MARKET TRADING FORUM NON-UTILITY SECTOR ALLOCATION

FINAL REPORT FROM THE ALLOCATIONS WORKING GROUP

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ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BLS	Black liquor solids
CAA	Clean Air Act
CWPB	center-worked prebake cells
DCE	Direct contact evaporator
dscf	dry standard cubic foot
ESPs	electrostatic precipitators
FCCU	fluid catalytic cracking unit
GCVTC	Grand Canyon Visibility Transport Commission
H_2S	hydrogen sulfide
HSS	horizontal stud Soderberg
ICI	industrial, commercial, and institutional
kg	kilogram
LAER	Lowest Achievable Emission Reduction
lbs/MMBtu	pounds per million British thermal units
Mg	megagram
MTF	Market Trading Forum
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
ppm	parts per million
ppmv	parts per million volume
PTE	potential to emit
RECLAIM	Regional Clean Air Incentives Market
SCC	Source Classification Code
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SRU	Sulfur Recovery Unit
SWPB	side-worked prebake cells
tpy	tons per year
VSS	vertical stud Soderberg
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

This study was performed for a Working Group of the Western Regional Air Partnerships' (WRAP) Market Trading Forum. It provides a current, best estimate of the floor allocation for non-utility sources in the region that would be established if western States and tribes adopt a regional, backstop trading program for sulfur dioxide (SO_2) to meet the requirements of Section 309 of the regional haze rule. The major SO_2 emitting non-utility source categories evaluated in this study include the following: petroleum refineries, lime manufacturing, industrial boilers and co-generators, pulp and paper manufacturing, cement manufacturing, natural gas processing and oil and gas production, elemental phosphorus production, glass manufacturing, aluminum smelters, sulfuric acid plants, and coke production. Of these industry sectors, phosphorus, aluminum smelters, sulfuric acid plants, and coke production plants were not considered in the original source categories for the Market Trading Forum. The floor control technology (or emission rate or SO_2 control effectiveness) was determined by evaluating the emissions performance of other sources in that source category in the western States. The floor is defined to be best available control technology (BACT), best available retrofit technology (BART), or lowest achievable emission rate (LAER) for existing sources. For some sources, EPA has not determined what these levels of emissions are. SO_2 floor allocations were computed for each of about 200 major non-utility sources in the western States, where major is defined as those sources emitting greater than 100 tons per year (tpy).

While this analysis uses plant and process-level information to estimate floor allocations, if the backstop trading program is triggered, SO_2 allowances under the trading program will be allocated by the participating transport region States and Tribes at that time. This study is only an approximation of how the allocations might be made based upon the limited information that we have today. It is expected that the States and Tribes would be able to obtain more detailed information about current emissions and controls for these non-utility sources than has been available for the current project.

The floor allocation analysis has been performed separately for each of the 12 major non-utility source categories in the west. The text below summarizes the key findings for each source category.

To simplify the analysis, it was determined that California SO_2 sources are already highly controlled. The California floor allocation of 27,335 tpy is based on the opt-in/out 2018 SO_2 allocation that has been estimated previously by the WRAP Market Trading Forum.

Petroleum Refining: There are ten petroleum refineries outside California in the WRAP transport region. Data were received from all of these refineries for the allocation process. These floor allocations were computed for each of the four major SO_2 emitting processes at refineries: sulfur plants, fluidized catalytic cracking units (FCCUs), fuel combustion units, and flares. The SO_2 floor allocation for these ten refineries is 11,418 tpy, or about 5,400 tpy less than historic emissions during 1996 to 2000. This is one of the best characterized source categories.

Cement Manufacturing: The control technology analyses for cement kilns showed that there was no demonstrated SO_2 control technique at western State sources that could be applied to reduce SO_2 across the source population. There are widely varying SO_2 emissions rates from these kilns, and the process itself removes sulfur from the off gas. As a result, this sector's floor allocation of 7,761 tpy was based on recent historic emissions. *The analysis for lime manufacturing reached the same conclusion as that for cement.* The lime manufacturing floor allocation is 2,103 tpy.

Boilers and Co-generators: The floor for boilers and co-generators at industrial facilities was estimated by applying the equivalent of 85 percent SO_2 control to coal and oil-fired sources not already at, or near, this control level. Average capacity factors were used to estimate boiler utilization for estimating the floor with a 5 percent growth margin. This assumption is consistent with that used in the utility boiler floor allocations. Some non-utility boilers are operating at low utilization rates. The industrial boiler and cogenerator floor allocation is 7,910 tpy.

Pulp and Paper Industry: Recovery furnaces and lime kilns are the SO_2 sources at the Kraft pulp mills in the west. Most of these mills are in Oregon. Floor allocations for recovery furnaces and lime kilns are based on standard U.S. Environmental Protection Agency (EPA) emission factors and 100 percent capacity utilization (or recent annual throughput, if capacity estimates were not available). The pulp and paper floor allocation is 7,184 tpy.

Natural Gas Processing Plants and Oil and Gas Production: SO_2 emissions from natural gas processing plants result from combustion of sour gases. It was decided that the current New Source Performance Standard (NSPS) would serve as the floor. The NSPS requires a variable sulfur removal efficiency based on the hydrogen sulfide (H_2S) content of the acid gas and the amount of sulfur in the gas. If a facility had current control levels higher than the assumed floor, the actual average emissions over the past three years were used to estimate the floor. Since emissions from flaring operations both in the plant and the well field are not amenable to control, floor emissions are assumed to be the average of the emissions in three recent years. Data availability was a significant issue in determining the floor allocations for some gas plants. The floor allocation for this source category is 28,884 tpy.

Elemental Phosphorus Production: One of the two U.S. elemental phosphorus production facilities is in Idaho. Because of the uniqueness of this facility, no floor control technology was identified. The floor allocation is set at year 2000 SO_2 emissions, which were 15,861 tpy. It is expected that the State of Idaho will perform a more detailed evaluation of this facility during preparation of its regional haze State Implementation Plan (SIP).

Glass Manufacturing: The major source of SO_2 emissions in the glass industry is the glass melting operation. There are only two active glass manufacturing facilities in the 8 non-California WRAP States. With a lack of information about SO_2 control techniques in practice, the floor allocation for glass manufacturing plants was set according to historical SO_2 emissions. The glass manufacturing floor allocation is 368 tpy.

Copper Smelters: Because of the uniqueness of the existing copper smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. A double contact acid plant is considered the appropriate retrofit control equipment. All copper smelters in the western States are currently equipped with double contact acid plants. The current year SO_2 allocation for the six copper smelters in the 9-State region is 86,000 tons. This allocation is reduced to 78,000 tons by 2013 and is the same in 2018.

Aluminum Production: There are only 2 primary aluminum plants in the study region and both are located in Oregon. The primary SO_2 source in aluminum production is the sulfur in the coke, and the coal tar pitch binder used to produce the anodes. The floor control technology for aluminum smelters was determined by evaluating the emissions performance at the two Oregon facilities. One facility uses a wet scrubber to achieve a 70 percent SO_2 emission reduction. Therefore, a wet scrubber with a 70 percent SO_2 reduction was selected as the floor technology for aluminum smelters. The aluminum smelter floor allocation is 2,076 tpy.

Sulfuric Acid Plants: The only significant source of air emissions from a contact sulfuric acid plant is the tail gas leaving the final absorbing tower. This gas contains small amounts of SO_2 and even smaller amounts of sulfur trioxide, sulfuric vapor, and sulfuric acid mist. Based on the information available for the 4 sulfuric acid plants in the west, it was decided that the floor allocation should be estimated by applying the NSPS requirements to each sulfuric acid plant. Achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent SO_2 collection mechanism in a controlled facility. However, recent historical SO_2 emissions for these facilities were lower than the NSPS emission rate times capacity estimated values, so the sulfuric acid plant floor was estimated using these historical SO_2 emission values. The resulting floor allocation for these sulfuric acid plants is 5,386 tpy.

Metallurgic Coke Production: SO_2 emissions from coke oven operations primarily result from combustion of the byproduct coal gas in the oven. There were three coke production facilities operating in the west during the 1990s. Coke production has recently ceased at two of these facilities. The only facility that continues to operate is a rotary calciner in Wyoming. Because of the uniqueness of this operation, the floor allocation is based on recent historic SO_2 emissions, and is 631 tpy.

There are two benchmarks that can be used to put the floor allocations in perspective. One is year 2000 historic emissions and the other is the non-utility SO_2 emissions forecast for 2018. The floor allocation estimate in this report is about 2,500 tons higher than year 2000 historical emissions. However, this comparison of the respective emission totals is skewed by the fact that year 2000 copper smelter emission were about one-half of the 78 thousand ton allocation for this sector. When copper smelters are removed from the totals, the floor allocation is about 45 thousand tons lower than year 2000 emissions. A comparison of the floor allocation with the SO_2 emissions in the 2018 opt-in/out emission allocations shows that the floor allocation is approximately the same.

CHAPTER I
INTRODUCTION

This report describes an analysis that was prepared for a Working Group of the Western Regional Air Partnership's (WRAP) Market Trading Forum (MTF). It provides the current best estimate of the floor allocation for non-utility sources in the region that would be established if western States and tribes adopt a regional, backstop trading program for sulfur dioxide (SO_2) to meet the requirements of Section 309 of the regional haze rule. Note that this does not establish final allocations for sources in the region. Each State and tribe will determine the appropriate floor level for sources within their jurisdiction, and will include this information in their State or tribal implementation plan. The program is voluntary for western States and tribes. Information is provided to assist eligible States and tribes evaluate the impacts of the program, but decisions to participate in the program will be made by each separate jurisdiction.

The distribution of regional SO_2 allowances to existing sources in the nine Commission Transport States is composed of two portions: floor and reducible allocation. There are two components of the floor allocation - an allocation for the California Regional Clean Air Incentives Market (RECLAIM) program, and source-specific floor allocations for non-RECLAIM sources. The floor allocation is a minimum allocation for all existing sources, which will be calculated to ensure that well-controlled sources will receive a full allocation.

California RECLAIM Program: 3,462 SO_2 allowances will be included in the California budget for RECLAIM sources. These credits will be a subset of the existing source pool for the State of California and, hence, will not consume any extra credits from the total credit pool.

Source-specific Floor Allocation: A floor allocation will be calculated for all existing sources in the region based on some specified level of control (e.g., Best Available Control Technology [BACT], Best Available Retrofit Technology [BART], Lowest Achievable Emission Reduction [LAER]) for non-utility sources.

The sources affected by the backstop trading programs are all those stationary sources in participating States and tribes that emit SO_2 in an amount greater than or equal to 100 tons per year (tpy). The 100 ton cut off will be assessed at the plant level to correspond with the methodology used in the 1990 emissions inventory. Among the source types covered by this definition are utility and industrial boilers, refineries, smelters, pulp and paper mills, cement and lime kilns, and all of the other source categories listed in section 169(g)(7) of the Clean Air Act (CAA).

In this report, the geographic area of analysis is defined to be the nine Commission Transport Region States, which are Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming. Facilities included in the analysis are those that emitted 100 tpy or more of SO_2 sometime during the period 1990 to 2000. Plants that are electric utilities are excluded from this analysis.

A. ANALYSIS METHODS

The floor allocation analysis for the non-utility sector was performed using the following steps:

1. It was assumed that the SO_2 sources in the State of California are already at the floor. This is expected because of the stringency of the air emission regulations in that State.

2. Because copper smelter allocations for 2018 have already been determined, no additional analyses were performed for copper smelters. Smelter allocations are presented in Chapter X.

3. The focus of the analysis was on non-California, non-smelter facilities that had at least 100 tpy of SO_2 emissions during at least one year in the period 1990 to 2000. States included in this analysis were Arizona, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming.

4. The major SO_2 emitting non-utility source categories evaluated in this study included the following: petroleum refineries, lime manufacturing, industrial boilers and co-generators, pulp and paper manufacturing, cement manufacturing, natural gas processing and oil and gas production, elemental phosphorus production, glass manufacturing, aluminum smelting, sulfuric acid production, and metallurgical coke production.

5. The floor control technology or emission rate or SO_2 control effectiveness was determined by evaluating the emissions performance of other sources in that source category in the western States. The floor is defined to be BACT, BART, or LAER for *existing* sources. The floor for each of the major source categories is summarized in Table I-1.

6. The primary source of emissions information for the western States is the 1996 WRAP point source inventory. The 1996 emission estimates were prepared under contract to the Western Governors' Association (WGA) by Pacific Environmental; Services and Eastern Research Group, Inc. under contract to the WGA (PES, 2001). However, this data set was not sufficient for providing all of the information needed to compute the floor allocation for each source. The State air pollution control agencies in each of the 8 States were contacted to obtain supplementary data. For most source categories, this additional information included estimates of unit capacities. This could be either the design capacity for boilers, or the production capacity for industrial processes.

7. Once data was received from the State agencies, it was used to estimate the floor allocation by source and facility based on the control technologies listed in Table I-1 and the unit or plant-specific information about existing capacities and SO_2 control techniques.

The chapters that follow explain the floor allocation analyses for each of the key industrial sector source categories in the western United States.

Table I-1
Methodology for the Calculation of the Floor Allocations for Non-Utility Sources

Source Category	Technologies or Standard for Floor	
Copper Smelters	Due to the uniqueness of the existing smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. Currently, the Hidalgo smelter is the only BART-eligible source on the list in this category. A double-contact acid plant will be considered the appropriate retrofit control equipment (all smelters in the region are currently equipped with double-contact acid plants). On August 21, 2000, New Mexico completed an engineering analysis that verified earlier determinations by the MTF that the fugitive SO_2 capture system at Hidalgo satisfies BART at 96% overall capture.	
Refineries	There are four sources of SO_2 emissions at the refinery level. Floor based upon New Source Performance Standards (NSPS) where applicable.	
	Description	Assumed Average Control Level
	Sulfur Recovery Unit (SRU)	Meet NSPS Subpart J or the equivalent of 3-stage Claus units with a tail gas unit (NSPS and the tail gas unit does not apply to Claus units smaller than 20 long tons/day or less).
	Fuel gas combustion units	Fix at the NSPS emission limit rate of 0.027 pounds per million British thermal units (lbs/MMBtu) assuming fuel gas input and not fuel oil.
	Catalytic crackers	NSPS (J) selected 9.8 lbs of SO_2 per 1,000 lbs of coke burned.
	Flares	Based upon average of the last 5 years' emission, AP42 factors for calculated. No additional controls.
Natural Gas Processing	Description	Assumed Average Level of Control
	Process Emissions	Reduction to satisfy NSPS. Variable reduction depending on hydrogen sulfide (H_2S) content and plant size.
	Flaring	Based upon average of the last 5 years' emission.
Oil & Gas Production	Description	Assumed Average Level of Control
	Flaring	Based upon average of the last 5 years' emission.
Lime Plants	No additional reduction. Approximately 50% control inherent in the process. Additional SO_2 controls are not in place at lime plants in the western States.	

Table I-1 (continued)

Source Category	Technologies or Standard for Floor
Industrial Boilers (Cogens)	Technology determination dependent upon current level of control. Description — Assumed Average Level of Control Uncontrolled Units — 85% Units controlled at less than 70% — Treat as uncontrolled (see above). Units controlled between 70-80% — Increase reductions by 5% (i.e., if a unit is at 72%, would be assumed to control to 77%). Units controlled greater than 80% — No additional reductions.
Pulp and Paper	Sulfur sources are recovery furnaces and boilers. Boiler discussions covered with industrial boilers. Recovery Furnaces: No additional reduction. Low emissions coupled with lack of more than one example of scrubbing.
Cement Plants	No additional reduction. Approximately 70-90 percent control inherent in the process. Additional SO_2 controls are not typically applied to these levels of processes.
Aluminum Smelters	A wet scrubber with a 70 percent SO_2 emission reduction selected as the floor based on achieved control levels at NW Aluminum in Oregon.
Sulfuric Acid Plants	No additional reduction. Existing units are already controlled to NSPS levels (4 lbs per ton of 100% acid produced).
Coke Production	Only one facility is still operating. Because of the uniqueness of this rotary calciner, the floor allocation is established at historic SO_2 emission levels.

CHAPTER II
PETROLEUM REFINING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The petroleum refining industry involves numerous processes that convert crude oil into more than 2,500 products, including gasoline, liquefied petroleum gas, kerosene, jet fuel, diesel fuel, other fuel oils, lubricating oils, and feed stock for the petrochemical industry. Petroleum refinery activities include the storage of crude oil at the refinery, petroleum handling and refining operations, and storage of the refined products prior to shipment. As of January 1990, there were 189 operating refineries in the United States with a total crude capacity of 15.4 million barrels per calendar day.

Removal of sulfur from refinery streams is a part of refining. It would be desirable to remove all sulfur compounds before any crude processing begins, but because this is impractical, sulfur is removed throughout the refining process. There are several reasons, besides air pollution control, for removing sulfur from intermediate fractions and products of crude oil. Sulfur removal reduces corrosion, odor, breakdown frequency, catalyst poisoning, and gum formation and improves octane rating, color, and lube oil life.

B. FLOOR ALLOCATION ESTIMATION METHODS

There are four possible unit types (SO_2 emission points) within a refinery, as noted in the methodology for the calculation of the floor allocations for non-utility sources. These four SO_2 sources are: (1) the SRU; (2) fuel gas combustion units; (3) catalytic crackers; and (4) flares. The approach for estimating SO_2 floor allocations is unique for each of these four SO_2 source types within the refinery. Floor calculation methods are presented below for each of these four source types.

1. Sulfur Recovery Units

Sulfur recovery refers to conversion of H_2S to elemental sulfur. H_2S is a by product of processing natural gas and refining high sulfur crude oils. The most common conversion method used is the Claus process. Approximately 90 to 95 percent of recovered sulfur is produced by the Claus process. The Claus process typically recovers 95 to 97 percent of the H_2S feed stream.

The average production rate of a sulfur recovery plant in the United States varies from 51 to 203 megagrams (Mg) (56 to 224 tons) per day. Some of the small to mid-sized refineries in the western States have sulfur plant capacities that are lower than these average values.

The SO_2 floor allocation for SRUs depends on the size of the sulfur plant. For sulfur plants of 20 long tons per day or larger, the NSPS require a 3-stage Claus unit with a tail gas unit. Existing NSPS limit sulfur emissions from Claus sulfur recovery plants of greater than 20.32 Mg (22.40 tons) per day capacity to 0.025 percent by volume (250 parts per million volume [ppmv]). The NSPS and tail gas unit do not apply to Claus units smaller than 20 long tons per day or less. For these smaller sulfur plants, the SO_2 floor allocations are estimated as 95 percent SO_2 control.

Table 8.13-1 in AP-42 provides the following SO_2 emission factors for modified Claus Recovery Plants:

Emission Factors for Modified Claus Sulfur Recovery Plants

		SO_2 Emissions	
Number of Catalytic Stages	Average % Sulfur Recovery	Kilograms (kg)/Mg of Sulfur Produced	lbs/ton of Sulfur Produced
1, Uncontrolled	93.5	139	278
3, Uncontrolled	95.5	94	188
4, Uncontrolled	96.5	73	145
2, Controlled	98.6	29	57
3, Controlled	96.8	65	129

The SO_2 emission factor for 99.8 percent sulfur recovery is 8 lbs/ton and for 96.8 percent sulfur recovery is 132 lbs/ton of sulfur produced. This emission factor value is multiplied by the sulfur plant capacity in tons per day, 365 days per year, and 1 ton per 2,000 lbs to arrive at an annual SO_2 emissions floor estimate. Equation (1) below shows the above description as a formula:

$$Sulfur\ plant\ capacity\left(\frac{tons}{day}\right) * \frac{lbs\ SO_2}{ton} * \frac{365\ days}{year} * \frac{1\ ton}{2{,}000\ lbs} = \frac{SO_2\ tons}{year} \quad (1)$$

For refineries with sulfur plants smaller than 20 long tons per day, and lower H_2S contents in their acid gas, an SO_2 control level of 96.8 percent may not be achievable. In that situation, an alternative way to calculate the floor is to use the sulfur feed rate and the H_2S content of the acid gas of the affected facility to compute the appropriate minimum SO_2 reduction efficiency using the relationships shown in Table II-1. This table is from the NSPS for onshore natural gas production.

