards Division

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, N.C. 27711

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1.0 INTRODUCTION

This report provides an overview of the regulatory baseline, technical basis, and alternative control levels available for developing new source performance standards (NSPS) limiting sulfur dioxide (SO_2) emissions from small steam generating units (i.e., boilers). Small boilers are defined as industrial-commercial-institutional steam generating units having a heat input capacity of 29 MW (100 million Btu/hour) or less.

Many SO_2 control techniques were considered for the purpose of evaluating alternative SO_2 emission standards for small boilers. Detailed discussions of the design and operating principles of each of these techniques can be found in the report entitled "Small Steam Generating Unit Characteristics and Emission Control Techniques"[1] and References 2 and 3.

This report discusses the quantity of SO_2 emissions generated and the technical feasibility of controlling those emissions from boilers with heat input capacities of 29 MW (100 million Btu/hour) and less. However, this report does not address natural gas or nonfossil fuels because they have negligible amounts of sulfur and correspondingly low SO_2 emissions potential.

2.0 SUMMARY

The national average State implementation plan (SIP) emission limit for small, oil-fired boilers is 1,010 ng/J (2.35 lb/million Btu). However, projected fuel prices are available only for fuel oils capable of meeting SO_2 emission limits of 1,290 and 690 ng/J (3.0 and 1.6 lb/million Btu). Consequently, for purposes of analysis, the regulatory baseline emission level selected for oil-fired boilers is 1,290 ng/J (3.0 lb/million Btu) heat input.

The control techniques considered for reducing SO_2 emissions from oil-fired boilers include medium sulfur oil, very low sulfur oil, sodium scrubbing flue gas desulfurization (FGD), dual alkali FGD, and lime/limestone FGD. The use of medium sulfur oil can reduce SO_2 emissions to 690 ng/J (1.60 lb/million Btu) heat input. Similarly, the use of very low sulfur oil can reduce SO_2 emissions to 210 ng/J (0.50 lb/million Btu) heat input. The use of FGD systems can reduce SO_2 emissions from oil-fired boilers by 90 percent or more over uncontrolled levels. Emission levels of 690 ng/J (1.6 lb/million Btu), 210 ng/J (0.50 lb/million Btu), and 90 percent SO_2 reduction, therefore, are selected as Alternative Control Levels 1, 2, and 3, respectively, to represent the SO_2 control performance of medium sulfur oil, very low sulfur oil, and FGD systems.

The national average SIP emission limit for small, coal-fired boilers is 1,460 ng/J (3.4 lb/million Btu) heat input. However, projected fuel prices are only available for coals capable of meeting SO_2 emission limits of 1,550 and 1,120 ng/J (3.6 and 2.6 lb/million Btu). Consequently, for purposes of analysis, the regulatory baseline emission level selected for coal-fired boilers is 1,550 ng/J (3.6 lb/million Btu).

The control techniques considered for reducing SO_2 emissions from coal-fired boilers include low sulfur coal, sodium scrubbing FGD, dual alkali FGD, lime/limestone FGD, lime spraying drying FGD, and fluidized bed combustion (FBC). The use of low sulfur coal can reduce SO_2 emissions from small coal-fired boilers to 520 ng/J (1.2 million Btu/hour). The use of FGD systems or FBC units can reduce SO_2 emissions by 90 percent or more over uncontrolled levels. An emission level of 520 ng/J (1.2 lb/million Btu) heat input is, therefore, selected as Alternative Control Level 1 and 90 percent reduction is selected as Alternative Control Level 2 to represent the SO_2 control performance of low sulfur coal and FGD or FBC systems, respectively.

3.0 OIL SO_2 EMISSIONS AND CONTROL TECHNIQUES

The control techniques considered for reducing SO_2 emissions from small oil-fired boilers include medium sulfur oil, very low sulfur oil, sodium scrubbing FGD, dual alkali FGD, and lime/limestone FGD.

3.1 REGULATORY BASELINE EMISSION LEVELS

The regulatory baseline SO_2 emission level for small oil-fired boilers is based on the national average SIP emission limit for small, oil-fired boilers. The national average SIP SO_2 emission limit for small oil-fired boilers is 1,010 ng/J (2.35 lb/million Btu) and is essentially independent of boiler size. However, projected fuel prices are available only for oils capable of meeting SO_2 emission limits for 1,290 and 690 ng/J (3.0 and 1.6 lb/million Btu). As a result, a regulatory baseline of 1,290 ng/J (3.0 lb/million Btu) is selected for purposes of analysis.

3.2 MEDIUM, LOW, AND VERY LOW SULFUR OIL

The sulfur content of fuel oil determines the SO_2 emission rate from an oil-fired steam generating unit. Use of medium, low, or very low sulfur oil limits SO_2 emissions by reducing the amount of sulfur available for SO_2 formation. Table 3-1 presents the oil classification scheme used to represent fuel oils fired in steam generating units. In this classification scheme, oil is classified by its sulfur content. This classification scheme originated from classifications used by the U.S. Department of Energy to study fuel oil use patterns and to report refinery production data. The classifications reflect the fact that many distillate and residual oils are produced to meet market demands created by existing Federal, State, and local SO_2 emission regulations. For example, "low sulfur" distillate and residual fuel oils can be fired to meet the 1971 NSPS (40 CFR Part 60, Subpart D) emission limit of 340 ng/J (0.80 lb/million Btu) heat input for steam generating units with a heat input capacity greater than 73 MW (250 million Btu/hour), or more stringent standards adopted by State or

TABLE 3-1. SO_2 EMISSION RATES FOR VARIOUS OIL TYPES

Oil Type	SO_2 Emission Rate ng/J (lb/million Btu)
Very Low Sulfur	130 (0.3)
Low Sulfur	340 (0.8)
Medium Sulfur	690 (1.6)
High Sulfur	1,290 (3.0)

local governments. Factors such as refinery techniques, storage and transportation methods, and fuel handling at the steam generating unit site serve to make a given fuel oil shipment relatively homogeneous with respect to fuel sulfur content. Thus, there is little variability in SO_2 emissions resulting from the combustion of a specific fuel oil shipment.

Fuel oils with low sulfur contents are generally produced by refining low sulfur content crude oils, however, a number of hydrodesulfurization (HDS) processes are available for producing low sulfur oil from high sulfur oil.[2,4] Although both distillate oils and low sulfur residual oils can be produced from any crude oil, most low sulfur residual oils are produced from low sulfur crude oils and/or by blending with lower sulfur oils. Low sulfur oils can be fired in any steam generating unit designed to fire oil, although different burners may be required to achieve good combustion and fuel heating may be required to reduce viscosity for pumping and proper atomization at the burner tip.

A distinction exists between the sulfur content of most residual oils and distillate oils. Residual oils generally are higher in sulfur content and have a wider range of sulfur contents than distillate oil. The sulfur content of residual oil, for example, can vary from as little as 0.3 weight percent to over 3.0 weight percent. Although the sulfur content of distillate oil can be as low as 0.2 weight percent, the maximum sulfur content is limited to 0.5 weight percent by fuel oil specifications adopted by the American Society for Testing and Materials (ASTM).

Medium sulfur residual oil is widely available throughout the United States.[5] Generally speaking, low and very low sulfur residual oils are not widely available throughout the United States. Distillate oil, however, is widely available. The maximum sulfur content of distillate oil (0.5 weight percent), therefore, serves as a useful benchmark for identifying the sulfur content of those very low sulfur fuel oils that are widely available throughout the United States. In a few areas, both distillate oil and very low sulfur residual oils with sulfur contents of less than 210 ng/J (0.5 lb/million Btu) heat input will be available.

Because of their national availability and extensive use in small steam generating units, medium sulfur oils and very low sulfur oils (distillate oil and very low sulfur residual oils) are considered demonstrated control techniques for reducing SO_2 emissions from small steam generating units.

