

**PM_{2.5} SIP Evaluation Report – Kennecott Utah Copper LLC- Molybdenum
Autoclave Process, Refinery and Smelter**

UTAH PM_{2.5} SIP SERIOUS SIP

Salt Lake City Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

July 1, 2018

DAQ-2018-007702

PM2.5 SERIOUS SIP EVALUATION REPORT

KENNECOTT UTAH COPPER LLC- MAP, REFINERY AND SMELTER

1.0 Introduction

The following is an updated version of the original RACT evaluation that was completed on October 1, 2013 as a part of the Technical Support Documentation for Section IX, Parts H.11, 12 and 13 of the Utah SIP; to address the Salt Lake City PM_{2.5} and Provo, Utah PM_{2.5} Nonattainment Areas.

1.1 Facility Identification

Name: Kennecott Utah Copper LLC (KUC)

Address: 8362 West 10200 South
Bingham Canyon, UT 84006

Owner/Operator: Rio Tinto/KUC

UTM coordinates:

401,173 m Easting, 4,508,975 m Northing, UTM Zone 12 (MAP)

401,532 m Easting, 4,508,441 m Northing, UTM Zone 12 (Refinery)

398,821 m Easting, 4,508,539 m Northing, UTM Zone 12 (Smelter)

1.2 Facility Process Summary

The KUC Molybdenum Autoclave Processing (MAP) Plant, Refinery and Smelter Facilities are located in Salt Lake County, Utah. A Best Available Control Technology (BACT) analysis of sources at the KUC site that emit fine particulate matter (PM_{2.5}) and PM_{2.5} precursors was prepared by KUC as input to the State of Utah's State Implementation Plan (SIP). This report is a review of that BACT analysis.

The KUC Facility is categorized under Standard Classification Code (SIC) 3331 (Primary Copper) and North American Industry Classification System (NAICS) code 3314411 (Primary Smelting and Refining of Copper). Based on actual air emissions, the KUC Facility is a major source of particulate matter (PM), sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon monoxide (CO). The KUC Facility is classified as an area source for hazardous air pollutants. Operation of the KUC Facilities is conducted according to air emissions limits and other requirements specified in a Title V Operating Permit for the KUC Refinery (Refinery) and KUC Smelter (Smelter), and an Approval Order (AO) for the KUC MAP (MAP) plant that were issued by the State of Utah Department of Environmental Quality (DEQ).

KUC constructed the MAP plant that was schedule to begin operation in 2014 but do to market conditions has not begun operation. In the copper ore, molybdenum exists as molybdenum disulfide (MoS₂). The Copperton Concentrator produces bulk concentrate which consists of copper, molybdenum, gold, and silver among other metals. The molybdenum concentrate is separated from the bulk concentrate using differential

flotation. The MAP plant will process bulk molybdenum disulfide concentrate into molybdenum trioxide and ammonia perrenate. The MAP plant is a hydrometallurgical process that consists of a series of operations beginning with oxidation in an autoclave, and a pressurized steam-heated vessel used to dry and oxidize the concentrate. A series of process steps then follows including solution purification and crystallization, and finally product drying, calcining, and packaging.

KUC operates a copper smelter and refinery in Salt Lake County, Utah. The Smelter and Refinery were modernized with a new Refinery facility completed in 1995 and Smelter facility completed during 1995 and again modified in 1997. The Smelter employs flash smelting technology with flash converting technology to produce copper anodes and high concentration sulfur dioxide gases. The gases are treated by electrostatic precipitators (ESP), baghouses, scrubbers, and a high-efficiency double contact acid plant. The Refinery uses an electrolytic refining process to convert the Smelter produced anode copper to cathode copper and also recovers precious metals from the electrolytic refining slimes in a precious metals circuit.

The copper ore concentrates received at the Smelter is first dewatered, and then dried to reduce the moisture content. The dried concentrate then is blended with fluxes and secondary copper-bearing materials. This mixture is fed to a flash smelting furnace where the ore is melted and reacts to produce copper matte, a molten solution of copper sulfide mixed with iron sulfide. The Outokumpu flash smelting process used at the Smelter is a closed process that captures the SO₂ rich off-gases from the furnace for the production of sulphuric acid. The copper matte from the smelting furnace next is converted to blister copper (approximately 98% pure copper) by oxidization to remove remaining sulfur as SO₂ gas and the iron as a ferrous oxide slag. The Smelter uses a continuous copper converting process in which solid matte granules are fed to a flash smelting furnace-like vessel. The molten slag from converting is cooled, processed in slag concentrators to remove residual copper, and ultimately disposed in on-site waste piles. The SO₂ gases from smelting and converting are vented to a sulfuric acid plant. Molten blister copper is transferred from the converting vessel to an anode furnace for fire-refining to further remove residual impurities and oxygen. The blister copper is reduced in the anode furnace to remove oxygen by injecting natural gas producing a high purity copper. The molten copper from the anode furnace is poured in molds to cast solid copper ingots called anodes.

The anode copper produced at the Smelter is moved to the copper Refinery co-located near the Smelter where it is further purified using an electrolytic process to obtain the high-purity cathode copper sold. The Refinery uses the Kidd Process technology. For this process, the copper anodes from the Smelter are submerged in tanks containing an electrolyte solution in batch operations. An electric current is applied to the tank for a 10-day period during which copper ions migrate from the anode to form a cathode of 99.99% pure copper. Precious metals (gold, silver) are recovered from the electrolytic refining slimes removed from the tanks in a series of hydrometallurgical operations.

The Smelter, Refinery, and MAP together have over 70 individual sources. The Smelter

recently had UDAQ permitting actions. A modified approval order (AO) was issued for the Smelter on June 10, 2014. AO DAQE-AN0103460054-14 allows the Smelter to operate a crushing and screening plant and significant modifications were made to the Smelter AO in the last 5 years.

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source maximum achievable control technology (MACT) standard (40 Code of Federal Regulations [CFR] 63 Subpart (Environmental Protection Agency, 2002) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEEEE)(Environmental Protection & Agency, 2007). Specific discussion of the unique aspects of pollution controls at the Smelter are included in the Federal Register notices associated with the draft((Environmental Protection Agency, 2006) and final promulgation of both rules. Both standards establish a separate category for only the Smelter due to its unique design and emission performance not achievable by conventional technology. The primary copper smelting area source MACT standard specifically identifies the Smelter main stack emission performance as MACT for copper smelters (existing sources, not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA’s designation of the modernized Smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred after promulgation of the MACT standards.

AO DAQE-AN01013460045-10 for the Refinery was issued in 2010 to add the combined heat and power (CHP) unit. The CHP unit utilizes SoLoNO_xTM burners minimizing NO_x emissions from the unit. The Smelter and Refinery facilities operate under a single Title V Operating Permit # 3500030003.

The MAP facility will process molybdenum disulfide into molybdenum trioxide and ammonia. The MAP facility was originally permitted in 2008 and was modified in March 2013 (AO DAQE-AN0103460052-13) to reflect the updated design of the plant. The permitting actions require thorough control technology analysis and the plant will implement BACT to minimize emissions from the facility.

1.3 Facility 2016 Baseline Emissions

Site-wide 2016 Actual Emissions (tons/yr) for Refinery and Smelter.

PM _{2.5}	NO _x	SO ₂	VOC	NH ₃
420.01	159.96	704.35	10.38	5.62

1.4 Facility Criteria Air Pollutant Emissions Sources

Emission Unit	Potential to Emit (TPY)				
	PM _{2.5}	NO _x	SO ₂	VOC	NH ₃

MAP	9.99	35.57	2.43	6.71	0.00
Refinery	25.64	38.57	4.44	8.42	0.61
Smelter	426.35	185.29	1,085.72	13.50	

The following emission units are not source specific. A separate BACT analysis has been conducted on these common emission units. The technical support for these sources is in the PM_{2.5} Serious SIP – BACT for Small Source document (“PM_{2.5} Serious SIP – BACT for Small Sources,” 2017).

MAP

Cooling Tower
IT Building Backup Generator
Emergency Fire Water Pump
Startup Boiler
Briquette Dryers
Additional Boiler
Testing Laboratory

Refinery

Space Heaters
Gasoline Fueling
Cooling Tower #1
Cooling Tower #2
Degreasing
Paint
Primer Diesel Generators
Refinery LPG Emergency Communication generator

Smelter

10 Cold solvent degreaser part washer
Carpenter Shop
Cyclone
Lab Baghouse (BH)
Fueling
Feed Strg Xfer Belt BH
Feed Strg Bldg BH
Feed Xfer Belt BH
Wet Feed BH
Dry Feed BH
Limestone Silo BH
Ground Matte Silo BH

Silo BH
Power House Cooling Tower
Granulator Cooling Tower
Acid Plant Cooling Tower
Loading to Storage Pile on Patio
Emergency backup power generator
Emergency backup power generator
Diesel generator
Misc. Storage Piles & Loadout
Vacuum Cleaning System
Mold Coating Silo BH
Recycle and Crushing Building
Anode Area Lime Silo
Secondary Gas System Lime Silo
Diesel Compressor
Smelter LPG Emergency Communication generator

2.0 BACT Selection Methodology

The general procedure for identifying and selecting BACT is through use of a process commonly referred to as the “top-down” BACT analysis. The top-down process consists of five steps which consecutively identify control measures, and gradually eliminate less effective or infeasible options until only the best option remains. This process is performed for each emission unit and each pollutant of concern. The five steps are as follows:

1. **Identify All Existing and Potential Emission Control Technologies:** UDAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to: federal regulations, Utah regulations, regulations of other states, the RBLC, recently issued permits, and emission unit vendors.
2. **Eliminate Technically Infeasible Options:** Any control options determined to be technically infeasible are eliminated in this step. This includes eliminating those options with physical or technological problems that cannot be overcome, as well as eliminating those options that cannot be installed in the projected attainment timeframe.
3. **Evaluate Control Effectiveness of Remaining Control Technologies:** The remaining control options are ranked in the third step of the BACT analysis. Combinations of various controls are also included.
4. **Evaluate Most Effective Controls and Document Results:** The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked options. This evaluation includes energy, environmental, and economic impacts of the control option.

5. Selection of BACT: The fifth step in the BACT analysis selects the “best” option. This step also includes the necessary justification to support the UDAQ’s decision.

Should a particular step reduce the available options to zero (0), no additional analysis is required. Similarly, if the most effective control option is already installed, no further analysis is needed.

The final BACT evaluations for the Kennecott MAP, Refinery and Smelter sites were performed using data that Kennecott submitted (CH2M, 2017), (CH2M, 2018), comments received from Techlaw on the Kennecott RACT submittal, comments received from EPA, comments received from the public, AOs, and the Title V permit.

2.1 Emission Unit (EU) and Existing Controls

Refinery

- 2.1.1 Boilers
- 2.1.2 CHP Unit
- 2.1.3 Hydrometallurgical Precious Metals Processing
- 2.1.4 Tankhouse Sources

Description:

The copper refining and precious metal recovery used at the Refinery are hydrometallurgical processes. Because these processes do not require the materials to be molten and instead are handled in a wet or moist form, most of these individual sources on an annual basis emitted less than the 2 tons of a single. The major sources of PM_{2.5} and PM_{2.5} precursors at the Refinery are the Refinery boilers, and the combined heat and power (CHP) unit (a stationary combustion turbine with a heat recovery steam generator equipped with a natural gas-fired duct burner).

Emission Unit	Potential to Emit (TPY)				
	PM _{2.5}	NO _x	SO ₂	VOC	NH ₃
Boilers	0.76	12.90	0.06	0.55	
CHP Unit	11.8	24.9	1.2	6.3	0.32
Cooling Towers	5.50				
Propane Communications Generator		0.28		0.04	
Degreasers				0.06	
Fueling Stations				0.24	
Emergency Generator	0.013	0.181	0.012	0.015	
Soda Ash Storage Silo	0.05				
Precious Metal Packaging Area	2.00				
Hydrometallurgical Precious Metals Processing	2.70		3.10		0.61

Tankhouse Sources 1.92

The emissions for the Refinery are combined with the Smelter. The 2014 Actual Emissions (tpy) for the Refinery and Smelter as listed in the emissions inventory are as follows:

PM _{2.5}	NO _x	SO ₂	VOC	NH ₃
420.01	704.35	159.96	10.37	5.62

2.1.1 Boilers

Description:

The two boilers are each rated at 82 MMBtu/hr when burning natural gas and 79 MMBtu/hr when burning fuel oil and are permitted to operate on natural gas to meet the steam demand at the Refinery. During natural gas curtailment, the boilers are permitted to operate on oil. Emissions of NO_x are limited with flue gas recirculation (FGR) and low NO_x burners (LNB) with good combustion practices. Emissions of PM_{2.5}, SO₂, and VOCs are limited with good combustion practices, good design, opacity limits, sulfur content limit, and proper operation of the boilers.

Emissions Summary:

The potential to emit emissions (tons/yr) for both boilers are as follows:

PM _{2.5}	SO ₂	NO _x	VOC	NH ₃
0.76	0.06	12.90	0.55	0.32

Pollutant [(NO_x)]

Control Options:

Selective Catalytic Reduction (SCR)
FGR
LNB with good combustion practices
Ultra-low-NO_x burners (ULNB) with good combustion practices

Technological Feasibility:

All control technologies are technically feasible. The Refinery boilers are equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR will reduce the emissions by 90%. This will be from 12.9 tpy (based on based on 2016 actual emissions for both boilers or 6.45 tpy per boiler) to 1.29 tpy. This is 11.61 tpy reduction in NO_x.

The SCR will reduce the emissions by 90% and replacing the boiler with one that has ULNB will reduce the emissions from 50 ppm to 9 ppm. The SCR is a 90% reduction

whereas the ULNB would only be an 82% reduction.

Economic Feasibility:

From the Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boilers, 1994 Alternative Controls Techniques (ACT) document, Table 6-7 presents controlled NO_x emission rates for various control technologies (U.S. Environmental Protection Agency, 1994). For the 50 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.02 lb/MMBtu (the 100 MMBtu/hr boiler controlled NO_x emission rate with SCR is listed at 0.03 lb/MMBtu). From Table 6-5 of the ACT document, the total annualized cost for the 50 MMBtu/hr gas boiler (closest entry to 82 MMBtu/hr Refinery boiler) is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74. The estimated cost for the Refinery boilers is \$428,040 for both boilers, this is \$214,020 per boiler.

Based on the costs for the SCRs of \$428,040, and 11.61 tpy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$36,868 for the Refinery boilers. Based on this cost, it is not cost effective to install an SCR on both boilers.

Replacing the burners with ULNBs will result in an 82% reduction. This would decrease the emissions from 6.45 tpy to 1.16 tpy (5.29 tpy reduction). In a comparable boiler upgrade that resulted in ULNBs being installed that were rated at 9 ppm NO_x the cost was \$900,000. This included upgrading the boiler and the building to include the additional equipment required for ULNBs. The estimated cost for the ULNB is \$900,000, and over a 15 year amortization period at 5% interest, the annual payment is \$86,708 per year per boiler for the ULNB.

Based on the annualized costs for the ULNB over a 20 year period of \$109,941 (Cleaver Brooks, 2017), and 3.29 tpy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$33,379 per boiler. If one of the boilers is replaced and the other is on standby, then the cost is \$26,594 per ton of NO_x removed for one boiler and \$43,638 per ton of NO_x removed for the other boiler. Based on this cost, it is cost effective to install ULNBs on the one of the boilers.

BACT Selection:

FGR, good combustion practices, good design, and proper operation and an ULNB on each boiler constitute BACT for this source.

Implementation Schedule:

The next shutdown at Kennecott is scheduled for 2020. Installation of an ULNB on one of the boilers can be completed by December 2020 (Steve Schnoor, 2018).

Pollutant [PM_{2.5}, SO₂ and VOC]

Control Options:

Use of pipeline quality natural gas
Good combustion practices

Good Combustion Practices

Several operations are listed in the U.S. EPA's RBLC database where good combustion practices are the accepted technology for minimizing particulate emissions. Particulate emissions are reduced by good combustion practices by keeping the burners maintained properly so that they continue to operate according to their design.

Use of Natural Gas as Fuel

Particulate emissions from combustion of natural gas are typically very low and generally lower than from combustion of other fuels such as diesel. KUC currently employs natural gas as fuel for control of particulate emissions from combustion sources at the facility and fuel oil as a backup.

Technological Feasibility:

All control technologies are technically feasible.

Economic Feasibility:

All control technologies are economically feasible. Therefore, an economic feasibility was not performed.

BACT Selection:

Use of pipeline quality natural gas, good combustion practices, and good design and proper operation constitute is BACT for the boilers.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Refinery Boilers are designed to be operated 24 hours per day, seven days per week to meet steam demands of the facility. The boiler load is adjusted based on the facility steam demand and the CHP Unit operations. The Boilers may undergo a shutdown for maintenance activities, planned facility shutdowns, or if affected due to a natural gas curtailment. These operating practices limit the emissions for startup/shutdown procedures.

FGR, LNBs, SCR and good combustion practices will control emissions during startup/shutdown. Good combustion practices and proper operation of the boiler include good engineering design, adherence to operation and maintenance procedures, inspections, use of clean burning fuel, and burner optimization analysis.

2.1.2 CHP

The CHP unit will generate power and steam to support Refinery operations. The CHP unit uses a low NO_x duct burner and the turbine has SoLoNO_x burners. Emissions of PM_{2.5}, SO₂, and VOC are limited with good design and proper operation.

Emissions Summary:

The potential to emit emissions (tons/yr) for the CHP unit are as follows:

PM _{2.5}	SO ₂	NO _x	VOC
8.68	1.24	29.79	6.74

Pollutant [NO_x]

Control Options:

SCR
LNB with good combustion practices

The CHP unit is equipped with LNB on the duct burner and SoLoNO_x technology burners on turbine to reduce NO_x emissions.

Technological Feasibility:

All control technologies are technically feasible. The addition of the SCR will reduce actual annual emissions from the CHP unit by 90% (CH2M, 2017). This would reduce the NO_x emissions from 29.79 tpy (based on Revised NOI Spread sheet submitted November 9, 2009 NOI) to 2.98 tpy.

Economic Feasibility:

The addition of the SCR will reduce actual annual emissions from the CHP unit by 90%. This will reduce the NO_x emissions from 12.24 tpy (used the lesser increase as shown in the 2010 AO) to 1.50 tpy. Solar Turbines, Inc. developed an estimation spreadsheet for the Taurus 70 combustion turbine and duct burner arrangement, which utilized vendor quotations for the installation of an SCR system. From the Solar calculations, the capital and operating costs were estimated to be \$932,100 per year.

Based on the annual \$932,100 cost for the SCR and a 13.49 tpy reduction in NO_x, which makes the cost of additional control per ton of NO_x removed to be \$69,096 per ton of NO_x removed for the CHP. Based on this cost, it is not cost effective to install an SCR on the CHP.

BACT Selection:

FGR, LNB with good combustion practices, good design, and proper operation constitute BACT for this source.

Implementation Schedule:

Proper operations are already in place.

Pollutant [PM_{2.5}, SO₂ and VOC]

Control Options:

Use of pipeline quality natural gas
Good combustion practices

Good Combustion Practices

Several operations are listed in the U.S. EPA's RBLC database where good combustion practices are the accepted technology for minimizing particulate emissions. Particulate emissions are reduced by good combustion practices by keeping the burners maintained properly so that they continue to operate according to their design.

Use of Natural Gas as Only Fuel

Particulate emissions from combustion of natural gas are typically very low and generally lower than from combustion of other fuels such as diesel. KUC currently employs natural gas as fuel for control of particulate emissions from combustion sources at the facility.

Technological Feasibility:

All control technologies are technically feasible.

Economic Feasibility:

All technically feasible options are already implemented, no additional technologies were identified. Therefore, an economic feasibility was not performed.

BACT Selection:

Use of pipeline quality natural gas, good combustion practices, and good design and proper operation constitute is BACT for the boilers.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Refinery CHP is designed to be operated 24 hours per day, seven days per week to The Refinery CHP unit is designed to be operated 24 hours per day, seven days per week. CHP may be shutdown for scheduled maintenance activities, planned facility shutdowns, or if affected due to a natural gas curtailment.

Low NO_x burners, SoLoNO_x, and good combustion practices will control emissions during startup/shutdown. Good combustion practice and proper operation of the unit include good engineering design, adherence to operation and maintenance procedures, inspections, use of clean burning fuel, and burner optimization. Standard operating procedures will be developed for the CHP unit to ensure operation in accordance with the above practices. These practices are already in place and effective in minimizing emissions during periods of startup and shutdown.

2.1.3 Hydrometallurgical Precious Metals Processing

The Refinery has a precious metals processing and recovery area. Particulate matter, ammonia and SO₂ from the process are vented to a scrubber.

Emissions Summary:

Pollutant [PM_{2.5}, SO₂ and NH₃]

Control Options:

Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses and wet scrubbers.

Technological Feasibility:

The fabric filter (baghouse) is more effective at capturing fine particulate. However, due to high temperature of the exhaust steam and its pH level, baghouses are not technically feasible. Wet scrubbers are therefore the only technically feasible control of particulate emissions and SO₂.

Economic Feasibility:

All technically feasible options are already implemented. Therefore, an economic feasibility was not performed.

BACT Selection:

Scrubbers are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2016 actual PM_{2.5} and precursor emissions from the processes were 0.58 tpy. The use of scrubbers to control particulate emissions, ammonia and SO₂ also represents the most stringent measure for the precious metals processing area.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

There are no startup/shutdown operations to be considered for these sources.

2.1.4 Tankhouse Sources

The Refinery Tankhouse and MPC buildings include liberator, cathode wash and anode scrub wash processes that result in sulfuric acid mist emissions. Potential sulfuric acid mist from the processes are vented to a mist eliminator. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Emissions Summary:

Pollutant [PM_{2.5}]

Control Options:

Baghouses
Scrubbers
Mist eliminators

Although review of other nonattainment areas, RBLC and CARB did not provide controls for the specific operation, and possible sulfuric acid control technologies.

Technological Feasibility:

The presence of acid in the exhaust stream cannot be effectively captured by a baghouse. Therefore, Baghouses are not technically feasible for these sources. The presence of electrolytes in the exhaust stream cannot be effectively captured with a wet scrubber. Therefore, wet scrubbers are not technically feasible for these sources. Mist eliminators are technically feasible and effective in minimizing sulfuric acid mist emissions.

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Economic Feasibility:

No additional technologies were identified as technologically feasible. Therefore, an economic feasibility was not performed.

BACT Selection:

Mist eliminators are the most effective control technology for controlling sulfuric acid mist emissions and constitute BACT.

It should be noted that the 2016 actual sulfuric acid mist as PM2.5 emissions from the Tankhouse sources were 0.005 tpy. The use of mist eliminators to control sulfuric acid mist emissions also represents the most stringent measure for the Tankhouse sources.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

There are no startup/shutdown operations to be considered for these sources.

2.3 EU and Existing Controls

Smelter

- 2.3.1 Main Stack
- 2.3.2 Powerhouse Holman Boiler
- 2.3.3 Soda Matte and Slag Granulators
- 2.3.4 Feed Process (Wet and Dry)
- 2.3.5 Feed Storage Building
- 2.3.6 Anode Area Fugitives
- 2.3.7 Smelter Fugitives
- 2.3.8 Acid Plant Fugitives
- 2.3.9 Powerhouse Foster Wheeler Boiler
- 2.3.10 Miscellaneous Storage Piles/Loadout
- 3.2.11 Hydrometallurgical Precious Metals Processing
- 2.3.11 Slag Concentrator
- 2.3.12 Smelter Cooling Towers
- 2.3.13 Ground Matte Silo
- 2.3.14 Molding Coatings Storage Silo

- 2.3.15 Lime Storage Silos
- 2.3.16 Limestone Storage Silo
- 2.3.17 Recycle and Crushing Building
- 2.3.18 Smelter Laboratory
- 2.3.19 Propane Communications Generator
- 2.3.20 Cold Solvent Degreaser
- 2.3.21 Gasoline Fueling Stations
- 2.3.22 Diesel Emergency Generator for Pyrometallurgical
- 2.3.23 Hot Water Boiler

Description:

The Smelter is the only primary copper smelter in the United States that uses flash smelting with continuous flash copper converting technology.

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 CFR 63 Subpart QQ) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the Smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules (e.g., the design of the Smelter is based on the furnace technology). Both standards go so far as to establish a separate category for the Smelter due to its unique design and emission performance not achievable by conventional technology. Typical smelting operations require batch processing which intermittently produces high concentrations of SO₂ and particulate in a manner that can reduce the efficiency of the acid plant as a control device. By employing the flash smelting and flash converting technologies, KUC can eliminate many of the problems inherent with batch type smelter operations. These technologies include continuous flow of off-gases to the acid plant during the flash converting process as well as reduced total volume of off-gases. Additionally, the furnaces are stationary which improves the ability to capture the off-gases as well as the ability to capture any fugitive emissions with the secondary capture system, which cleans the gases with baghouses and scrubbers before venting to the main stack. As a result, both MACT standards go so far as to establish a separate category for the Smelter due to its unique design and emission performance not achievable by conventional technology.

The primary copper smelting area source MACT standard specifically identifies the Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). The Smelter employs several technologies to minimize the smelting emissions that report to the main stack.

The concentrate dryer burns natural gas to heat/dry concentrate for use in the flash smelting furnace. Operation with LNB along with lower dryer temperatures minimizes the formation of NO_x while also preventing the formation of SO₂. KUC operates both a baghouse and a scrubber as controls for the concentrate dryer.

The secondary gas system collects fugitive emissions in the hot metals building (typically associated with the furnaces) and vents them through a baghouse and a sodium based scrubber before they are vented to the main stack.

The matte grinding circuit crushes and dries granulated matte for use in the flash converting furnace. The particulate from the ground matte is collected in a baghouse and pneumatically conveyed to the flash converting furnace feed bin. NO_x emissions from natural gas combustion are minimized with LNB and low temperature firing and PM_{2.5} emissions are controlled with the production baghouse.

In the anodes area, blister copper from the flash converting furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap, which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the main stack. NO_x reduction activities also include maintaining furnaces to prevent ingress of air.

The shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. LNBs are used to reduce NO_x from the natural gas combustion and a baghouse is operated to control PM_{2.5} emissions. The shaft furnace is in the anodes area, but vents separately to the main stack.

Emission Unit	Potential to Emit (TPY)			
	PM _{2.5}	NO _x	SO ₂	VOC
Main Stack	372.30	153.30	924.18	2.80
Powerhouse Holman Boiler	2.09	24.09	0.25	0.59
Matte and Slag Granulators	13.4		7.88	
Feed Storage Building	62.61			
Anode Area Fugitives		2.31		
Smelter fugitives			157	
Acid Plant fugitives	0.47		0.16	
Powerhouse Foster				
Wheeler Boiler	2.01	23.17	0.24	0.56
Miscellaneous Storage Piles/Loadout	2.15			
Slag Concentrator	3.00			
Smelter Cooling Towers	0.03			
Ground Matte Silo	1.20			
Molding Coating Storage Silo	1.20			
Lime Storage Silos	2.40			
Limestone Storage Silos	1.20			
Recycle and Crushing Building	0.11			
Smelter laboratory	1.80			
Cold Solvent Degreasers				1.00
Fueling stations				1.17

Diesel Emergency Generators	0.03	3.93	0.06	0.11
Hot Water Boiler	372.30	1.4	924.18	2.80

2.3.1 Main Stack

Description:

Emissions from multiple processes and equipment are routed through the main stack. The emissions from these sources are monitored at the main stack. PM_{2.5} is tested every year, and NO_x and SO₂ are monitored with continuous Emission Monitors (CEM). Processes routed to the stack include the matte granulators, acid plant, anode building, power house, furnaces, dryers and grinding circuits. Many of these sources of emissions have their own primary control devices (baghouse, scrubbers, etc.). Some are then routed to the secondary gas system and then through the main stack. The processes that vent to the main stack at the Smelter include the following:

<u>Equipment</u>	<u>Pollutants</u>	<u>Primary emissions control</u>
Concentrate Dryer Powerhouse	PM _{2.5} , SO ₂ , NO _x ,	LNB, baghouse, scrubber
Superheater	PM _{2.5} , SO ₂ , NO _x , VOC	ULNB, FGR, fuel throughput limits, Good operational practices
Powerhouse FW Aux Boiler	PM _{2.5} , SO ₂ , NO _x , VOC	LNB, FGR, fuel throughput limits, Good operational practices
Matte Grinding	PM _{2.5} , SO ₂	Baghouse
Anode Refining Furnaces	PM _{2.5} , SO ₂ , NO _x , VOC	Oxy-fuel burners, Baghouse, scrubbers
Anode Shaft Furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse
Anode Holding Furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse
Vacuum Cleaning System	PM _{2.5}	Baghouse
North and South Matte Granulator	PM _{2.5} , SO ₂	Scrubber, SGS baghouse, SGS Scrubbers
Acid Plant	SO ₂	Mist eliminators

Pollutant [PM_{2.5}, NO_x, SO₂, and VOC]

Control Options:

The primary copper smelting area source MACT standard specifically identifies the Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized Smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred after promulgation of the MACT standards.

Baghouses used to control particulate emissions from the concentrate dryer, matte grinding, anode furnaces and granulators are maintained regulatory and the bags are replaced as recommended by the vendors. The exhaust from these processes is at high temperature and low pH due to the acidic nature of the materials. Over the years, KUC has experimented with different types of bags, such as pleated bags, that are more effective in removing particulate. However, these bags could not provide optimum performance due to high temperature and low pH. Therefore, upgrading to different types of bags is not technically feasible for these processes.

Again, KUC maintains and replaces bags in these baghouses as recommended by vendors to maintain performance, pressure differential and particulate removal efficiency. The Smelter continues to be the cleanest Smelter operations in the United States. KUC reviewed emission reductions alternatives for anode furnaces venting through the main stack. The operations at the Smelter are continuously optimized to ensure high efficiency operation of the facility, including periodic upgrades of the burners to maintain optimum operations. KUC performed a pre-feasibility level study to evaluate NO_x emissions reductions options for the anodes furnaces at the Smelter. The study evaluated emission reduction strategies such as SCR, SNCR, oxidation systems and wet scrubbers.

Technological Feasibility:

All identified control technologies are technically feasible.

Economic Feasibility:

While all the identified technologies were determined to be feasible, each had significant energy and economic impacts. Based on the pre-feasibility study, the costs per ton of NO_x removed from these technologies ranges from \$55,000 to \$590,000 (CH2M, 2017). These costs are based on the pre-feasibility study and actual implantation costs are expected to be higher as major process and structural modifications would need to be made to implement these alternatives.

Therefore, NO_x emissions reduction technologies such as SCR, SNCR and wet scrubber

are not cost effective for BACT for the anode furnaces venting to the main stack.

BACT Selection:

Because no new major developments in technologies have occurred after the promulgation of the MACT standards, the control technologies currently in place constitute BACT.

Complying with applicable requirements of the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEEEE) represent the most stringent measure for the main stack.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

The emissions for the Smelter main stack, acid plant, and Holman boiler are limited during startup/shutdown by hourly limits for NO_x and/or SO₂. The emissions from the main stack and acid plant are monitored by CEMs, and the Holman boiler emissions are monitored by alternative monitoring.

Specific procedures for startup and shutdown have been developed for the Smelter. These procedures are developed based on design of its operations and best management practices.

2.3.2 Powerhouse Holman Boiler

The boiler is rated at 187 MMBTU and is used to provide process steam at the Smelter. Emissions of NO_x are limited with FGR, LNB, opacity limits, an alternative monitoring plan which requires continuous monitoring of operational parameters (fuel use, stack oxygen, steam output), and operational controls with good combustion practices. Emissions of PM_{2.5}, SO₂, and VOC are limited with use of pipeline quality natural gas, good combustion practices, gas consumption limit, good design, opacity limits, and proper operation of the boiler. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [NO_x]

Control Options:

SCR

FGR

LNB with good combustion practices

Ultra-low-NO_x burners (ULNB) with good combustion practices

Technological Feasibility:

All control technologies are technically feasible.

The SCR will reduce the emissions by 90% and replacing the boiler with one that has ULNB will reduce the emissions from 50 ppm to 9 ppm. The SCR will result in a greater reduction in NO_x than will the ULNB.

Economic Feasibility:

The Holman boiler is equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR would reduce the emissions by 90% from the boiler from 9.9 tpy (based on 2016 actual emissions) to 1.0 tpy.

From the Alternative Control Techniques (ACT) Document — NO_x Emissions from Industrial/Commercial/ Institutional Boilers, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5 of the ACT document, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from Consumer Price Index (CPI) Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the Holman boiler, the estimated cost is \$487,287. The annual estimated cost for the SCR.

Based on the annualized costs for the SCR over a 15 year period of \$487,287, and a 8.9 tpy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$54,751 for the Holman boiler. Based on this cost, it is not cost effective to install an SCR on the Holman boiler.

Replacing the burners with ULNBs will result in a 82% reduction. This would decrease the emissions from 9.9 tpy to 1.78 tpy. In a comparable boiler upgrade that resulted in ULNBs being installed that were rated at 9 ppm NO_x the cost was \$900,000. This included upgrading the boiler and the building to include the additional equipment required for ULNBs. The estimated cost for the ULNB is \$900,000, and over a 15 year amortization period with 5% interest, the rate is \$86,708 per year for the ULNB.

Based on the annualized costs for the ULNB over a 15 year period of \$86,708, and a 8.12

typy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$10,678 for the Holman boiler. Based on this cost, it is cost effective to install ULNBs on the Holman boiler.

On May 15, 2018, KUC submitted additional information (Process Combustion Systems, 2018) with revised costs analysis for the Holman boiler. The total capital cost is now \$3,069,851 with an annualized cost of \$360,584. This new cost analysis and with a NO_x reduction of 7.70 tons per year results in a cost per ton of NO_x removed at \$46,804 per ton. This makes it not economically feasible to upgrade the boiler.

BACT Selection:

Using the current FGR, with good combustion practices, limited gas consumption, good design, and proper operation constitute BACT for this source.

KUC continuously monitors operational parameters to predict NO_x emissions and ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lb/hr), stack oxygen (to monitor proper boiler operation and compliance with NO_x lb/MMBtu emission limit), and steam output (used to estimate heat input if fuel use is unavailable). The ranges for these parameters were developed during a 30-day monitoring campaign where data from a certified NO_x analyzer were used to develop predictive equations with the operation parameters.

Implementation Schedule:

Proper operations are already in place.

Pollutant [PM_{2.5}, SO₂, and VOC]

Control Options:

Use of pipeline quality natural gas and good combustion practices

Technological Feasibility:

All control technologies are technically feasible.

Economic Feasibility:

All technically feasible options are already implemented, no additional technologies were identified. Therefore, an economic feasibility was not performed.

BACT Selection:

Use of pipeline quality natural gas, good combustion practices, opacity limits, good design, and proper operation of the boiler constitute BACT for this emission source.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

The emissions for the Smelter main stack, acid plant, and Holman Boiler are limited during startup/shutdown by hourly limits for NO_x and/or SO₂. The emissions from the main stack and acid plant are monitored by CEMs, and the Holman Boiler emissions are monitored by alternative monitoring.

Specific procedures for startup and shutdown have been developed for the Smelter. These procedures are developed based on design of its operations and best management practices.

2.3.3 Matte and Slag Granulators

Matte and slag granulators are each equipped with a three-stage impingement plate scrubber. The Smelter operates two matte granulators and one slag granulator. The molten matte is granulated with water in two separate granulation tanks (two matte granulators), each equipped with a scrubber. The converter slag is granulated in a separate granulator (one slag granulator), also equipped with a scrubber. The matte granulators are vented through the main stack. The slag granulator is vented to the atmosphere through a separate stack. PM_{2.5} and SO₂ emissions are controlled by a neutral pH three stage impingement plate scrubber. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM_{2.5}, and SO₂]

Control Options:

Although review of other nonattainment areas, RBLC and CARB did not provide controls for these specific operations, other possible particulate control technologies include baghouses, cyclones, ESP, and scrubbers.

Technological Feasibility:

While baghouses are most effective in controlling particulate emissions, this technology is not feasible for the granulators. The exhaust from the granulators has very high moisture content, which is not suitable for baghouses. Moisture condensation can cause

accumulation of mud on the bags and baghouse walls. This results in blinded bags and clogged dust removal equipment. A dryer would have to be installed to remove the moisture from the exhaust before a baghouse could be used. This would increase PM, SO₂ and NO_x emissions. For these same reasons an ESP is also technologically infeasible. As discussed in the Western Regional Air Partnership (WRAP) Fugitive Dust Handbook, cyclones are mainly used to control large particles. Therefore, scrubbers are the only technically feasible option.

Economic Feasibility:

The only technically feasible options is already implemented, no additional technologies were identified. Therefore, an economic feasibility was not performed.

BACT Selection:

Scrubbers constitute BACT for the granulators. The use of scrubbers also represents the most stringent measure for both the matte and slag granulators.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

The emissions for the Smelter main stack are limited during startup/shutdown by hourly limits for NO_x and/or SO₂. The emissions from the main stack are monitored by CEMs.

Specific procedures for startup and shutdown have been developed for the Smelter. These procedures are developed based on design of its operations and best management practices.

2.3.4 Feed Process (Wet and Dry)

Silica flux, concentrate, and converter slag are transferred directly to feed bins then conveyed to the dryer. Particulate emissions from the loading of the flux and concentrate, and from transfer points of the conveyor are vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM_{2.5}]

Control Options:

Although review of other nonattainment areas, RBLC and CARB did not provide controls for these specific operations, other possible particulate control technologies include baghouses, cyclones, ESP, and scrubbers.

Technological Feasibility:

All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP, because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP and then by wet scrubbers.

Economic Feasibility:

All of the available control technologies are economically feasible. The most effective control technology, a baghouse, is already in place. Therefore, an economic feasibility was not performed.

BACT Selection:

Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT. The use of a baghouse to control particulate emissions also represents the most stringent measure for both the wet and dry feed process.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

2.3.5 Feed Storage Building

Wet copper concentrate feed is stored in the enclosed wet feed storage building. Particulate matter from loading materials into the feed storage building, from reclaiming materials, and from conveyor/transfer point SME 002-A, are vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM_{2.5}]

Control Options:

Although RBLC and CARB did not provide controls for these specific operations, other possible particulate control technologies include baghouses, cyclones, ESP, and scrubbers.

Technological Feasibility:

All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.

Economic Feasibility:

All of the available control technologies are economically feasible. The most effective control technology, a baghouse, is already in place. Therefore, an economic feasibility was not performed.

BACT Selection:

The use of enclosures and baghouse to control particulate emissions also represents the most stringent measure for the feed storage building.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments.

2.3.6 Anode Area Fugitives

Emissions from the anode building process are controlled with a baghouse, quench tower, and scrubber. However, some emissions can escape as fugitives. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM_{2.5}]

Control Options:

The review of other nonattainment areas, RBLC and CARB do not identify any specific control technologies for process fugitives. The MACT, however, does address such emissions.

40 CFR 63.11147(a)(3) states, “You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, re-melt anode copper, or re-melt anode scrap and convey each collected gas stream to a control device. One control device may be used for multiple collected gas streams.” KUC certified compliance with 63.11147(a)(3), as required by 63.11150(b)(4), in a letter dated and received by UDAQ on January 30, 2007.

40 CFR 63.11150(b)(4) states “Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11147(a)(3): “This facility complies with the requirement to capture gases from operations in the anode refining department and convey them to a PM control device in accordance with § 63.11147(a)(3).”

Technological Feasibility:

Current anode process units and the collection hoods on anode building processes have been designed to collect fugitives.

Economic Feasibility:

All of the available control technologies are economically feasible. The most effective control technology, a baghouse, quench tower, and scrubber, are already in place. Therefore, an economic feasibility was not performed.

BACT Selection:

In addition to opacity limits and required maintenance, collection hoods have been engineered/ designed to reduce fugitives and the current design of anode process units and the collection hoods on anode building processes practices constitute BACT. The current design of anode process units and the collection hoods on anode building

processes were engineered/designed to reduce fugitives and these represent the most stringent measure.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

2.3.7 Smelter Fugitives

Emissions from Smelter processes are controlled with appropriate control technologies including closed processes, launder hoods and others outlined below. However, some emissions can escape as fugitives. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM2.5]

Control Options:

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 CFR 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the Smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules. Regarding the design and fugitive emission controls of the Smelter, the EPA provided the following discussion when promulgating the final copper smelting MACT standard (FR Vol. 67, No. 113, Page 40488):

Due to its unique design and operations, most of the process fugitive emission sources associated with smelters using batch converting are eliminated at the Smelter. There are no transfers of molten material in open ladles between the smelting, converting, and anode refining departments at the Smelter. In addition, there are no fugitive emissions associated with the repeated rolling-out of converters for charging, skimming, and pouring. Also, only one continuous flash converter is needed at the Smelter compared with the need for three or more batch copper converters at the other smelters.

Both standards go so far as to establish a separate category for only the Smelter due to its unique design and emission performance not achievable by conventional technology. Smelter process and emission controlling technologies that contributed to the EPA's designation of the modernized Smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and

precursor emissions. No new major developments in technologies or costs have occurred after the promulgation of the MACT standards.

Specific notes regarding control techniques listed in Table 5 of Attachment 5 of the EPA comments are listed below:

- a. Smelter hot metals operations are serviced by an extensive local ventilation (secondary gas) system. This system collects gasses and routes them through baghouses and scrubbers before venting them to the main stack where they are continuously monitored for multiple pollutants.
- b. Smelter hot metals operations are completely enclosed in a building.
- c. KUC processes only grade 1 scrap in its melting furnaces.
- d. A leak detection/prevention/repair program is not applicable to Smelter furnaces and hot metals process units because they are enclosed and operate at negative pressure due to their inherent design.
- e. Because KUC furnaces are enclosed and do not require open air transfer of molten metal, they are not dependent on hooding systems for process gas collection.
- f. It is not necessary to add curtains to improve hood performance at the Smelter as the process does not rely on hoods to capture process gasses.
- g. The KUC process does not require the open-air transfer of molten metal from smelting to converting vessels so it is not necessary to collect these emissions.
- h. The EPA noted in the primary copper smelting MACT standard, KUC was the first smelter in the United States to capture and control emissions from anode refining furnaces.

Technological Feasibility:

Not applicable due to the design of the smelting, converting, and anode refining at the Smelter.

Economic Feasibility:

Not applicable.

BACT Selection:

Best operational practices may include, (1) placement or adjustment of negative pressure ductwork and collection hoses, (2) welding of process gas leaks, or (3) containment of process gas leaks. These practices and current design of processes were engineered/designed to reduce fugitives and therefore constitute BACT.

The best operational practices currently implemented and the current designs of the processes also represent the most stringent measure for the acid plant fugitives.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations:

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

2.3.8 Acid Plant Fugitives

The double contact acid plant removes SO₂ from the off-gases of the flash furnaces. The sulfuric acid produced by the plant is sold. Among other technologies, the system is equipped with tubular candle fiber mist eliminators and the tail gas is discharged to the main stack. However, some emissions can escape as fugitives, which are controlled using best operational practices to minimize emissions. Best operational practices to minimize the emissions include opacity limits, weekly visual opacity surveys and the requirement of prompt repair or correction and control to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [SO₂]

Control Options:

Review of other nonattainment areas, the RBLC and CARB do not identify any specific control technologies for such fugitives.

Technological Feasibility:

No controls identified to conduct a feasibility study.

Economic Feasibility:

No controls identified, therefore, an economic feasibility was not performed.

BACT Selection:

Best operational practices may include, (1) placement or adjustment of negative pressure ductwork and collection hoses, (2) welding of process gas leaks, or (3) containment of process gas leaks. These practices and current design of processes were engineered/ designed to reduce fugitives and therefore constitute BACT.

The best operational practices currently implemented and the current designs of the processes also represent the most stringent measure for the acid plant fugitives.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

2.3.9 Powerhouse Foster Wheeler Boiler

This boiler is used to produce superheated steam to start the Smelter, drive acid plant compressors, and standby power. Emissions of NO_x are limited with FGR, LNB with good combustion practice, continuous monitoring of NO_x at the Smelter main stack, and limitations on fuel throughput. Emissions of PM_{2.5}, SO₂, and VOCs are limited with use of pipeline quality natural gas; good combustion practices; good design and proper operation of the boiler; and continuous monitoring of opacity, particulate, and SO₂ at the Smelter main stack. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [NO_x]

Control Options:

SCR

FGR

ULNB with good combustion practices

LNB with good combustion practices

Technological Feasibility:

All control technologies are technically feasible.

The SCR will reduce the emissions by 90% and replacing the boiler with one that has ULNB will reduce the emissions from 50 ppm to 9 ppm. The SCR will result in a greater reduction in NO_x than will the Ultra LNB.

Economic Feasibility:

The Foster Wheeler boiler is equipped with FGR and LNB to reduce NO_x emissions. Emissions from this boiler are vented through the main stack and it is difficult to differentiate the boiler NO_x emissions from the main stack emissions. Based on the understanding of operations at the Smelter, the addition of the SCR might reduce the annual emissions by 90% for the boiler from 5.3 tpy (based on 2016 actual emissions and engineering estimates) to 0.53 tpy.

From the Alternative Control Techniques Document – NO_x Emissions from

Industrial/Commercial/Institutional Boiler, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the powerhouse boiler the estimated cost is \$261,000.

Based on the annualized costs for the SCR of \$261,400, and a 4.77 tpy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$54,800 for the Foster Wheeler boiler. Based on this cost, it is not cost effective to install an SCR on the Foster Wheeler boiler.

Replacing the burners with ULNBs will result in an 82% reduction. This would decrease the emissions from 5.3 tpy to 0.95 tpy. In a comparable boiler upgrade that resulted in ULNBs being installed that were rated at 9 ppm NO_x the cost was \$900,000. This included upgrading the boiler and the building to include the additional equipment required for ULNBs. The estimated cost for the ULNB is \$900,000, and over a 15 year amortization period, this is \$86,708 per year for the SCR.

Based on the annualized costs for the ULNB over a 15 year period of \$86,708, and a 4.35 tpy reduction in NO_x, the cost of additional control per ton of NO_x removed is \$19,992 for the Foster Wheeler boiler. Based on this cost, it is cost effective to install ULNBs on the Foster Wheeler boiler.

On May 15, 2018, KUC submitted additional information (Process Combustion Systems, 2018) with revised costs analysis for the Holman boiler. The total capital cost is now \$3,069,851 with an annualized cost of \$360,584. This new cost analysis and with a NO_x reduction of 7.70 tons per year results in a cost per ton of NO_x removed at \$46,804 per ton. This makes it not economically feasible to upgrade the boiler.

BACT Selection:

Using the current FGR, with good combustion practices, limited gas consumption, good design, and proper operation constitute BACT for this source.

Implementation Schedule:

Proper operations are already in place.

Pollutant [PM_{2.5}, SO₂, and VOC]

Control Options:

Use of pipeline quality natural gas and good combustion practices

Technological Feasibility:

All control technologies are technically feasible.

Economic Feasibility:

All control technologies are economically feasible. Therefore, an economic feasibility was not performed.

BACT Selection:

Use of pipeline quality natural gas, good combustion practices, opacity limits, good design, and proper operation of the boiler constitute BACT for this emission source.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

The Smelter and associated equipment is designed to operate on a continuous basis. The operations are run in shutdown or startup modes during scheduled maintenance, plant shutdowns and during periods of natural gas curtailments

The emissions for the Smelter main stack are limited during startup/shutdown by hourly limits for NO_x and/or SO₂. The emissions from the main stack are monitored by CEMs.

Specific procedures for startup and shutdown have been developed for the Smelter. These procedures are developed based on design of its operations and best management practices.

2.3.10 Miscellaneous Storage Piles/Loadout

Concentrate, granulated matte, slag, and other materials are stored in storage piles on pads. Water sprays or chemicals are applied as necessary to minimize fugitive emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Control Options:

See control options for minor sources

2.3.11 Slag Concentrator

Emissions associated with the crushing, grinding, and slag processing at the Smelter are minimized with the water sprays and enclosures. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Pollutant [PM_{2.5}]

Control Options:

Baghouses
Cyclones
Scrubbers
Water sprays
Enclosures.

Technological Feasibility:

Baghouses are not feasible for the slag processing equipment. The slag stock piles are sprayed with water frequently to minimize emissions. The material as a result has very high moisture content, which is not suitable for baghouses. Moisture droplets and condensation can cause accumulation of mud on the bags, baghouse walls, and ductwork. This results in blinded bags and clogged dust removal equipment. Further, when ambient temperatures are below freezing, the mud will freeze on the baghouse bags and plug them.

Wet scrubbers are not expected to be effective in minimizing emissions from crushing and grinding operations. Operation of the scrubbers is compromised due to below freezing ambient temperatures and very cold water streams in the scrubber. The duct work of the scrubbers will freeze during subfreezing ambient temperature conditions. As discussed in the WRAP Fugitive Dust Handbook (Countess Environmental, 2006), cyclones are mainly used to control large particles.

Economic Feasibility:

The remaining technologies of water sprays and enclosures are economically feasible.

BACT Selection:

Water sprays and enclosures are used to minimize particulate emissions from the slag concentrator, which were demonstrated to be very effective. The use of water sprays and

enclosures to minimize particulate emissions represent the most stringent measure from the slag concentrator.

Implementation Schedule:

Proper operations are already in place.

Startup/Shutdown Considerations

There are no startup/shutdown operations to be considered for these sources.

2.3.12 Smelter Cooling Towers

Three noncontact water cooling towers are used for various Smelter processes. The towers are equipped with drift eliminators with drift a loss rated at 0.001 percent.

Control Options:

PM_{2.5} Emissions

PM_{2.5} emissions are generated as water evaporates from a cooling tower and small droplets of water become entrained in the air stream and are carried out as drift droplets. The drift droplets will often contain impurities from the water flowing through the system, so they are considered a type of emission (USEPA, 2015). These impurities are often from water treatment additives, such as anti-fouling or anti-corrosion additives, or from direct contact between the cooling water and the process fluid (Brady et al., 1998).

RBLC and Technical Documents

The following control technologies were identified as available options for PM_{2.5} emissions from cooling towers:

- Use of dry cooling (no water circulation) heat exchanger units
- High efficiency drift eliminators
- Limitations on TDS in the circulating water

Dry Cooling Towers

Dry cooling towers use fans to move dry ambient air through the towers and cool the process stream. Because these towers do not rely on the evaporation of water for heat transfer, they do not generate drift emissions (Baker et al., 2001).

Drift Eliminators

High efficiency drift eliminators remove droplets before the air is discharged to the atmosphere. Drift eliminators are rated by the percentage of emissions from the cooling tower water circulation rate. The drift rates in the RBLC database range between 0.0005% and 0.02%; the majority of drift rates reported are under 0.001%.

Limitations on TDS in Circulating Water

Dissolved solids in the circulating water increase in concentrations as the circulating water evaporates (USEPA, 2015). TDS can also occur as a result of the addition of anti-corrosion or anti-biocide additives. A filtration system can be used to reduce TDS concentrations in circulating water (Reisman & Frisbie, 2002). Monitoring the TDS content in circulation water is an effective approach to ensure that excess emissions are not generated as a result of high TDS levels in circulation water. The TDS concentration limitations in the RBLC database range between 1,000 mg/L and 6,009 mg/L.

VOC Emissions

VOC emissions are caused when a VOC-containing process stream contaminates circulation water due to a leak in the system or if the circulation water is treated with VOC-containing material (TCEQ, 2003). VOC emissions from cooling towers are more likely to occur in petroleum refineries or chemical manufacturing

RBLC and Technical Documents

Identifying leaks by routinely monitoring VOC concentrations in circulation water was the only control technology identified as an available option for VOC control from cooling towers.

Elevated VOC concentrations can be an indication of leaks in the system. By routinely monitoring VOC concentrations in circulation water, leaks can be identified and repaired. The El Paso Method is commonly used to monitor VOC concentrations in circulation water (TCEQ, 2003). TCEQ established a VOC concentration of 0.08 ppmw for identifying a leak in the system. The RBLC database identified a VOC limit of 0.05 ppm.

BACT Selection:

Evaluation of Findings & Control Selection:

The cooling towers operating at major sources in the PM_{2.5} nonattainment area are equipped with drift eliminators with loss rates ranging from 0.2% to 0.0005%. Routine monitoring of TDS concentrations in circulating water is a common operating practice for these cooling towers.

DAQ has determined that BACT for PM_{2.5} emissions from cooling towers is drift eliminators combined with TDS limitations. A specific drift eliminator efficiency and TDS limitation is not specified in this BACT analysis as these limitations are dependent on the specific cooling tower design and the industrial process.

DAQ has determined that BACT for VOC emissions from cooling towers is implementation of a leak detection program, in accordance to an applicable Subpart and/or with the El Paso Method. This is only applicable to process streams that may contain VOC or if the circulated water is treated with VOC-containing materials.

2.3.13 Ground Matte Silo, Molding Coatings Storage Silo, Lime and Limestone Storage Silos,

Ground matte material is stored in silos. Particulate matter from loading materials into the silos is vented to a baghouse. The 2016 actual PM_{2.5} emissions from the silo baghouse were 0.04 tpy.

Control Options:

The EPA and the State of Utah have regulations and requirements that apply to this process.

40 CFR 63 Subpart AAAAA applies to lime manufacturing plants that are major sources due to major HAP emissions. This subpart defines processed stone handling (PSH) to include bulk loading or unloading systems. Table 1 of this subpart applies to PSH operations and limits subject sources to the following (e-CFR, 2004):

- Fugitive Emissions –10%
- Stack emissions from all PSH –7%
- PM emissions must not exceed 0.05 g/dscm

40 CFR 60 Subpart OOO applies to nonmetallic mineral processing plants' enclosed truck or railcar loading stations. This subpart applies to this activity and limits PM emissions to 0.022 gr/dscf for any emission unit constructed between 8/31/1983 and 4/21/2008. Sources constructed or modified on or after 4/22/2008 must meet a limit of 0.014 gr/dscf. (e-CFR, 2009).

Utah rule R307-309 for Nonattainment and Maintenance Areas for PM₁₀ and PM_{2.5}: Fugitive Emissions and Fugitive Dust applies to this process. Specifically, R307-309-5: General Requirements for Fugitive Dust limits on-site fugitive dust opacity to 20% and 10% at the property boundary. Additionally, R307-309-6: Fugitive Dust Control Plan requires that sources create and follow a plan to reduce and mitigate fugitive dust emissions.

Other states have varying requirements for this process. New Jersey's State BART analysis from 2011 lists possible PM controls for this process as: particle enclosure and a fabric filter (pg.407); or ducting to a control system that has a bin vent filter with a 100% capture rate and a 0.02 gr/dscf filtration rate for PM₁₀ (pg. 467) (State of New Jersey Department of Environmental Protection, 2011). Missouri requires that all loadout operations be controlled by a baghouse ("DNR MACC- Permit to Construct: Mississippi Lime Company," 2015). The Nelson Lime Plant in Arizona was permitted with a baghouse controlling lime loadout into railcars and a subsequent emission limit of 0.01 gr/dscf ("Nelson Lime Plant - Permit #42782")

To meet these requirements possible controls include; using enclosed trucks during transport, utilizing a venting system controlled with vent, fabric filtered vents, or a baghouse ("Lime Handling Systems," 1984).

BACT Selection:

Both bin vents and baghouses are feasible options for lime silo controls. A baghouse can control multiple silos at once. The use of a baghouse may be more applicable depending on the operator's needs. Bin vents are an acceptable control for lime silos and operates independently on each silo. This control limits emissions during material transfers and movements. As the system is enclosed and the only venting point is through the silo vent, this control is considered BACT for this process.

2.3.14 Recycle and Crushing Building, and Smelter Laboratory

The matte and slag material is recycled and crushed in a building. Particulate matter from these small-scale operations are minimized as they occur inside the building and are controlled with a baghouse. The 2016 actual PM_{2.5} emissions from the Recycle and Crushing Building baghouse were 0.03 tpy.