Table II-1
Sulfur Plants - Required Minimum SO_2 Emission Reduction Efficiency

H_2S Content of Acid Gas (Y), %	Sulfur Feed Rate (x), Long Tons per Day			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	.... $85.35X^{0.0144}Y^{0.0128}$ .... or 99.8, whichever is smaller		
$20 \le Y < 50$	74.0	.... $85.35X^{0.0144}Y^{0.0128}$ .... or 97.5, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

2. Fuel Gas Combustion Units

Fuel gas combustion units in refineries were defined to include all process heaters and boilers, and their combined oil and gas combustion capacity. SO_2 floor allocations are estimated as the combined oil and gas combustion capacity multiplied by 0.027 lbs/MMBtu. This emission rate is an approximation of the SO_2 emission factor for a fuel gas combustion unit meeting the NSPS of 0.10 grains H_2S per dry standard cubic foot (dscf) as required by 40 CFR 60 Subpart J.

This H_2S value is converted to an SO_2 emission rate in lbs/MMBtu using the equation below:

$$SO2\left(\frac{lb}{MMBtu}\right) = \frac{010\ grains\ H2S}{dscf}\ x\ \frac{1\ lb}{7{,}000\ grains}\ x\ \frac{64\ lb\ moles\ SO2}{34\ lb\ moles\ H2S}\ x\ \frac{1000\ scf}{MMBtu} = \frac{0.027\ lb}{MMBtu}$$

In the floor allocation estimates for fuel gas combustion units, the fuel gas combustion capacity is based on reported values for the refineries in Colorado, New Mexico, and Utah as well as for Wyoming Refining and Frontier Refining in Wyoming. Where this value has not been reported, it is estimated to be 5 percent of the crude oil processing capacity at that refinery. The industry norm is reported to be in the range of 5 to 10 percent. The 5 percent value was used because it is the average value for the western State refineries for which data on fuel gas combustion capacity were provided.

3. Catalytic Crackers

The SO_2 floor allocation for catalytic crackers at petroleum refineries is computed using the NSPS for fluid catalytic cracking units (FCCUs). The NSPS for FCCUs without add-on controls is 9.8 kg SO_x per 1,000 kg coke burn-off. For FCCUs without add-on control devices, EPA decided that the regulated pollutant should be SO_x, because SO_3 could constitute a significant portion of the total SO_2 emissions from FCCUs using SO_x reduction catalysts. The standard for FCCUs without add-on controls requires the use of Method 8 to determine the total SO_x emissions from affected facilities.

One of the issues in applying the NSPS emission rate to estimate the SO_2 floor allocation is the availability of information about the amount of coke burn-off for each FCCU. The Source Classification Code (SCC) units used in emission inventories, and AP-42 SO_2 emission factors, are expressed as lbs/1,000 barrels of fresh feed. Therefore, it is necessary to develop a conversion factor to go from an emission limit expressed as an SO_x emission rate per 1,000 kg coke burn-off to an emission limit expressed in AP-42 or SCC units if the coke burn rate is not available for a refinery.

In order to apply the NSPS SO2 emission rate to estimate the floor allocation for FCCUs, information about the coke burn rate was needed for each refinery. For 10 of the Western State refineries listed in Table II-1, estimates of the coke burn rate in pounds per hour were available from a data set that the American Petroleum Institute provided to EPA as part of the MACT standard setting process. These coke burn rates are based on 1997 operations. For the refineries with FCCUs and no coke burn rate available, the coke burn rates were estimated using the relationship between the FCCU feed capacity in barrels per calendar day and the coke burn rate (pounds per hour) for the 10 western refineries with reported values. The relationship used was 16 pounds coke per barrel of oil. Refineries where this default value was applied included the two Colorado refineries and Flying J, Inc. in Utah. Wyoming Refining provided a design coke burn rate for its FCCU.

4. Flares

Flares are commonly used for the disposal of waste gases during process upsets and emergencies. They are basically safety devices that are also used to destroy organic constituents in waste emission streams. The AP-42 SO_2 emission factor for a vapor recovery system and flaring is 26.9 lbs per 1,000 barrels refinery feed. This emission factor is applied to estimate the SO_2 emissions floor for flares at each refinery.

C. FLOOR ALLOCATION RESULTS

Table II-2 includes the floor allocation calculation for the refineries in the 8 non-California Western Regional Air Partnership (WRAP) States. The *Oil & Gas Journal Worldwide Refining Survey for 2000* provided the values for sulfur plant capacity, catalytic cracking unit capacity, and crude capacity listed in Table II-2 where they were not otherwise provided by State air agencies or refinery companies. Fuel gas combustion capacities in MMBtu/hour (hr) are estimated using information provided by State air pollution control agencies. Sinclair Corporation provided data for its two Wyoming refineries (Greene, 2002).

Table II-2
Petroleum Refining Floor Allocation Calculation

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
Conoco Inc.	Commerce City	CO	Sulfur Recovery Unit	70	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	102.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	112.9
			Oil		MMBtu/hr			
			Total	955	MMBtu/hr			
			FCCU	12,666	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	554.8
			Flares	57,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	282.3
			All Sources Combined					1,052.2
Colorado Refining	Denver	CO	Sulfur Recovery Unit	4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	96.4
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	60.2
			Oil		MMBtu/hr			
			Total	509	MMBtu/hr			
			FCCU	5,333	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per coke burn off	233.6
			Flares	35,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	171.8
			All Sources Combined					562.0
Giant Refining Co.	Bloomfield	NM	Sulfur Recovery Unit	2	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	48.2
			Fuel Gas Combustion					
			Gas	328	MMBtu/hr	0.027	lbs of SO_2 per million Btu	38.8
			Oil		MMBtu/hr			

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Total	328	MMBtu/hr			
			FCCU	5,400	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	236.5
			Flares	18,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	90.8
			All Sources Combined					414.3
Giant Refining Co.	Gallup	NM	Sulfur Recovery Unit	2	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	48.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	37.3
			Oil		MMBtu/hr			
			Total	315	MMBtu/hr			
			FCCU	8,200	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	359.2
			Flares	32,200	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	158.1
			All Sources Combined					602.7
Navajo Refining Co.	Artesia	NM	Sulfur Recovery Unit	140	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	204.4
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	109.3
			Oil		MMBtu/hr			
			Total	924	MMBtu/hr			
			FCCU	13,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	569.4
			Flares	70,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	343.6

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			All Sources Combined					1,226.7
BP/now Tesoro Petroleum	Salt Lake City	UT	Sulfur Recovery Unit	17.4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	419.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	100.0
			Oil		MMBtu/hr			
			Total	846	MMBtu/hr			
			FCCU	14,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	613.2
			Flares	52,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	255.3
			All Sources Combined					1,387.7
Chevron Products Co.	Salt Lake City	UT	Sulfur Recovery Unit	22.4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	539.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	145.9
			Oil		MMBtu/hr			
			Total	1,234	MMBtu/hr			
			FCCU	6,500	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	284.7
			Flares	55,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	270.0
			All Sources Combined					1,240.3
Silver Eagle Refining Inc.	Woods Cross	UT	Sulfur Recovery Unit	0	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	0.0
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	15.6

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Oil		MMBtu/hr			
			Total	132	MMBtu/hr			
			FCCU	0	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	0.0
			Flares	12,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	61.4
			All Sources Combined					77.0
Flying J Inc.	Salt Lake City	UT	Sulfur Recovery Unit	7	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	168.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	57.8
			Oil		MMBtu/hr			
			Total	489	MMBtu/hr			
			FCCU	7,533	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn	329.9
			Flares	24,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	117.8
			All Sources Combined					674.2
Phillips Petroleum Co.	Woods Cross	UT	Sulfur Recovery Unit	14	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	337.3
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	83.4
			Oil		MMBtu/hr			
			Total	705	MMBtu/hr			
			FCCU	5,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	219.0
			Flares	25,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	122.7

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			All Sources Combined					762.4
Frontier Refining Inc.	Cheyenne	WY	Sulfur Recovery Unit	110	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	160.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	155.5
			Oil		MMBtu/hr			
			Total	1,315	MMBtu/hr			
			FCCU	7,330	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	321.1
			Flares	46,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	225.8
			All Sources Combined					863.0
Sinclair Oil Corp.	Casper	WY	Sulfur Recovery Unit	21.7	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	522.8
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	77.1
			Oil		MMBtu/hr			
			Total	652	MMBtu/hr			
			FCCU	7,590	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	332.4
			Flares	22,000	Based on 2001 operations (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	108.0
			All Sources Combined					1,040.3
Sinclair Oil Corp.	Sinclair	WY	Sulfur Recovery Unit	52.6	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	76.8
			Fuel Gas Combustion					

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	119.9
			Oil		MMBtu/hr			
			Total	1,014	MMBtu/hr			
			FCCU	13,120	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	574.7
			Flares	60,000	Based on 2001 operations (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	294.6
			All Sources Combined					1,066.0
Wyoming Refining Co.	Newcastle	WY	Sulfur Recovery Unit	3	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	72.3
			Fuel Gas Combustion					
			Gas	0	MMBtu/hr	0.027	lbs of SO_2 per million Btu	51.6
			Oil	0	MMBtu/hr			
			Total	436.6	MMBtu/hr			
			FCCU	6,028.5	Data provided by Wyoming Refining (lbs/hr) design coke burn rate	20	lbs of SO_2 per ton coke burned	264.0
			Flares	12,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	61.4
			All Sources Combined					449.3
Total Floor Allocation (CO, NM, UT, WY)								**11,418**

D. COMPARISON WITH HISTORICAL EMISSIONS

Table II-3 summarizes historical SO_2 emissions from petroleum refineries located in the 9 WRAP States. California refineries are included in this table. This table provides a point of comparison with the floor allocations shown in Table II-2.

E. EXAMPLE CALCULATION

This section provides an example calculation of the refinery floor allocation using the data provided for this project by Wyoming Refining. This refinery is located in Newcastle, Wyoming. This same information can be found in Table II-2 in condensed form.

1. Sulfur Recovery Unit

The SO_2 floor allocation for the SRU is based on the capacity of the unit. Because the capacity of the Wyoming Refining sulfur plant is less than 20 long tons per day, a sulfur recovery efficiency of 96.8 percent is applied in the floor calculation. (If the sulfur plant was larger than 20 long tons per day, a 99.8 percent sulfur recovery value would be applied.)

The SO_2 emission factor for 96.8 percent sulfur recovery is 132 lbs SO_2 per ton of sulfur produced as shown below:

$$\frac{\mathbf{3.2}\ \textit{tons S emitted}}{\mathbf{96.8}\ \textit{tons S removed}} * \frac{\mathbf{2000}\ \textit{lbs}}{\textit{ton}} \times \frac{\mathbf{64}\ \textit{lbs moles } SO_2}{\mathbf{32}\ \textit{lbs moles S}} = \frac{\mathbf{132}\ \textit{lbs } SO_2}{\textit{ton S produced}}$$

Then, the SO_2 floor allocation is the sulfur plant capacity (3 short tons per day) multiplied by the SO_2 emission factor and 365 days per year, as follows:

$$SO_2\ \textit{Floor (tons per year)} = \textit{Sulfur plant capacity (tons / day)} * SO_2\ \textit{emission factor (lbs / ton)} * \frac{1\ \textit{ton}}{2000\ \textit{lbs}} \times 365\ \textit{days / year}$$

$$= (3.0)(132)(365) \div 2000 = 72.3$$

2. Fuel Gas Combustion

The SO_2 floor allocation for fuel gas combustion is based on the combined boiler and process heater combustion capacity with each refinery. Wyoming Refining estimates that its total boiler plus process heater fired duty capacity at the refinery is 436.6 MMBtu per hour. The SO_2 floor allocation is estimated to be the combined oil and gas combustion capacity multiplied by 0.027
lbs/MMBtu.

$$SO_2\ \textit{Floor (tons per year)} = \textit{Combustion Capacity (MMBtu / hr)} * SO_2\ \textit{emission factor (lbs / MMBtu)} * \frac{1\ \textit{ton}}{2000\ \textit{lbs}} * \frac{8760\ \textit{hrs}}{\textit{year}}$$

$$= (436.6)(0.027)(5 \times 10^{-4})(8760)$$

$$= 51.6$$

Table II-3
Petroleum Refineries – Historical Emissions – 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	005	0001	42	2911	6	Oil/Gas	Intermountain Refining		803	0	0	0
CA	6	037	800012	14	2911	6	Oil/Gas	ARCO (NSR USE ONLY)	ARCO PRODUCTS CO	1,919	2,359	1,706	2,315
CA	6	037	800030	14	2911	6	Oil/Gas	CHEVRON U.S.A. INC (EIS USE) - EL SEGUNDO	CHEVRON PRODUCTS CO.	833	1,795	938	1,208
CA	6	013	10	11	2911	6	Oil/Gas	CHEVRON USA INC - RICHMOND	CHEVRON PRODUCTS COMPANY	1,291	1,018	1,413	1,244
CA	6	095	15	11	2911	6	Oil/Gas	EXXON CORPORATION - BENICIA		4,922	6,042	5,779	5,779
CA	6	029	37	13	2911	6	Oil/Gas	KERN OIL & REFINING CO.		319	425	443	364
CA	6	037	800089	14	2911	6	Oil/Gas	MOBIL OIL CORP (EIS USE) - TORRANCE	MOBIL OIL CORP (EIS USE)	256	807	725	1,018
CA	6	013	32	11	2911	6	Oil/Gas	PACIFIC REFINING COMPANY	NOW PLANT ID 11587	278	290	0	0
CA	6	029	25	13	2911	6	Oil/Gas	SAN JOAQUIN REFINERY	SAN JOAQUIN REFINING COMPANY	337	313	138	0
CA	6	013	11	11	2911	6	Oil/Gas	SHELL OIL COMPANY - MARTINEZ	MARTINEZ REFINING COMPANY	2,790	2,518	2,374	1,159
CA	6	037	800223	14	2911	6	Oil/Gas	TEXACO REFINING & MARKETING IN - WILMINGTON		546	727	590	953
CA	6	029	33	13	2911	6	Oil/Gas	TEXACO REFINING AND MARKETING - BAKERSFIELD	EQUILON ENTERPRISES LLC	471	190	94	72
CA	6	013	12758	11	2911	6	Oil/Gas	TOSCO CORP AVON REFINERY		7,661	4,459	5,422	5,422
CA	6	037	800026	14	2911	6	Oil/Gas	ULTRAMAR INC (NSR USE ONLY)		341	959	669	620
CA	6	037	800144	14	2911	6	Oil/Gas	UNION OIL CO OF CAL (NSR USE O	TOSCO REFINING COMPANY	724	1,005	806	806
CA	6	079	4	13	2911	6	Oil/Gas	UNOCAL CARBON	TOSCO SANTA MARIA REFINERY	0	0	0	0
CA	6	079	4	13	2911	6	Oil/Gas	UNOCAL CHEM DIV-UNOCAL CORP - ARROYO GR	TOSCO	3,034	3,950	0	0
CA	6	013	16	11	2911	6	Oil/Gas	UNOCAL CORPORATION - RODEO	TOSCO RODEO REFINERY	584	728	675	615
CA	6	037		14	2911	6	Oil/Gas	UNOCAL REFINING & MARKETING CO	TOSCO REFINING (L.A.)	0	343	508	587
CA	6	079	13	13	2911	6	Oil/Gas	UNOCAL- SANTA MARIA REFINERY	TOSCO SANTA MARIA REFINERY	647	225	3,501	3,727
CA	6	037	800047	14	2911	6	Oil/Gas	FLETCHER OIL & REF CO (EIS USE		107	0	0	0
CA	6	037	800184	14	2911	6	Oil/Gas	GOLDEN WEST REF CO (EIS USE)		232	0	0	0
CA	6	037	800103	14	2911	6	Oil/Gas	POWERINE OIL CO (EIS USE)		196	0	1	1
CA	6	037	800115	14	2911	6	Oil/Gas	SHELL OIL CO (EIS USE) - CARSON	SHELL OIL PRODUCTS	778	0	0	0
CO	8	001	0004	53	2911	6	Oil/Gas	COLO REFINING		632	664	526	545
CO	8	001	0003	53	2911	6	Oil/Gas	CONOCO DENVER		2,336	2,610	2,496	1,972
CO	8	077	0001	55	2911	6	Oil/Gas	LANDMARK PETROLEUM		157	0	0	0
NM	35	045	0023	60	2911	6	Oil/Gas	GIANT INDUSTRIES/BLOOMFIELD REF		676	772	920	920
NM	35	031	0008	61	2911	6	Oil/Gas	GIANT REFINING/CINIZA REFINERY		1,346	1,115	1,779	1,779
NM	35	015	0010	65	2911	6	Oil/Gas	NAVAJO REFINING/ARTESIA REFINERY		1,549	1,552	969	980
UT	49	035	0004	32	2911	6	Oil/Gas	Amoco Petroleum Products	TESORO PETROLEUM	6,701	983	1,116	1,368
UT	49	011	0003	31	2911	6	Oil/Gas	Chevron Products Company		2,424	1,116	845	1,242
UT	49	011	0008	31	2911	6	Oil/Gas	Flying J Incorporated		312	574	225	300
UT	49	011	0013	31	2911	6	Oil/Gas	Phillips 66 Company		5,672	864	862	601
WY	56	021	0001	9	2911	6	Oil/Gas	FRONTIER OIL & REFINING - CHEYENNE		1,521	1,769	1,422	1,396
WY	56	025	0001	9	2911	6	Oil/Gas	LITTLE AMERICA REFINING COMPANY	SINCLAIR - CASPER	1,899	1,629	1,305	1,458
WY	56	007	0011	9	2911	6	Oil/Gas	SINCLAIR @ SINCLAIR		5,917	3,990	3,524	3,407
WY	56	045	0001	9	2911	6	Oil/Gas	WYOMING REFINING CO	WYOMING REFINING - NEWCASTLE	630	930	804	876
WY	56	025	0002	9	2911	6	Oil/Gas	AMOCO REFINERY		1,153	0	0	0
Totals										**61,994**	**46,721**	**42,575**	**42,734**

3. Catalytic Crackers

The SO_2 floor allocation for catalytic crackers is based on the coke burn rate at the FCCU and the NSPS SO_2 emission rate. The FCCU for Wyoming Refining has a design feed rate of 5,300 barrels per day, or 6,029 lbs per hour. The NSPS SO_2 emission rate is 20 lbs SO_2 per ton coke burn-off.

$$SO_2\ Floor\ (tons\ per\ year) = Coke\ burn\ rate\ (lbs\ /\ hr) * \frac{1\ ton}{2000\ lbs} * SO_2\ emission\ \ factor\ (lbs\ /\ ton) * \frac{1\ ton}{2000\ lbs} * \frac{8760\ hrs}{year}$$

$$= (6029)\,(5 \times 10^{-4})\,(20)\,(5 \times 10^{-4})\,(8760)$$

$$= 264.0$$

4. Flares

The SO_2 floor allocation for the flares at Wyoming Refining is estimated according to the total crude processing capacity of the facility. The estimated crude processing capacity for Wyoming Refining is 12,500 barrels per calendar day. This capacity value is multiplied by the AP-42 SO_2 emission factor for a vapor recovery system and flaring of 26.9 lbs per 1,000 barrels refinery feed.

$$SO_2\ Floor\ (tons\ per\ year) = refinery\ capacity \left(\frac{1000\ bbls}{cd}\right) * 26.9 \left(\frac{lbs}{1000\ bbls}\right) * \left(\frac{1\ ton}{2000\ lbs}\right) * \left(\frac{365\ days}{year}\right)$$

$$= (12.5)\ (26.9)\ (5 \times 10^{-4})\ (365)$$

$$= 61.4$$

REFERENCES

40 CFR Part 60, 2001a: Code of Federal Regulations, “Subpart J - Standards of Performance for Petroleum Refineries,” (60.100-60.109), 2001.