3.3 SODIUM SCRUBBING FGD SYSTEMS

Sodium scrubbing FGD systems employ an aqueous solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) in the scrubber to absorb SO_2 from the boiler flue gas. Sodium scrubbers are the most extensively used wet FGD systems in the industrial boiler sector and have been widely applied on small oil-fired boilers.

The vast majority of sodium scrubbing systems have been applied on small oil field steam generating units. Sodium scrubbers used in these applications are package systems that are skid-mounted, shipped to the site, and installed for operation with a minimum of on-site fabrication. One report estimates that 89 percent of all sodium scrubbers in operation are used on oil field steam generating units, and 74 percent of all sodium scrubbers in operation are used on boiler size equivalents (i.e., the heat generating capacity serviced by the scrubber) less than 29 MW (100 million Btu/hour).[6]

These boilers usually operate under constant, high-load conditions, whereas other small industrial-commercial-institutional boilers can experience significant load swings. However, boiler load swings can be monitored and accommodated by the scrubber system's process control instrumentation and, as a result, have not been shown to be deleterious to sodium scrubber operation.[7]

In response to changes in flue gas flow rate and/or SO_2 gas concentration, changes can be made to the scrubber liquid pumping rate and the reagent addition rate. Moreover, the buffering capacity of these systems allows changes to be made without affecting SO_2 removal performance. The popularity of sodium scrubbers can be attributed primarily to their ease of operation (requiring minimal operator training and attention) and overall reliability.

Table 3-2 presents SO_2 emissions data for 20 oil-fired steam generating units equipped with sodium scrubbers and operated to produce steam for tertiary oil recovery. All SO_2 emission tests were short-term compliance tests (typically over a 3-hour period). Sulfur dioxide emissions were measured using either EPA Reference Method 8 or continuous emission monitors (CEM). The short-term CEM tests were performed using ultraviolet photometry. These tests are considered as alternative methods to measure SO_2. From this table, it can be seen that SO_2 removal efficiency ranged from 87.5 to 99.5 percent for oils having sulfur contents ranging from 0.6 to 1.66 weight percent. Boiler operating loads ranged from 67 to 108 percent of full load.

Table 3-3 shows that SO_2 removal efficiency for these 20 sodium scrubbers averaged 95.2 percent. The average SO_2 outlet emissions were 30 ng/J (0.07 lb/million Btu). The sulfur content of the oils and operating load for the 20 boilers averaged 1.21 weight percent and 87.5 percent of full load, respectively.

Although long-term performance data are not available for sodium scrubbing systems operating on small oil-fired boilers, the long-term performance of sodium scrubbing systems on oil-fired boilers can be inferred from analyzing the long-term performance of sodium scrubbers on coal-fired boilers. Thirty days of SO_2 emission data were available and were analyzed for SO_2 reduction variability for one sodium scrubbing FGD system on a coal-fired boiler. The data are discussed below in Section 4.3. Although these data were collected for a sodium scrubber on a larger [55 MW (188 million Btu/hour)] boiler, the variability of a smaller sodium scrubbing system should not be significantly different. Also, because the sulfur content of oils is more consistent and less variable than the sulfur content of coals, the variability results using the 30-day SO_2 emissions data from a coal-fired boiler would be a conservatively high estimate of the emission variability for sodium scrubbers on oil-fired boilers.

The variability results from the coal-fired boiler/sodium scrubber system, when applied to oil-fired boiler/sodium scrubber systems, indicate that sodium scrubbers on oil-fired boilers could comply with a 90 percent SO_2 reduction specification using a 30-day rolling averaging period if the

TABLE 3-2. EMISSION DATA FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO OIL-FIRED SMALL STEAM GENERATORS (8)

Boiler I.D.	Absorber type (a)	Boiler equivalent size, MW (million Btu/hr) heat input	Oil sulfur content (percent)	Percent of full load	Scrubber inlet pH	Blowdown pH	SO2 removal efficiency (percent)	Outlet SO2 emissions (ng/J) (g)	SO2 test method (number of runs) (h)
7	LJE	6.7 (23)	1.00	92 (d)	NA (f)	NA	91.0	38.7	EPA 8 (3)
8	LJE	8.1 (27.5)	1.00	75 (d)	NA	NA	89.0	43.0	EPA 8 (3)
12	LJE	14.7 (50)	1.65	92 (e)	NA	NA	96.9	21.5	EPA 8 (3)
30	LJE	14.7 (50)	1.34	96 (e)	NA	NA	96.3	25.8	EPA 8 (3)
6	SB	16.2 (55.2)	0.60	73 (d)	NA	NA	95.0	17.2	EPA 8 (3)
11	SB	7.3 (25)	1.00	95 (d)	NA	NA	99.5	1.7	EPA 8 (3)
U-24	SB	14.7 (50)	1.46	88 (e)	NA	NA	98.1	12.9	EPA 8 (3)
22-4	TA (b)	6.4 (22)	1.56	71	7.23	6.60	87.5	103.0	CEM (4)
22-41	TA	6.4 (22)	1.61	67	7.57	6.27	94.4	38.7	CEM (1)
30-7	TA (b)	14.7 (50)	1.58	105	6.97	6.20	89.7	77.4	CEM (5)
30-71	TA	14.7 (50)	1.66	101	7.10	5.75	95.8	34.4	CEM (1)
1	VS	18.3 (62.5)	0.85	86 (d)	NA	NA	97.0	17.2	EPA 8 (3)
2	VS	18.3 (62.5)	1.15	91 (d)	NA	NA	97.4	12.9	EPA 8 (3)
34	VS	18.3 (62.5)	1.00	84 (d)	NA	NA	96.0	21.5	EPA 8 (3)
38	VS	18.3 (62.5)	1.10	82 (d)	NA	NA	96.0	17.2	EPA 8 (3)
64	VS	18.3 (62.5)	1.10	82 (d)	NA	NA	96.0	21.5	EPA 8 (3)
4	ST	18.3 (62.5)	1.01	108 (d)	NA	NA	98.0	19.2	EPA 8 (3)
3	UNK (c)	18.3 (62.5)	0.80	94 (d)	NA	NA	99.2	4.3	EPA 8 (3)
5	UNK	8.8 (30)	1.20	76 (d)	NA	NA	93.5	30.1	EPA 8 (3)
U-23	UNK	7.3 (25)	1.46	92 (e)	NA	NA	98.1	12.9	EPA 8 (3)

TABLE 3-2. EMISSION DATA FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO OIL-FIRED SMALL STEAM GENERATORS (CONTINUED) (8)

(a) LJE = Liquid jet eductor; SB = Spray baffle; TA = Tray absorber; VS = Venturi scrubber; ST = Spray tower.

(b) Both sites use two tray absorbers. Two tray absorbers are known to have lower SO2 removal efficiencies than three tray absorbers. The other two sites (22-41 and 30-71) use three tray absorbers.

(c) UNK = Unknown.

(d) The heat input during the test is determined by multiplying the oil flow rate to the boiler and an assumed heating value of 43,000 kJ/kg (18,500 Btu/lb). Results of fuel analysis (actual heating value) are not available.

(e) The heat input during the test is determined using the F-factor, the flue gas flow rate, and the flue gas oxygen content.

(f) NA = Not available.

(g) Divide ng/J by 430 for conversion to lb/million Btu.

(h) All tests were short-term (about 1 hour per run). EPA 8 = EPA Reference Method 8; CEM = Continuous emission monitor.