Control Options:

Baghouses are considered a control for multiple source categories. There are no federal or state requirements that regulate baghouse selection or filter type. Typically, baghouse filters are rated with a control efficiency of 99%. Therefore, one percent of a source's emissions are vented into ambient air.

Potential controls for the emitted particulates include using a more efficient filter in the baghouse. While fabric filters are typically rated at 99% efficiency, newer filters are available with a rating at 99.9% ("San Joaquin SIP," 2015, "PTFE Membrane Baghouse Filters," 2017).

BACT Selection:

In some cases, using a more efficient filter is a cost effective, technically feasible control option that reduces particulate emissions. The higher efficiency filter bags require no additional operational or maintenance changes. The increased efficiency bags will reduce emissions and are considered BACT for this operation.

However, there are other operations where a higher efficiency bag is not technically feasible and/or cost effective.

Each site must evaluate the feasibility based on operation type and design.

In all operations, to ensure control efficiencies, operators must follow manufacturer recommended operation and maintenance. This includes monitoring and maintaining the pressure drop across filter bags, cleaning the filters, and replacing the filters as needed. This is considered standard practice for baghouse operations. (State of New Jersey Department of Environmental Protection, 2011).

In 40 CFR 63 Subpart X, §63.548, best practices include the development of a source baghouse leak procedure. The procedure includes daily pressure gauge inspections, weekly visual inspections of the dust collection hoppers, and quarterly inspections of the physical integrity of the bags and fans (“40 CFR 63.548”). This procedure could be implemented to all source categories using baghouses for controls.

2.3.15 Propane Communications Generator

The Smelter operates a propane fired communication generator. This generator is used to support communication systems during emergencies or loss of power at the Smelter. Emissions are controlled with good combustion practices while operating the generator.

Control Options:

The following sources were reviewed to identify available control technologies:

- EPA’s RBLC
- EPA's Air Pollution Technology Fact Sheets
- EPA’s Control Techniques Guidelines and Alternative Control Techniques Documents
- Various state regulations
- 40 CFR 60 Subpart JJJJ and 40 CFR 63 Subpart ZZZZ
- Various state-specific example permits
- A thorough literature search using the Google search engine

After a review of the above sources, the DAQ determined that many state and federal regulations provide specific exemptions for the control and applicability of various regulations and control devices to emergency engines. The following control options were found for controlling emissions from stationary natural gas-fired engines:

Control Options for NOX:

- Non-Selective Catalytic Reduction (for rich-burn engines with carburetors) (CleanAIR Systems, 2009)
- Exhaust Gas Recirculation (CS, 2009)
- Lean NOX Catalyst (for lean-burn engines) (CS, 2009)
- Selective Catalytic Reduction (for lean-burn engines) (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for VOC:

- Non-Selective Catalytic Reduction (for rich-burn engines) (CS, 2009)
- Oxidation Catalyst (for lean-burn engines) (CS, 2009)

Additional control options for all pollutants include replacement of older engines with new engines, and adherence to emission limitations contained in 40 CFR 60 Subpart JJJJ. 40 CFR 63 Subpart ZZZZ contains no additional requirements for emergency engines

beyond operational and maintenance practices. For older engines that do not comply with an emission limitation in 40 CFR 60 Subpart JJJJ, emissions could be controlled by one of the above methods.

BACT Selection:

Control Options for NO_x: The retrofit of an existing portable propane-fired emergency engine to become a low emissions combustion unit could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart JJJJ. This control selection is not applicable to newer engines. Therefore, the DAQ recommends as BACT a site-by-site analysis to determine as necessary if older engines need to be retrofitted to become low emissions combustion units.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for control of VOC emissions.

2.3.16 Cold Solvent Degreaser

Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis. The 2014 actual VOC emissions from the degreasers at the Smelter were 0.002 tpy.

Solvent degreasers are used to remove various contaminants from pieces of equipment. Solvent degreasing is the physical process of using an organic or inorganic solvent to remove tars, greases, fats, oils, waxes, or soil from metal, plastic, printed circuit boards, or other surfaces. This cleaning is typically done prior to such processes as painting, plating, heat treating, and machining, or as part of maintenance operations. The solvent containers can be horizontal or vertical. The solvent may be agitated. Agitation increases the cleaning efficiency of the solvent. Agitation can be used with pumping, compressed air, vertical motion, or ultrasonics.

Control Options:

- Carbon adsorption
- Refrigerated primary condensers
- Increased freeboard ratio
- Combination of covers
- Water covers
- Internal Draining Rack
- Spray hose/spray nozzle
- Reduced room drafts
- Selected operation and maintenance practices

BACT Selection:

Compliance with the requirements of R307-335 is considered BACT for solvent degreasers.

2.3.17 Diesel Emergency Generator for Pyrometallurgical Process

The Smelter operates one 998 HP diesel-fired emergency generator to support the pyrometallurgical process during emergencies. The emergency generator is equipped with turbo charger and after cooling and complies with applicable New Source Performance Standards to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis. The 2014 actual PM_{2.5} and precursor emissions from the generator were 0.78 tpy

Control Options:

Control Options for PM_{2.5}:

- Catalyzed Diesel Particulate Filter (CleanAIR Systems, 2009)
- Diesel Oxidation Catalyst (CS, 2009)
- Diesel Particulate Filter (CS, 2009)

Control Options for NO_x:

- Exhaust Gas Recirculation (CS, 2009)
- NO_x Adsorber Catalyst (CS, 2009)
- Selective Catalytic Reduction (CS, 2009)
- Turbocharging and aftercooling (US EPA, 1993)
- Engine Ignition Timing Retardation (US EPA, 1993)
- Modifying air-to-fuel ratio (US EPA, 1993)

Control Options for SO₂:

- Ultra-Low Sulfur Diesel Fuel (Bradley Nelson, 2010)

Control Options for VOC:

- Catalyzed Diesel Particulate Filter (CS, 2009)
- Diesel Oxidation Catalyst (CS, 2009)

BACT Selection:

Evaluation of Findings & Control Selection:

Control Options for PM_{2.5}: The DAQ did not find any PM_{2.5} controls that were cost effective for controlling PM_{2.5} emissions. Therefore, BACT for direct PM_{2.5} emissions is proper maintenance and operation of the emergency stationary diesel engine.

Control Options for NO_x: The installation of a new emergency stationary diesel engine subject to the newest requirements for stationary emergency engines as specified in 40 CFR 60 Subpart IIII could potentially be cost effective and feasible for this source category, depending on a site-by-site analysis. This is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII. This control selection is not applicable to newer engines. In the absence of replacing an old engine with a new engine, the installation of exhaust gas recirculation technology on older engines could be cost effective and feasible, again depending on a site-by-site basis of actual cost to retrofit the stationary emergency diesel engine on site. This control selection is assuming an old engine that is not currently subject to 40 CFR 60 Subpart IIII.

Control Options for SO₂: The DAQ recommends the use of ultra-low sulfur diesel fuel as BACT for SO₂ control.

Control Options for VOC: The DAQ did not find any VOC controls that were cost effective for controlling VOC emissions. Depending on the age of the engine and site-specific information, a diesel oxidation catalyst could be cost effective for controlling VOC emissions. However, the DAQ does not recommend a diesel oxidation catalyst as BACT for this source category due to the fact this control option is probably not cost effective. Therefore, the DAQ recommends proper maintenance and operation of the emergency stationary diesel engine as BACT for control of VOC emissions. A site-specific cost/ton removed could be derived for making a determination on the requirement of installing a diesel oxidation catalyst.

2.3.18 Hot Water Boiler

Natural gas-fired water boilers are used for water heating throughout the Smelter. The water boilers use low NO_x burners (LNB) and regular inspections are done to the units to ensure optimum combustion performance. The water heaters are rated at less than 10 MMBTU/hr. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis. The 2016 actual PM_{2.5} and precursor emissions from the generator were 0.61 tpy.

Control Options:

The following control technologies were identified as available options for PM_{2.5} emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Use of gaseous fuels
- Baghouses
- Cyclone
- Wet Scrubber
- Electrostatic Precipitators

The following control technologies were identified as available options for NO_x

emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Pre-combustion modifications (oven fire air, low excess air, air staging, etc)
- Combustion controls
- FGR
- Low NOX burners
- Ultra-low NOX burners
- SCR
- SNCR

The following control technologies were identified as available options for SO₂ emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Use of low sulfur fuels
- Wet Scrubbers

The following control technologies were identified as available options for VOC emissions from boilers with input ratings less than or equal to 10 MMBtu/hr.

- Good combustion practices
- Carbon Adsorption
- Thermal Oxidizers
- Catalytic Oxidizers

BACT Selection:

The economic feasibility analysis demonstrates that retrofit options and boiler replacements are generally not cost effective options for boilers under 5 MMBtu/hr. Retrofitting or replacing boilers between 5 and 10 MMBtu/hr could both be cost effective options depending on the boiler size, age, and hours of operation.

The estimated costs for low NO_x burner retrofits start at \$8,454 per ton of NO_x removed and boiler replacements start at \$13,542. Retrofitting or replacing existing low-NO_x boilers with ultra-low NO_x boilers also proved to be cost prohibitive. Retrofits costs start at \$24,735 per ton of NO_x removed and replacement costs start at \$46,173 (“PM2.5 Serious SIP – BACT for Small Sources,” 2017).

DAQ recommends the use of natural gas as primary fuel and good combustion practices as BACT for the existing boilers operating at major sources within the nonattainment area. Diesel or fuel oil may only be used as backup fuel or in areas where natural gas is not available. The sulfur content of any diesel or fuel oil burned shall not exceed 15 ppm by weight.

An evaluation to determine whether retrofitting or replacing boilers between 5 and 10

MMBtu/hr with low-NO_x or ultra-low NO_x burners is economically feasible should be conducted on a case-by-case basis.

3.0 Consideration of Ammonia

The only sources of ammonia emissions at the Refinery and the Smelter is from the SCRs that will be installed on the CHP, combustion of natural gas and the Hydrometallurgical Silver Production and the Refinery.

The unreacted ammonia can be treated as a PM_{2.5} precursor. Although ammonia was previously not considered as a precursor pollutant in Utah's PM_{2.5} Serious SIP, and the source's BACT analysis did not include an analysis of BACT for ammonia emissions, an analysis is being included here for completeness.

There are only sources of ammonia emissions at the Refinery and Smelter that could be controlled. The SCR units used to control emissions of NO_x from the CHP combustion turbine. The catalyst serves to lower the reaction temperature required and helps speed the process. Ideally, a stoichiometric amount of ammonia would be added – just enough to fully reduce the amount of NO_x present in the exhaust stream. However, some amount of ammonia will always pass through the process unreacted; and since the process possesses some degree of variability, a small amount of additional ammonia is added to account for minor fluctuations. The ammonia which passes through the process unreacted and exits in the exhaust stream is termed “slip” (sometimes “ammonia slip”). The amount varies from facility to facility, but ranges from almost zero to as high as 30 ppm in poorly controlled systems. Also, as catalyst systems degrade over time, the degree of ammonia slip will gradually increase as increasing amounts of ammonia are added to maintain NO_x reduction performance. The unreacted ammonia can be treated as a PM_{2.5} precursor.

Control Options:

There is only one control technique considered available for ammonia emissions. Monitoring of ammonia slip emissions and setting a “not to exceed” emission rate limitation. This allows for setting up a feedback process where the source can adjust ammonia injection rates based on both parameters: NO_x emission reduction levels and ammonia slip levels. Should catalyst activity, over time, degrade to the point where both parameters cannot be met, then the SCR catalyst should be replaced.

Technological Feasibility:

This represents a work practice standard, and is inherently technically feasible.

A review of recently issued permits for SCR units at large combustion turbine installations reveals NH₃ emission limits ranging between 2.0 ppm and 5.0 ppm.

The source has not provided a cost effectiveness breakdown for upgrading the ammonia

injection systems at the Refinery and Smelter so that a limitation could be established. This is not an easy task, as it is not as simple as merely upgrading the injection system. An entire SCR upgrade might be required to guarantee that the SCR unit itself was still operating with required removal efficiency at the tighter ammonia injection levels. Increased monitoring would also be required.

Economic Feasibility:

All control technologies are economically feasible. Therefore, an economic feasibility was not performed.

BACT Selection:

Given the difficulty in redesigning a new SCR system for control of a pollutant not currently listed as a precursor pollutant, and the expected high cost for this process, no change in ammonia slip requirements is recommended at this time. Retention of the existing ammonia slip design parameter of 10 ppm as a limitation is recommended as BACT. Existing work-practice standards should suffice to minimize emissions.

Implementation Schedule:

A proper design of the SCRs when they are installed to limit the ammonia slip.

Startup/Shutdown Considerations

There are no startup/shutdown operations to be considered for these sources.

4.0 Conclusion- Emissions Reduction through BACT implementation

4.1 Reduction in emissions at the Refinery

One of the boilers at the Refinery will be upgraded with ULNB. Currently the annual emission rate is 12.9 tpy and will be reduced by 11.61 tpy to 1.29 tpy. The installation of the ULNBs will be by December 2020.

PM_{2.5}, SO₂ and VOCs are estimated to remain the same.

4.1 Reduction in emissions at the Smelter

Reduction in NO_x limit on Holman boiler from 14.0 to 9.0 lbs per hour.

5.0 Implementation Schedule and Testing Requirements

5.1 Refinery

Installation of ULNBs on one the boilers by December 2020.

5.2 Smelter

Installation of ULNBs on the boilers by December 2019.

Currently the limit for the Holman boiler is 14.0 lbs/hr (calendar-day average). This will be reduced to 9.0 lbs/hr (calendar-day average).

Currently there are no testing limits on the Foster Wheeler boiler. The boiler is rated at 100 MMBTU/hr and using the same emission factor as the Holman boiler which is 0.05 lb NO_x/MMBTU, the emission rate is 5.0 lb/hr.

6.0 New PM_{2.5} SIP – KUC Smelter and Refinery Specific Requirements

The Smelter and Refinery specific conditions in Section IX.H.12 address those limitations and requirements that apply only to the Smelter and Refinery in particular.

n. Kennecott Utah Copper: Smelter and Refinery.

i. SMELTER:

A. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

I. Main Stack (Stack No. 11)

1. PM_{2.5}
 - a. 85 lbs/hr (filterable)
 - b. 434 lbs/hr (filterable + condensable)
2. SO₂
 - a. 552 lbs/hr (3 hr. rolling average)
 - b. 422 lbs/hr (daily average)
3. NO_x 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
 - a. 9.0 lbs/hr, (calendar-day average)

B. Stack testing to show compliance with the emissions limitations of Condition (A) above shall be performed as specified below:

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)	PM _{2.5} SO ₂	Every Year CEM

	NO _x	CEM
II. Holman Boiler	NO _x	Every three years and alternate method according to applicable NSPS standards

The Holman boiler shall use an EPA approved test method every three years and in between years use an alternate method according to applicable NSPS standards.

- C. During startup/shutdown operations, NO_x and SO₂ emissions are monitored by CEMS or alternate methods in accordance with applicable NSPS standards.
- D. KUC must operate and maintain the air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

ii. REFINERY:

- A. Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
The sum of two (Tankhouse) Boilers	NO _x	9.5 lbs/hr (Before December 2020)
(Upgraded Tankhouse Boiler)	NO _x	1.5 lbs/hr (After December 2020)
Combined Heat Plant	NO _x	5.96 lbs/hr

- B. Stack testing to show compliance with the above emission limitations shall be performed as follows:

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
Tankhouse Boilers	NO _x	every three years*
Combined Heat Plant	NO _x	every year

*Stack testing shall be performed on boilers that have operated more than 300 hours during a three year period.

- C. One 82 MMBTU/hr Tankhouse boiler shall be upgraded to meet a NO_x rating of 9 ppm no later than December 31, 2020. The remaining Tankhouse boiler shall not consume more than 100,000 MCF of natural gas per rolling 12- month period unless upgraded so the NO_x emission rate is no greater than 30 ppm

- D. KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Records shall be kept on site which indicate the date, and time of startups and shutdowns.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.22.k.i.A is specifically outlined in IX.H.22.k.i.B; while IX.H.22.k.i.C is addressed in IX.H.22.k.i.D. Recordkeeping is subject to the requirements of IX.H.21.c and IX.H.21.f.

6.0 References

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Document - NOx Emissions from Industrial/Commercial/ Institutional Boilers.

RioTinto

Rio Tinto Kennecott
4700 Daybreak Parkway
South Jordan, Utah 84095
801-204-2814

Steve Schnoor
Manager – Environment, Land and Water

April 27, 2017

Mr. Bryce Bird
Utah Division of Air Quality
150 North 1950 West
Salt Lake City, Utah 84114

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY

APR 28 2017

DIVISION OF AIR QUALITY

Attn: Mr. Nando Meli

Subject: **Kennecott Utah Copper LLC
PM_{2.5} SIP Best Available Control Technology Analysis**

Dear Mr. Bird:

Kennecott Utah Copper LLC (KUC) is submitting the PM_{2.5} State Implementation Plan (SIP) Best Available Control Technology (BACT) analysis, as requested by the Utah Division of Air Quality. Attached are BACT determinations for emission sources at the following KUC facilities –

- Bingham Canyon Mine and Copperton Concentrator
- Utah Power Plant, Tailings and Laboratory
- Smelter, Refinery and Molybdenum Autoclave Process Plant

Should you have any questions, please feel free to contact Cassady Kristensen at 801-204-2129.

Sincerely,



Steve Schnoor
Manager – Environment, Land and Water

Enclosure

FINAL REPORT

Kennecott Utah Copper

**PM_{2.5} State Implementation Plan Best
Available Control Technology
Determinations**

Submitted to
Utah Division of Air Quality

Prepared for:
Kennecott Utah Copper

Prepared by:



April 2017

FINAL

BACT Determinations for the Bingham Canyon Mine and Copperton Concentrator

Prepared for

Kennecott Utah Copper

April 2017

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Acronyms and Abbreviations

AO	approval order
BACT	best available control technology
BCM	Bingham Canyon Mine
CAA	Clean Air Act
CO	carbon monoxide
EPA	Environmental Protection Agency
gr/dscf	grains per standard cubic feet
GPS	Global Positioning System
KUC	Kennecott Utah Copper
MMBTU/hr	million British Thermal Units per hour
NAAQS	National Ambient Air Quality Standard
NH ₃	ammonia
NO _x	nitrogen oxides
PM ₁₀	particulate matter less than or equal to 10 micrometers in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 micrometers in aerodynamic diameter
ppm	parts per million
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearing house
SIP	State Implementation Plan
SO ₂	sulfur dioxide
TPY	tons per year
UDAQ	Utah Department of Air Quality
VOC	volatile organic compound

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Introduction

Kennecott Utah Copper LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities: Bingham Canyon Mine (BCM) and the Copperton Concentrator. In addition to a BACT analysis, KUC has also documented Most Stringent Measures for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and meet any reasonable further progress requirements. As requested by the Utah Division of Air Quality (UDAQ), the BACT analysis should identify and evaluate reasonable and available control technologies for each relevant pollutant. The technical and economic feasibility of each potential technology are components of the BACT analysis that help to show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environment Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 micrometers in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOCs). For each emission source, the BACT analysis followed a four step process:

Step 1—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC)

Step 2—Eliminate technically infeasible options

Step 3—Eliminate economically/chronologically infeasible options

Step 4—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent Most Stringent Measures.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important that these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS were combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends that BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development standard.

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SECTION 2

Recent Permitting Actions

Current operations at the BCM are permitted under Approval Order (AO) DAQE-AN105710037-15, issued on November 10, 2015.

Emissions from the BCM are mainly limited by the following conditions:

- “Total material moved (ore and waste) shall not exceed 260 million tons per rolling 12-month period.” This condition limits the total material moved at the Bingham Canyon Mine, thus limiting both fugitive and tailpipe emissions.
- “Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles.” This condition limits daily vehicle miles travelled at the Bingham Canyon Mine, thus limiting both fugitive and tailpipe emissions.
- “Emissions of particulate matter less than or equal to 10 micrometers in aerodynamic diameter (PM₁₀), NO_x, and SO₂ combined shall not exceed 7,350 tons and emissions of PM_{2.5}, NO_x, and SO₂ shall not exceed 6,205 tons per rolling 12-month period.”
- “KUC shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.”

KUC is required to submit an annual fugitive dust control report that provides a description of the fugitive dust control practices implemented at the BCM.

Current operations at the Copperton Concentrator are permitted under AO DAQE-AN105710035-13 issued on June 25, 2013. Potential to Emit (PTE) emissions for the Copperton Concentrator are a very small percentage of combined emissions from the mine and concentrator facilities. Emissions for the Copperton Concentrator are limited by implementation of BACT controls.

PTE emissions in tpy for the BCM and the Copperton Concentrator are shown in Table 2-1.

Table 2-1
Facility Potential to Emit Emissions (Including Fugitive and Nonroad Engine Emissions)

	PM ₁₀ PTEs (tpy)	PM _{2.5} PTEs (tpy)	NO _x PTEs (tpy)	SO ₂ PTEs (tpy)	VOC PTEs (tpy)
Bingham Canyon Mine	1,519	369	5,838	7	314
Copperton Concentrator	25.3	13.86	10.66	0.1	4.04

Notes:

- PM₁₀ = Particulate matter 10 microns or smaller in aerodynamic diameter
- NO_x = oxides of nitrogen
- SO₂ = sulfur dioxide
- VOC = volatile organic compounds
- PM_{2.5} = Particulate matter 2.5 microns or smaller in aerodynamic diameter
- PTE = potential to emit
- tpy = tons per year

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SECTION 3

BACT Determinations

This section provides BACT determinations for emission sources deemed significant at the BCM and the Copperton Concentrator.

3.1 Bingham Canyon Mine

3.1.1 In-pit Crusher

Source Description: The crusher is used to crush copper ore mined at the BCM. Particulate emissions from the in-pit crusher are controlled with a baghouse.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies baghouse (fabric filter) and enclosures with water sprays as possible control technologies for limiting emissions from crusher.

Step 2—Eliminate Technically Infeasible Options. Not Applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies are feasible.

Step 4—Identify BACT. Fabric filters are the most effective in controlling emissions. Therefore, baghouse (fabric filter) constitutes BACT for the in-pit crusher.

The baghouse for the crusher is permitted at a grain loading of 0.002 grains per standard cubic feet (gr/dscf). Review of the RBLC did not identify emission rates lower than 0.002 gr/dscf for the similarly used baghouses. This emission rate therefore represents Most Stringent Measure for the in-pit crusher. Additionally, this emission rate was established by UDAQ as BACT for the BCM permitting in 2011.

3.1.2 Disturbed Areas

Source Description: Disturbed areas from mining activities. KUC current practices include application of palliatives and revegetation of the areas as soon as practical, as well as water application from passing water trucks in the operational areas to minimize dust.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies revegetation, adding moisture, and enclosures (wind screens) as possible control technologies for fugitive emissions.

Step 2—Eliminate Technically Infeasible Options.

Applying additional moisture (water) on the disturbed areas as mining occurs is not technically feasible for KUC's mine operations. The ore is transferred through a series of conveyors. Excessive moisture in the ore material causes the conveyors to foul and breakdown resulting in costly equipment repairs. Therefore, adding moisture to the ore material is not technically feasible.

Because the disturbed areas are so expansive and cover varying terrain, adding enclosures or wind screens are not technically feasible for this mine source.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 were technically infeasible or selected as BACT.

Step 4—Identify BACT. The practice of applying palliatives and revegetation is the most effective in reducing emissions. Therefore, the application of palliatives and revegetation constitute BACT.

The application of palliatives and revegetation also represent BACM for the disturbed areas. Because best available measures are in use, they also represent Most Stringent Measures.

3.1.3 Waste Rock Offloading from Trucks

Source Description: Haul trucks dump waste rock or overburden at the waste rock disposal areas while minimizing the height of the drop.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies water application and enclosures as possible control technologies for fugitive emissions from such sources of emissions.

Another possible control technology not identified, but effective in reducing emissions from batch drop transfer points, is minimizing the drop distance while the waste rock is being dumped.

Step 2—Eliminate Technically Infeasible Options.

Because the drop location is not static an enclosure is not technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable as the remaining technology of minimizing the drop distance, while the waste rock is being dumped, is selected as BACT.

Step 4—Identify BACT. Minimizing drop distances while the waste rock is being dumped is effective in controlling emissions and constitute BACT.

Minimizing drop distances while the waste rock is being dumped also represents BACM. Because best available measures are in use, they also represent Most Stringent Measures.

3.1.4 Graders

Source Description: The graders primarily operate on the haul roads, maintaining surfaces of the roads. Particulate is controlled by the application of water and chemical dust suppressants to the roads.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies the application of water and chemical dust suppressants as a possible control technology for fugitive emissions.

Step 2—Eliminate Technically Infeasible Options. Not Applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary constitute BACT.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the graders. Because best available measures are in use, they also represent Most Stringent Measures.

3.1.5 Bulldozers

Source Description: The dozers operate in the pit, on the haul roads performing cleanup operations, and in dumping operations at the waste rock disposal areas.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies the application of water and chemical dust suppressants as required as a possible control technology for fugitive emissions.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary constitute BACT.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the bull dozers. Because best available measures are in use, they also represent Most Stringent Measures.

3.1.6 Unpaved Haul Roads

Source Description: Haul roads are used to transfer ore and waste rock.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies potential technologies for control of fugitive emissions on unpaved haul roads as; paving the unpaved roads, the application of water and the use of dust suppression chemicals, limiting unnecessary traffic on roads and routine maintenance (through the use of road base material) of haul roads.

Step 2—Eliminate Technically Infeasible Options. Paving the haul roads is not technically feasible at the BCM because of the weight of the haul trucks and the rapid deterioration that would occur and the frequently changing road locations.

Application of chemical dust suppressants is not technically feasible for some haul road locations because of the adverse effect the chemical can have on the coefficient of friction of the road surface. Given that the grade of the haul roads exceeds 10 percent in some locations, creating a slippery skin on the road inhibits the ability of mobile equipment to brake and steer safely while traveling on the grade.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The remaining technologies of water application, chemical dust suppressants out of the pit influence boundary, limiting unnecessary traffic on roads, and routine maintenance of haul roads are economically and chronologically feasible.

Step 4—Identify BACT. The application of water and road-base material within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary is effective in minimizing emissions. Watering the unpaved haul road reduces fugitive PM_{2.5} and PM₁₀ emissions by binding the soil particles together, reducing free particles available to be picked up by wind or vehicles. Additional watering and application of chemical dust suppressants on certain locations of unpaved haul roads also occurs when heavy traffic is expected along the road. Water is applied on a scheduled basis and supplemented as needed based on dust conditions. Dust is also reduced through performing regular and routine maintenance of the haul roads (through use of road-base material) and limiting unnecessary traffic on roads.

In recent years, KUC has purchased newer haul trucks with higher capacity where possible, which has led to a decrease in the round-trips and vehicle miles traveled, thereby reducing fugitive dust emissions.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the unpaved haul roads. Because best available measures are in use, they also represent Most Stringent Measures.

3.1.7 Tailpipe Emissions from Mobile Sources

Source Description: Tailpipe emissions from haul trucks and support equipment such as graders and dozers. Tailpipe emissions from the haul trucks and support equipment meet the required EPA standards for NONROAD equipment.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies no add on control technologies for tailpipe emissions from haul trucks and support equipment of the size used at the Bingham Canyon Mine.

Step 2—Eliminate Technically Infeasible Options. Not applicable.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable.

Step 4—Identify BACT. Haul trucks and support equipment used at the facility meet the required EPA standards for nonroad equipment. The facility uses on-road specification diesel fuel in its off-road equipment. In 2007, an EPA ruling required sulfur content in all on-road specification diesel fuels be reduced (from 50 parts per million [ppm] formerly to 15 ppm currently). Because only on-road specification diesel fuel is used in its equipment, the facility has also made a transition to ultra-low sulfur diesel fuel. All of the facility's diesel-powered equipment now runs on ultra-low sulfur diesel fuel.

Additionally, the facility periodically upgrades its haul truck fleet to also take advantage of available higher-tier-level, lower-emitting engines. In recent years, KUC has purchased newer haul trucks with higher capacity where possible, which has led to a decrease in round-trips and truck operating hours, thereby reducing emissions.

KUC purchases newer haul trucks with higher capacity and Tier level which meet its mining needs. This also represents Most Stringent Measures.

3.1.8 Fueling Stations

Source Description: Adding gasoline and diesel to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies two control techniques for controlling VOC emissions from gasoline and diesel fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. Stage 1 and 2 vapor recovery constitutes BACT for these sources.

The use of Stage 1 and Stage 2 vapor recovery systems also represent Most Stringent Measures for the fueling stations.

3.1.9 Cold Solvent Degreasers

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies operating practices such as closing the degreaser lids a method to control/minimize VOC emissions.

Step 2—Eliminate Technically Infeasible Options. Not applicable as the identified control technology is technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. When not in use, the lids on the degreasers are kept closed at all times to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for degreasers.

The above identified practices also represent Most Stringent Measures for the degreasers.

3.2 Copperton Concentrator

3.2.1 Tioga Heaters

Source Description: Natural gas-fired heaters are used throughout the Copperton Concentrator. The individual heaters are rated at less than 5 MMBTU/hr each. The heaters are regularly inspected for optimum combustion performance.

3.2.1.1 NO_x BACT

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The technology identified in the RBLC for controlling NO_x emissions from heaters of good combustion practices is already in use and constitute BACT.

3.2.1.2 PM_{2.5}, SO₂, CO, and VOC BACT

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, CO, and VOC emissions from heaters.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The RBLC identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, CO, and VOC emissions from heaters and these control technologies constitute BACT.

Low NO_x burners and use of pipeline quality natural gas and good combustion practices also represent most stringent measures for the Tioga heaters.

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SECTION 4

BACT Summary

This section provides a summary of BACT for the remaining emission sources at the BCM and the Copperton Concentrator.

Table 4-1. BACT Summary

Emission Source ID/Name	Emission Source Description	BACT Summary
C6/C7 Conveyor Transfer Point	Conveyor Transfer Point	Emissions from the transfer point are controlled with a baghouse rated at 0.007 gr/dscf. With the top control technology implemented, it also represents most stringent measures.
C7/C8 Conveyor Transfer Point	Conveyor Transfer Point	Emissions from the transfer point are controlled with a baghouse rated at 0.007 gr/dscf. With the top control technology implemented, it also represents most stringent measures.
Product Molly Dryer	Natural Gas Product Dryer	Emissions are minimized with low NO _x burners and use of pipeline quality natural gas.
Lgr Product Molly Dryer	Natural Gas Product Dryer	Emissions are minimized with low NO _x burners and use of pipeline quality natural gas.
Lime Bin	Lime Storage Bin	Emissions are controlled with a bin vent filter.
Lime Bin	Lime Storage Bin	Emissions are controlled with a bin vent filter.
Sample Preparation	Sample preparation building at the mine	Emissions are controlled with a baghouse.
Molly Storage Bins	Moly storage bin	Emissions are controlled with a bin vent filter.
Molly Vacuum	Process Area	Process is enclosed to minimize emissions.
Molly Loading (Bags)	Process Area	Process is enclosed to minimize emissions.
Truck Dispatch EG at 6690	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
Communications EG at 6190	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
EmResp EG at Lark Gate	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
Galena Gulch	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
Dinkyville Hill	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
Zelnora	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards
Prd Dryer Heater	Natural Gas Heater	Emissions are minimized with low NO _x burners and use of pipeline quality natural gas.
Prod Dryer Heater	Natural Gas Heater	Emissions are minimized with low NO _x burners and use of pipeline quality natural gas.

SECTION 4 BACT SUMMARY

Table 4-1. BACT Summary

Emission Source ID/Name	Emission Source Description	BACT Summary
Truck Offloading Ore Main In-pit Crusher	Material Offloading/Loading	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Truck Offloading Ore Stockpile	Material Offloading/Loading	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Main In-Pit Enclosed Transfer Points 1, 2 and 3	Conveyor Transfer Point	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
In-pit Enclosed Transfer Point 4	Conveyor Transfer Point	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Conveyor-stacker Transfer Point	Conveyor Transfer Point	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Coarse Ore Stacker	Conveyor Transfer Point	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Reclaim Tunnels	Conveyor Transfer Point	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
Front End Loaders		Application of water and/or chemical dust suppressants to minimize emissions.
Truck Loading	Material Offloading/Loading	Minimal emissions due to material characteristics such as large ore size and presence of very small quantities of fine material.
SXEW Copper Extraction		Mist eliminator and enclosures minimize emissions from the process.
Tertiary Crushing	Road base crushing system	Water sprays and enclosures minimize emissions from road base crushing system.
Screening	Road base crushing system	
Transfer Points	Road base crushing system	
Copper Ore Storage Pile	Ore Stockpile	Water sprays and compaction is used to minimize emissions.
Blasting with Minimized Area	Blasting operations at the mine	Water injection and controlled blasting minimize emissions from these operations.
Drilling with Water Injection	Drilling operations at the mine	
Gasoline Fueling	Fueling stations at the Concentrator	Stage 1 and Stage 2 vapor recovery systems minimize emissions.
Cold Solv. Degrease. Washers	Cold solvent degreasers at the Concentrator	Keeping the lids closed on the degreasers minimize solvent loss and emissions.
Pebble Crushing in Crusher CR-01	Pebble crushing system at the Concentrator	Water sprays and enclosures minimize emissions from pebble-crushing system.
Pebble Crushing in Crusher CR-02	Pebble crushing system at the Concentrator	
Transfer from CNV CV-04 onto CNV CV-05	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-05 into Crushed Pebble Surge Bin BN-02	Material transfer in the pebble crushing circuit	

Table 4-1. BACT Summary

Emission Source ID/Name	Emission Source Description	BACT Summary
Transfer from SAG No. 1 Belt Feeder FE-03 onto CNV CV-06 and CNV CV-11	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-11 to SAG 1 Feed Chute	Material transfer in the pebble crushing circuit	
Transfer from SAG No. 2 Belt Feeder FE-04 onto CNV CV-10	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-10 to SAG 2 Feed Chute	Material transfer in the pebble crushing circuit	
Transfer from SAG No. 3 Belt Feeder FE-05 onto CNV CV-09	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-09 to SAG 3 Feed Chute	Material transfer in the pebble crushing circuit	
Transfer from SAG No. 4 Belt Feeder FE-06 onto CNV CV-07 and CNV CV-08	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-08 to SAG 4 Feed Chute	Material transfer in the pebble crushing circuit	Water sprays and enclosures minimize emissions from pebble-crushing system.
Transfer onto CNV CV-02	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-02 onto CNV CV-03	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-03 into the Surge Bin BN-01	Material transfer in the pebble crushing circuit	
Transfer from Belt Feeders FE-02 and FE-01 into crushers CR-01 and CR-02	Material transfer in the pebble crushing circuit	
Transfer from bottom of crushers CR-01 and CR-02 onto CNV CV-04	Material transfer in the pebble crushing circuit	
Transfer from CNV CV-03 into the Surge Bin BN-03	Material transfer in the pebble crushing circuit	
Transfer from Belt Feeders FE-07 onto CNV CV-04	Material transfer in the pebble crushing circuit	

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Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

5.1 Bingham Canyon Mine

KUC is proposing the following limitations and monitoring requirements for the Bingham Canyon Mine.

- Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles. KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System (GPS) or equivalent.

This condition establishes a limitation on daily activity. The daily mileage limitation effectively limits fugitive road dust emissions, tailpipe emissions from the haul trucks, and overall activity of sources at the mine. Ore processing at the Copperton Concentrator, which results in minimal emissions, is also limited through the BCM activity limitations.

Emissions resulting from the movement of ore and waste around the mine represent a significant portion of overall emissions at the BCM. The emissions related to material movement include fugitive dust generated from truck travel on the haul roads and the tailpipe emissions from the haul trucks. Specifically, on an annual basis, greater than 99.9 percent of total mine emissions for NO_x and SO₂ come from the haul truck tailpipes. Also, on an annual basis, material movement represents 85 percent of the overall particulate emissions at the BCM. Based on these emissions, the material movement of ore and waste by haul trucks represents a vast majority of overall emissions at the BCM and can effectively be used to represent mine operations.

Daily emissions from the BCM can be regulated with the limitation on vehicle miles traveled by ore and waste haul trucks of 30,000 miles per day. Compliance to this limitation is demonstrated on a daily basis and is an appropriate metric for a 24-hour particulate standard.

It should be noted; the 30,000 miles per day limitation also limits overall BCM operations. Ancillary mining activities such as operation of the in-pit crusher, mining support equipment, *blasting*, and *drilling* only occur to produce adequate amount of ore and waste rock that can be hauled via the trucks and sent to the concentrator via the conveyor system.

On a 24-hour basis, these emissions can be represented with a 30,000 miles per day limitation. Since they effectively represent mine operations, a single daily limitation is appropriate in the SIP for the BCM. These emissions have been included in the appropriate SIP model.

KUC uses a real time tracking system for both tracking haul trucks as well as for recording miles travelled. These records are used to comply with the 30,000 miles per day limitation. The system may be a GPS or a system with similar tracking capabilities necessary to comply with this condition.

- KUC Shall Use Ultra-low Sulfur Diesel Fuel in Its Haul Trucks.

This condition establishes a requirement for the use of ultra-low sulfur diesel fuel in haul trucks.

- To minimize emissions at the mine:

SECTION 5 LIMITATIONS AND MONITORING REQUIREMENTS

- The owner/operator shall control emissions from the in-pit crusher with a baghouse.
- Apply water to all active haul roads as weather and operational conditions warrant, except during precipitation or freezing conditions, and shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.
- A chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.

These conditions require the control of emissions from the in-pit crushers with a baghouse.

The condition also establishes requirements for reducing and controlling fugitive particulate emissions from active unpaved haul roads at the mine. Water and chemical dust suppressants shall be used to minimize fugitive dust.

Specifically, active ore and waste haulage roads within the pit influence boundary are water sprayed and/or treated with a commercial dust suppressant. Crushed road-base material is applied to active ore and waste haulage roads within the pit influence boundary to enhance the effectiveness of fugitive dust control measures. Commercial dust suppressants are applied to active ore and waste haulage roads outside of the pit influence boundary no less than twice per year.

Each year KUC reports dust control measures implemented at the BCM during the previous year with details such as volume of water applied, commercial dust suppressant activity, etc.

- KUC is Subject to the Requirements in the Most Recent Federally approved Fugitive Emissions and Fugitive Dust Rule.

KUC is subject to the fugitive dust rules approved by UDAQ and EPA. These rules outline requirements that mines are to follow in minimizing the fugitive dust from the mining operations.

5.2 Copperton Concentrator

No limitations or monitoring requirements are proposed for the Copperton Concentrator emission sources as the emissions from the facility are minimal and are effectively controlled with the implementation of BACT.

FINAL

BACT Determinations for the Utah Power Plant, Tailings Site, and Laboratory

Prepared for

Kennecott Utah Copper

April 2017

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Acronyms and Abbreviations

AO	approval order
BACT	best available control technology
CAA	Clean Air Act
CatOx	catalytic oxidation
CO	carbon monoxide
DLN	dry low nitrogen
EPA	Environmental Protection Agency
KUC	Kennecott Utah Copper
LNB	low NO _x burner
MMBTU/hr	million British Thermal Units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standard
NO _x	nitrogen oxides
OFA	over-fire air
PM ₁₀	particulate matter less than or equal to 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppmvd	parts per million by volume dry
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearing house
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO ₂	sulfur dioxide
tpy	tons per year
UDAQ	Utah Department of Air Quality
UPP	Utah Power Plant
VOC	volatile organic compound

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Introduction

Kennecott Utah Copper, LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities located at the northwest corner of Salt Lake County, Utah: Utah Power Plant (UPP), tailings site, and the laboratory. The tailings site receives tailings in slurry form. The slurry is deposited in the tailings pond. The UPP is a coal and natural gas fired power plant that supplies power for KUC operations. Coal is used to fuel the plant in spring, summer, and fall; while natural gas is approved for use in the winter months. The laboratory is used to perform various tests and also functions to optimize operations through analysis of materials. In addition to a BACT analysis, KUC has also documented the most stringent measures for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and to meet any reasonable further progress requirements. As requested by the Utah Division of Air Quality (UDAQ), the BACT analysis should identify and evaluate BACT for each relevant pollutant. The technical and economic feasibility of each potential technology are components of the BACT analysis that help to show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environment Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOC). For each emission source, the BACT analysis followed a four step process:

Step 1—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC)

Step 2—Eliminate technically infeasible options

Step 3—Eliminate economically/chronologically infeasible options

Step 4—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent most stringent measures.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS was combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends that BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development.

Recent Permitting Actions

An approval order (AO) was issued for the UPP on November 10, 2015, which authorized the construction and operation of a natural gas fired emergency generator. Issued in 2011, AO DAQE-AN105720026-11 authorized KUC to replace Boiler Units 1, 2, and 3 with a new natural gas fired combustion turbine operating in combined cycle mode with a heat recovery steam generator. The new combustion turbine will be equipped with state of the art add-on controls to minimize emissions from the unit and represents BACT. Dry low nitrogen oxide (DLN) combustors and the selective catalytic reduction (SCR) system will control NO_x emissions. The catalytic oxidation (CatOx) system will control carbon monoxide (CO) and VOC emissions. Good combustion practices and burning natural gas will minimize emissions of the remaining pollutants.

The tailings site was permitted under AO DAQE-AN10572018-06. The emissions sources at the laboratory are permitted under AO DAQE-261-95. All three facilities operate under a single Title V operating permit, #3500346002.

The current potential to emit (PTE) emissions in tons per year (tpy) for the tailing site, UPP, and the laboratory are shown in Table 1-1.

Table 2-1. Facility Potential to Emit

	PM ₁₀ PTE (tpy)	PM _{2.5} PTE (tpy)	NO _x PTE (tpy)	SO ₂ PTE (tpy)	VOC PTE (tpy)
UPP	248	248	1,641	2,577	41
Tailings Site	36.3	5.4**	0.26	—*	0.04
Laboratory	0.12	0.12	0.68	0.13	0.12

Notes:

PM_{2.5} = particulate matter 2.5 microns or smaller in aerodynamic diameter

PM₁₀ = particulate matter 10 microns or smaller in aerodynamic diameter

PTE = potential to emit

NO_x = oxides of Nitrogen

SO₂ = sulfur dioxide

tpy = tons per year

VOC = volatile organic compounds

CO = carbon monoxide

*Permitted combustion sources result in negligible SO₂ emissions at the tailings site.

**PM_{2.5} emissions are estimated to be 15 percent of PM₁₀ emissions.

Distinguishing by season of operation is allowed under EPA's *Implementation Guidance for the 2006 24-hour Fine Particle NAAQS* (March 2, 2012), which specifically acknowledges that several nonattainment areas located in the western United States only have experienced exceedances during the winter season. In such cases, the EPA authorizes states to (1) develop a seasonal emission inventory and (2) evaluate emission reduction strategies for a single season only [p. 11]. "When following a seasonal approach, the EPA believes that *the control strategy evaluation* (based on seasonal emission reduction measures) and the assessment of future year air quality concentrations (through air quality modeling or other analyses) *should be conducted for that season.*" [p. 12]. In view of the nature of Utah's PM_{2.5} nonattainment circumstance, the BACT analysis for UPP focuses primarily on a wintertime control strategy.

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BACT Determinations

This section provides BACT determinations for emission sources deemed significant at the UPP and tailings site. Emissions at the laboratory are minimal, currently effectively controlled with implementation of BACT, and therefore not included in this analysis.

3.1 Utah Power Plant

Historically, KUC has operated three coal fired boilers rated at 100 megawatts (MW) combined, referred to as Units 1-3, at the UPP. The units operated on coal during the summer months, but were limited to burning natural gas during the winter months between November 1 and March 1. In October 2016, KUC has permanently ceased operation of Units 1-3. Therefore, a BACT analysis for Units 1-3 is not included in this document.

3.1.1 UPP Unit 4 Boiler

Source Description: Tangentially fired boiler capable of burning both coal and natural gas, rated at 838 million British Thermal Units per hour (MMBTU/hr) (coal), or 872 MMBTU/hr (natural gas), equipped with an electrostatic precipitator. Since the ambient 24-hour concentrations of PM_{2.5} exceed the NAAQS only during the winter months, the BACT analysis is limited to controls for the combustion of natural gas, which are the only controls that may affect the attainment of the PM_{2.5} NAAQS in the Salt Lake City nonattainment area.

3.1.1.1 NO_x BACT

Step 1—Identify All NO_x Control Technologies listed in RBLC. The RBLC identifies (1) low NO_x burners with over-fire air (low NO_x burner [LNB] with over-fire air [OFA]) and (2) LNB with OFA and SCR as potential technologies for NO_x control from a natural gas fired boiler.

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Previous SIP determination for UPP Unit 4 required the installation of LNB with OFA and SCR with 90% NO_x control when operating on natural gas during the winter months between November 1 and March 1. Because the top technology is already identified in previous SIPs, additional analysis is not necessary.

Step 4—Identify BACT. LNB with OFA and SCR with 90% control efficiency constitute BACT for controlling NO_x emissions from natural gas combustion in the boiler during the wintertime period (November 1 through March 1).

3.1.1.2 SO₂ BACT

Step 1—Identify all SO₂ Control Technologies listed in RBLC. The RBLC identifies the use of pipeline quality natural gas as a control when burning natural gas.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The use of pipeline quality natural gas constitute BACT when burning natural gas.

3.1.1.3 PM_{2.5} BACT

Step 1—Identify all PM_{2.5} Control Technologies listed in RBLC. The RBLC identifies good combustion practices as a control for reducing PM_{2.5} when burning natural gas.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. Good combustion practices constitute BACT while burning natural gas.

3.1.1.4 VOC BACT

Step 1—Identify all VOC Control Technologies listed in RBLC. The RBLC identifies good combustion practices as a control when burning natural gas.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4— Identify BACT. Good combustion practices constitute BACT for VOC while burning natural gas.

Controlling NO_x emissions by 90 percent with LNB, OFA, and SCR and the use of pipeline quality natural gas and good combustion practices represent most stringent measures for Unit 4 at the UPP when operating on natural gas between November 1 and March 1.

3.1.2 UPP Unit 5 Combustion Turbine and Duct Burner

Source Description: A combustion turbine and duct burner in combined-cycle operation with a nominal generating capacity of approximately 275 MW, equipped with SCR and CatOx.

3.1.2.1 NO_x BACT

Step 1—Identify All NO_x Control Technologies listed in RBLC. The RBLC identifies selective noncatalytic reduction (SNCR) and SCR as potential technologies for NO_x control. The SCR technology is the most stringent control alternative listed in the RBLC.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. SCR constitutes BACT for controlling NO_x emissions from the Unit 5 combustion turbine and duct burner.

3.1.2.2 VOC BACT

Step 1—Identify All CO and VOC Control Technologies listed in RBLC. The RBLC identifies CatOx to control emissions of CO and VOC.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. CatOx constitutes BACT for controlling CO and VOC emissions from the combustion turbine and duct burner.

3.1.2.3 SO₂ BACT

Step 1—Identify All SO₂ Control Technologies listed in RBLC. The RBLC identifies the use of pipeline quality natural gas and good combustion practices as a control when burning natural gas.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The use of pipeline quality natural gas and good combustion practices constitute BACT for controlling SO₂ emissions from the Unit 5 combustion turbine and duct burner.

3.1.2.4 PM_{2.5} BACT

Step 1—Identify All PM_{2.5} Control Technologies listed in RBLC. The RBLC identifies the use of pipeline quality natural gas and good combustion practices as a control when burning natural gas.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The use of pipeline quality natural gas and good combustion practices constitute BACT for controlling PM_{2.5} emissions from the Unit 5 combustion turbine and duct burner.

Limiting NO_x emissions to 2 parts per million by volume dry (ppmvd) at 15% O₂ and the use of pipeline quality natural gas and good combustion practices represent the most stringent measures for Unit 5 at the UPP.

3.1.3 Cooling Towers

Source Description: Noncontact water cooling towers are used to control waste heat from the boilers. All towers are equipped with drift eliminators with drift loss rated at 0.002 percent.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. Drift eliminators and good operating practices constitute BACT.

The use of drift eliminators with drift loss rated at 0.002 percent and good operating practices represent most stringent measures for the cooling towers.

3.1.4 Tioga Space Heaters

Source Description: Natural gas-fired space heaters are used for comfort heating and cooling, and water heating throughout the power plant. The space heaters use low NO_x burners (LNB) and regular inspections are done to the units to ensure optimum combustion performance. All space heaters are rated at less than 5 MMBTU/hr.

3.1.4.1 NO_x BACT

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies LNB and good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The technologies identified in the RBLC for controlling NO_x emissions from heaters (LNB and good combustion practices) are already in use and constitute BACT.

3.1.4.2 PM_{2.5}, SO₂, and VOC BACT

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from heaters.

Step 2—Eliminate Technically Infeasible Options. Not applicable as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. The RBLC identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from heaters and these control technologies constitute BACT.

The use of pipeline quality natural gas, LNB and good combustion practices represent the most stringent measures for Tioga Space Heaters at the UPP.

3.2 Tailings Site

3.2.1 Wind Erosion from Tailings Embankment

Source Description: Tailings are sent to the tailings site via a slurry pipeline. At the facility, tailings are separated by size in a cyclone with the larger particles used to build the embankments and the smaller particles discharged in slurry form in the impoundment. Emissions from the tailings site are mainly from wind erosion of dry tailings on the embankment. The facility has a current dust control plan approved by the UDAQ Executive Director for control of fugitive particulate matter.

Step 1—Identify All Control Technologies Listed in RBLC. The following control technologies were identified in the RBLC for particulate control from impoundment type emissions sources:

- Watering
- Polymer application
- Revegetation
- Enclosures

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Polymer Application: As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. Polymers suppress emissions by changing the physical characteristics of the surface material. The polymers form a hardened surface that binds the particles together, thereby reducing their likelihood to become airborne.

Revegetation: Revegetation assists with minimizing emissions. The vegetation holds the soil surface together and therefore makes it less prone to wind erosion.

Enclosures: Enclosures reduce the wind shear at the surface and thereby reduce wind erosion and emissions.

Step 2—Eliminate Technically Infeasible Options. Because of the size of the impoundment, enclosures are not feasible. All remaining technologies are feasible and are further evaluated below.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The tailings site can be categorized into four operational areas: impoundment, flat embankment, sloped embankment, and reclaimed areas. The impoundment area is saturated with water and does not result in windblown dust emissions. Visual inspections are routinely performed to ensure the impoundment is saturated with water and in the unlikely event an area appears to be drying out, the area would be resaturated.

The tailings are actively deposited in the embankment areas. In an active embankment cell, the tailings are deposited every fourth day. The tailings are extremely wet when deposited. Areas can remain moist for several days. Application of water for dust control in active areas is not feasible as it tends to channelize directly to the drain point instead of spreading across the surface. The flat embankment areas will therefore have a potential for wind erosion on days 2, 3, and 4. Emissions are estimated based on days with potential for wind erosion.

In the inactive embankment areas, where tailings deposition has been completed for the year, KUC installs sprinklers for watering. In 2010 and 2011, KUC converted this to an automated sprinkler system that wets the surface at regular intervals. This upgrade allows the surface to maintain its moisture.

The embankment slopes are sprayed with polymers to minimize windblown dust. Polymer is reapplied as necessary to maintain its effectiveness to minimize emissions.

Once released for reclamation, KUC implements a revegetation plan to reclaim the areas. Polymers are applied to areas still waiting to be reclaimed.

The control technologies cannot be ranked based on effectiveness as each control technology is effective for specific areas at the tailings site.

Step 4—Identify BACT. The current practices of reducing particulate emissions by following the approved dust control plan is most effective in reducing emissions. The dust control plan requires frequent monitoring of the impoundment for wind erosion potential, applying chemical dust suppressants in the late spring, applying water via water trucks and the dust suppression sprinkler system as needed to maintain adequate moisture content. Therefore, KUC recognizes water spray/wet suppression, polymer application, and revegetation are selected as BACT for the tailings site.

The current practices of dust management at the tailings site also represent most stringent measures.

3.3 Service Roads

Source Description: Service roads exist throughout the tailings site and are used by KUC personnel daily.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies potential technologies for control of fugitive emissions on unpaved roads as; paving the unpaved roads, the application of water and the use of dust suppression chemicals, limiting unnecessary traffic on roads and routine maintenance of roads.

SECTION 3 – BACT DETERMINATIONS

Step 2—Eliminate Technically Infeasible Options. Paving the haul roads is not technically feasible at the tailings site because of the frequently changing road locations over time resulting from tailing placement.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The remaining technologies of water application, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads are economically and chronologically feasible.

Step 4—Identify BACT. The application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads are identified as BACT for the service roads.

The application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads also represent most stringent measures for the service roads at the tailings site.

SECTION 4

BACT Summary

This section provides a summary of BACT for emission sources deemed insignificant at the UPP, tailings site, and the laboratory.

Table 4-1. BACT Summary

Emission Source ID/Name	Emission Source Description	BACT Summary
Natural Gas Steam Boiler	Natural Gas Steam Boiler	Emissions are minimized with low NO _x burners and use of pipeline quality natural gas.
Nat Gas Purge Vents	Natural Gas Safety Purge Vents	Operating procedures minimize emissions from purging events.
Gasoline Fueling	Fueling Station at the UPP	Stage 1 and Stage 2 vapor recovery systems minimize emissions.
Coal Storage Pile	Coal Storage Pile	Water sprays are used to minimize emissions from the storage pile.
Drop to Coal Storage Pile	Coal Transfer	Enclosures and water sprays are used to minimize emissions.
Coal Transfer Point	Coal Transfer	Enclosures and water sprays are used to minimize emissions.
Ash Handling	Ash Transfer	Water sprays are used to minimize emissions from ash handling operations.
Salt Lake City Biosolids	Organic matter used to enhance reclamation	Emissions are minimized by inherent moisture content of approximately 40%.
South Valley Biosolids	Organic matter used to enhance reclamation	Emissions are minimized by inherent moisture content of approximately 40%.
Cold Solv. Degrease. Washers	Cold Solvent Degreasers	Keeping the lids closed on the degreasers minimize solvent loss and emissions.
Unpaved	Service Roads at the UPP	The unpaved roads are treated with magnesium chloride and watered at regular frequency to minimize emissions.
Paved	Service Roads at the UPP	Paving the surface is the highest form of dust control for roads.
Tailings Diesel Engine	Diesel Emergency Generator	Emissions comply with applicable New Source Performance Standards.
UPP Diesel Engine	Diesel Emergency Generator	Emissions comply with applicable New Source Performance Standards.
Natural Gas Generators	Natural Gas Generators	Emissions comply with applicable New Source Performance Standards.
LPG Engine 1	LPG Communications Generator	Emissions comply with applicable New Source Performance Standards.

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SECTION 5

Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

5.1 Utah Power Plant

KUC is proposing the following limitations and monitoring requirements for the UPP.

Unit 5 shall not exceed the following emission rates to the atmosphere

Pollutant	lb/hr	Ppmvd (15% O ₂ dry)
NO _x		2.0*
PM _{2.5} with duct firing: Filterable and condensable	18.8	

*Under steady state operation

Stack testing to show compliance with the above Unit 5 emissions limitations shall be performed as follows:

Pollutant	Test Frequency
PM _{2.5}	every year
NO _x	every year

The heat input during all compliance testing shall be no less than 90% of the design rate.

The following requirements are applicable to Unit 4 during the period November 1 to February 28/29 inclusive:

During the period from November 1, to the last day in February inclusive, only natural gas shall be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment.

Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Pollutant	Grains/dscf	ppmdv (3% O ₂) 68°F, 29.92 in. Hg
PM _{2.5} Filterable	0.004	
Filterable and condensable	0.03	
NO _x		336
NO _x (after 1/1/2018)		60

If operated during the winter months, stack testing to show compliance with the above Unit #4 emissions limitations shall be performed as follows:

Pollutant	Test Frequency
PM _{2.5}	every year
NO _x	every year

The heat input during all compliance testing shall be no less than 90% of the maximum average hourly production rate achieved in any 24-hour period during the previous three (3) years. The limited use of natural gas during startup, for maintenance firings and break-in firings does not constitute operation and does not require stack testing.

5.2 Tailings Site

The primary source of emissions at the tailings site is wind-blown dust. The intent of the PM_{2.5} serious nonattainment SIP is to review emissions during winter time inversions. Since these inversions represent stagnant wind conditions, emissions from the tailings site will be minimal and therefore tailings site SIP conditions are not necessary for the PM_{2.5} SIP. Emissions at the tailings site are effectively controlled with the implementation of BACT and most stringent measures.

5.3 Laboratory

No limitations or monitoring requirements are proposed for the laboratory emission sources as the emissions from the facility are minimal and are effectively controlled with the implementation of BACT and most stringent measures.

FINAL

Best Available Control Technology Determinations for the Smelter, Refinery, and Molybdenum Autoclave Process

Prepared for

Kennecott Utah Copper

April 2017

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Acronyms and Abbreviations

ACT	Alternative control techniques
AO	approval order
BACT	best available control technology
BCM	Bingham Canyon Mine
CAA	Clean Air Act
CEM	Continuous emissions monitor
<i>CFR</i>	<i>Code of Federal Regulations</i>
CHP	Combined heat and power
CO	carbon monoxide
CPI	<i>Consumer Price Index</i>
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator
FGR	Flue gas recirculation
FS	Flash Smelting
GPS	Global Positioning System
gr/dscf	grains per standard cubic feet
KUC	Kennecott Utah Copper
LNB	Low NO _x burner
MACT	maximum achievable control technology
MAP	molybdenum autoclave process
MMBtu/hr	million British Thermal Units per hour
NAAQS	National Ambient Air Quality Standard
NH ₃	ammonia
NO _x	nitrogen oxides
PM ₁₀	particulate matter less than or equal to 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppm	parts per million
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearing house
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SOP	Standard operating procedure
TEG	Turbine Electric Generator
tpy	tons per year

ACRONYMS AND ABBREVIATIONS (CONTINUED)

UDAQ	Utah Department of Air Quality
ULNB	Ultra-low NOx burner
VOC	volatile organic compound
WRAP	Western Regional Air Partnership

Introduction

Kennecott Utah Copper LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities: smelter, refinery, and the molybdenum autoclave process (MAP). In addition to a BACT analysis, KUC has also documented the most stringent measures for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and meet any reasonable further progress requirements. As requested by the Utah Department of Air Quality (UDAQ), the BACT analysis should identify and evaluate reasonable and available control technologies for each relevant pollutant. The technical and economic feasibility of each potential control technology are components of the BACT analysis that help show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environment Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOCs). For each emission source, the BACT analysis followed a four step process:

Step 1—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC)

Step 2—Eliminate technically infeasible options

Step 3—Eliminate economically/chronologically infeasible options

Step 4—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent most stringent measures.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important that these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS were combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends the BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development.

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Recent Permitting Actions

The smelter, refinery, and MAP together have over 70 individual significant and insignificant sources. The smelter recently had UDAQ permitting actions. A modified approval order (AO) was issued for the smelter on June 10, 2014. AO DAQE-AN0103460054-14 allows the smelter to operate a crushing and screening plant and modifies stack testing requirements for the smelter emissions sources. No other significant modifications were made to the smelter AO in the last 5 years.

The EPA performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source maximum achievable control technology (MACT) standard (40 *Code of Federal Regulations* [CFR] 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC smelter are included in the Federal Register notices associated with the draft and final promulgation of both of these rules. Both of these standards establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology. The primary copper smelting area source MACT standard specifically identifies the KUC smelter main stack emission performance as MACT for copper smelters (existing sources, not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred subsequent to promulgation of the MACT standards.

AO DAQE-AN01013460045-10 for the refinery was issued in 2010 to add the combined heat and power (CHP) unit. The CHP unit utilizes SoLoNO_xTM burners minimizing NO_x emissions from the unit. The smelter and refinery facilities operate under a single Title V Operating Permit # 3500030003.

The MAP facility, will process molybdenum disulfide into molybdenum trioxide and ammonia. The MAP facility was originally permitted in 2008 and was modified in March 2013 (AO DAQE-AN0103460052-13) to reflect the updated design of the plant. The permitting actions require thorough control technology analysis and the plant will implement BACT to minimize emissions from the facility.

Potential to emit (PTE) emissions in tons per year (tpy) for the Smelter, Refinery and MAP are shown in Table 2-1.

Table 2-1. Facility Potential to Emit Emissions

	PM ₁₀ PTEs (tpy)	PM _{2.5} PTEs (tpy)	NO _x PTEs (tpy)	SO ₂ PTEs (tpy)	VOC PTEs (tpy)
Smelter	510.82	426.35	185.29	1,085.72	13.50
Refinery	25.64	25.64	38.57	4.44	8.42
MAP	13.11	9.99	35.57	2.43	6.71

Notes:

PM₁₀ = Particulate matter 10 microns or smaller in aerodynamic diameter

NO_x = oxides of nitrogen

SO₂ = sulfur dioxide

VOC = volatile organic compounds

PM_{2.5} = Particulate matter 2.5 microns or smaller in aerodynamic diameter

PTE = potential to emit

tpy = tons per year

Best Available Control Technology Determinations

This section provides BACT determinations for emission sources deemed significant at the smelter, refinery, and the MAP facility.

3.1 Smelter

The EPA performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules (e.g., the design of the smelter is based on the furnace technology). Typical smelting operations require batch processing which intermittently produces high concentrations of SO₂ and particulate in a manner that can reduce the efficiency of the acid plant as a control device. By employing the flash smelting (FS) and flash converting (FC) technologies, KUC is able to eliminate many of the problems inherent with batch type smelter operations. These improvements include continuous flow of off-gases to the acid plant during the FC process as well as reduced total volume of off-gases. Additionally, the furnaces are stationary which improves the ability to capture the off-gases as well as the ability to capture any fugitive emissions with the secondary capture system, which cleans the gases with baghouses and scrubbers before venting to the main stack. As a result, both MACT standards go so far as to establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology.

The primary copper smelting area source MACT standard specifically identifies the KUC Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). The KUC Smelter employs several technologies to minimize the smelting emissions that report to the main stack.

- The concentrate dryer burns natural gas to heat/dry concentrate for use in the FS furnace. Operation with low-NO_x burners (LNB) along with lower dryer temperatures minimizes the formation of NO_x while also preventing the formation of SO₂. KUC operates both a baghouse and a scrubber as controls for the concentrate dryer.
- The secondary gas system collects fugitive emissions in the hot metals building (typically associated with the furnaces) and vents them through a baghouse and a sodium-based scrubber before they are vented to the main stack.
- The matte grinding circuit crushes and dries granulated matte for use in the FC furnace. The ground matte is collected in a baghouse and pneumatically conveyed to the FC furnace feed bin. NO_x emissions from natural gas combustion are controlled with LNB and low temperature firing and PM₁₀ emissions are controlled with the production baghouse.
- In the anodes area, blister copper from the FC furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap, which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the main stack. NO_x reduction activities also include maintaining furnaces to prevent ingress of air.
- The shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. LNBs are used to reduce NO_x from the natural gas combustion and a

baghouse is operated to control PM₁₀ emissions. The shaft furnace is in the anodes area, but vents separately to the main stack.

3.1.1 Main Stack

Source Description. Multiple process equipment emissions are routed through the main stack. Such equipment includes the matte granulators, acid plant, anode building, powerhouse, furnaces, dryers, and grinding circuits. Many of these sources of emissions have their own primary control devices (baghouse, scrubbers, etc.). Some are then routed to the secondary gas system and then through the main stack.

Equipment emissions routed through the main stack at the smelter include:

Equipment	Pollutant Emissions	Primary Emissions Control
Concentrate dryer	PM _{2.5} , SO ₂ , NO _x	LNB, baghouse, and scrubber
Powerhouse superheater	PM _{2.5} , SO ₂ , NO _x , VOC	Ultra-low NO _x burner (ULNB), Flue gas recirculation (FGR), fuel throughput limits, and good operational practices
Powerhouse Foster Wheeler aux boiler	PM _{2.5} , SO ₂ , NO _x , VOC	LNB, FGR, fuel throughput limits, and good operational practices
Matte grinding	PM _{2.5} , SO ₂	LNB, baghouse and good operational practices
Anode refining furnaces	PM _{2.5} , SO ₂ , NO _x , VOC	Oxy-fuel burners, baghouse, and scrubbers
Anode shaft furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse
Anode holding furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse
Vacuum cleaning system	PM _{2.5}	Baghouse
North and south matte granulators	PM _{2.5} , SO ₂	Scrubber, SGS baghouse, and SGS scrubbers

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies different control technologies for process equipment eventually routed through the main stack. These control technologies are currently in place as previously discussed.

The EPA performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC smelter are included in the Federal Register notices associated with the draft and final promulgation of both of these rules. Both of these standards go so far as to establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology. The primary copper smelting area source MACT standard specifically identifies the KUC smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred subsequent to promulgation of the MACT standards.

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 selected as BACT.

Step 4—Identify BACT. Because no new major developments in technologies have occurred subsequent to the promulgation of the MACT standards, the control technologies currently in place constitute BACT.

Complying with applicable requirements of the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEE) represent the most stringent measures for the main stack.

3.1.2 Powerhouse Holman Boiler

Source Description: The boiler is used to provide process steam at the smelter. Emissions of NO_x are limited with flue gas recirculation, LNB, opacity limits, an alternate monitoring plan; which requires continuous monitoring of operational parameters (fuel use, stack oxygen, steam output) and operational controls with good combustion practices. Emissions of PM_{2.5}, CO, SO₂, and VOC are limited with use of pipeline quality natural gas, good combustion practices, gas consumption limit, good design, opacity limits, and proper operation of the boiler.

3.1.2.1 NO_x BACT

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies the following as possible control technologies for NO_x for natural gas-fired boilers:

- Selective catalytic reduction (SCR)
- FGR
- LNBs with good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The Holman boiler is equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR would reduce the emissions from the boiler from 9.9 tpy (based on 2016 actual emissions) to 2.0 tpy.

From the Alternative Control Techniques (ACT) Document — NO_x Emissions from Industrial / Commercial / Institutional Boilers, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5 of the ACT document, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from Consumer Price Index (CPI) Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the Holman boiler, the estimated cost is \$487,287.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$62,000 and is therefore not cost effective for BACT.

Step 4—Identify BACT. FGR, LNBs with good combustion practices, limited gas consumption, good design, and proper operation constitute BACT for this source.

KUC continuously monitors operation parameters to predict NO_x emissions and ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lb/hr), stack oxygen (to monitor proper boiler operation and compliance with NO_x lb/MMBtu emission limit), and steam output (used to estimate heat input if fuel use is unavailable). The ranges for these parameters were developed during a 30-day monitoring

campaign where data from a certified NO_x analyzer were used to develop predictive equations with the operation parameters.

3.1.2.2 SO₂, VOC, and PM_{2.5} BACT

Step 1—Identify All Control Technologies listed in the RBLC. The RBLC identifies the following as possible control technologies for boilers:

- Use of pipeline quality natural gas and good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable because all potential technologies identified in Step 1 were selected as BACT.

Step 4—Identify BACT. Use of pipeline quality natural gas, good combustion practices, opacity limits, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNBS with good combustion practices, limited gas consumption, good design, and proper boiler operation represent the most stringent measures for the Holman Boiler.

3.1.3 Feed Process (Wet and Dry)

Source Description: Silica flux, concentrate, and converter slag are transferred directly to feed bins then conveyed to the dryer. Particulate emissions from the loading of the flux and concentrate, and from transfer points of the conveyor, are vented to a baghouse.

Step 1—Identify All Control Technologies listed in RBLC. Although RBLC did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, electrostatic precipitators (ESPs), and wet scrubbers.

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP, because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP and then by wet scrubbers.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable as most effective technology identified in Step 1 selected as BACT.

Step 4—Identify BACT. Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

The use of a baghouse to control particulate emissions also represents the most stringent measures for both the wet and dry feed process.

3.1.4 Matte and Slag Granulators

Source Description: Slag and matte granulators are each equipped with a three-stage impingement plate scrubber. The smelter operates two matte granulators and one slag granulator. The molten matte is granulated with water in two separate granulation tanks (two matte granulators), each equipped with a scrubber. The converter slag is granulated in a separate granulator (one slag granulator), also equipped with a scrubber. The matte granulators are vented through the main stack. The slag granulator is vented to the atmosphere through a separate stack. PM_{2.5} and SO₂ emissions are controlled by a neutral pH three-stage impingement plate scrubber.

3.1.4.1 PM_{2.5} BACT

Step 1—Identify All Control Technologies Listed in RBLC. Although RBLC did not provide controls for the specific operation, other possible particulate control technologies include baghouses, cyclones, ESP, and scrubbers.

Step 2—Eliminate Technically Infeasible Options. While baghouses are most effective in controlling particulate emissions, this technology is not feasible for the granulators. The exhaust from the granulators has very high moisture content, which is not suitable for baghouses. Moisture condensation can cause accumulation of mud on the bags and baghouse walls. This results in blinded bags and clogged dust removal equipment. As discussed in the Western Regional Air Partnership (WRAP) Fugitive Dust Handbook, cyclones are mainly used to control large particles.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, as most technically feasible technology for this process, identified in Step 2, was selected as BACT.

Step 4—Identify BACT. Scrubbers constitute BACT for the granulators.

3.1.4.2 SO₂ BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC does not identify any specific control technologies for the granulators.

Step 2—Eliminate Technically Infeasible Options. Not applicable

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable

Step 4—Identify BACT. Scrubbers constitute BACT for the granulators.

The use of scrubbers also represent the most stringent measures for both the matte and slag granulators.

3.1.5 Feed Storage Building

Source Description: Wet copper concentrate feed is stored in the enclosed wet feed storage building. Particulate matter from loading materials into the feed storage building, from reclaiming materials, and from conveyor/transfer point SME 002-A, are vented to a baghouse.

Step 1—Identify All Control Technologies listed in RBLC. Although RBLC did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, as most effective technology, identified in Step 1, selected as BACT.

Step 4—Identify BACT. Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

The use of a baghouse to control particulate emissions also represents Most Stringent Measures for the feed storage building.

3.1.6 Anode Area Fugitives

Source Description: Emissions from the anode building process are controlled with a baghouse, quench tower, and scrubber. However, some emissions escape as fugitives.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC does not identify any specific control technologies for process fugitives. The MACT, however, does address such emissions.

40 *CFR* 63.11147(a)(3) states, “You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, re-melt anode copper, or re-melt anode scrap and convey each collected gas stream to a control device. One control device may be used for multiple collected gas streams.”

KUC certified compliance with 63.11147(a)(3), as required by 63.11150(b)(4), in a letter dated and received by UDAQ on January 30, 2007.

Step 2—Eliminate Technically Infeasible Options. Not applicable

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable

Step 4—Identify BACT. In addition to opacity limits and required maintenance, current design of anode process units and the collection hoods on anode building processes have been engineered/designed to reduce fugitives and these practices constitute BACT.

The current design of anode process units and the collection hoods on anode building processes were engineered/designed to reduce fugitives and these represent most stringent measures.

3.1.7 Smelter Fugitives

Source Description: Emissions from smelter processes are controlled with appropriate control technologies including closed processes, launder hoods and others outlined below. However, some emissions escape as fugitives.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC does not identify any specific control technologies for such fugitives.

The EPA performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules. Regarding the design and fugitive emission controls of the KUC smelter, the EPA provided the following discussion when promulgating the final copper smelting MACT standard (FR Vol. 67, No. 113, Page 40488):

Due to its unique design and operations, most of the process fugitive emission sources associated with smelters using batch converting are eliminated at the Kennecott smelter. There are no transfers of molten material in open ladles between the smelting, converting, and anode refining departments at the Kennecott smelter. In addition, there are no fugitive emissions associated with the repeated rolling-out of converters for charging, skimming, and pouring. Also, only one continuous flash converter is needed at the Kennecott smelter compared with the need for three or more batch copper converters at the other smelters.

Both standards go so far as to establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology. Smelter process and emission controlling technologies that contributed to the EPA’s designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred subsequent to the promulgation of the MACT standards.

Specific notes regarding control techniques listed in Table 5 of Attachment 5 of the EPA comments are listed below:

- KUC smelter hot metals operations are serviced by an extensive local ventilation (secondary gas) system. This system collects gasses and routes them through baghouses and scrubbers before venting them to the main stack where they are continuously monitored for multiple pollutants.
- KUC smelter hot metals operations are completely enclosed in a building.
- KUC processes only clean scrap in its melting furnaces.
- A leak detection/prevention/repair program is not applicable to KUC smelter furnaces and hot metals process units because they are enclosed and operate at negative pressure due to their inherent design.
- Because KUC furnaces are enclosed and do not require open air transfer of molten metal, they are not dependent on hooding systems for process gas collection.
- It is not necessary to add curtains to improve hood performance at the KUC smelter as the process does not rely on hoods to capture process gasses.
- The KUC process does not require the open air transfer of molten metal from smelting to converting vessels so it is not necessary to collect these emissions.
- The EPA noted in the primary copper smelting MACT standard, KUC was the first smelter in the United States to capture and control emissions from anode refining furnaces.

Step 2—Eliminate Technically Infeasible Options. Not applicable

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable

Step 4—Identify BACT. In addition to opacity limits and required maintenance, current designs of processes were engineered/designed to reduce fugitives and therefore these practices constitute BACT.

The current designs of processes were engineered/designed to reduce fugitives and therefore these practices also represent the most stringent measures.

3.1.8 Acid Plant Fugitives

Source Description: The double contact acid plant removes SO₂ from the off-gases of the flash furnaces. The sulfuric acid produced by the plant is sold. Among other technologies, the system is equipped with tubular candle fiber mist eliminators and the tail gas is discharged to the main stack. However, some emissions escape as fugitives, which are controlled using best operational practices to minimize emissions. Best operational practices to minimize the emissions include opacity limits, weekly visual opacity surveys and the requirement of prompt repair or correction and control to minimize emissions.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC does not identify any specific control technologies for such fugitives.

Step 2—Eliminate Technically Infeasible Options. Not applicable

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable

Step 4—Identify BACT. Best operational practices may include, but are not limited to (1) placement or adjustment of negative pressure ductwork and collection hoses, (2) welding of process gas leaks, or (3) containment of process gas leaks. These practices and current design of processes were engineered/designed to reduce fugitives and therefore constitute BACT.

The best operational practices currently implemented and the current design of the processes also represent the most stringent measures for the acid plant fugitives.

3.1.9 Powerhouse Foster Wheeler Boiler

Source Description: This boiler is used to produce superheated steam to start the smelter, drive acid plant compressors, and standby power. Emissions of NO_x are limited with FGR, LNB with good combustion practice, continuous monitoring of NO_x at the smelter main stack, and limitations on fuel throughput. Emissions of PM_{2.5}, CO, SO₂, and VOCs are limited with use of pipeline quality natural gas; good combustion practices; good design and proper operation of the boiler; and continuous monitoring of opacity, particulate, and SO₂ at the smelter main stack.

3.1.9.1 NO_x BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for NO_x for natural gas-fired boilers.

- SCR
- FGR
- LNB with good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The powerhouse boiler is equipped with FGR and LNB to reduce NO_x emissions. Emissions from this boiler are vented through the main stack and it is difficult to differentiate the boiler NO_x emissions from the main stack emissions. Based on the understanding of operations at the Smelter, the addition of the SCR might reduce the annual emissions from the boiler from 5.3 tpy (based on 2016 actual emissions and engineering estimates) to 1.1 tpy.

From the Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boiler, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the powerhouse boiler the estimated cost is \$261,000.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$62,000 and is therefore not cost effective for BACT.

Step 4—Identify BACT. FGR, LNB with good combustion practices, good design and proper operation constitute BACT.

3.1.9.2 SO₂, VOC, and PM_{2.5} BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for boilers.

- Use of pipeline quality natural gas and good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, because all potential technologies identified in Step 1 are selected as BACT.

Step 4—Identify BACT. Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measures for the Powerhouse Foster Wheeler Boiler.

3.1.10 Miscellaneous Storage Piles/Loadout

Source Description: Concentrate, granulated matte, slag, and other materials are stored in storage piles on pads. Water sprays or chemicals are applied as necessary to minimize fugitive emissions.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies dry foggers, adding moisture, and enclosures as possible control technologies for fugitive emissions. Other possible technologies available to control fugitive dust emissions that are not identified in the RBLC include chemical dust suppression, baghouse, cyclone, and scrubber.

Step 2—Eliminate Technically Infeasible Options. The emission sources are fugitive in nature and therefore it is not technically feasible to duct emissions to a baghouse, scrubber, or cyclone. Additionally, the locations of the storage piles are also changing, making the construction of permanent enclosures difficult. Therefore, these control technologies are not technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The remaining technology of water or chemical applications is economically and chronologically feasible.

Step 4—Identify BACT. KUC uses water sprays, chemical dust suppressants, and temporary enclosures to minimize particulate emissions from the miscellaneous storage piles, which were demonstrated to be very effective. These business practices constitute BACT for this emission source.

The use of water sprays, chemical dust suppressants, and temporary enclosures to minimize particulate emissions from the miscellaneous storage piles also represent the most stringent measures.

3.1.11 Slag Concentrator

Source Description: Emissions associated with the crushing, grinding, and slag processing at the smelter are minimized with the water sprays and enclosures.

Step 1—Identify All Control Technologies Listed in RBLC. Although RBLC did not provide controls for the specific operation, other possible particulate control technologies include baghouses, cyclones, scrubbers, water sprays, and enclosures.

Step 2—Eliminate Technically Infeasible Options. Baghouses are not feasible for the slag processing equipment. The slag stock piles are sprayed with water frequently to minimize emissions. The material as a result has very high moisture content, which is not suitable for baghouses. Moisture droplets and condensation can cause accumulation of mud on the bags, baghouse walls, and ductwork. This results in blinded bags and clogged dust removal equipment. Further, when ambient temperatures are below freezing, the mud will freeze on the baghouse bags and plug them.

Wet scrubbers are not expected to be effective in minimizing emissions from crushing and grinding operations. Operation of the scrubbers is compromised due to below freezing ambient temperatures and very cold water streams in the scrubber. The duct work of the scrubbers will freeze during subfreezing ambient temperature conditions.

As discussed in the WRAP Fugitive Dust Handbook, cyclones are mainly used to control large particles.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The remaining technology of water sprays and enclosures is economically and chronologically feasible.

Step 4—Identify BACT. KUC uses water sprays and enclosures to minimize particulate emissions from the slag concentrator, which were demonstrated to be very effective. These business practices constitute the BACT for this emission source.

The use of water sprays and enclosures to minimize particulate emissions represent the most stringent measures from the slag concentrator.

3.1.12 Smelter Cooling Towers

Source Description: Three noncontact water cooling towers are used for various smelter processes. The towers are equipped with drift eliminators with drift loss rated at 0.001 percent.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.

Step 2—Eliminate Technically Infeasible Options. Not applicable, as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, because all potential technologies identified, in Step 1, are selected as BACT.

Step 4—Identify BACT. Drift eliminators and good operating practices constitute BACT.

The use of drift eliminators with drift loss rated at 0.001 percent and good operating practices represent most stringent measures for the cooling tower.

3.2 Refinery

3.2.1 Boilers

Source Description: The two boilers are rated at 82 MMBtu/hr (gas) and 79 MMBtu/hr (oil) each and are permitted to operate on natural gas to meet the steam demand at the refinery. During natural gas curtailment, the boilers are permitted to operate on oil. Emissions of NO_x are limited with FGR and LNB with good combustion practices. Emissions of PM_{2.5}, SO₂, and VOCs are limited with good combustion practices, good design, opacity limits, sulfur content limit, and proper operation of the boilers.

3.2.1.1 NO_x BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for NO_x for natural gas-fired boilers

- SCR
- FGR
- LNB with good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The refinery boilers are equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR will reduce the emissions from the boilers from 12.9 tpy (based on based on 2016 actual emissions) to 2.6 tpy.

From the Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boilers, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 50 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing

SCR technology is 0.02 lb/MMBtu (the 100 MMBtu/hr boiler controlled NO_x emission rate with SCR is listed at 0.03 lb/MMBtu). From Table 6-5 of the ACT document, the total annualized cost for the 50 MMBtu/hr gas boiler (closest entry to 82 MMBtu/hr Refinery boiler) is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74. The estimated costs for the refinery boilers is \$428,040 for both boilers.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$42,000 for the refinery boilers and is, therefore, not cost effective for BACT.

Step 4—Identify BACT. FGR, LNB with good combustion practices, good design, and proper operation constitute BACT for this source.

3.2.1.2 SO₂, VOC, and PM_{2.5} BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for natural gas fired boilers:

- Use of pipeline quality natural gas and good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, because all potential technologies identified, in Step 1, selected as BACT.

Step 4—Identify BACT. Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measures for the boilers.

3.2.2 CHP Unit

Source Description: The CHP unit will generate power and steam to support refinery operations. The CHP unit uses a low NO_x duct burner and the turbine has SoLoNO_x burners. Emissions of PM_{2.5}, SO₂, and VOC are limited with good design and proper operation.

3.2.2.1 NO_x BACT

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for NO_x for natural gas-fired turbines and duct burners.

- SCR
- LNB with good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. The CHP unit is equipped with LNB (SoLoNO_x technology burners on turbine) to reduce NO_x emissions. The addition of the SCR will reduce actual annual emissions from the CHP unit from 12.2 tpy (based on 2014 actual emissions) to 1.2 tpy. The CHP unit had major work performed in 2015 and 2016, therefore 2014 emissions are used for the analysis.

Solar developed an estimation spreadsheet for the Taurus 70 combustion turbine and duct burner arrangement, which utilized vendor quotations for the installation of an SCR system. From the Solar calculations, the annualized capital and operating costs were estimated to be \$932,100/yr.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$85,000 for the CHP unit and is therefore not cost effective for BACT.

Step 4—Identify BACT. LNB with good combustion practices, good design, and proper operation of the CHP Unit constitute BACT for this source.

3.2.2.2 SO₂, VOC, and PM_{2.5} Best Available Control Technologies

Step 1—Identify All Control Technologies listed in RBLC. The RBLC identifies the following as possible control technologies for small turbines and duct burners:

- Use of pipeline quality natural gas and good combustion practices
- Good design and proper operation

Step 2—Eliminate Technically Infeasible Options. All control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, because all potential technologies identified, in Step 1, selected as BACT.

Step 4—Identify BACT. Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the CHP unit constitute BACT for this emission source.

LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measures for the CHP unit.

3.2.3 Refinery Cooling Towers

Source Description: Two noncontact water cooling towers are used for various refinery processes. The towers are equipped with drift eliminators with drift loss rated at 0.001 percent.

Step 1—Identify All Control Technologies Listed in RBLC. The RBLC identifies drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.

Step 2—Eliminate Technically Infeasible Options. Not applicable, as all identified control technologies are technically feasible.

Step 3—Eliminate Economically/Chronologically Infeasible Options. Not applicable, because all potential technologies identified, in Step 1, are selected as BACT.

Step 4—Identify BACT. Drift eliminators and good operating practices constitute BACT.

The use of drift eliminators with drift loss rated at 0.001 percent and good operating practices represent most stringent measures for the cooling tower.

SECTION 4

Best Available Control Technology Summary

This section provides a summary of BACT for emission sources deemed insignificant at the Smelter and Refinery.

Table 4-1. Best Available Control Technology Summary for Smelter and Refinery

Emission Source ID/Name	Emission Source Description	BACT Summary
Building heating	Natural gas heaters	Emissions are minimized with LNB and use of pipeline quality natural gas.
At water heaters	Natural gas water heaters	Emissions are minimized with LNB and use of pipeline quality natural gas.
Ground Matte Silo BH	Storage silo	Emissions controlled with a baghouse.
Mold Coating Silo BH	Storage silo	Emissions controlled with a baghouse.
Hydromet Plt Limestone Silo BH	Storage silo	Emissions controlled with a baghouse.
Hydromet Plt Lime Silo BH	Storage silo	Emissions controlled with a baghouse.
Lab BH	Smelter laboratory	Emissions controlled with a baghouse.
Recycle and Crushing Building	Recycle and crushing building	Process is enclosed to minimize emissions.
Anode Area Lime Silo	Storage silo	Emissions controlled with a baghouse.
Secondary Gas System Lime Silo	Storage silo	Emissions controlled with a baghouse.
Loading to Storage Pile on Patio	Material handling	Emissions are minimized with water sprays and enclosures.
Fueling	Fueling stations at the smelter	Stage 1 and Stage 2 vapor recovery systems minimize emissions.
Degreasing	Cold solvent degreasers at the Smelter	Keeping the lids closed on the degreasers minimize solvent loss and emissions.
Emergency backup power generators	Emergency generators	Emissions comply with applicable New Source Performance Standards.
Smelter Comm. Generator	LPG communications generator	Emissions comply with applicable New Source Performance Standards.
Cathode Wash	Process area	Emissions are minimized through enclosures and complying with standard operating procedures (SOPs).
Anode Scrap	Process area	Emissions are minimized through enclosures and complying with SOPs.
Hydrometallurgical Precious Metals Recovery Scrubber	Process area	Emissions controlled with scrubber
Hydrometallurgical Silver Production Scrubber	Process area	Emissions controlled with scrubber
Se Crushing/Packing Baghouse	Process area	Emissions controlled with baghouse

Table 4-1. Best Available Control Technology Summary for Smelter and Refinery

Emission Source ID/Name	Emission Source Description	BACT Summary
Au/Ag Baghouse	Process area	Emissions controlled with baghouse
Soda Ash Filter	Process area	Emissions controlled with bin vent filter
Space Heaters	Natural gas heaters	Emissions are minimized with LNB and use of pipeline quality natural gas.
Gasoline Fueling	Fueling stations at the refinery	Stage 1 and Stage 2 vapor recovery systems minimize emissions.
Degreasing	Cold solvent degreasers at the Smelter	Keeping the lids closed on the degreasers minimize solvent loss and emissions.
Paint	Process area	Emissions minimized with enclosures
Primer	Process area	Emissions minimized with enclosures
Diesel Generators	Emergency generator	Emissions comply with applicable New Source Performance Standards.
LPG Generator	LPG communications generator	Emissions comply with applicable New Source Performance Standards.

The MAP facility was first permitted in 2008 and was modified in March 2013 (AO DAQE-AN0103460052-13) to reflect the updated design of the plant. The permitting actions have required thorough control technology analysis that the plant will implement BACT to minimize emissions from the facility. Due to this very recent permitting action, KUC has not developed a detailed BACT analysis for the emission sources at MAP facility. However, KUC has developed the following summary of BACT for emission sources at the MAP facility.

Table 4-2. Best Available Control Technology Summary for the Molybdenum Autoclave Process Facility

Emission Source ID/Name	Emission Source Description	BACT Summary
CHP Unit	Combined Heat and Power Unit	LNB and use of pipeline quality natural gas will minimize emissions
Cooling Tower	20,000 gallon per minute (gpm) Cooling Tower	Drift eliminator with efficiency of 0.0005 percent will minimize emissions
IT Building Backup Generator	LPG Communications Generator	Emissions will comply with applicable New Source Performance Standards.
Emergency Fire Pump	Emergency Fire Pump	Emissions will comply with applicable New Source Performance Standards.
Dryers and Re-oxidizer	Three Process dryers and re-oxidizer each rated less than 5 MMBtu/hr	Use of pipeline quality natural gas will minimize emissions
Calciner	Process calciner rated at 16 MMBtu/hr	LNB and use of pipeline quality natural gas will minimize emissions
Startup Boiler	Process startup boiler rated at 30 MMBtu/hr	LNB and use of pipeline quality natural gas will minimize emissions
Scrubbers	Process ammonia, sulfuric acid and hydrogen sulfide emissions	Emissions will be controlled with scrubbers

Table 4-2. Best Available Control Technology Summary for the Molybdenum Autoclave Process Facility

Emission Source ID/Name	Emission Source Description	BACT Summary
Packaging Area	Material Packaging Area	Emissions will be controlled with baghouse and bin vent filters
Reagent Storage	Reagent Storage Tanks and Bins	Emissions will be controlled with bin vent filters and scrubbers
Material Handling	Concentrate transfer and handling	Emission sources will be located inside building and enclosures
Solvent Extraction Lines	Solvent tanks and mixers	Emissions will be minimized through SOPs
Test Laboratory	Laboratory for the MAP operations	Emissions will be controlled with baghouse
Process Boiler	Process boiler rated at 12 MMBtu/hr	LNB and use of pipeline quality natural gas will minimize emissions

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SECTION 5

Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

5.1 Smelter

Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Emission Point	Pollutant	Test Frequency
Main Stack (Stack No. 11)	PM _{2.5}	<ul style="list-style-type: none"> • 89.5 lbs (filterable, daily average) • 434 lbs/hr (filterable + condensable daily average)
	SO ₂	<ul style="list-style-type: none"> • 552 lbs/hr (3 hr. rolling average) • 422 lbs/hr (daily average)
	NO _x	<ul style="list-style-type: none"> • 154 lbs/hr (daily average)
Holman Boiler	NO _x	<ul style="list-style-type: none"> • 14.0 lbs/hr (calendar-day average)

Stack testing to show compliance with the emissions limitations of Condition (A) above shall be performed as specified below:

Emission Point	Pollutant	Test Frequency
Main Stack	PM ₁₀	Every year
	SO ₂	Continuous Emissions Monitor (CEM)
	NO _x	CEM
Holman Boiler	NO _x	Every 3 years and alternate method determined according to applicable new source performance standards

During startup/shutdown operations, NO_x and SO₂ emissions are monitored by CEMs or alternate methods in accordance with applicable NSPS standards. This condition establishes emissions limitations and compliance requirements for the smelter main stack and the Holman Boiler.

KUC continuously monitors operational parameters to predict NO_x emissions and to ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lb/hr), stack oxygen (to monitor proper boiler operation and compliance with NO_x lb/MMBtu emission limit), and steam output (used to estimate heat input if fuel use unavailable). The ranges for these parameters were developed during a 30-day monitoring campaign where data from a certified NO_x analyzer were used to develop predictive equations with the operational parameters. The alternative monitoring method identified in this condition is consistent with the applicable NSPS.

5.2 Refinery

Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission
The sum of two (tankhouse) boilers	NO _x	9.5 lb/hr
Combined heat plant	NO _x	5.96 lbs/hr

Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Tankhouse boilers	NO _x	Every 3 years*
Combined heat plant	NO _x	Every year

Notes:

*Stack testing shall be performed on boilers that have operated more than 300 hours during a 3-year period.

KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Records shall be kept on site which indicate the date, and time of startups and shutdowns. This condition establishes emissions limitations and compliance requirements for the Refinery Boilers and Combined Heat and Power unit.

5.3 Molybdenum Autoclave Process

Emissions to the atmosphere from the natural gas turbine, combined with the duct burner, and with the turbine electric generator (TEG); firing shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission Rate
Combined heat plant	NO _x	5.01 lbs/hr

Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Combined heat plant	NO _x	Every year

Records shall be kept on site which indicate the date and time of startups and shutdowns. This condition establishes emissions limitation and compliance requirements for the MAP facility combined heat and power unit.

FINAL REPORT

Kennecott Utah Copper

**PM_{2.5} State Implementation Plan:
Best Available Control
Technology Determinations**

Submitted to

Utah Division of Air Quality

Prepared for:

Kennecott Utah Copper

Prepared by:



February 2018

FINAL

BACT Determinations for the Bingham Canyon Mine and Copperton Concentrator

Prepared for

Kennecott Utah Copper

February 2018

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Acronyms and Abbreviations

AO	approval order
BACT	best available control technology
BCM	Bingham Canyon Mine
CAA	Clean Air Act
CO	carbon monoxide
EPA	Environmental Protection Agency
gr/dscf	grains per dry standard cubic feet
GPS	Global Positioning System
KUC	Kennecott Utah Copper
MMBTU/hr	million British Thermal Units per hour
NAAQS	National Ambient Air Quality Standard
NH ₃	ammonia
NO _x	nitrogen oxides
PM ₁₀	particulate matter less than or equal to 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppm	parts per million
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearing house
SIP	State Implementation Plan
SO ₂	sulfur dioxide
TPY	tons per year
UDAQ	Utah Department of Air Quality
VOC	volatile organic compound

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Introduction

Kennecott Utah Copper LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities: Bingham Canyon Mine (BCM) and the Copperton Concentrator. In addition to a BACT analysis, KUC has also documented Most Stringent Measures for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and meet any reasonable further progress requirements. As requested by the Utah Division of Air Quality (UDAQ), the BACT analysis should identify and evaluate reasonable and available control technologies for each relevant pollutant. The technical and economic feasibility of each potential technology are components of the BACT analysis that help to show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environment Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOCs). For each emission source, the BACT analysis followed a four-step process:

- **Step 1**—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC) and/or California Environmental Protection Agency – Air Resource Board BACT Clearinghouse (CARB)
- **Step 2**—Eliminate technically infeasible options
- **Step 3**—Eliminate economically/chronologically infeasible options
- **Step 4**—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent the most stringent measure.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important that these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS were combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends that BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development standard.

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Recent Permitting Actions

Current operations at the BCM are permitted under Approval Order (AO) DAQE-AN105710042-18, issued on January 10, 2018.

Emissions from the BCM are mainly limited by the following conditions:

- “Total material moved (ore and waste) shall not exceed 260 million tons per rolling 12-month period.” This condition limits the total material moved at the BCM, thus limiting all point, fugitive and tailpipe emissions.
- “Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles.” This condition limits daily vehicle miles travelled at the BCM, thus limiting both fugitive and tailpipe emissions.
- “Emissions of particulate matter less than or equal to 10 microns in aerodynamic diameter (PM₁₀), NO_x, and SO₂ combined shall not exceed 7,350 tons and emissions of PM_{2.5}, NO_x, and SO₂ shall not exceed 6,205 tons per rolling 12-month period.”
- “KUC shall apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.”

KUC is required to submit an annual fugitive dust control report that provides a description of the fugitive dust control practices implemented at the BCM.

Current operations at the Copperton Concentrator are permitted under AO DAQE-AN105710035-13 issued on June 25, 2013. Potential to Emit (PTE) emissions for the Copperton Concentrator are a very small percentage of combined emissions from the mine and concentrator facilities. Emissions for the Copperton Concentrator are limited by implementation of BACT controls.

PTE emissions in tpy for the BCM and the Copperton Concentrator are shown in Table 2-1.

Table 2-1. Facility Potential to Emit Emissions (Including Fugitive and Nonroad Engine Emissions)

	PM ₁₀ PTEs (tpy)	PM _{2.5} PTEs (tpy)	NO _x PTEs (tpy)	SO ₂ PTEs (tpy)	VOC PTEs (tpy)
Bingham Canyon Mine	1,519	369	5,838	7	314
Copperton Concentrator	25.3	13.86	10.66	0.1	4.04

Notes:

NO_x = oxides of nitrogen

PM₁₀ = Particulate matter 10 microns or smaller in aerodynamic diameter

PM_{2.5} = Particulate matter 2.5 microns or smaller in aerodynamic diameter

PTE = potential to emit

tpy = tons per year

SO₂ = sulfur dioxide

VOC = volatile organic compounds

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BACT Determinations

This section provides BACT determinations for emission sources deemed significant at the BCM and the Copperton Concentrator.

KUC has reviewed publicly available permitting documents for open pit mines around the country. Permits for two facilities were reviewed in detail – the Morenci Mine and Rosemont Copper Project in Arizona. Although on a smaller scale, the Rosemont project was reviewed as the permit was based on recent BACT determinations for mining operations. Operations at the Morenci mine closely resemble those at KUC. Similar to the BCM and Copperton Concentrator, at these facilities emissions from large crushing operations are controlled with fabric filters, emissions from open areas, roads, storage piles and material handling are minimized with practices such as dust suppressant application and watering. Visible emissions limitations are included in the permit for mobile sources such as graders, dozers and haul trucks.

3.1 Bingham Canyon Mine

3.1.1 In-pit Crusher

Source Description: The crusher is used to crush copper ore mined at the BCM. Particulate emissions from the in-pit crusher are controlled with a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific emissions controls information for copper ore crushers. However, the databases identify baghouse (fabric filter) and enclosures with water sprays as possible control technologies for limiting emissions from crushers. The databases did not provide needed information on copper ore crushing. Therefore, due to differences in the material type listed in the databases and copper ore crushed at the BCM, a direct comparison of baghouse grain loading cannot be established.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are economically feasible.
- **Step 4—Identify BACT.** Fabric filters are the most effective in controlling emissions. Therefore, use of a baghouse (fabric filter) constitutes BACT for the in-pit crusher.

The existing baghouse for the crusher is permitted at a grain loading of 0.016 grains per dry standard cubic feet (gr/dscf). KUC investigated the options of either upgrading the filter system in the baghouse or replacing the baghouse.

Based on the review the RBLC and CARB databases, KUC found small baghouses with the grain loading of 0.002 gr/dscf to 0.003 gr/dscf. Using the most stringent emissions rates, KUC requested vendor information on baghouse upgrades to meet the 0.002 gr/dscf grain loading. Based on the data provided by the vendors, the total installed costs for the upgraded baghouse would be about \$608,000. Based on the grain loading of the upgraded baghouse, PM_{2.5} emissions from the crusher will be reduced from 2.28 tpy after the primary control to 0.28 tpy. The vendor provided information is included in the Appendix.

Based on the costs for the baghouse replacement, the cost per ton of PM_{2.5} removed is \$304,000. Therefore, replacing the crusher baghouse is not cost effective for BACT. Additionally, the vendors are unable to guarantee continuous compliance with the low emission rate from the baghouse for the in-pit crusher.

The current emission rate therefore represents the most stringent measure for the in-pit crusher.

3.1.2 Disturbed Areas

Source Description: Disturbed areas from mining activities. KUC current practices include application of dust palliatives and revegetation of the areas as soon as practical, as well as water application from passing water trucks in the operational areas to minimize dust. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific emissions controls information for disturbed areas from mining activities. However, the databases identify revegetation, adding moisture, and enclosures (wind screens) as possible control technologies for fugitive emissions.

- **Step 2—Eliminate Technically Infeasible Options.**

Applying additional moisture (water) on the disturbed areas, as mining occurs, is not technically feasible for KUC's mine operations. The ore is transferred through a series of conveyors. Excessive moisture in the ore material causes the conveyors to foul and breakdown resulting in costly equipment repairs. Therefore, adding moisture to the ore material is not technically feasible.

Because the disturbed areas are so expansive and cover varying terrain, adding enclosures or wind screens are not technically feasible for this mine source.

However, at the request of UDAQ, KUC had discussions with mine management about the feasibility of application of water for dust control on the disturbed areas that have been released for reclamation.

Because the areas are so expansive, set up of irrigation systems for watering is not technically feasible. Using water trucks would disturb the reclaimed areas and would not provide benefit over reclamation and would therefore not be technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 were technically infeasible or selected as BACT.
- **Step 4—Identify BACT.** The practice of applying dust palliatives and revegetation is the most effective in reducing emissions from disturbed areas that have been released for reclamation. Therefore, the application of palliatives and revegetation constitute BACT for areas released for reclamation.

The application of palliatives and revegetation also represent BACM for the disturbed areas. Because best available measures are in use, they also represent the most stringent measure.

3.1.3 Waste Rock Offloading from Trucks

Source Description: Haul trucks dump waste rock or overburden at the waste rock disposal areas while minimizing the height of the drop. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify water application and enclosures as possible control technologies for fugitive emissions from similar sources of emissions. Another possible control technology not identified, but effective in reducing emissions from batch drop transfer points, is minimizing the drop distance while the waste rock is being dumped.
- **Step 2—Eliminate Technically Infeasible Options.**

Because the drop location is not static, an enclosure is not technically feasible. Water application is not technically feasible because excessive water application may result in geotechnical issues on the waste rock dumps. Additionally, an installation or setup of a water irrigation system for water application is not technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable as the remaining technology of minimizing the drop distance, while the waste rock is being dumped, is selected as BACT.
- **Step 4—Identify BACT.** Minimizing drop distances while the waste rock is being dumped is effective in controlling emissions and constitutes BACT.

Minimizing drop distances while the waste rock is being dumped also represents BACM. Because best available measures are in use, they also represent the most stringent measure.

3.1.4 Graders

Source Description: The graders primarily operate on the haul roads, maintaining surfaces of the roads. Particulate matter is controlled by the application of water and chemical dust suppressants to the roads. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify the application of water and chemical dust suppressants as a possible control technology for similar fugitive emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary constitute BACT.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the graders. Because best available measures are in use, they also represent the most stringent measure.

3.1.5 Bulldozers and Front-end Loaders

Source Description: The dozers and front-end loaders operate in the pit, on the haul roads performing cleanup operations, and in dumping operations at the waste rock disposal areas. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify the application of water and chemical dust suppressants as required as a possible control technology for similar fugitive emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary constitute BACT.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the bulldozers and front-end loaders. Because best available measures are in use, they also represent the most stringent measure.

3.1.6 Unpaved Haul Roads

Source Description: Haul roads are used to transfer ore and waste rock. The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary minimize emissions from the unpaved haul roads. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify potential technologies for control of fugitive emissions on unpaved haul roads as: paving the unpaved roads, the application of water and the use of dust suppression chemicals, limiting unnecessary traffic on roads and routine maintenance (including the use of road base material) of haul roads.
- **Step 2—Eliminate Technically Infeasible Options.** Paving the haul roads is not technically feasible at the mine because of the weight of the haul trucks, the rapid deterioration that would occur, and the frequently changing road locations. The location of these roads changes regularly making the paving of the surface infeasible. Paving the roads to minimize emissions is not technically feasible and will not be evaluated further. Additionally, with changing mine plans and haul routes, it is impossible to accurately estimate the costs for paving the road surface.

Application of chemical dust suppressants is not technically feasible for some haul road locations because of the adverse effect the chemical can have on the coefficient of friction of the road surface. Given that the grade of the haul roads exceeds 10 percent in some locations, creating a slippery skin on the road inhibits the ability of mobile equipment to brake and steer safely while traveling on the grade.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The remaining technologies of water application, chemical dust suppressants outside of the pit influence boundary, limiting unnecessary traffic on roads, and routine maintenance of haul roads are economically and chronologically feasible.
- **Step 4—Identify BACT.** The application of water and road-base material within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary is effective in minimizing emissions. Watering the unpaved haul road reduces fugitive PM_{2.5} and PM₁₀ emissions by binding the soil particles together, reducing free particles available to be picked up by wind or vehicles. Additional watering and application of chemical dust suppressants on certain locations of unpaved haul roads also occurs when heavy traffic is expected along the road. Water is applied on a scheduled basis and supplemented as needed based on road conditions. Dust is also reduced through performing regular and routine maintenance of the haul roads (through use of road-base material) and limiting unnecessary traffic on roads.

In recent years, KUC has purchased newer haul trucks with higher capacity where possible, which has led to a decrease in the round-trips and vehicle miles traveled, thereby reducing fugitive dust emissions.

The annual fugitive dust control report for the mine is provided in the Appendix for reference.

The application of water within the pit influence boundary and water and chemical dust suppressants outside the pit influence boundary also represents BACM for the unpaved haul roads. Because best available measures are in use, they also represent the most stringent measure.

3.1.7 Tailpipe Emissions from Mobile Sources

Source Description: Tailpipe emissions from haul trucks and support equipment such as graders and dozers. Tailpipe emissions from the haul trucks and support equipment meet the required EPA standards for

NONROAD equipment. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify no add on control technologies for tailpipe emissions from haul trucks and support equipment of the size used at the BCM.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable.
- **Step 4—Identify BACT.** Haul trucks and support equipment used at the facility meet the required EPA standards for nonroad equipment. The facility uses on-road specification diesel fuel in its off-road equipment. In 2007, an EPA ruling required sulfur content in all on-road specification diesel fuels be reduced (from 50 parts per million [ppm] formerly to 15 ppm currently). Because only on-road specification diesel fuel is used in its equipment, the facility has also made a transition to ultra-low sulfur diesel fuel. All the facility's diesel-powered equipment now runs on ultra-low sulfur diesel fuel.

Additionally, the facility periodically upgrades its haul truck fleet to also take advantage of available higher-tier-level, lower-emitting engines. In recent years, KUC has purchased newer haul trucks with higher capacity where possible, which has led to a decrease in round-trips and truck operating hours, thereby reducing emissions.

Purchasing new haul trucks with higher capacity and Tier level which meet its mining needs also represents the most stringent measure.

During the previous SIP work in 2014, KUC developed a detailed analysis for the haul truck engine repowering and upgrade to higher tier level trucks. The analysis is provided in the Appendix.

3.1.8 Fueling Stations

Source Description: Adding gasoline and diesel to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify two control techniques for controlling VOC emissions from gasoline and diesel fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Stage 1 and 2 vapor recovery constitutes BACT for these sources.

The use of Stage 1 and Stage 2 vapor recovery systems also represent the most stringent measure for the fueling stations.

3.1.9 Cold Solvent Degreasers

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify operating practices such as closing the degreaser lids a method to control/minimize VOC emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as the identified control technology is technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** When not in use, the lids on the degreasers are kept closed always to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for degreasers.

A Safety Data Sheet for the degreasing solvent is provided in the Appendix. KUC has experimented with low-VOC content degreasers in the past. However, these solvents were found ineffective in cleaning parts and often resulted in residue on the parts. As a result, transition to low-VOC solvent as a degreasing agent is not further investigated for this analysis. Additionally, the 2014 actual VOC emissions from degreasers at the mine were 1.7 tpy. The previously identified practices also represent the most stringent measure for the degreasers.

3.1.10 Mine Conveyor Transfer Points

Source Description: The mine has two ore conveyor transfer drop points — Point C6/C7 and Point C7/C8. All exhaust air and particulate emissions from each transfer drop point are routed through the respective baghouse before being vented to the atmosphere. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify baghouse (fabric filter) and enclosures with water sprays as possible control technologies for limiting emissions from transfer points.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Fabric filters are the most effective in controlling emissions. Therefore, the baghouse (fabric filter) constitutes BACT for the conveyor transfer points.

The baghouse for each of the transfer points is permitted at a grain loading of 0.007 gr/dscf. The 2014 actual PM_{2.5} emissions for conveyor transfer points controlled with a baghouse were 0.69 and 0.42 tpy each. Due to the low level of emissions from these sources, the BACT analysis did not evaluate the upgrade of the baghouses for these units. Additionally, based on the economics data presented in Section 3.1.1 of this document for baghouse replacement/upgrades, any upgrades or replacement would not be economically feasible.

This emission rate also represents the most stringent measure for the conveyor transfer points.

3.1.11 Lime Bins

Source Description: The Copperton Concentrator has two lime silos used for lime storage. Particulate emissions generated during loading and unloading operations are vented through a filter. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify vent filters and enclosures as possible control technologies for limiting emissions from storage silos.

- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Vent filters are the most effective in controlling emissions. Therefore, bin vent filters constitute BACT for the lime silos/bins.

The vent filter for each of the lime silos is permitted at a grain loading of 0.016 gr/dscf. These units are operated intermittently. The 2014 actual PM_{2.5} emissions for the two lime silos controlled with a baghouse were 0.02 tpy. Due to the low level of emissions from these sources, the upgrade of the vent filters for these units would not be economically feasible.

This emission rate also represents the most stringent measure for the lime silos.

3.1.12 Sample Preparation Building

Source Description: The sample preparation building at the mine is used for preparation of waste rock and ore samples for testing. Particulate emissions from the sample preparation building are vented through a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify baghouses and enclosures as possible control technologies for limiting emissions from buildings or enclosed areas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Baghouses are the most effective in controlling emissions. Therefore, the fabric filters (baghouse) constitute BACT for the sample preparation building.

The baghouse for the sample preparation building is permitted at a grain loading of 0.016 gr/dscf. The building and the control system are operated intermittently. The 2014 actual PM_{2.5} emissions for the sample preparation building controlled with a baghouse were 0.05 tpy. Due to the low level of emissions from these sources, the upgrade of the baghouse for the unit would not be economically feasible.

This emission rate also represents the most stringent measure for the sample preparation building.

3.1.13 Propane Communications Generators

Source Description: The mine operates six (6) propane fired communications generators. These generators are used to support mine communication systems during emergencies or loss of power in the mine. Emissions are controlled with good combustion practices while operating the generators. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify good combustion practices as the primary control technology for emergency generators between 70 HP and 150 HP operated on propane. The emergency generators must also comply with the applicable New Source Performance Standards established by EPA.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Good combustion practices are identified as BACT for the propane fired emergency generators. The emergency generators also comply with applicable New Source Performance Standards.

It should be noted that the 2014 actual PM_{2.5} and precursor emissions for all the propane emergency generators combined were 0.18 tpy.

Good combustion practices also represent the most stringent measure for the propane communication generators.

3.1.14 Ore Handling

Source Description: The mined ore is moved around the mine through conveyors and trucked to the stock piles as needed. The sources include Truck Offloading Ore Main In-pit Crusher, Truck Offloading Ore Stockpile, Main In-Pit Enclosed Transfer Points, Conveyor-stacker Transfer Point, Coarse Ore Stacker and Reclaim Tunnels. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific emission controls for such material handling sources from a copper mine. The location of many of these sources change regularly making the construction of emission controls such as enclosures and application of dust suppressants infeasible for such sources. Therefore, potential control technologies include material characteristics such as large size with minimal quantities of fine material, enclosures and inherent moisture content as applicable to the emission source.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Material characteristics such as large ore size and presence of very small quantities of fine material are identified as BACT for the ore handling sources.

It should be noted that the 2014 actual PM_{2.5} emissions for these ore handling sources were 0.94 tpy.

The material characteristics such as large ore size and presence of very small quantities of fine material, inherent moisture content and enclosures also represent the most stringent measure for the ore handling emission sources.

3.1.15 Ore Storage Pile

Source Description: Low grade ore is stockpiled at the mine and blended into the process as necessary. Potential wind-blown dust emissions are minimized through application of water sprays and chemical dust suppressants and compaction. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify water sprays, chemical dust suppressants and compaction as potential control technologies to minimize emissions from large storage piles.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Water sprays, chemical dust suppressants and compaction are identified as BACT for the ore storage pile.

It should be noted that the 2014 actual PM_{2.5} emissions for the ore storage pile were 0.33 tpy.

These controls also represent the most stringent measure for the ore storage pile.

3.1.16 Road Base Crushing and Screening Plant

Source Description: The mine has semiportable plants that crush and screen rock for use for base material on the unpaved haul roads. Particulate emissions from the crushing, screening, and transfer operations are effectively controlled with water sprays and belt enclosures. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific emission controls for a road base crushing and screening plant for a copper mine. However, possible control technologies include baghouses, enclosures and water sprays for minimizing emissions from the road base crushing and screening plant.
- **Step 2—Eliminate Technically Infeasible Options.** The road base crushing system is moved through the mine to facilitate the production of road base material to meet demands. As a result, permanent installation of a baghouse to control emissions from the plant is not technically feasible. Water Sprays and temporary enclosures are feasible for the plant.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technically feasible technologies are economically feasible.
- **Step 4—Identify BACT.** Water sprays and enclosures are identified as BACT for the road base crushing and screening plant.

It should be noted that the 2014 actual PM_{2.5} emissions for the road base crushing and screening plant were 0.05 tpy.

These controls also represent the most stringent measure for the road base crushing and screening plants.