40 CFR Part 60, 2001b: Code of Federal Regulations, “Subpart LLL - Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions,” 2001.

EPA, 1989: U.S. Environmental Protection Agency, “Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators – Background Information for Promulgated Standards – Final EIS,” EPA-450/3-82-013b, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1989.

EPA, 1993: U.S. Environmental Protection Agency, “Compilation of Air Pollutant Emission Factors (AP-42), Section 8.13 Sulfur Recovery,” Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1993.

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Greene, 2002: Letter from Samuel B. Greene, P.E., Sinclair Oil Corporation, Salt Lake City, UT, to Jim Wilson, E.H. Pechan & Associates, Inc., Springfield, VA, Re: Sinclair Oil Corporation Western Regional Air Partnership - Market Trading Forum, Non-Utility SO_2 Floor Allocation Study, Transmittal of Requested Information, September 30, 2002.

Oil & Gas Journal, 2000: *Oil & Gas Journal*, “2000 Worldwide Refining Survey,” December 18, 2000, Volume 98.51, 2000.

CHAPTER III
LIME MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Lime is the high temperature product of the calcination of limestone. Although limestone deposits are found in every State, only a small portion is pure enough for industrial lime manufacturing. The Standard Industrial Classification (SIC) code for lime manufacturing is 3274. The six-digit SCC for lime manufacturing is 3-05-016.

The heart of a lime plant is the kiln. The prevalent type of kiln is the rotary kiln, accounting for about 90 percent of all U.S. lime production. This kiln is a long, cylindrical, slightly inclined, refractory-lined furnace, through which the limestone and hot combustion gases pass concurrently. Coal, oil, and natural gas may all be fired in rotary kilns. Product coolers and kiln feed preheaters of various types are commonly used to recover heat from the hot lime product and hot exhaust gases, respectively.

The next most common type of kiln in the United States is the vertical, or shaft, kiln. This kiln can be described as an upright heavy steel cylinder lined with refractory material. The limestone is charged at the top and is calcined as it descends slowly to discharge at the bottom of the kiln. A primary advantage of vertical kilns over rotary kilns is higher average fuel efficiency. The primary disadvantages of vertical kilns are their relatively low production rates and the fact that coal cannot be used without degrading the quality of the lime produced. There have been few recent vertical kiln installations in the United States because of high product quality requirements.

Other, must less common, kiln types include rotary hearth and fluidized bed kilns. Both kiln types can achieve high production rates, but neither can operate with coal. The “calcimatic” kiln, or rotary hearth kiln, is a circular kiln with a slowly revolving doughnut-shaped hearth. In fluidized bed kilns, finely divided limestone is brought into contact with hot combustion air in a turbulent zone, usually above a perforated grate. Because of the amount of lime carryover into the exhaust gases, dust collection equipment must be installed on fluidized bed kilns for process economy.

SO_2 emissions are influenced by several factors, including the fuel sulfur content, the sulfur content and numeralogical form (pyrite or gypsum) of the stone feed, the quality of lime being produced, and the type of kiln. The dominant source of SO_2 emissions is the kiln’s fuel, and the vast majority of the fuel sulfur is not emitted because of reactions with calcium oxides in the kiln. SO_2 emissions may be further reduced if the pollution equipment uses a wet process or if it brings calcium oxides and SO_2 into intimate contact.

Table III-1 provides SO_2 emission factors for lime manufacturing. This table shows that there is a wide range of SO_2 emissions performance depending on the kiln type, pollution control equipment, feedstock, and fuel.

Because of differences in the sulfur content of the raw material and fuel and in process operations, a mass balance on sulfur may yield a more representative emission factor for a specific facility than AP-42 emission factors.

B. FLOOR ALLOCATION ESTIMATION METHODS

With the wide range of SO_2 emission factors for lime manufacturing, the SO_2 control that is inherent in the lime manufacturing process, and additional controls are not typically applied to lime plants, the SO_2 floor allocation for lime plants will be based on historical emissions. The historical emissions for the 1990 to 2000 period are listed in Table III-2. The calendar year 2000 SO_2 emission total for lime manufacturing is 2,316 tons.

REFERENCES

AWMA, 2000: Air & Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, edited by Wayne T. Davis, 2000.

EPA, 1998: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, AP-42, Section 11:17: Lime Manufacturing," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

Table III-1
Emission Factors for Lime Manufacturing[a]

Source	SO_2[b]	Emission Factor Rating
Coal-fired rotary kiln (SCC 3-05-016-18)	5.4	D
Coal-fired rotary kiln with fabric filter (SCC 3-05-016-18)	1.7	D
Coal-fired rotary kiln with wet scrubber (SCC 3-05-016-18)	0.30	D
Gas-fired rotary kiln (SCC 3-05-016-19)	ND	
Coal- and gas-fired rotary kiln with venturi scrubber (SCC 3-05-016-20)	ND	
Coal- and coke-fired rotary kiln with venturi scrubber (SCC 3-05-016-21)	ND	
Coal-fired rotary preheater kiln with dry PM controls (SCC 3-05-016-22)	2.3	E
Coal-fired rotary preheater kiln with multiclone, water spray, and fabric filter (SCC 3-05-016-22)	6.4	E
Gas-fired calcimatic kiln (SCC 3-05-016-05)	ND	
Gas-fired parallel flow regenerative kiln with fabric filter (SCC 3-05-016-23)	0.0012	D
Product cooler (SCC 3-05-016-11)	ND	

NOTES: [a]Factors represent uncontrolled emissions unless otherwise noted. Factors are lbs/ton of lime produced unless noted. ND = no data. Classification Code.
[b]Mass balance on sulfur may yield a more representative emission factor for a specific facility.

Table III-2
Lime Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Allocation*
AZ	4	025	0011	41	3274	10	Metals/Mining/Minerals	CHEMICAL LIME (CHEMSTAR)	CHEMICAL LIME CO - NELSON PLANT	141	122	562	702	632
AZ	4	003	0003	47	3274	10	Metals/Mining/Minerals	CHEMICAL LIME (DOUGLAS)	CHEMICAL LIME CO - DOUGLAS PLANT	212	634	724	742	733
CA	6	053	12	12	3274	10	Metals/Mining/Minerals	NATIONAL REFRACTORIES&MINERALS	CHEMICAL LIME CO - NATIVIDAD PLANT	243	<100	69	82	76
NV	32	003	0003	22	3274	10	Metals/Mining/Minerals	CHEMSTAR APEX	CHEMICAL LIME CO - APEX PLANT	783		175	210	193
NV	32	007	0261		3274	10	Metals/Mining/Minerals	CONTINENTAL LIME INC., PILOT PEAK PLANT	GRAYMONT WESTERN US INC, PILOT PEAK PLANT	<100	136	235	249	242
UT	49	027		35	3274	10	Metals/Mining/Minerals	CONTINENTAL LIME INC., CRICKET MOUNTAIN PLANT	GRAYMONT WESTERN US, INC., CRICKET MOUNTAIN PLANT	115	297	275	331	303
Totals										**1,594**	**1,289**	**2,040**	**2,316**	**2,179**

NOTE: *Based on 1998 and 2000 historical SO_2 emission estimates.

CHAPTER IV
INDUSTRIAL BOILERS AND COGENERATORS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Industrial, commercial and institutional (ICI) boilers produce steam or heat water for use in industrial processes, electrical/mechanical power generation, or space heating. Some have a dual functionality such as the cogeneration of steam and electricity. Auxiliary boilers provide backup power and power for startup/shutdown of large units. Large boilers ($\geq$150 MMBtu/hr) are generally field-erected units while small boilers are preassembled, packaged units. The design of an individual ICI boiler is often dependant on the application of steam and the space limitations in a particular plant.

ICI boilers generate steam at lower temperatures and pressures than utility boilers, therefore, their heat inputs are smaller. Industrial boilers generally have heat input rates ranging from 30 to 250 MMBtu/hr, but may be as high as 1,500 MMBtu/hr (EPA, 1994). Commercial and institutional boilers typically have heat input rates ranging from 0.4 to 12 MMBtu/hr, but may be as high as 100 MMBtu/hr (EPA, 1994). The overall population of ICI boilers have small heat inputs, with 80 percent of the population operating at less than 5 MMBtu/hr per boiler (STAPPA, 1994). Over 80 percent of the ICI boilers burn oil and gas. The remaining boilers burn primarily coal, with a small number burning biomass, waste or other non-fossil fuel. ICI combustion units often burn a mixture of conventional fuels and biomass or waste. Pulverized coal-fired units account for approximately 1 percent of the total ICI boiler population. However, they have large heat inputs, greater than 100 MMBtu/hr, therefore, they represent 14 percent of the total ICI boiler capacity. Oil and gas fired ICI boilers are smaller in size than coal-fired boilers, typically less than 250 MMBtu/hr.

The use of ICI boilers varies with the industrial application. In addition, the application of steam from an industrial boiler can change with the seasons, and can vary through the course of a day as well, depending on the processes and activities underway at a given moment and their demand for steam. Therefore, ICI boilers may have a much lower annual operating load or capacity factor than a typical utility boiler.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to facilities which emit greater than 100 tpy of SO_2 in total, and/or individual units which emit greater than 25 tpy of SO_2. In addition, only coal and oil fired units were analyzed. Auxiliary boilers were included in the floor allocation estimation if the unit had a potential to emit (PTE) greater than 25 tpy. This includes boilers larger than 5 MMBtu/hr firing fossil fuel with a sulfur content of 1 percent or more.

The air pollution agencies for each WRAP State provided information for each ICI boiler being analyzed. This information included the boiler design capacity, annual fuel consumption for recent calendar years, fuel type (coal or oil), fuel sulfur content, SO_2 control device information, and the control device SO_2 control efficiency, or permitted SO_2 emissions limit for each unit.

The SO_2 floor allocations are calculated for each facility based on the current level of control. An average level of control is then assumed for each facility, according to Table IV-1 below:

Table IV-1
Assumed Level of Control for SO_2 Floor Allocation

Current Facility Level of Control	Assumed Average Level of Control for Estimating the Floor
Uncontrolled, 0%	85% Reduction
Units controlled at 0% to <70%	85% Reduction
Units controlled at 70% to 80 %	Increase reduction by 5%
Units controlled at 80% or greater	No additional reduction

Floor allocations for industrial boilers/cogenerators were also based on the average capacity utilization during the most recent calendar years. Some States were able to provide as many as five years worth of boiler utilization data. The recent years of boiler utilization (fuel consumption) data were used to estimate an average capacity factor for each unit. This average capacity factor was used, along with a 5 percent margin for growth, in the SO_2 floor allocation calculation for each boiler/cogenerator.

1. Coal Fired Units

Coal fired units were assumed to fire subbituminous coal with a heating value of 9,000 Btu/lb (18 MMBtu/ton) of coal burned, unless a specific coal type or heating value was reported (AWMA, 2000). The ICI boilers in the WRAP States were assumed to burn subbituminous coal since it has a low sulfur content. In addition, a lower grade of subbituminous coal, class C coal, was assumed to be used for ICI applications. The fuel sulfur content used to calculate the floor allocation was facility-specific, where available. For facilities that did not report sulfur content, an average sulfur content (1 percent) for the type of coal being fired was used (AWMA, 2000).

The SO_2 emission factor for subbituminous coal fired boilers in pounds of SO_2 emitted per ton of coal burned is given in AP-42 as:

$$EF_{SO2}\left(\frac{\text{lb of SO2}}{\text{ton}}\right) = 35 \times S$$

where S is the percentage sulfur content of the coal burned by each combustion unit (EPA, 1998a).

2. Oil Fired Units

Oil fired units were assumed to have a heating value of 0.15 MMBtu/gal unless a specific oil type or heating value was reported (AWMA, 2000). The fuel sulfur content used to calculate the floor allocation was facility-specific. For facilities not reporting sulfur content, an average sulfur content for the type of oil being fired was used (AWMA, 2000).

The SO_2 emission factor for No. 2 and No. 6 oil fired boilers in pounds of SO2 emitted per 1,000 gallons of oil burned is given in AP-42 as:

$$EF_{oil}\left(\frac{\text{lb of SO2}}{\text{1,000 gal}}\right) = 157 \times S$$

where S is the percentage sulfur content of the oil burned by each combustion unit (EPA 1998b).

Units that burn natural gas and oil are assumed to burn natural gas as a primary fuel, if the emission data indicated SO_2 emission < 5 tpy. If natural gas is the primary fuel, no allocations are computed.

C. FLOOR ALLOCATION RESULTS

Table IV-2 summarizes the floor allocation calculation for the ICI boilers in the 8 non-California Western Regional Air Partnership (WRAP) States.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table IV-3 summarizes historical SO_2 emissions from industrial boilers located in Arizona, Colorado, Idaho, Oregon, Utah, and Wyoming. This table provides a point of comparison with the floor allocations shown in Table IV-2 and historical emissions at each facility. Note that the historical emissions are the total plant emissions, not just those resulting from operation of the boiler. In general, boilers which currently have a scrubber are able to meet their SO_2 floor allocations based on historical emissions.

E. EXAMPLE USE OF CAPACITY UTILIZATION DATA FOR FLOOR ALLOCATION ESTIMATES

The floor allocation estimation method for boilers and cogenerators takes into account utilization of these fuel combustion units in the most recent historical years. This section provides an example of how the capacity factor calculation was performed for one boiler at Abitibi Consolidated in Arizona.

In order to estimate the average annual capacity factors of each unit, Pechan requested the actual fuel throughput data for the last 5 years for each boiler. The data was supplied by the air pollution agencies for each WRAP State. The fuel throughput data supplied by the Arizona DEQ for Abitibi Consolidated is listed in Table IV-4.

Fuel throughput for all fuel types, coal, oil and natural gas were used to estimate the annual heat input for each unit using the following equation:

$$Q_{annual} = \left(T_{coal} \times HC_{coal}\right) + \left(T_{oil} \times HC_{oil}\right) + \left(T_{gas} \times HC_{gas}\right)$$

where:

Q_{annual}	=	annual heat input for each boiler (MMBtu/yr),
T	=	throughput for given fuel type, and
HC	=	heat content for a given fuel type.

Most States did not specify the heat content for each fuel, therefore, the following default values were used:

Coal	Heat content = 18.0 MMBtu/ton
Oil	Heat content = 0.15 MMBtu/gal
Natural Gas	Heat content = 1,020 MMBtu/MMscf

The boiler design capacity at Abitibi Power boiler #2 is 1,132 MMBtu per hour. In this exercise, the annual fuel consumption is compared with this boiler design capacity to estimate the percentage of total capacity that is used in each year. The Arizona DEQ was able to provide fuel throughput, or fuel consumption, estimates for four calendar years: 1998 through 2001. This particular unit burns coal and oil, but not natural gas. Fuel consumption estimates were provided by the State in tons for coal and gallons for oil. The average heat contents of these two fuels are listed in Table IV-4 and are used to compute an *All Fuels Combined Throughput* value in column J. Column K contains the boiler design capacity value converted to an annual equivalent. The capacity factor for each calendar year is computed (in column L) as the ratio of column J to column K. For Abitibi Power boiler #2, these capacity factors range from 60 to 70 percent, with an average capacity factor of 64 percent. The 64 percent average capacity factor value is used in the floor allocation estimate. (Note that during a leap year (2000), the potential hours of operation are greater.)

This average capacity factor is used to calculate the SO_2 floor allocation. This value is multiplied by 1.05 to provide some margin for future increases in operations. Only the primary fuel (coal in this example) is assumed to burned by the boiler in the floor allocation estimation. The SO_2 allocations are calculated using the assumed control efficiency (85 percent) as specified in Table IV-1. The SO_2 floor allocation is calculated using the following equation:

$$SO_2 = \frac{Q_{design}}{HC_{prime}} \frac{EF_{SO2}}{2000 \ \frac{\text{lb}}{\text{ton}}} \left(1.05 \times CF\right) \left(\frac{100 - \text{CE}}{100}\right)$$

where:

SO_2	=	SO_2 floor allocation (tons/yr),
Q_{design}	=	annual heat input (MMBtu/yr),
HC_{prime}	=	heat content of primary fuel (MMBtu/ton, MMBtu/gal),
EF	=	SO_2 emissions factor (lb/ton, lb/gal),
CF	=	average capacity factor (%), and
CE	=	required control efficiency (%).

For Abitibi Power boiler #2, the appropriate values for the above equation are:

Q_{design}	=	9,916,320
HC_{prime}	=	18
EF	=	35
CF	=	0.64
CE	=	85

As is shown in column P of Table IV-4, the SO_2 floor allocation estimate for Abitibi Power boiler #2 is 978 tpy.

REFERENCES

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EPA, 1998a: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42), Section 1.1 Bituminous And Subbituminous Coal Combustion," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

EPA, 1998b: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42), Section 1.3 Fuel Oil Combustion," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

STAPPA, 1994: State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO), "Controlling Nitrous Oxides," July 1994.