TABLE 3-3. AVERAGE RESULTS FROM SODIUM SCRUBBING FGD SYSTEMS APPLIED TO OIL-FIRED SMALL STEAM GENERATORS[9]

<u>SO_2 Removal Efficiencies, Percent</u>	
Average Efficiency (± Standard Deviation)	95.2 ± 3.4
<u>Outlet SO_2 Emissions, ng/J (lb/10^6 Btu)</u>	
Average SO_2 Outlet Emissions (± Standard Deviation)	30 ± 26 (0.07 ± 0.06)
<u>Sulfur Content of Oil, Weight Percent</u>	
Average Sulfur Content of Oil Fired (± Standard Deviation)	1.21 ± 0.31
<u>Boiler Load, Percent of Full Load</u>	
Average Load (± Standard Deviation)	87.5 ± 11.3

mean SO_2 reduction is 91 percent or greater. The average SO_2 removal efficiency of the short-term test data summarized above was 95.2 percent, well above the required 91 percent reduction level. Thus, the ability of sodium scrubbers to continuously reduce SO_2 emission by 90 percent on a 30-day rolling average basis is considered demonstrated.

3.4 DUAL ALKALI FGD SYSTEMS

Dual alkali FGD systems are the second most prevalent wet FGD technology for industrial boiler applications. The dual alkali FGD process is similar to sodium scrubbing FGD in the absorption stage; both technologies use a clear sodium solution for SO_2 removal. However, dual alkali FGD includes a regeneration stage where lime or limestone is used to regenerate the active sodium alkali for SO_2 sorption. Dual alkali technology has been applied primarily to coal-fired units. However, emissions data were available for one dual alkali system applied to an oil-fired steam generating unit.[10] As shown in Table 3-4, the SO_2 removal performance of the dual alkali system applied to the oil-fired unit is comparable to that of the coal-fired units. The data for the oil-fired unit were obtained from a compliance test; the test duration was unavailable. The boiler had a heat input capacity of 91 MW (310 million Btu/hour). The sulfur content of the oil fired was 1.5 weight percent. The outlet emissions were 0.091 lb SO_2/million Btu, and the SO_2 removal efficiency was 91.7 percent.

Long-term performance data are not available for dual alkali systems operating on small oil-fired boilers. However, the design and operating principles for dual alkali technology are similar for both coal- and oil-fired boilers. Thus, the performance of these systems on oil-fired boilers can be evaluated from analyzing their performance on large and small coal-fired boilers. Seventeen and 24 days of SO_2 emission data were available for a dual alkali system comprising two scrubbers applied on two coal-fired boilers with a single regeneration section. These test data are discussed below in Section 4.4. The average SO_2 removal efficiency of these scrubbers was 92 percent.

TABLE 3-4. SHORT-TERM EMISSIONS DATA FOR DUAL ALKALI SYSTEMS USING EPA TESTING METHODS (11)

Company (location)	Boiler capacity treated (a) (million Btu/hour)		Fuel type	Sulfur content of fuel (weight percent)	Outlet SO2 emissions (lb/million Btu)	SO2 removal efficiency (percent)
ARCO Polymers (Monaca, PA)	1,360		Coal	2.5 - 2.8	0.65	88.0 (b)
General Motors (Parma, OH)	570	Scrubber I	Coal	2.5	0.30	92.2 (c)
		Scrubber II	Coal	2.5	0.32	91.6 (d)
Grissom Air Force Base (Peru, IN)	140	System I	Coal	3.0 - 3.5	0.56	88.1 (b)
		System II	Coal	3.0 - 3.5	0.38	94.2
Santa Fe Energy	310		Oil	1.5	0.091	91.7 (b)
Average				2.61	0.38	91.0

(a) Total capacity of all boilers treated.
(b) Data from short-term compliance tests.
(c) 24-day test.
(d) 17-day test.

Thus, the ability of dual alkali scrubbers to reduce SO_2 emissions by 90 percent on a 30-day rolling average basis for small oil-fired steam generating units is considered demonstrated.

3.5 LIME/LIMESTONE FGD SYSTEMS

Lime/limestone FGD systems employ a slurry of calcium oxide (CaO, lime) or calcium carbonate ($CaCO_3$, limestone) to remove SO_2 from industrial-commercial-institutional steam generating units. Although no emission data are available to document the performance of lime/limestone FGD systems on oil-fired boilers, emission data are available for lime and limestone FGD systems applied to small and large coal-fired units. These data, which are presented and discussed below in Section 4.5, show SO_2 removal efficiencies for lime and limestone FGD systems of 91.5 and 94.3 percent, respectively. Due to the similarity in system design and operation, it can be inferred from analyzing this performance data that the performance of a lime/limestone FGD system as applied to an oil-fired boiler would be comparable to the same system applied to a coal-fired boiler.

3.6 ALTERNATIVE CONTROL LEVELS

The evaluation of SO_2 control techniques for small oil-fired boilers indicates that use of medium sulfur oil, very low sulfur oil, sodium scrubbing FGD systems, dual alkali FGD systems, and lime/limestone FGD systems are demonstrated techniques that could serve as the technical basis for developing NSPS for small boilers. Medium sulfur oil combustion will reduce SO_2 emissions to 690 ng/J (1.6 lb/million Btu); consequently, this level is selected as Alternative Control Level 1. Very low sulfur oil combustion will reduce SO_2 emissions to 210 ng/J (0.50 lb/million Btu) heat input; thus, an emission level of 210 ng/J (0.50 lb/million Btu) heat input is selected as Alternative Control Level 2. Flue gas desulfurization systems are capable of 90 percent SO_2 emission reduction and, as a result, 90 percent reduction is selected as Alternative Control Level 3.

4.0 COAL SO_2 EMISSIONS AND CONTROL TECHNIQUES

The control techniques considered for reducing SO_2 emissions from small coal-fired boilers include low sulfur coal, sodium scrubbing FGD, dual alkali FGD, lime/limestone FGD, lime spray drying FGD, dry alkali injection, FBC, limestone injection multistage burner (LIMB), coal gasification, and coal liquefaction.

Limestone injection multistage burner and dry alkali injection technologies are still in the process development stage and, thus, are not considered further. Despite the potential of coal gasification for producing a low sulfur fuel, few gasifiers have been designed specifically for small boiler applications. Furthermore, coal gasification is unlikely to achieve widespread application to new small boilers in the near future. Hence, coal gasification is not examined further. Several pilot-scale coal liquefaction plants have been built and tested. However, no commercial coal liquefaction plants have been constructed to date, nor are any planned or under construction. In view of the long lead time associated with the design, construction, and start-up of coal liquefaction plants, it is unlikely that these fuels will be available for use in small boiler applications in the near future. As a result, coal liquefaction also is not considered further.

4.1 REGULATORY BASELINE EMISSION LEVELS

The regulatory baseline SO_2 emission level for small coal-fired boilers is based on the national average SIP emission limit for small, coal-fired boilers. Average SO_2 limits for small, coal-fired boilers range from 1,400 to 1,510 ng/J (3.26 to 3.51 lb/million Btu) for boilers of 29 and 2.9 MW (100 and 10 million Btu/hour) heat input capacity, respectively. The overall national average SIP emission limit is 1,460 ng/J (3.4 lb/million Btu). However, projected fuel prices are only available for coals capable of meeting SO_2 emission limits of 1,550 and 1,120 ng/J (3.6 and 2.6 lb/million Btu) heat input. As a result, a regulatory baseline of 1,550 ng/J (3.6 lb/million Btu) heat input is selected for purposes of analysis.

As noted in Table 4-1, the medium sulfur Type F coal which corresponds to the regulatory baseline is characterized by a maximum expected SO_2 emission rate of 1,550 ng/J (3.6 lb/million Btu) heat input. The difference between this value and the long-term average SO_2 emission rate of 1,230 ng/J (2.86 lb/million Btu) heat input reflects the allowance for SO_2 emissions variability that applies to this coal type.