3.1.17 Drilling and Blasting

Source Description: Drilling and blasting are performed at the mine to access new ore bodies. Water injection is used to minimize emissions from drilling. The blast areas are controlled as practical to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific controls for drilling and blasting in open pit mines. Based on the mining experience, KUC identifies water injection and maintaining control of blast areas as potential control technologies to minimize emissions from drilling and blasting.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.

- **Step 4—Identify BACT.** Water injection and maintaining control of blast areas are identified as BACT from drilling and blasting operations.

It should be noted that the 2014 actual PM_{2.5} and precursor emissions for drilling and blasting sources were 0.75 tpy. These controls also represent the most stringent measure for the drilling and blasting operations.

3.1.18 Solvent Extraction and Electrowinning Process

Source Description: Tanks, mixers and settlers are used in the solvent extraction and electrowinning process. Covers are used to minimize emissions from these sources. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases do not identify specific controls for solvent extraction and electrowinning process. Based on the mining experience, KUC identifies covers on process equipment to minimize emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Use of covers is identified as BACT for the solvent extraction and electrowinning process.

It should be noted that potential emissions of PM_{2.5} and precursors for solvent extraction and electrowinning are minimal.

These controls also represent the most stringent measure for the solvent extraction and electrowinning process.

3.2 Copperton Concentrator

3.2.1 Tioga Heaters

Source Description: Natural gas-fired heaters are used throughout the Copperton Concentrator. The heaters are rated at less than 5 MMBTU/hr each. Specifically, the facility includes seven (7) 4.2 MMBtu/hr natural gas fired heaters and one (1) 2.4 MMBtu/hr natural gas fired heater. The heaters are regularly inspected for optimum combustion performance. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.1.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technology identified in the RBLC for controlling NO_x emissions from heaters of good combustion practices is already in use and constitutes BACT.

3.2.1.2 PM_{2.5}, SO₂, CO, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify the use of pipeline quality natural gas and good combustion practices as control technology for minimizing PM_{2.5}, SO₂, CO, and VOC emissions from heaters.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, CO, and VOC emissions from heaters and these control technologies constitute BACT.

At the request of UDAQ, KUC contacted vendors regarding the feasibility of replacement of the 8 Tioga heaters at the Copperton Concentrator.

Based on the data provided by the vendors, the total installed cost of the eight new heaters is estimated to be \$940,000. The costs assume the installation costs to be 35 percent of the equipment costs. These heaters will be equipped with the latest burner technology. Assuming the new heaters will minimize NO_x emissions by 90% from current levels, the new heaters might reduce the annual emissions from the Tioga heaters from 6.2 tpy (based on PTE emissions for the heaters) to 0.68 tpy. The vendor provided information is included in the Appendix.

Based on the costs for the new heaters, the cost of new heaters per ton of NO_x removed is \$153,000. Therefore, replacing the Tioga heaters is not cost effective for BACT.

Low NO_x burners, use of pipeline quality natural gas and good combustion practices also represent the most stringent measure for the Tioga heaters.

3.2.2 Pebble Crushing System

Source Description: The pebble crushing system includes crusher and ore handling conveyors and transfer points. The system is placed inside a building to minimize particulate emissions to the atmosphere. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify baghouses, wet scrubbers, water sprays and enclosures as possible control technologies to minimize emissions from a crushing plant.
- **Step 2—Eliminate Technically Infeasible Options.** Because the emissions will be vented inside the building, wet scrubbers and fabric filters are not technically feasible. Water sprays are not feasible as the water makes the material too wet to crush.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technically feasible technologies are feasible.
- **Step 4—Identify BACT.** Enclosures, or placing the source inside the building, is effective in minimizing emissions from the crusher operations and identified as BACT for the pebble crushing system.

It should be noted, the 2014 actual PM_{2.5} emissions for the pebble crushing system were 0.07 tpy. This control also represents the most stringent measure for the pebble crushing system.

3.2.3 Cold Solvent Degreasers

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify operating practices such as closing the degreaser lids a method to control/minimize VOC emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as the identified control technology is technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** When not in use, the lids on the degreasers are kept closed always to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for degreasers.

A Safety Data Sheet for the degreasing solvent is provided in the Appendix. KUC has experimented with low-VOC content degreasers in the past. However, these solvents were found ineffective in cleaning parts and often resulted in residue on the parts. As a result, transition to low-VOC solvent as a degreasing agent is not further investigated for this analysis. Additionally, the 2014 actual VOC emissions from degreasers at the concentrator were 0.08 tpy.

The previously identified practices also represent the most stringent measure for the degreasers.

3.2.4 Gasoline Fueling Stations

Source Description: Adding gasoline to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify two control techniques for controlling VOC emissions from gasoline fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Stage 1 and 2 vapor recovery constitutes BACT for these sources.

It should be noted that the 2014 actual VOC emissions for the gasoline fueling stations at the Copperton Concentrator were 0.29 tpy.

The use of Stage 1 and Stage 2 vapor recovery systems also represent the most stringent measure for the gasoline fueling stations.

3.2.5 Molybdenum Storage Bins and Loading Bags

Source Description: The Copperton Concentrator has molybdenum storage bins from which bags are loaded for offsite shipping. Particulate emissions generated during loading and unloading operations are vented through a filter. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify vent filters and enclosures as possible control technologies for limiting emissions from storage silos.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Vent filters are the most effective in controlling emissions. Therefore, bin vent filters constitute BACT for the molybdenum storage bins and loading bags.

The 2014 actual PM_{2.5} emissions for these operations controlled with a bin vent filter were 0.5 tpy. Due to the low level of emissions from these sources, the upgrade of the vent filters for these units would not be economically feasible.

This control technology also represents the most stringent measure for the process.

3.2.6 Feed and Product Dryer Oil Heaters

Source Description: Natural gas-fired heaters provide heat to the feed and product dryers that are used in molybdenum process at the Copperton Concentrator. The heaters are rated at 5.7 MMBTU/hr and 2.2 MMBTU/hr each. The heaters are regularly inspected for optimum combustion performance. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.6.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify Low NO_x burners and good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 10 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technology identified in the RBLC and CARB for controlling NO_x emissions from heaters of Low NO_x Burners and good combustion practices is already in use and constitutes BACT.

3.2.6.2 PM_{2.5}, SO₂, CO, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB databases identify use of pipeline quality natural gas and good combustion practices as control technologies for minimizing PM_{2.5}, SO₂, CO, and VOC emissions from heaters.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC and CARB databases identify use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, CO, and VOC emissions from heaters and these control technologies constitute BACT.

SECTION 3 BACT DETERMINATIONS

Low NO_x burners, use of pipeline quality natural gas and good combustion practices also represent the most stringent measure for the heaters. Due to low level of emissions from these units, upgrading these would not be economically feasible.

Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

4.1 Bingham Canyon Mine

KUC is proposing the following limitations and monitoring requirements for the Bingham Canyon Mine.

- Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles. KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System (GPS) or equivalent.
- KUC Shall Use Ultra-low Sulfur Diesel Fuel in Its Haul Trucks.
- To minimize emissions at the mine:
- The owner/operator shall control emissions from the in-pit crusher with a baghouse.
- Apply water to all active haul roads as weather and operational conditions warrant, except during precipitation or freezing conditions, and apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.
- A chemical dust suppressant shall be applied as weather and operational conditions warrant except during precipitation or freezing conditions on unpaved access roads that receive haul truck traffic and light vehicle traffic.
- KUC is Subject to the Requirements in the Most Recent Federally approved Fugitive Emissions and Fugitive Dust Rule.

Supporting Information

The condition above establishes a limitation on daily activity. The daily mileage limitation effectively limits fugitive road dust emissions, tailpipe emissions from the haul trucks, and overall activity of sources at the mine. Ore processing at the Copperton Concentrator, which results in minimal emissions, is also limited through the BCM activity limitations.

Emissions resulting from the movement of ore and waste around the mine represent a significant portion of overall emissions at the BCM. The emissions related to material movement include fugitive dust generated from truck travel on the haul roads and the tailpipe emissions from the haul trucks. Specifically, on an annual basis, greater than 99.9 percent of total mine emissions for NO_x and SO₂ come from the haul truck tailpipes. Also, on an annual basis, material movement represents 85 percent of the overall particulate emissions at the BCM. Based on these emissions, the material movement of ore and waste by haul trucks represents a vast majority of overall emissions at the BCM and can effectively be used to represent mine operations.

Daily emissions from the BCM can be regulated with the limitation on vehicle miles traveled by ore and waste haul trucks of 30,000 miles per day. Compliance with this limitation is demonstrated daily and is an appropriate metric for a 24-hour particulate standard.

It should be noted that the 30,000 miles per day limitation also limits overall BCM operations. Ancillary mining activities such as operation of the in-pit crusher, mining support equipment, blasting, and drilling only occur to

produce an adequate amount of ore and waste rock that can be hauled via the trucks and sent to the concentrator via the conveyor system.

On a 24-hour basis, these emissions can be represented with the 30,000 miles per day limitation. Since they effectively represent mine operations, a single daily limitation is appropriate in the SIP for the BCM. These emissions have been included in the appropriate SIP model.

KUC uses a real-time tracking system for both tracking haul trucks as well as for recording miles travelled. These records are used to comply with the 30,000 miles per day limitation. The system may be a GPS or a system with similar tracking capabilities necessary to comply with this condition.

The condition also establishes a requirement for the use of ultra-low sulfur diesel fuel in haul trucks.

The conditions require the control of emissions from the in-pit crushers with a baghouse.

The condition also establishes requirements for reducing and controlling fugitive particulate emissions from active unpaved haul roads at the mine. Water and chemical dust suppressants shall be used to minimize fugitive dust.

Specifically, active ore and waste haulage roads within the pit influence boundary are water sprayed and/or treated with a commercial dust suppressant. Crushed road-base material is applied to active ore and waste haulage roads within the pit influence boundary to enhance the effectiveness of fugitive dust control measures. Commercial dust suppressants are applied to active ore and waste haulage roads outside of the pit influence boundary no less than twice per year.

Each year KUC reports dust control measures implemented at the BCM during the previous year with details such as volume of water applied, commercial dust suppressant activity, etc.

KUC is subject to the fugitive dust rules approved by UDAQ and EPA. These rules outline requirements that mines are to follow in minimizing the fugitive dust from the mining operations.

4.2 Copperton Concentrator

No limitations or monitoring requirements are proposed for the Copperton Concentrator emission sources as the emissions from the facility are minimal and are effectively controlled with the implementation of BACT.

Attachments

- In-pit Crusher Baghouse Vendor Data
- Mine FDCP Report
- Haul Trucks Analysis
- Degreaser Solvent SDS
- Tioga Heaters Vendor Information

FINAL

BACT Determinations for the Utah Power Plant, Tailings Site, and Laboratory

Prepared for

Kennecott Utah Copper

February 2018

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Acronyms and Abbreviations

AO	approval order
BACT	best available control technology
CAA	Clean Air Act
CatOx	catalytic oxidation
CO	carbon monoxide
DLN	dry low nitrogen
EPA	Environmental Protection Agency
KUC	Kennecott Utah Copper
LNB	low NO _x burner
MMBTU/hr	million British Thermal Units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standard
NO _x	nitrogen oxides
OFA	over-fire air
PM ₁₀	particulate matter less than or equal to 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppmvd	parts per million by volume dry
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearinghouse
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO ₂	sulfur dioxide
tpy	tons per year
UDAQ	Utah Department of Air Quality
UPP	Utah Power Plant
VOC	volatile organic compound

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Introduction

Kennecott Utah Copper, LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities located at the northwest corner of Salt Lake County, Utah: Utah Power Plant (UPP), tailings site, and the laboratory. The tailings site receives tailings in slurry form. The slurry is deposited in the tailings pond. The UPP is a coal and natural gas fired power plant that supplies power for KUC operations. Coal is used to fuel the plant in spring, summer, and fall; while natural gas is approved for use in the winter months. The laboratory is used to perform various tests and functions to optimize operations through analysis of materials. In addition to a BACT analysis, KUC has also documented the most stringent measure for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and to meet any reasonable further progress requirements. As requested by the Utah Division of Air Quality (UDAQ), the BACT analysis should identify and evaluate BACT for each relevant pollutant. The technical and economic feasibility of each potential technology are components of the BACT analysis that help to show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environment Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOC). For each emission source, the BACT analysis followed a four-step process:

- **Step 1**—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC) and/or California Environmental Protection Agency – Air Resource Board BACT Clearinghouse (CARB)
- **Step 2**—Eliminate technically infeasible options
- **Step 3**—Eliminate economically/chronologically infeasible options
- **Step 4**—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent most stringent measure.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important that these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS was combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends that BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development.

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Recent Permitting Actions

An approval order (AO) was issued for the UPP on November 10, 2015, which authorized the construction and operation of a natural gas fired emergency generator. Issued in 2011, AO DAQE-AN105720026-11 authorized KUC to replace Boiler Units 1, 2, and 3 with a new natural gas fired combustion turbine operating in combined cycle mode with a heat recovery steam generator. The new combustion turbine will be equipped with state of the art add-on controls to minimize emissions from the unit and represents BACT. Dry low nitrogen oxide (DLN) combustors and the selective catalytic reduction (SCR) system will control NO_x emissions. The catalytic oxidation (CatOx) system will control carbon monoxide (CO) and VOC emissions. Good combustion practices and burning natural gas will minimize emissions of the remaining pollutants.

The tailings site is permitted under AO DAQE-AN10572018-06. The emissions sources at the laboratory are permitted under AO DAQE-261-95. All three facilities operate under a single Title V Operating Permit #3500346002.

The current potential to emit (PTE) emissions in tons per year (tpy) for the tailings site, UPP, and the laboratory are shown in Table 1-1.

Table 2-1. Facility Potential to Emit

	PM ₁₀ PTE (tpy)	PM _{2.5} PTE (tpy)	NO _x PTE (tpy)	SO ₂ PTE (tpy)	VOC PTE (tpy)
UPP	248	248	1,641	2,577	41
Tailings Site	36.3	5.4**	0.26	—*	0.04
Laboratory	0.12	0.12	0.68	0.13	0.12

Notes:

PM_{2.5} = particulate matter 2.5 microns or smaller in aerodynamic diameter

PM₁₀ = particulate matter 10 microns or smaller in aerodynamic diameter

PTE = potential to emit

NO_x = oxides of Nitrogen

SO₂ = sulfur dioxide

tpy = tons per year

VOC = volatile organic compounds

*Permitted combustion sources result in negligible SO₂ emissions at the tailings site.

**PM_{2.5} emissions are estimated to be 15 percent of PM₁₀ emissions.

Distinguishing by season of operation is allowed under EPA's *Implementation Guidance for the 2006 24-hour Fine Particle NAAQS* (March 2, 2012), which specifically acknowledges that several nonattainment areas located in the western United States only have experienced exceedances during the winter season. In such cases, the EPA authorizes states to (1) develop a seasonal emission inventory and (2) evaluate emission reduction strategies for a single season only [p. 11]. "When following a seasonal approach, the EPA believes that *the control strategy evaluation* (based on seasonal emission reduction measures) and the assessment of future year air quality concentrations (through air quality modeling or other analyses) *should be conducted for that season.*" [p. 12]. In view of the nature of Utah's PM_{2.5} nonattainment circumstance, the BACT analysis for UPP focuses primarily on a wintertime control strategy.

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BACT Determinations

This section provides BACT determinations for emission sources deemed significant at the UPP, Tailings site, and Laboratory.

3.1 Utah Power Plant

Historically, KUC has operated three coal fired boilers rated at 100 megawatts (MW) combined, referred to as Units 1-3, at the UPP. The units operated on coal during the spring, summer and fall months, but were limited to burning natural gas during the winter months between November 1 and March 1. In October 2016, KUC permanently ceased operation of Units 1-3. Therefore, a BACT analysis for Units 1-3 is not included in this document.

3.1.1 UPP Unit 4 Boiler

Source Description: Tangentially fired boiler capable of burning both coal and natural gas, rated at 838 million British Thermal Units per hour (MMBTU/hr) (coal), or 872 MMBTU/hr (natural gas), equipped with an electrostatic precipitator. Since the ambient 24-hour concentrations of PM_{2.5} exceed the NAAQS during the winter months, the BACT analysis is limited to controls for the combustion of natural gas, which are the only controls that may affect the attainment of the PM_{2.5} NAAQS in the Salt Lake City nonattainment area. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.1.1 NO_x BACT

- **Step 1—Identify All NO_x Control Technologies listed in RBLC and CARB.** The RBLC and CARB identifies (1) low NO_x burners with over-fire air (low NO_x burner [LNB] with over-fire air [OFA]) and (2) LNB with OFA and SCR as potential technologies for NO_x control from a natural gas fired boiler.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Previous SIP determination for UPP Unit 4 required the installation of LNB with OFA and SCR with 90% NO_x control when operating on natural gas during the winter months between November 1 and March 1. Because the top technology is already identified in previous SIPs, additional analysis is not necessary.
- **Step 4—Identify BACT.** LNB with OFA and SCR with 90% control efficiency constitute BACT for controlling NO_x emissions from natural gas combustion in the boiler during the wintertime period (November 1 through March 1).

Control efficiency of 90% for LNB with OFA and SCR is a default value used by the industry. A detailed design of the control systems would be necessary to develop anticipated control efficiency for Unit 4. Due to SIP time constraints, a detailed design is not feasible and therefore it is recommended that UDAQ use the default value.

3.1.1.2 SO₂ BACT

- **Step 1—Identify all SO₂ Control Technologies listed in RBLC and CARB.** The RBLC identifies the use of pipeline quality natural gas as a control when burning natural gas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4— Identify BACT.** The use of pipeline quality natural gas constitutes BACT when burning natural gas.

3.1.1.3 PM_{2.5} BACT

- **Step 1—Identify all PM_{2.5} Control Technologies listed in RBLC.** The RBLC identifies good combustion practices as a control for reducing PM_{2.5} when burning natural gas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Good combustion practices constitute BACT while burning natural gas.

3.1.1.4 VOC BACT

- **Step 1—Identify all VOC Control Technologies listed in RBLC.** The RBLC identifies good combustion practices as a control when burning natural gas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4— Identify BACT.** Good combustion practices constitute BACT for VOC while burning natural gas.

Controlling NO_x emissions by 90 percent with LNB, OFA, and SCR and the use of pipeline quality natural gas and good combustion practices represent the most stringent measure for Unit 4 at the UPP when operating on natural gas between November 1 and March 1.

3.1.2 UPP Unit 5 Combustion Turbine and Duct Burner

Source Description: A combustion turbine and duct burner in combined-cycle operation with a nominal generating capacity of approximately 275 MW, equipped with SCR and CatOx. Construction of Unit 5 is not complete at this time.

3.1.2.1 NO_x BACT

- **Step 1—Identify All NO_x Control Technologies listed in RBLC and CARB.** The RBLC and CARB databases identifies selective noncatalytic reduction (SNCR) and SCR as potential technologies for NO_x control. The SCR technology is the most stringent control alternative listed in the RBLC.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** SCR constitutes BACT for controlling NO_x emissions from the Unit 5 combustion turbine and duct burner.

3.1.2.2 VOC BACT

- **Step 1—Identify All CO and VOC Control Technologies listed in RBLC and CARB.** The RBLC identifies CatOx to control emissions of CO and VOC.

- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** CatOx constitutes BACT for controlling CO and VOC emissions from the Unit 5 combustion turbine and duct burner.

3.1.2.3 SO₂ BACT

- **Step 1—Identify All SO₂ Control Technologies listed in RBLC and CARB.** The RBLC identifies the use of pipeline quality natural gas and good combustion practices as a control when burning natural gas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The use of pipeline quality natural gas and good combustion practices constitute BACT for controlling SO₂ emissions from the Unit 5 combustion turbine and duct burner.

3.1.2.4 PM_{2.5} BACT

- **Step 1—Identify All PM_{2.5} Control Technologies listed in RBLC and CARB.** The RBLC identifies the use of pipeline quality natural gas and good combustion practices as a control when burning natural gas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The use of pipeline quality natural gas and good combustion practices constitute BACT for controlling PM_{2.5} emissions from the Unit 5 combustion turbine and duct burner.

Limiting NO_x emissions to 2 parts per million by volume dry (ppmvd) at 15% O₂; CatOx for control of CO and VOC emissions; and the use of pipeline quality natural gas and good combustion practices represent the most stringent measure for Unit 5 at the UPP.

3.1.3 Cooling Towers

Source Description: Noncontact water cooling towers are used to control waste heat from the boilers. All towers are equipped with drift eliminators with drift loss rated at 0.002 percent. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC identifies drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Drift eliminators and good operating practices constitute BACT.

The existing Unit 4 Cooling Tower could be upgraded with 0.001 percent drift factor from the existing 0.002%. Based on KUC's discussions with the vendors, the total installed costs for the upgrade of the drift eliminator would be \$177,000. The upgrade of the drift eliminators would reduce the annual emissions from the Unit 4 Cooling Tower from 3.49 tpy (PTE emissions for the cooling tower) to about 1.75 tpy. The vendor provided information is included in the Appendix.

Based on the costs for the drift eliminator upgrade, the cost per ton of PM_{2.5} removed is \$102,000. Therefore, replacing the existing drift eliminator with a high efficiency drift eliminator is not cost effective for BACT. Based on this cost effectiveness analysis, eliminators with 0.0005% drift loss are not further evaluated as they would not be cost effective as well.

The use of drift eliminators with drift loss rated at 0.002 percent and good operating practices represent the most stringent measure for the cooling towers.

The overall cost is \$102,000 per ton of PM_{2.5} removed but when amortized over a 20 year period the cost is reduced to \$5,100/ton of PM_{2.5} removed. This is cost effective as BACT.

If the cooling towers with a 0.0005% drift loss were implemented, then the cost may even be lower.

3.1.4 Tioga Space Heaters

Source Description: Natural gas-fired space heaters are used for comfort heating and cooling, and water heating throughout the power plant. The space heaters use low NO_x burners (LNB) and regular inspections are done to the units to ensure optimum combustion performance. All space heaters are rated at less than 5 MMBTU/hr. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.4.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC identifies LNB and good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technologies identified in the RBLC and CARB for controlling NO_x emissions from heaters (LNB and good combustion practices) are already in use and constitute BACT.

3.1.4.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC identifies use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from heaters.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC and CARB identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from heaters and these control technologies constitute BACT.

The use of pipeline quality natural gas, LNB and good combustion practices represent the most stringent measure for Tioga Space Heaters at the UPP. As discussed in the BACT analysis for other KUC facilities, replacing the existing space heaters with new heaters is not cost effective for the BACT analysis.

3.1.5 Cold Solvent Degreaser

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies operating practices such as closing the degreaser lids as a method to control/minimize VOC emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as the identified control technology is technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** When not in use, the lids on the degreasers are kept closed at all times to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for the degreaser.

A Safety Data Sheet for the degreasing solvent is provided in the Appendix. KUC has experimented with low-VOC content degreasers in the past. However, these solvents were found ineffective in cleaning parts and often resulted in residue on the parts. As a result, transition to low-VOC solvent as a degreasing agent is not further investigated for this analysis. Additionally, the 2014 actual VOC emissions from degreasers at the UPP were 0.3 tpy.

The previously identified practices also represent the most stringent measure for the degreasers.

3.1.6 Natural Gas Emergency Generators

Source Description: The UPP operates two 1.2 MMBTU/hr natural gas generators. Emissions are controlled with good combustion practices while operating the generator. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as the primary control technology for natural gas generators less than 5 MMBTU/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Good combustion practices are identified as BACT for the natural gas generators.

It should be noted, the 2014 actual emissions for PM_{2.5} and precursors for the natural gas generators were 0.18 tpy.

Good combustion practices also represent the most stringent measure for the natural gas generators.

3.1.7 Roads at UPP

Source Description: Unpaved and paved access roads exist throughout the UPP and are used by KUC personnel daily. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC.** The RBLC identifies potential technologies for control of fugitive emissions on unpaved roads as: paving the unpaved roads, the application of water and the use of dust suppression chemicals, limiting unnecessary traffic on roads and routine maintenance of roads.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 4—Identify BACT.** Paving sections of the road, the application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads are identified as BACT for the roads at the UPP.

It should be noted that the 2014 actual PM_{2.5} emissions from roads at the UPP were 0.27 tpy. Paving sections of the road, the application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads also represent the most stringent measure for the roads at the UPP.

3.1.8 Hot Water Heater

Source Description: Natural gas-fired water heater is used for water heating throughout the power plant. The water heater uses low NO_x burners (LNB) and regular inspections are done to the unit to ensure optimum combustion performance. The water heater is rated at 7.13 MMBTU/hr. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.8.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC.** The RBLC identifies LNB and good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 10 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technologies identified in the RBLC for controlling NO_x emissions from the heater (LNB and good combustion practices) are already in use and constitute BACT.

3.1.8.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC.** The RBLC identifies use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from the heater.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.

- **Step 4—Identify BACT.** The RBLC identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from the heater and these control technologies constitute BACT.

The use of pipeline quality natural gas, LNB and good combustion practices represent the most stringent measure for the hot water heater at the UPP.

3.1.9 Coal and Ash Handling at UPP

Source Description: Coal and ash handling system that includes small coal storage pile, conveyors, and coal and ash storage silos. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC.** The RBLC identifies potential technologies for control of fugitive emissions from coal and ash handling as enclosures and water sprays.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 4—Identify BACT.** Enclosures and water sprays are identified as BACT for coal and ash handling at the UPP.

It should be noted, the 2014 actual PM_{2.5} emissions from coal and ash handling at the UPP were 0.92 tpy. Enclosures and water sprays also represent the most stringent measure for coal and ash handling at the UPP.

3.1.10 Gasoline Fueling Stations

Source Description: Adding gasoline to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify two control techniques for controlling VOC emissions from gasoline fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Stage 1 and 2 vapor recovery constitutes BACT for these sources.

It should be noted, the 2014 actual VOC emissions for the gasoline fueling stations at the UPP were 0.33 tpy.

The use of Stage 1 and Stage 2 vapor recovery systems also represent the most stringent measure for the gasoline fueling stations.

3.1.11 Diesel Fire Pump

Source Description: The UPP operates 175 HP diesel-fired fire pump during emergencies. The fire pump complies with applicable New Source Performance Standards to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** Potential emission control technologies identified in the RBLC and CARB for similar sized diesel fire pumps include good combustion practices and limiting the sulfur content of fuel to 0.0015 percent. Certification and compliance with applicable New Source Performance Standards is an acceptable means of demonstrating BACT for emergency fire pumps.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements are identified as BACT for all pollutants emitted from the emergency fire pump.

It should be noted that the 2014 actual emissions from the fire pump of PM_{2.5} and precursors were 0.12 tpy.

Good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements also represent the most stringent measure for the emergency fire pump.

3.1.12 Diesel Engine for Coal Unloading System

Source Description: The UPP had a 170 HP diesel-fired engine to operate the coal unloading system. This emission source no longer exists at the UPP. Therefore, a BACT analysis has not been developed for this emission source.

3.2 Tailings Site

3.2.1 Wind Erosion from Tailings Site

Source Description: Tailings are sent to the tailings site via a slurry pipeline. At the facility, tailings are separated by size in a cyclone with the larger particles used to build the embankments and the smaller particles discharged in slurry form in the impoundment. Emissions from the tailings site are mainly from wind erosion of dry tailings on the embankment. The facility has a current dust control plan approved by the UDAQ Executive Director for control of fugitive particulate matter. A copy of the quarterly report that documents dust control measures implemented at the facility is included in the Appendix for reference. The dust control plan requires frequent monitoring of the impoundment for wind erosion potential, applying chemical dust suppressants in the late spring, applying water via water trucks and the dust suppression sprinkler system as needed to maintain adequate moisture content.

In 2013, KUC conducted a study to identify and evaluate the range of dust control practices that have been attempted and successfully applied for mine tailings impoundments. A study also reviewed published literature and available air quality compliance documentation to extend the breadth of the evaluation. The study is included in the Appendix.

The tailings site can be categorized into four operational areas: impoundment, active embankment, inactive embankment, and reclaimed areas. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.2 BACT Analysis for Tailings Impoundment

- **Step 1—Identify All Control Technologies Listed in RBLC.** The following control technologies were identified in the RBLC for particulate control from impoundment type emissions sources:

Watering

Polymer application

Revegetation

Enclosures

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Polymer Application: As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. Polymers suppress emissions by changing the physical characteristics of the surface material. The polymers form a hardened surface that binds the particles together, thereby reducing their likelihood to become airborne.

Revegetation: Revegetation assists in minimizing emissions. The vegetation holds the soil surface together and therefore makes it less prone to wind erosion.

Enclosures: Enclosures reduce the wind shear at the surface and thereby reduce wind erosion and emissions.

- **Step 2—Eliminate Technically Infeasible Options.** Because of the size of the impoundment, enclosures are not feasible. All remaining technologies are feasible and are further evaluated below.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.**

The control technologies cannot be ranked based on effectiveness as each control technology is effective for specific areas at the tailings site.

- **Step 4—Identify BACT.** The impoundment area is saturated with water and does not result in windblown dust emissions. Visual inspections are routinely performed to ensure the impoundment is saturated with water and in the unlikely event an area appears to be drying out, the area would be re-saturated. The current practices of reducing particulate emissions by following the approved dust control plan is most effective in reducing emissions. Additionally, the impoundment area is saturated with water and does not result in windblown dust emissions.

The current practices of dust management at the tailings site also represent the most stringent measure.

3.2.3 BACT Analysis for Tailings Active (Flat) Embankments

- **Step 1—Identify All Control Technologies Listed in RBLC.** The following control technologies were identified in the RBLC for particulate control from impoundment type emissions sources:

Watering

Polymer application

Revegetation

Enclosures

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Polymer Application: As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. Polymers suppress emissions by changing the physical characteristics of the surface

material. The polymers form a hardened surface that binds the particles together, thereby reducing their likelihood to become airborne.

Revegetation: Revegetation assists with minimizing emissions. The vegetation holds the soil surface together and therefore makes it less prone to wind erosion.

Enclosures: Enclosures reduce the wind shear at the surface and thereby reduce wind erosion and emissions.

- **Step 2—Eliminate Technically Infeasible Options.** Because of the size of the embankment, enclosures are not feasible. All remaining technologies are feasible and are further evaluated below.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The control technologies cannot be ranked based on effectiveness as each control technology is effective for specific areas at the tailings site.
- **Step 4—Identify BACT.** The tailings are actively deposited in the embankment areas. In an active embankment cell, the tailings are deposited every fourth day. The tailings are extremely wet when deposited. Areas can remain moist for several days. Application of water for dust control in active areas is not feasible as it tends to channelize directly to the drain point instead of spreading across the surface. The flat embankment areas will therefore have a potential for wind erosion on days 2, 3, and 4. Emissions are estimated based on days with potential for wind erosion. The current practices of reducing particulate emissions by following the approved dust control plan is most effective in reducing emissions and identified as BACT.

The current practices of dust management at the tailings site also represent the most stringent measure.

3.2.4 BACT Analysis for Tailings Inactive and Sloped Embankments

- **Step 1—Identify All Control Technologies Listed in RBLC.** The following control technologies were identified in the RBLC for particulate control from impoundment type emissions sources:

Watering

Polymer application

Revegetation

Enclosures

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Polymer Application: As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. Polymers suppress emissions by changing the physical characteristics of the surface material. The polymers form a hardened surface that binds the particles together, thereby reducing their likelihood to become airborne.

Revegetation: Revegetation assists with minimizing emissions. The vegetation holds the soil surface together and therefore makes it less prone to wind erosion.

Enclosures: Enclosures reduce the wind shear at the surface and thereby reduce wind erosion and emissions.

- **Step 2—Eliminate Technically Infeasible Options.** Because of the size of the embankment, enclosures are not feasible. All remaining technologies are feasible and are further evaluated below.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The control technologies cannot be ranked based on effectiveness as each control technology is effective for specific areas at the tailings site.

- **Step 4—Identify BACT.** In the inactive embankment areas, where tailings deposition has been completed for the year, KUC installs sprinklers for watering. Over the past few years, KUC converted this to an automated sprinkler system that wets the surface at regular intervals. This upgrade allows the surface to maintain its moisture.

The embankment slopes are sprayed with polymers to minimize windblown dust. Polymer is reapplied as necessary to maintain its effectiveness to minimize emissions. The current practices of reducing particulate emissions by following the approved dust control plan is most effective in reducing emissions and identified as BACT.

The current practices of dust management at the tailings site also represent the most stringent measure.

3.2.5 BACT Analysis for Tailings Reclaimed Areas

- **Step 1—Identify All Control Technologies Listed in RBLC.** The following control technologies were identified in the RBLC for particulate control from impoundment type emissions sources:

Watering

Polymer application

Revegetation

Enclosures

Watering: Watering increases the moisture content of the surface, which conglomerates particles and reduces their likelihood to become airborne. The control efficiency for watering depends on how fast the area dries after water is added. Frequent watering is necessary to maintain its effectiveness.

Polymer Application: As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. Polymers suppress emissions by changing the physical characteristics of the surface material. The polymers form a hardened surface that binds the particles together, thereby reducing their likelihood to become airborne.

Revegetation: Revegetation assists with minimizing emissions. The vegetation holds the soil surface together and therefore makes it less prone to wind erosion.

Enclosures: Enclosures reduce the wind shear at the surface and thereby reduce wind erosion and emissions.

- **Step 2—Eliminate Technically Infeasible Options.** Because of the size of the reclaimed areas, enclosures are not feasible. All remaining technologies are feasible and are further evaluated below.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The control technologies cannot be ranked based on effectiveness as each control technology is effective for specific areas at the tailings site.
- **Step 4—Identify BACT.** Once released for reclamation, KUC implements a revegetation plan to reclaim the areas. Polymers are applied to areas still waiting to be reclaimed. The current practices of reducing particulate emissions by following the approved dust control plan is most effective in reducing emissions and are identified as BACT.

The current practices of dust management at the tailings site also represent the most stringent measure.

3.2.6 Service Roads

- **Source Description:** Service roads exist throughout the tailings site and are used by KUC personnel daily.
- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies potential technologies for control of fugitive emissions on unpaved roads as; paving the unpaved roads, the

application of water and the use of dust suppression chemicals, limiting unnecessary traffic on roads and routine maintenance of roads.

- **Step 2—Eliminate Technically Infeasible Options.** Paving the haul roads is not technically feasible at the tailings site because of the frequently changing road locations over time resulting from tailing placement.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The remaining technologies of water application, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads are economically and chronologically feasible.
- **Step 4—Identify BACT.** The application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads are identified as BACT for the service roads.

The application of water, chemical dust suppressants, limiting unnecessary traffic on roads, and routine maintenance of roads also represent the most stringent measure for the service roads at the tailings site.

3.2.7 Propane Communication Generator

Source Description: The tailings facility operates a propane fired communication generator. This generator is used to support communication systems during emergencies or loss of power at the tailings facility. Emissions are controlled with good combustion practices while operating the generator.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as the primary control technology for emergency generators around 75 HP operated on propane. The emergency generators must also comply with the applicable New Source Performance Standards established by EPA.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Good combustion practices are identified as BACT for the propane fired emergency generator. The emergency generator also complies with applicable New Source Performance Standards.

Good combustion practices also represent the most stringent measure for the propane communication generator.

3.2.8 Biosolids Application

Source Description: Salt Lake County and Salt Lake City operate small landfill type operations that produce organic material which are used by the Tailings Facility to enhance the reclamation of closed tailings areas. The application of biosolids does not result in any emissions of PM_{2.5}, SO₂, NO_x or VOC. Very small quantities of ammonia emissions are estimated from these operations resulting from the natural process of decomposition. Therefore, a BACT analysis is not developed for this emission source. The 2014 actual emissions from the source were 0.021 tpy of ammonia.

3.3 Laboratory

3.3.1 Hot Water Boiler

Source Description: Natural gas-fired water boiler is used for water heating for the laboratory. The water boiler uses low NO_x burners (LNB) and regular inspections are done to the units to ensure optimum combustion performance. The water heater is rated at 7.1 MMBTU/hr.

3.1.8.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies LNB and good combustion practices as control technologies for minimizing NO_x emissions from boilers less than 10 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technologies identified in the RBLC and CARB for controlling NO_x emissions from the boiler (LNB and good combustion practices) are already in use and constitute BACT.

3.1.8.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from the boiler.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC and CARB identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from the boiler and these control technologies constitute BACT.

The use of pipeline quality natural gas, LNB and good combustion practices represent the most stringent measure for the hot water boiler at the laboratory.

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Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

4.1 Utah Power Plant

Unit 5

KUC is proposing the following limitations and monitoring requirements for the UPP. Unit 5 shall not exceed the following emission rates to the atmosphere.

Pollutant	lb/hr	ppmvd (@ 15% O ₂)
NO _x		2.0*
PM _{2.5} with duct firing: Filterable and condensable	18.8	

Note:

*Under steady state operation

Stack testing to show compliance with the above Unit 5 emissions limitations shall be performed as follows:

Pollutant	Test Frequency
PM _{2.5}	every year
NO _x	every year

The heat input during all compliance testing shall be no less than 90% of the design rate.

Unit 4

The following requirements are applicable to Unit 4 during the period November 1 to February 28/29 inclusive:

During the period from November 1, to the last day in February inclusive, only natural gas shall be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment.

Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Pollutant	Grains/dscf	ppmdv (3% O ₂) 68°F, 29.92 in. Hg
PM _{2.5} Filterable	0.004	
Filterable and condensable	0.03	
NO _x		336
NO _x (after 1/1/2018)		60

If operated during the winter months, stack testing to show compliance with the above Unit #4 emissions limitations shall be performed as follows:

Pollutant	Test Frequency
PM _{2.5}	every year
NO _x	every year

The heat input during all compliance testing shall be no less than 90% of the maximum average hourly production rate achieved in any 24-hour period during the previous three (3) years. The limited use of natural gas during startup, for maintenance firings and break-in firings does not constitute operation and does not require stack testing.

4.2 Tailings Site

The primary source of emissions at the tailings site is wind-blown dust. The intent of the PM_{2.5} serious nonattainment SIP is to review emissions during winter time inversions. Since these inversions represent stagnant wind conditions, emissions from the tailings site will be minimal and therefore tailings site SIP conditions are not necessary for the PM_{2.5} SIP. Emissions at the tailings site are effectively controlled with the implementation of BACT and the most stringent measure.

4.3 Laboratory

No limitations or monitoring requirements are proposed for the laboratory emission sources as the emissions from the facility are minimal and are effectively controlled with the implementation of BACT and the most stringent measure.

Attachments

- UPP Cooling Tower Vendor Data
- Tailings Quarterly Report
- Tailings Dust Control Practices Study
- Tailings FDCP
- Degreaser Solvent SDS

FINAL

Best Available Control Technology Determinations for the Smelter and Refinery

Prepared for

Kennecott Utah Copper

February 2018

Prepared by



4245 South Riverboat Road
Suite 210
Taylorsville, UT 84123

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Attachments

- Smelter Dryer/Granulator baghouse information
- Anodes Furnaces NO_x study
- Degreaser Solvent SDS
- EPA Compliance Letter

Tables

2-1	Facility Potential to Emit Emissions (Including Fugitive and Nonroad Engine Emissions)
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Acronyms and Abbreviations

ACT	Alternative control techniques
AO	approval order
BACT	best available control technology
BCM	Bingham Canyon Mine
CAA	Clean Air Act
CEM	Continuous emissions monitor
<i>CFR</i>	<i>Code of Federal Regulations</i>
CHP	Combined heat and power
CO	carbon monoxide
CPI	Consumer Price Index
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator
FGR	Flue gas recirculation
FS	Flash Smelting
GPS	Global Positioning System
gr/dscf	grains per standard cubic feet
KUC	Kennecott Utah Copper
LNB	Low NO _x burner
MACT	maximum achievable control technology
MMBtu/hr	million British Thermal Units per hour
NAAQS	National Ambient Air Quality Standard
NH ₃	ammonia
NO _x	nitrogen oxides
PM ₁₀	particulate matter less than or equal to 10 microns in aerodynamic diameter
PM _{2.5}	particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppm	parts per million
PTE	potential to emit
RBLC	RACT/BACT/LAER Clearing house
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SOP	Standard operating procedure
TEG	Turbine Electric Generator
tpy	tons per year
UDAQ	Utah Department of Air Quality

ACRONYMS AND ABBREVIATIONS (CONTINUED)

ULNB	Ultra-low NOx burner
VOC	volatile organic compound
WRAP	Western Regional Air Partnership

Introduction

Kennecott Utah Copper LLC (KUC) is submitting best available control technology (BACT) determinations for emission sources at the following KUC facilities: Smelter and Refinery. In addition to a BACT analysis, KUC has also documented the most stringent measure for emission sources at these facilities.

The Clean Air Act (CAA) requires that stationary sources implement BACT to demonstrate attainment as expeditiously as possible and meet any reasonable further progress requirements. As requested by the Utah Department of Air Quality (UDAQ), the BACT analysis should identify and evaluate reasonable and available control technologies for each relevant pollutant. The technical and economic feasibility of each potential control technology are components of the BACT analysis that help show whether a control technology is reasonable. The BACT analysis presented in this document was developed in accordance with the guidance established by the Environmental Protection Agency (EPA) and the CAA.

A BACT analysis was developed for emissions of particulate matter less than or equal to 2.5 microns in aerodynamic diameter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and volatile organic compounds (VOCs). For each emission source, the BACT analysis followed a four-step process:

- **Step 1**—Identify all control technologies listed in the RACT/BACT/LAER Clearinghouse (RBLC) and/or California Environmental Protection Agency – Air Resource Board BACT Clearinghouse (CARB)
- **Step 2**—Eliminate technically infeasible options
- **Step 3**—Eliminate economically/chronologically infeasible options
- **Step 4**—Identify BACT

In addition, KUC reviewed available information, including recent BACT determinations (less than 10 years old by UDAQ) to determine if the permitted emissions represent the most stringent measure.

KUC understands additional controls beyond BACT may be required by UDAQ to demonstrate attainment of the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). However, a beyond BACT analysis is a separate and distinct review process from the BACT analysis and requires that a modeling analysis be performed demonstrating that implementation of additional controls beyond BACT would advance the attainment of the standard. It is important that these steps be implemented discretely and sequentially. The modeling of additional controls required to meet the $PM_{2.5}$ NAAQS were combined with the UDAQ State Implementation Plan (SIP) BACT request. KUC contends the BACT is determined and then modeled to determine attainment as part of the preparation of the SIP. KUC understands further controls may be necessary to meet the $PM_{2.5}$ NAAQS as part of the SIP development.

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Recent Permitting Actions

The Smelter and Refinery together have over 70 individual significant and insignificant sources. The Smelter recently had UDAQ permitting actions. A modified approval order (AO) was issued for the smelter on June 10, 2014. AO DAQE-AN0103460054-14 allows the Smelter to operate a crushing and screening plant and modifies stack testing requirements for the Smelter emissions sources. No other significant modifications were made to the Smelter AO in the last 5 years.

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source maximum achievable control technology (MACT) standard (40 *Code of Federal Regulations* [CFR] 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC Smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules. Both standards establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology. The primary copper smelting area source MACT standard specifically identifies the KUC Smelter main stack emission performance as MACT for copper smelters (existing sources, not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred after promulgation of the MACT standards.

AO DAQE-AN01013460045-10 for the Refinery was issued in 2010 to add the combined heat and power (CHP) unit. The CHP unit utilizes SoLoNO_xTM burners minimizing NO_x emissions from the unit. The Smelter and Refinery facilities operate under a single Title V Operating Permit # 3500030003.

Potential to emit (PTE) emissions in tons per year (tpy) for the Smelter, Refinery and MAP are shown in Table 2-1.

Table 2-1. Facility Potential to Emit Emissions

	PM ₁₀ PTEs (tpy)	PM _{2.5} PTEs (tpy)	NO _x PTEs (tpy)	SO ₂ PTEs (tpy)	VOC PTEs (tpy)
Smelter	510.82	426.35	185.29	1,085.72	13.50
Refinery	25.64	25.64	38.57	4.44	8.42

Notes:

PM₁₀ = Particulate matter 10 microns or smaller in aerodynamic diameter

NO_x = oxides of nitrogen

SO₂ = sulfur dioxide

VOC = volatile organic compounds

PM_{2.5} = Particulate matter 2.5 microns or smaller in aerodynamic diameter

PTE = potential to emit

tpy = tons per year

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Best Available Control Technology Determinations

This section provides BACT determinations for emission sources deemed significant at the Smelter and Refinery.

KUC has reviewed publicly available permitting documents for smelters around the country. Based on the review of the Hayden Smelter in Arizona, it was determined the technology implemented at the KUC Smelter is different from that at the Hayden Smelter. The permitting documents show that emissions from sources such as acid plant, anode plant and furnaces are limited with baghouses, optimum operation of processes and visible emissions limitations.

3.1 Smelter

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC Smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules (e.g., the design of the Smelter is based on the furnace technology). Typical smelting operations require batch processing which intermittently produces high concentrations of SO₂ and particulate in a manner that can reduce the efficiency of the acid plant as a control device. By employing the flash smelting (FS) and flash converting (FC) technologies, KUC can eliminate many of the problems inherent with batch type smelter operations. These improvements include continuous flow of off-gases to the acid plant during the FC process as well as reduced total volume of off-gases. Additionally, the furnaces are stationary which improves the ability to capture the off-gases as well as the ability to capture any fugitive emissions with the secondary capture system, which cleans the gases with baghouses and scrubbers before venting to the main stack. As a result, both MACT standards go so far as to establish a separate category for only the KUC Smelter due to its unique design and emission performance not achievable by conventional technology.

The primary copper smelting area source MACT standard specifically identifies the KUC Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). The KUC Smelter employs several technologies to minimize the smelting emissions that report to the main stack.

- The concentrate dryer burns natural gas to heat/dry concentrate for use in the FS furnace. Operation with low-NO_x burners (LNB) along with lower dryer temperatures minimizes the formation of NO_x while also preventing the formation of SO₂. KUC operates both a baghouse and a scrubber as controls for the concentrate dryer.
- The secondary gas system collects fugitive emissions in the hot metals building (typically associated with the furnaces) and vents them through a baghouse and a sodium-based scrubber before they are vented to the main stack.
- The matte grinding circuit crushes and dries granulated matte for use in the FC furnace. The particulate from the ground matte is collected in a baghouse and pneumatically conveyed to the FC furnace feed bin. NO_x emissions from natural gas combustion are minimized with LNB and low temperature firing and PM₁₀ emissions are controlled with the production baghouse.

- In the anodes area, blister copper from the FC furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap, which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the main stack. NO_x reduction activities also include maintaining furnaces to prevent ingress of air.
- The shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. LNBS are used to reduce NO_x from the natural gas combustion and a baghouse is operated to control PM₁₀ emissions. The shaft furnace is in the anodes area, but vents separately to the main stack.

3.1.1 Main Stack

Source Description. Multiple process equipment emissions are routed through the main stack. Such equipment includes the matte granulators, acid plant, anode building, powerhouse, furnaces, dryers, and grinding circuits. Many of these sources of emissions have their own primary control devices (baghouse, scrubbers, etc.). Some are then routed to the secondary gas system and then through the main stack. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

Equipment emissions routed through the main stack at the Smelter include:

Equipment	Pollutant Emissions	Primary Emissions Control
Concentrate dryer	PM _{2.5} , SO ₂ , NO _x	LNB, baghouse, and scrubber
Powerhouse superheater	PM _{2.5} , SO ₂ , NO _x , VOC	Ultra-low NOx burner (ULNB), Flue gas recirculation (FGR), fuel throughput limits, and good operational practices
Powerhouse Foster Wheeler aux boiler	PM _{2.5} , SO ₂ , NO _x , VOC	LNB, FGR, fuel throughput limits, and good operational practices
Matte grinding	PM _{2.5} , SO ₂	LNB, baghouse and good operational practices
Anode refining furnaces	PM _{2.5} , SO ₂ , NO _x , VOC	Oxy-fuel burners, baghouse, and scrubbers
Anode shaft furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse, LNB and good operational practices
Anode holding furnace	PM _{2.5} , SO ₂ , NO _x , VOC	Baghouse, LNB and good operational practices
Vacuum cleaning system	PM _{2.5}	Baghouse
North and south matte granulators	PM _{2.5} , SO ₂	Scrubber, SGS baghouse, and SGS scrubbers

- **Step 1—Identify All Control Technologies Listed in RBL and CARB.** The RBL identifies different control technologies for process equipment eventually routed through the main stack. These control technologies are currently in place as previously discussed.

The EPA performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC Smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules. Both standards go so far as to establish a separate category for only the KUC Smelter due to its unique design and emission performance not achievable by conventional technology. The

primary copper smelting area source MACT standard specifically identifies the KUC Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred after promulgation of the MACT standards.

Baghouses used to control particulate emissions from the concentrate dryer, matte grinding, anode furnaces and granulators are maintained regulatory and the bags are replaced as recommended by the vendors. The bags currently used by KUC in these baghouses are provided in the Appendix. The exhaust from these processes is at high temperature and low pH due to the acidic nature of the materials. Over the years, KUC has experimented with different types of bags, such as pleated bags, that are more effective in removing particulate. However, these bags could not provide optimum performance due to high temperature and low pH. Therefore, upgrading to different types of bags is not technically feasible for these processes.

Again, KUC maintains and replaces bags in these baghouses as recommended by vendors to maintain performance, pressure differential and particulate removal efficiency.

The KUC Smelter continues to be the cleanest Smelter operations in the world. KUC reviewed emission reductions alternatives for anode furnaces venting through the main stack. The operations at the Smelter are continuously optimized to ensure high efficiency operation of the facility, including periodic upgrades of the burners to maintain optimum operations. KUC performed a pre-feasibility level study to evaluate NO_x emissions reductions options for the anodes furnaces at the Smelter. The study evaluated emission reduction strategies such as SCR, SNCR, oxidation systems and wet scrubbers. Portions of the study are provided as an Attachment. The entire study is not included to ensure project confidentiality.

While all the identified technologies were determined to be feasible, each had significant energy and economic impacts. Based on the pre-feasibility study, the costs per ton of NO_x removed from these technologies ranges from \$55,000 to \$590,000. These costs are based on the prefeasibility study and actual implantation costs are expected to be higher as major process and structural modifications would need to be made to implement these alternatives.

Therefore, NO_x emissions reduction technologies such as SCR, SNCR and wet scrubber are not cost effective for BACT for the anode furnaces venting to the main stack.

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 selected as BACT.
- **Step 4—Identify BACT.** Because no new major developments in technologies have occurred after the promulgation of the MACT standards, the control technologies currently in place constitute BACT.

Complying with applicable requirements of the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE) represent the most stringent measure for the main stack.

3.1.2 Powerhouse Holman Boiler

Source Description: The boiler is used to provide process steam at the smelter. Emissions of NO_x are limited with flue gas recirculation (FGR), LNB, opacity limits, an alternative monitoring plan which requires continuous monitoring of operational parameters (fuel use, stack oxygen, steam output), and operational controls with good combustion practices. Emissions of PM_{2.5}, CO, SO₂, and VOC are limited with use of pipeline quality natural gas, good combustion practices, gas consumption limit, good design, opacity limits, and proper operation of the boiler. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.2.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies the following as possible control technologies for NO_x for natural gas-fired boilers:
 - Selective catalytic reduction (SCR)
 - FGR
 - LNBs with good combustion practices
 - Good design and proper operation
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The Holman boiler is equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR would reduce the emissions from the boiler from 9.9 tpy (based on 2016 actual emissions) to 2.0 tpy.

From the Alternative Control Techniques (ACT) Document — NO_x Emissions from Industrial/Commercial/Institutional Boilers, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5 of the ACT document, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from Consumer Price Index (CPI) Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the Holman boiler, the estimated cost is \$487,287.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$26,000 and is therefore not cost effective for BACT.

- **Step 4—Identify BACT.** FGR, LNBs with good combustion practices, limited gas consumption, good design, and proper operation constitute BACT for this source.

KUC continuously monitors operational parameters to predict NO_x emissions and ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lb/hr), stack oxygen (to monitor proper boiler operation and compliance with NO_x lb/MMBtu emission limit), and steam output (used to estimate heat input if fuel use is unavailable). The ranges for these parameters were developed during a 30-day monitoring campaign where data from a certified NO_x analyzer were used to develop predictive equations with the operation parameters.

3.1.2.2 SO₂, VOC, and PM_{2.5} BACT

- **Step 1—Identify All Control Technologies listed in the RBLC and CARB.** The RBLC and CARB identifies the following as possible control technologies for boilers:
 - Use of pipeline quality natural gas and good combustion practices
 - Good design and proper operation
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 were selected as BACT.
- **Step 4—Identify BACT.** Use of pipeline quality natural gas, good combustion practices, opacity limits, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNBs with good combustion practices, limited gas consumption, good design, and proper boiler operation represent the most stringent measure for the Holman Boiler.

3.1.3 Feed Process (Wet and Dry)

Source Description: Silica flux, concentrate, and converter slag are transferred directly to feed bins then conveyed to the dryer. Particulate emissions from the loading of the flux and concentrate, and from transfer points of the conveyor, are vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, electrostatic precipitators (ESPs), and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP, because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable as most effective technology identified in Step 1 selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

The use of a baghouse to control particulate emissions also represents the most stringent measure for both the wet and dry feed process.

3.1.4 Matte and Slag Granulators

Source Description: Slag and matte granulators are each equipped with a three-stage impingement plate scrubber. The smelter operates two matte granulators and one slag granulator. The molten matte is granulated with water in two separate granulation tanks (two matte granulators), each equipped with a scrubber. The converter slag is granulated in a separate granulator (one slag granulator), also equipped with a scrubber. The matte granulators are vented through the main stack. The slag granulator is vented to the atmosphere through a separate stack. PM_{2.5} and SO₂ emissions are controlled by a neutral pH three-stage impingement plate scrubber. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.4.1 PM_{2.5} BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, other possible particulate control technologies include baghouses, cyclones, ESP, and scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** While baghouses are most effective in controlling particulate emissions, this technology is not feasible for the granulators. The exhaust from the granulators has very high moisture content, which is not suitable for baghouses. Moisture condensation can cause accumulation of mud on the bags and baghouse walls. This results in blinded bags and clogged dust removal equipment. As discussed in the Western Regional Air Partnership (WRAP) Fugitive Dust Handbook, cyclones are mainly used to control large particles. Therefore, scrubbers are the technically feasible option.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most technically feasible technology for this process, identified in Step 2, was selected as BACT.
- **Step 4—Identify BACT.** Scrubbers constitute BACT for the granulators.

3.1.4.2 SO₂ BACT

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** The RBLC and CARB do not identify any specific control technologies for the granulators.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable
- **Step 4—Identify BACT.** Scrubbers constitute BACT for the granulators.

The use of scrubbers also represents the most stringent measure for both the matte and slag granulators.

3.1.5 Feed Storage Building

Source Description: Wet copper concentrate feed is stored in the enclosed wet feed storage building. Particulate matter from loading materials into the feed storage building, from reclaiming materials, and from conveyor/transfer point SME 002-A, are vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

The use of enclosures and baghouse to control particulate emissions also represents the most stringent measure for the feed storage building.

3.1.6 Anode Area Fugitives

Source Description: Emissions from the anode building process are controlled with a baghouse, quench tower, and scrubber. However, some emissions can escape as fugitives. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB do not identify any specific control technologies for process fugitives. The MACT, however, does address such emissions.

40 *CFR* 63.11147(a)(3) states, “You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, re-melt anode copper, or re-melt anode scrap and convey each collected gas stream to a control device. One control device may be used for multiple collected gas streams.”

KUC certified compliance with 63.11147(a)(3), as required by 63.11150(b)(4), in a letter dated and received by UDAQ on January 30, 2007. This document is included as an attachment to this report.

- **Step 2—Eliminate Technically Infeasible Options.** Not applicable
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable
- **Step 4—Identify BACT.** In addition to opacity limits and required maintenance, current design of anode process units and the collection hoods on anode building processes have been engineered/designed to reduce fugitives and these practices constitute BACT.