Table IV-2
Facility SO_2 Floor Allocation Estimation for ICI Boilers

Facility	Unit	Capacity in MMBtu/hr	Fuel	Sulfur Content	Current SO_2 Controls	Percent Reduction	SO_2 Limit	Average Capacity Factor (%)	Assumed Percent Reduction	Floor Allocation (tpy)
Arizona										
Abitibi Consolidated	No. 2 Power Boiler	1,132	Coal	1.0	None	0		64	85	978
Colorado										
TRIGEN - Colorado Energy Corp	Boiler #3	225	Coal	0.39		0		43	85	
TRIGEN - Colorado Energy Corp	Boiler #4	360	Coal	0.38		0		62	85	
TRIGEN - Colorado Energy Corp	Boiler #5	650	Coal	0.43		0		59	85	387
Idaho										
Amalgamated Sugar, Nampa	S-B1	105	Coal	1.0	None	0		34	85	
Amalgamated Sugar, Nampa	S-B2	105	Coal	1.0	None	0		35	85	
Amalgamated Sugar, Nampa	S-B3	250	Coal	1.0	None	0		43	85	242
Amalgamated Sugar Company, Paul	S-B1	200	Coal	1.0	None	0		35	85	
Amalgamated Sugar Company, Paul	S-B2	200	Coal	1.0	None	0		23	85	155
Amalgamated Sugar Company, Twin Falls	P-B1	280	Coal	1.0	None	0		30	85	
Amalgamated Sugar Company, Twin Falls	P-B2	285	Coal	1.0	None	0		24	85	203
Oregon										
Boise Cascade [c]	Power Boiler 6-9	N/A	Oil	2.0	No	0	4125 tpy	--	85	411
Amalgamated Sugar	B&W Boilers	204	Coal	1.5	Wet Scrubber	45	200 tpy	12	85	
Amalgamated Sugar	Foster Riley Boiler	136	Coal	1.5		0	265 tpy	20	85	
Amalgamated Sugar	Foster Wheeler Boiler	300	Coal	1.5		0	775 tpy	21	85	74
Georgia Pacific West	Power Boiler #1	Unknown	Oil	2.0	None	0	429.6 tpy	--	85	143
Pope & Talbot	Power Boiler #1	Unknown	Oil	2.0	None	0	391 tpy	--	85	107
West Linn Paper Co.	Boilers 1 & 2		Oil	2.0	None	0	492.74 tpy	46	85	211
Georgia-Pacific Wauna	Power Boiler	Unknown	Oil	2.0	None	0	641.1 tpy	--	85	
Georgia-Pacific Wauna	Package Boiler	Unknown	Oil	2.0	None	0	0.5 tpy	0	85	277
Weyerhaeuser Springfield	Power Boiler	Unknown	Oil	2	None	0	590 tpy	--	85	
Weyerhaeuser Springfield	Package Boiler	Unknown	Oil	0.55	None	0	73 tpy	--	85	
Weyerhaeuser Springfield	Package Boiler	16	Oil	2	None	0	39 tpy	0	85	362
Utah										
Sunnyside Cogeneration Associates	FBC Boiler #1	700	Coal	1.0	Scrubber	86	462 lbs/hr	84	86	1,270
Kennecott Utah Copper Corp N. Concentator	Unit 1	431	Coal	0.68	None [a]	0	1258 tpy	41	85	
Kennecott Utah Copper Corp N. Concentator	Unit 2	431	Coal	0.68	None [a]	0	1258 tpy	33	85	
Kennecott Utah Copper Corp N. Concentator	Unit 3	431	Coal	0.68	None [a]	0	1258 tpy	28	85	
Kennecott Utah Copper Corp N. Concentator	Unit 4	838	Coal	0.68	None [a]	0	2445 tpy	39	85	700
Brigham Young University	Units #2, #3, and #5	128	Coal	0.70	None [a]	0	217 tpy	0	85	
Brigham Young University	Auxiliary #7	5	Oil	1.5		0		6	85	0
Brush Wellman Incorporated	S-11 - Main Boiler	81.2	Oil	1.5	None	46	0.85 lb/MBtu	32	85	
Brush Wellman Incorporated	S-10 Backup Boiler	12.66	Oil	1.5	None	46	0.85 lb/MBtu	19	85	23

Table IV-2 (continued)

Facility	Unit	Capacity in MMBtu/hr	Fuel	Sulfur Content	Current SO_2 Controls	Percent Reduction	SO_2 Limit	Average Capacity Factor (%)	Assumed Percent Reduction	Floor Allocation (tpy)
Geneva Steel	Power Boiler 1	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 2	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 3	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 4	205	Coal/Gas	1.0	None	0		0		
Geneva Steel	Power Boiler 5	205	Coal/Gas	1.0	None	0	520.2 tpy	0	96	17
Wyoming										
Solvay Minerals, Inc.	Boiler #18	350	Coal	0.7	Scrubber	85	0.2	62	85	
Solvay Minerals, Inc.	Boiler #19	350	Coal	0.7	Scrubber	85	0.2	61	85	294
General Chemical	Boiler C	534	Coal	0.5	No	0	1.2	74	85	
General Chemical	Boiler D	880	Coal	0.5	No	0	1.2	71	85	750
Holly Sugar-Torrington Plant		221.2	Coal	0.7	No	0	None	17	85	23
FMC Corp - Green River Plant	Boiler #6	887	Coal	0.5	Scrubber [b]	0	1.2	70	85	
FMC Corp - Green River Plant	Boiler #7	887	Coal	0.5	Scrubber [b]	0	1.2	70	85	956
University of Wyoming Central Heating Plant	Boiler #2	73.1	Coal	0.5	No	0	1.2	18	85	
University of Wyoming Central Heating Plant	Boiler #3	73.1	Coal	0.5	No	0	1.2	25	85	22
University of Wyoming Central Heating Plant	Boiler #4	73.1	Coal					20		
FMC Granger	Boiler #1	358	Coal	1.0	Scrubber	99	0.2 lb/MMbtu	48	99	
FMC Granger	Boiler #2	358	Coal	1.0	Scrubber	99	0.2 lb/MMbtu	48	99	305
Total Floor Allocation										**7,910**

NOTES: [a]Natural gas is fired during winter months per SIP requirements.
[b]Scrubber is for the entire plant not just the boiler.

Table IV-3
Comparison of SO_2 Floor Allocation with Historical Emissions for ICI Boilers

Facility	Unit	Capacity (MMBtu/hr)	SO_2 Floor Allocation (tpy)	Historical SO_2 Emissions 1990 (tpy)	1996 (tpy)	1998 (tpy)	2000 (tpy)
Arizona							
Abitibi Consolidated	Power Boiler #2	1,132	978		2,455	2,448	1,893
Colorado							
TRIGEN - Colorado Energy Corp [b]	Boiler #3	225					
TRIGEN - Colorado Energy Corp [b]	Boiler #4	360					
TRIGEN - Colorado Energy Corp [b]	Boiler #5	650	387	2,675		3,708	2,583
Idaho							
Amalgamated Sugar, Nampa	S-B1	105					
Amalgamated Sugar, Nampa	S-B2	105					
Amalgamated Sugar, Nampa	S-B3	250	242	1,008	1,660	1,787	1,697
Amalgamated Sugar Company, Paul	S-B1	200					
Amalgamated Sugar Company, Paul	S-B2	200	155	608	306	217	1,322
Amalgamated Sugar Company, Twin Falls	P-B1	280					
Amalgamated Sugar Company, Twin Falls	P-B2	268	203	599	1,364	1,053	1,053
Oregon							
Boise Cascade [c]	Power Boiler 6-9	N/A	411	2,453	685	746	1,834
Amalgamated Sugar [c]	B&W Boilers	204					
Amalgamated Sugar [c]	Foster Riley Boiler	136					
Amalgamated Sugar [c]	Foster Wheeler Boiler	300	74	594	625	1,235	987
Georgia Pacific West [c]	Power Boiler #1	Unknown	143				
Pope & Talbot [c]	Power Boiler #1	Unknown	107			39	161
West Linn Paper Co. [a]	Boilers 1 & 2	365	211				
Georgia-Pacific - Wauna [c]	Power Boiler	Unknown					
Georgia-Pacific - Wauna [c]	Package Boiler	18	277			254	165
Weyerhaeuser Springfield	Power Boiler	Unknown	297				
Weyerhaeuser Springfield	Package Boiler	Unknown	65				
Weyerhaeuser Springfield	Package Boiler	16	0				
Utah							
Sunnyside Cogeneration Associates [b]	FBC Boiler #1	700	1,270	0	1,006	970	1,054
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 1	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 2	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 3	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 4	838	700	2,905	2,141	2,200	2,534
Brigham Young University	Units 2, 3, and 5	128					
Brigham Young University	Auxiliary #7	5	0	248	90	158	125
Brush Wellman Incorporated	S-11 Main Boiler	81.2					
Brush Wellman Incorporated	S-10 Back-up Boiler	12.66	23	161	175	208	179

Table IV-3 (continued)

Facility	Unit	Capacity (MMBtu/hr)	SO_2 Floor Allocation (tpy)	Historical SO_2 Emissions 1990 (tpy)	1996 (tpy)	1998 (tpy)	2000 (tpy)
Geneva Steel	Power Boiler 1	411					
Geneva Steel	Power Boiler 2	411					
Geneva Steel	Power Boiler 3	411					
Geneva Steel	Power Boiler 4	205					
Geneva Steel	Power Boiler 5	205	17	8,473	2,020	881	979
Wyoming							
Solvay Minerals, Inc. [b]	Boiler #18	350					
Solvay Minerals, Inc. [b]	Boiler #19	350	294		101	72	52
General Chemical [b]	Boiler C	534					
General Chemical [b]	Boiler D	880	750	4,196	5,651	4,538	5,000
Holly Sugar-Torrington Plant [b]		221.2	23	374	266	154	178
FMC Corp - Green River Plant [b]	Boiler #6	887					
FMC Corp - Green River Plant [b]	Boiler #7	887	956	4,795	5,256	4,533	4,901
University of Wyoming Central Heating Plant [a]	Boiler #2	73.1					
University of Wyoming Central Heating Plant [a]	Boiler #3	73.1	22	152	154	223	193
University of Wyoming Central Heating Plant [a]	Boiler #4	73.1					
FMC Granger	Boiler #1	358					
FMC Granger	Boiler #2	358	305	475	473	149	212

NOTES: [a]Facility with boilers as only SO_2 source.
[b]Facility has multiple sources, emissions are total plant.
[c]Facility has multiple sources, emissions are boilers only.

Table IV-4
Example Use of Capacity Utilization Data for Floor Allocation Estimates

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
			Coal		Oil		Natural Gas								
Facility	Unit	Year	Throughput (ton/yr)	Heat Value (MMBtu/ton)	Throughput (gal/yr)	Heat Value (MMBtu/gal)	Throughput (MMcf/yr)	Heat Value (MMBtu/ft^3)	Throughput All Fuels Combined (MMBtu/yr)	Design Capacity (MMBtu/yr)	Capacity Factor	Primary Fuel Sulfur Content (%)	SO_2 EF (lb/ton)	SO_2 Reduction (%)	SO_2 Allocation (tons)
Arizona															
Abitibi Consolidated	Power Boiler # 2	1998	387,532	18.0	44,000	0.15	0.0		6,982,176		70%				
	1,132 MMBtu/hr	1999	353,163	18.0	-	0.15	0.0		6,356,934		64%				
		2000	350,531	18.0	29	0.15	0.0		6,309,562		64%				
		2001	327,428	18.0	193,000	0.15	0.0		5,922,654		60%				
				18.0						**9,916,320**	**64%**	**1.00**	**35.0**	**85.0**	**978**

NOTE: Throughput is the annual fuel consumption in the calendar year.

CHAPTER V
PULP AND PAPER INDUSTRY

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The processing of wood for a variety of products is one of the ten largest industries in the United States. To produce paper or paperboard, wood must be pulped first. In general, the pulp and paper production processes can be divided into three steps: pulp making, pulp processing, and paper/paperboard processing. The three basic types of pulping processes, which are the major sources of SO_2, are chemical pulping, mechanical pulping, and semi-chemical pulping. Chemical wood pulping involves cooking wood chips or sawdust in an aqueous chemical solution to dissolve the lignin that binds the cellulose fibers together. There are two major types of chemical pulping used: Kraft/soda pulping and sulfite pulping. Kraft pulping accounts for over 80 percent of the chemical pulp produced in the United States.

Sources of SO_2 in a Kraft mill include: (1) boilers generating steam for power and heat, using coal, oil, natural gas, or bark/wood waste as fuel; (2) recovery furnaces where SO_2 emissions occur from the oxidation of reduced sulfur compounds; and (3) lime kilns when fuel oil is being combusted.

Allocations for boilers are discussed in Chapter IV, "Industrial Boilers and Cogenerators." Floor allocations for recovery furnaces and lime kilns are described in this chapter. Note that the calculations for these sources are the same as those for like configurations set forth in other chapters.

1. Recovery Furnaces

After the cooking period, the pulp and the liquor in which it cooked are separated, the spent liquor (black liquor) is evaporated and concentrated to about 65 percent solids. Concentrated black liquor is then sprayed into the furnace and the organic compounds are combusted. The combustion of black liquor in a recovery furnace results in SO_2 emissions that vary with liquor properties (i.e., sulfidity, heat value), combustion air and liquor firing patterns, furnace design and operational patterns.

SO_2 reduction is achieved by altering the process, rather than applying control technology. Strategies to lower liquor sulfidity and optimize combustion and firing patterns in such way that yields maximum and uniform temperatures in the lower furnace are used to minimize SO_2 emissions. Flue gas desulfurization is energy intensive and its efficiency uncertain, considering the generally low concentrations and fluctuating levels of SO_2 in the furnace flue gases.

2. Lime Kilns

In a pulp and paper lime kiln, the inorganic molten smelt that forms and collects at the bottom of the furnace is withdrawn through spouts into a smelt-dissolving tank where jets of water are used to quench the molten smelt, forming green liquor. The green liquor is then combined with quicklime (CaO), resulting in a white liquor solution containing NaOH, Na_2S and lime mud precipitate (mainly $CaCO_3$). This lime mud is washed, dried and calcined in the lime kiln to regenerate quicklime. The regenerated quicklime in the kiln acts as an in-situ-scrubbing agent and the Venturi scrubber that usually follows the kiln further reduces SO_2 levels. Emissions from smelt-dissolving tanks and lime kilns are generally negligible.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to pulp and paper facilities that emit greater than 100 tpy of SO_2 from all processes. There are seven pulp and paper facilities evaluated – six located in the State of Oregon and one in Idaho. The Oregon Department of Environmental Quality provided data on the unit capacity for each Oregon facility. However, the data given were the permitted SO_2 emission levels and the design capacity of production of each recovery furnace or kiln.

Abitibi in Navajo County, Arizona no longer operates a recovery furnace. They are no longer pulping and have converted to recycled paper processing. Therefore, they receive no floor allocation for recovery furnace operation.

1. Recovery Furnaces

The floor allocation for recovery furnaces is determined assuming that the process provides sufficient SO_2 reductions. No further SO_2 reductions will be required when estimating the floor allocations. Pechan estimated the floor allocation using the emission factor given in AP-42 in lbs/air-dried ton of pulp (ADT) and the designed pulp production capacity. The SO_2 floor allocations are given by the equation:

$$A_F(tpy) = EF_{SO_2}\left(\frac{lb}{ADT\ of\ pulp}\right) x\ capacity \left(\frac{ADT\ of\ pulp}{day}\right) x\ \%\ capacity\ x\ \frac{1\ ton}{2{,}000\ lb}\ x\ \frac{365\ days}{1\ year}$$

where:

A_F = SO_2 allocation for recovery furnaces in the facility, and
EF_{SO2} = AP-42 emission factor = 7 lbs/ADT.

For facilities where pulp production capacity was not given, but fuel throughput was reported in its place, SO_2 allocations are estimated as the fuel throughput multiplied by the EPA AP-42 SO_2 emission factor.

2. Lime Kilns

The floor allocation for lime kilns is determined in the same manner as recovery furnaces. The floor allocation for lime kilns assumes no further SO_2 reductions will be required when estimating the floor allocations. Using the emission factor for lime kilns given in AP-42, the SO_2 floor allocation equation for lime kilns is given by:

$$A_K(tpy) = EF_{SO_2}\left(\frac{lb}{ADT\ of\ pulp}\right) x\ capacity \left(\frac{ADT\ of\ pulp}{day}\right) x\ \%\ capacity\ x\ \frac{1\ ton}{2000\ lb}\ x\ \frac{365\ days}{1\ year}$$

where:

A_K = SO_2 allocation for lime kilns in the facility, and
EF_{SO2} = AP-42 emission factor = 0.3 lbs/ADT.

For facilities where pulp production capacity was not given, but fuel throughput was reported in its place, SO_2 allocations are estimated as the fuel throughput multiplied by the EPA AP-42 SO_2 emission factor.

C. FLOOR ALLOCATION RESULTS

Table V-1 presents the floor allocation calculations for pulp and paper plants in Oregon based on the permitted capacity of the recovery furnaces and kilns. Unit capacity values were given in air-dried tons of pulp per day. For the floor calculations, it was assumed that the furnace was operated 365 days per year at 100 percent capacity.

Table V-2 presents the floor allocation for facilities where the pulp production capacity was not given, but fuel throughput was reported instead. The Potlatch facility listed in Table V-2 is located in Idaho. All other pulp and paper mills listed in Tables V-1 and V-2 are in Oregon. Therefore, the computed floor allocations by State are 1,807 tpy for Idaho, and 5,377 tpy for Oregon. The California allocation for pulp/paper is based on the 1996, 1998, and 2000 historical SO_2 emissions data in Table V-3, and is 324 tpy.

Table V-1
Facility SO_2 Floor Allocation Estimation for Pulp and Paper Facilities Based on Unit Capacity Values

Facility	Unit	Capacity* (ADTP/day)	SO_2 Allocations (tpy)
Boise Cascade Corporation	Recovery Furnace#2	450	575
	Recovery Furnace#3	700	894
	Lime Kiln#4	1,150	63
Georgia-Pacific (Wauna Mill)	Recovery Furnace	1,015	1,297
	Lime Kiln	1,174	64
Weyerhauser Springfield	#3 Recovery Boiler	1,150	760
	#4 Recovery Boiler	1,150	790
	Lime Kilns	2,156	118

NOTE: *Design and actual capacity are unknown, the values given are the permitted levels.

Table V-2
Facility SO_2 Floor Allocation Estimation for Pulp and Paper Facilities Based on Fuel Throughput

Facility	Unit	Fuel	Throughput	SO_2 Allocations (tpy)
Georgia-Pacific West, Inc.	Recovery Furnace#1	DCE-BLS	242,725 tpy	129
		Nat. gas		
	Recovery Furnace#2	DCE-BLS	242,725 tpy	129
		Nat. gas		
	Lime Kiln#2	Nat. gas	553.7*10E6 ft^3/y	0
		RFO		
		#6 oil		
	Lime Kiln#3	Nat. gas	553.7*10E6 ft^3/y	0
		RFO		
		#6 oil		
Willamette Industries, Inc.	Recovery Furnace#5	BLS	495,000 tpy	235
		Nat. gas	350 $MMft^3$	0
		No.2 fuel oil	1E06 gal/y	39
	Lime Kiln #3	Oil/nat.gas/LPG	1.35E05 ton lime mud/y	36
Pope & Talbot, Inc.	Recovery Furnace	BLS	461,081 tpy	67
		Oil	1.2E06 gal/y	173
	Lime Kiln	CaO	55,536 tpy	0
		Oil	1.8E06 gal/y	1
		NCG/CaO	5,662 tpy	7
Potlatch	#4 Recovery Boiler	BLS	117,113 tpy	410
	#5 Recovery Boiler	Pulp	393,548 tpy	1,377
	#2 Lime Kiln	CaO	10,247 tpy	2
	#3 Lime Kiln	CaO	61,467 tpy	9
	#4 Lime Kiln	CaO	60,147 tpy	9

D. COMPARISON WITH HISTORICAL EMISSIONS

Table V-3 summarizes historical SO_2 emissions from pulp and paper facilities. This table provides a point of comparison with the floor allocations shown in Tables V-1 and V-2 and historical emissions at each facility. Note that the historical emissions are the total plant emissions, not just those resulting from operation of the recovery furnace and lime kiln.

REFERENCES

AWMA, 2000: Air and Waste Management Association, “Air Pollution Engineering Manual,” 2nd edition, Chapter 18 -Wood Processing Industry, 2000.