4.2 LOW SULFUR COAL

Use of low sulfur coal limits SO_2 emissions by reducing the amount of sulfur available in the fuel for SO_2 formation. Low sulfur coal is defined as coal that can meet an emission limit of 520 ng/J (1.2 lb/million Btu) heat input on a continuous basis using a 30-day rolling average without additional SO_2 control.

Low sulfur coal is obtained primarily from naturally occurring low sulfur coal deposits. Low sulfur coal may also be produced through coal treatment to reduce the naturally occurring sulfur content. A commercially available method for producing low sulfur coal is physical coal cleaning (PCC). The design and operating factors and the mechanism by which PCC can reduce SO_2 emissions are discussed in Reference 12. Low sulfur coal can be burned in any small boiler designed to fire coal, so its applicability is not limited by boiler size.

Coal markets that supply coals with low sulfur contents [520 ng/J (1.2 lb/million Btu) heat input or less] have developed throughout the Nation. Because of widespread availability and extensive use of low sulfur coal for steam generating purposes, use of low sulfur coal is considered to be a demonstrated technique for reducing SO_2 emissions from small steam generating units.

Unlike SO_2 emissions from oil combustion, SO_2 emissions from coal combustion exhibit variability because the sulfur content of coal is not homogeneous. Coal produced from a single coal mine will vary in sulfur content. This variability may be further influenced by mining practices. Whether coal is cleaned or blended with other coals also will influence its SO_2 emissions variability when it is combusted.

TABLE 4-1. MAXIMUM EXPECTED EMISSION RATES FOR COAL COMBUSTION[13]

Coal Category	Coal Type[d]	Long-Term Average SO_2 Emissions ng/J	(lb/million Btu)	Maximum Expected SO_2 Emission Rate[a] ng/J	(lb/million Btu)
Low Sulfur[b]	Type B	464	(1.08)	520	(1.2)
Low Sulfur[b]	Type D	620	(1.45)	690	(1.6)
Medium Sulfur[c]	Type E	900	(2.10)	1,120	(2.6)
Medium Sulfur[c]	Type F	1,230	(2.86)	1,550	(3.6)
High Sulfur[c]	Type G	1,790	(4.15)	2,240	(5.2)
High Sulfur[c]	Type H	2,380	(5.54)	2,920	(6.8)

[a]Once in 10-year maximum expected 30-day rolling average SO_2 emission rate.

[b]Based on a daily average SO_2 emission rate relative standard deviation of 0.10.

[c]Based on a daily average SO_2 emission rate relative standard deviation of 0.20.

[d]All coals are bituminous coals.

The SO_2 emissions variability associated with combustion of low sulfur coals has been addressed in earlier reports.[14-16] This variability leads to the maximum expected emission rates shown in Table 4-1. These maximum expected emission rates represent the SO_2 emission limits that could be achieved by combustion of low sulfur coals in small boilers.

4.3 SODIUM SCRUBBING FGD SYSTEMS

Sodium scrubbing FGD technology has been directly applied on small, coal-fired boilers and is commercially available for small, coal-fired boiler applications. One leading manufacturer of sodium scrubbers has designed, constructed, and started up systems to service steam generators as small as 1.5 MW (5 million Btu/hour).[17]

Emission test data are available to document sodium scrubber performance for coal firing. Thirty days of certified CEM test data were gathered from a sodium scrubber applied to a pulverized coal-fired boiler rated at 55 MW (188 million Btu/hour) heat input.[18] The FGD system tested was a tray and quench liquid scrubber that consisted of a three-stage impingement tower with a Chevron mist eliminator. The scrubbing medium was a 50 percent aqueous NaOH solution. The makeup rate to the scrubber was 2.2 liters per second (l/s) (35 gal/min). The scrubbing solution pH was 8.1. The boiler operated at loads between 40 and 60 percent of full load and averaged 48 percent of full load for the test duration. The sulfur content of the coal fired was 3.6 weight percent. The design SO_2 efficiency of this system was 90 percent at an inlet SO_2 concentration of 2,000 ppmv.

Figure 4-1 shows consistently high SO_2 removal efficiencies for this system, averaging 96.2 percent for the test period. The daily average outlet SO_2 emissions ranged from 56 to 267 ng/J (0.13 to 0.62 lb/million Btu), averaging 86 ng/J (0.20 lb/million Btu) for the 30-day test period.

The performance data from this 30-day test were analyzed for SO_2 emission reduction variability. The results of the variability analysis indicate that a long-term mean of 91 percent SO_2 reduction would be necessary to comply with a 90 percent SO_2 reduction requirement based on a 30-day rolling average with no more than one exceedance every 10 years.[20] A relative standard deviation (RSD) of 1.2 percent and an autocorrelation

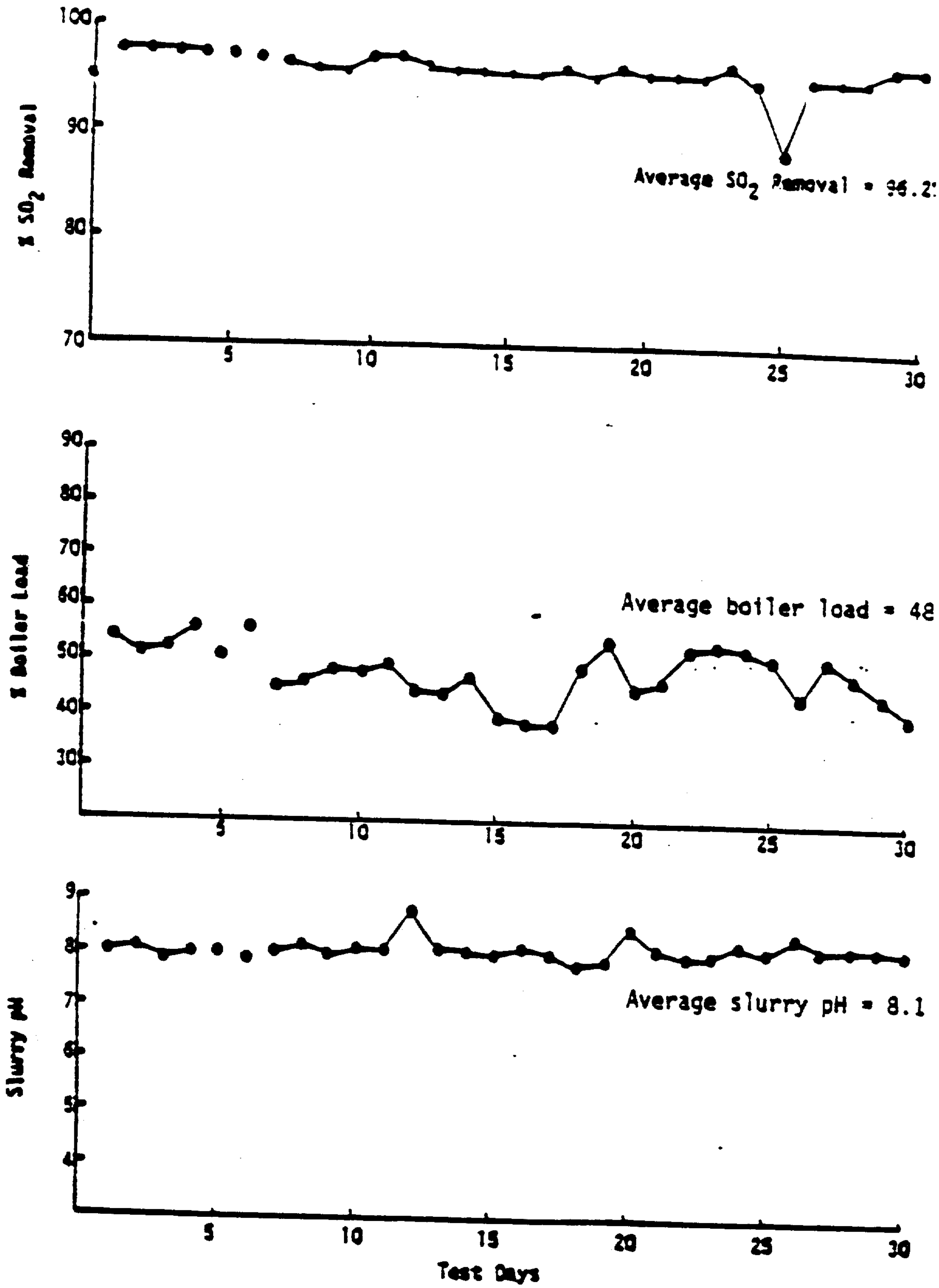

Figure 4-1. Daily average SO_2 removal, boiler load, and slurry pH for coal-fired boiler equipped with a sodium scrubber[19]