The current design of anode process units and the collection hoods on anode building processes were engineered/designed to reduce fugitives and these represent the most stringent measure.

3.1.7 Smelter Fugitives

Source Description: Emissions from Smelter processes are controlled with appropriate control technologies including closed processes, launder hoods and others outlined below. However, some emissions can escape as fugitives. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB do not identify any specific control technologies for such fugitives.

The EPA performed extensive technology reviews of Smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 *CFR* 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 *CFR* 63 Subpart EEEEE). Specific discussion of the unique aspects of pollution controls at the KUC smelter are included in the Federal Register notices associated with the draft and final promulgation of both rules. Regarding the design and fugitive emission controls of the KUC smelter, the EPA provided the following discussion when promulgating the final copper smelting MACT standard (FR Vol. 67, No. 113, Page 40488):

Due to its unique design and operations, most of the process fugitive emission sources associated with smelters using batch converting are eliminated at the Kennecott smelter. There are no transfers of molten material in open ladles between the smelting, converting, and anode refining departments at the Kennecott smelter. In addition, there are no fugitive emissions associated with the repeated rolling-out of converters for charging, skimming, and pouring. Also, only one continuous flash converter is needed at the Kennecott smelter compared with the need for three or more batch copper converters at the other smelters.

Both standards go so far as to establish a separate category for only the KUC smelter due to its unique design and emission performance not achievable by conventional technology. Smelter process and emission controlling technologies that contributed to the EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off-gases from furnaces, also contribute to the control of fine particulate and precursor emissions. No new major developments in technologies or costs have occurred after the promulgation of the MACT standards.

Specific notes regarding control techniques listed in Table 5 of Attachment 5 of the EPA comments are listed below:

- KUC Smelter hot metals operations are serviced by an extensive local ventilation (secondary gas) system. This system collects gasses and routes them through baghouses and scrubbers before venting them to the main stack where they are continuously monitored for multiple pollutants.

- KUC Smelter hot metals operations are completely enclosed in a building.
- KUC processes only grade 1 scrap in its melting furnaces.
- A leak detection/prevention/repair program is not applicable to KUC Smelter furnaces and hot metals process units because they are enclosed and operate at negative pressure due to their inherent design.
- Because KUC furnaces are enclosed and do not require open air transfer of molten metal, they are not dependent on hooding systems for process gas collection.
- It is not necessary to add curtains to improve hood performance at the KUC Smelter as the process does not rely on hoods to capture process gasses.
- The KUC process does not require the open-air transfer of molten metal from smelting to converting vessels so it is not necessary to collect these emissions.
- The EPA noted in the primary copper smelting MACT standard, KUC was the first Smelter in the United States to capture and control emissions from anode refining furnaces.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable
- **Step 4—Identify BACT.** In addition to opacity limits and required maintenance, current designs of processes were engineered/created to reduce fugitives and therefore these practices constitute BACT. KUC has implemented best management practices to minimize fugitive emissions. These practices are reviewed frequently and improvements are implemented to minimize emissions.

The current designs of processes were engineered/created to reduce fugitives and therefore these practices also represent the most stringent measure.

3.1.8 Acid Plant Fugitives

Source Description: The double contact acid plant removes SO₂ from the off-gases of the flash furnaces. The sulfuric acid produced by the plant is sold. Among other technologies, the system is equipped with tubular candle fiber mist eliminators and the tail gas is discharged to the main stack. However, some emissions can escape as fugitives, which are controlled using best operational practices to minimize emissions. Best operational practices to minimize the emissions include opacity limits, weekly visual opacity surveys and the requirement of prompt repair or correction and control to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB do not identify any specific control technologies for such fugitives.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable
- **Step 4—Identify BACT.** Best operational practices may include, (1) placement or adjustment of negative pressure ductwork and collection hoses, (2) welding of process gas leaks, or (3) containment of process gas leaks. These practices and current design of processes were engineered/created to reduce fugitives and therefore constitute BACT.

The best operational practices currently implemented and the current designs of the processes also represent the most stringent measure for the acid plant fugitives.

3.1.9 Powerhouse Foster Wheeler Boiler

Source Description: This boiler is used to produce superheated steam to start the smelter, drive acid plant compressors, and standby power. Emissions of NO_x are limited with FGR, LNB with good combustion practice, continuous monitoring of NO_x at the smelter main stack, and limitations on fuel throughput. Emissions of PM_{2.5}, CO, SO₂, and VOCs are limited with use of pipeline quality natural gas; good combustion practices; good design and proper operation of the boiler; and continuous monitoring of opacity, particulate, and SO₂ at the Smelter main stack. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.9.1 NO_x BACT

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** The RBLC and CARB identify the following as possible control technologies for NO_x for natural gas-fired boilers.

SCR

FGR

LNB with good combustion practices

Good design and proper operation

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The powerhouse boiler is equipped with FGR and LNB to reduce NO_x emissions. Emissions from this boiler are vented through the main stack and it is difficult to differentiate the boiler NO_x emissions from the main stack emissions. Based on the understanding of operations at the smelter, the addition of the SCR might reduce the annual emissions from the boiler from 5.3 tpy (based on 2016 actual emissions and engineering estimates) to 1.1 tpy.

From the Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boiler, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 100 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.03 lb/MMBtu. From Table 6-5, the total annualized cost for the 100 MMBtu/hr gas boiler is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74; therefore, for the powerhouse boiler the estimated cost is \$261,000.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$15,000 and is therefore not cost effective for BACT.

- **Step 4—Identify BACT.** FGR, LNB with good combustion practices, good design and proper operation constitute BACT.

3.1.9.2 SO₂, VOC, and PM_{2.5} BACT

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** The RBLC and CARB identify the following as possible control technologies for boilers.

Use of pipeline quality natural gas and good combustion practices

Good design and proper operation

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measure for the Powerhouse Foster Wheeler Boiler.

3.1.10 Miscellaneous Storage Piles/Loadout

Source Description: Concentrate, granulated matte, slag, and other materials are stored in storage piles on pads. Water sprays or chemicals are applied as necessary to minimize fugitive emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify dry foggers, adding moisture, and enclosures as possible control technologies for fugitive emissions. Other possible technologies available to control fugitive dust emissions that are not identified in the RBLC include chemical dust suppression, baghouse, cyclone, and scrubber.
- **Step 2—Eliminate Technically Infeasible Options.** The emission sources are fugitive in nature and therefore it is not technically feasible to duct emissions to a baghouse, scrubber, or cyclone. Additionally, the locations of the storage piles are always changing, making the construction of permanent enclosures difficult. Therefore, these control technologies are not technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The remaining technology of water or chemical applications is economically and chronologically feasible.
- **Step 4—Identify BACT.** KUC uses water sprays, chemical dust suppressants, and temporary enclosures to minimize particulate emissions from the miscellaneous storage piles, which were demonstrated to be very effective. These business practices constitute BACT for this emission source.

The use of water sprays, chemical dust suppressants, and temporary enclosures to minimize particulate emissions from the miscellaneous storage piles also represent the most stringent measure.

3.1.11 Slag Concentrator

Source Description: Emissions associated with the crushing, grinding, and slag processing at the smelter are minimized with the water sprays and enclosures. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, other possible particulate control technologies include baghouses, cyclones, scrubbers, water sprays, and enclosures.
- **Step 2—Eliminate Technically Infeasible Options.** Baghouses are not feasible for the slag processing equipment. The slag stock piles are sprayed with water frequently to minimize emissions. The material as a result has very high moisture content, which is not suitable for baghouses. Moisture droplets and condensation can cause accumulation of mud on the bags, baghouse walls, and ductwork. This results in blinded bags and clogged dust removal equipment. Further, when ambient temperatures are below freezing, the mud will freeze on the baghouse bags and plug them.

Wet scrubbers are not expected to be effective in minimizing emissions from crushing and grinding operations. Operation of the scrubbers is compromised due to below freezing ambient temperatures and very cold water

streams in the scrubber. The duct work of the scrubbers will freeze during subfreezing ambient temperature conditions.

As discussed in the WRAP Fugitive Dust Handbook, cyclones are mainly used to control large particles.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The remaining technology of water sprays and enclosures is economically and chronologically feasible.
- **Step 4—Identify BACT.** KUC uses water sprays and enclosures to minimize particulate emissions from the slag concentrator, which were demonstrated to be very effective. These business practices constitute the BACT for this emission source.

The use of water sprays and enclosures to minimize particulate emissions represent the most stringent measure from the slag concentrator.

3.1.12 Smelter Cooling Towers

Source Description: Three noncontact water cooling towers are used for various Smelter processes. The towers are equipped with drift eliminators with drift loss rated at 0.001 percent. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable, as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Drift eliminators and good operating practices constitute BACT.

The use of drift eliminators with drift loss rated at 0.001 percent and good operating practices represent the most stringent measure for the cooling tower. As determined in the BACT analysis for other KUC facilities, upgrading the drift eliminators with lower drift loss is not cost effective for the BACT analysis.

3.1.13 Ground Matte Silo

Source Description: Ground matte material is stored in silos. Particulate matter from loading materials into the silos is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.

- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the silo baghouse were 0.04 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for the ground matte silo.

3.1.14 Molding Coatings Storage Silo

Source Description: Coatings material is stored in silos. Particulate matter from loading materials into the silos is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the silo baghouse were 0.003 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for the coatings storage silo.

3.1.15 Lime Storage Silos

Source Description: The Smelter has three lime storage silos. These silos are used to store lime for the hydrometallurgical plant, anode area and the secondary gas system. Particulate matter from loading materials into the silos is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the three silo baghouses were 0.01 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for the silos used to store lime for the hydrometallurgical plant, anode area and the secondary gas system.

3.1.16 Limestone Storage Silos

Source Description: The silo is used to store limestone for the hydrometallurgical plant. Particulate matter from loading materials into the silos is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the silo baghouse were 0.04 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for silo used to store limestone for the hydrometallurgical plant.

3.1.17 Recycle and Crushing Building

Source Description: The matte and slag material is recycled and crushed in a building. Particulate matter from these small-scale operations are minimized as they occur inside the building and are controlled with a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, enclosures, and water sprays.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is most effective at capturing fine particulate and minimizing emissions.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Conducting operations inside the building and use of a baghouse are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the recycle and crushing building were 0.03 tpy. Conducting crushing and recycling operations inside the building and use of a baghouse to control particulate emissions also represents the most stringent measure.

3.1.18 Smelter Laboratory

Source Description: The laboratory at the Smelter is used for preparation of samples for testing which sometimes results in dust. Particulate emissions from the laboratory building are vented through a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify baghouses and enclosures as possible control technologies for limiting emissions from buildings or enclosed areas.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Baghouses are the most effective in controlling emissions. Therefore, fabric filters (baghouse) constitute BACT for the Smelter Laboratory.

It should be noted that the 2014 actual PM_{2.5} emissions for the laboratory controlled with a baghouse were 0.78 tpy. This emission rate also represents the most stringent measure for the Smelter Laboratory.

3.1.19 Propane Communication Generator

Source Description: The Smelter operates a propane fired communication generator. This generator is used to support communication systems during emergencies or loss of power at the Smelter. Emissions are controlled with good combustion practices while operating the generator. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as the primary control technology for emergency generators around 75 HP operated on propane. The emergency generators must also comply with the applicable New Source Performance Standards established by EPA.
- **Step 2—Eliminate Technically Infeasible Options.** Not Applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Good combustion practices are identified as BACT for the propane fired emergency generator. The emergency generator also complies with applicable New Source Performance Standards.

Good combustion practices also represent the most stringent measure for the propane communication generator.

3.1.20 Cold Solvent Degreaser

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies operating practices such as closing the degreaser lids a method to control/minimize VOC emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as the identified control technology is technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** When not in use, the lids on the degreasers are kept closed at all times to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for the degreaser.

A Safety Data Sheet for the degreasing solvent is provided in the Appendix. KUC has experimented with low-VOC content degreasers in the past. However, these solvents were found of ineffective in cleaning parts and often resulted in residue on the parts. As a result, transition to low-VOC solvent as a degreasing agent is not further investigated for this analysis. Additionally, the 2014 actual VOC emissions from degreasers at the Smelter were 0.002 tpy.

The previously identified practices also represent the most stringent measure for the degreasers.

3.1.21 Gasoline Fueling Stations

Source Description: Adding gasoline to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify two control techniques for controlling VOC emissions from gasoline fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Stage 1 and 2 vapor recovery constitutes BACT for these sources.

It should be noted that the 2014 actual VOC emissions for the gasoline fueling stations at the Smelter were 0.07 tpy. The use of Stage 1 and Stage 2 vapor recovery systems also represent the most stringent measure for the gasoline fueling stations.

3.1.22 Diesel Emergency Generator for Pyrometallurgical Process

Source Description: The Smelter operates one 998 HP diesel-fired emergency generator to support the pyrometallurgical process during emergencies. The emergency generator is equipped with turbo charger and after cooling and complies with applicable New Source Performance Standards to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** Potential emission control technologies identified in the RBLC and CARB for similar sized diesel generators include turbo charger and after cooling, good combustion practices and limiting the sulfur content of fuel to 0.0015 percent. Certification and compliance with applicable New Source Performance Standards is an acceptable means of demonstrating BACT for emergency generators.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.

- **Step 4—Identify BACT.** Turbo charger and after cooling, good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements are identified as BACT for all pollutants emitted from the emergency generator.

It should be noted that the 2014 actual emissions from the generator of PM_{2.5} and precursors were 0.78 tpy.

Turbo charger and after cooling, good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements also represent the most stringent measure for the emergency generator.

3.1.23 Space Heaters

Source Description: Natural gas-fired heaters are used throughout the Smelter. The individual heaters are rated at less than 5 MMBTU/hr each. The heaters are regularly inspected for optimum combustion performance. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.23.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technology identified in the RBLC for controlling NO_x emissions from heaters of good combustion practices is already in use and constitute BACT.

3.1.23.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from heaters.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC and CARB identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from heaters and these control technologies constitute BACT.

The 2014 actual emissions from the heaters for PM_{2.5} and precursors were 0.48 tpy. The use of pipeline quality natural gas and good combustion practices also represent the most stringent measure for the space heaters. As discussed in the BACT analysis for other KUC facilities, replacing the existing space heaters with new heaters is not cost effective for the BACT analysis.

3.1.24 Hot Water Boiler

Source Description: Natural gas-fired water boilers are used for water heating throughout the Smelter. The water boilers use low NO_x burners (LNB) and regular inspections are done to the units to ensure optimum

combustion performance. The water heaters are rated at less than 10 MMBTU/hr. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.1.24.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies LNB and good combustion practices as control technologies for minimizing NO_x emissions from boilers less than 10 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technologies identified in the RBLC and CARB for controlling NO_x emissions from the boilers (LNB and good combustion practices) are already in use and constitute BACT.

3.1.24.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from the boilers.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from the boilers and these control technologies constitute BACT.

The 2014 actual emissions from the boilers for PM_{2.5} and precursors were 0.61 tpy. The use of pipeline quality natural gas, LNB and good combustion practices represent the most stringent measure for the hot water boilers at the Smelter.

3.2 Refinery

3.2.1 Boilers

Source Description: The two boilers are rated at 82 MMBtu/hr (gas) and 79 MMBtu/hr (oil) each and are permitted to operate on natural gas to meet the steam demand at the Refinery. During natural gas curtailment, the boilers are permitted to operate on oil. Emissions of NO_x are limited with FGR and LNB with good combustion practices. Emissions of PM_{2.5}, SO₂, and VOCs are limited with good combustion practices, good design, opacity limits, sulfur content limit, and proper operation of the boilers. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.1.1 NO_x BACT

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** The RBLC and CARB identifies the following as possible control technologies for NO_x for natural gas-fired boilers

SCR

FGR

LNB with good combustion practices

Good design and proper operation

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The Refinery boilers are equipped with FGR and LNB to reduce NO_x emissions. The addition of the SCR will reduce the emissions from the boilers from 12.9 tpy (based on based on 2016 actual emissions) to 2.6 tpy.

From the Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boilers, 1994 ACT document, Table 6-7 presents controlled NO_x emission rates for various control technologies. For the 50 MMBtu/hr natural gas packaged water tube boiler, the controlled NO_x emission rate utilizing SCR technology is 0.02 lb/MMBtu (the 100 MMBtu/hr boiler controlled NO_x emission rate with SCR is listed at 0.03 lb/MMBtu). From Table 6-5 of the ACT document, the total annualized cost for the 50 MMBtu/hr gas boiler (closest entry to 82 MMBtu/hr Refinery boiler) is \$1,500 to \$1,900 per MMBtu/hr. To estimate the impact of escalating capital cost from 1992 to 2017 dollars, cost indices from CPI Inflation Calculator (http://www.bls.gov/data/inflation_calculator.htm) can be used. The escalation multiplier is determined to be 1.74. The estimated cost for the refinery boilers is \$428,040 for both boilers.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$65,000 for the Refinery boilers and is, therefore, not cost effective for BACT.

- **Step 4—Identify BACT.** FGR, LNB with good combustion practices, good design, and proper operation constitute BACT for this source.

3.2.1.2 SO₂, VOC, and PM_{2.5} BACT

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** The RBLC and CARB identifies the following as possible control technologies for natural gas fired boilers:
 - Use of pipeline quality natural gas and good combustion practices
 - Good design and proper operation
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, because all potential technologies identified, in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the boiler constitute BACT for this emission source.

FGR, LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measure for the boilers.

3.2.2 CHP Unit

Source Description: The CHP unit will generate power and steam to support Refinery operations. The CHP unit uses a low NO_x duct burner and the turbine has SoLoNO_x burners. Emissions of PM_{2.5}, SO₂, and VOC are limited with good design and proper operation. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.2.1 NO_x BACT

- **Step 1—Identify All Control Technologies listed in RBLC.** The RBLC identifies the following as possible control technologies for NO_x for natural gas-fired turbines and duct burners.

SCR

LNB with good combustion practices

Good design and proper operation

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** The CHP unit is equipped with LNB (SoLoNO_x technology burners on turbine) to reduce NO_x emissions. The addition of the SCR will reduce emissions by 90 percent.

Solar Turbines, Inc. developed an estimation spreadsheet for the Taurus 70 combustion turbine and duct burner arrangement, which utilized vendor quotations for the installation of an SCR system. From the Solar calculations, the annualized capital and operating costs were estimated to be \$932,100/yr.

Based on the annualized costs for the SCR, the cost of additional control per ton of NO_x removed is \$35,000 for the CHP unit and is therefore not cost effective for BACT.

- **Step 4—Identify BACT.** LNB with good combustion practices, good design, and proper operation of the CHP Unit constitute BACT for this source.

3.2.2.2 SO₂, VOC, and PM_{2.5} Best Available Control Technologies

- **Step 1—Identify All Control Technologies listed in RBLC.** The RBLC identifies the following as possible control technologies for small turbines and duct burners:

Use of pipeline quality natural gas and good combustion practices

Good design and proper operation

- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, because all potential technologies identified, in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Use of pipeline quality natural gas, good combustion practices, good design, and proper operation of the CHP unit constitute BACT for this emission source.

LNB with good combustion practices, good design, and proper operation on pipeline quality natural gas also represent the most stringent measure for the CHP unit.

3.2.3 Refinery Cooling Towers

Source Description: Two noncontact water cooling towers are used for various refinery processes. The towers are equipped with drift eliminators with drift loss rated at 0.001 percent. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify drift eliminators and good operating practices as control techniques for minimizing particulate emissions from cooling towers.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable, as all identified control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, because all potential technologies identified, in Step 1, are selected as BACT.
- **Step 4—Identify BACT.** Drift eliminators and good operating practices constitute BACT.

The use of drift eliminators with drift loss rated at 0.001 percent and good operating practices represent the most stringent measure for the cooling tower. As determined in the BACT analysis for other KUC facilities, upgrading the drift eliminators with lower drift loss is not cost effective for the BACT analysis.

3.2.4 Propane Communication Generator

Source Description: The Refinery operates a propane fired communication generator. This generator is used to support communication systems during emergencies or loss of power at the Refinery. Emissions are controlled with good combustion practices while operating the generator. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as the primary control technology for emergency generators around 75 HP operated on propane. The emergency generators must also comply with the applicable New Source Performance Standards established by EPA.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies are feasible.
- **Step 4—Identify BACT.** Good combustion practices are identified as BACT for the propane fired emergency generator. The emergency generator also complies with applicable New Source Performance Standards.

Good combustion practices also represent the most stringent measure for the propane communication generator.

3.2.5 Cold Solvent Degreaser

Source Description: Cold solvents are used to degrease and clean equipment parts. The degreaser lids are kept closed when the unit is not in use to minimize solvent loss and emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identifies operating practices such as closing the degreaser lids a method to control/minimize VOC emissions.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as the identified control technology is technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** When not in use, the lids on the degreasers are kept closed always to minimize emissions. The solvent is recycled frequently, and no significant loss in volume is observed, implying minimal losses as emissions. These practices constitute BACT for the degreaser.

A Safety Data Sheet for the degreasing solvent is provided as an Attachment. KUC has experimented with low-VOC content degreasers in the past. However, these solvents were found of ineffective in cleaning parts and often resulted in residue on the parts. As a result, transition to low-VOC solvent as a degreasing agent is not further investigated for this analysis. Additionally, the 2014 actual VOC emissions from degreasers at the Refinery were 0.02 tpy.

The above identified practices also represent the most stringent measure for the degreasers.

3.2.6 Gasoline Fueling Stations

Source Description: Adding gasoline to storage tanks and dispensing from the storage tanks into vehicles. The fueling operation is equipped with Stage 1 and Stage 2 vapor recovery systems. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify two control techniques for controlling VOC emissions from gasoline fueling operations. They are Stage 1 and Stage 2 vapor recovery systems.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Stage 1 and 2 vapor recovery constitutes BACT for these sources.

It should be noted that the 2014 actual VOC emissions for the gasoline fueling stations at the Refinery were 0.04 tpy.

The use of Stage 1 and Stage 2 vapor recovery systems also represent the most stringent measure for the gasoline fueling stations.

3.2.7 Space Heaters

Source Description: Natural gas-fired heaters are used throughout the Refinery. The individual heaters are rated at less than 5 MMBTU/hr each. The heaters are regularly inspected for optimum combustion performance. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

3.2.7.1 NO_x BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify good combustion practices as control technologies for minimizing NO_x emissions from heaters less than 5 MMBtu/hr.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The technology identified in the RBLC and CARB for controlling NO_x emissions from heaters of good combustion practices is already in use and constitute BACT.

3.3.7.2 PM_{2.5}, SO₂, and VOC BACT

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** The RBLC and CARB identify use of pipeline quality natural gas and good combustion practices as a control technology for minimizing PM_{2.5}, SO₂, and VOC emissions from heaters.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** The RBLC and CARB identifies use of pipeline quality natural gas and good combustion practices as a means of controlling PM_{2.5}, SO₂, and VOC emissions from heaters and these control technologies constitute BACT.

The use of pipeline quality natural gas and good combustion practices also represent the most stringent measure for the space heaters. As discussed in the BACT analysis for other KUC facilities, replacing the existing space heaters with new heaters is not cost effective for the BACT analysis.

3.2.8 Diesel Emergency Generator

Source Description: The Refinery operates one 487 HP diesel-fired emergency generator to support the precious metals plant at the Refinery during emergencies. The emergency generator complies with applicable New Source Performance Standards to minimize emissions. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies Listed in RBLC and CARB.** Potential emission control technologies identified in the RBLC and CARB for similar sized diesel generators include good combustion practices and limiting the sulfur content of fuel to 0.0015 percent. Certification and compliance with applicable New Source Performance Standards is an acceptable means of demonstrating BACT for emergency generators.
- **Step 2—Eliminate Technically Infeasible Options.** Not applicable as all identified control technologies are technically feasible.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable because all potential technologies identified in Step 1 are selected as BACT.
- **Step 4—Identify BACT.** Good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements are identified as BACT for all pollutants emitted from the emergency generator.

It should be noted, the 2014 actual emissions from the generator of PM_{2.5} and precursors were 0.12 tpy.

Good combustion practices, limiting the sulfur content of fuel to 0.0015 percent and complying with applicable New Source Performance Standards requirements also represent the most stringent measure for the emergency generator.

3.2.9 Soda Ash Storage Silo

Source Description: The Refinery has on soda ash storage silo. The silo is used to store soda ash for the Refinery. Particulate matter from loading materials into the silo is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.

- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses in form of a bin vent filters are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the silo baghouse were 0.004 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for the silo.

3.2.10 Precious Metals Packaging Area

Source Description: The Refinery has a small precious metals packaging area. Particulate matter from the process is vented to a baghouse. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses, cyclones, ESP, and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** All control technologies are technically feasible. The fabric filter (baghouse) is more effective at capturing fine particulate than an ESP because ESPs tend to collect larger particles selectively. Cyclones are only effective in capturing larger particulate. Wet scrubbers, although effective at capturing fine particulate, produce a wet sludge requiring disposal. Also, wet scrubbers have higher operating costs and lower removal efficiencies than fabric filters. Based on their control effectiveness, the fabric filter ranks at the top, followed by an ESP, and then by wet scrubbers.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Baghouses are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} emissions from the packaging area baghouses were 0.008 tpy. The use of a baghouse to control particulate emissions also represents the most stringent measure for the precious metals packaging area.

3.2.11 Hydrometallurgical Precious Metals Processing

Source Description: The Refinery has a precious metals processing and recovery area. Particulate matter, ammonia and SO₂ from the process are vented to a scrubber. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible particulate control technologies include baghouses and wet scrubbers.
- **Step 2—Eliminate Technically Infeasible Options.** The fabric filter (baghouse) is more effective at capturing fine particulate. However, due to high temperature of the exhaust steam and its pH, baghouses are not technically feasible. Wet scrubbers are therefore the only technically feasible control of particulate emissions and SO₂.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Scrubbers are the most effective control technology for controlling particulate emissions and constitute BACT.

It should be noted that the 2014 actual PM_{2.5} and precursor emissions from the processes were 0.58 tpy. The use of scrubbers to control particulate emissions, ammonia and SO₂ also represents the most stringent measure for the precious metals processing area.

3.2.13 Tankhouse Sources

Source Description: The Refinery Tankhouse and MPC buildings include liberator, cathode wash and anode scrub wash processes that result in sulfuric acid mist emissions. Potential sulfuric acid mist from the processes are vented to a mist eliminator. Potential control technologies in other nonattainment areas in states such as California and Alaska were reviewed for this analysis.

- **Step 1—Identify All Control Technologies listed in RBLC and CARB.** Although RBLC and CARB did not provide controls for the specific operation, possible sulfuric acid control technologies include scrubbers and mist eliminators.
- **Step 2—Eliminate Technically Infeasible Options.** The presence of electrolytes in the exhaust stream cannot be effectively captured with a wet scrubber. Therefore, wet scrubbers are not technically feasible for these sources. Mist eliminators are technically feasible and effective in minimizing sulfuric acid mist emissions.
- **Step 3—Eliminate Economically/Chronologically Infeasible Options.** Not applicable, as most effective technology, identified in Step 1, selected as BACT.
- **Step 4—Identify BACT.** Mist eliminators are the most effective control technology for controlling sulfuric acid mist emissions and constitute BACT.

It should be noted that the 2014 actual sulfuric acid mist as PM_{2.5} emissions from the Tankhouse sources were 0.005 tpy. The use of mist eliminators to control sulfuric acid mist emissions also represents the most stringent measure for the Tankhouse sources.

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Limitations and Monitoring Requirements

This section provides a summary of appropriate limitations and monitoring requirements for the emission sources included in the BACT analysis.

4.1 Smelter

Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Emission Point	Pollutant	Test Frequency
Main Stack (Stack No. 11)	PM _{2.5}	<ul style="list-style-type: none"> 85 lbs/hr (filterable) 434 lbs/hr (filterable + condensable)
	SO ₂	<ul style="list-style-type: none"> 552 lbs/hr (3 hr. rolling average) 422 lbs/hr (daily average)
	NO _x	<ul style="list-style-type: none"> 154 lbs/hr (daily average)
Holman Boiler	NO _x	<ul style="list-style-type: none"> 14.0 lbs/hr (calendar-day average)

Stack testing to show compliance with the emissions limitations of Condition (A) above shall be performed as specified below:

Emission Point	Pollutant	Test Frequency
Main Stack	PM _{2.5}	Every year
	SO ₂	Continuous Emissions Monitor (CEM)
	NO _x	CEM
Holman Boiler	NO _x	Every 3 years and alternate method determined per applicable new source performance standards

Supporting Information

During startup/shutdown operations, NO_x and SO₂ emissions are monitored by CEMs or alternate methods in accordance with applicable NSPS rules. This condition establishes emissions limitations and compliance requirements for the Smelter main stack and the Holman Boiler.

KUC continuously monitors operational parameters to predict NO_x emissions and to ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lb/hr), stack oxygen (to monitor proper boiler operation and compliance with NO_x lb/MMBtu emission limit), and steam output (used to estimate heat input if fuel use unavailable). The ranges for these parameters were developed during a 30-day monitoring campaign where data from a certified NO_x analyzer were used to develop predictive equations with the

operational parameters. The alternative monitoring method identified in this condition is consistent with the applicable NSPS.

4.2 Refinery

Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission
The sum of two (tank house) boilers	NO _x	9.5 lb/hr
Combined heat plant	NO _x	5.96 lbs/hr

Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Tank house boilers	NO _x	Every 3 years*
Combined heat plant	NO _x	Every year

Note:

*Stack testing shall be performed on boilers that have operated more than 300 hours during a 3-year period.

Supporting Information

KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions always including during startup, shutdown, and malfunction. Records shall be kept on site which indicate the date, and time of startups and shutdowns. This condition establishes emissions limitations and compliance requirements for the Refinery Boilers and Combined Heat and Power unit.

Attachments

- Smelter Dryer/Granulator Baghouse Information
- Anodes Furnaces NO_x Study
- Degreaser Solvent SDS
- EPA Compliance Letter



Federal Register

**Tuesday,
January 23, 2007**

Part II

Environmental Protection Agency

40 CFR Part 63

**National Emission Standards for
Hazardous Air Pollutants for Area
Sources: Polyvinyl Chloride and
Copolymers Production, Primary Copper
Smelting, Secondary Copper Smelting,
and Primary Nonferrous Metals: Zinc,
Cadmium, and Beryllium; Final Rule**

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2006-0510; FRL-8257-4]

RIN 2060-AN45

National Emission Standards for Hazardous Air Pollutants for Area Sources: Polyvinyl Chloride and Copolymers Production, Primary Copper Smelting, Secondary Copper Smelting, and Primary Nonferrous Metals: Zinc, Cadmium, and Beryllium

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rules.

SUMMARY: EPA is issuing national emission standards for hazardous air pollutants (NESHAP) for four area source categories. These final NESHAP include emissions limits and/or work practice standards that reflect the generally available control technologies (GACT) and/or management practices in each of these area source categories.

DATES: These final rules are effective on January 23, 2007. The incorporation by reference of certain publications listed in these rules is approved by the Director of the Federal Register as of January 23, 2007.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2006-0510. All documents in the docket are listed in the Federal Docket Management System index at <http://www.regulations.gov>. Although listed in the index, some

information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through www.regulations.gov or in hard copy at the EPA Docket Center, Public Reading Room, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Ms. Sharon Nizich, U.S. EPA, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Metals and Minerals Group (D243-02), Research Triangle Park, North Carolina 27711, telephone number: (919) 541-2825, fax number (919) 541-3207, e-mail address: nizich.sharon@epa.gov.

SUPPLEMENTARY INFORMATION:

Outline

The information presented in this preamble is organized as follows:

- I. General Information
 - A. Does this action apply to me?
 - B. Where can I get a copy of this document?
 - C. Judicial Review
- II. Background Information for Final Area Source Standards

- III. Summary of Final Rule and Changes Since Proposal
 - A. NESHAP for Polyvinyl Chloride and Copolymers Production Area Sources
 - B. NESHAP for Primary Copper Smelting Area Sources
 - C. NESHAP for Secondary Copper Smelting Area Sources
 - D. NESHAP for Primary Nonferrous Metals—Zinc, Cadmium, and Beryllium Area Sources
- IV. Summary of Comments and Responses
 - A. Existing Area Source Facilities
 - B. Part 63 General Provisions
 - C. Primary Copper Smelters
 - D. Primary Zinc Smelters
 - E. Basis for Area Source Standards
 - F. Compliance Date
- V. Statutory and Executive Order Reviews
 - A. Executive Order 12866: Regulatory Planning and Review
 - B. Paperwork Reduction Act
 - C. Regulatory Flexibility Act
 - D. Unfunded Mandates Reform Act
 - E. Executive Order 13132: Federalism
 - F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
 - G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
 - H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
 - I. National Technology Transfer Advancement Act
 - J. Congressional Review Act

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by these final standards include:

Category	NAICS code ¹	Examples of regulated entities
Industry:		
Polyvinyl chloride and copolymers production.	325211	Area source facilities that polymerize vinyl chloride monomer to produce vinyl chloride and/or copolymer products.
Primary copper smelting	331411	Area source facilities that produce copper from copper sulfide ore concentrates using pyrometallurgical techniques.
Secondary copper smelting	² 331423	Area source facilities that process copper scrap in a blast furnace and converter or use another pyrometallurgical purification process to produce anode copper from copper scrap, including low-grade copper scrap.
Primary nonferrous metals—zinc, cadmium, and beryllium.	331419	Area source facilities that produce zinc, zinc oxide, cadmium, or cadmium oxide from zinc sulfide ore concentrates using pyrometallurgical techniques and area source facilities that produce beryllium metal, alloy, or oxide from beryllium ore.
Federal government	Not affected.
State/local/tribal government	Not affected.

¹ North American Industry Classification System.

² This final rule applies only to secondary copper smelters and does not apply to copper, brass, and bronze ingot makers or remelters that may also be included under this NAICS code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility is regulated by this action, you should examine the

applicability criteria in 40 CFR 63.11140 of subpart DDDDDD (NESHAP for Polyvinyl Chloride and Copolymers Production Area Sources), 40 CFR 63.11146 of subpart EEEEEEE (NESHAP for Primary Copper Smelting Area

Sources), 40 CFR 63.11153 of subpart FFFFFFF (NESHAP for Secondary Copper Smelting Area Sources), or 40 CFR 63.11160 of subpart GGGGGG (NESHAP for Primary Nonferrous Metals—Zinc, Cadmium, and Beryllium

Area Sources). If you have any questions regarding the applicability of this action to a particular entity, consult either the air permit authority for the entity or your EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: <http://www.epa.gov/ttn/oarpg/>. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of these final rules is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 26, 2007. Under section 307(d)(7)(B) of the CAA, only an objection to these final rules that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information for Final Area Source Standards

Sections 112(c)(3) and 112(k)(3)(B) of the CAA instruct EPA to identify not less than 30 HAP which, as a result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas, and to list sufficient area source categories¹ to ensure that sources representing 90 percent or more of the emissions of each of the 30 listed HAP ("area source HAP") are subject to regulation. Sierra Club sued EPA, alleging a failure to complete standards for the source categories listed pursuant to CAA sections 112(c)(3) and (k)(3)(B) within the timeframe specified by the statute.

¹ Under section 112(a) of the Clean Air Act, an area source is defined as a stationary source that is not a major source. A major source is defined as a stationary source or a group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP.

See Sierra Club v. Johnston, No. 01–1537, (D.D.C.). On March 31, 2006, the court issued an order requiring EPA to promulgate standards under CAA section 112(d) for those area source categories listed pursuant to CAA sections 112(c)(3) and (k)(3)(B).

Among other things, the order requires that, by December 15, 2006, EPA complete standards for four of the listed area source categories. On October 6, 2006 (71 FR 59302) we proposed NESHAP for the following four listed area source categories that we have selected to meet the December 15, 2006 deadline: (1) Primary Copper Smelting; (2) Secondary Copper Smelting; (3) Polyvinyl Chloride and Copolymers Production; and (4) Primary Nonferrous Metals—Zinc, Cadmium, and Beryllium. These final NESHAP complete the required regulatory action for four area source categories.

Under CAA section 112(d)(5), the Administrator may, in lieu of standards requiring maximum achievable control technology (MACT) under section 112(d)(2), elect to promulgate standards or requirements for area sources "which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants." Under section 112(d)(5), the Administrator has the discretion to use generally available control technology (GACT) or management practices in lieu of MACT. As mentioned in the proposed NESHAP for these four area source categories, we have decided not to issue MACT standards and concluded that requirements that provide for the use of GACT or generally available management practices are appropriate for these four source categories (71 FR 59302, 59304, October 6, 2006).

III. Summary of Final Rules and Changes Since Proposal

A. NESHAP for Polyvinyl Chloride and Copolymers Production Area Sources

As proposed, we are adopting the requirements in 40 CFR part 61, subpart F that apply to polyvinyl chloride (PVC) plants as the NESHAP for the Polyvinyl Chloride and Copolymer Production area source category. The only change since the proposed rule is that this final rule does not adopt either the startup, shutdown, and malfunction (SSM) requirements in 40 CFR 63.6(e)(3) or the preconstruction notification requirements in 40 CFR 63.5. As discussed in more detail in section IV.B of this preamble, under the construct of part 61 standards, sources must comply with the standards at all times, including periods of SSM. Because in

this final rule we are adopting the part 61 standards for PVC plants as the area source standard, separate requirements governing SSM are not necessary. We have also determined that the preconstruction notification requirements at 40 CFR 63.5 are not necessary because a comparable preconstruction notification is already required under the part 61 General Provisions (40 CFR part 61, subpart A), which apply to this NESHAP.

1. Applicability and Compliance Dates

This final rule applies to both new and existing PVC and copolymer plants that are area sources of HAP. The owner or operator of an existing source must comply with all the requirements of this area source NESHAP by January 23, 2007. The owner or operator of a new source must comply with this area source NESHAP by January 23, 2007 or at startup, whichever is later.

2. Emissions Limits and Work Practice Standards

The Polyvinyl Chloride and Copolymers Production area source category was listed for its contribution to the emissions of the area source HAP vinyl chloride. As proposed, we are adopting the requirements in 40 CFR part 61, subpart F that are applicable to PVC plants as the NESHAP for the Polyvinyl Chloride and Copolymer Production area source category. These requirements in subpart F include numerical emissions limits for reactors; strippers; mixing, weighing, and holding containers; monomer recovery systems; emissions sources following the stripper(s); and reactors used as strippers. In addition, they include emissions limits and work practice requirements that apply to discharges from manual vent valves on a PVC reactor and relief valves in vinyl chloride service, fugitive emissions sources, and equipment leaks. Subpart F also requires a new or existing source to comply with the requirements at 40 CFR part 61, subpart V for the control of equipment leaks. As discussed in the proposal preamble, we have determined that these requirements represent GACT for sources in this area source category.

3. Compliance Requirements

We are including in this NESHAP the monitoring, testing, recordkeeping, and reporting requirements in 40 CFR part 61, subpart F. This final NESHAP requires a vinyl chloride continuous emissions monitoring system (CEMS) for the regulated emissions sources (except for sources following the stripper) and for any control system to which reactor emissions or fugitive

emissions must be ducted. Plants using a stripper to comply with this NESHAP must also determine the daily average vinyl chloride concentration for each type of resin. The owner or operator must submit quarterly reports containing information on emissions or resin concentrations that exceed the applicable limits. Records are required to demonstrate compliance, including a daily operating log for each reactor. Plants are required to comply with the testing, monitoring, recordkeeping, and reporting requirements in the part 61 General Provisions (40 CFR part 61, subpart A). For the reasons discussed in sections III.A and IV.B of this preamble, this final NESHAP does not require that the owner or operator comply with the SSM requirements at 40 CFR 63.6(e)(3) and the preconstruction notification requirements at 40 CFR 63.5.

4. Exemption From Title V Permit Requirements

Section 502(a) of the CAA provides that EPA may exempt one or more area sources from the requirements of title V if EPA finds that compliance with such requirements is "impracticable, infeasible, or unnecessarily burdensome" on such area sources. EPA must determine whether to exempt an area source from title V at the time we issue the relevant section 112 standard (40 CFR 70.3(b)(2)). For the reasons discussed in the preamble to the proposed rule, we are exempting PVC and copolymers production area sources from the requirements of title V. PVC and copolymers production area sources are not required to obtain title V permits solely as a function of being the subject of the NESHAP; however, if they were otherwise required to obtain title V permits, such requirement(s) would not be affected by this exemption. We received no comments on our proposal to exempt PVC and copolymer production area sources from the requirements of title V.

B. NESHAP for Primary Copper Smelting Area Sources

The Primary Copper Smelting area source category was listed for its contribution to the emissions of the area source HAP arsenic, cadmium, chromium, lead, and nickel. As discussed in more detail in section IV.C of this preamble, the major change since the proposed rule is that we established a subcategory of primary copper smelters that use the batch converting technology and developed separate standards for this subcategory. At the time of the proposed rule, we were not aware of any area sources using the batch converting technology. Since

then, we received comments indicating that there may or will be primary copper smelting area sources that use the batch converting technology. Because batch technology is quite different from the continuous converting technology we used to develop the proposed standards for the Primary Copper Smelting area source category in terms of process operation, emissions points, and achievable levels of control, we believe that the proposed standards do not represent GACT for existing primary copper smelting area sources that use the batch converting technology. Accordingly, we developed a separate standard for existing sources that use the batch converting technology, and we developed that standard based on the title V permit of one batch converting facility that we have determined to be effectively controlling its HAP emissions by complying with its permit terms and conditions.

In response to comments, we also made several changes to the proposed rule for primary copper smelters that do not use the batch converting technology. As explained in the preamble to the proposed rule, we have determined that certain terms and conditions in the title V permit of the only area source primary smelter of which we are aware provide effective control of HAP emissions and represent GACT for these sources. We made changes in the proposed rule to more accurately capture the relevant terms and conditions in this existing area source's title V permit. Specifically, we clarified that capture and control systems are not required for anode casting and holding operations; that the sampler required for existing sources is a continuous PM sampler; that the emissions limit is expressed as PM less than 10 microns in aerodynamic diameter (PM₁₀) rather than PM; and that a single gas collection system could serve multiple process vessels.

As discussed in section IV.B of this preamble, we allow new and existing sources to comply with either the SSM requirements in 40 CFR 63.6(e)(3) or the detailed SSM requirements in the final rule that were developed from the existing sources' title V permits, which are substantially equivalent to the SSM requirements in 40 CFR part 63.

1. Applicability and Compliance Dates

This final rule applies to each new or existing primary copper smelter that is an area source of HAP. The owner or operator of an existing affected source must comply by January 23, 2007. The owner or operator of a new affected source must comply by January 23, 2007 or upon initial startup, whichever is later. An affected source is new if

construction or reconstruction of the affected source was commenced on or after October 6, 2006.

2. Emissions Limits and Work Practice Standards

As previously mentioned, we have developed separate standards for existing sources that use the batch converting technology and for those that do not. However, the standards for new sources apply to all new area source primary copper smelters irrespective of the converting technology utilized.

Under this final rule, the owner or operator of an existing area source using any converting technology is required to control HAP emissions from copper concentrate drying, copper concentrate smelting, copper matte drying and grinding, copper matte converting, and copper anode refining. As discussed in the proposal preamble, we are using PM as a surrogate for HAP metals. Gases and fumes generated by these processes must be captured and vented through one or more PM control devices. For existing primary copper smelters that do not use the batch converting process, the total emissions of PM₁₀ from the captured gas streams from all of these processes is limited to 89.5 pounds per hour (lb/hr) as determined on a 24-hour average basis.

For existing primary copper smelters using the batch converting technology, the exhaust gases from each smelter vessel and each converter must be collected and sent to a PM control device and to a sulfuric acid plant. A secondary gas collection system must be installed on each smelting vessel and converter, and PM emissions from the secondary capture and control system must not exceed 0.02 grains per dry standard cubic foot (gr/dscf). The PM emissions from each copper concentrate dryer must not exceed 0.022 gr/dscf.

Similarly, the owner or operator of a new area source using any converting technology must control HAP emissions from all primary copper smelting processes, including but not limited to those processes mentioned above that are applicable to the new source's smelter design. Gases and fumes generated by these processes at a new source must be captured and vented through one or more PM control devices. We are requiring a new source to achieve a facility input-based emissions rate for total PM no greater than a daily (24-hour) average of 0.6 pounds per ton (lb/ton) of copper concentrate feed charged to the smelting vessel.

This final rule for new area source primary copper smelters also requires a secondary gas system for each smelting

vessel and converting vessel that collects the gases and fumes released during the molten material transfer operations and conveys the collected gas stream to a control device. Capture systems that collect gas and fumes and convey them to a control device also are required for operations in the anode refining. These capture and control requirements apply to all new and existing area sources using any copper smelting technology.

3. Compliance Requirements

In this final rule, we have adopted the testing, monitoring, operation and maintenance, recordkeeping, and reporting requirements for PM emissions that are in the title V permits of the existing area source smelters. Compliance with the emissions limit for existing area sources not using the batch converting technology is based on the daily average PM₁₀ emissions measured by a continuous PM sampler. For smelters using the batch conversion technology, compliance is based on performance tests at least every 2.5 years and continuous monitoring using continuous opacity monitoring systems (COMS) for electrostatic precipitators and bag leak detection systems for baghouses.

The operation and maintenance requirements in this final rule for existing sources using any converting technology are based on the existing sources' title V permits. At all times, the owner or operator must to the extent practicable, maintain and operate any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. In addition, all pollution control equipment must be installed, maintained, and operated properly. Instructions from the vendor or established maintenance practices that maximize pollution control must be followed. Maintenance records must be made available to the permitting authority upon request.

This final rule allows any new or existing source to meet the SSM requirements specified in this final rule or the SSM requirements in 40 CFR 63.6(e)(3). The SSM requirements that are specified in this final rule were developed from the existing sources' title V permit requirements, and we believe these requirements are equally applicable to new and existing area sources irrespective of the converting technology used. Sources may nevertheless choose to comply with the SSM provisions in 40 CFR 63.6(e)(3), in lieu of the SSM requirements specified in this final rule. The SSM provisions in

this final rule require that all malfunctions be reported within two working days of the event. The report must include a description of the malfunction, steps taken to mitigate emissions, and corrective actions taken. In addition, the owner or operator must show through signed contemporaneous logs or other relevant evidence that: (1) A malfunction occurred and the probable cause can be identified, (2) the facility was being operated properly at the time the malfunction occurred, and (3) all reasonable steps were taken to minimize emissions that exceeded the emission standards. A malfunction or emergency does not include events caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

The owner or operator of an existing area source using any copper smelting technology must comply with notification requirements in 40 CFR 63.9 of the General Provisions (40 CFR part 63, subpart A). In the notification of compliance status required in 40 CFR 63.9(h), the owner or operator may certify initial compliance with the emissions limit based on monitoring data collected during a previous compliance test. The owner or operator also must certify initial compliance with the work practice standards.

The owner or operator of a new primary copper smelter must install, operate, and maintain a CEMS to measure and record PM concentrations and gas stream flow rates for each emissions source subject to the emissions limit. The standard requires that the PM CEMS meet EPA Performance Specification 11 (40 CFR part 60, appendix B). A device to measure and record the weight of the copper concentrate feed charged to the smelting furnace each day also is required. The owner or operator must continuously monitor PM emissions, determine and record the daily (24-hour) value for each day, and calculate and record the daily average pounds of total PM per ton of copper concentrate feed charged to the smelting furnace. A monthly summary report of the daily averages of PM per ton of copper concentrate feed charged to the smelting vessel also is required. All notification, monitoring, testing, operation and maintenance, recordkeeping, and reporting requirements of the part 63 General Provisions apply to the owner or operator of a new source. This final rule allows a new source to meet the specific SSM requirements that were developed from the title V permit requirements for existing sources or the SSM requirements in 40 CFR 63.6(e)(3).

C. NESHAP for Secondary Copper Smelting Area Sources

We did not receive any comments on our determination of GACT for secondary copper smelters, and we are promulgating the standard as proposed without any changes.

1. Applicability and Compliance Dates

This final rule applies to each new secondary copper smelter that is an area source of HAP. The owner or operator of a new affected source is required to comply by January 23, 2007 or upon initial startup, whichever is later.

2. Emissions Limit and Work Practice Standards

This final rule does not include requirements for existing area sources of secondary copper smelters. As we explained in the preamble to the proposed rule, currently there are no existing major or area sources of secondary copper smelters. Therefore, there is not any, nor would there ever be, an existing secondary copper smelter that would be subject to this rule. In this circumstance, we are not issuing standards for existing area sources of secondary copper smelters. However, this final rule contains requirements for new area sources of secondary copper smelters. The Secondary Copper Smelting area source category was listed for its contribution to the emissions of the area source HAP cadmium, lead and dioxin. We have established requirements for new sources in this category to ensure that any potential emission of these area source HAP from future secondary copper smelting area sources will be appropriately controlled.

We are requiring that the owner or operator of any new secondary copper smelter operate a capture and control system for PM emissions from any process operation that melts copper scrap, alloys, or other metals or that processes molten material. Emissions of PM from the control device must not exceed 0.002 gr/dscf. The owner or operator must also prepare and follow a written plan for the selection, inspection, and pretreatment of copper scrap to minimize, to the extent practicable, the amount of oil and plastics in the scrap that is charged to smelting or melting furnaces. As we explained in the proposal preamble, we are using PM as a surrogate for establishing standards for metal HAP, which are cadmium and lead in this case. The United Nations Environmental Programme (UNEP) has also recommended using control devices with high efficiency PM removal to reduce dioxin emissions. The pollution

prevention measure described above (i.e., presorting and pretreating materials) is another UNEP recommendation for reducing dioxin emissions. We have determined that these requirements represent GACT for new sources of secondary copper smelters and requested comments on this determination in the proposed rule. We did not receive any comments on this determination.

3. Compliance Requirements

Fabric filters (baghouses) are expected to be needed to meet the NESHAP emissions limit. Consequently, the monitoring requirements include bag leak detection systems when baghouses are used. For additional information on bag leak detection systems that operate on the triboelectric effect, see "Fabric Filter Bag Leak Detection Guidance", U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1997, EPA-454/R-98-015, NTIS publication number PB98164676. This document is available from the National Technical Information Service (NTIS), 5385 Port Royal Road, Springfield, VA 22161. The owner or operator must prepare a written plan for the selection, inspection, and pretreatment of copper scrap and keep records to document conformance with the requirements in the written plan. If a control device other than a baghouse is used, the owner or operator must submit a monitoring plan to the permitting authority for approval. The monitoring plan must include performance test results showing compliance with the PM emissions limit, a plan for operation and maintenance of the control device, a list of operating parameters that will be monitored, and operating parameter limits that were established during the performance test.

The owner or operator must conduct a performance test to demonstrate initial compliance with the PM emissions limit and report the results in the notification of compliance status required by 40 CFR 63.9(h) of the General Provisions. If a baghouse is used, the PM concentration is to be determined using EPA Method 5 (for negative pressure baghouses) or Method 5D (for positive pressure baghouses) in 40 CFR part 60, appendix A. Repeat performance tests are required every 5 years to demonstrate compliance with the PM emissions limit. All requirements of the part 63 General Provisions apply to the owner or operator of a new source, including the notification, monitoring, testing, operation and maintenance, SSM, recordkeeping, and reporting requirements.

D. NESHAP for Primary Nonferrous Metals—Zinc, Cadmium, and Beryllium Area Sources

1. NESHAP for Primary Zinc Production

In this final rule, we have adopted a limit in grains per dry standard cubic foot (gr/dscf) for certain melting furnaces at existing zinc production area sources in addition to the proposed pound per hour (lb/hr) limits for these furnaces at existing sources. This gr/dscf limit is the limit that we proposed for the same furnaces at new sources. Both the gr/dscf limit and the lb/hr limits reflect the level of emission control that can be achieved based on the technology we identified as GACT for these furnaces (i.e., a well-operated and well-maintained baghouse). However, whereas the lb/hr limits were based on the specific operations at the two existing sources of which we are aware, the gr/dscf emission limit is not operation specific and can apply to these furnaces at any primary zinc production area source irrespective of its operation. For this reason, we proposed this gr/dscf emissions limit for these furnaces at new sources. In this final rule, we similarly allow an existing source to meet this gr/dscf limit for these furnaces. This final rule provides existing sources the option of meeting either the lb/hr limits or the gr/dscf limit for these furnaces. We believe that including both the lb/hr and gr/dscf limits in this final rule will ensure effective control of these furnaces at all existing primary zinc production area sources in the event that there are facilities other than the two we know and with very different operations from the two known sources.

In addition, as discussed in section IV.B of this preamble, we allow new and existing sources to comply with either the SSM requirements in 40 CFR 63.6(e)(3) or with the detailed SSM requirements in the final rule that were developed from the existing sources' title V permits, which are substantially equivalent to the SSM requirements in part 63.

Applicability and compliance dates. This final rule applies to each new or existing primary zinc production facility that is an area source of HAP. The owner or operator of an existing affected source must comply by January 23, 2007. The owner or operator of a new affected source must comply by January 23, 2007 or upon initial startup, whichever is later.

Emissions limits and work practice standards. Primary zinc production facilities were included as part of the Primary Nonferrous Metals area source category due to their contributions to

the emissions of the area source HAP arsenic, cadmium, lead, manganese, and nickel, all of which are metal HAP. As we mentioned in the proposal preamble, cadmium is produced as a by-product of zinc smelting processes. There are no primary cadmium smelters in the United States. Accordingly, the requirements for area sources of zinc production in this final rule also address emissions associated with any cadmium production at these zinc production facilities.

As previously mentioned, we are using PM as a surrogate for establishing standards for metal HAP. Under this final rule, the owner or operator of an area source of zinc production is required to exhaust roaster off-gases to PM removal equipment and a sulfuric acid plant. Bypassing the sulfuric acid plant during charging of the roaster is prohibited.

Emissions limits apply to the different types of melting furnaces at primary zinc production facilities. For existing sources, this NESHAP limit PM emissions to 0.93 lb/hr for zinc cathode melting furnaces; 0.1 lb/hr for furnaces that melt zinc dust, chips, and off-specification zinc materials; and 0.228 lb/hr for the combined exhaust from furnaces that melt zinc scrap and alloys. As an alternative to the lb/hr limits for these furnaces at existing sources, the owner or operator may elect to meet a limit of 0.005 gr/dscf. For new sources, the PM limit is 0.005 gr/dscf for the furnaces mentioned above. Other PM limits are 0.014 gr/dscf for anode casting furnaces and 0.015 gr/dscf for cadmium melting furnaces at new and existing sources.

Emissions limits also apply to any sintering machine at a new or existing area source facility. If there is a sintering machine, the owner or operator must comply with the PM limit at 40 CFR 60.172 and the opacity limit at 40 CFR 60.174(a) of the new source performance standard (NSPS) for primary zinc smelters (40 CFR part 60, subpart Q).

Compliance requirements. We are adopting for existing area sources certain monitoring, recordkeeping, and reporting requirements in the title V permits of the two existing facilities that relate to PM emissions control. The owner or operator of an existing area source must monitor baghouse pressure drop, perform routine baghouse maintenance, and keep records to document compliance. In addition, we are requiring repeat performance tests (at least once every 5 years) for existing sources. This final rule also requires a continuous opacity monitoring system (COMS) for any sintering machine in accordance with 40 CFR 60.175.

The owner or operator of an existing area source must comply with initial notification requirements in 40 CFR 63.9 of the General Provisions. In the notification of compliance status required by 40 CFR 63.9(h), the owner or operator may certify initial compliance with the HAP emissions limits based on the results of a PM performance test for each of the regulated emissions sources conducted within the past 5 years. The owner or operator must also certify initial compliance with the work practice standards.