EPA, 1998: U.S. Environmental Protection Agency, “Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Source, Section 10.2 Chemical Wood Pulping,” Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

Table V-3
Pulp and Paper - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	017	0007	43	2611	3	Wood/Paper/Pulp	STONE CONTAINER	ABITIBI	8,536	2,455	2,448	1,893
CA	6	023	21	10	2611	3	Wood/Paper/Pulp	SIMPSON PAPER COMPANY	SIMPSON PAPER CO	1,021	315	315	
CA	6	089	23		2611	3	Wood/Paper/Pulp	SHASTA PAPER-ANDERSON					216
CA	6	013	3257	11	2611	3	Wood/Paper/Pulp	GAYLORD CONTAINER CORPORATION		263	0	0	
CA	6	023	37	10	2611	3	Wood/Paper/Pulp	LOUISIANA-PACIFIC CORP.		302	<100	42	42
CA	6	077	191	11	2621	3	Wood/Paper/Pulp	NEWARK SIERRA PAPERBOARD CORP.		270	0	0	
ID	16	045			2611	3	Wood/Paper/Pulp	BOISE CASCADE - EMMETT					252
ID	16	069	0001	3	2621	3	Wood/Paper/Pulp	POTLATCH		1,379	700	700	1,694
OR	41	009	1849	6	2621	3	Wood/Paper/Pulp	Boise Cascade Company		2,453	685	746	1,834
OR	41	041	0005	5	2631	3	Wood/Paper/Pulp	Georgia-Pacific West, Inc.		56	207	322	452
OR	41	019	0036	5	2631	3	Wood/Paper/Pulp	International Paper		874	602	1,006	0
OR	41	007	0004	5	2621	3	Wood/Paper/Pulp	James River II, Inc.	Georgia- Pacific (Wauna Mill)	331	573	617	643
OR	41	043	3501	5	2621	3	Wood/Paper/Pulp	Pope & Talbot Pulp, Inc.		485	133	92	293
OR	41	071	6142	5	2621	3	Wood/Paper/Pulp	Smurfit Newsprint Corporation 2		592	368	461	519
OR	41	043	0471	5	2631	3	Wood/Paper/Pulp	Willamette Industries, Inc.		396	54	485	327
OR	41	039	8850	5	2631	3	Wood/Paper/Pulp	Collins Products LLC	Weyerhaeuser Co. (Particleboard)	202	0	3	1,721
OR	41	047	5398	5	2621	3	Wood/Paper/Pulp	Ogden Martin Systems of Marion, Inc.	Covanta Marion, Inc.	127	18	22	
										17,287	**6,210**	**7,259**	**9,886**

CHAPTER VI
CEMENT MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The cement industry involves the calcining of limestone in clinker and the subsequent crushing of the clinker into cement. Cement manufacturing activities include the process the mining and mixture of raw materials such as limestone and other materials, the pryoprocessing of the raw materials into a clinker, and the grinding of the clinker and other materials such as silicates into the final cement. As of December 2000, there were 201 kilns with a total capacity of 84 million tpy. The kiln is a predominate source of SO_2 emissions. The SO_2 emissions result from the combustion of the sulfur in the fuel and the sulfur (generally in the form of pyrite) that can occur in the feedstock.

Kilns generally take five forms:

- wet (where the feedstock contains up to 43 percent water);
- dry;
- semi-dry;
- dry with a pre-heater;
- and dry with a pre-calciner.

SO_2 emissions vary by kiln type generally based on how effectively the kiln type mixes the SO_2 containing gases with the alkaline calcium compounds. The pre-heater and pre-calciner kilns can remove 90+ percent of the SO_2 in the gas stream while the dry process kiln removes about 70 percent. In addition, the type of particulate control devices can impact the amount of SO_2 removed in the process. Fabric filters, both because they mix the SO_2 containing gases with the particles collected on the filter, and because they operate at a generally lower temperature then electrostatic participators (ESPs), collect more SO_2 than ESPs.

B. FLOOR ALLOCATION ESTIMATION METHODS

Estimation of the floor allocation procedure for the cement industry poses several difficulties. First, there is no demonstrated control technology for control of SO_2 emissions from cement kilns. Second, emissions from kilns vary considerably due to numerous variables including kiln type and sulfur content of feedstock. According to EPA AP-42 emission factors, emissions can vary by as much as a factor of 20. Emission data from two similar kilns in Utah shows that changes in feedstock can cause a change in emissions up to a factor of 100. Because of this variability and lack of predictability of emissions, the floor allocation was based on the average emissions from each plant over the past several years.

C. FLOOR ALLOCATION RESULTS

Table VI-1 shows the allocation results of the emissions to each plant. As discussed above, the data are based on the emissions reported in State inventories unless otherwise indicated (See Table VI-2). Several of the sources added new kilns in the past several years. For these sources only emission data after the new kiln were included. Permit

Table VI-1
Floor Allocations

State	Plant Name	SO_2 Floor Allocation (tpy)	State Totals (tpy)
AZ	Phoenix Cement Portland Cement Plant	320[1]	
			320
CO	Holcim Portland	3,374	
CO	Holcim Laporte	1,402	
CO	Cemex	160	
			4,936
ID	Ash Grove Inkom	522	
			522
NV	Nevada Cement	305	
NV	Royal Cement	143[2]	
			448
NM	Rio Grande	1,103[3]	
			1,103
UT	Holcim	267[2]	
			267
WY	Centex	165[4]	
			165
TOTAL		**7,761**	**7,761**

NOTES: [1]Permit limited potential to emit.
[2]Only two years after new kiln included.
[3]Only one year of data available.
[4]New kiln in 1997.

Table VI-2
Cement Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	019			3241	4	Cement/Concrete	Arizona Portland Cement		101	13	10	8
AZ	4	025		41	3241	4	Cement/Concrete	Phoenix Cement		<100	197	339	539
CA	6	029	9	13	3241	4	Cement/Concrete	CAL PORTLAND CEMENT CO.		429	245	245	245
CA	6	029	20	13	3241	4	Cement/Concrete	CALAVERAS CEMENT CO		286	286	286	286
CA	6	085	17	11	3241	4	Cement/Concrete	KAISER CEMENT CORPORATION	HANSON PERMANENTE CEMENT	474	464	416	474
CA	6	087	11	11	3241	4	Cement/Concrete	LONE STAR INDUST CEMENT PLANT	RMC PACIFIC MATERIALS	250	286	393	314
CA	6	071	7000000	15	3241	4	Cement/Concrete	MITSUBISHI CEMENT		28	574	946	298
CA	6	071	1200003	15	3241	4	Cement/Concrete	RIVERSIDE CEMENT COMPANY		0	527	527	164
CA	6	071	100005	15	3241	4	Cement/Concrete	CEMEX-CALIFORNIA CEMENT		0	0	0	427
CA	6	071		15	3241	4	Cement/Concrete	SOUTHWESTERN PORTLAND CEMENT C	SOUTHDOWN-VICTORVILLE PLANT	108	0	0	0
CO	8	069	0002	52	3241	4	Cement/Concrete	HOLNAM LAPORTE	HOLCIM	623	623	375	404
CO	8	043	0001	58	3241	4	Cement/Concrete	HOLNAM PORTLAND	HOLCIM	4,069	3,615	3,219	3,288
CO	8	013	0003	53	3241	4	Cement/Concrete	SOUTHWEST PORTLAND	CEMEX-LYONS PLT.	967	160	160	50
ID	16	005	0004	7	3241	4	Cement/Concrete	ASHGROVE CEMENT		790	200	200	1,327
NV	32	019	0387	20	3241	4	Cement/Concrete	NEVADA CEMENT COMPANY	FERNLEY PLANT	360	340	346	172
NM	35	001			3241	4	Cement/Concrete	RIO GRANDE PORTLAND CEMENT		0	0	0	1,103
UT	49	029	0001	31	3241	4	Cement/Concrete	Holnam Incorporated	HOLCIM	911	3	247	288
										9,496	**7,533**	**7,709**	**9,387**

limits were selected, since the kiln is under construction and there was no actual emission data. Table VI-3 provides an example of this calculation.

Table VI-3
Example Calculation

Facility	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Estimate[1]
Nevada Cement	340	346	172	286
Holcim Laporte	632	375	404	470

[1]Floor estimate based on the average of these 3 years.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table VI-2 shows a comparison of emissions to the historical emissions based on State emissions inventories. Since the floor is based on historical emissions, the general match is very close, but for any individual plant, the floor may be higher or lower than recent emissions.

REFERENCES

EPA, 1995: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42)," Chapter 11.6, Cement Manufacturing, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1995.

PCA, 2001: Portland Cement Association, U.S. and Canadian Portland Cement Industry Plant Information Summary, Data as of December 31, 2000, Portland Cement Association, Economic Research Department, 2001.

CHAPTER VII
NATURAL GAS PROCESSING PLANTS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

SO_2 emissions from natural gas processing plants result from the combustion of sour gases. Sour gases may contain less than 1 percent H_2S to over 20 percent H_2S.

H_2S is removed from the natural gas by scrubbing with an amine solution. The amine solution is heated to regenerate the amine solution. Heating the amine also produces a very concentrated H_2S stream. This H_2S stream can be treated to produce sulfur. The most common treatment is by using a Claus plant. The Claus plant can convert about 80-98.6 percent of the H_2S to sulfur depending on the number of stages and the concentration of H_2S. The average recovery percentage for a 3-stage Claus plant would be about 96 percent, on average. The residual H_2S after the Claus plant is either flared or converted to additional sulfur in a "tail gas" treatment plant like the SCOT or Stretford-Beavon process. H_2S conversion efficiencies of up to 99.9 percent are possible. Residual H_2S may be flared.

In addition to the plant tail gas flare, SO_2 emissions also result from upset conditions at the plant, or in the well field, or emissions when new wells are brought in. Upsets at the plant cause the sulfur recovery plant to be bypassed and the H_2S is flared to produce SO_2. Upsets in the well field may result in sour natural gas being flared as a safety precaution to reduce exposure to toxic levels of H_2S.

B. FLOOR ALLOCATION ESTIMATION METHODS

The requirements for, and the economics of, sour gas control are a function of a number of variables, including the amount of H_2S in the offgas, the size and age of the facility, and the air pollution control requirements in existence at the time the facility was built. Existing sour gas processing plants may have been built in situations where no regulations existed, under the 1987 NSPS, or under a BACT review under prevention of significant deterioration regulations.

It was decided that the current NSPS would serve as the floor. The NSPS requires a variable sulfur removal efficiency based on the H_2S content of the acid gas and the amount of sulfur in the gas. The required emission reduction for each facility was based on the equations in Table VII-1 since these are the long term reductions called for in the NSPS. If a facility had current control levels higher than the assumed floor, the actual average emissions over the past three years were assumed to be the floor. Since emissions from flaring operations, both in the plant and the well field, are not amenable to control, floor emissions will be assumed to be the average of three years emissions, whenever the data is available.

Table VII-1
Sulfur Plants - Required Minimum SO_2 Emission Reduction Efficiency

H_2S Content of Acid Gas (Y), %	Sulfur Feed Rate (x), Long Tons per Day			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	. . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . or 99.8, whichever is smaller		
$20 \le Y < 50$	74.0	. . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . or 97.5, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

Data availability was a significant issue in determining the floor allocation for some plants. The data from New Mexico was not adequate to distinguish between process plant, upset flare, and well field emissions.

C. FLOOR ALLOCATION RESULTS

1. General Plants

Table VII-2 shows the floor allocation calculation for the natural gas processing plants in the 8 non-California Western Regional Air Partnership (WRAP) States.

In Table VII-2, the plant name and SCC code are those provided in the State inventory. The emission source column (process or flare) notes whether the emissions are likely to come from the normal processing of natural gas (process) or the result of upset or well field emissions (flare). The distinction was made on the basis of comments in the emission inventory and confirmed in conversations with the State. Current emissions are based on the average of several years data (2000, 1998, 1996) if available, and on one year's data if that was all that was available. In some cases, new plants were under construction and permit levels were used in lieu of actuals. Current reductions were based on data in the State inventories and confirmed via conversations with State agencies.

Floor emissions vary by the H_2S content of the gas, the amount of sulfur produced by the plant, the age of the plant (older plants are not subject to the NSPS), and State regulations. In Wyoming, although individual plants vary, the average H_2S content of natural gas is higher than in other States and the degree of control required under the NSPS is greater. In addition, newer plants tend to be larger and have undergone a BACT review. In New Mexico, the relatively low H_2S content means that less control may be required under the NSPS. This is due both to the H_2S content as well as the small amount of sulfur produced by the processing plants. However, a State rule (20.2.35 NMAC) requires a minimum of a 90 percent reduction for plants that release more than 5 tons per day of sulfur from existing plants regardless of the H_2S content of the gas.

The level of control assumed to be the floor will be the most stringent of all of the potential regulatory requirements. However, the application of the potential floor procedures can result in no SO_2 controls having to be applied on some sources. For example, the Duke Energy Artesia plant in New Mexico processes less than 2 long tons per day of sulfur (this is equivalent to about 1,600 tpy of SO_2 emissions) and therefore the NSPS does not apply. State regulations do not apply, since the sulfur throughput is below the regulatory threshold. The floor for this plant is based on the average emissions over the past three years.

2. Specific Example

The Burlington Northern Lost Cabin facility in Wyoming provided additional information needed to demonstrate how the floor calculations could be applied to a specific facility. The Lost Cabin facility consists of two existing gas processing lines with a capacity of 133 MMCF/day and has one new train with a capacity of 133 MMCF/day. Both lines process a gas with a methane concentration of 68 percent, a carbon dioxide concentration of 20 percent, and an H_2S content of 12 percent.

Each train is controlled by a three stage Claus unit followed by a SCOT tail gas unit. The unit is required to have a conversion efficiency of 99.8 percent. Plantwide emissions are limited to 642 lbs/hr and 1,367 tpy.

The plant underwent a BACT review under PSD and exceeds all requirements of the NSPS. Under the NSPS, a reduction of 97.5 percent would have been required since the H_2S content of the acid gas stream is 37 percent (which is defined as the gas stream leaving the amine regenerator and can be calculated as the ratio of the acid gases [H_2S and CO_2] in the input gas stream) and the sulfur production exceeds 300 long tons per day (see Table VII-1). Since the required reduction exceeds the floor level, the permitted levels represent the floor.

Since much of the plant is new, no data on upset emissions is available. Emissions from well-field activities are very variable. Wells are very large at this plant and one very large well can have up to 1,000 tons of emissions. The plant estimates that annual SO_2 emissions of about 500 tpy from well field activities can be expected.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table VII-3 summarizes historical SO_2 emissions from natural gas processing plants located in the 9 WRAP States. California facilities are included in this table. This table provides a point of comparison with the floor allocations shown in Table VII-2. For Wyoming, the historic emissions are close to floor for most sources due to the high level of control. However, a direct comparison is difficult since the historical emissions may include well field and upset emissions. Two New Mexico sources will require additional control or additional emission allocations.

Table VII-2
Possible Floor - Natural Gas Processing Units

State	Plant	SCC	Emission Source (Process vs Flare)	Current % Reduction	Permit Emissions	Floor Emission Reduction	Possible SO_2 Floor (tpy)
NM	Conoco-Maljamar	31000028	Plant	0	3,574	87	222
NM	Western Gas Resources	31000208	Plant	90	3,127	90	3,127
NM	Agave Energy	31000205	Plant	0	2,983	86.3	365
NM	Duke Energy Eunice	31000208	Plant	90	2,756	90	2,250
NM	Duke Energy Artesia	31000208	Plant	0	1,459	0	1,192
NM	Dynergy Midstream Monument	31000208	Plant	90	1,431	90	675
NM	Dynergy Midstream Saunders	31000208	Plant	90	1,387	90	163
NM	Duke Energy Plant 5	31000205	Plant	96.4	1,300	96.4	1,181
NM	Sid Richardson	31000201	Plant	91.7	1,206	91.7	1,206
NM	JL Davis Gas Processing Denton Plant	31000205	Plant	0	1,158	0	840
NM	Marathon Oil	31000201	Plant	90	1,100	90	665
NM	Duke Energy Lee Gas	31000299	Plant	93	818	93	0[4]
NM	ARCO Permian Empire Abo Plant	31000208	Plant	96	565	96	431
NM	Duke Energy Burton Flats	31000205	Plant	0	246	0	164
NM	Duke Energy Dagger Draw Plant	31000208	Plant	98	243	98	218
NM	Duke Energy Huber Gas Plant	31000205	Unknown	0	231	0	163
UT	Tom Brown- Lisbon Plant		Plant	95	1,593[2]	95	1,593
WY	Howell Petroleum - Elk Basin	31000205	Plant	93.5	1,200	93.5	1,200
WY	Burlington Resources Lost Cabin		Plant	99.8	1,367[2]	99.8	1,367
WY	Burlington Resources Lost Cabin		Flare	0	500[1]	0	500
WY	KCS Mountain Ainsworth Flare	31000205	Flare	0	843	0	843
WY	KCS Mountain Rushmore Flare	31000205	Flare	0	118[1]	0	118
WY	Marathon Pitchfork Battery	31000205	Flare	0	61[1]	0	61
WY	Exxon Shute Creek	31000205	Plant	99.7	1,206	99.7	1,206
WY	Exxon Shute Creek	31000205	Flare	0	330[1]	0	330
WY	Amoco Whitney Canyon	31000205	Plant	99	5,379	99	5,379
WY	Amoco Whitney Canyon	31000205	Flare	0	223[1]	0	223
WY	Texaco Byron	31000205	Plant	0	200	0	200

Table VII-2 (continued)

State	Plant	SCC	Emission Source (Process vs Flare)	Current % Reduction	Permit Emissions	Floor Emission Reduction	Possible SO_2 Floor (tpy)
WY	Chevron Carter Creek	31000205	Plant	99+	0[3]		0
WY	Chevron Carter Creek	31000205	Flare	0	200	0	200
WY	Hallwood Petroleum Federal Packsaddle 1-24	31000205	Flare	0	133	0	133
WY	Hallwood Petroleum Federal Packsaddle 1	31000205	Flare	0	960[1]	0	960
WY	Oregon Basin Gas Plant	31000205	Plant	90	391	90	391
WY	KCS Gold Eagle Flare	31000205	Flare	0	790	0	790
WY	Interenergy Hiland Gas Plant	31000205	Flare	0	281[1]	0	281
WY	Marathon Oil Mill Iron	31000205	Flare	0	247	0	247
	Emission Totals				**39,606**		**28,884**

NOTES: 1. Only one year of data available; 2. Floor based on permit levels; 3. Plant does not incinerate tail gas - no SO_2 emitted; 4. Plant has no emissions listed for the past three years.
State SO_2 floor allocations based on the estimates in this table are NM (12,862 tpy), UT (1,593 tpy), and WY (14,429 tpy).