coefficient (AC) of 0.13 were determined from the SO_2 reduction data for this boiler.[21] If the mean SO_2 reduction performance of 96.2 percent measured in the 30-day test were maintained at full load, then the sodium scrubber would exceed the level necessary for compliance (i.e., 91 percent SO_2 reduction) with a 90 percent SO_2 reduction specification using a 30-day rolling average.

The SO_2 removal efficiency of sodium scrubbing systems can vary during load swings. Further, changes in flue gas flow rate and SO_2 concentration result in imbalances in the sodium-to-sulfur ratio and the pH of the scrubber solution. Therefore, to maintain a constant SO_2 removal efficiency, these two parameters must be adjusted during load swings. With proper design and operation of the scrubber system, consistently high SO_2 removal rates can be maintained during fluctuations in boiler load.

Although the sodium scrubber in this 30-day test was applied to a boiler rated above 29 MW (100 million Btu/hour) heat input, the performance data from this scrubber are applicable to small boilers. This application can be made because sodium scrubber design and operating characteristics (e.g., L/G ratio, pH, gas distribution, etc.) do not vary significantly with size in this general size range. As a result, performance and variability of smaller systems would be similar to those of the scrubber examined here. Thus, achievement of a 90 percent SO_2 reduction by sodium scrubbing systems on small coal-fired boilers on a 30-day rolling average basis is considered demonstrated.

4.4 DUAL ALKALI FGD SYSTEMS

Dual alkali FGD technology has been applied primarily to large coal-fired units, but is commercially available for units of most sizes. Tests of dual alkali FGD systems operating on coal-fired steam generating units have shown short-term SO_2 removal efficiencies of greater than 90 percent, with long-term efficiencies of around 92 percent.[22]

Emission data are available from two long-term tests to document dual alkali FGD system performance for small coal-fired steam generating units. As discussed in Reference 23, the dual alkali system tested consisted of two SO_2 absorbers, each serving a separate steam generating unit, and a single regeneration section. Seventeen days of test data were gathered from one absorber applied to a coal-fired spreader stoker steam generating unit rated at 40 MW (135 million Btu/hour), and 24-days of test data were gathered from the other absorber applied to a unit rated at 23 MW (77 million Btu/hour). Data were collected using continuous SO_2 emission monitors on both the inlet and outlet of the FGD system.

The sulfur content of the bituminous coal received at the plant during these tests averaged 1,490 ng SO_2/J (3.47 lb SO_2/million Btu). During these tests, the steam generating units also burned oil with an average sulfur content of 320 ng SO_2/J (0.74 lb SO_2/million Btu). During both tests, the dual alkali FGD system operated at a reliability level of 100 percent.

In the 17-day test, the steam generating unit operated at an average load of 67 percent, with the load varying between 42 and 96 percent. The SO_2 removal efficiency averaged 91.6 percent. In the 24-day test, the steam generating unit operated at an average load of 62 percent, with loads varying between 5 and 95 percent. The SO_2 removal efficiency averaged 92 percent.

Results of the 24-day test show that at least 90 percent SO_2 removal can be reliably and consistently achieved on a small coal-fired steam generating unit. In addition, the results of the 17-day test indicate that the SO_2 removal efficiency achieved on a large steam generating unit [>29 MW (>100 million Btu/hour)] is essentially the same as that achieved on a small steam generating unit [$\leq$29 MW ($\leq$100 million Btu/hour)]. This same level of performance can be achieved at full load conditions if vigorous gas-liquid contact is maintained in the absorber and the sodium-to-sulfur and liquid-to-gas ratios are maintained at a level sufficient to provide an adequate supply of active sodium species.

Based on these analyses of system performance, dual alkali FGD is a demonstrated technology for reducing SO_2 emissions from small coal-fired industrial-commercial-institutional steam generating units by 90 percent on a 30-day rolling average basis.

4.5 LIME/LIMESTONE FGD SYSTEMS

Emission data from two long-term tests are available to document lime/limestone FGD performance on industrial steam generating units. As discussed in Reference 24, the scrubbing system serviced six coal-fired stoker boilers with a total heat input capacity of 62 MW (210 million Btu/hour).

The tests were conducted using continuous SO_2 emission monitors at both the inlet and outlet of the FGD system. Data were collected for a 29-day period while the system used a lime reagent and for 30 days while the system used a limestone reagent.

During the 29-day data collection period when lime was used as the reagent in the wet scrubbing system, the sulfur content of the bituminous coal fired averaged 2,150 ng SO_2/J (5.0 lb SO_2/million Btu). During this period, the steam generating unit load varied from 34 to 65 percent of full load. The SO_2 removal efficiency averaged 91.5 percent, and the lime wet scrubbing FGD system operated at a reliability level of over 91 percent.

During the 30-day test period when limestone was used as the reagent in the wet scrubbing system, the sulfur content of the bituminous coal burned averaged about 2,150 ng SO_2/J (5.0 lb SO_2/million Btu). During this period, the steam generating unit load varied from 30 to 67 percent of full load. The SO_2 removal efficiency averaged 94.3 percent, and the system operated at a reliability level of 94 percent.

The long-term data presented above for lime and limestone FGD systems show SO_2 removal efficiencies of 91.5 and 94.3 percent, respectively, which are near or above the long-term average required to meet consistently a once in ten year 30-day rolling average minimum performance level of 90 percent emission reduction. Although these results were obtained at less than maximum load conditions, new systems could achieve this level of performance at full load by operating at a higher liquid-to-gas ratio. In addition, new systems would likely be equipped with a spray tower or turbulent contact absorber to provide increased mass transfer area and gas residence time for improved SO_2 absorption.

Based on this analysis of system performance and system variability, the lime/limestone wet scrubbing FGD technology is considered a demonstrated technology for reducing SO_2 emissions from small coal-fired industrial-commercial-institutional steam generating units by 90 percent using a 30-day rolling average to calculate emission reductions.

4.6 LIME SPRAY DRYING FGD SYSTEMS

Lime spray drying is a dry scrubbing process that involves contacting the flue gas with an atomized lime slurry or a solution of sodium carbonate. The hot flue gas dries the droplets to form a dry waste product while the absorbent reacts with SO_2 in the flue gas. The dry waste solids, consisting of sulfite and sulfate salts, unreacted sorbent, and fly ash are collected in a baghouse or ESP for disposal.