If an existing source has not conducted a performance test to demonstrate compliance with the emissions limits for a furnace, the owner or operator must conduct a test according to the requirements at 40 CFR 63.7 using EPA Method 5 (40 CFR part 60, appendix A) to determine the PM concentration or an alternative method previously approved by the permitting authority. For a sintering machine, the owner or operator must conduct a performance test according to the procedures in 40 CFR 60.176(b) using EPA Method 5 to determine the PM concentration and EPA Method 9 (40 CFR part 60, appendix B) to determine the opacity of emissions.

The operation and maintenance requirements in the final rule for existing sources are based on the sources' title V permits. The owner or operator must maintain all equipment covered under the subpart in such a manner that the performance or operation of the equipment does not cause a deviation from the applicable requirements. A maintenance record must be kept for each item of air pollution control equipment. At a minimum, this record must show the dates of performing maintenance and the nature of preventative maintenance activities.

This final rule allows any existing source to meet the specific SSM requirements that were developed from the title V permit requirements for existing sources or the SSM requirements in 40 CFR 63.6(e)(3). The specific SSM provisions in this final rule require that all malfunctions be reported within two working days of the event. The report must include a description of the malfunction, steps taken to mitigate emissions, and corrective actions taken. In addition, the owner or operator must show through signed contemporaneous logs or other relevant evidence that: (1) A malfunction occurred and the probable cause can be identified, (2) the facility was being operated properly at the time the malfunction occurred, and (3) all

reasonable steps were taken to minimize emissions that exceeded the emission standards. A malfunction or emergency does not include events caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

As required in the existing permits, the owner or operator must submit a notification to the permitting authority of any deviation from the requirements of this final NESHAP. The notification must describe the probable cause of the deviation and any corrective actions or preventative measures taken. Existing facilities are also required to submit semiannual monitoring reports which clearly describe any deviations. Records of baghouse maintenance, all required monitoring data, and support information also are required. The owner or operator of an existing area source must also comply with the notification requirements in 40 CFR 63.9 of the General Provisions.

The owner or operator of a new area source is required to install and operate a bag leak detection system for each baghouse used to comply with a PM emissions limit. For additional information on bag leak detection systems that operate on the triboelectric effect, see "Fabric Filter Bag Leak Detection Guidance", U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, September 1997, EPA-454/R-98-015, NTIS publication number PB98164676. This document is available from the National Technical Information Service (NTIS), 5385 Port Royal Road, Springfield, VA 22161. In addition, we are requiring repeat PM performance tests (once every 5 years) for each furnace at a new source. The owner or operator must also install, operate, and maintain a COMS for each sintering machine according to EPA Performance Specification 1 (40 CFR part 60, appendix B).

The owner or operator of a new affected source must demonstrate initial compliance with the applicable emissions limits by conducting a performance test according to the requirements at 40 CFR 63.7 and using EPA 5 or 5D (40 CFR part 60, appendix A), as applicable, to determine the PM concentration. An initial performance test is also required for a sintering machine according to the methods and procedures in 40 CFR 60.176(b). All of the notification, testing, monitoring, operation and maintenance, recordkeeping, and reporting requirements of the part 63 General Provisions apply to a new area source. This final rule allows a new source to meet the specific SSM requirements in

this final rule or the SSM requirements in 40 CFR 63.6(e)(3).

2. NESHAP for Primary Beryllium Production Area Sources

The only change since proposal is that this final rule does not adopt the SSM requirements in 40 CFR 63.6(e)(3) and the preconstruction notification requirements in 40 CFR 63.5. As discussed in more detail in section IV.B of this preamble, we have determined that the SSM requirements are not necessary for standards under part 61 that must be met at all times, and the preconstruction notification is already required under the part 61 General Provisions.

Applicability and compliance dates. For this final rule, we are adopting all of the requirements in the National Emission Standard for Beryllium at 40 CFR part 61, subpart C. The owner or operator of an existing area source must comply with this NESHAP by January 23, 2007. The owner or operator of a new area source must comply by January 23, 2007 or at startup, whichever is later.

Emissions limits. Primary beryllium production facilities were included as part of the Primary Nonferrous Metals area source category due to their contributions to the emissions of the area source HAP arsenic, cadmium, lead, manganese, and nickel, all of which are metal HAP. As discussed in the proposal preamble, we are using beryllium as a surrogate for HAP metals. We are adopting the 40 CFR part 61, subpart C standard as the requirements for both new and existing primary beryllium production facilities in this final rule. The part 61, subpart C standard limits emissions from extraction plants (i.e., primary beryllium production facilities) to 10 grams (0.022 lb) of beryllium over a 24-hour period. Alternatively, the owner or operator of a beryllium production facility may request to meet an ambient concentration limit instead of the emissions limit. As discussed in the preamble to the proposed rule, the part 61 standard is highly effective in controlling PM and metal HAP emissions from the only existing beryllium production facility known to us at the time of the proposal. We have determined that these requirements reflect GACT for area sources of beryllium production. We did not receive any comments on this determination.

Compliance requirements. This final rule requires the owner or operator to comply with the testing, monitoring, recordkeeping, and reporting requirements in 40 CFR part 61, subpart

C. An owner or operator subject to the ambient concentration limit must operate air sampling sites to continuously monitor the concentrations of beryllium in the ambient air according to an EPA-approved plan.

The owner or operator must comply with recordkeeping requirements in 40 CFR part 61, subpart C, as well as the testing, monitoring, recordkeeping, and reporting requirements in the part 61 General Provisions in 40 CFR part 61, subpart A. For the reasons discussed in section IV.B of this preamble, this final rule does not require that the owner or operator comply with the requirements for SSM plans and reports in 40 CFR 63.6(e)(3) or the preconstruction notification requirements in 40 CFR 63.5.

IV. Summary of Comments and Responses

A. Existing Area Source Facilities

At proposal, we stated that we did not know of any existing sources in the Polyvinyl Chloride and Copolymer area source category, and we requested comments on whether there are or ever will be any area sources in this area source category. We also stated that currently there is only one area source of primary copper production in operation in the United States and that there are no primary beryllium production area sources.

Comment: One commenter informed us of an area source PVC plant in Alabama. In addition, two commenters stated that there are a few (at least three) PVC plants that they believe may qualify as area sources. According to the commenters, these were once major sources that have reduced HAP emissions significantly or that are currently shut down but are expected to start up again with significantly less emissions than from previous operations as major sources. The commenters requested that EPA clarify the meaning of "potential to emit" in its definition of an "area source" in the proposed rule, as well as the proposed rule's applicability to plants that have obtained or, for the ones that are not currently operating, will obtain permits that limit emissions to levels below the major source thresholds. In addition, the commenters requested clarification of the proposed rule's applicability to PVC plants co-located at chemical complexes that are major sources.

One commenter notified us of an area source primary beryllium plant in Utah. The commenter sought clarification of the proposed rule's applicability to a primary beryllium plant that is a major

source because of perchloroethylene emissions and that may become an area source in the future by eliminating the use of perchloroethylene.

We also received comments that there are two operating primary copper smelters that are area sources rather than just one, as EPA stated in the proposed rule. The company operating this second source reported that it was an area source (synthetic minor) based on a determination by the permitting authority. The company also stated that it is planning to restart a primary copper smelter in Texas that has been shutdown and under "care and maintenance" for several years. This facility will incorporate feedstock limitations to remain below major source thresholds, and the company expects that this facility will qualify as an area source when the renewed permits are issued. The commenter sought clarification of the applicability of the proposed rule to the two primary copper smelters described above.

Response: Section 112(a) of the CAA defines the terms "major source" and "area source." An "area source" is defined as any stationary source that is not a major source. In the proposed rule, we included a definition for "area source" and that definition attempted to summarize the statutory definitions of "major source" and "area source." Commenters sought clarification of the meaning of the term "potential to emit" contained in the proposed definition of "area source." Based on the comment, it appears that the proposed definition of "area source" has caused confusion. Because the proposed definition of "area source" was merely intended to summarize the statutory definitions of "major source" and "area source" and is redundant of the definition of "area source" contained in the General Provisions (40 CFR part 63, subpart A), we have decided not to finalize the proposed "area source" definition. Instead, as noted in the NESHAP for each of these four area source categories, the definitions of "major source," "area source," and "potential to emit" in 40 CFR 63.2 apply to this final rule.² To the

² In 1995, the Court of Appeals for the District of Columbia Circuit reviewed the definition of "potential to emit" (PTE) contained in 40 CFR in 40 CFR 63.2 (*National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 1995)). In July 2005, the D.C. Circuit remanded the definition to EPA to the extent the definition required that physical or operational limitations be "federally enforceable" (*National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 1995)). The court did not vacate the 40 CFR part 63 regulations and therefore the definition of "potential to emit" in 40 CFR part 63 remains in place. EPA is currently in the process of developing a proposed rule that responds to the court's remand. EPA has a transitional policy that relates to PTE. See "Options for Limiting the Potential to Emit

extent the commenters have questions as to whether their facility is a major source or an area source, EPA cannot answer these site-specific applicability questions in the context of this national rulemaking. We refer the commenters to the definitions of "major source," "area source," and "potential to emit" found in 40 CFR 63.2, and recommend that the commenters consult with the relevant permitting authority or submit a request for an applicability determination to the EPA regional office in the region where the source is located.

In addition, we want to clarify that a plant that is co-located with other facilities that together qualify as a major source is part of that major source and not an area source.

B. Part 63 General Provisions

Comment: One commenter representing the two beryllium plants objected to the part 63 SSM requirements in the proposed NESHAP for the Primary Beryllium Production area source category. The commenter stated that these two beryllium plants are already subject to 40 CFR part 61, subpart C, which EPA has adopted in this final rule, as well as the SSM requirements in State implementation plans (SIP), State laws, and title V permits. According to the comment, because these plants are subject to a strict ambient air standard for beryllium under the part 61 NESHAP, which requires that the plants monitor continuously and meet the required limits under all conditions, the part 63 SSM requirements are not necessary. Commenters representing facilities in the PVC industry provided similar comments. In addition, they stated that by requiring compliance with part 61 and the SSM provisions in 40 CFR 63.6, the proposed rule would impose two different SSM schemes in one standard. It would also impose more burdensome reporting and recordkeeping obligations on the lower emitting (area) sources.

Representatives of two primary copper companies also stated that the SSM requirements are unnecessary and duplicative of existing requirements and should be deleted. Their title V permits contain existing functionally equivalent

(PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)" (Jan. 25, 1995), available at <http://www.epa.gov/Region7/programs/artd/air/title5/t5memos/ptememo.pdf>. EPA has extended the transition policy several times. See "Third Extension of January 25, 1995 Potential to Emit Transition Policy" (December 20, 1999), available at <http://www.epa.gov/Region7/programs/artd/air/title5/t5memos/4thext.pdf>. Under the Third Extension, sources can rely on State-only enforceable PTE limits until we finalize our response to the remand.

SSM provisions, including requirements for timely notification and reporting.

Response: We agree that the SSM requirements in the 40 CFR part 63 General Provisions need not be included in the NESHAP for the PVC and Copolymer Production and the Primary Beryllium Production area source categories, both of which adopted the relevant part 61 standards for these categories. Under the construct of the part 61 standards, sources must comply with the standards at all times, including periods of SSM. Therefore, separate requirements governing SSM are not necessary. Accordingly, we have revised the proposed rule to eliminate the part 63 SSM requirements for new and existing primary beryllium and PVC plants.

We also examined the SSM requirements that are in title V permits for other source categories. The primary copper smelters and primary zinc production plants have similar requirements in their permits. Our review indicates that these requirements are substantially equivalent to the part 63 SSM requirements. For example, the title V permits for these plants require that all malfunctions be reported within two working days of the event. The report must include a description of the malfunction, steps taken to mitigate emissions, and corrective actions taken. In addition, the permittee must show through signed contemporaneous logs or other relevant evidence that: (1) A malfunction occurred and the permittee can identify the probable cause, (2) the facility was being operated properly at the time the malfunction occurred, and (3) all reasonable steps were taken to minimize emissions that exceeded the emission standards or other requirements of the permit. The permit also makes it clear that a malfunction or emergency does not include events caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

Based on the comments and our review of title V permits, we are including in this final rule alternative SSM requirements that we have formulated based on our review of the title V permits mentioned above. Under this final rule, a new or existing primary copper smelter or primary zinc production facility may choose to meet the SSM requirements in 40 CFR 63.6(e)(3) or the alternative SSM requirements provided in this final rule.

This final rule also includes operation and maintenance requirements for existing sources that are based on the permits. For primary copper smelters, the owner or operator must to the extent

practicable, maintain and operate any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. In addition, all pollution control equipment must be installed, maintained, and operated properly. Instructions from the vendor or established maintenance practices that maximize pollution control must be followed. All necessary equipment control and operating devices, such as pressure gauges, ampere meters, volt meters, flow rate indicators, temperature gauges, continuous emissions monitoring systems, etc., must be installed, operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instructions for pollution control equipment and pollution emitting equipment must be maintained at the facility site. These instructions must be available to all employees who operate the equipment and must be made available to the permitting authority upon request. Maintenance records must be made available to the permitting authority upon request.

Comment: One commenter stated that we should not adopt the preconstruction notification requirements in the part 63 General Provisions (40 CFR part 63, subpart A) because they were unnecessary and duplicate the very similar requirements already in the part 61 General Provisions (40 CFR part 61, subpart A). EPA should not impose the additional burden of submitting and processing two duplicative applications and should just rely on the provisions already in the part 61 General Provisions.

Response: We agree that if a preconstruction notification is submitted under the part 61 General Provisions (40 CFR 61.07), it is not necessary to submit another preconstruction notification under the part 63 General Provisions. We have revised the proposed rule to reflect this change.

Comment: One commenter stated that EPA should not incorporate any of the part 63 General Provisions into area source standards that adopt the part 61 NESHAP. These provisions, including those in 40 CFR 63.1 (Applicability), are already addressed in the part 61 General Provisions and enhanced by SIP requirements and title V permits.

Response: We have previously addressed the SSM requirements and preconstruction notifications for facilities subject to part 61 standards. The only other section of the part 63 General Provisions that we have included for these sources deals with

applicability in 40 CFR 63.1 (§§ 63.1(a)(1) through (10), 63.1(b)(1), 63.1(c), and 63.1(d)). The provisions on applicability impose no burden on the facility and provide clarity and useful information related to the applicability of standards under part 63. Consequently, the final rule includes portions of § 63.1 from the part 63 General Provisions.

C. Primary Copper Smelters

Comment: Two commenters identified two primary copper smelters as area sources in addition to the one smelter identified as an area source in the proposal preamble. One of these smelters is operating, and the company stated that the facility is an area source (i.e., a synthetic minor source). The other smelter has been shut down for several years, but it is in the process of obtaining permits to re-start and expects to be an area source. Both of these smelters use the batch converting process, whereas the smelter that was identified as an area source at proposal and was the basis for GACT uses flash continuous converting technology. The company pointed to the process descriptions in the proposal preamble that noted the numerous differences in the two technologies. The company suggested that their two smelters fit into a separate subcategory (batch converting technology) and should have rule requirements based on that technology. The requirements in the proposed rule are not appropriate for their smelters because the proposed rule is based on the flash continuous converting technology.

Response: The commenters asserted that there are two area source primary copper smelters that use the batch converting technology. As we described in the proposal preamble (71 FR 59308, October 6, 2006), there are numerous differences in process operation, emissions points, and achievable levels of control. We believe that our proposed standard for existing sources, which is based on flash continuous converting technology, would not be appropriate for existing sources of primary copper smelting that use the batch converting technology and that separate standards are needed to address the different technology used by these existing smelters. Solely for purposes of this analysis, we accept, as true, the commenter's assertion that there are existing area source facilities that use batch processing. As explained above, to the extent the commenter has any question as to whether the smelters identified above are major or area sources, they should consult with the relevant permitting authority or submit

a request for an applicability determination to the EPA regional office in the region where the source is located.

In developing the requirements for sources using the batch converting technology, we reviewed the title V permit of the currently operating source identified in the comment. The emissions from this facility are controlled as a result of its title V permit requirements to capture and control emissions of PM. The vast majority of the gases from the smelting furnace and converter are collected by a primary capture system, sent to control equipment to remove PM, and then processed in a sulfuric acid plant. Fugitive emissions are collected by a secondary capture system and sent to a baghouse for control of PM emissions. We determined that these current permit requirements represent GACT for existing primary copper smelters using the batch converting process and have included these requirements in this final rule as the requirements for existing primary copper smelting area sources that use batch converting technology.

According to these requirements, plants that use batch converting technology must operate primary capture systems on each smelting vessel and each copper converter. Secondary capture systems must be installed to capture emissions from tapping copper matte and slag from the smelting vessel and emissions from charging, skimming, pouring, and holding when the converter mouth is partially rotated out from the primary collection hood. All of the collected gases must be routed to an emissions control system. In addition, emissions from the primary collection system for the smelting vessel and converter must be routed to a sulfuric acid plant after PM removal.

Emissions from each copper concentrate dryer must be controlled and must not exceed 0.022 gr/dscf. Emissions from secondary capture systems that are not vented to a sulfuric acid plant must not exceed 0.02 gr/dscf.

We also examined the monitoring requirements in the title V permit of this primary smelter using the batch technology and found that they would ensure that control devices are working properly on a continuous basis. We therefore included these monitoring requirements in this final rule as requirements for primary copper smelting area sources that use the batch converting technology. Under these requirements, a COMS meeting Performance Specification 1 (40 CFR part 60, appendix B) must be installed on each electrostatic precipitator. If the

24-hour rolling average opacity exceeds 15 percent, the plant must investigate the cause of the problem and take corrective action. Each baghouse must be equipped with and monitored by a bag leak detection system to ensure proper operation. We have also required performance tests every 2.5 years to determine compliance with PM limits.

Comment: A commenter representing the primary copper plant that was the basis for GACT stated that EPA did not properly capture the facility's title V permit requirements in some cases. The commenter supplied additional details and clarifications. Clarification is needed for the requirements for anode casting and holding operations, the emissions limit should not be referred to as "smelter wide" but as the limit for the main stack, the limit should be expressed as PM₁₀ rather than PM, and the continuous PM sampler should not be referred to as a CEMS. The commenter also asked that EPA modify the proposed rule to clearly state that a single secondary gas collection system can capture and control emissions from multiple processing vessels (i.e., each vessel does not have to have its own separate collection system). The commenter also requested more flexibility in the monitoring requirements so that the permitting authority could approve improved monitoring technology should it become available in the future.

Response: We agree with the commenter and will make most of the suggested changes. The facility's title V permit was the basis for our GACT determination, and we intended that the proposed area source rule incorporate the permit requirements of this well-controlled facility. We understand that in some cases, a gas collection system may be applied to multiple process vessels, and we have included this clarification in this final rule. We understand that flexibility in monitoring is important, especially as improved monitoring techniques become commercially available and demonstrated in metallurgical operations. That said, it is not necessary to revise the proposed rule to allow a facility to request approval of an alternative monitoring method because the procedure for making such requests is contained in 40 CFR 63.8, which applies to the NESHAP for the Primary Copper Smelting area source category in this final rule.

Comment: One commenter noted that the new source standard for primary copper was based on the newer flash continuous converter technology and would not be appropriate for new plants using the batch converting technology.

The commenter stated that continuous converting has more limited applicability to ore concentrates that have high impurities levels than does batch converting. The commenter stated that because a new smelter could use either of the technologies, the emission standards for new sources should be reflective of the performance of either of these technologies. This can be achieved by providing flexibility in the emission limits that are adopted. The commenter recommended that the standard for new smelters using the batch converting technology be based on the best performing existing facility with the technology. In addition, a provision should be made to allow an alternate emissions limit to be authorized by either EPA or the permitting authority that is equally protective.

Response: The emissions limit that we proposed for new primary copper smelters is in lb/ton of copper concentrate feed and is applied on a facility wide basis. The format and requirements of the standard can be applied to and achieved by a facility using any primary copper smelting technology if it is well controlled. The format of the standard also provides flexibility because multiple process vessels can have different levels of emissions as long as they collectively meet the overall lb/ton limit. The limit has been demonstrated as achievable by an existing area source that uses a continuous converting process. Unlike existing sources, new sources using any smelting technology have the opportunity to incorporate state-of-the-art capture and control systems into their design, construction, and operation. Based on our engineering experience with capture and control systems that have been applied to primary copper processes and also those that have been applied to similar processes in other metallurgical industries, we believe that the emissions limit for new sources can be achieved by primary copper smelters using any processing technology, including both the continuous and batch converting processes. The standard for new primary copper smelters represents a level of control that is generally available for new sources. Consequently, we chose to promulgate the limit as proposed as GACT for new primary copper smelters.

Comment: Three commenters objected to the requirement of using a PM CEMS for monitoring at new primary copper smelter area sources. Although improvements in PM CEMS have been made as they continue to be developed, there is not sufficient operating history

to prove its feasibility for continuous monitoring at primary copper smelters.

Response: The PM CEMS have been demonstrated in many different applications, including processes with exhaust gases similar to those from primary copper smelters (e.g., at electric utilities where the temperatures and exhaust gas compositions are similar). The commenters did not provide any information that the exhaust gases from primary copper smelting are uniquely different. We have included PM CEMS as the monitoring technology for new sources in this final rule.

D. Primary Zinc Smelters

Comment: One commenter asked if the proposed rule was meant to apply to any zinc refinery that processes any amount of zinc sulfide concentrate. If so, what is the timeframe for using zinc sulfide concentrate and its percentage of the feed that qualifies a facility as a primary zinc smelter? Is EPA really trying to regulate zinc refineries, which produce cathodes in a cathode melting furnace and use zinc sulfide concentrate as a feed material, and not regulate thermal zinc smelters, who do not produce cathodes and do not currently use zinc sulfide concentrate?

Response: The commenter is correct in that this final rule applies to any area source facility that produces zinc products from any amount of zinc sulfide ore concentrates using pyrometallurgical processes (i.e., a "primary zinc smelter"). This final rule does not apply to thermal zinc smelters if they do not process zinc sulfide concentrate. (Facilities processing only zinc scrap and residues containing zinc would be classified as secondary zinc smelters.) If a facility meets the definition of primary zinc smelter and is an area source on the compliance date, it is subject to this final rule. If the facility is not processing zinc sulfide concentrate but subsequently begins processing it, meets the definition of primary zinc smelter, and is an area source, it is subject to this final rule when it begins processing the zinc sulfide concentrate. Under these facts, such a facility would be subject to the standards for new sources if construction or reconstruction of the primary zinc smelter (the affected source) commenced on or after October 6, 2006.

We are not making a distinction between zinc refineries and thermal zinc smelters as described by the commenter. Either type of facility is subject to this final rule if it is an area source and meets the definition of primary zinc smelter.

Comment: One commenter noted that the proposed rule requires demonstrating compliance by stack testing within 180 days after the compliance date. Their plant has a process that is not operating, it is subject to the rule, but it may not restart until more than 180 days after the compliance date. As the proposed rule reads, they would have to demonstrate compliance by a stack test even though the process is not operating.

Response: We have clarified the proposed rule to indicate that if a process subject to this final rule is not operating on the compliance date and subsequently starts up, compliance testing must be performed within 180 days after startup of the process.

Comment: One commenter noted that the proposed rule requires that initial compliance must be demonstrated "for each furnace at your facility." A zinc smelter may have other types of furnaces that are not subject to emission limits. The commenter assumes that this requirement will have no impact on these furnaces.

Response: The commenter is correct. We have clarified the proposed rule to state that initial compliance must be demonstrated "for each furnace at your facility that is subject to an emissions limit under this subpart."

Comment: One commenter stated that the emissions limit of 0.005 gr/dscf for certain furnaces at new sources is greater than the emissions limit for the same furnaces at existing sources. The commenter suggested that the greater of the two values be applied in this case to provide a level playing field for new and existing sources.

Response: We disagree with the comment that the emissions limit of 0.005 gr/dscf for certain furnaces at new sources is greater than the emissions limits for the same furnaces at existing sources. The emissions limit of 0.005 gr/dscf for new sources is applied to the exhaust vent of a zinc cathode melting furnace; scrap zinc melting furnace; furnace melting zinc dust, zinc chips, and other materials containing zinc; and alloy melting furnace. For existing sources, the limits are 0.1 lb/hr from the exhaust vent of a furnace that melts zinc dust, zinc chips, and/or other materials containing zinc; and 0.228 lb/hr from the vent for the combined exhaust from a furnace melting zinc scrap and an alloy furnace. Although the limits for the furnaces mentioned above are expressed in different formats for new and existing sources, both formats reflect the level of emission control that can be achieved based on the technology we identified as GACT for these furnaces (i.e., a well-operated and

well-maintained baghouse). However, whereas the lb/hr limits for the above-noted furnaces in the proposed rule were based on the specific operations at the two existing sources of which we are aware, the gr/dscf emission limit is not operation specific and can apply to these furnaces at any primary zinc production area source. We have therefore adopted the gr/dscf limit in addition to the proposed lb/hr limit, and sources can meet either the limit expressed in lb/hr or the limit expressed in gr/dscf.

E. Basis for Area Source Standards

Comment: We received a comment from the National Association of Clean Air Agencies (NACAA) expressing concern with EPA's establishment of area source standards under section 112 of the CAA by adopting existing Federal and/or State area source standards. In the comment, the NACAA stated that the existence of State and local regulations does not relieve EPA of its obligation to establish area source standards under the CAA. The NACAA expressed concern that some States cannot have requirements more stringent than those of the Federal government and may, therefore, be required to change their regulations of area sources to be consistent with EPA's area source standards. The NACAA stated that, if the permit requirements that make these sources "well controlled" are not contained within the Federal rule, the nonfederal rules could be relaxed. The NACAA further stated that, in the absence of Federal requirements, there would be nothing to prevent "backsliding" by these sources.

The NACAA was particularly concerned with EPA's proposed PVC rule, which adopted the part 61 standards for PVC plants. According to the NACAA, the part 61 standards for PVC plants are outdated and inappropriate as a model for GACT. The NACAA submitted with its comment a recommendation for the standards for area sources of PVC plants. The NACAA previously recommended these limits to EPA as the MACT standards for major sources of PVC plants. The NACAA believes the submittal contains valuable information for EPA in developing PVC regulations for area sources as well.

Response: We have traditionally reviewed operating permits and current standards in the standards development process, and we used this approach in developing the NESHAP for the four area source categories in this final rule. The NACAA did not explain why it would be inappropriate for EPA to adopt existing Federal, State or local standards that EPA has determined to be

effective in controlling HAP emissions. Contrary to the commenter's assertions, EPA is setting final area source standards for the four source categories at issue in this rule. The emissions limits and/or work practice standards in each of the four NESHAP in this final rule have been reviewed, determined by EPA to be the appropriate standards for the relevant area source category, and established by EPA in this final rule as the Federal requirements for that category pursuant to section 112 of the CAA.

It is conceivable that for those States with laws that preclude the State from issuing regulations that are more stringent than EPA's regulations, a State may need to change its existing area source regulation in response to this final rule. However, the NACAA has not identified any existing State regulation that would require modification in this regard. Further, as previously mentioned, we established the area source standards in this final rule based on GACT, which may or may not be reflected by more stringent State or local requirements. The NACAA also asserted that the part 61 standards for PVC plants are outdated and inappropriate as GACT for area source PVC plants. NACAA's statement was apparently based on the fact that the part 61 standards were issued prior to the 1990 Amendments to the Clean Air Act and were based on risk. However, the fact that these are risk-based standards are not per se evidence that they do not reflect GACT for area sources of PVC plants. We believe that the record supports our determination as to what constitutes GACT for the four categories at issue here.

Moreover, we reviewed the information submitted by the commenter that contained their "presumptive" determination of MACT that they issued as guidance to State and local agencies. These recommended limits were based on the best-controlled plants, most if not all of which are major sources.³ We believe that these recommended limits may represent MACT or something beyond MACT, but we do not believe that they are appropriate for these particular area source categories. As previously mentioned, we have decided to establish the standards for the PVC and Copolymer Production area source category based on GACT. We do not believe that NACAA's recommended limits represent GACT for area sources

of PVC plants. Because we expect PVC plants to be operating in accordance with the part 61 standards for PVC plants, we believe that these standards represent a level of control that is generally available and is therefore a reasonable representation of GACT for area sources in this source category.

Comment: One commenter stated that area source standards are not needed for primary beryllium plants. All of these plants, including major and area sources, are already subject to NESHAP under 40 CFR part 61. In addition, the proposed area source standard will not achieve any reduction in HAP emissions. A second commenter stated that absent EPA's statutory obligation to establish standards for area sources, there would be no need to regulate PVC and copolymer plants because they are already governed by the existing NESHAP. However, the commenter recognizes EPA's obligation to regulate PVC and copolymer area sources and supports the adoption of the part 61 NESHAP as the area source standard.

Response: The second commenter has captured the issue and provides the response to the first commenter: EPA has a statutory obligation to establish area source NESHAP for primary beryllium plants.

F. Compliance Date

Comment: Two commenters stated that requiring compliance on the date of publication of the final rule in the **Federal Register** does not allow sufficient time for existing sources to develop a SSM plan.

Response: We believe that we have addressed the commenter's concern regarding existing sources' abilities to develop SSM plans by the compliance date. With respect to primary copper smelting and primary zinc production area sources, this final rule allows existing sources in these two area source categories to address SSM according to the relevant requirements in their title V permits, which do not require a SSM plan. As previously discussed in our response to the comments on the necessity of the part 63 SSM requirements (section IV.B of this preamble), we have reviewed the SSM requirements in the title V permits for the existing sources of primary copper smelting and primary zinc production area sources and have determined that these provisions are adequate to replace the SSM requirements in the General Provisions, which require a SSM plan. See 40 CFR 63.6(e)(3). We have therefore included in the final NESHAP for primary copper smelting and primary zinc production area sources requirements that are based on these

title V permit terms and conditions. To provide flexibility, sources can comply with the SSM requirements specified in this final rule or comply with the provisions contained in the General Provisions at 40 CFR 63.6(e).

Accordingly, the existing sources in these two area source categories are not required to develop SSM plans and may instead continue to follow their title V permit requirements regarding SSM.

In addition, as previously mentioned, we are not requiring SSM plans and reports in 40 CFR 63.6(e)(3) for area source PVC plants and beryllium production facilities. Because the NESHAP for these source categories in this final rule adopt part 61 standards, which require compliance at all times, specific provisions governing SSM are unnecessary. For all of the reasons stated above, we believe that the concern expressed in this comment has been addressed.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action" because it may raise novel legal or policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The NESHAP for Polyvinyl and Copolymers Production Area Sources do not impose any new information collection burden. New and existing plants that are area sources are required to comply with the same testing, monitoring, reporting, and recordkeeping requirements as those in the National Emission Standards for Vinyl Chloride (40 CFR part 61, subpart F), to which these area sources are currently subject, and the information collection requirements in the part 61 NESHAP General Provisions (40 CFR part 61, subpart A), which are incorporated into the NESHAP. The OMB has previously approved the information collection requirements in 40 CFR part 61, subpart F, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060-0071, EPA Information Collection Request (ICR) number 0186.10.

A copy of the OMB-approved ICR for the National Emission Standards for

³ It is not clear whether the one polyvinyl chloride area source plant known to the National Association of Clean Air Agencies (NACAA) was among the plants that the NACAA analyzed in developing the recommended limits.

Vinyl Chloride may be obtained from Susan Auby, Collection Strategies Division, U.S. EPA (2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460, by e-mail at auby.susan@epa.gov, or by calling (202) 566-1672.

The requirements for primary beryllium production facilities in the NESHAP for Primary Nonferrous Metals Area Sources do not impose any new information collection burden. New and existing plants that are area sources are required to comply with the same testing, monitoring, recordkeeping, and reporting requirements as those in the National Emission Standards for Beryllium (40 CFR part 61, subpart C), to which these area sources are currently subject, and the information collection requirements in the part 61 General Provisions (40 CFR part 61, subpart A), which are incorporated into the NESHAP for these sources. The OMB has previously approved the information collection requirements in 40 CFR part 61, subpart C, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060-0092, EPA ICR number 0193.08.

A copy of the OMB-approved ICR for the National Emission Standards for Beryllium may be obtained from Susan Auby, Collection Strategies Division, U.S. EPA (2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460, by e-mail at auby.susan@epa.gov, or by calling (202) 566-1672.

The information requirements in the NESHAP for Polyvinyl Chloride and Copolymers Production Area Sources, Primary Copper Smelting Area Sources, Secondary Copper Smelting Area Sources, and Primary Nonferrous Metals—Zinc, Cadmium, and Beryllium Area Sources have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information collection requirements for primary copper smelting and primary zinc production are based on the current title V permitting requirements for existing sources and the information collection requirements in the part 63 General Provisions (40 CFR part 63, subpart A), most of which are incorporated into the NESHAP for new sources. The ICR document includes the burden estimates for all applicable General Provisions. These recordkeeping and reporting requirements are mandatory pursuant to section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the information collection

requirements for which a claim of confidentiality is made is safeguarded according to CAA section 114(c) and the Agency's implementing regulations at 40 CFR part 2, subpart B.

The PM testing, monitoring, recordkeeping, and reporting requirements with which existing primary copper smelting and primary zinc smelting area sources must comply are the same as the requirements that are in these facilities' current title V operating permits. The only new information collection requirements that apply to these area sources consist of initial notifications. There are no existing secondary copper smelting facilities, and there are no requirements for existing secondary copper smelting area sources.

Any new primary zinc production facility, primary copper smelter, or secondary copper smelter area source is subject to all information collection requirements in the part 63 General Provisions. No costs or burden hours are estimated for new primary copper smelters, secondary copper smelters, or primary zinc production area sources because no new sources are estimated during the 3-year period of the ICR. No new sources have been constructed in more than 10 years, no new construction has been announced, and we have no indication there will be any new sources in the next 3 years.

The annual burden for this information collection (including all four source categories) averaged over the first 3 years of this ICR is estimated to total 23 labor hours per year at a cost of \$1,948 for the three existing primary copper smelting area sources and 15.4 labor hours per year at a cost of \$1,305 for the two existing primary zinc smelting area sources. No capital/startup costs or operation and maintenance costs are associated with the requirements.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose, or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR part 63 are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendments for the approved information collection requirements contained in the final rules.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

For the purposes of assessing the impacts of the area source NESHAP on small entities, small entity is defined as: (1) A small business that meets the Small Business Administration size standards for small businesses at 13 CFR 121.201 (less than 1,000 employees for primary copper smelting and less than 750 employees for PVC and copolymers production, secondary copper smelting, and primary nonferrous metals manufacturing); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of these final rules on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by these final rules are small businesses. We have determined that existing small businesses in these area source categories will not incur any adverse impacts on existing area sources of PVC and copolymer production facilities, primary copper smelters, and non-ferrous metal production facilities because the rules do not create any new requirements or burdens other than minimal notification requirements. There will be no adverse impacts on existing secondary copper area sources because there are no existing sources in the category. Although these final NESHAP contain emission control

requirements for new area sources in all four source categories, we are not aware of any new sources being constructed now or planned in the near future, and consequently, we did not estimate any impacts for new sources.

Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. These final rules are designed to harmonize with existing State or local requirements. In addition, we have deleted the proposed requirements for SSM plans and reports.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of \$100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final rules do not contain a Federal mandate

that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The estimated expenditures for the private sector in any one year are less than \$2,500. Thus, the final rules are not subject to the requirements of sections 202 and 205 of the UMRA. In addition, the final rules do not significantly or uniquely affect small governments. The final rules contain no requirements that apply to such governments, impose no obligations upon them, and will not result in expenditures by them of \$100 million or more in any one year or any disproportionate impacts on them. Therefore, the final rules are not subject to section 203 of the UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

These final rules do not have federalism implications. They will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These final rules impose requirements on owners and operators of specified area sources and not State and local governments. Thus, Executive Order 13132 does not apply to these final rules.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." These final rules do not have tribal implications, as specified in Executive Order 13175. They will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the

Federal government and Indian tribes, as specified in Executive Order 13175. These final rules impose requirements on owners and operators of specified area sources and not tribal governments. Thus, Executive Order 13175 does not apply to these final rules.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant," as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by EPA.

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5-501 of the Executive Order has the potential to influence the regulation. These final rules are not subject to the Executive Order. They are based on control technology and not on health or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

These final rules are not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because they are not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that these final rules are not likely to have any adverse energy effects because energy requirements would remain at existing levels. No additional pollution controls or other equipment that consume energy are required by these final rules.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104-113, section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. The VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS

bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency does not use available and applicable VCS.

This rule involves technical standards. The EPA cites the following standards: EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 3B, 4, 5, 5D, and 9 in 40 CFR part 60, appendix A; and Performance Specifications 1 and 11 in 40 CFR part 60, appendix B. The search identified one VCS as an acceptable alternative to EPA Method 3B. The method ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” is cited in two of these final rules for its manual method for measuring the oxygen, carbon dioxide, and carbon monoxide content of the exhaust gas. This part of ASME PTC 19.10–1981 is an acceptable alternative to EPA Method 3B.

The standard ASTM D6216 (1998), “Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications,” was designated an acceptable alternative for the design specifications given in EPA’s Performance Specification 1. As a result, EPA incorporated ASTM D6216–98 by reference into Performance Specification 1 as the design specifications for opacity monitors in August 2000.

The search for emissions measurement procedures identified 13 other VCS. The EPA determined that these 13 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in these final rules were impractical alternatives to EPA test methods for the purposes of the rules. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the 13 methods are in the docket for these rules.

For the methods required or referenced by these rules, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures under §§ 63.7(f) and 63.8(f) of subpart A of the General Provisions.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of Congress and to the Comptroller General of the United States. The EPA will submit a report containing these final

rules and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the final rules in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a “major rule” as defined by 5 U.S.C. 804(2). These final rules will be effective on January 23, 2007.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: December 11, 2006.

Stephen L. Johnson,
Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—[Amended]

■ 2. Section 63.14 is amended by revising paragraph (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus],” IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), and Table 5 of subpart DDDDD of this part.

* * * * *

■ 3. Part 63 is amended by adding subpart DDDDDD to read as follows:

Subpart DDDDDD—National Emission Standards for Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production Area Sources

Sec.

Applicability and Compliance Dates

63.11140 Am I subject to this subpart?

63.11141 What are my compliance dates?

Standards and Compliance Requirements

63.11142 What are the standards and compliance requirements for new and existing sources?

Other Requirements and Information

63.11143 What General Provisions apply to this subpart?

63.11144 What definitions apply to this subpart?

63.11145 Who implements and enforces this subpart?

Applicability and Compliance Dates

§ 63.11140 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a plant specified in 40 CFR 61.61(c) that produces polyvinyl chloride (PVC) or copolymers and is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is the collection of all equipment and activities in vinyl chloride service necessary to produce PVC and copolymers. An affected source does not include portions of your PVC and copolymers production operations that meet the criteria in 40 CFR 61.60(b) or (c).

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before October 6, 2006.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after October 6, 2006.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 63.11141 What are my compliance dates?

(a) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions in this subpart by January 23, 2007.

(b) If you own or operate a new affected source, you must achieve compliance with the applicable provisions in this subpart by the dates in paragraphs (b)(1) and (2) of this section.

(1) If you start up a new affected source on or before January 23, 2007, you must achieve compliance with the

applicable provisions in this subpart not later than January 23, 2007.

(2) If you start up a new affected source after January 23, 2007, you must achieve compliance with the provisions in this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11142 What are the standards and compliance requirements for new and existing sources?

You must meet all the requirements in 40 CFR part 61, subpart F, except for 40 CFR 61.62 and 40 CFR 61.63.

Other Requirements and Information

§ 63.11143 What General Provisions apply to this subpart?

(a) All the provisions in 40 CFR part 61, subpart A, apply to this subpart.

(b) The provisions in 40 CFR part 63, subpart A, applicable to this subpart are specified in paragraphs (b)(1) and (2) of this section.

(1) § 63.1(a)(1) through (10).

(2) § 63.1(b) except paragraph (b)(3), § 63.1(c), and § 63.1(e).

§ 63.11144 What definitions apply to this subpart?

The terms used in this subpart are defined in the CAA; 40 CFR 61.02; 40 CFR 61.61; and § 63.2 for terms used in the applicable provisions of part 63, subpart A, as specified in § 63.11143(b).

§ 63.11145 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of an alternative means of emissions limitation under 40 CFR 61.12(d).

(2) Approval of a major change to test methods under 40 CFR 61.13(h). A "major change to test method" is defined in § 63.90.

(3) Approval of a major change to monitoring under 40 CFR 61.14(g). A

"major change to monitoring" is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under 40 CFR 61.10. A "major change to recordkeeping/reporting" is defined in § 63.90.

■ 4. Part 63 is amended by adding subpart EEEEEEE to read as follows:

Subpart EEEEEEE—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting Area Sources

Sec.

Applicability and Compliance Dates

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Applicability and Compliance Dates

§ 63.11146 What are the applicability provisions and compliance dates?

(a) You are subject to this subpart if you own or operate a primary copper smelter that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new or existing affected source. The affected source is each primary copper smelter.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before October 6, 2006.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after October 6, 2006.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the Clean Air Act (CAA).

(d) If you own or operate an area source subject to this subpart, you must obtain a permit under 40 CFR part 70 or 40 CFR part 71.

(e) If you own or operate an existing affected source, you must achieve compliance with the applicable provisions of this subpart by January 23, 2007.

(f) If you own or operate a new affected source, you must achieve compliance with the applicable provisions of this subpart by the dates in paragraphs (f)(1) and (2) of this section.

(1) If you startup a new affected source on or before January 23, 2007, you must achieve compliance with the applicable provisions of this subpart not later than January 23, 2007.

(2) If you startup a new affected source after January 23, 2007, you must achieve compliance with the applicable provisions of this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11147 What are the standards and compliance requirements for existing sources not using batch copper converters?

(a) *Emissions limits and work practice standards.* (1) You must not discharge to the atmosphere through any combination of stacks or other vents captured process exhaust gases from the copper concentrate dryers, smelting vessels, converting vessels, matte drying and grinding plants, secondary gas systems, and anode refining department that contain particulate matter less than 10 microns in aerodynamic diameter (PM₁₀) in excess of 89.5 pounds per hour (lb/hr) on a 24-hour average basis.

(2) You must operate a capture system that collects the gases and fumes released during the transfer of molten materials from smelting vessels and converting vessels and conveys the collected gas stream to a control device.

(3) You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, remelt anode copper, or remelt anode scrap and convey each collected gas stream to a control device. One control device may be used for multiple collected gas streams.

(b) *Compliance requirements.* For purposes of determining compliance with the emissions limit in paragraph (a)(1) of this section, you must comply with the requirements in paragraphs (b)(1) through (7) of this section.

(1) You must calibrate, maintain and operate a system to continuously measure emissions of particulate matter (PM) from the smelter's main stack.

(2) All PM collected by the smelter main stack continuous PM sampling system is reported as PM₁₀ unless you

demonstrate to the satisfaction of the permitting authority that, due to an infrequent event, the measured PM contains a large fraction of particles greater than 10 microns in diameter.

(3) To determine the mass emissions rate, the PM₁₀ concentration as determined by the smelter main stack continuous PM sampling system is multiplied by the volumetric flow rate for the smelter main stack and any necessary conversion factors.

(4) Compliance with the PM₁₀ emissions limit is demonstrated based on the average mass PM₁₀ emissions rate for each 24-hour period.

(5) The results of the PM monitoring and calculated average mass PM₁₀ emissions rate for each 24-hour period must be recorded and the records maintained for at least 5 years. Collected data must be available for inspection when the required laboratory analysis is completed.

(6) You must submit to the permitting authority by the 20th day of each month a report summarizing the 24-hour average mass PM₁₀ emissions rates for the previous month.

(7) You may certify initial compliance with the emissions limit in paragraph (a)(1) of this section based on the results of PM sampling conducted during the previous month.

(c) *Operation and maintenance requirements.* (1) At all times, including periods of startup, shutdown, and malfunction, you must to the extent practicable, maintain and operate any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the permitting authority which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(2) All pollution control equipment must be installed, maintained, and operated properly. Instructions from the vendor or established maintenance practices that maximize pollution control must be followed. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, continuous emission monitors, etc., must be installed, operated properly, and easily accessible to compliance inspectors. A copy of all manufacturers' operating instructions for pollution control equipment and pollution emitting

equipment must be maintained at your facility site. These instructions must be available to all employees who operate the equipment and must be made available to the permitting authority upon request. Maintenance records must be made available to the permitting authority upon request.

(3) You must document the activities performed to assure proper operation and maintenance of the air pollution control equipment and monitoring systems or devices.

(4) Except as provided in paragraph (c)(5) of this section, in the event of an emergency situation the owner or operator must comply with the requirements in paragraphs (c)(4)(i) through (iii) of this section. For the purposes of complying with this paragraph, an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that requires immediate corrective action to restore normal operation, and that causes the affected source to exceed an applicable emissions limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(i) During the period of the emergency, you must implement all reasonable steps to minimize levels of emissions that exceed the emissions standards or other applicable requirements in this subpart.

(ii) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (c)(4)(i) of this section.

(iii) You must submit a notice of the emergency to the permitting authority within two working days of the time when emissions limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(5) As an alternative to the requirements in paragraph (c)(4) of this section, you must comply with the startup, shutdown, and malfunction requirements in 40 CFR 63.6(e)(3).

(d) *Deviations.* You must submit written notification to the permitting

authority of any deviation from the requirements of this subpart, including the probable cause of such deviations and any corrective actions or preventative measures taken. You must submit this notification within 14 days of the date the deviation occurred.

(e) *Reports.* You must submit semiannual monitoring reports to your permitting authority. All instances of deviations from the requirements of this subpart must be clearly identified in the reports.

(f) *Records.* (1) You must retain records of all required monitoring data and support information. Support information includes all calibration and maintenance records, all original strip charts or appropriate recordings for continuous monitoring instrumentation, and copies of all reports required by this subpart. For all monitoring requirements, the owner or operator must record, where applicable, the date, place, and time of sampling or measurement; the date analyses were performed; the company or entity that performed the analyses; the analytical techniques or methods used; the results of such analyses; and the operating conditions existing at the time of sampling or measurement.

(2) You must maintain records of the activities performed to assure proper operation and maintenance of the air pollution control equipment and monitoring systems or devices. Records of these activities must be maintained for at least 5 years.

§ 63.11148 What are the standards and compliance requirements for existing sources using batch copper converters?

(a) *Emissions limits and work practice standards.* (1) For each copper concentrate dryer, you must not discharge to the atmosphere from the dryer vent any gases that contain total particulate matter (PM) in excess of 0.022 grains per dry standard cubic foot (gr/dscf).

(2) You must exhaust the process off gas from each smelting vessel to a control device according to the requirements in paragraphs (a)(2)(i) and (ii) of this section.

(i) During periods when copper ore concentrate feed is charged to and smelted to form molten copper matte and slag layers in the smelting vessel, you must exhaust the process off gas from the smelting vessel to a gas cleaning system controlling PM and to a sulfuric acid plant prior to discharge to the atmosphere.

(ii) During periods when no copper ore concentrate feed is charged to or molten material tapped from the smelting vessel but the smelting vessel

remains in operation to temporarily hold molten material in the vessel before resuming copper production, you must exhaust the process off gas from the smelting vessel to an electrostatic precipitator or baghouse prior to discharge to the atmosphere.

(3) You must control the process emissions released when tapping copper matte or slag from a smelting vessel according to paragraphs (a)(3)(i) and (ii) of this section.

(i) You must operate a capture system that collects the gases and fumes released when copper matte or slag is tapped from the smelting vessel. The design and placement of this capture system must be such that the tapping port opening, launder, and receiving vessel (e.g., ladle, slag pot) are positioned within the confines or influence of the capture system's ventilation draft during those times when the copper matte or slag is flowing from the tapping port opening.

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (a)(3)(i) of this section any gases that contain total PM in excess of 0.022 gr/dscf.

(4) For each batch copper converter, you must meet the requirements in paragraphs (a)(4)(i) through (iv) of this section.

(i) You must operate a primary capture system that collects the process off gas vented when one or more batch copper converters are blowing. If you operate a batch copper converter that does not use a "U"-shaped side flue located at one end of the converter, then the capture system design must include use of a primary hood that covers the entire mouth of each batch copper converter vessel when the copper converter is positioned for blowing. The capture system may use multiple intake and duct segments through which the ventilation rates are controlled independently of each other.

(ii) If you operate a batch copper converter that does not use a "U"-shaped side flue located at one end of the converter, then you must operate a secondary capture system that collects gases and fumes released from the batch copper converter when the converter mouth is rotated out partially or totally from within the confines or influence of the primary capture system's ventilation draft during charging, skimming, pouring, or holding. The capture system design must use additional hoods (e.g., sliding secondary hoods, air curtain hoods) or other capture devices (e.g., building evacuation systems). The capture system may use multiple intake and duct segments through which the

ventilation rates are controlled independently of each other, and individual duct segments may be connected to separate PM control devices.

(iii) You must exhaust the process off gas captured by the primary capture system that is used to comply with paragraph (a)(4)(i) of this section to a gas cleaning system controlling PM and to a sulfuric acid plant prior to discharge to the atmosphere.

(iv) For each secondary capture system that is used to comply with paragraph (a)(4)(ii) of this section and is not vented to a gas cleaning system controlling PM and a sulfuric acid plant, you must not cause to be discharged to the atmosphere any gases that contain total particulate matter in excess of 0.02 grains/dscf.

(b) *Monitoring requirements for electrostatic precipitators.* To monitor the performance of each electrostatic precipitator used to comply with the PM emissions limits in paragraph (a) of this section, you must use a continuous opacity monitoring system (COMS) that is installed at the outlet of each electrostatic precipitator or a common duct at the outlet of multiple electrostatic precipitators.

(1) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(2) You must comply with the quality assurance requirements in paragraphs (b)(2)(i) through (v) of this section.

(i) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(iii) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique

to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(v) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(3) You must evaluate opacity measurements from the COMS on a 24-hour rolling average excluding periods of startup, shutdown, and malfunction. If the 24-hour rolling average opacity exceeds 15 percent, you must initiate investigation of the relevant controls or equipment within 24 hours of the first discovery of the high opacity incident and, if necessary, take corrective action as soon as practicable to adjust or repair the controls or equipment to reduce the opacity average to below the 15 percent level.

(4) You must log in ink or electronic format and maintain a record of 24-hour opacity measurements performed in accordance with paragraph (b)(3) of this section and any corrective actions taken, if any. A record of corrective actions taken must include the date and time during which the 24-hour rolling average opacity exceeded 15 percent and the date, time and type of the corrective action.

(c) *Monitoring requirements for baghouses.* To monitor the performance of each baghouse used to comply with PM emissions limits in paragraph (a) of this section, you must use a bag leak detection system according to the requirements in paragraphs (c)(1) through (4) of this section.

(1) You must install, calibrate, maintain, and continuously operate a bag leak detection system for the baghouse to monitor the baghouse performance.

(2) The baghouse leak detection system must meet the specifications and requirements in paragraphs (c)(2)(i) through (v) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations that can effectively discern any dysfunctional leaks of the baghouse.

(ii) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(iii) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(iv) The bag leak detection system must be installed downstream of the baghouse.

(v) The bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations. The calibration of the system must, at a minimum, consist of establishing the relative baseline output level by adjusting the sensitivity and the averaging period of the device and establishing the alarm set points and the alarm delay time.

(3) If the bag leak detection system alarm sounds, you must initiate investigation of the baghouse within 24 hours of the first discovery of the alarm and, if necessary, take corrective action as soon as practicable to adjust or repair the baghouse to minimize possible exceedances of the applicable PM emissions limits in paragraph (a) of this section.

(4) You must log in ink or electronic format and maintain a record of installation, calibration, maintenance, and operation of the bag leak detection system. If the bag leak detection system alarm sounds, the records must include an identification of the date and time of all bag leak detection alarms, their cause, and an explanation of the corrective actions taken, if any.

(d) *Alternative monitoring requirements for baghouses.* As an alternative to the requirements in paragraph (c) of this section for bag leak detection systems, you must monitor the performance of each baghouse used to comply with a PM emissions limit in paragraph (a) of this section using a COMS that is installed at the outlet on the baghouse or a common duct at the outlet of multiple baghouses. Each COMS must meet the requirements in paragraphs (b)(1) through (4) of this section.

(e) *Performance testing.* (1) You must demonstrate initial compliance with the applicable PM emissions limits in

paragraph (a) of this section based on the results of a performance test for each affected source.

(i) You may certify initial compliance for an affected source based on the results of a previous performance test conducted within the past 12 months before your compliance date.

(ii) If you have not conducted a performance test to demonstrate compliance with the applicable emissions limits within the past 12 months before your compliance date, you must conduct a performance test within 180 days of your compliance date and report the results in your notification of compliance status.

(2) You must demonstrate subsequent compliance with the applicable PM emissions limits in paragraph (a) of this section based on the results of repeat performance tests conducted at least every 2.5 years for each affected source.

(3) You must conduct each performance test according to § 63.7(e)(1) using the test methods and procedures in paragraphs (e)(3)(i) through (v) of this section.

(i) Method 1 or 1A (40 CFR part 60, appendix A) to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A) to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B (40 CFR part 60, appendix A) to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses" (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(iv) Method 4 (40 CFR part 60, appendix A) to determine the moisture content of the stack gas.

(v) Method 5 (40 CFR part 60, appendix A) to determine the PM concentration for negative pressure baghouses or Method 5D (40 CFR part 60, appendix A) for positive pressure baghouses. A minimum of three valid test runs are needed to comprise a PM performance test.

(f) *Operation and maintenance requirements.* (1) At all times, including periods of startup, shutdown, and malfunction, you must to the extent practicable, maintain and operate any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of

whether acceptable operating and maintenance procedures are being used will be based on information available to the permitting authority which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(2) All pollution control equipment must be installed, maintained, and operated properly. Instructions from the vendor or established maintenance practices that maximize pollution control must be followed. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, continuous emissions monitor, etc., must be installed, operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instructions for pollution control equipment and pollution emitting equipment must be maintained at your facility site. These instructions must be available to all employees who operate the equipment and must be made available to the permitting authority upon request. Maintenance records must be made available to the permitting authority upon request.

(3) You must document the activities performed to assure proper operation and maintenance of the air pollution control equipment and monitoring systems or devices. Records of these activities must be maintained as required by the permitting authority.

(4) Except as specified in paragraph (f)(5) of this section, in the event of an emergency situation, you must comply with the requirements specified in paragraphs (f)(4)(i) through (iii) of this section. For the purpose of complying with this paragraph, an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that requires immediate corrective action to restore normal operation and that causes the affected source to exceed applicable emission limitation under this subpart due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(i) During the period of the emergency you must implement all reasonable steps to minimize levels of emissions that exceeded the emission standards or other applicable requirements in this subpart.

(ii) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (f)(4)(i) of this section.

(iii) You must submit a notice of the emergency to the permitting authority within two working days of the time when emission limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(5) As an alternative to the requirements in paragraph (f)(4) of this section, you must comply with the startup, shutdown, and malfunction requirements in 40 CFR 63.6(e)(3).

(g) *Recordkeeping requirements.* (1) You must maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected source subject to this subpart; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(2) You must maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this section recorded in a permanent form suitable for inspection. The file must be retained for at least 5 years following the date of such measurements, maintenance, reports.

(h) *Reporting requirements.* (1) You must prepare and submit to the permitting authority an excess emissions and monitoring systems performance report and summary report every calendar quarter. A less frequent reporting interval may be used for either report as approved by the permitting authority.

(2) The summary report must include the information in paragraphs (h)(2)(i) through (iv) of this section.

(i) The magnitude of excess emissions computed, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The

process operating time during the reporting period.

(ii) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(iii) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(iv) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information must be stated in the report.

§ 63.1149 What are the standards and compliance requirements for new sources?

(a) *Emissions limits and work practice standards.* (1) You must not discharge to the atmosphere exhaust gases that contain total PM in excess of 0.6 pound per ton of copper concentrate feed charged on a 24-hour average basis from any combination of stacks, vents, or other openings on furnaces, reactors, or other types of process vessels used for the production of anode copper from copper sulfide ore concentrates by pyrometallurgical techniques. Examples of such process equipment include, but are not limited to, copper concentrate dryers, smelting flash furnaces, smelting bath furnaces, converting vessels, combined smelting and converting reactors, anode refining furnaces, and anode shaft furnaces.