Table VII-3
Oil and Gas Production - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
CA	6	029	1141	13	1311	6	Oil/Gas	SANTA FE ENERGY	TEXACO CA INC	1,539	855	2,050	2,050
CA	6	029	1129	13	1311	6	Oil/Gas	TEXACO EXPLOR & PROD INC		1	89	112	63
CA	6	029	206	13	1311	6	Oil/Gas	BERRY PETROLEUM COMPANY		237	0	0	0
CA	6	019	71	12	1311	6	Oil/Gas	CHEVRON USA INC. - COALINGA		809	0	0	
CA	6	029	272	13	1311	6	Oil/Gas	M H WHITTIER	SENECA RESOURCES	347	0	0	
CA	6	053	19	12	1311	6	Oil/Gas	MOBIL OIL CORP - SAN ARDO	AERA ENERGY	304	0	1	6
CA	6	029	1135	13	1311	6	Oil/Gas	SHELL KERNRIDGE	AERA ENERGY LLC	294	<100	82	55
CA	6	019	64	12	1311	6	Oil/Gas	SHELL WESTERN E&P INC. - COALINGA		144	0	0	
CA	6	029	331	13	1311	6	Oil/Gas	SWEPI-WEST COAST DIVISION	AERA ENERGY LLC	775	<100	10	
CA	6	053	30	12	1311	6	Oil/Gas	TEXACO INC - SAN ARDO		100	<100	36	32
CA	6	029	299	13	1311	6	Oil/Gas	UNOCAL - BAKERSFIELD	UNOCAL OIL & GAS DIVISION	159	0	0	
CA	6	059	42775	14	1311	6	Oil/Gas	WEST NEWPORT OIL CO		297	<100	10	11
CO	8	045	24	51	1311	6	Oil/Gas	UNOCAL RETORT-PARACHUTE		679	0	0	0
CO	8	045	0025	51	1311	6	Oil/Gas	UNOCAL UPGRADE		177	0	0	0
NM	35	015	0024	65	1311	6	Oil/Gas	AGAVE ENERGY/YATES PLANT		962	962	962	2,983
NM	35	015	0002	65	1311	6	Oil/Gas	ARCO PERMIAN/EMPIRE ABO GAS PLNT		700	565	565	565
NM	35	015	0006	65	1311	6	Oil/Gas	GPM GAS/INDIAN HILLS AMINE PLNT		900	450	450	900
NM	35	025	0046	65	1311	6	Oil/Gas	GPM GAS/LEE GAS PLANT		818	0	818	818
NM	35	025	0007	65	1311	6	Oil/Gas	J.L. DAVIS GAS PROCESS/DENTON		385	890	891	1,158
NM	35	025	0052	65	1311	6	Oil/Gas	TEXACO/EUNICE NORTH GAS PLANT		673	1,076	1,346	673
NM	35	025	0051	65	1311	6	Oil/Gas	TEXACO/EUNICE SOUTH GAS PLANT		4,019	4,386	3,355	5,476
NM	35	015	0003	65	1311	6	Oil/Gas	TRANSWESTERN PIPE	DUKE ENERGY/HUBER GAS	221	231	231	231
NM	35	041	0001	63	1311	6	Oil/Gas	WARREN PETROLEUM/BLUITT GAS PLANT		270	3,348	582	270
NM	35	025	0061	65	1311	6	Oil/Gas	WARREN PETROLEUM/MONUMENT PLANT	MONUMENT PLANT	1,460	1,709	1,432	1,432
NM	35	045	0247	60	1311	6	Oil/Gas	WESTERN GAS PROCESSORS/SAN JUAN RVR		5,475	980	980	3,138
NM	35	025	0128	65	1311	6	Oil/Gas	CITATION/ANTELOPE RDG GAS PLANT		291	0	NA	
NM	35	025	0118	65	1311	6	Oil/Gas	CONOCO/BELL LAKE 2 WELL #6		129	0	NA	
NM	35	015	0125	65	1311	6	Oil/Gas	FEAGAN ENERGY/W DAGGER DRAW GAS PLT		240	0	NA	
NM	35	005	0050	65	1311	6	Oil/Gas	YATES PETROLEUM/PATHFINDER AMINE		227	57	57	

Table VII-3 (continued)

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
UT	49	037		35	1311	6	Oil/Gas	UNOCAL CORPORATION	TOM BROWN - LISBON PLANT	1,575	1,391	1,478	1,252
WY	56	029	0012	9	1311	6	Oil/Gas	AMOCO - ELK BASIN	HOWELL PETROLEUM - ELK BASIN	1,096	1,218	1,422	2,638
WY	56	041	0012	9	1311	6	Oil/Gas	AMOCO - WHITNEY CANYON		6,401	5,835	11,130	6,889
WY	56	041	0009	9	1311	6	Oil/Gas	CHEVRON - CARTER CREEK		1,537	1,165	3,330	2,096
WY	56	023	0013	8	1311	6	Oil/Gas	EXXON - SHUTE CREEK		1,078	1,999	2,015	1,383
WY	56				1311	6	Oil/Gas	EXXON BLACK CANYON DEHY & WELL FIELD					167
WY	56	017		9	1311	6	Oil/Gas	KCS MOUNTAIN RESOURCES - GOLDEN EAGLE			558	942	17
WY	56	003		9	1311	6	Oil/Gas	KCS MOUNTAIN RESOURCES - AINSWORTH			807	845	0
WY	56	029	0007	9	1311	6	Oil/Gas	MARATHON GAS PLANT - OREGON BASIN		406	456	388	358
WY	56	017		9	1311	6	Oil/Gas	MARATHON OIL - MILL IRON			234	260	0
WY	56	003	0012	9	1311	6	Oil/Gas	TEXAS-BYRON PLANT	BIG HORN GAS PROCESSING - BYRON	192	169	605	257
WY	56	037	0008	9	1311	6	Oil/Gas	UNION PAC - BRADY	RME PETROLEUM - BRADY	415	331	576	300
WY	56	013	008	9	1311	6	Oil/Gas	DEVON SFS OPERATING CO.	BEAVER CREEK				831
WY	56	037	0014	9	1311	6	Oil/Gas	COLORADO INTERSTATE GAS - TABLE ROCK		522	20	39	
WY	56	003	0013	9	1311	6	Oil/Gas	MARATHON OIL COMPANY - GARLAND		257	7	10	
WY	56	013		9	1311	6	Oil/Gas	LOUISIANA LAND & EXPLOR - LOST CABIN	BURLINGTON RESOURCES-LOST CABIN		4,547	1,336	1,700
										36,111	**34,735**	**38,346**	**37,749**

CHAPTER VIII
ELEMENTAL PHOSPHORUS PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

P4 Production has an elemental phosphorus facility near Soda Springs, Idaho. This is one of the two elemental phosphorus production facilities in the United States. Year 2000 SO_2 emissions from this facility are estimated to be 15,861 tpy. This reflects increased utilization compared with 1996 and 1998 operations. This facility has no SO_2 emissions limit in its operating permit. The Idaho Department of Environmental Quality is currently evaluating this facility's SO_2 emissions situation. For the purposes of this report, the floor allocation for P4 Production is set at its year 2000 SO_2 emissions level of 15,861 tons. It is expected that the State of Idaho will perform a more detailed evaluation of this facility during preparation of its regional haze State Implementation Plan (SIP).

B. FLOOR ALLOCATION ESTIMATION PROCEDURES

Recent historical emissions for P4 Production are listed below in Table VIII-1.

Table VIII-1
Elemental Phosphorus Production - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
ID	16	029	0001	7	2819	5	Chemicals/Plastics	MONSANTO/P4 PRODUCTION	P4 PRODUCTION	7,543	7,988	7,601	15,861

CHAPTER IX
GLASS MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The air emissions from glass manufacturing are in three zones: (1) raw material blending and transport, (2) melting, and (3) forming and finishing. The majority of air emissions are in the melting furnace operation.

Melting for container and flat glass is generally conducted in a continuous reverbatory furnace fired by natural gas or oil. Electric boost furnaces have been introduced in some operations to minimize flue gas emissions.

The major source of SO_2 emissions in the glass industry is the glass melting operation. Forming and annealing operations are minor sources. Furnace emissions appear to be attributable to both the manufacturing process and the fuel burned. Fuel-derived SO_2 emissions are lower from natural gas-fired furnaces than from oil-fired furnaces, unless the oil has been desulfurized. Flue gases from furnaces burning natural gas have been reported to contain 2 parts per million (ppm) SO_2, or less. About 600 ppm SO_2 can be expected in flue gas from a furnace burning fuel oil containing one percent sulfur. Greater use of electric furnaces or electric boosting may decrease SO_2 emissions.

Process modifications that may reduce SO_2 emissions include altering the raw material charge to reduce the sulfur content or to increase the fraction of recycled glass, changing the furnace controls or equipment, and altering the pull rate. Process modifications that reduce the salt cake content in the raw batch can significantly reduce SO_2 emissions. For example, one California flat-glass plant reportedly reduced furnace emissions of SO_2 by 78 percent from 2.1 to 0.5 kilograms per megagram (kg/Mg) (5.0 to 1.1 lbs/ton) by reducing the salt cake in the raw batch 60 percent (from 12 to 5 kg/Mg, 30 to 12 lbs/ton of sand). Similarly, another California flat-glass plant has reportedly reduced its SO_2 emissions 75 percent (from 1.6 to less than 0.4 kg/Mg, 4 to less than 1 lbs/ton of batch constituents) by reducing the input of salt cake. Glass quality was not compromised in either case. The salt cake cannot be reduced below certain minimums without effecting glass quality. The minimum salt cake required varies depending upon furnace type, pull rate, glass type, and other variables.

Fuel changes have also been shown to reduce SO_2 emissions. These include switching to natural gas or low-sulfur fuel oil, switching to all-electric melting, and using electric boosting for melting. Electric melters significantly reduce SO_2, NO_x, and particulate emissions because they eliminate the combustion of fossil fuels. Electric melting also is reported to minimize SO_2 and other gaseous losses from the vaporization of raw materials because the surface of the melt is insulated by a semisolid crust. Gases discharged through the crust of the melt consist mainly of carbon dioxide and water. Today, borosilicate, opal, and green glass are produced with electric furnaces. The capacities of such furnaces are about 100 to 110 Mg/day (110 to 120 tons/day). Electric melters have not been demonstrated for larger operations, such as large container furnaces, the nominal capacities of which are about 220 Mg/day (240 tons/day), and flat-glass furnaces, which range from about 600 to 800 Mg/day (660 to 880 tons/day).

Several emission control systems that are available to the glass industry for particulate control are also capable of achieving various levels of secondary SO_2 control. For example, a venturi scrubber system can control SO_2 emissions from commercial glass plants. The system includes a packed tower where part of the sulfate particulates are removed from the hot furnace flue gases, a dual-throat venture scrubber, where SO_2 and additional particulates are removed by alkaline washing, and a cyclone for final particulate collection. Currently, only the container glass segment of the glass industry is reported to use scrubber systems for emission control.

Injecting a sorbent such as alumina, limestone, or nepheline syenite into a fabric filter system can effectively remove SO_2 from furnace flue gases. The spent sorbent may be landfilled or possibly recycled.

One patented system of dry removal involves the combined use of hydrated lime and nepheline syenite for acid gas neutralization and fine particle agglomeration. In this system, hot furnace flue gas is first mixed with quench water, hydrated lime for primary SO_2 removal, and secondary air to cool the gas stream to a temperature range of 94° to 427°C (200° to 800°F). Next, nepheline syenite is added to the gas stream to capture residual SO_2 and submicrometer particulates. The gas stream enters the fabric filter where the solid product is removed for either recycling to the furnace or landfilling.

Dry sorbent systems at several commercial glass furnaces reduced SO_2 by 80 to 95 percent at a container glass furnace, 50 to 90 percent at a fiberglass furnace, and 88 to 98 percent at a flat-glass furnace.

Mist eliminators apparently have no effect on SO_x gases. One sampling test indicated no decrease in SO_2 and SO_3 concentrations through the control device (EPA, 1981).

B. FLOOR ALLOCATION ESTIMATION METHODS

It is expected that the floor allocation for glass manufacturing plants will be set according to recent historical SO_2 emissions from these facilities. These SO_2 emissions are listed in Table IX-1.

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 15 - Mineral Products Industry, 2000.

EPA, 1981: U.S. Environmental Protection Agency, "Control Techniques for Sulfur Oxide Emissions from Stationary Sources," Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

Table IX-1
Glass Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Allocation
CA	6	037	106797	14	3221	8	Glass	BALL-FOSTER GLASS CONTAINER CO	SAINT-GOBAIN CONTAINER	<100	<100	166	174	
CA	6	099	1662	11	3221	8	Glass	GALLO GLASS CO		61	271	269	440	
CA	6	039	801	12	3221	8	Glass	MADERA GLASS COMPANY		108	170	190	104	
CA	6	077	593	11	3221	8	Glass	OWENS ILLINOIS	OWENS-BROCKWAY GLASS CONTAINER	319	285	218	248	
CA	6	037	7427	14	3221	8	Glass	OWENS-BROCKWAY GLASS CONTAINER - VERNON		193	323	280	435	
CA	6	001	2086	11	3221	8	Glass	ANCHOR GLASS CONTAINER CORPORA		119	0	0		
CA	6	001	30	11	3221	8	Glass	OWENS-BROCKWAY GLASS CONTAINER - OAKLAND		122	128	64	57	
CO	8	059	0008	53	3221	8	Glass	COORS GLASS	ROCKY MOUNTAIN BOTTLE	159	221	234	255	237
OR	41	051	1876	5	3221	8	Glass	Owens-Brockway Glass Container, Inc.		103	169	116	108	131
										1,284	**1,667**	**1,537**	**1,821**	

CHAPTER X
COPPER SMELTERS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Primary copper smelters in the WRAP States process copper sulfide ore concentrate to produce anode copper. There are six primary copper smelters in the WRAP region. Five of the primary copper smelters are near the copper mines in the southwest United States. These smelters use a batch copper converting process (either Pierce-Smith or Hoboken converter designs) to produce blister copper. Currently, only two of these smelters are producing copper (the ASARCO smelter in Hayden, Arizona and the Phelps Dodge smelter in Miami, Arizona). The other three smelters have suspended operations and are not producing copper at this time.

The sixth primary copper smelter in the WRAP States is the Kennecott Utah Copper Corporation near Garfield, Utah. The Kennecott smelter was built during the mid-1990s (replacing the existing smelter at the site) and uses a flash copper converting technology. This technology allows blister copper to be produced in a continuous process.

All primary copper smelters in the region control SO_2 emissions by routing the process off-gases from the smelting and converting processes to double contact sulfuric acid plants.

B. FLOOR ALLOCATION ESTIMATION METHODS

Because of the uniqueness of the existing copper smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. Currently, the Hidalgo smelter is the only BART-eligible source in this category. A double contact acid plant is considered the appropriate retrofit control equipment (all smelters in the western States are currently equipped with double contact acid plants). On August 21, 2000, New Mexico completed an engineering analysis that verified earlier determinations by the MTF that the fugitive SO_2 capture system at Hidalgo satisfies BART at 96 percent overall SO_2 capture.

The Annex to the Grand Canyon Visibility Transport Commission's (GCVTC) recommendations defines stepped reduction milestones through 2018 for SO_2 emissions from large industrial sources in the 9-State Commission Transport Region. The current year SO_2 allocation for the six copper smelters in the 9-State region is 86,000 tons. This allocation is reduced to 78,000 tons by 2013 and is the same in 2018. For the recent Emission Forecasts to 2018 analysis, the plant-level difference SO_2 emissions difference between 86,000 tons and 78,000 tons was simulated by subtracting 2,000 tons each from the four largest smelters, which are ASARCO-Hayden, BHP-San Manuel, Phelps-Dodge Chino Mines, and Phelps Dodge-Hidalgo. The resulting allocations of 2018 SO_2 emissions by facility are shown in Table X-1. Note that the 78,000 tons of SO_2 allocation for copper smelters is an aggregate value for the region, rather than a requirement for each smelter to reduce emissions to prescribed levels. Table X-1 illustrates one way that this regional allocation might be met. Many other examples are provided in the EPA regional haze rule.

Table X-1
Copper Smelter SO_2 Emission Projections (tpy)

State	Facility Name	2018
AZ	ASARCO Smelter-Hayden	21,000
AZ	BHP-San Manuel	14,000
AZ	Cyprus Miami Mine	8,000
NM	Phelps Dodge-Chino Mines	14,000
NM	Phelps Dodge-Hidalgo Smelter	20,000
UT	Kennecott Utah Copper Corp.	1,000
	Total Copper Smelter	78,000

C. COMPARISON WITH HISTORICAL EMISSIONS

Table X-1 SO_2 emission estimates can be compared with recent historical (1990 to 2000) emissions for those smelters shown in Table X-2.

Table X-2
Recent Historical Copper Smelter SO_2 Emissions

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
Smelter Sector													
AZ	4	007	0004	45	3331	2	Copper	ASARCO SMELTER - HAYDEN		29,814	33,124	22,077	16,753
AZ	4	021	0032	46	3331	2	Copper	BHP(Magma Metals)	BHP - San Manuel	15,900	16,678	10,409	0
AZ	4	007	0006	45	3331	2	Copper	CYPRUS MIAMI MINE		5,676	5,737	6,097	6,810
AZ	4	019	0040	46	1021	2	Copper	Cyprus Sierrita		800	548	<100	<100
NM	35	017	0001	64	3331	2	Copper	PHELPS DODGE/CHINO MINES		28,058	14,784	15,685	11,420
NM	35	023	0003	64	3331	2	Copper	PHELPS DODGE/HIDALGO SMELTER		41,433	32,121	29,188	0
UT	49	035	0030	32	3331	2	Copper	Kennecott Utah Copper Corp.		26,829	1,556	762	937
										148,510	**104,549**	**84,218**	**35,920**

CHAPTER XI
ALUMINUM PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Primary aluminum production plants in the United States produce aluminum metal by electrolytically reducing alumina that have been refined from bauxite ore. There are 23 primary aluminum plants in the United States. There are only 2 plants in the study region and both are located in Oregon.

Aluminum production is carried out in a semibatch manner in large electrolytic cells called pots with a direct current input of up to 280,000 amperes at about 5 volts. The pot, a rectangular steel shell ranging in size from 30-50 feet long, 9-12 feet wide, and 3-4 feet high, is lined with a refractory insulating shell on which carbon blocks are placed to form the cathode.

An aluminum pot will typically emit 20-35 kg per metric ton of gaseous and particulate fluoride and roughly an equal amount of particulate matter. The NSPS limits emissions to no more than 1 kg fluoride/Mg (2.0 lbs/ton) of aluminum produced for potroom groups at Soderberg plants, 0.95 kg/Mg (1.9 lbs/ton) of aluminum produced at pre-bake plants, and 0.05 kg/Mg (0.1 lbs/ton) of aluminum equivalent for anode bake plants.

The reduction cells in use for aluminum production in the United States are of two basic types – prebake and Soderberg. There are two types of Soderberg cells that are designated according to the manner of mounting the stud in the carbon anode: vertical stud Soderberg (VSS) or horizontal stud Soderberg (HSS).

Prebake cells are so named because the anodes are preformed and then baked in a separate facility often referred to as an anode bake plant. The anodes are then mounted in the cell and are consumed in the aluminum production. The anode butts, which remain after the anode is consumed, are recycled for use in the preparation of new anodes.

In the Soderberg process, continuously formed, consumable anodes are used. The anode paste is baked by the heat generated in the reduction cell.

The primary source of sulfur oxide emissions in aluminum production is the sulfur in the coke (normally petroleum coke) and the coal tar pitch binder used to produce the anodes. In the prebake process, the combustion fuel to bake the anodes may be a significant SO_2 emission source. Petroleum coke usually contains 2.5 to 5 percent sulfur, but may vary from 1.5 to 7 percent sulfur. Pitch normally contains about 0.5 percent sulfur. The sulfur content of the coke depends on the crude petroleum stock and the tendency of the sulfur to concentrate in the still bottoms at the refinery and thus in the coke.

As the coke is processed (during prebake) or consumed in the reduction cell, sulfur oxides are released. The emissions include those from the anode prebake operation (prebake), the "primary" emissions (which are captured by the pot hood exhaust system), and the "secondary" emissions (which escape the primary exhaust system and exit through the roof monitors). The great majority of SO_2 emissions are collected by the pot hood exhaust system.

One source reports uncontrolled SO_2 emissions from anode bake plants range from 5 to 47 ppm, which is 0.7 to 2 kg SO_2/Mg aluminum produced (1.4 to 4 lbs SO_2/ton aluminum produced). Other data indicate that emissions are in the range of 0.09 to 1.7 kg SO_2/Mg aluminum produced (0.18 to 3.4 lbs SO_2/ton aluminum produced).