Emission test data are available in Reference 25 to document lime spray drying performance for coal firing. As shown in Table 4-2, a series of four short-term tests were conducted to demonstrate lime spray drying performance. The first short-term test was a compliance test conducted over approximately 2 hours, where the lime spray drying system treated flue gas from a pulverized coal-fired steam generating unit with a heat input capacity of 82 MW (280 million Btu/hour). This unit burned bituminous coal with an average sulfur content of 1,430 ng SO_2/J (3.33 lb SO_2/million Btu) and operated at 100 percent of full load. The SO_2 removal efficiency averaged 74.5 percent.[26]

The second short-term test was also conducted over approximately 2 hours, where the system treated flue gas from a pulverized coal-fired unit with a heat input capacity of 34 MW (115 million Btu/hour). This unit, which fired a mixture of bituminous coal with an average sulfur content of 410 ng SO_2/J (0.96 lb SO_2/million Btu), operated at about 75 percent of full load. Of the total heat input to the unit, 94.2 percent was derived from coal and the remainder from oil. Sulfur dioxide removal efficiencies averaged 92.4 percent during this test period.

A series of three short-term tests was conducted over 8 hours at a third site. The coal-fired spreader stoker unit for these tests operated

TABLE 4-2. SUMMARY OF SHORT-TERM EMISSION DATA FOR FOUR INDUSTRIAL LIME SPRAY DRYING FGD SYSTEMS (25)

Location	Number of runs	Test duration (hours)	Average SO2 removal (%)	Boiler load (%)	Reagent ratio	Coal average sulfur content (ng SO2/J) (a)	Approach temperature, degrees C (degrees F)	Unit heat input capacity, MW (million Btu/hr)
1	6	2	74.5	100	NA (b)	1,430	19 (35)	82 (280)
2	6	2	92.4	75	NA	2,530 (c)	14 (25)	34 (115)
3	1	8	79.7	35	0.6	2,190	13 (23)	69 (235)
3	1	8	89.9	70	1.4	2,190	13 (23)	69 (235)
3	1	8	95.6	82	1.9	2,190	13 (23)	69 (235)
3	1	4	64.0	50-74	1.1	2,840	17 (30)	69 (235)
3	1	4	78.0	50-74	1.2	2,840	17 (30)	69 (235)
3	1	4	74.0	50-74	1.3	2,840	17 (30)	69 (235)
3	1	4	80.8	50-74	1.0	2,840	17 (30)	69 (235)
3	1	4	83.0	50-74	1.1	2,840	17 (30)	69 (235)
3	1	4	87.0	50-74	1.2	2,840	17 (30)	69 (235)
3	1	4	90.0	50-74	1.3	2,840	17 (30)	69 (235)
3	1	4	96.0	50-74	1.6	2,840	17 (30)	69 (235)
4	3	1	96.6	100	3.3	410	28-39 (50-70)	69 (235)

(a) Divide ng/J by 430 for conversion to lb/million Btu.
(b) NA = Not available.
(c) Coal/oil mixture with 94.2% coal heat input.

with a heat input capacity of 69 MW (235 million Btu/hour) and fired bituminous coal with an average sulfur content of 2,190 ng SO_2/J (5.09 lb SO_2/million Btu). During these three tests, unit load was maintained at 35, 70, and 82 percent of full load. The reagent ratio was varied during each testing period to obtain the following results: 79.7 percent SO_2 removal at 0.6 reagent ratio; 89.9 percent SO_2 removal at 1.4 reagent ratio; and 95.6 percent SO_2 removal at 1.9 reagent ratio.

A second series of short-term tests was also conducted at this same site over a 4-hour period. For this test series, the unit fired bituminous coal with an average sulfur content of 2,840 ng SO_2/J (6.60 lb SO_2/million Btu) and operated at loads that varied between 50 and 74 percent of full load. Both the reagent ratio and approach to saturation temperature were varied during the testing. At a 17°C (30°F) approach to saturation temperature, SO_2 removal efficiencies of 64, 78, and 74 percent were achieved with reagent ratios of 1.1, 1.2, and 1.3, respectively. Lowering the approach to saturation temperature to 12°C (22°F) resulted in 80.8 percent SO_2 removal at a reagent ratio of 1.0. At a 11°C (20°F) approach to saturation temperature, SO_2 removal efficiencies of 83, 87, 90, and 96 percent were achieved with reagent ratios of 1.1, 1.2, 1.3, and 1.6, respectively.

The fourth short-term test, which was conducted over three 1-hour periods, involved a lime spray drying system treating flue gas from a pulverized coal-fired steam generating unit with a heat input capacity of 69 MW (235 million Btu/hour). This unit burned bituminous coal with an average sulfur content of 410 ng SO_2/J (0.96 lb SO_2/million Btu) and operated at 100 percent of full load. The SO_2 removal efficiency averaged 96.6 percent.

The short-term performance data from these tests indicate that lime spray drying systems are capable of achieving at least 93 percent reduction in SO_2 emissions from industrial-commercial-institutional steam generating units. Few long-term data are available, but long-term removal rates as low as 70 percent have been reported. This, however, reflects the fact that many large commercial systems have not been required to achieve high removal levels, rather than any inherent limitation of the technology. One spray drying vendor believes that high reliability can be achieved at high performance levels and is prepared to offer a 95 percent reliability guarantee on lime spray drying systems, irrespective of coal sulfur content and SO_2 removal guarantees. Such a guarantee, however, would require that owners/operators follow proper maintenance and operating procedures.

As a result, there appear to be no technical barriers to achieving greater than 90 percent SO_2 removal with a lime spray drying system on a sustained basis at high (90 percent) reliabilities. Furthermore, due to similarities in design and operation between large and small systems, it has been concluded that lime spray dryers would also be capable of meeting the 90 percent SO_2 reduction levels on small industrial-commercial-institutional units. Therefore, this control technique is considered demonstrated for purposes of establishing performance standards for small coal-fired steam generating units.

4.7 FLUIDIZED BED COMBUSTION (FBC)

Fluidized bed combustion is a boiler design option which, because of its ability to incorporate limestone addition, can achieve significant SO_2 emission reductions. This technology offers a variety of advantages over conventional boiler designs, including SO_2 emission reduction without the use of FGD systems as well as greater flexibility in fuel use.

Atmospheric fluidized bed combustion (AFBC) boilers have developed rapidly over the past five years and are now being applied to small boiler sizes. Two AFBC design alternatives that are currently available are the conventional bubbling fluidized bed (with or without solids recycle) and the circulating fluidized bed. Pressurized FBC technology has been under development for over a decade, but has not yet been used in commercial practice and is unlikely to be applied to small boiler applications.

Table 4-3 presents SO_2 emission data for one circulating bed FBC and four bubbling bed boilers, ranging in size from 15 to 61 MW (50 to 208 million Btu/hour). Certified CEM or EPA Reference Methods were used to measure SO_2 emissions. Tests using EPA Reference Methods were short-term tests (approximately three-hour tests) unless otherwise stated in Table 4-3, while tests using CEM's were long-term tests. The results from this table

TABLE 4-3. FLUIDIZED BED COMBUSTION EMISSION TEST DATA (28)

Plant owner (location)	Type of unit (a)	Boiler capacity, MW (million Btu/hr) heat input	Percent sulfur in coal	Percent of full load	Ca/S ratio	Sorbent type	Sorbent size (millimeters)	Bed temperature (degrees C)	Recycle ratio	SO2 Emissions Data: SO2 removal efficiency (percent)	SO2 Emissions Data: Outlet SO2 emissions (ng/J) (b)	Emission test method (test duration) (d)
Iowa Beef Processors (Amarillo, TX)	PSB	26.4 (90)	4.2	59	3.1	Dolomite	16 x 21.7	878 (763) (c)	0	91	258	CEM (1 day)
Idaho National Engineering Labs (Scoville, ID)	PBB	24.0 (82)	0.85	56	ND (e)	Limestone	3.2 x 0.8	NA (f)	0	86	69	CEM (67 days)
Sohio Oil Corp. (Lima, OH)	PBB	28.4 (97)	3.6	72	NA	Limestone	6.3 x 0	NA	0	90	267	EPA-6 (3 hours)
Summerside CFB (Prince Edward Island, Canada)	PBB	14.7 (50)	6.0	72	3.7	Limestone	2.4 x 0.8	837	ND (g)	94	258	CEM (7.5 days)
Summerside CFB (Prince Edward Island, Canada)	PBB	14.7 (50)	6.5	66	4.5	Limestone	6.3 x 0	838	ND (g)	91	430	CEM (15 hours)
Summerside CFB (Prince Edward Island, Canada)	PBB	14.7 (50)	5.7	56	7.2	Limestone	2.4 x 0.8	799	ND (g)	99	26	CEM (5 hours)
California Portland Cement (Colton, CA)	FEC	60.9 (208)	0.43	100	NA	Limestone	0.125 x 0.039	NA	by design	82	56	EPA-8 (3 hours)

(a) PSB = Packaged staged bubbling bed; PBB = Packaged bubbling bed; FEC = Field-erected circulating bed.