(2) You must operate a capture system that collects the gases and fumes released during the transfer of molten materials from smelting vessels and converting vessels and conveys the collected gas stream to a baghouse or other PM control device.

(3) You must operate one or more capture systems that collect the gases and fumes released from each vessel used to refine blister copper, remelt anode copper, or remelt anode scrap and convey each collected gas stream to a baghouse or other PM control device. One control device may be used for multiple collected gas streams.

(b) *Monitoring requirements.* (1) You must install, operate, and maintain a PM continuous emissions monitoring system (CEMS) to measure and record PM concentrations and gas stream flow rates for the exhaust gases discharged to the atmosphere from each affected source subject to the emissions limit in paragraph (a)(1) of this section. A single PM CEMS may be used for the combined exhaust gas streams from

multiple affected sources at a point before the gases are discharged to the atmosphere. For each PM CEMS used to comply with this paragraph, you must meet the requirements in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must install, certify, operate, and maintain the PM CEMS according to EPA Performance Specification 11 in 40 CFR part 60, appendix B, and the quality assurance requirements of Procedure 2 in 40 CFR part 60, appendix F.

(ii) You must conduct an initial performance evaluation of the PM CEMS according to the requirements of Performance Specification 11 in 40 CFR part 60, appendix B. Thereafter, you must perform the performance evaluations as required by Procedure 2 in 40 CFR part 60, appendix F.

(iii) You must perform quarterly accuracy determinations and daily calibration drift tests for the PM CEMS according to Procedure 2 in 40 CFR part 60, appendix F.

(2) You must install, operate, and maintain a weight measurement system to measure and record the weight of the copper concentrate feed charged to the smelting vessel on a daily basis.

(c) *Compliance requirements.* (1) You must demonstrate initial compliance with the emissions limit in paragraph (a)(1) of this section using the procedures in paragraph (c)(2) this section within 180 days after startup and report the results in your notification of compliance status no later than 30 days after the end of the compliance demonstration.

(2) You must demonstrate continuous compliance with the emissions limit in paragraph (a)(1) of this section using the procedures in paragraph (c)(2)(i) through (iii) of this section whenever your facility is producing copper from copper concentrate.

(i) You must continuously monitor and record PM emissions, determine and record the daily (24-hour) value for each day, and calculate and record the daily average pounds of total PM per ton of copper concentrate feed charged to the smelting vessel according to the requirements in paragraph (b) of this section.

(ii) You must calculate the daily average at the end of each calendar day for the preceding 24-hour period.

(iii) You must maintain records of the calculations of daily averages with supporting information and data, including measurements of the weight of copper concentrate feed charged to the smelting vessel. Collected PM CEMS data must be made available for inspection.

(d) *Alternative startup, shutdown, and malfunction requirements.* You must comply with the requirements specified in this paragraph as an alternative to the requirements in 40 CFR 63.6(e)(3). In the event of an emergency situation, you must comply with the requirements specified in paragraphs (d)(1) through (3) of this section. For the purpose of complying with this paragraph, an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that requires immediate corrective action to restore normal operation, and that causes the affected source to exceed an applicable emissions limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(1) During the period of the emergency, you must implement all reasonable steps to minimize levels of emissions that exceeded the emission standards or other applicable requirements in this subpart.

(2) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (d)(1) of this section.

(3) You must submit a notice of the emergency to the permitting authority within two working days of the time when emissions limitations were exceeded due to the emergency (or an alternate timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(e) *Reports.* You must submit to the permitting authority by the 20th day of each month a summary of the daily average PM per ton of copper concentrate feed charged to the smelting vessel for the previous month.

Other Requirements and Information

§ 63.11150 What General Provisions apply to this subpart?

(a) If you own or operate a new or existing affected source, you must comply with the requirements of the General Provisions (40 CFR part 63, subpart A) as specified in Table 1 to this subpart.

(b) If you own or operate an existing affected source subject to § 63.11147, your notification of compliance status required by § 63.9(h) must include the information specified in paragraphs (b)(1) through (4) of this section.

(1) If you certify initial compliance with the PM emissions limit in § 63.11147(a)(1) based on monitoring data from the previous month, your notification of compliance status must include this certification of compliance, signed by a responsible official: "This facility complies with the PM emissions limit in § 63.11147(a)(1) based on monitoring data that were collected during the previous month."

(2) If you conduct a new performance test to demonstrate initial compliance with the PM emissions limit in § 63.11147(a)(1), your notification of compliance status must include the results of the performance test, including required monitoring data.

(3) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11147(a)(2): "This facility complies with the requirement to capture gases from transfer of molten materials from smelting vessels and converting vessels and convey them to a control device in accordance with § 63.11147(a)(2)."

(4) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11147(a)(3): "This facility complies with the requirement to capture gases from operations in the anode refining department and convey them to a PM control device in accordance with § 63.11147(a)(3)."

(c) If you own or operate an existing affected source subject to § 63.11148, your notification of compliance status required by § 63.9(h) must include the information specified in paragraphs (c)(1) through (4) of this section.

(1) If you certify initial compliance with the PM emissions limit in § 63.11148(a)(1), (a)(3)(ii), and (a)(4)(iv) based on the results of a previous performance test conducted within the past 12 months before your compliance date, your notification of compliance status must include this certification of compliance, signed by a responsible official: "This facility complies with the PM emissions limit in § 63.11148(a)(1) based on the results of a previous performance test."

(2) If you conduct a new performance test to demonstrate initial compliance with the PM emissions limits in § 63.11148(a)(1), (a)(3)(ii), and (a)(4)(iv), your notification of compliance status

must include the results of the performance test, including required monitoring data.

(3) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standards in § 63.11148(a)(2), and (a)(4)(iii): "This facility complies with the requirement to vent captured process gases to a gas cleaning system controlling PM and to a sulfuric acid plant in accordance with § 63.11148(a)(2) and (a)(4)(iii)."

(3) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11148(a)(3)(i): "This facility complies with the requirement to operate capture systems to collect gases and fumes released when copper matte or slag is tapped from the smelting vessel in accordance with § 63.11148(a)(3)(i)."

(4) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11148(a)(4): "This facility complies with the requirement to operate capture systems to collect gases and fumes released during batch copper converter operations in accordance with § 63.11148(a)(4)."

(d) If you own or operate a new affected source, your notification of compliance status required by § 63.9(h) must include the information in paragraphs (d)(1) through (3) of this section.

(1) Your notification of compliance status must include the results of the initial performance test and monitoring data collected during the test that demonstrate compliance with the emissions limit in § 63.11149(a)(1).

(2) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11149(a)(2): "This facility complies with the requirement to capture gases from transfer of molten materials from smelting vessels and converting vessels and convey them to a PM control device in accordance with § 63.11149(a)(2)."

(3) Your notification of compliance status must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11149(a)(3): "This facility complies with the requirement to capture gases from each vessel used to refine blister copper, remelt anode copper, or remelt anode scrap, and convey them to a PM control device in accordance with § 63.11149(a)(3)."

§ 63.11151 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in 40 CFR 63.2, and in this section as follows:

Anode refining department means the area at a primary copper smelter in which anode copper refining operations are performed. Emissions sources in the anode refining department include anode refining furnaces and anode shaft furnaces.

Baghouse means a control device that collects particulate matter by filtering the gas stream through bags. A *baghouse* is also referred to as a "fabric filter."

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse in order to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, transmittance or other effect to continuously monitor relative particulate matter loadings.

Batch copper converter means a converter in which molten copper matte is charged and then oxidized to form blister copper by a process that is performed in discrete batches using a sequence of charging, blowing, skimming, and pouring.

Capture system means the collection of components used to capture gases and fumes released from one or more emissions points and then convey the captured gas stream to a control device. A capture system may include, but is not limited to, the following components as applicable to a given capture system design: Duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

Charging means the operating mode for a batch copper converter during which molten or solid material is added into the vessel.

Control device means air pollution control equipment used to remove PM from a gas stream.

Converting vessel means a furnace, reactor, or other type of vessel in which copper matte is oxidized to form blister copper.

Copper concentrate means copper ore that has been beneficiated to increase its copper content.

Copper concentrate dryer means a vessel in which copper concentrates are heated in the presence of air to reduce the moisture content of the material. Supplemental copper-bearing feed materials and fluxes may be added or mixed with the copper concentrates fed to a copper concentrate dryer.

Copper concentrate feed means the mixture of copper concentrate, secondary copper-bearing materials, recycled slags and dusts, fluxes, and other materials blended together for feeding to the smelting vessel.

Copper matte means a material predominately composed of copper and iron sulfides produced by smelting copper ore concentrates.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Holding means the operating mode for a batch copper converter or a holding furnace associated with a smelting furnace during which the molten bath is maintained in the vessel but no blowing or smelting is performed nor is material added into or removed from the vessel.

Matte drying and grinding plant means the area at a primary copper smelter in which wet granulated matte copper is ground in a mill, dried by blowing heated air through the mill, and then separated from the drying air stream using a control device such as a baghouse.

Pouring means the operating mode for a batch copper converter during which molten copper is removed from the vessel.

Primary copper smelter means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

Responsible official means responsible official as defined at 40 CFR 70.2.

Secondary gas system means a capture system that collects the gases and fumes released when removing and transferring molten materials from one or more vessels using tapping ports, launders, and other openings in the vessels. Examples of molten material include, but are not limited to: Copper matte, slag, and blister copper.

Skimming means the batch copper converter operating mode during which molten slag is removed from the vessel.

Smelting vessel means a furnace, reactor, or other type of vessel in which copper ore concentrate and fluxes are smelted to form a molten mass of material containing copper matte and slag. Other copper-bearing materials may also be charged to the smelting vessel.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof.

§ 63.11152 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of an alternative opacity emissions standard under § 63.6(h)(9).

(3) Approval of a major change to a test method under § 63.7(e)(2)(ii) and (f). A "major change to test method" is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A "major change to monitoring" is defined in § 63.90.

(5) Approval of a major change to recordkeeping/reporting under § 63.10(f). A "major change to recordkeeping/reporting" is defined in § 63.90.

As required in § 63.11150(a), you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 1 TO SUBPART EEEEEEE OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART EEEEEEE

Citation	Subject	Applies to subpart EEEEEEE?	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)–(a)(12) (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention	Yes.	
63.5	Preconstruction Review and Notification Requirements.	No.	
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5).	Compliance with Standards and Maintenance Requirements—Applicability and Compliance Dates.	Yes.	
63.6(e)	Operation and Maintenance Requirements.	Yes/No	Operation and maintenance requirements do not apply to existing sources except that the startup, shutdown, and malfunction requirements in § 63.6(e)(3) are allowed as an alternative to the rule requirements for emergency situations. Operation and maintenance requirements apply to new sources except that the rule requirements for emergency situations are allowed as an alternative to the startup, shutdown, and malfunction requirements in § 63.6(e)(3).
63.6(f), (g), (i), (j)	Compliance with Nonopacity Emission Standards.	Yes.	
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.6(h)(1)–(h)(4), (h)(5)(i)–(h)(5)(iii), (h)(6)–(h)(9).	Yes/No	Requirements apply to new sources but not existing sources.
63.7(a), (e), (f), (g), (h)	Performance Testing Requirements	Yes.	
63.7(b), (c)	Yes/No	Notification of performance tests and quality assurance program apply to new sources but not existing sources.
63.8(a)(1), (a)(2), (b), (c), (f), (g)	Monitoring Requirements	Yes.	
63.8(a)(3)	Reserved	No.	
63.8(a)(4)	No	Subpart EEEEEEE does not require flares.
63.8(d), (e)	Yes/No	Requirements for quality control program and performance evaluations apply to new sources but not existing sources.
63.9(a), (b)(1), (b)(2), (b)(5), (c), (d), (h)(1)–(h)(3), (h)(5), (h)(6), (i), (j).	Notification Requirements	Yes.	
63.9(b)(3), (h)(4)	Reserved	No.	
63.9(b)(4), (f)	No.	
63.9(e), (g)	Yes/No	Notification requirements for performance test and use of continuous monitoring systems apply to new sources but not existing sources.
63.10(a), (b)(1), (d)(1), (d)(2), (d)(4), (d)(5), (f).	Recordkeeping and Reporting Requirements.	Yes/No	Recordkeeping requirements apply to new sources but not existing sources.
63.10(b)(2), (b)(3), (c)(1) (c)(5)–(c)(8), (c)(10)–(c)(15), (e)(1), (e)(2).	Yes/No	Recordkeeping requirements apply to new sources but not existing sources.
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.10(d)(3), (e)(4)	No	Reporting requirements apply to new sources but not existing sources.
63.10(e)(3)	Yes/No	Reporting requirements apply to new sources but not existing sources.
63.11	Control Device Requirements	No	Subpart EEEEEEE does not require flares.
63.12	State Authorities and Delegations	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference	Yes.	
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions	Yes.	

■ 5. Part 63 is amended by adding subpart FFFFFFFF to read as follows:

Subpart FFFFFFFF—National Emission Standards for Hazardous Air Pollutants for Secondary Copper Smelting Area Sources

Sec.

Applicability and Compliance Dates

63.11153 Am I subject to this subpart?

63.11154 What are my compliance dates?

Standards and Compliance Requirements

63.11155 What are the standards and compliance requirements for new sources?

63.11156 [Reserved]

Other Requirements and Information

63.11157 What General Provisions apply to this subpart?

63.11158 What definitions apply to this subpart?

63.11159 Who implements and enforces this subpart?

Table 1 to Subpart FFFFFFFF of Part 63—
Applicability of General Provisions to
Subpart FFFFFFFF

Applicability and Compliance Dates

§ 63.11153 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a new secondary copper smelter that is an area source of hazardous air pollutant (HAP) emissions.

(b) This subpart applies to each new affected source. The affected source is each secondary copper smelter. Your secondary copper smelter is a new affected source if you commenced construction or reconstruction of the affected source before October 6, 2006.

(c) This subpart does not apply to research and development facilities, as defined in section 112(c)(7) of the CAA.

(d) If you own or operate an area source subject to this subpart, you must obtain a permit under 40 CFR part 70 or 40 CFR part 71.

§ 63.11154 What are my compliance dates?

(a) If you startup a new affected source on or before January 23, 2007, you must achieve compliance with the applicable provisions of this subpart not later than January 23, 2007.

(b) If you startup a new affected source after January 23, 2007, you must achieve compliance with the applicable provisions of this subpart upon startup of your affected source.

Standards and Compliance Requirements

§ 63.11155 What are the standards and compliance requirements for new sources?

(a) You must not discharge to the atmosphere any gases which contain

particulate matter (PM) in excess of 0.002 grains per dry standard cubic foot (gr/dscf) from the exhaust vent of any capture system for a smelting furnace, melting furnace, or other vessel that contains molten material and any capture system for the transfer of molten material.

(b) For each smelting furnace, melting furnace, or other vessel that contains molten material, you must install and operate a capture system that collects the gases and fumes from the vessel and from the transfer of molten material and convey the collected gas stream to a control device.

(c) You must prepare and operate at all times according to a written plan for the selection, inspection, and pretreatment of copper scrap to minimize, to the extent practicable, the amount of oil and plastics in the scrap that is charged to the smelting furnace. Your plan must include a training program for scrap inspectors. You must keep records to demonstrate continuous compliance with the requirements of your plan. You must keep a current copy of your pollution prevention plan onsite and available for inspection.

(d) You must install, operate, and maintain a bag leak detection system on all baghouses used to comply with the PM emissions limit in paragraph (a) of this section according to paragraph (d)(1) of this section, prepare and operate by a site-specific monitoring plan according to paragraph (d)(2) of this section, take corrective action according to paragraph (d)(3) of this section, and record information according to paragraph (d)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (d)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger.)

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (d)(1)(iv) of this section, and the alarm must be located such that it can be

heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (d)(1)(vi) of this section.

(vi) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (d)(2) of this section.

(vii) You must install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) You must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (d)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (d)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this specific

condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (d)(2)(vi) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) You must maintain records of the information specified in paragraphs (d)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of an alarm were initiated, whether procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(e) You must conduct a performance test to demonstrate initial compliance with the PM emissions limit within 180 days after startup and report the results in your notification of compliance status. You must conduct each PM test according to § 63.7(e)(1) using the test methods and procedures in paragraphs (e)(1) through (5) of this section.

(1) Method 1 or 1A (40 CFR part 60, appendix A) to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the

control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(2) Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A) to determine the volumetric flow rate of the stack gas.

(3) Method 3, 3A, or 3B (40 CFR part 60, appendix A) to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(4) Method 4 (40 CFR part 60, appendix A) to determine the moisture content of the stack gas.

(5) Method 5 (40 CFR part 60, appendix A) to determine the PM concentration for negative pressure baghouses and Method 5D (40 CFR part 60, appendix A) for positive pressure baghouses. The sampling time and volume for each run must be at least 60 minutes and 0.85 dry standard cubic meters (30 dry standard cubic feet). A minimum of three valid test runs are needed to comprise a PM performance test.

(f) You must conduct subsequent performance tests to demonstrate compliance with the PM emissions limit at least once every 5 years.

(g) If you use a control device other than a baghouse, you must prepare and submit a monitoring plan to the Administrator for approval. Each plan must contain the information in paragraphs (g)(1) through (5) of this section.

(1) A description of the device;

(2) Test results collected in accordance with paragraph (e) of this section verifying the performance of the device for reducing PM to the levels required by this subpart;

(3) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer’s instructions for routine and long-term maintenance) and continuous monitoring system.

(4) A list of operating parameters that will be monitored to maintain continuous compliance with the applicable emission limits; and

(5) Operating parameter limits based on monitoring data collected during the performance test.

§ 63.11156 [Reserved]

Other Requirements and Information

§ 63.11157 What General Provisions apply to this subpart?

(a) If you own or operate a new affected source, you must comply with

the requirements of the General Provisions in 40 CFR part 63, subpart A as specified in Table 1 to this subpart.

(b) Your notification of compliance status required by § 63.9(h) must include the following:

(1) The results of the initial performance tests and monitoring data collected during the test.

(2) This certification of compliance, signed by a responsible official, for the work practice standard in § 63.1155(b): “This facility complies with the requirement for a capture system for each smelting furnace, melting furnace, or other vessel that contains molten material in accordance with § 63.11155(b).”

(3) This certification of compliance, signed by a responsible official, for the work practice standard in § 63.1155(c): “This facility complies with the requirement for a written plan for the selection, inspection, and pretreatment of copper scrap in accordance with § 63.11155(c).”

(4) This certification of compliance, signed by a responsible official, for the work practice standard in § 63.11155(d)(2): “This facility has an approved monitoring plan in accordance with § 63.11155(d)(2).”

(5) This certification of compliance, signed by a responsible official, for the work practice standard in § 63.11157(g): “This facility has an approved monitoring plan in accordance with § 63.11157(g).”

§ 63.11158 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in 40 CFR 63.2, and in this section as follows:

Anode copper means copper that is cast into anodes and refined in an electrolytic process to produce high purity copper.

Capture system means the collection of components used to capture gases and fumes released from one or more emissions points and then convey the captured gas stream to a control device. A capture system may include, but is not limited to, the following components as applicable to a given capture system design: duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

Melting furnace means any furnace, reactor, or other type of vessel that heats solid materials and produces a molten mass of material.

Secondary copper smelter means a facility that processes copper scrap in a blast furnace and converter or that uses another pyrometallurgical purification process to produce anode copper from copper scrap, including low-grade

copper scrap. A facility where recycled copper scrap or copper alloy scrap is melted to produce ingots or for direct use in a manufacturing process is not a secondary copper smelter.

Smelting furnace means any furnace, reactor, or other type of vessel in which copper scrap and fluxes are melted to form a molten mass of material containing copper and slag.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof.

§ 63.11159 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA, or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA

Administrator has delegated authority to a State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (4) of this section.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A “major change to test method” is defined in § 63.90.

(3) Approval of a major change to monitoring under § 63.8(f). A “major change to monitoring” is defined in § 63.90.

(4) Approval of a major change to recordkeeping/ reporting under § 63.10(f). A “major change to recordkeeping/reporting” is defined in § 63.90.

As required in § 63.11157(a), you must comply with the requirements of the General Provisions (40 CFR part 63, subpart A) as shown in the following table.

TABLE 1 TO SUBPART FFFFFFFF OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART FFFFFFFF

Citation	Subject	Applies to subpart FFFFFFFF?	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)–(a)(12), (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention	Yes.	
63.5	Preconstruction Review and Notification Requirements.	No.	
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5), (e)(3)(i), (e)(3)(iii)–(e)(3)(ix), (f), (g), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.	
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.6(h)(1)–(h)(4), (h)(5)(i)–(h)(5)(iii), (h)(6)–(h)(9).	No	Subpart FFFFFFFF does not include opacity or visible emissions standards.
63.7	Performance Testing Requirements	Yes.	
63.8(a)(1), (a)(2), (b), (f)(1)–(5)	Monitoring Requirements	Yes.	
63.8(a)(3)	Reserved	No.	
63.8(c), (d), (e), (f)(6), (g)	No	Subpart FFFFFFFF does not require a continuous monitoring system.
63.8(a)(4)	No	Subpart FFFFFFFF does not require flares.
63.9(a), (b)(1), (b)(2), (b)(5), (c), (d), (e), (f), (g), (h)(1)–(h)(3), (h)(5), (h)(6), (i), (j).	Notification Requirements	Yes.	
63.9(b)(3), (h)(4)	Reserved	No.	
63.9(b)(4)	No.	
63.9(f)	No	Subpart FFFFFFFF does not include opacity or visible emissions standards.
63.9(g)	No	Subpart FFFFFFFF does not require a continuous monitoring system.
63.10(a), (b)(2)(i)–(b)(2)(v), (b)(2)(xiv), (d)(1), (d)(2), (d)(4), (d)(5), (e)(1), (e)(2), (f).	Recordkeeping and Reporting Requirements.	Yes.	
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.10(b)(2)(vi)–(b)(2)(xiii), (c)(1), (c)(5)–(c)(14), (e)(1)–(e)(2), (e)(4).	No	Subpart FFFFFFFF does not require a continuous monitoring system.
63.10(d)(3)	No	Subpart FFFFFFFF does not include opacity or visible emissions standards.
63.10(e)(3)	Yes.	
63.11	Control Device Requirements	No	Subpart FFFFFFFF does not require flares.
63.12	State Authorities and Delegations	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference	Yes.	

TABLE 1 TO SUBPART FFFFFFF OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART FFFFFFF—
Continued

Citation	Subject	Applies to subpart FFFFFFF?	Explanation
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions	Yes.	

■ 6. Part 63 is amended by adding subpart GGGGGG to read as follows:

Subpart GGGGGG—National Emission Standards for Hazardous Air Pollutants for Primary Nonferrous Metals Area Sources—Zinc, Cadmium, and Beryllium

Sec.

Applicability and Compliance Dates

- 63.11160 Am I subject to this subpart?
- 63.11161 What are my compliance dates?

Primary Zinc Production Facilities

- 63.11162 What are the standards and compliance requirements for existing sources?
- 63.11163 What are the standards and compliance requirements for new sources?
- 63.11164 What General Provisions apply to primary zinc production facilities?

Primary Beryllium Production Facilities

- 63.11165 What are the standards and compliance requirements for new and existing sources?
- 63.11166 What General Provisions apply to primary beryllium production facilities?

Other Requirements and Information

- 63.11167 What definitions apply to this subpart?
- 63.11168 Who implements and enforces this subpart?

Table 1 to Subpart GGGGGG of Part 63—
Applicability of General Provisions to
Primary Zinc Production Area Sources

Applicability and Compliance Dates

§ 63.11160 Am I subject to this subpart?

(a) You are subject to this subpart if you own or operate a primary zinc production facility or primary beryllium production facility that is an area source of hazardous air pollutant (HAP) emissions.

(b) The affected source is each existing or new primary zinc production facility or primary beryllium production facility.

(1) An affected source is existing if you commenced construction or reconstruction of the affected source before October 6, 2006.

(2) An affected source is new if you commenced construction or reconstruction of the affected source on or after October 6, 2006.

(c) If you own or operate a new or existing affected source, you must obtain a permit under 40 CFR part 70 or 71.

§ 63.11161 What are my compliance dates?

(a) If you have an existing affected source, you must achieve compliance with applicable provisions in this subpart by January 23, 2007. If you startup a new sintering machine at an existing affected source after January 23, 2007, you must achieve compliance with the applicable provisions in this subpart not later than 180 days after startup.

(b) If you have a new affected source, you must achieve compliance with applicable provisions in this subpart according to the dates in paragraphs (b)(1) and (2) of this section.

(1) If you startup a new affected source on or before January 23, 2007, you must achieve compliance with applicable provisions in this subpart not later than January 23, 2007.

(2) If you startup a new affected source after January 23, 2007, you must achieve compliance with applicable provisions in this subpart upon initial startup.

Primary Zinc Production Facilities

§ 63.11162 What are the standards and compliance requirements for existing sources?

(a) You must exhaust the off-gases from each roaster to a particulate matter (PM) control device and to a sulfuric acid plant, including during the charging of the roaster.

(b) Except as provided in paragraph (b)(6) of this section, you must not discharge to the atmosphere any gases which contain PM in excess of the emissions limits in paragraphs (b)(1) through (5) of this section.

(1) 0.93 pound per hour (lb/hr) from the exhaust vent of a zinc cathode melting furnace.

(2) 0.1 lb/hr from the exhaust vent of a furnace that melts zinc dust, zinc chips, and/or other materials containing zinc.

(3) 0.228 lb/hr from the vent for the combined exhaust from a furnace melting zinc scrap and an alloy furnace.

(4) 0.014 grains per dry standard cubic foot (gr/dscf) from the exhaust vent of an anode casting furnace.

(5) 0.015 gr/dscf from the exhaust vent of a cadmium melting furnace.

(6) You may elect to meet an emissions limit of 0.005 gr/dscf as an alternative to the emissions limits in lb/hr in paragraphs (b)(1) through (3) of this section.

(c) You must establish an operating range for pressure drop for each baghouse applied to a furnace subject to an emissions limit in paragraph (b) of this section based on the minimum and maximum values recorded during a performance test that demonstrates compliance with the applicable PM emissions limit. Alternatively, you may use an operating range that has been previously established and approved by your permitting authority within the past 5 years. You must monitor the pressure drop daily, maintain the pressure drop for each baghouse within the established operating range, and record the pressure drop measurement in a daily log. You must perform routine maintenance on each baghouse and record maintenance activities in a baghouse maintenance log. Baghouse maintenance logs must include, but are not limited to, inspections, criteria for changing bag filters, and dates on which the bag filters are replaced. Both logs must be maintained in a suitable permanent form and kept available for inspection.

(d) If you own or operate a sintering machine at your facility, you must comply with the PM emissions limit in 40 CFR 60.172(a) and the opacity emissions limit in 40 CFR 60.174(a) for that sintering machine.

(e) If you own or operate a sintering machine at your facility, you must install and operate a continuous opacity monitoring system (COMS) for each sintering machine according to the requirements in 40 CFR 60.175(a). Each COMS must meet Performance Specification 1 (40 CFR part 60, appendix B).

(f) For each furnace at your facility subject to an emissions limit in paragraph (b) of this section, you must demonstrate initial compliance with the applicable PM emissions limit in

paragraph (b) of this section based on the results of a performance test for that furnace. If you own or operate a sintering machine, you must also demonstrate initial compliance with the PM and opacity emissions limits in paragraph (d) of this section based on the results of a performance test for that sintering machine.

(1) You may certify initial compliance for a furnace (and sintering machine, if applicable) based on the results of a previous performance test conducted during the past 5 years.

(2) If you have not conducted a performance test to demonstrate compliance with the applicable emissions limits during the past 5 years, you must conduct a performance test within 180 days of your compliance date and report the results in your notification of compliance status. If a furnace subject to an emissions limit in paragraph (b) of this section is not operating on the compliance date and subsequently resumes operation, you must conduct a performance test within 180 days of startup and report the results in your notification of compliance status.

(3) You must conduct each PM test for a furnace according to § 63.7(e)(1) using the test methods and procedures in paragraphs (f)(3)(i) through (v) of this section.

(i) Method 1 or 1A (40 CFR part 60, appendix A) to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A) to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B (40 CFR part 60, appendix A) to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(iv) Method 4 (40 CFR part 60, appendix A) to determine the moisture content of the stack gas.

(v) Method 5 (40 CFR part 60, appendix A) to determine the PM concentration for a negative pressure baghouse, Method 5D (40 CFR part 60, appendix A) for a positive pressure baghouse, or an alternative method previously approved by your permitting authority. A minimum of three valid test runs are needed to comprise a PM performance test.

(4) You must conduct each PM test for a sintering machine according to § 63.7(e)(1) and 40 CFR 60.176(b)(1) using the test methods in paragraph (f)(3) of this section. You must determine the PM concentration using EPA Method 5 (40 CFR part 60, appendix A). You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses” (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(5) You must conduct each opacity test for a sintering machine according to the requirements in § 63.6(h)(7). You must determine the opacity of emissions using EPA Method 9 (40 CFR part 60, appendix A).

(g) For each furnace subject to an emissions limit in paragraph (b) of this section, you must conduct subsequent performance tests according to the requirements in paragraph (f)(3) of this section to demonstrate compliance with the applicable PM emissions limit for the furnace every 5 years.

(h) You must submit a notification to your permitting authority of any deviation from the requirements of this subpart within 30 days after the deviation. The notification must describe the probable cause of the deviation and any corrective actions or preventative measures taken.

(i) You must submit semiannual monitoring reports to your permitting authority containing the results for all monitoring required by this subpart. All deviations that occur during the reporting period must be clearly identified.

(j) You must keep records of all required monitoring data and support information. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this subpart.

(k) You must comply with the operation and maintenance requirements specified in paragraphs (k)(1) and (2) of this section and the requirements for emergency situations specified in paragraph (k)(3) or (4) of this section.

(1) You must maintain all equipment covered under this subpart in such a manner that the performance or operation of such equipment does not cause a deviation from the applicable requirements.

(2) You must keep a maintenance record for each item of air pollution control equipment. At a minimum, this record must show the dates of performing maintenance and the nature of preventative maintenance activities.

(3) Except as specified in paragraph (k)(4) of this section, in the event of an emergency situation you must comply with the requirements in paragraphs (k)(3)(i) through (iii) of this section. For the purpose of complying with this paragraph, an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that require immediate corrective action to restore normal operation, and that cause the affected source to exceed applicable emission limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(i) During the period of the emergency you must implement all reasonable steps to minimize levels of emissions that exceeded the emission standards or other applicable requirements in this subpart.

(ii) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (k)(3)(i) of this section.

(iii) You must submit a notice of the emergency to the permitting authority within two working days of the time when emission limitations were exceeded due to the emergency (or an alternative timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(4) As an alternative to the requirements in paragraph (k)(3) of this section, you must comply with the startup, shutdown, and malfunction requirements in 40 CFR 63.6(e)(3).

§ 63.11163 What are the standards and compliance requirements for new sources?

(a) You must exhaust the off-gases from each roaster to a PM control device and to a sulfuric acid plant, including the charging of the roaster.

(b) You must not discharge to the atmosphere any gases which contain PM in excess of the emissions limits in paragraphs (b)(1) through (3) of this section.

(1) 0.005 gr/dscf from the exhaust vent of a zinc cathode melting furnace; scrap zinc melting furnace; furnace melting zinc dust, zinc chips, and other

materials containing zinc; and alloy melting furnace.

(2) 0.014 gr/dscf from the exhaust vent of an anode casting furnace.

(3) 0.015 gr/dscf from the exhaust vent of a cadmium melting furnace.

(c) For each melting furnace, you must install and operate a capture system that collects gases and fumes from the melting furnace and from the transfer of molten materials and conveys the collected gases to a control device.

(d) You must install, operate, and maintain a bag leak detection system on all baghouses used to comply with the PM emissions limit in paragraph (b) of this section according to paragraph (d)(1) of this section, prepare and operate by a site-specific monitoring plan according to paragraph (d)(2) of this section, take corrective action according to paragraph (d)(3) of this section, and record information according to paragraph (d)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (d)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger.)

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (d)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (d)(1)(vi) of this section.

(vi) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects,

including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (d)(2) of this section.

(vii) You must install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) You must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (d)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures as specified in paragraph (d)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (d)(2)(vi) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may

cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) You must maintain records of the information specified in paragraphs (d)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(e) If there is a sintering machine at your primary zinc production facility, you must comply with the PM emissions limit in 40 CFR 60.172(a) and the opacity emissions limit in 40 CFR 60.174(a) for that sintering machine.

(f) If there is a sintering machine at your primary zinc production facility, you must install and operate a COMS for each sintering machine according to the requirements in 40 CFR 60.175(a). Each COMS must meet EPA Performance Specification 1 (40 CFR part 60, appendix B).

(g) For each furnace (and sintering machine, if applicable) at your facility, you must conduct a performance test to demonstrate initial compliance with each applicable PM emissions limit for that furnace (and the PM and opacity limits for a sintering machine, if applicable) within 180 days after startup and report the results in your notification of compliance status.

(1) You must conduct each PM test for a furnace according to § 63.7(e)(1) using the test methods and procedures in paragraphs (g)(1)(i) through (v) of this section.

(i) Method 1 or 1A (40 CFR part 60, appendix A) to select sampling port locations and the number of traverse points in each stack or duct. Sampling

sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere.

(ii) Method 2, 2A, 2C, 2D, 2F, or 2G (40 CFR part 60, appendix A) to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B (40 CFR part 60, appendix A) to determine the dry molecular weight of the stack gas. You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses” (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(iv) Method 4 (40 CFR part 60, appendix A) to determine the moisture content of the stack gas.

(v) Method 5 (40 CFR part 60, appendix A) to determine the PM concentration for negative pressure baghouses or Method 5D (40 CFR part 60, appendix A) for positive pressure baghouses. A minimum of three valid test runs are needed to comprise a PM performance test.

(2) You must conduct each PM test for a sintering machine according to § 63.7(e)(1) and 40 CFR 60.176(b)(1) using the test methods in paragraph (g)(1) of this section. You must determine the PM concentration using EPA Method 5 (40 CFR part 60, appendix A). You may use ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses” (incorporated by reference—see § 63.14) as an alternative to EPA Method 3B.

(3) You must conduct each opacity test for a sintering machine according to the requirements in § 63.6(h)(7). You must determine the opacity of emissions using EPA Method 9 (40 CFR part 60, appendix A).

(h) You must conduct subsequent performance tests according to the requirements in paragraph (g)(1) of this section for each furnace subject to an emissions limit in paragraph (b) of this section to demonstrate compliance at least once every 5 years.

(i) If you use a control device other than a baghouse, you must prepare and submit a monitoring plan to the Administrator for approval. Each plan must contain the information in paragraphs (i)(1) through (5) of this section.

(1) A description of the device;

(2) Test results collected in accordance with paragraph (g) of this section verifying the performance of the device for reducing PM and opacity to the levels required by this subpart;

(3) Operation and maintenance plan for the control device (including a preventative maintenance schedule consistent with the manufacturer’s

instructions for routine and long-term maintenance) and continuous monitoring system;

(4) A list of operating parameters that will be monitored to maintain continuous compliance with the applicable emission limits; and

(5) Operating parameter limits based on monitoring data collected during the performance test.

(i) As an alternative to the startup, shutdown, and malfunction requirements in 40 CFR 63.6(e)(3), you must comply with the requirements specified in this paragraph. In the event of an emergency situation, you must comply with the requirements in paragraphs (i)(1) through (3) of this section. For the purpose of complying with this paragraph, an emergency situation is any situation arising from sudden and reasonably unforeseeable events beyond the control of the facility owner or operator that require immediate corrective action to restore normal operation, and that cause the affected source to exceed applicable emission limitation under this subpart, due to unavoidable increases in emissions attributable to the emergency. An emergency must not include noncompliance to the extent it is caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(1) During the period of the emergency you must implement all reasonable steps to minimize levels of emissions that exceeded the emission standards or other applicable requirements in this subpart.

(2) You must document through signed contemporaneous logs or other relevant evidence that an emergency occurred and you can identify the probable cause, your facility was being operated properly at the time the emergency occurred, and the corrective actions taken to minimize emissions as required by paragraph (i)(1) of this section.

(3) You must submit a notice of the emergency to the permitting authority within two working days of the time when emission limitations were exceeded due to the emergency (or an alternative timeframe acceptable to the permitting authority). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

§ 63.1164 What General Provisions apply to primary zinc production facilities?

(a) If you own or operate an existing affected source, you must comply with the requirements of the General Provisions in 40 CFR part 63, subpart A, according to Table 1 to this subpart and

paragraphs (a)(1) through (3) of this section.

(1) Your notification of compliance status required by § 63.9(h) must include this certification of compliance, signed by a responsible official, for the work practice standards in § 63.11162(a): “This facility complies with the work practice standards in § 63.11162(a).”

(2) If you certify compliance with the PM emissions limits in § 63.11162(b) based on a previous performance test, your notification of compliance status required by § 63.9(h) must include this certification of compliance, signed by a responsible official: “This facility complies with the PM emissions limits in § 63.11162(b) based on a previous performance test.”

(3) If you conduct a new performance test to demonstrate compliance with the PM emissions limits for a furnace in § 63.11162(b), your notification of compliance status required by § 63.9(h) must include the results of the performance test, including required monitoring data.

(b) If you own or operate a new affected source, you must comply with the requirements of the General Provisions (40 CFR part 63, subpart A) as provided in Table 1 to this subpart and paragraphs (b)(1) through (4) of this section.

(1) Your notification of compliance status required in § 63.9(h) must include the results of the initial performance tests, including required monitoring data.

(2) Your notification of compliance status required by § 63.9(h) must include this certification of compliance, signed by a responsible official, for the work practice standard in § 63.11163(a): “This facility complies with the work practice standards in § 63.11163(a).”

(3) Your notification of compliance status required by § 63.9(h) must include this certification of compliance, signed by a responsible official, for the capture system requirements in § 63.11163(c): “This facility has installed capture systems according to § 63.11163(c).”

(4) If you use a baghouse that is subject to the requirements in § 63.11163(d), your notification of compliance status required by § 63.9(h) must include this certification of compliance, signed by a responsible official, for the bag leak detection system requirements in § 63.11163(d): “This facility has an approved monitoring plan in accordance with § 63.11163(d).”

(5) If you use control devices other than baghouses, your notification of compliance status required by § 63.9(h)

must include this certification of compliance, signed by a responsible official for the monitoring plan requirements in § 63.11163(i): “This facility has an approved monitoring plan in accordance with § 63.11163(i).”

Primary Beryllium Production Facilities

§ 63.11165 What are the standards and compliance requirements for new and existing sources?

You must comply with the requirements in 40 CFR 61.32 through 40 CFR 61.34 of the National Emission Standards for Beryllium (40 CFR part 61, subpart C).

§ 63.11166 What General Provisions apply to primary beryllium production facilities?

(a) You must comply with all of the requirements of the General Provisions in 40 CFR part 61, subpart A.

(b) You must comply with the requirements of the General Provisions in 40 CFR part 63, subpart A, that are specified in paragraphs (b)(1) and (2) of this section.

(1) Section 63.1(a)(1) through (10).

(2) Section 63.1(b) except paragraph (b)(3), § 63.1(c), and § 63.1(e).

Other Requirements and Information

§ 63.11167 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; 40 CFR 60.2; 60.171; 61.02; 61.31; 61.61; 63.2; and in this section as follows:

Alloy furnace means any furnace used to melt alloys or to produce zinc that contains alloys.

Anode casting furnace means any furnace that melts materials to produce the anodes used in the electrolytic process for the production of zinc.

Bag leak detection system means a system that is capable of continuously monitoring the relative particulate matter (dust) loadings in the exhaust of a baghouse to detect bag leaks and other conditions that result in increases in particulate loadings. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, electrodynamic, light scattering, light transmittance, or other effect to continuously monitor relative particulate matter loadings.

Cadmium melting furnace means any furnace used to melt cadmium or produce cadmium oxide from the cadmium recovered in the zinc production process.

Capture system means the collection of equipment used to capture gases and fumes released from one or more emissions points and then convey the captured gas stream to a control device.

A capture system may include, but is not limited to, the following components as applicable to a given capture system design: duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emissions limitation or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emissions limitation or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Primary beryllium production facility means any establishment engaged in the chemical processing of beryllium ore to produce beryllium metal, alloy, or oxide, or performing any of the intermediate steps in these processes. A primary beryllium production facility may also be known as an extraction plant.

Primary zinc production facility means an installation engaged in the production, or any intermediate process in the production, of zinc or zinc oxide from zinc sulfide ore concentrates through the use of pyrometallurgical techniques.

Responsible official means responsible official as defined in 40 CFR 70.2.

Roaster means any facility in which a zinc sulfide ore concentrate charge is heated in the presence of air to eliminate a significant portion (more than 10 percent) of the sulfur contained in the charge.

Sintering machine means any furnace in which calcines are heated in the presence of air to agglomerate the calcines into a hard porous mass called sinter.

Sulfuric acid plant means any facility producing sulfuric acid from the sulfur dioxide (SO₂) in the gases from the roaster.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof.

Zinc cathode melting furnace means any furnace used to melt the pure zinc from the electrolytic process.

§ 63.11168 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to a State, local, or tribal agency, then that Agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) and (d) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) For primary zinc production facilities subject to this subpart, the authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emissions standard under § 63.6(g).

(2) Approval of an alternative opacity emissions standard under § 63.6(h)(9).

(3) Approval of a major change to test methods under § 63.7(e)(2)(ii) and (f). A “major change to test method” is defined in § 63.90

(4) Approval of a major change to monitoring under § 63.8(f). A “major change to monitoring” is defined in § 63.90.

(5) Approval of a major change to recordkeeping/reporting under § 63.10(f). A “major change to recordkeeping/reporting” is defined in § 63.90.

(d) For primary beryllium manufacturing facilities subject to this subpart, the authorities that will not be delegated to State, local, or tribal agencies are listed in paragraphs (d)(1) through (4) of this section.

(1) Approval of an alternative non-opacity emissions standard under 40 CFR 61.12(d).

(2) Approval of a major change to test methods under 40 CFR 61.13(h). A “major change to test method” is defined in § 63.90.

(3) Approval of a major change to monitoring under 40 CFR 61.14(g). A “major change to monitoring” is defined in § 63.90.

(4) Approval of a major change to recordkeeping/reporting under 40 CFR 61.10. A “major change to recordkeeping/reporting” is defined in § 63.90.

As required in § 63.11164(a) and (b), CFR part 63, subpart A) as shown in the following table. you must comply with the requirements of the NESHAP General Provisions (40

TABLE 1 TO SUBPART GGGGGG OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO PRIMARY ZINC PRODUCTION AREA SOURCES

Citation	Subject	Applies to subpart GGGGGG	Explanation
63.1(a)(1), (a)(2), (a)(3), (a)(4), (a)(6), (a)(10)–(a)(12), (b)(1), (b)(3), (c)(1), (c)(2), (c)(5), (e).	Applicability	Yes.	
63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3), (c)(4), (d).	Reserved	No.	
63.2	Definitions	Yes.	
63.3	Units and Abbreviations	Yes.	
63.4	Prohibited Activities and Circumvention	Yes.	
63.5	Preconstruction Review and Notification Requirements	No.	
63.6(a), (b)(1)–(b)(5), (b)(7), (c)(1), (c)(2), (c)(5).	Compliance with Standards and Maintenance Requirements—Applicability Compliance Dates.	Yes.	
63.6(e)	Operation and Maintenance Requirements.	Yes/No	Operation and maintenance requirements do not apply to existing sources except that the startup, shutdown, and malfunction requirements in § 63.6(e)(3) are allowed as an alternative to the rule requirements for emergency situations. Operation and maintenance requirements apply to new sources except that the rule requirements for emergency situations are allowed as an alternative to the startup, shutdown, and malfunction requirements in § 63.6(e)(3).
63.6(f), (g), (i), (j)	Compliance with Nonopacity Emission Standards.	Yes.	
63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv).	Reserved	No.	
63.6(h)(1)–(h)(4), (h)(5)(i)–(h)(5)(iii), (h)(6)–(h)(9).	Yes.	
63.7(a), (e), (f), (g), (h)	Performance Testing Requirements	Yes.	
63.7(b), (c)	Yes/No	Notification of performance tests and quality assurance program apply to new sources but not existing sources.
63.8(a)(1), (a)(2), (b), (c), (f), (g)	Monitoring Requirements	Yes	Requirements in § 63.6(c)(4)(i)–(ii), (c)(5), (c)(6), (d), (e), (f)(6), and (g) apply if a COMS is used.
63.8(a)(3)	Reserved	No.	
63.8(a)(4)	No	Subpart GGGGGG does not require flares.
63.8(d), (e)	Yes/No	Requirements for quality control program and performance evaluations apply to new sources but not existing sources.
63.9(a), (b)(1), (b)(2), (b)(5), (c), (d), (f), (g), (h)(1)–(h)(3), (h)(5), (h)(6), (i), (j).	Notification Requirements	Yes/No	Notification of performance tests and opacity or visible emissions observations apply to new sources but not existing sources.
63.9(b)(3), (h)(4)	Reserved	No.	
63.9(b)(4)	No.	
63.10(a), (b)(1), (b)(2)(i)–(v), (d)(4), (d)(5)(i), (f).	Recordkeeping and Reporting Requirements.	Yes.	
63.10(b)(2), (b)(3), (c)(1), (c)(5)–(c)(8), (c)(10)–(c)(15), (d)(1)–(d)(3), (d)(5)(ii), (e)(1), (e)(2), (e)(4).	Yes/No	Recordkeeping and reporting requirements apply to new sources but not existing sources.
63.10(c)(2)–(c)(4), (c)(9)	Reserved	No.	
63.10(e)(3)	Yes/No	Reporting requirements apply to new sources but not existing sources.
63.11	Control Device Requirements	No	Subpart GGGGGG does not require flares.
63.12	State Authorities and Delegations	Yes.	
63.13	Addresses	Yes.	
63.14	Incorporations by Reference	Yes.	

TABLE 1 TO SUBPART GGGGGG OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO PRIMARY ZINC PRODUCTION AREA SOURCES—Continued

Citation	Subject	Applies to sub-part GGGGGG	Explanation
63.15	Availability of Information and Confidentiality.	Yes.	
63.16	Performance Track Provisions	Yes.	

[FR Doc. E7-532 Filed 1-22-07; 8:45 am]

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Federal Register

**Wednesday,
June 12, 2002**

Part III

Environmental Protection Agency

40 CFR Part 63

**National Emission Standards for
Hazardous Air Pollutants for Primary
Copper Smelting; Final Rule**

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 63**

[FRL-7214-9]

RIN 2060-AE41

National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting**AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Final rule.

SUMMARY: This action promulgates national emission standards for hazardous air pollutants (NESHAP) for primary copper smelting. Primary copper smelters can potentially emit significant amounts of certain toxic metals listed as hazardous air pollutants (HAP) in Clean Air Act (CAA) section 112(b)(1). These metals include antimony, arsenic, beryllium, cadmium, cobalt, lead, manganese, nickel and selenium. Exposure to these substances has been demonstrated to cause adverse health effects such as diseases of the lung, kidney, central nervous system, and cancer. The final rule establishes emissions limitations and work practice standards for primary copper smelters that are (or are part of) a major source of HAP emissions and that use batch copper converters. The standards reflect the application of the maximum achievable control technology (MACT). When fully implemented, we estimate the rule will reduce annual nationwide HAP emissions from the source category by approximately 23 percent or 22 megagrams per year.

EFFECTIVE DATE: June 12, 2002.

ADDRESSES: Docket No. A-96-22 contains supporting information used in developing the rule. The docket is located at the U.S. EPA, 401 M Street, SW., Washington, DC 20460 in Room M-1500, Waterside Mall (ground floor), and may be inspected from 8:30 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays.

FOR FURTHER INFORMATION CONTACT: Mr. Eugene Crumpler, Metals Group, Emission Standards Division (C439-02), U.S. EPA, Research Triangle Park, NC, 27711, telephone number (919) 541-0881, facsimile number (919) 541-5450, electronic mail address "crumpler.gene@epa.gov".

SUPPLEMENTARY INFORMATION: *Docket.* The docket is an organized and complete file of all the information considered by the EPA in the development of the rule. The docket is a dynamic file because material is added

throughout the rulemaking process. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the proposed and promulgated rules and their preambles, the contents of the docket will serve as the record in the case of judicial review. (See CAA section 307(d)(7)(A).) Other material related to this rulemaking is available for review in the docket or copies may be mailed on request from the Air Docket by calling (202) 260-7548. A reasonable fee may be charged for copying docket materials.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of today's final rule will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at <http://www.epa.gov/ttn/oarpg>. The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541-5384.

Judicial Review. Today's action constitutes final administrative action on the proposed NESHAP for primary copper smelting (63 FR 19582, April 20, 1998; 65 FR 39326, June 26, 2000). Under CAA section 307(b)(1), judicial review of the final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by August 12, 2002. Under CAA section 307(b)(2), the requirements that are the subject of this document may not be challenged later in civil or criminal proceedings brought by the EPA to enforce these requirements.

Regulated Entities. Entities potentially regulated by this action are primary copper smelters (North American Industry Classification System (NAICS) Code 331411 Primary Smelting and Refining of Copper). No federal government entities nor State/local/tribal government entities are regulated by this rule.

This description of the regulated entities is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in § 63.1440 of the final rule. If you have any questions regarding the applicability of this action to a particular entity, consult the appropriate person listed in the

preceding **FOR FURTHER INFORMATION CONTACT** section.

Outline. The information in this preamble is organized as follows:

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 - C. How Did We Develop the Rule?
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- II. Summary of Final Rule and Changes Since Proposal
 - A. Who Must Comply With This Rule?
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- New and Existing Sources?
- V. Administrative Requirements
- A. Executive Order 12866, Regulatory Planning and Review
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 - E. Unfunded Mandates Reform Act of 1995
 - F. Regulatory Flexibility Act (RFA), as Amended by Small Business Regulatory Enforcement Act of 1996 (SBREFA), 5 U.S.C. 601 *et seq.*
 - G. Paperwork Reduction Act
 - H. National Technology Transfer and Advancement Act of 1995
 - I. Congressional Review Act
 - J. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

I. Background

A. What is the Statutory Authority for NESHAP?

Section 112 of the CAA requires us to list categories and subcategories of major sources and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. The category of major sources covered by today's final NESHAP, "primary copper smelting," was listed on July 16, 1992 (57 FR 31576). Major sources of HAP are those that have the potential to emit greater than 10 tons per year (tpy) of any one HAP or 25 tpy of any combination of HAP.

B. What Criteria Are Used in the Development of NESHAP?

Section 112 of the CAA requires that we establish NESHAP for the control of HAP from both new and existing major sources. The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAP that is achievable. This level of control is commonly referred to as MACT.

The MACT floor is the minimum control level allowed for NESHAP and is defined under CAA section 112(d)(3). In essence, the MACT floor ensures that the standards are set at a level that assures that all major sources achieve the level of control at least as stringent as that already achieved by the better controlled and lower emitting sources in each source category or subcategory. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be

less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory (or the best performing five sources for categories or subcategories with fewer than 30 sources).

In developing MACT, we also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of cost of achieving the emissions reductions, any health and environmental impacts, and energy requirements.

C. How Did We Develop the Rule?

We proposed the NESHAP for the primary copper smelting source category on April 20, 1998 (63 FR 19582). A 90-day comment period was provided for the proposed rule. We received a total of 11 comment letters. A copy of each of these comment letters is available in the docket for this rulemaking (Docket No. A-96-22).

After our review and evaluation of the comments and additional information we collected after proposal, we decided that several changes to our proposed rule were appropriate. On June 26, 2000, a supplemental proposal to the rule was published in the **Federal Register** (65 FR 39326). Specifically, we proposed a particulate matter emission limit for sulfuric acid plants used at primary copper smelters to control the process off-gas discharged from the smelting and converting operations. We also proposed a limit on bag leak detector alarms for those baghouses used to comply with the particulate emission limit standards under the rule. A 60-day comment period was provided for the supplemental proposal. We received a total of eight comment letters regarding our supplement to the proposed rule. A copy of each of these letters also is available in Docket No. A-96-22.

All of the comments regarding the primary copper smelter NESHAP were reviewed and carefully considered. To clarify and obtain additional information about some specific comments, we held follow-up discussions with individual commenters. The promulgated rule reflects our full consideration of all the comments we received on the initial and supplemental rule proposals.

D. How Has the Copper Industry Changed Since Rule Proposal?

Since proposal of the NESHAP for the primary copper smelting source category, several changes have occurred

in the copper industry in the United States. First, corporate ownership has changed for three of the primary copper smelters potentially subject to the NESHAP. The smelter near Miami, Arizona, owned and operated by the Cyprus Miami Mining Corporation during the time we were developing the proposed rule, is now owned by the Phelps Dodge Corporation. The name of this smelter is now the Phelps Dodge Miami smelter. The smelters located in Hayden, Arizona and El Paso, Texas were owned and operated by Asarco Incorporated at the time of rule proposal. As a result of a corporate merger, Asarco is now a subsidiary of Grupo Mexico, S.A. de C.V., the third largest producer of copper in the world.

Second, since proposal of the rule, four of the smelters potentially subject to the NESHAP have suspended operations and are not producing copper: the Asarco smelter in El Paso, Texas; the BHP Copper smelter near San Manuel, Arizona; and both of the Phelps Dodge smelters in New Mexico. At this time, it is unknown when and even if these smelters will resume production.

II. Summary of Final Rule and Changes Since Proposal

After the proposal of the NESHAP for primary copper smelters, the EPA adopted a new "plain language" format for all rulemakings. Accordingly, we have revised the organization, wording style, and presentation of the final rule. While these changes to the rule make it appear substantially different from the proposed rule, most of the technical and administrative requirements remain the same as proposed. In addition, for the final rule, we are correcting the name of the source category as published in the proposed rule from primary copper smelters to primary copper smelting, which is the way the source category name appears on the source category list and promulgation schedule.

A. Who Must Comply With This Rule?

The final rule applies to any owner or operator of a primary copper smelter that is a major source of HAP emissions and uses batch copper converters. A batch converter is a cylindrical vessel in which copper matte produced by the flash smelting of copper ore concentrates is oxidized in discrete batches following a sequence of steps consisting of charging, blowing, skimming, and pouring. Examples of batch converters are Pierce-Smith converters and Hoboken converters. A smelter that uses batch converters but is not a major source of HAP emissions is not subject to the rule.

For the final rule, we changed the definition of "primary copper smelter" to be consistent with the definition that is used in two related rules applicable to primary copper smelters. These are 40 CFR part 60, subpart P, Standards of Performance for Primary Copper Smelters, and 40 CFR part 61, subpart O, National Emission Standard for Inorganic Arsenic Emissions from Primary Copper Smelters. A primary copper smelter is defined as any installation or intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

B. What Sources at Primary Copper Smelters Are Affected?

The final rule establishes standards for: (1) Copper concentrate dryers; (2) smelting furnaces; (3) slag cleaning vessels; (4) batch converters; and (5) fugitive dust sources associated with the handling, transfer, and storage of copper concentrate, dross, reverts, slag, speiss, and other solid copper-bearing materials.

C. When Must an Affected Source Comply With the Standards?

For the final rule, the compliance date for existing sources is 3 years from June 12, 2002. An affected source is an existing source if its construction began before April 20, 1998. An affected source is a new source if its construction or reconstruction began on or after April 20, 1998. An affected source has been reconstructed if it meets the definition of "reconstruction" in 40 CFR 63.2. A new or reconstructed source must be in compliance on June 12, 2002, or, if it is not yet operational, upon initial startup of the source.