The total amount of SO_2 generated per unit of aluminum produced is essentially the same for the prebake, VSS, and HSS cases. The "primary" cell hooding configuration for collection of process fumes is affected by the characteristics of the different cell types. There are two types of prebake cells, center-worked prebake cells (CWPB) and side-worked prebake cells (SWPB), as well as the two Soderberg processes, VSS and HSS, which are in use by the domestic aluminum industry. Information from seven primary aluminum plants indicates the following:

Cell Type	Primary Hood Collection Efficiency, %	Primary Collector Exhaust Rate (10^6 square cubic feet per ton of aluminum)
CWPB	65 to 98	(4.11 to 5.05)
SWPB	85	(3.44)
VSS	81	(0.67)
HSS	80 to 95	(5.06 to 7.85)

This information indicates that the gas volume associated with the production of a fixed amount of aluminum is in the range of 5 to 12 times (average 8 times) greater for CWPB, SWPB, or HSS than for VSS. Consequently, the concentration of SO_2 in a volume of exhaust gas in the primary collector system can be expected to be about 8 times greater for a VSS unit than for other units.

Reported data on uncontrolled "primary" exhaust system SO_2 emissions are as follows:

Unit	Source	SO_2 Concentration, ppm	Total SO_2 emissions, kg SO_2/Mg Aluminum (lbs SO_2/ton aluminum)
Prebake Cell	A	5	Not reported
	B	Not reported	20.9 to 23.4 (41.7 to 46.8) [average of 22.4 (44.8)]
	C	Not reported	30 (60) [3% sulfur in the coke]
VSS Cell	A	80	Not reported
	B	200 to 300	17.5 to 25 (35 to 50)
	C	200 (average)	Not reported

The trend in construction of new aluminum plants is toward prebake systems. A major factor influencing this trend is the lower power requirement of the prebake cell compared with Soderberg cells. It is reported that 9 of the 11 aluminum plants opened since 1960 are of the prebake type, and 99 percent of the 324 Gigagrams (357,000 tons) capacity added since 1973 has been at prebake facilities. Of the 23 primary aluminum production plants in the United States, 18 use the prebake process and 5 use the Soderberg process.

B. FLOOR ALLOCATION ESTIMATION METHODS

There are two aluminum smelters located within the study region, and they are both located in Oregon. The data provided by the Oregon Department of Environmental Quality on the unit capacities and SO_2 emissions potential for these two smelters is provided in Table XI-1. This table shows that the SO_2 emissions potential for Reynolds Metal, if operated at its design capacity, is 4,700 tpy. This is the same as their permitted SO_2 emission limit. For NW Aluminum, the SO_2 emissions potential is 518 tpy.

The NSPS for primary aluminum plants limits fluoride emissions, but does not affect SO_2 emissions. Washington is the only State that has established an SO_2 emission limit specifically for primary aluminum plants. The rule limits the maximum allowable total SO_2 emissions from all sources within the plant to 60 lbs per ton of aluminum produced on a monthly basis. Based on the SO_2 emission rates by process for Reynolds Metal, which is 65.3 lbs SO_2 per ton of aluminum produced, applying the State of Washington rule would only provide an 8 percent reduction in SO_2 emissions.

Comparing the capacity-based SO_2 emission estimates in Table XI-1 with recent historical emissions (see Table XI-2) shows that recent historic SO_2 emissions from Reynolds Metals are considerably below their capacity/permitted emission limit, and that they vary considerably from year-to-year. NW Aluminum SO_2 emissions in the period 1996 to 2000 average about 80 percent of total capacity.

The floor control technology for aluminum smelters was determined by evaluating the emissions performance of Reynolds Metals and NW Aluminum. NW Aluminum uses a wet scrubber to achieve a 70 percent SO_2 emission reduction. Therefore, a wet scrubber with a 70 percent SO_2 reduction was selected as the floor technology for aluminum smelters. The effect of this floor technology application is shown in the rightmost column of Table XI-1.

REFERENCES

CFR, 2001: Code of Federal Regulations, “Subpart S - Standards of Performance for Primary Aluminum Plants (60.190-60.195),” July 1, 2001.

EPA, 1981: U.S. Environmental Protection Agency, “Control Techniques for Sulfur Oxide Emissions from Stationary Sources,” Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

Table XI-1
Aluminum Plant Data Used to Estimate Floor Allocations

Company	Emissions Unit	Fuel Type	Actual Capacity	Capacity Units	Control Device	SO_2 Emission Factors (lbs/ton)	SO_2 Control Efficiency	SO_2 Emissions Actual Capacity (tons/yr)	Floor Allocation at 70% Control (tons/yr)
Reynolds Metals	Carbon bakes	Natural gas				0.18-.19		27	27
	Potroom fugitives	N/A			N/A	2.5	N/A	177	177
	Potroom emissions	N/A			N/A	62.5	N/A	4,488	1,346.4
	Backup fuel	#2 fuel oil				0.105		7.5	7.5
	Plant total							4,700	1,557.9
NW Aluminum	Cell line	N/A	97,500	TAP/yr	Wet scrubber		0.7	517	517
	Cell line	Propane	144,000	gallons/yr	No		N/A	<0.1	<0.1
	Casthouse furnace	Natural gas	80,000,000	cubic feet/yr	No		N/A	1	1
	Plant total							<518	518
Total								**5,218**	**2,076**

NOTES: Control Device: While there are no physical control devices, the most effective form of SO_2 control is limiting the amount of sulfur in fuel oil. For example, the sulfur content in distillate fuel oil sold in NW usually averages much less than 0.1, whereas the rule limit is 0.5. Actual Capacity Emission is limited by the SO_2 PSEL. SO_2 emission factors are in lbs per ton of aluminum produced.

Table XI-2
Aluminum Smelting - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
100 tpy or More SO_2													
OR	41	065	0001	5	3334	10	Metals/Mining/Minerals	Northwest Aluminum Company, Inc.		423	448	375	397
OR	41	051	1851	5	3334	10	Metals/Mining/Minerals	Reynolds Metals Company		3,340	0	503	1,510
										3,763	**448**	**878**	**1,907**

CHAPTER XII
SULFURIC ACID PLANTS

Sulfuric acid is the most widely used industrial chemical. The chief uses of sulfuric acid are in production of fertilizer, manufacture of chemicals, oil refining, pigment production, iron and steel processing, synthetic fiber production, and metallurgical operations. The predominant process used for the production of sulfuric acid is the contact process. The entire discussion in this chapter focuses on the contact process.

Sulfuric acid is produced by burning sulfur or sulfur-bearing materials to form SO_2. Sources of SO_2 include: (1) elemental sulfur; (2) spent acid; (3) smelter off-gas; (4) pyrites; and (5) waste gas from fossil-fuel-fired boilers.

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Contact sulfuric acid plants are classified as hot gas (sulfur burning) or cold gas (metallurgical and spent acid) systems. Plants operating on elemental sulfur receive hot SO_2 gas directly from the sulfur burner and waste heat recovery system. When SO_2 gas from a metallurgical operation or other byproduct source (such as spent acid or iron pyrites) is used, it is received cold from the wet scrubber-cooler and purification systems.

A basic variation of the contact process is the double absorption technique, also known as double catalysis. This design is largely based on the need to meet air pollution control regulations.

The only significant source of air emissions from a contact sulfuric acid plant is the tail gas leaving the final absorbing tower. This gas contains small amounts of SO_2 and even smaller amounts of SO_3, sulfuric vapor, and sulfuric acid mist.

SO_2 emissions are determined primarily by overall plant design (e.g., number of catalyst passes, amount of catalyst, dual or single absorption, etc.). New plants are usually designed to meet NSPS emission limits using the dual absorption process. In certain situations, plants can achieve better than NSPS limits using the dual absorption process. For example, in a metallurgical acid plant, lower SO_2 emissions can sometimes be achieved catalytically if the process gas from a smelter has a sufficiently high oxygen-to-SO_2 ratio. Proper catalyst volumes and interpass cooling can be incorporated into the initial design, however. Existing plants that are required to reduce their SO_2 emissions usually choose to convert to dual absorption or install a tail gas scrubber.

Dual absorption has been generally accepted as BACT. Conceptually, dual absorption is the addition of another converter and absorbing tower on the tail end of a single absorption plant (with appropriate heating and cooling of the gas stream) so there is no new technology involved. Only sulfuric acid is produced in the dual absorption equipment.

Various scrubbing, or tail gas, technologies are available for removing SO_2 from gas streams. Tail gas treatment is rarely used to achieve NSPS limits for new plants. A tail gas process at the end of a dual absorption plant may be the preferred technology where local regulations require substantially lower than NSPS emission rates.

Tail gas processes that produce a by-product that can be recycled to the acid plant (e.g., weak sulfuric acid) are of special interest because they eliminate the need for off-site by-product disposal. Two such processes are hydrogen peroxide scrubbing and SO_2 oxidation with activated carbon.

B. FLOOR ALLOCATION ESTIMATION METHODS

Based on the information available for sulfuric acid plants in the west, it was determined that it is appropriate to estimate the floor allocation by applying the NSPS requirements to each sulfuric acid plant.

Subpart H - Standards of Performance for Sulfuric Acid Plants

60.82 Standard for Sulfur Dioxide

On or after the date on which the performance test required to be conducted by Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain SO_2 *in excess of 4 lbs per ton of acid produced. Achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent* SO_2 *collection mechanism in a controlled facility.*

Table XII-1 lists the sulfuric acid plants, their characteristics, and the estimated annual SO_2 floor allocations. An initial SO_2 floor allocation was estimated by multiplying the daily throughput limit by the NSPS emission rate (4 lbs SO_2 per ton 100 percent acid produced), times 365 days per year, converted from lbs to tons by dividing by 2000. In equation form, this is:

$$Daily\ throughput\left(\frac{tons}{day}\right) * \frac{4\ lbs}{ton} * \frac{365\ days}{year} * \frac{1\ ton}{2000\ lbs}$$

This based on throughput initial floor allocation was found to exceed the annual SO_2 permit limits for each of these units. Therefore, the estimated floor allocations for these sulfuric acid plants was established using recent historic SO_2 emissions data. These historic emission values are all slightly below the annual SO_2 permit limits.

REFERENCES

AWMA, 2000: Air and Waste Management Association, “Air Pollution Engineering Manual,” 2nd edition, Chapter 12 - Chemical Process Industry, 2000.

CFR, 2001: Code of Federal Regulations, Subpart H - Standards of Performance for Sulfuric Acid Plants (60.82), July 1, 2001.

Idaho DEQ, 2002a: State of Idaho, Department of Environmental Quality, Air Quality Tier 1 Operating Permit, J.R. Simplot Co. - Don Siding Plant, 2002.

Idaho DEQ, 2002b: State of Idaho, Department of Environmental Quality, Air Quality Tier 1 Operating Permit, Nu-West Industries, Inc.; Agrium Conda Phosphate Operations, 2002.

Table XII-1
Sulfuric Acid Plants

State	Facility Name	Start Date	Sulfuric Acid Plant ID	Process	Control Technique	Annual SO_2 Permit Limit (tons)	Daily Throughput Limit (tons)	Based on Throughput SO_2 Floor Allocation (tpy)	Floor Allocation Using Historic Emissions Average (tpy)
Idaho	Nu-West Industries		East	NA	NA	945	1,550	1,131	612
Idaho	JR Simplot		300	Single contact	2 stage scrubber system	750	1,750	1,277	1,939
			400	Double contact	Double contact with mist eliminator	1,458	NA	1,458	
Wyoming	SF Phosphates, Inc.	1995	Source 9b	MEC		963.6	1,320	964	1,638
		1984	Source 9a	Lurgi		1,387	1,900	1,387	
Wyoming	Koch Sulfur Products		EU-1		NA	719	NA	719	1,197
			EU-5		NA	721	NA	721	

NA = not available.

CHAPTER XIII
METALLURGIC COKE PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Metallurgical coke is derived from coal and used in iron and steel industry processes. Coke is manufactured by pyrolysis, the heating of coal in the absence of air. In this process, high grade, bituminous coal is heated in a enclosed chamber to approximately 1050°C (1925°F), which removes all volatile components of the coal. The resulting product is a solid material consisting of elemental carbon and any minerals that were not volatilized in the heating process.

1. By Product Coke Ovens

In a typical coking operation, 35 to 100 coke ovens are located in a row referred to as the oven battery. Each oven has three main parts: coking chambers, heating chambers, and regenerative chambers. The coking chamber has ports in the top for charging (loading) of the coal. A typical U.S. coke oven produces 7.5 tons to 39 tons of coke per cycle. Most coke plants are co-located with iron and steel production facilities.

All ovens currently operating in the United States are by-product recovery ovens. These ovens operate by reusing gases (volatiles) emitted by the hot coal. In by-product recovery ovens, the volatiles from the coal are collected and sent to a by-product recovery plant. The off gas is condensed and separated into a liquid fraction (coal tar) and a gaseous fraction (coal gas). The coal gas contains a number of contaminants including hydrogen sulfide. Some by-product recovery processes remove the sulfur from the gas prior to combustion. Approximately 33 percent to 40 percent of the clean coal gas is then returned to the oven battery to be used as fuel. The remaining coal gas can be used as fuel for other processes at the plant or sold to other facilities.

Emissions of SO_2 from coke ovens operations primarily result from combustion of the byproduct coal gas in the oven. A small portion of SO_2 emissions comes from uncontrolled “charging”, the process of loading coal into the oven. Control of SO_2 from combustion of coal gas is primarily accomplished by; (a) removing the sulfur from the gas prior to combustion or (b) utilizing low sulfur coal in the coking process. There are a number of methods for removing sulfur from the coal gas, such as wet scrubbing.

2. Rotary Calciners

There is only one known rotary calciner used for coke production in the United States, P4 Production in Rock Springs, WY. It uses a Salem Brosius, 65 foot diameter, continuous feed rotary hearth calciner. Basically, the process involves feeding a mixture of coal and petroleum (pet) coke onto a rotating table located inside a furnace. The coal is heated to a high temperature as it rotates to produce coke. The coke exits the hearth and enters a cooling chamber. Like byproduct recovery ovens, the furnace operates by reusing the volatile gases emitted from the coal. However, in this process, the furnace is initially started with natural gas. Once started, the coal gas being emitted during the coking process is utilized as fuel directly. The waste gas is then ducted to an incinerator. Byproducts of the process include fine coke, ash, CO_2, SO_2, and rock.

Emissions of $SO_2$from a rotary hearth calciner are primarily due to the volatiles from the heated coal. The waste gas is ducted to an incinerator and baghouse prior to being emitted to the atmosphere. There is no desulfurization of the waste gas. The amount of SO_2 emitted from the facility is a function of the properties of the feed coal.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to facilities which emit greater than 100 tpy of SO_2 in total. There are three facilities which have been identified. Two are coking plants, Astaris Coking Plant in Wyoming and Geneva Steel in Utah. There is one rotary calciner in Wyoming, P4 Production, Rock Springs Coal Calcining Plant. The air pollution agencies for Wyoming and Utah provided information on the coking and calcining facilities for estimating floor allocations.

Astaris Coking Plant was shut down in April of 2001. Therefore, this facility does not receive an SO_2 allocation.

Geneva Steel has committed to ceasing all SO_2 emissions from the coke ovens and the sinter plant. These emissions have been banked for future use or trading as precursor pollutants within the current local Utah County PM_{10} SIP. The Utah Air Quality Board approved this change on June 5, 2002. Since the SO_2 emissions for coking and sintering at the plant are now essentially zero, the SO_2 floor allocation for coking is also zero.

The third facility is P4 Production, Rock Springs Coal Calcining Plant. The plant is designed to process 220,000 tpy of feed materials to produce 110,000 tpy of coke product. The plant operates for up to 8,000 hours per year. This works out to a design process rate of 27.5 tons per hour (tph) or 660 tons per day (tpd) of feed. According to the operating permit, the total facility potential to emit is 2,841.1 tpy of SO_2 based on 8,760 operating hours. There are no NSPS requirements the facility must comply with for SO_2. This rotary coker was built in 1972 and thus is "grandfathered" from the Wyoming Air Quality Division's permit requirements. The historical emissions for this facility are presented in Table XIII-1.

Table XIII-1
Historical SO_2 Emissions at P4 Production, Rock Springs, WY

Historical Emissions of SO_2 (tpy)					Average Annual SO_2 Emissions (tpy)
1990	**1996**	**1997**	**1998**	**2000**	**1996 - 2000**
933	663	586	642	633	631

As stated previously, the SO_2 emitted is a function of the feed coal. The plant uses a blend of coal and petroleum coke (pet coke). The 1994 annual inventory showed that the pet coke blend was 7.2 percent for the year, with SO_2 emissions of 420.0 tpy; up 15 percent from the 365.6 tpy emitted in 1993, when straight coal was used as 100 percent of the feedstock. The most recent year's data shows that the pet coke blend was 25 percent for 1998, the maximum allowable amount to maintain compliance with the SO_2 emissions limit.

The procedure for estimating the floor allocation for P4 Productions is difficult for several reasons. First, there are no identified control technologies available for the rotary calciner. Second, there are no NSPS requirements. Third, P4 Production has a potential to emit 2,841.1 tpy based on 8,760 hours of operation. This is much higher than the annual emissions reported by the plant. Lastly, the SO_2 emissions from the rotary calciner are a function of the sulfur content of the feed which varies over time. Since the coking process at P4 Production is unique and cannot be compared with emissions from other facilities, the SO_2 allocations for P4 Productions will be based on its average annual emissions. This is consistent with the allocation approach developed for source categories with no technology available for reducing sulfur and variable sulfur content in the feed such as flaring.

The allocation for P4 Production will be based on emissions of SO_2 from years 1996, 1997, 1998 and 2000. Averaging historical emissions results in a floor allocation of 631 tpy of SO_2 for the P4 Production facility. As stated previously, the SO_2 floor allocations for Astaris and Geneva Steel are zero.

C. COMPARISON WITH HISTORICAL EMISSIONS

Table XIII-2 presents the historical SO_2 emissions and the SO_2 floor allocations for all three coking facilities. Note that Geneva Steel has an SO_2 allocation for its boilers, which is discussed in Section IV.

Table XIII-2
Coking Plant - Historical Emissions - 1990 to 2000

State	County ID	Facility ID	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	SO_2 Floor Allocation
WY	037	0003		10	Metals/Mining/ Minerals	Sweetwater Resources	P4 Production - Rock Springs	933	663	642	633	631
WY	023	001		10	Metals/Mining/ Minerals	FMC Coking Plant	Astaris Coking Plant	1,194	1,413	1,454	1,409	0
UT	049	0027	3312	10	Metals/Mining/ Minerals	Geneva Steel		8,473	2,020	881	979	0

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 14 - Metallurgical Industry, 2000.

EPA, 1981: U.S. Environmental Protection Agency, "Control Techniques for Sulfur Oxide Emissions from Stationary Sources," Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

EPA, 1998: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," AP-42, Fifth Edition, Volume I: Stationary Point and Area Source, Section 12.2 Coke Production" Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

CHAPTER XIV
FLOOR ALLOCATION SUMMARY

Table XIV-1 summarizes the SO_2 floor allocation estimates from all of the previous chapters by State and by sector. California estimates listed in Table XIV-1 are based on average SO_2 emissions in these sectors from 1996, 1998, and 2000. Table XIV-1 shows the estimated SO_2 floor allocation for non-utility sources in the 9-State Commission Transport Region to be about 195 thousand tons. If copper smelter SO_2 allocations in 2018 are subtracted from this amount, the floor allocation is 117 thousand tons. The non-smelter, non-California SO_2 emissions total is 89,000 tons.

Table XIV-2 provides a complete list of the facility-level SO_2 floor allocations, and includes year 2000 SO_2 emissions as a point of comparison.