(b) Divide ng/J by 430 for conversion to lb/million Btu.

(c) Number in parentheses is the desulfurization bed temperature. Number not in parentheses is the combustion bed temperature.

(d) CEM = certified continuous emission monitor; EPA-6 = EPA Reference Method 6 EPA-8 = EPA Reference Method 8.

(e) ND = not determined; the Ca/S ration could not be determined at this site because the coal and limestone feed rates were inaccurate.

(f) NA = Not available.

(g) ND = Not determined; at this site, solids were recycled to the boiler, but the rate of solids recycled was not determined for the above tests. However, the recycle ratio was estimated as 4.0 at test conditions similar to those for the 7.5-day test as reported in this table.

show that SO_2 removal efficiencies ranged from 86 to 99 percent for tests on the four bubbling bed boilers. The outlet SO_2 emissions for a 15 MW (50 million Btu/hour) bubbling bed boiler at Prince Edward Island, Nova Scotia, ranged from 69 ng/J (0.16 lb/million Btu) when firing a 5.7 weight percent sulfur coal and operating at a calcium-to-sulfur (Ca/S) ratio of 7.2:1 to 420 ng/J (0.98 lb/million Btu) when firing a 6.5 weight percent sulfur coal and operating at a Ca/S ratio of 3.1:1. This corresponds to 99 and 91 percent SO_2 removal efficiency, respectively.[27]

In addition to the three test results reported in Table 4-3 for the 15 MW (50 million Btu/hour) boiler at Prince Edward Island, emission data were collected for the entire test period of 30 days. Figures 4-2 to 4-4 show the trends in SO_2 removal efficiency, Ca/S molar ratio, and boiler load, respectively, for the entire test period. The results shown in these figures are based on daily average data. The daily average SO_2 removal efficiency ranged from 73 to 97 percent, averaging 93.5 percent. The lower daily average SO_2 removal efficiency of 73 percent on day 10 was attributed to operating the boiler at a low Ca/S ratio of 2.5:1.

Emission data for the first 7.5 days of continuous operation from the FBC boiler at Prince Edward Island were analyzed for SO_2 emission reduction variability.[27] This time period represented the longest continuous operating period for which emission and operating data were collected. During this period, the FBC unit operated at 94 percent mean SO_2 reduction efficiency. The results of variability analyses applied to the SO_2 reduction data of this period indicate that a long-term mean of at least 91.3 percent SO_2 reduction would be required to comply with a 90 percent SO_2 reduction limit based on a 30-day rolling average with no more than one exceedance every 10 years. If the mean SO_2 reduction performance of 93.5 percent measured in the 7.5 day test were maintained at full load, then the FBC unit would exceed the level (i.e., 91.3 percent SO_2 reduction) required for compliance with a 90 percent SO_2 reduction specification using a 30-day rolling average.

Although these performance levels are based primarily on bubbling bed designs, equal or better performance is expected from circulating and dual bed systems because of more rapid carbon burnout, higher limestone particle

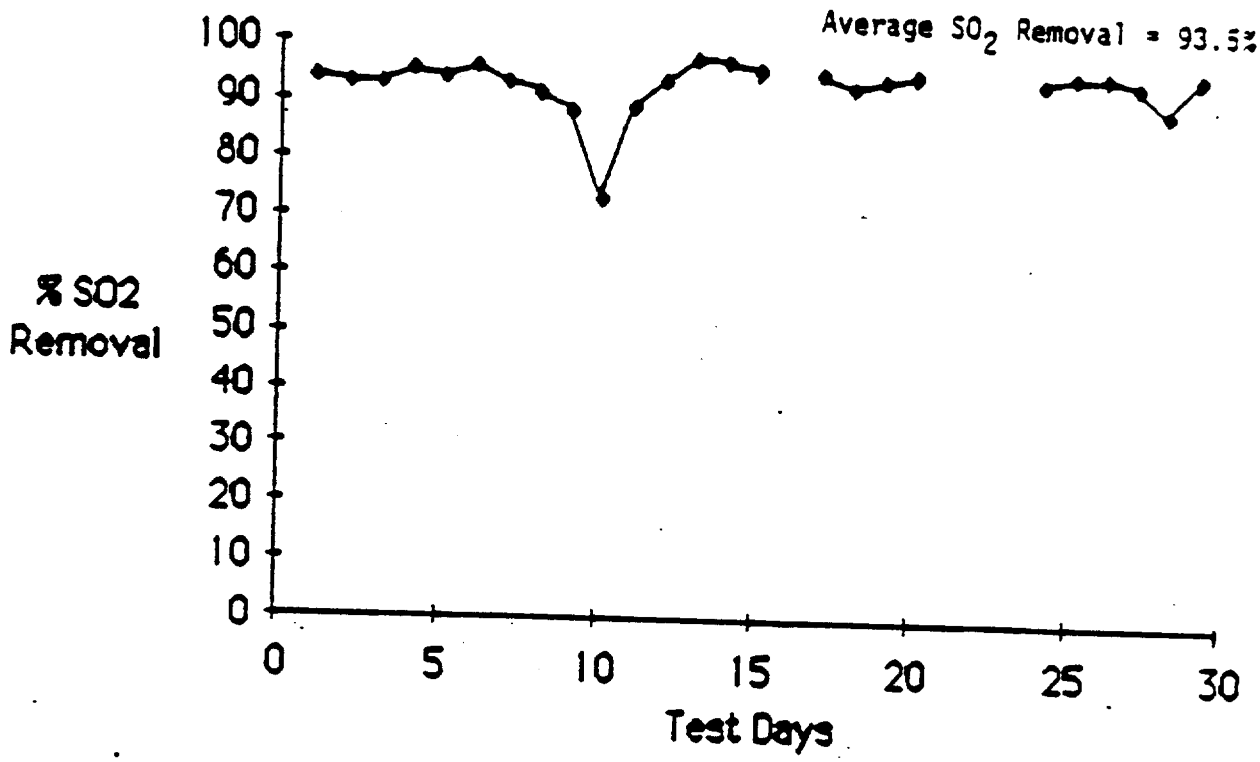

Figure 4-2. Daily average SO_2 removal efficiency for the FBC boiler at Prince Edward Island.[29]