Table XIV-1
State/Sector Summary of SO_2 Floor Allocations
(tons per year)

	Sectors												
States	**Refineries**	**Lime Manufacturing***	**Industrial Boilers**	**Pulp and Paper**	**Cement Manufacturing**	**Natural Gas Processing**	**Elemental Phosphorus****	**Glass Manufacturing*****	**Copper Smelters**	**Aluminum Plants**	**Sulfuric Acid Plants**	**Coke Production**	**Total**
Arizona		1,365	978		320				43,000				45,663
California													27,335
Colorado	1,614		387		4,936			237					7,174
Idaho			601	1,807	522		15,861				2,551		21,342
Nevada		435			448								883
New Mexico	2,244				1,103	12,862			34,000				50,209
Oregon			1,585	5,377				131		2,076			9,169
Utah	4,142	303	2,010		267	1,593			1,000				9,315
Wyoming	3,418		2,350		165	14,429					2,835	631	23,828
Total	**11,418**	**2,103**	**7,911**	**7,184**	**7,761**	**28,884**	**15,861**	**368**	**78,000**	**2,076**	**5,386**	**631**	**194,918**

NOTES: *Based on 1998 and 2000 historical SO_2 emission estimates.
**Based on year 2000 SO_2 emission estimates for P4 Production, which are substantially higher than 1996 or 1998 emissions.
***Based on 1996, 1998, and 2000 historical SO_2 emission estimates.

Table XIV-2
Facility-Level SO_2 Floor Allocations
Comparison with Year 2000 SO_2 Emissions (tons per year)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
AZ		Cement/Concrete	Arizona Portland Cement		X		320	0		0	
AZ	0011	Metals/Mining/Minerals	CHEMICAL LIME (CHEMSTAR)	CHEMICAL LIME - NELSON	X		702	632		632	
AZ	0003	Metals/Mining/Minerals	Chemical Lime (Douglas)		X		742	733		733	
AZ		Cement/Concrete	Phoenix Cement		X		539	320		320	
AZ	0007	Wood/Paper/Pulp	STONE CONTAINER	ABITIBI	X		1,893	0	978	978	
AZ	0001	Oil/Gas	Intermountain Refining		X	Closed	0	0		0	
AZ	0004	Copper	ASARCO SMELTER - HAYDEN		X		16,753	21,000		21,000	
AZ	0032	Copper	BHP(Magma Metals)	BHP - San Manuel	X		0	14,000		14,000	
AZ	0006	Copper	CYPRUS MIAMI MINE		X		6,810	8,000		8,000	
AZ	0040	Copper	Cyprus Sierrita		X		0	0		0	
											45,663
CO	0048	Metals/Mining/Minerals	CFI				267			0	
CO	0004	Oil/Gas	COLO REFINING		X	Refinery	545	562		562	
CO	0003	Oil/Gas	CONOCO DENVER		X	Refinery	1,972	1,052		1,052	
CO	0008	Glass	COORS GLASS	ROCKY MOUNTAIN BOTTLE	X		255	237		237	
CO	0002	Cement/Concrete	HOLNAM LAPORTE	HOLCIM LAPORTE	X		404	1,402		1,402	
CO	0001	Cement/Concrete	HOLNAM PORTLAND	HOLCIM PORTLAND	X		3,288	3,374		3,374	
CO	0097	Misc.	METRO WASTEWATER				56			0	
CO	0003	Cement/Concrete	SOUTHWEST PORTLAND	CEMEX-LYONS PLT.	X		50	160		160	
CO	9	Misc.	GENERAL SERVICES ADMINISTRATION				0			0	
CO	0001	Oil/Gas	LANDMARK PETROLEUM				0			0	
CO		CHP	TRIGEN-COLORADO ENERGY CORP.		X		2,583	0	387	387	
CO	24	Oil/Gas	UNOCAL RETORT-PARACHUTE		X		0			0	
CO	0025	Oil/Gas	UNOCAL UPGRADE		X		0			0	
CO	0001	Food	WESTERN SUGAR 1				19			0	
CO	0002	Food	WESTERN SUGAR 2				0			0	
											7,174
ID		Wood/Paper/Pulp/Cogeneration	Tamarack Energy				117			0	
ID	0004	Cement/Concrete	ASHGROVE CEMENT		X		1,327	522		522	
ID		Power	Avista				130			0	
ID		Food	Basic American Foods (Shelly)				149			0	
ID		Wood/Paper/Pulp	Boise Cascade - Emmett				252			0	
ID	0001	Misc.	DOE-INEEL				460			0	
ID	0005	Chemicals/Plastics	FMC	ASTARIS			0			0	
ID		Food	MAGIC VALLEY FOODS				0			0	
ID	0001	Chemicals/Plastics	MONSANTO/P4 PRODUCTION	P4 Production	X	Elemental Phosphorus	15,861	15,861		15,861	
ID	0003	Chemicals/Plastics	NU WEST INDUSTRIES			Sulfuric acid plants	86			612	
ID	0001	Wood/Paper/Pulp	POTLATCH		X	Paper Mill	1,694	1,807		1,807	
ID		Misc.	RICKS COLLEGE				0			0	
ID	0006	Chemicals/Plastics	SIMPLOT			Sulfuric acid plants	543			1,939	
ID	0010	Food	TASCO (NAMPA)	Amalgamated Sugar (Nampa)			1,697		242	242	
ID	0001	Food	TASCO (PAUL)	Amalgamated Sugar (Paul)			1,322		155	155	
ID	0001	Food	TASCO (TWIN)	Amalgamated Sugar (Twin)			1,053		203	203	
ID		Food	Idaho Supreme				0			0	
ID	0001	Misc.	MTN. HM. AFB				144			0	
											21,341
NV	0003	Metals/Mining/Minerals	CHEMSTAR APEX	CHEMICAL LIME CO-APEX PLANT	X	Lime plant	210	193		193	
NV	0387	Cement/Concrete	NEVADA CEMENT COMPANY	FERNLEY PLANT	X		172	305		305	
NV		Cement/Concrete	Royal Cement			Not in previous report		143		143	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
NV	0261	Metals/Mining/Minerals	GRAYMONT WESTERN US INC	PILOT PEAK	X	Lime plant	249	242		242	
NV	0451	Metals/Mining	SANTA FE PACIFIC GOLD CORP	TWIN CREEKS/NEWMONT MINING CORP			113			0	
NV	0433	Metals/Mining/Minerals	BASIC INC.(Now PREMIER CHEMICALS LLC)	PREMIER SERVICES (Gabbs Facility)						0	
NV	0863	Misc.	HAWTHORNE ARMY							0	
NV		Metals/Mining	Independence Big Springs	ANGLO GOLD						0	
NV	0019	Metals/Mining/Minerals	TITANIUM METALS							0	
											883
NM	0024	Oil/Gas	AGAVE ENERGY/YATES PLANT	Agave Plant	X		2,983	365		365	
NM	0002	Oil/Gas	ARCO PERMIAN/EMPIRE ABO GAS PLNT		X		565	431		431	
NM	0004	Oil/Gas	CONOCO/MALJAMAR GAS PLANT	MALJAMAR GAS PLANT	X		3,574	222		222	
NM	0023	Oil/Gas	GIANT INDUSTRIES/BLOOMFIELD REF		X	Refinery	920	414		414	
NM	0008	Oil/Gas	Giant Refining/Ciniza Refinery	(Gallup)	X	Refinery	1,779	603		603	
NM	0044	Oil/Gas	GPM GAS EUNICE GAS PLANT	VERSADO GAS PRODUCERS LLC	X		2,759			0	
NM	0011	Oil/Gas	GPM GAS/ARTESIA GAS PLANT	DUKE ENERGY/ARTESIA GAS PLANT	X		1,459	1,192		1,192	
NM	0006	Oil/Gas	GPM GAS/INDIAN HILLS AMINE PLNT				900			0	
NM	0046	Oil/Gas	GPM GAS/LEE GAS PLANT	Duke Energy Lee Plant	X		818	0		0	
NM	0035	Oil/Gas	GPM GAS/LINAM RANCH GAS PLANT	Duke Energy Plant 5			1,304	1,181		1,181	
NM	0007	Oil/Gas	J.L. DAVIS GAS PROCESS/DENTON		X		1,158	840		840	
NM	0008	Oil/Gas	MARATHON OIL/INDIAN BSN GAS PLT		X		1,100	665		665	
NM	0010	Oil/Gas	NAVAJO REFINING/ARTESIA REFINERY		X	Refinery	980	1,227		1,227	
NM	138	Oil/Gas	PAN ENERGY/BURTON FLATS GAS PLT	Duke Energy Burton Plant	X		246	164		164	
NM	0285	Oil/Gas	PAN ENERGY/DAGGER DRAW GAS PLT	DUKE ENERGY/DAGGER DRAW	X		247	218		218	
NM		Cement/Concrete	RIO GRANDE PORTLAND CEMENT		X		1,103	1,103		1,103	
NM	0008	Oil/Gas	SID RICHARDSON GASOLINE/JAL#3		X		0	1,206		1,206	
NM	55	Oil/Gas	TEXACO/BUCKEYE GASOLINE PLANT	DYNERGY			673			0	
NM	0052	Oil/Gas	TEXACO/EUNICE NORTH GAS PLANT		X		5,476			0	
NM	0051	Oil/Gas	TEXACO/EUNICE SOUTH GAS PLANT		X		231			0	
NM	0003	Oil/Gas	TRANSWESTERN PIPE	DUKE ENERGY/HUBER GAS	X		270	163		163	
NM	0001	Oil/Gas	WARREN PETROLEUM/BLUITT GAS PLANT		X		1,226			0	
NM	0060	Oil/Gas	WARREN PETROLEUM/EUNICE GAS PLANT	Duke Energy EUNICE GAS PLANT			2,756	2,250		2,250	
NM	0061	Oil/Gas	WARREN PETROLEUM/MONUMENT PLANT	Dynergy MONUMENT PLANT	X		1,387	675		675	
NM	0063	Oil/Gas	WARREN PETROLEUM/SAUNDERS PLANT	Dynergy SAUNDERS PLANT			0	163		163	
NM	0064	Oil/Gas	WARREN PETROLEUM/VADA GAS PLANT				3,138			0	
NM	0247	Oil/Gas	WESTERN GAS PROCESSORS/SAN JUAN RVR	Western Gas Resources	X			3,127		3,127	
NM	0128	Oil/Gas	CITATION/ANTELOPE RDG GAS PLANT		X					0	
NM	0118	Oil/Gas	CONOCO/BELL LAKE 2 WELL #6		X					0	
NM	0125	Oil/Gas	FEAGAN ENERGY/W DAGGER DRAW GAS PLT	Duke Energy Dagger Draw	X					0	
NM	0050	Oil/Gas	YATES PETROLEUM/PATHFINDER AMINE		X		0	0		0	
NM	0001	Copper	PHELPS DODGE/CHINO MINES		X		11,420	14,000		14,000	
NM	0003	Copper	PHELPS DODGE/HIDALGO SMELTER		X		0	20,000		20,000	
											50,209
OR	0002	Food	Amalgamated Sugar Company, The		X		987	0	74	74	
OR		Wood/Paper/Pulp			X	Not in previous report		0			
OR	1849	Wood/Paper/Pulp	Boise Cascade Company		X		1,834	1,532	411	1,943	
OR		Oil/Gas			X	Not in previous report					
OR	0005	Wood/Paper/Pulp	Georgia-Pacific West, Inc.		X		452	258	143	401	
OR	0007	Metals/Mining	Glenbrook Nickel Company				0			0	
OR	2125	Metals/Mining/Minerals	Globe Metallurgical Inc.				197			0	
OR	0036	Wood/Paper/Pulp			X		0	0			
OR	0004	Wood/Paper/Pulp	James River II, Inc.	Georgia- Pacific (Wauna Mill)	X		643	1,361	277	1,638	
OR	0001	Metals/Mining/Minerals	Northwest Aluminum Company, Inc.		X		397	518		518	
OR	1876	Glass	Owens-Brockway Glass Container, Inc.		X		108	131		131	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
OR	3501	Wood/Paper/Pulp	Pope & Talbot Pulp, Inc.		X		293	248	107	355	
OR	1851	Metals/Mining/Minerals	Reynolds Metals Company		X		1,510	1,558		1,558	
OR	6142	Wood/Paper/Pulp	Smurfit Newsprint Corporation 2		X	No longer pulping	519	0		0	
OR		Wood/Paper/Pulp	West Linn Paper Co.		X	Not in previous report		0	211	211	
OR	8866	Wood/Paper/Pulp	Weyerhaeuser Company	SierraPine, Ltd.	X		0	0	0	0	
OR	0471	Wood/Paper/Pulp	Willamette Industries, Inc.		X		327	310		310	
OR	8850	Wood/Paper/Pulp	Collins Products LLC	Weyerhaeuser Co.	X	Weyerhaeuser Springfield	1,721	1,668	362	2,030	
OR	5034	Misc.	Cascade Steel Rolling Mills, Inc.				0			0	
OR	2028	Oil/Gas		Kinder Morgan Energy Partners, L.P	X						
OR	0041	Chemicals/Plastics	Georgia-Pacific Resins, Inc.							0	
OR	0013	Wood/Paper/Pulp	J. Peterkort & Company	Collins Products LLC						0	
OR	5398	Wood/Paper/Pulp	Ogden Martin Systems of Marion, Inc.	Covanta Marion, Inc.	X					0	
OR	2050	Misc.	Oregon Health Sciences University	OHSU	X		0	0			
OR	0015	Wood/Paper/Pulp	Weyerhauser - Coos Bay			Hog waste-fired boiler	882			0	
											9,169
UT	10572	Copper	Kennecott Utah Copper Corp.		X	Smelter	2,534	1,000	700	1,700	
UT	10096	CHP	Sunnyside Cogeneration Associates		X		1,054		1,270	1,270	
UT	0004	Oil/Gas	Amoco Petroleum Products	Tesoro	X	Refining	1,368	1,388		1,388	
UT	0004	Misc.	Brigham Young University		X		125		1	1	
UT	0001	Metals/Mining/Minerals	Brush Wellman Inc.		X		179		23	23	
UT	0003	Oil/Gas	Chevron Products Company		X	Refining	1,242	1,240		1,240	
UT	-9902	Metals/Mining/Minerals	Continental Lime Inc.	Graymont	X	Lime	331	303		303	
UT	0008	Oil/Gas	Flying J Incorporated		X	Refining	300	674		674	
UT	0027	Metals/Mining/Minerals	Geneva Steel		X	Shutdown coke ovens and sinter plant	979		17	17	
UT	0001	Cement/Concrete	Holnam Incorporated	Holcim	X	Cement	288	267		267	
UT	0013	Oil/Gas	Phillips 66 Company		X	Refining	601	762		762	
UT		Oil/Gas	Silver Eagle Refining Inc.		X	Not in previous report (Refining)		77		77	
UT	-9901	Oil/Gas	Unocal Corporation	Tom Brown-Lisbon Plant	X	Natural gas processing	1,252	1,593		1,593	
UT		10676	Utelite Corporation				133	0		0	
											9,315
WY	0012	Oil/Gas	AMOCO - ELK BASIN	HOWELL PETROLEUM - ELK BASIN	X		2,638	1,200		1,200	
WY	0012	Oil/Gas	AMOCO - WHITNEY CANYON		X		6,889	5,602		5,602	
WY	0009	Oil/Gas	CHEVRON - CARTER CREEK		X		2,096	200		200	
WY		Cement/Concrete	Centex		X	Not in previous report		165		165	
WY	0013	Oil/Gas	EXXON - SHUTE CREEK		X		1,383	1,536		1,536	
WY		Oil/Gas	EXXON BLACK CANYON DEHY & WELLFIELD				167			0	
WY	0010	Metals/Mining/Minerals	FMC - GRANGER (TEXAS GULF)		X		212		305	305	
WY	48	Metals/Mining/Minerals	FMC - GREEN RIVER		X		4,901		956	956	
WY	0001	Metals/Mining/Minerals	FMC COKING PLANT	ASTARIS COKING PLANT	X	Shutdown April 2001	1,409			0	
WY	0001	Oil/Gas	FRONTIER OIL & REFINING - CHEYENNE		X	Refining	1,396	863		863	
WY	0002	Metals/Mining/Minerals	GENERAL CHEMICAL		X		5,000		750	750	
WY	0001	Food	HOLLY SUGAR - TORRINGTON		X		178		23	23	
WY		Oil/Gas	INTERENERGY - HILAND	WILDHORSE ENERGY - HILAND	X		269	281		281	
WY		Oil/Gas	KCS MOUNTAIN RESOURCES - GOLDEN EAGLE		X		17	790		790	
WY		Oil/Gas	KCS MOUNTAIN RESOURCES - AINSWORTH		X		0	843		843	
WY	1	Oil/Gas	KCS Mountain Resources Rushmore		X		118	118		118	
WY	0005	Chemicals/Plastics	KOCH SULFUR PRODUCTS COMPANY	PEAK SULFUR	X	Sulfuric acid plants	1,245	1,197		1,197	
WY		Oil/Gas	LOUISIANA LAND & EXPLOR - LOST CABIN [b]	BURLINGTON RESOURCES - LOST CABIN	X		213	1,867		1,867	
WY	0007	Oil/Gas	MARATHON GAS PLANT - OREGON BASIN	Oregon Basin Gas Plant	X		358	391		391	
WY		Oil/Gas	MARATHON OIL - MILL IRON		X		0	247		247	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
WY	1	Oil/Gas	Marthon Oil Pitch Fork Battery		X		61	61		61	
WY	0003	Metals/Mining/Minerals	SWEETWATER RESOURCES	P4 PRODUCTION - ROCK SPRINGS	X	Rotary coker	633	631		631	
WY	0022	Chemicals/Plastics	SF PHOSPHATES, INC		X	Sulfuric acid plants	1,790	1,638		1,638	
WY	0001	Oil/Gas	LITTLE AMERICA REFINING COMPANY	SINCLAIR - CASPER	X	Refining	1,458	1,040		1,040	
WY	0011	Oil/Gas	SINCLAIR @ SINCLAIR		X	Refining	3,407	1,066		1,066	
WY		Oil/Gas	SNYDER OIL - RIVERTON DOME	DEVON SFS - RIVERTON DOME			492			0	
WY		Metals/Mining/Minerals	SOLVAY MINERALS		X		52		294	294	
WY	0012	Oil/Gas	TEXAS-BYRON PLANT	BIG HORN GAS PROCESSING - BYRON	X	Texaco	257	200		200	
WY	0008	Oil/Gas	UNION PAC - BRADY	RME PETROLEUM - BRADY	X		300			0	
WY	0005	Misc.	UW CENTRAL HEAT PLANT		X		193		22	22	
WY	0001	Oil/Gas	WYOMING REFINING CO	WYOMING REFINING - NEWCASTLE	X	Refining	876	449		449	
WY	008	Oil/Gas	DEVON SFS OPERATING CO.	BEAVER CREEK	X		831			0	
WY	0003	Metals/Mining/Minerals	AMERICAN COLLOID - WEST COLONY							0	
WY	0002	Oil/Gas	AMOCO REFINERY			Closed	0			0	
WY	0001	Metals/Mining/Minerals	BENTONITE CORPORATION	LOVELL			0			0	
WY	0014	Oil/Gas	COLORADO INTERSTATE GAS - TABLE ROCK				0			0	
WY	0013	Oil/Gas	MARATHON OIL COMPANY - GARLAND				0			0	
WY		Oil/Gas	Hallwood Petroleum-Federal Packsaddle 1-24		X	Not in previous report		133		133	
WY		Oil/Gas	Hallwood Petroleum-Federal Packsaddle 1		X	Not in previous report		960		960	
											23,828
TOTALS							**170,226**			**167,583**	**167,583**

[a]SO_2 Allocation based on historical emissions.
[b]Plant has just added capacity and allocation is based on current (July 2002 capacity).