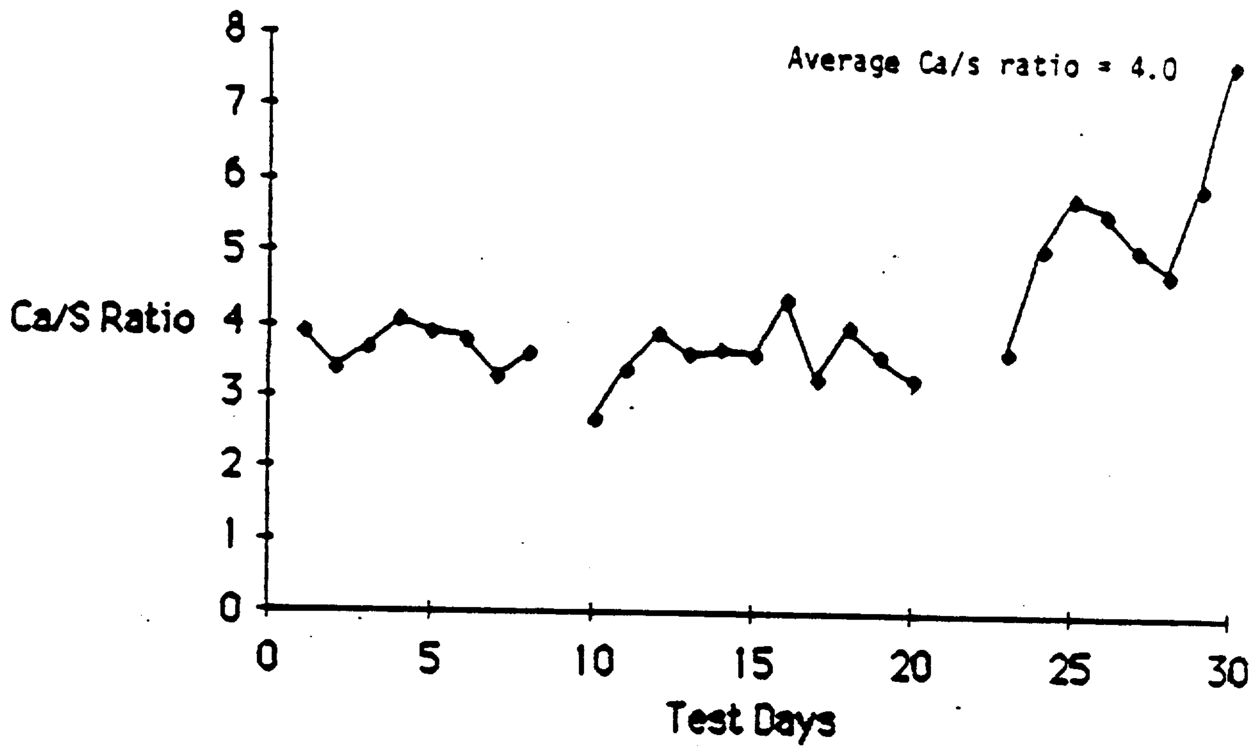

Figure 4-3. Daily average Ca/S molar feed ratio for the FBC boiler at Prince Edward Island.[30]

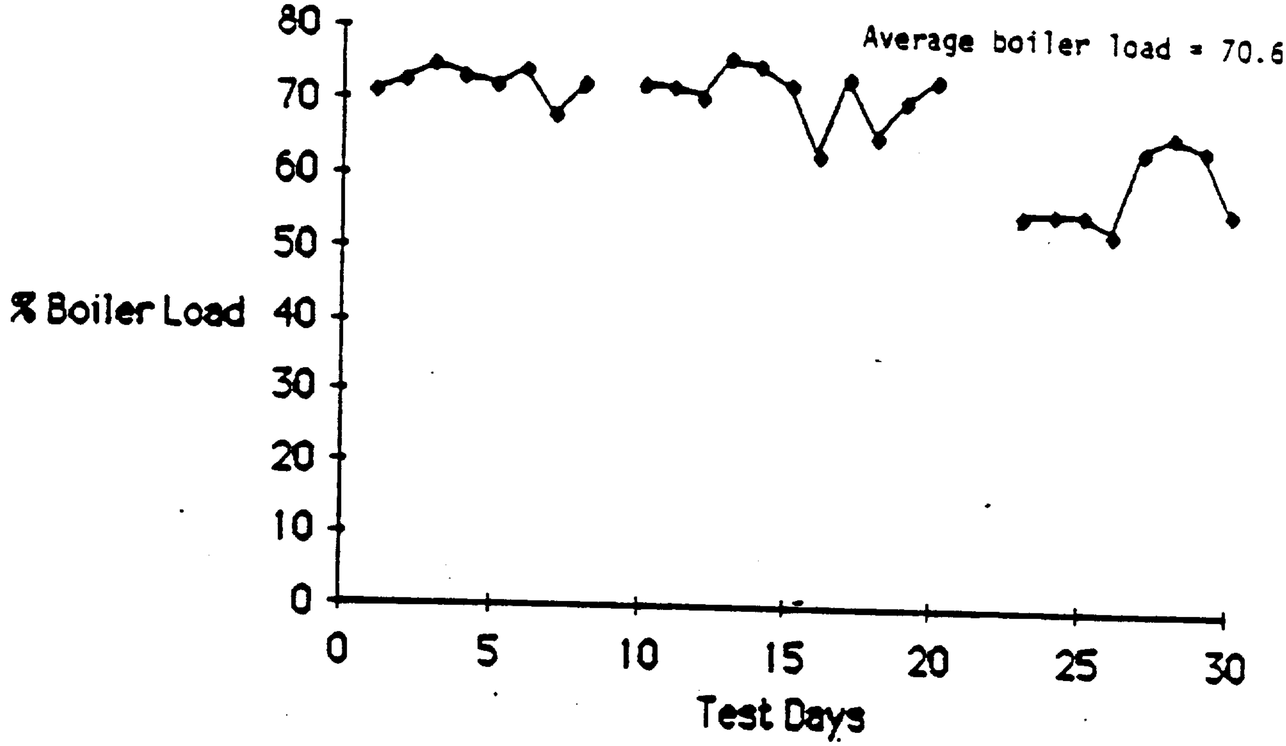

Figure 4-4. Daily average boiler load for the FBC boiler at Prince Edward Island.[31]

densities in the freeboard area, and more uniform gas-solid contact between SO_2 and limestone. These factors are discussed in more detail in Reference 32.

The SO_2 removal efficiency of FBC systems can vary during load swings. Changes in coal feed rate and coal sulfur content result in imbalances in the calcium-to-sulfur ratio of the fluidized bed. To maintain a constant SO_2 removal efficiency, this parameter must be adjusted during load swings by adjusting the limestone feed rate. Alternatively, the fluidized bed can be operated with a higher-than-required calcium-to-sulfur ratio to accommodate transient increases in boiler load (i.e., coal feed rate) or coal sulfur content. With proper design and operation of the FBC system, consistently high SO_2 removal rates can be maintained during fluctuations in boiler load.

As a result of the above-described technical analysis of FBC units, the ability of FBC units to continuously reduce SO_2 emissions by 90 percent or more on a 30-day rolling average is considered demonstrated.

4.8 ALTERNATIVE CONTROL LEVELS

The evaluation of SO_2 control techniques for small coal-fired boilers indicates that use of low sulfur coal, sodium scrubbing FGD systems, dual alkali FGD systems, lime/limestone FGD systems, lime spray drying FGD systems, and FBC units are demonstrated techniques which can serve as the technical basis for developing NSPS for small boilers. Low sulfur coal combustion will reduce SO_2 emissions to 520 ng/J (1.2 lb/million Btu) or less. This, therefore, is selected as Alternative Control Level 1.

Flue gas desulfurization systems and FBC units are capable of 90 percent SO_2 reduction. Consequently, 90 percent SO_2 reduction is selected as Alternative Control Level 2.

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32. Reference 7.

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16. ABSTRACT

This report provides a summary of the technical data used in developing proposed new source performance standards (NSPS) for small industrial-commercial-institutional steam generating units (small boilers). The report focuses on sulfur dioxide (SO_2) emissions from boilers firing coal and oil with heat input capacities of 100 million Btu/hour or less. Conclusions are drawn from the data regarding the performance of technologies available to reduce SO_2 emissions. Alternative control levels are then chosen based on the conclusions drawn from the data.

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