D. What Are the Emission Limits and Work Practice Standards?

1. Copper Concentrate Dryers

The emission limit for an existing copper concentrate dryer is no more than 50 milligrams per dry standard cubic meter (mg/dscm) of total particulate matter, as measured by Method 5—Determination of Particulate Emissions From Stationary Sources in 40 CFR part 60, appendix A. The emission limit for a new copper concentrate dryer is no more than 23 mg/dscm of total particulate matter, as measured by Method 5.

2. Smelting Furnaces

We changed the proposed emission limit (in the supplemental proposal) for the by-product sulfuric acid plant tail gas from a limit on total particulate matter to a limit on nonsulfuric acid

particulate matter. Under the final rule, nonsulfuric acid particulate matter in the tail gas discharged to the atmosphere from sulfuric acid plant can be no more than 6.2 mg/dscm, as measured by Method 5B—

Determination of Nonsulfuric Acid Particulate Matter From Stationary Sources in 40 CFR part 60, appendix A.

A second revision to the standards for smelting furnaces is the particulate matter emission limit for process fugitive emissions from matte and slag tapping. The limit has been changed from 16 mg/dscm to 23 mg/dscm of total particulate matter, as measured by Method 5. The value of this emission limit was changed based on our reconsideration of the test data.

3. Slag Cleaning Vessels

The standards for slag cleaning vessels have been revised to be consistent with changes discussed above that we made for the process off-gas and process fugitive emission limits for smelting furnaces. The final standard requires that the process off-gas from slag cleaning vessels be vented to a sulfuric acid plant that meets a 6.2 mg/dscm emission limit for nonsulfuric acid particulate matter (as measured by Method 5B). As an alternative to meeting this standard, an owner or operator may choose to vent the process off-gas from the slag cleaning vessel to a wet scrubber that meets a 46 mg/dscm emission limit for total particulate matter (as measured using Method 5). The particulate matter limit for process fugitive emissions generated by tapping molten material from the slag cleaning vessel is revised to be consistent with the standard for smelting furnaces (23 mg/dscm of total particulate matter, as measured by Method 5).

4. Copper Converter Departments

Where applicable, the standards for batch converters have been revised to be consistent with the final particulate matter emission limits for process off-gas and process fugitive emissions from smelting furnaces. Process off-gas captured during converter blowing must be vented to the smelter's sulfuric acid plant that meets the 6.2 mg/dscm emission limit for nonsulfuric acid particulate matter. The particulate matter limit for process fugitive emissions generated by converter operations is set at 23 mg/dscm of total particulate matter, as measured by Method 5.

We also made several revisions to the proposed opacity limit requirements for copper converter departments. First, we modified the test protocol used to determine compliance with the

applicable opacity limit. We revised how the field opacity data are compiled and averaged in order to reduce the duration of the observation period needed to obtain the required number of acceptable opacity readings. The test protocol in the final rule requires that the average opacity value for the affected source be calculated using a minimum of 120 1-minute intervals during which at least one copper converter was blowing and there were no visible emission interferences as specified in the rule (i.e., during the 1-minute interval, there were no other copper production events generating visible emissions inside the converter building that potentially could interfere with the visible emissions from the converter capture systems as seen by the outside observers).

Next, considering the above revision to the test protocol, we decided it was necessary to reexamine the test data used to establish the opacity limit for existing Pierce-Smith converters to determine the effect of using the new protocol on the proposed opacity limit. Based on this analysis, we changed the opacity limit for existing Pierce-Smith converter departments to 4 percent opacity. In the final rule, the opacity limit for existing Hoboken copper converter departments is the same value as proposed, 4 percent opacity.

Finally, we have reconsidered the selection of new source MACT for copper converter departments by applying the level of process fugitive emissions control achieved by the best controlled similar source, flash converting technology. Based on this new source MACT for copper converting operations, we have selected, as the final standard for new sources, a work practice standard that prohibits altogether the operation of batch copper converters at new copper converter departments subject to the rule.

5. Fugitive Dust Sources

The final standards for fugitive dust sources are the same as proposed with one change. We added the requirement that the fugitive dust control plan, which the smelter owner or operator is required to prepare and adhere to at all times, must be approved by the State with delegated authority for enforcement. For the purpose of complying with the final rule, an existing fugitive dust control plan may be used, provided that this plan addresses the fugitive dust sources and includes the information specified in the rule. An existing fugitive dust control plan that meets these conditions and also has been incorporated into a State implementation plan is considered

to be approved for the purpose of complying with this requirement.

6. Alternative Emission Limit for Combined Gas Streams

The equation in the final rule that an owner or operator can elect to use to determine an alternative or equivalent particulate matter emission limit for gas streams combined from two or more affected sources has been corrected to include a potential control situation that was inadvertently omitted at proposal. For the final rule, the equation includes a component to address the situation where the off-gas stream exhausted from a slag cleaning vessel is not vented to the sulfuric acid plant or a dedicated wet scrubbing system, but instead is combined with other gas streams and vented to a common particulate control device.

E. What Are the General Compliance Requirements?

A new section is added to the final rule listing the general requirements for complying with the rule. The owner or operator must be in compliance with each applicable particulate matter emission limit and work practice standard at all times, except during periods of startup, shutdown, and malfunction. Each smelter owner or operator must develop and implement a written startup, shutdown, and malfunction plan for the smelter according to the general provisions of 40 CFR part 63 and the additional requirements specified in the rule.

Compliance with the opacity limits for copper converter departments is determined using the test protocol and requirements specified in the rule. The general provision requirements for compliance with opacity and visible emission standards under 40 CFR 63.6(h) do not apply to the opacity limit standards for copper converter departments.

F. How Is Initial Compliance Demonstrated?

Initial compliance with each of the particulate matter emission limits is to be determined by a performance test conducted according to 40 CFR 63.7 of the general provisions and specific EPA reference test methods. The average of three test runs is to be used to determine compliance with each of the applicable emission limits specified in the rule. During each initial performance test, the owner or operator is also required to establish limits for appropriate control device operating parameters based on the actual values recorded during the performance test.

We reconsidered our proposed requirements for when an owner or operator must conduct a performance test and decided it is appropriate to require periodic testing beyond the initial performance test to reaffirm compliance with the applicable emission limitation. Under the final rule, compliance with each applicable particulate matter emission limit must be demonstrated initially and, thereafter, at least once per year.

G. How Is Continuous Compliance Demonstrated?

To demonstrate continuous compliance with the applicable emission limitations and work practice standards under the final rule, an owner or operator must perform periodic inspections and continuous monitoring of air pollution control devices used to comply with the rule. In those situations when a deviation from the operating limits specified for a control device or capture system is indicated by the monitoring system, or when a damaged or defective component is detected during an inspection, the owner or operator must implement the appropriate corrective actions. Monthly visual inspections of all capture systems used to comply with the rule are required. Minor revisions to the procedures for these inspections were made for the final rule.

Each baghouse used to comply with a total particulate matter emission limit must be operated according to written operating and maintenance procedures that describe in detail the procedures to be used for inspection, maintenance, bag leak detection, and corrective action for the baghouse. The final rule includes the requirement as proposed in the supplemental proposal for an alarm operating limit on baghouse leak detectors. We have made minor revisions to the procedures used for inspection, maintenance, bag leak detection, and corrective action for baghouses so that the rule is consistent with the requirements for baghouses in other NESHAP.

H. What Are the Notification, Recordkeeping, and Reporting Requirements?

The final rule requires the notification, recordkeeping, and reporting requirements in the general provisions to 40 CFR part 63 with one exception. The notification, recordkeeping, and reporting requirements in the general provisions related directly to compliance with opacity and visible emission standards as specified in 40 CFR 63.6(h) do not apply to this rule. The specific

recordkeeping and reporting requirements for documenting compliance with the opacity limit provisions are specified in the rule. The dates by which the notifications and reports must be submitted to us (or the applicable delegated State authority) are specified in the rule.

Each affected owner or operator must submit a semiannual compliance report containing the information specified in the rule. The final rule requires that this report be submitted whether a deviation has or has not occurred during the reporting period. However, only summary information is required if no deviation occurred. The rule does not require emergency reports if actions taken are consistent with the smelter's startup, shutdown, and malfunction plan. If actions taken are not consistent with this plan, the events and the response are to be included in the semiannual compliance report.

III. Summary of Health, Environmental, Energy, and Economic Impacts

A. What Are the Health Impacts?

The HAP emitted from primary copper smelters include compounds of antimony, arsenic, beryllium, cadmium, cobalt, lead, manganese, nickel, and selenium. The HAP metal compounds controlled by this rule are associated with a variety of adverse health effects. These adverse health effects include chronic health disorders (e.g., diseases of the lung, kidney, central nervous system), and acute health disorders (e.g., lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the central nervous system). Arsenic and nickel compounds have been classified by the EPA as human carcinogens, and compounds formed from four other HAP metals (beryllium, cadmium, lead, and nickel) have been classified as probable carcinogens.

Emission data collected during development of the rule indicate that the HAP emitted in the largest quantities are arsenic and lead compounds. Exposure of humans to arsenic by inhalation or by ingestion has been shown to be associated with forms of lung, bladder, liver, and other cancers. Brain damage, kidney damage, and gastrointestinal distress may occur from acute exposure to high levels of lead in humans. Chronic exposure to lead by humans results in effects on the central nervous system, blood, blood pressure, and kidneys.

We do not have the detailed data on each of the primary copper smelters potentially subject to this rule or the people living around the facilities

necessary to determine the actual population exposures to the HAP emitted from these smelters and the potential for resultant health effects. Therefore, we do not know the extent to which the adverse health effects occur in the populations surrounding these facilities. However, to the extent the adverse effects do occur, the rule will reduce emissions and subsequent exposures.

B. What Are the Air Emission Reduction Impacts?

Current nationwide HAP emissions from the three currently operating primary copper smelters potentially subject to the final rule are estimated to be about 96 megagrams per year (Mg/yr). We estimate that implementation of the final rule will reduce these nationwide HAP emissions by approximately 23 percent or 22 Mg/yr.

C. What Are Other Non-air Environmental and Energy Impacts?

With only three of the potentially regulated smelter operating at this time, one of the affected smelters will need to install additional air pollution control equipment to meet the copper converter department standards. The additional controls at this smelter consists of doubling the converter secondary hood ventilation rate and venting the secondary hoods to a new baghouse (fabric filter). The non-air environmental impacts associated with operating these new controls will be a small increase in the amount of solid waste generated at each smelter from the particulate matter collected in the new baghouse. Operation of the fans used to increase the converter secondary hood ventilation rates will result in a small increase in overall smelter electricity usage. No significant adverse solid waste or energy impacts are expected as a result of operating these additional air pollution controls.

D. What Are the Cost and Economic Impacts?

Costs to smelter owners and operators for complying with the final rule were estimated. As noted above, one smelters will need to install additional air pollution control equipment to meet the copper converter department standards. The total capital costs for the purchase and installation of this additional control is estimated to be \$4.1 million. Total annual costs of meeting all of the requirements of the rule, including operating and maintenance costs, are estimated to be \$860,000 per year.

The economic impact of the rule is determined by comparing the annualized costs incurred by each

smelter to their estimated annual copper production revenues. The share of costs to estimated revenues for the affected smelters range from a low of 0.004 percent to a high of 0.2 percent. Thus, compared to the estimated production revenues for each affected smelter, the total annualized costs are minimal. Based on the smelter-specific total annual cost to sales ratios, impacts of the final rule on the companies owning the facilities are anticipated to be negligible. The economic impact analysis we prepared to support this finding is available in Docket No. A-96-22.

IV. Summary of Responses to Major Comments

A summary of our responses to selected major comments received on the proposed rule (including the supplemental proposal) is presented below. Our responses to all of the substantive public comments on the proposal are presented in the document titled *National Emission Standards for Hazardous Air Pollutant (NESHAP) for Primary Copper Smelters: Background Information Document for Promulgated Standards (BID)*. The BID is available in Docket No. A-96-22.

A. How Did We Select the Emission Limit for Sulfuric Acid Plant Tail Gas?

Comment. Seven commenters disagreed with our proposal to establish a particulate emission limit for the tail gas exhaust from the by-product sulfuric acid plants used to treat the process off-gases discharged from smelting furnaces, slag cleaning vessels, and batch converters. Reasons cited include: (1) Method 5 is an inappropriate test method for measuring HAP concentrations in acid plant tail gas because Method 5 measures as particulate matter material that is not HAP (i.e., sulfuric acid mist and waters of hydration); and (2) the proposed numerical limit is based on data for only four sources not the five best performing sources as is required by CAA section 112 for establishing MACT.

Response. For the process off-gases discharged from smelting furnaces, slag cleaning vessels, and batch converters, we originally proposed an equipment standard that would require these sulfur dioxide rich process off-gases to be vented to a by-product sulfuric acid plant with its ancillary particulate matter precleaning and conditioning systems, or other type of sulfur recovery process unit capable of achieving comparable levels of particulate matter removal. At the time of proposal, all six smelters in the source category operated by-product sulfuric acid plants.

After careful review and evaluation of comments received objecting to our use of an equipment standard rather than a numerical emission limit and new emissions data obtained since proposal, we concluded that a change in the proposed standards for process off-gas emissions was warranted. As a result, we issued a supplement to the proposed rule (65 FR 39326, June 26, 2000) in which we proposed a numerical emission standard that would limit the concentration of total particulate matter in the off-gases discharged. Specifically, we proposed to set a total particulate matter emission limit for acid plant tail gas of 23 mg/dscm based on Method 5 measurements.

In response to the commenters' concerns regarding the use of total particulate matter as the surrogate for HAP and the use of Method 5 for determining compliance, we examined more closely the suitability of Method 5 for measuring particulate matter in tail gas from sulfuric acid plants at primary copper smelters. Method 5 is the basic reference test method used for determining particulate matter emissions from stationary sources. The sampling probe and filter temperature specified for Method 5 (250°F) is below the acid dewpoint for sulfuric acid. Consequently, when sampling sulfuric acid plant tail gas by Method 5, condensed sulfuric acid mist and waters of hydration not driven off at the sampling temperature are included in the probe wash and filter catch, along with any metal HAP contained in the tail gas. Thus, we agree that establishing and determining compliance with a total particulate matter emission limit based on Method 5 may include sulfuric acid mist condensables not related to the control or emissions of metal HAP. Based on some limited test data obtained using Arizona Method A1 (a test method adopted by the State of Arizona for measuring particulate matter in sulfur containing gas streams that excludes acid condensate), the condensate may account for as much as 12 percent of the total particulate catch.

Method 5B was developed specifically to measure nonsulfuric acid particulate matter in circumstances when appreciable quantities of condensable sulfuric acid are present in the stack exhaust to be tested. The procedure is identical to Method 5 except that the front-half of the Method 5 sampling train is maintained at 320°F instead of 250°F, and the probe and filter samples are to be heated in an oven to 320°F for 6 hours prior to weighing. At the higher sampling temperature, most of the sulfuric acid mist and waters of hydration present pass

through the probe and filter without condensing. Heating the probe wash residues and sample filter in an oven before weighing volatilizes any condensed sulfuric acid that may have collected in the front-half. Because sulfuric acid mist and waters of hydration are not counted as part of the total particulate catch, the total particulate matter concentration value measured in the front-half by Method 5B will be lower than the concentration value that would have been measured on the filter using Method 5. Given the gas stream characteristics of sulfuric acid plant tail gas, it is our conclusion that Method 5B is the appropriate test method to use for setting a particulate matter concentration limit that serves as a surrogate for metal HAP emissions contained in the tail gas from sulfuric acid plants.

Lacking any available Method 5B emissions test data to set an emission limit, we convened a meeting with company representatives of each of the six smelters potentially subject to the NESHAP. Two options were considered: (1) Derive an emission limit based on the available Method 5 test data and a conversion factor inferred from the limited Arizona Method 1A test data; or (2) gather actual Method 5B test data by testing each of the operating by-product sulfuric acid plants. The consensus view was that Method 5B testing was needed to establish a credible emission limit.

A test program was planned and implemented jointly by us and the companies owning the three copper smelters currently producing copper. The source tests were conducted by an independent consultant hired by the smelter companies. Four individual test runs were conducted at each of the three smelters. To our best knowledge, all of the tests were conducted at normal smelter production levels and under normal acid plant operating conditions.

We considered two approaches in selecting the level of the standard: (1) Base the emission limit on the highest credible individual run measured at the three smelters; or (2) base the limit on the highest three-run average measured at the highest emitting smelter. If we base the emission limit on the highest individual run, the standard expressed in concentration units would be 6.2 mg/dscm. If we base the emission limit using the highest three-run average (highest single performance test), the standard would be 5.0 mg/dscm.

In selecting the appropriate level for the emission limit, consideration was given to the full range of smelter process and acid plant operating conditions which could reasonably be foreseen to

recur, under which the standard is to be achieved. This is especially important where the emission limit is applied to a gas stream in which the outlet loading will typically fluctuate within a range of values during the course of normal operations. After examining the design and operating conditions of the three acid plants tested, we can find no discernible differences among the three plants which would lead us to conclude that one is superior or inferior to another. In addition, we believe that each test run was conducted under conditions representative of acceptable sulfuric acid plant performance.

Based on the above considerations, we believe that the performance of the sulfuric acid plant under a reasonable worst case circumstance is best represented by the single highest individual run, and that selecting this highest value will ensure that the standard will be met under all foreseeable acceptable operating conditions. Therefore, we are selecting 6.2 mg/dscm of nonsulfuric acid particulate matter based on measurements using Method 5B as the emission limit for the sulfuric acid plant tail gas.

B. How Did We Select the Emission Limit for Process Fugitive Emissions?

Comment. Four commenters stated that the proposed emission limit of 16 mg/dscm for the process fugitive emissions from smelting furnaces, slag cleaning vessels, and batch converters is overly stringent and is not representative of the MACT floor. The commenters claimed that the source test data we used to select the value consisted of only a few source tests, and that these tests do not account for the range of variability in emissions associated with normal operating conditions. The commenters recommended that the value of the standard be increased to 50 mg/dscm which is consistent with the particulate matter emission limit we proposed for existing copper concentrate dryers.

Response. We selected the application of baghouses as MACT for controlling process fugitive HAP emissions based on the control devices used to control fugitive emissions (i.e., secondary emissions) from batch converters (63 FR 19595 and 19597, April 20, 1998). Four of the five smelters that use secondary hoods to capture the converter fugitive emissions vent the captured gas stream to a baghouse for control. The fifth smelter employs an electrostatic precipitator (ESP). Because the common practice at the smelters is to vent the emissions captured by the hoods over the smelting and slag cleaning vessel

tapping ports to the same control device used to control converter secondary emissions, we also selected use of baghouses as the MACT floor for controlling process fugitive emissions from the matte and slag tapping operations at the smelting furnaces and slag cleaning vessels. Consistent with other NESHAP based on application of baghouses as MACT for control of particulate matter emissions, we selected concentration units as the format of the standard.

The data used to select the proposed emission limit consist of results from four performance tests, one test for each of the four smelters employing baghouses for the control of converter secondary emissions. Each test is comprised of three test runs conducted at the baghouse outlets using Method 5.

For the proposed emission limit, we selected the highest average concentration (16 mg/dscm) measured among the four performance tests. Since proposal, we have reexamined the data and our approach to setting the standard. A close review of each of the performance tests shows a high degree of variability and imprecision among individual test runs within a performance test, with the highest measured values ranging from 1½ to 4½ times the lowest measured values. Given the lack of precision among the test results, we reconsidered whether relying on the highest three-run average measured at one smelter truly accounts for the full range of acceptable process and control device operating conditions which could be reasonably foreseen to recur. We believe that a more conservative and, perhaps, better approach in this case is to set the standard based on the highest single credible test run. This will provide better assurance that the standard is achievable under reasonable worst case circumstances. Of the 12 individual test runs, the value of the highest run and the value selected for the final standard is 23 mg/dscm.

C. How Did We Select MACT Floor for Pierce-Smith Converters?

Comment. Several commenters disagreed with our MACT floor determination for existing Pierce-Smith converters. The commenters claimed that CAA section 112(d)(3) requires us to determine the MACT floor for existing sources based on applicable "emissions limitations" rather than relying on actual emissions data as we did for the proposed rule. Using an emissions limitations approach based on application of existing State regulations, the commenters concluded that the opacity limit for existing Pierce-

Smith converters should be established at a value of 40 percent opacity.

Response. We disagree with the commenters' assertion that CAA section 112(d)(3) requires us to establish MACT floors for existing sources based on applicable "emissions limitations." We have and continue to use several approaches to establishing MACT floors, depending on the type and quality of the available information. Typically, we examine several approaches and rely on the one best suited for each particular circumstance. The approaches include: (1) Reliance on information such as test data on actual emissions from the pool of sources (the best five sources or best 12 percent) that comprise the best performers; (2) information on applicable emissions limitations or standards specified in State and local regulations and/or operating permits; or (3) a technology approach based on the application of a specific control technology and accompanying performance data. We believe that each of these approaches has merit, and we have relied on using each to various degrees throughout the MACT program.

The emissions limitations approach to establish the MACT floor for Pierce-Smith converters was examined at proposal and dismissed. Of the five smelters in the source category that operate Pierce-Smith converters, only three are subject to an emissions limitation. The converter building at one smelter is subject to a zero percent opacity limit specified in the facility's operating permit. The converter buildings at the two smelters located in Arizona are arguably subject to the State's general 40 percent opacity limit applicable to process fugitive emissions from any source. The converter buildings at the remaining two smelters, both located in New Mexico, are not subject to an opacity limit. Then and now, the commenters supported establishing the MACT floor based on the median or third most stringent emissions limitation. Using this approach, the MACT floor would be 40 percent opacity.

The emissions limitation approach advanced by the commenters is workable only when the outcome produces a realistic inference of actual performance of the best performing sources. This has been affirmed unequivocally by the DC Circuit Court in *Sierra Club vs. EPA, 167F.3d* in which the court opined that to comply with the statute, the EPA's method of setting emissions floors must reasonably estimate the performance of the relevant best performing sources. Observations made by us and the industry at all five of the smelters operating Pierce-Smith

converters indicate that actual visible emissions from the converter buildings are typically in the range of zero percent to 10 percent opacity, well below the 40 percent opacity value supported by the commenters. Consequently, we believe that the use of the emissions limitation approach in this case is not appropriate.

Comment. The same commenters making the above comment further stated that if test data on actual emissions is used for determining the MACT floor for Pierce-Smith converters, then the average emissions limitation should be represented by the emissions data for the median performing source of the five best performing sources rather than the average of the emissions data for all five sources as was done for the proposed standard. In this case, the commenters claimed that the median technology for Pierce-Smith converters is the use of primary and secondary ventilation systems for the prevention and capture of emissions coupled with air pollution control devices for sulfur dioxide and particulate matter control. The commenters identified the controls used at the Hayden and Hidalgo smelters as the median technology for Pierce-Smith converters.

Response. We assessed how using the median technology approach would affect the selection of the MACT floor for Pierce-Smith converters. To do so, we evaluated each of the five smelters operating Pierce-Smith converters to determine the median performing source based on both performance data and engineering design. Using either approach, our assessment shows that the Chino Mines smelter is the median performing source of the five smelters that operate Pierce-Smith converters, not the Hayden or Hidalgo smelters as suggested by the commenters. In addition, the opacity value prescribed to the Chino Mines smelter is 3 percent, the same as the value we proposed for the opacity limit for Pierce-Smith converters based on averaging opacity data for all five sources.

To select the median technology based on source performance data, we ranked the converter capture systems used at the five smelters in order of decreasing performance using the average overall opacity value for each smelter. This ranking assumes that the average opacity value is indicative of the overall capture efficiency of the control system (i.e., the lower the opacity, the higher the capture efficiency). For our assessment, we used the overall average opacity values rounded to the next highest whole percent for the five smelters used for the MACT floor determination at proposal. The results of this ranking show that the

best performing source is the El Paso smelter (zero percent opacity) followed by, in decreasing order, the San Manuel smelter (1 percent opacity), the Chino Mines smelter (3 percent), the Hidalgo smelter (5 percent), and the Hayden smelter (8 percent opacity). The median performing smelter of the five smelters that operate Pierce-Smith converters is the third best performer, the Chino Mines smelter.

For the engineering design assessment, we first assembled pertinent information on the primary and secondary capture systems used at each of the five affected smelters. The information included hood ventilation rates (both primary and secondary), converter blowing rates (amount of air blown through the tuyeres into the molten bath), and detailed information on the design and physical configurations of each secondary hood.

Each of the five smelters uses the same basic approach to capturing emissions from their Pierce-Smith converter during slag and copper blows. Specifically, a retractable primary hood for capturing the voluminous process emissions generated during blowing and a fixed or sliding secondary hood for capturing the secondary or fugitive emissions that escape capture by the primary hood. Although the basic approach used at each smelter is fundamentally the same, there are, however, differences among the smelters in both the design and operation of their primary and secondary capture systems that affect performance.

The El Paso smelter uses a converter capture system design that is unique compared to the designs used at any of the other smelters. Instead of the fixed or sliding secondary hood designs used by other four smelters, each converter at the El Paso smelter is equipped with an air curtain secondary hood. The air curtain hood encloses the sides and back area around the converter mouth. During converter blowing operations, a horizontal jet of air flows across the open top of the enclosure to provide a continuous sheet or curtain of air that sweeps the process fugitive emissions into an exhaust hood, and subsequently a particulate control device. Capture efficiencies in excess of 90 percent are achieved using air curtain hood systems. Also at the El Paso smelter, any process fugitive emissions that escape capture by the air curtain hoods are further controlled by evacuating the entire converter building to a particulate control device. Thus, effectively 100 percent of the process fugitive emissions from converter operations at the El Paso smelter are captured. Clearly, the use of

air curtain secondary hoods in combination with a tertiary building evacuation system represents the best capture system technology used at any of the five smelters that operate Pierce-Smith converters.

We believe that the second best performer is the San Manuel smelter which relies primarily on primary hood ventilation to effect capture. The San Manuel smelter is unique in that it has surplus by-product acid plant capacity which allows each of the converter primary hoods to operate at a substantially higher ventilation rate than is usual for other smelters. The primary hoods at the San Manuel smelter are operated at a primary hood ventilation rate to converter blowing rate ratio of 3.8. In contrast, for the converter primary hoods at other smelters, the ratios range from 2.2 to 2.6. As evidenced by the building opacity data for the San Manuel smelter, operation of the primary hoods at a substantially higher ventilation rate results in enhanced capture efficiency and minimal fugitive emissions due to leakage about the primary hood.

Our assessment of the remaining three smelters supports our earlier finding using the performance data approach; the median or third best performing smelter is the Chino Mines smelter. All three smelters operate their primary hoods similarly and each converter is equipped with a secondary hood. Each of the secondary hoods are, with minor variations, similar in design. The principal difference is that the ventilation rate during converter blowing used for the secondary hoods at the Chino Mines smelter 120,000 standard cubic feet per minute (scfm) is approximately twice that used at the Hayden or Hidalgo smelters (50,000 scfm and 60,000 scfm, respectively). We believe that by operating at this substantially higher ventilation rate, the secondary hood system operated at the Chino Mines smelter is more effective at capturing the process fugitive emissions that escape from the converter primary hood during blowing compared to the secondary capture systems used at the other two smelters. It is, thus, our conclusion that the emissions capture system applied at the Chino Mines smelter is the third best among the five smelters that operate Pierce-Smith converters.

Regardless of whether we base our assessment of performance on average opacity or on engineering design, the smelter that uses the third best performing or median control technology is the Chino Mines smelter. If we had used the median technology approach at proposal to select the

opacity limit for smelters that operate Pierce-Smith converters, we would have selected 3 percent, the same value we proposed.

D. Why Did We Modify the Test Protocol Used To Determine Compliance with the Opacity Limits for Existing Copper Converter Departments?

We received no comments on the duration of the observation period needed to obtain the required number of acceptable opacity readings specified by the proposed test protocol for determining compliance with the opacity limits for existing copper converter departments. However, based on our experience using the protocol in the field and further analysis of the data that we collected using the protocol, we decided to revise the test protocol for the final rule with respect to how the opacity data are compiled and averaged in order to reduce the duration of the observation period needed to obtain the required number of acceptable opacity readings for a compliance determination.

The proposed test protocol specified making opacity readings using Method 9 over an observation period sufficient to obtain a minimum of 20 continuous 6-minute average opacity values during times when at least one converter is blowing and none of the specific visible emissions interferences listed in the test protocol has occurred. Our experience indicates that to obtain the minimum 20 continuous 6-minute averages required by the proposed test protocol, an observation period lasting 4 to 5 days or longer would be needed. This occurs for two reasons. First, Method 9 requires an observer when making opacity readings to be positioned with the sun to the observer's back and at a position from the source such that the observer's line-of-sight is approximately perpendicular to the longer axis of the converter building. This generally limits the window for observation at a smelter to 4 to 5 hours on any given day. Second, many of the continuous 6-minute periods are invalidated due to unavoidable, normal production events that occur inside the converter building that are unrelated to the converter blowing operations but also generate visible emissions. These visible emissions can potentially interfere with the visible emissions from the converter capture systems as seen by the outside observers. Because such interferences may misrepresent the actual performance of the converter capture system at a given smelter, the opacity readings made during these periods are invalidated and excluded from the compliance determination.

We have decided to revise the test protocol to allow for a shorter, more reasonable observation period to obtain the required number of acceptable opacity readings (i.e., opacity readings when there is at least one converter blowing without any visible emissions interferences). We are revising the test protocol to require averaging a minimum of 120 acceptable 1-minute average opacity values in place of the proposed 20 acceptable 6-minute average opacity values. Under the final test protocol, compliance will be demonstrated against the average opacity recorded for a minimum of 120 1-minute averages of eight readings per minute (a team of two opacity observers, each making four readings at 15-second intervals). This revision provides the same minimum number of opacity values for a performance test (a minimum total of 120 minutes of acceptable opacity readings) as the proposed procedure, without the additional restriction that the acceptable readings also must be made in continuous 6-minute blocks. With this change, smelter owners and operators should be able to obtain the required number of acceptable opacity readings in a more reasonable 1- to 2-day observation period.

E. How Did We Select the Final Opacity Limits for Existing Copper Converter Departments?

1. Pierce-Smith Converters

Because of our decision to change the test protocol to facilitate compliance determinations, we concluded that a reexamination of the proposed opacity limit for existing Pierce-Smith converters using the new protocol was warranted to determine whether using the protocol affected the proposed, and ultimately, the final opacity limit. As specified by the new protocol, we considered all 1-minute average opacity values recorded during the field observations when at least one converter was blowing, and there were no visible emissions interferences from other copper production activities or malfunctions inside the copper converter building. Consistent with the MACT floor approach we used at proposal, we based our selection of the MACT floor on the average of the test data for the five best performing sources (in this case, all five smelters in the source category that operate Pierce-Smith converters).

The field data considered at proposal and reexamined include a compilation of visible emission observations and process data gathered in the spring of 1997 at each of the smelters operating

Pierce-Smith or Hoboken converters. A description of the field data collection and analysis procedures used to compile the data is available in the preamble to the proposed rule (63 FR 19596). In general, a sufficient number of opacity observations were obtained during the site visits to compile a data base that included for each smelter a total of 400 to 500 minutes of 1-minute average opacity readings. Not included in these data are any opacity readings made at a smelter during periods when the converter operations were judged not to be representative of normal operations (e.g., during a converter capture system malfunction) or when the opacity observation conditions did not meet Method 9 criteria (e.g., improper sun angle).

For each smelter, we prepared a data summary that listed the average opacity values for only those 1-minute intervals during which at least one of the converters was blowing, and there were no visible emissions interferences as defined by the test protocol. For four of the smelters, there are a sufficient number of acceptable 1-minute intervals to simulate two performance tests as specified by the test protocol (the total number of acceptable 1-minute intervals can be divided into two blocks with at least 120 1-minute average opacity values in each block). For the fifth smelter, we have a total of 167 minutes of acceptable 1-minute average opacity values which we treated as a single performance test. The individual performance test results are presented in the BID.

Next, we calculated the average percent opacity for each performance test for a given smelter. Each of the calculated averages that includes a fraction of a percent opacity was then rounded up to the next whole number. For the smelters having two performance tests, we selected the higher of the two recorded values as the indicator of performance for the smelter. Following this procedure, the average opacity values for the five individual smelters are, in order of increasing value, zero percent, 1 percent, 3 percent, 5 percent, and 10 percent. The arithmetic average of these five opacity values is 3.8 percent which rounds to 4 percent opacity. Therefore, we selected the MACT floor for Pierce-Smith converters to be 4 percent opacity.

In response to comments received since proposal, we have evaluated two possible beyond-the-floor alternatives for the control of Pierce-Smith converters: Alternative 1—retrofit of air curtain secondary hoods on each converter at each affected smelter to complement the primary and secondary

capture systems; and Alternative 2—installation of a converter building evacuation system. Total annual costs to implement these options were estimated assuming that each of the five smelters with Pierce-Smith converters would be subject to the rule (i.e., each smelter is a major source of HAP emissions). Total capital costs for implementing Alternative 1 at the five smelters are estimated to be \$41 million. Implementing Alternative 1 is estimated to reduce HAP emissions beyond the floor by 29 tpy at a total annual cost of \$12 million per year or about \$430,000 per ton of HAP reduction. Total capital costs for implementing Alternative 2 at the five smelters are estimated to be \$93 million. Implementing Alternative 2 is estimated to reduce HAP emissions beyond the floor by 34 tpy at a total annual cost of \$32 million per year or about \$910,000 per ton of HAP reduction. Taking into consideration the costs of implementing either of the beyond-the-floor alternatives against the level of additional emission reduction estimated to be achieved, we concluded that neither of these beyond-the-floor alternatives is reasonable. Therefore, MACT for Pierce-Smith converters is 4 percent opacity, and we chose this value for the final standard.

2. Hoboken Converters

Comment. One commenter stated that the proposed opacity limit for existing Hoboken converters was based on a set of opacity readings that was too small to adequately reflect an achievable emission limit. Furthermore, the commenter stated that these data are not representative of normal operating conditions at the one existing smelter using Hoboken converters. The commenter submitted additional opacity data for the existing Hoboken converters. The commenter stated that these data were more representative of a two-converter operation which is typical at the smelter and requested that the data be used to recalculate the opacity limit.

Response. We examined the new data submitted by the commenter according to the revised test protocol. It is important to remember that the test protocol allows consideration of only those opacity readings that are taken during converter blowing and when no visible emissions interferences occur (as defined in the test protocol). Opacity readings during periods when visible emissions interferences occur are excluded from the calculation. Our analysis of the new data provided by the commenter yields an average opacity value of 3.8 percent which supports the

4 percent opacity limit proposed for Hoboken converters.

F. Why Did We Change the Compliance Date for Existing Sources?

Comment. Three commenters requested that the compliance date for existing sources be extended to the full 3 years allowed under the CAA. The commenters, all companies operating primary copper smelters potentially subject to the NESHAP, claimed that the control measures required to meet the requirements of the proposed rule cannot be readily implemented within the proposed 2-year period. The principal reason expressed by the commenters for extending the compliance period to 3 years is the rule will require smelters to plan and implement several significant changes, some of which cannot be completed within a 2-year period.

Response. Section 112(i)(3) of the CAA directs us to establish a compliance date for existing sources which provides for compliance with the applicable standards as expeditiously as practicable but no later than 3 years after the effective date of the standards. For the final rule, we reconsidered our proposed compliance date for existing sources subject to the primary copper smelter NESHAP. We expect that many of the existing sources that could be subject to the rule already have the type of controls in place that are needed to comply with the standards. However, we also recognize that the control systems for some existing sources subject to the rule will likely need to be upgraded to meet the standards. To allow smelter owners and operators a reasonable period of time to design, procure, install, and startup these control upgrades, we decided to establish the compliance date for existing sources under the final rule at no later than 3 years after promulgation.

G. Why Did We Change the Inspection and Monitoring Requirements?

1. Batch Converter Capture System Inspection Requirements

Comment: Three commenters stated that the requirement to inspect the batch converter capture systems on a monthly basis should be limited to those components of the converter capture system that are readily accessible during normal operations. The proposed requirement to visually inspect each month all of the capture system components is not practical, if not impossible to achieve. For example, the fan blade inspection that would be required under the proposed rule can only be performed when the fan housing

is opened, and operations must be shutdown to do this. Another example is the practicality of inspecting duct components that are covered with insulation.

Response. The intended purpose of the monthly inspection is to visually check the accessible components of the capture system for any defects or damage that could diminish or impair capture system performance from the level that the capture system is capable of achieving when it is properly operated and maintained. We also recognize that certain components of the capture system, such as the examples cited by the commenters, cannot be inspected by workers without shutdown of the process or disassembling components. It would be impractical to inspect these components on a monthly basis. In the final rule, we have revised the wording of the visual inspection requirement for capture systems to clarify which capture system components are to be inspected on a monthly basis. The final rule specifies that the owner or operator inspect those components of the capture system that can affect the performance of the system to collect the gases and fumes emitted from the affected source (e.g., hoods, exposed ductwork, dampers, pressure sensors, damper switches). During each inspection, the inspector must visually check the physical appearance of the equipment (e.g., presence of holes, dents, or other damage in hoods or ductwork) and check the settings for each damper and other devices which can be adjusted to control flow in the capture system.

2. Operating Limit for Baghouse Leak Detector Alarms

Comment. Six commenters objected to our proposed 5 percent limit on baghouse leak detector alarms during each 6-month reporting period. Reasons cited included: (1) The use of baghouse leak detectors for baghouses operated at copper smelters is unproven technology; (2) the selection of the proposed alarm time limit is arbitrary; (3) experience of commenters has shown that the detectors are subject to false alarms; (4) any limit on baghouse leak detector time should not include alarms during periods of startup, shutdown, or malfunction; and (5) what the EPA means by "initiation of corrective action" is not clear for the purpose of counting the elapsed alarm time.

Response. The use of baghouse leak detectors is a proven technology that can provide an effective means for early detection of bag failures allowing the baghouse operator to take timely action to correct the problem and minimize

excessive particulate matter emissions that would result if the problem was not promptly addressed. These detectors currently are used for baghouse applications at primary lead smelters and other metallurgical facilities with gas stream characteristics and operating conditions similar to those control situations at primary copper smelters for which an owner or operator also may choose to use a baghouse to comply with the rule requirements. We believe that there is no reason why baghouse leak detectors cannot similarly be used on baghouses at primary copper smelters.

The selection of the limit value for alarm time is not arbitrary. We selected this value based on our judgement of an upper limit to the number of alarms that can reasonably be expected to occur (excluding false alarms) over a 6-month period for a baghouse for which the owner or operator implements good inspection and maintenance practices.

We reviewed the proposed language for use of baghouse leak detectors with respect to concerns raised by the commenters about false alarms. For the final rule, we have revised the requirements for baghouse leak detectors to be consistent with the requirements we promulgated for the Primary Lead Smelting NESHAP under 40 CFR part 63, subpart TTT. These requirements include provisions which address the concerns raised by the commenters about counting false alarms and alarms during startup, shutdown, or malfunctions in the alarm time limit compliance calculation. Under the Primary Copper Smelting NESHAP, alarms are not included in the sum of alarm times for purposes of calculating the percentage of time the alarm on the bag leak detection system sounds if it is determined that an alarm sounds solely as the result of a malfunction of the bag leak detection system, or if the alarm sounds as result of a condition that is described in the smelter's startup, shutdown, and malfunction plan (SSMP) and the procedures in the plan described to respond to this condition are implemented.

Finally, when an alarm first sounds from the bag leak detector, we recognize that there are situations when the cause of the alarm cannot be corrected or fixed immediately or within a short period of a few hours. The correction of a torn bag or other problem which can trip the alarm may require that the baghouse be shutdown to allow facility personnel to enter the baghouse when it is safe to do so. We revised the language for the final rule to clarify that alarm time is counted as the time elapsed from when the alarm first sounds until the owner or operator

acknowledges the alarm and determines the cause of the alarm. Alarm time is not the total time until the problem which tripped the alarm is corrected.

H. Is the Kennecott Utah Copper Smelter a Major or Area Source of HAP Emissions?

Comment. We received two comments challenging our conclusions that the Kennecott Utah Copper Corporation smelter located near Garfield, Utah, does not emit HAP at major source levels and is, therefore, an area source. The Utah Department of Environmental Quality (DEQ) commented that the information that we used to characterize the emissions potential of the smelter is incorrect or outdated. Data in the smelter's emission inventory report for the year 1997 indicate that the smelter did emit and has the potential to emit HAP at major source levels. The Kennecott Utah Copper Corporation (hereafter referred to as "Kennecott"), owner and operator of the smelter, commented and acknowledged that the HAP emissions from its smelter in 1997 exceeded the major source threshold levels, but that the company planned to install new air pollution control equipment in the anode furnace and casting departments that will reduce HAP emissions, especially emissions of lead compounds, to well below major source levels.

Response. The proposed rule was developed before any HAP emissions data were available based on the fulltime operation of the Kennecott smelter. At the time, all the available evidence indicated that the smelter would not be a "major source" of HAP emissions because of the smelter's unique design and anticipated level of emission control.

In their comments on the proposed rule, the Utah DEQ presented HAP emissions data obtained in 1997, the first full year of operation of the new smelter. Contrary to the company's, the State's, and our expectations, total annual HAP emissions from the smelter in 1997 exceeded the major source threshold level. Specifically, lead emissions, the most prominent HAP emitted, were reported to exceed 23 tpy. This level is well above the 10 tpy single HAP threshold level for major sources and exceeds substantially the smelter's title V permitted lead emission rate of 1.3 pounds per hour, which is equivalent to about 6 tpy.

Extensive in-plant testing by Kennecott determined that the primary source of the excess lead emissions was the two anode furnaces used to refine the blister copper flowing from the flash converting furnace prior to anode

casting. At the time, the combined off-gas from both furnaces was treated in two high-energy wet scrubbers installed in series and designed to achieve both sulfur dioxide and particulate matter control. Testing of the anode furnace off-gas and the scrubber system outlet gas stream showed much higher levels of fine particulate and lead emissions than originally anticipated. Results of particle size measurements performed on the anode furnace off-gas indicated that more than half of the particulate matter was less than 1 micron in diameter with significant portions less than 0.3 microns.

During 1999 and 2000, Kennecott installed additional air pollution control equipment to better control the fine particulate and lead compounds in the anode furnace process off-gas. A quench tower, a lime injection system, and a baghouse were installed upstream of the two wet scrubbers. With the installation and startup of the new controls, the levels of fine particulate matter and HAP metal compounds emitted in the anode furnace off-gas have been significantly reduced. Based on results from a month-long test program conducted in January 2001, total annual lead emissions from the smelter were determined to be approximately 1.75 tpy, and the emissions of all metals to be approximately 2.6 tpy. These annual HAP emissions levels are well below the 10 tpy major source threshold level for a single HAP and 25 tpy major source threshold level for total HAP. Consequently, the smelter is no longer a major source of HAP emissions.

On February 15, 2001, Kennecott submitted to the Utah DEQ a notification of compliance with all title V operating permit limits and conditions including its lead limit of 1.3 pounds per hour. The requirements of the smelter's title V operating permit are federally enforceable, and both the State of Utah and the EPA have authority to take enforcement action should Kennecott fail to continue to operate the smelter in compliance with its permitted emission limits.

I. To What Extent Was the Kennecott Utah Copper Smelter Considered in the MACT Floor Determinations for New and Existing Sources?

Comment. Two commenters objected to the exclusion of the Kennecott smelter from the primary copper smelter source category definition and from consideration as part of the MACT floor determination for new and existing sources. Both commenters argued for a broader definition than that contained in the April 1998 proposal. They supported a definition similar to that

used in the new source performance standard (NSPS) and Inorganic Arsenic NESHAP that would include smelters using continuous flash converters like that used at the rebuilt Kennecott smelter. Both commenters also argued for the need to include the Kennecott smelter and its continuous flash converter in the MACT floor determination for the six smelters that employ the more conventional batch converters (Pierce-Smith and Hoboken). In addition, one of the commenters suggested that Kennecott's continuous flash converter should be considered the best controlled similar source and, thus, new source MACT for the primary copper smelting source category.

Response. At the time we initiated work on the NESHAP, the primary copper smelting source category was comprised of seven smelters, all of which were engaged in the production of anode copper from copper ore concentrates by first smelting the concentrates to obtain molten copper matte in a flash smelting furnace, and then converting the molten matte to blister copper using batch converters followed by fire refining and anode casting. Consequently, every smelter that potentially could be a major HAP source used either Pierce-Smith converters (five smelters) or Hoboken converters (one smelter).

In the intervening years, Kennecott shutdown its existing smelter at Garfield, Utah, that had used batch converters. The company built a new smelter at the same location that uses a flash smelting furnace similar to that used at the other smelters, and a new continuous flash converter. The Kennecott smelter is the only domestic smelter that does not use batch converters, either Pierce-Smith or Hoboken designs, to produce blister copper.

From the perspective of raw materials processed and final product shipped, a smelter using batch-converting technology and a smelter using continuous flash-converting technology would appear to be similar, both process copper sulfide ore concentrate and produce anode copper for shipment to an electrolytic refining facility. We agree that, in general, the overall function of both of these smelters is to produce anode copper from copper ore concentrates. However, there are significant dissimilarities between how the anode copper is produced at the smelter using continuous flash converters compared with the smelters using batch converters.

The use of a continuous flash converter allows blister copper to be produced in a continuous process at the

Kennecott smelter instead of a batch process as is required at the other smelters. At the Kennecott smelter, molten copper matte tapped from the continuous flash smelting furnace is first granulated by quenching with water to form solid granules of copper matte. These matte granules are then ground to a fine texture and fed to the continuous flash converter. Slag and blister copper produced are tapped from ports near the bottom of the furnace. Molten slag is transferred from the furnace to a slag hauler for subsequent disposal. Molten blister copper is transferred in heated launders directly to the anode furnace for further refining into anode copper.

Due to its unique design and operation, most of the process fugitive emission sources associated with smelters using batch converting are eliminated at the Kennecott smelter. There are no transfers of molten material in open ladles between the smelting, converting, and anode refining departments at the Kennecott smelter. In addition, there are no fugitive emissions associated with the repeated rolling-out of converters for charging, skimming, and pouring. Also, only one continuous flash converter is needed at the Kennecott smelter compared with the need for three or more batch copper converters at the other smelters.

Another difference between continuous flash converters versus batch converters is that blister copper produced by the continuous flash converter at the Kennecott smelter contains higher levels of residual sulfur and metal HAP impurities than levels seen in blister copper produced by batch converters. As a result, the anode furnace and casting departments at the Kennecott smelter use emission controls for sulfur dioxide and metal HAP emissions that are not needed at smelters using batch converters.

These differences aside, we have reconsidered whether the source category definition included in the April 1998 proposal should be broadened to include smelters using continuous flash-converting technology like the Kennecott smelter. We have concluded that the definition should be broadened and made consistent with that used to define primary copper smelters pursuant to both the primary copper smelter NSPS and Inorganic Arsenic NESHAP. We are changing the definition of primary copper smelters to mean "any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques."

Relative to the inclusion of the Kennecott smelter in the MACT floor determination, we disagree with the commenters that primary copper smelters using continuous flash converting should be grouped with primary copper smelters using batch converting for the existing source MACT floor determination. Section 112 of the CAA provides the Administrator the discretion to divide categories of sources into subcategories where appropriate. In establishing such subcategories for other source categories in the NESHAP program, we have considered factors such as differences in process operations (including differences between batch and continuous operation), emission characteristics, control device applicability, and opportunities for pollution prevention.

We believe that the design and operating differences between these two classes of copper converters make these sources so dissimilar with respect to HAP emission sources, level of HAP emissions, and the subsequent control measures required to control HAP emissions from these sources as to warrant the creation of two separate subcategories of primary copper smelters: primary copper smelters using batch converters, and primary copper smelters using continuous flash converters. Thus, we conclude that consideration of the Kennecott smelter in the MACT floor determinations for existing sources within the subcategory of primary copper smelters using batch converters is inappropriate since it is not among the pool of sources that comprises the subcategory.

Regarding the comment on new source MACT, we believe that there is merit to the commenter's position that for the purpose of selecting new source MACT for copper converter operations, the best controlled similar source uses flash converting. This is especially true considering our decision to change the source category definition to include all smelters engaged in the production of copper from copper sulfide ore concentrates regardless of the pyrometallurgical (smelting) techniques used. The practical effect of a decision to base new source MACT on flash converting would be a ban on the construction of a new converter department employing batch converters, which would lead to the virtual elimination of process fugitive emissions discharged from new copper converter departments. This would be best accomplished through a work practice standard that would expressly prohibit the construction of a new copper converter department employing

batch copper converters. Consequently, we have selected as the final standard a work practice standard that prohibits altogether the operation of batch copper converters at new copper converter departments. We believe that the impact of this decision on the industry is none, given both the availability of newer and cleaner converting technologies, and the rigor of the new source review permitting process to which a new source would be subject.

V. Administrative Requirements

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Executive Order defines "significant regulatory action" as one that is likely to result in a rule that may:

- (1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;
- (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligation of recipients thereof; or
- (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

It has been determined that this rule is not a "significant regulatory action" under the terms of Executive Order 12866, and is therefore not subject to OMB review.

B. Executive Order 13132, Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires the EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

Under Section 6 of Executive Order 13132, the EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or the EPA consults with State and local officials early in the process of developing the proposed regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. No State or local governments own or operate primary copper smelters. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

C. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that the EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5-501 of the Executive Order has the potential to influence the regulation. This rule is not subject to Executive Order 13045 because it is based on control technology performance and not on health or safety risks.

D. Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with

Indian Tribal Governments” (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure “meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.” “Policies that have tribal implications” is defined in the Executive Order to include regulations that have “substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.”

Under section 5(b) of Executive Order 13175, the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation. Under section 5(c) of Executive Order 13175, the EPA may not issue a regulation that has tribal implications and that preempts tribal law, unless the Agency consults with tribal officials early in the process of developing the proposed regulation.

This final rule does not significantly or uniquely affect the communities of Indian tribal governments. No tribal governments own or operate primary copper smelters. Accordingly, the requirements of Executive Order 13175 do not apply to this action.

E. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, the EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with “Federal mandates” that may result in expenditures to State, local, and tribal governments, in aggregate, or to the private sector, of \$100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires the EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least-costly, most cost-effective, or least-burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are

inconsistent with applicable law. Moreover, section 205 allows the EPA to adopt an alternative other than the least-costly, most cost-effective, or least-burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before the EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. In addition, the EPA has determined that this final rule contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments or impose obligations upon them. Therefore, today’s final rule is not subject to the requirements of section 203 of the UMRA.

F. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today’s rule on small entities, small entity is defined as: (1) A small business that is a business having less than 1,000 employees; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently

owned and operated and is not dominant in its field.

Based on the Small Business Administration’s NAICS-based size definitions and reported employment data for the affected companies, the Agency identified no small businesses in the Primary Copper Smelting and Refining industry (NAICS code 331411). After considering the economic impacts of today’s final rule on small entities, it has been determined that this action will not have a significant economic impact on a substantial number of small entities. All smelters potentially subject to the rule are owned by international corporations and employ more than 1,000 employees. This rule will not impose any requirements on small entities. No small businesses, small government jurisdictions, nor small organizations own or operate primary copper smelters potentially subject to the rule.

G. Paperwork Reduction Act

The information collection requirements in this final rule are being submitted for approval to OMB under the requirements of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* An information collection request (ICR) document has been prepared by EPA (ICR No. 1850.03), and a copy may be obtained from Sandy Farmer, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2137), 1200 Pennsylvania Avenue, NW., Washington, DC 20460, or by calling (202) 260-2740.

The information collection requirements in the final rule include mandatory notifications, records, and reports required by the NESHAP general provisions (40 CFR part 63, subpart A). These information requirements are needed to confirm the compliance status of major sources, to identify any nonmajor sources not subject to the standard and any new or reconstructed sources subject to the standards to confirm that emission control devices are being properly operated and maintained and to ensure that the standards are being achieved. Based on the recorded and reported information, the EPA can decide which facilities, records, or processes should be inspected. These recordkeeping and reporting requirements are specifically authorized under CAA section 114 (42 U.S.C. 7414). All information submitted to EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B.

The annual public reporting and recordkeeping burden for this collection

of information (averaged over the first 3 years after the effective date of this rule and assuming that all six smelters with batch converters are operating and subject to the rule) is estimated to total 20,500 labor hours per year at a total annual cost of \$923,800. This estimate includes initial notifications, preparation of a SSMP, preparation of a fugitive dust control plan, annual performance testing, semiannual compliance reports, and recordkeeping. Total capital costs associated with the monitoring equipment over the 3-year period of the ICR is estimated at \$276,000. The total annualized cost of the monitoring equipment is estimated at \$98,000. This estimate includes the capital, operating, and maintenance costs associated with the installation and operation of the monitoring equipment.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control number for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

H. National Technology Transfer and Advancement Act of 1995

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. No. 104-113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in their regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, or business practices) that are developed or adopted by voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency does not use available

and applicable voluntary consensus standards.

This rulemaking involves technical standards. The Agency conducted a search to identify potentially applicable voluntary consensus standards. However, we identified no such standards, and none were brought to our attention in comments. Therefore, we have decided to use EPA Reference Methods 1, 2, 3, 4, 5, 5B, and 29 of 40 CFR part 60, appendix A.

I. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

J. Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution or Use

This final rule is not subject to Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: May 15, 2002.

Christine Todd Whitman,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

2. Part 63 is amended by adding subpart QQQ to read as follows:

Subpart QQQ—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting

Sec.

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Subpart QQQ—National Emission Standards for Hazardous Air Pollutants for Primary Copper Smelting

What This Subpart Covers

§ 63.1440 What is the purpose of this subpart?

This subpart establishes national emission standards for hazardous air pollutants (NESHAP) for primary copper smelters. This subpart also establishes requirements to demonstrate initial and continuous compliance with all applicable emission limitations, work practice standards, and operation and maintenance requirements in this subpart.

§ 63.1441 Am I subject to this subpart?

You are subject to this subpart if you own or operate a primary copper smelter that is (or is part of) a major source of hazardous air pollutant (HAP) emissions on the first compliance date that applies to you, and your primary copper smelter uses batch copper converters as defined in § 63.1459. Your primary copper smelter is a major source of HAP if it emits or has the potential to emit any single HAP at the rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

§ 63.1442 What parts of my plant does this subpart cover?

(a) This subpart applies to each new and existing affected source at your primary copper smelter. The affected sources are each copper concentrate dryer, each smelting furnace, each slag cleaning vessel, each copper converter department, and the entire group of fugitive emission sources, as defined in § 63.1459.

(b) An affected source at your primary copper smelter is existing if you commenced construction or reconstruction of the affected source before April 20, 1998.

(c) An affected source at your primary copper smelter is new if you commenced construction or reconstruction of the affected source on or after April 20, 1998. An affected source is reconstructed if it meets the definition of "reconstruction" in § 63.2.

§ 63.1443 When do I have to comply with this subpart?

(a) If you have an existing affected source, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this

subpart that applies to you no later than June 13, 2005.

(b) If you have a new affected source and its initial startup date is on or before June 12, 2002, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you by June 12, 2002.

(c) If you have a new affected source and its initial startup date is after June 12, 2002, you must comply with each emission limitation, work practice standard, and operation and maintenance requirement in this subpart that applies to you upon initial startup.

(d) If your primary copper smelter is an area source that becomes a major source of HAP, the compliance dates listed in paragraphs (d)(1) and (2) of this section apply to you.

(1) Any portion of the existing primary copper smelter that is a new affected source or a new reconstructed source must be in compliance with this subpart upon startup.

(2) All other parts of the primary copper smelter must be in compliance with this subpart no later than 3 years after it becomes a major source.

(e) You must meet the notification and schedule requirements in § 63.1454. Several of these notifications must be submitted before the compliance date for your affected source.

Emission Limitations and Work Practice Standards

§ 63.1444 What emissions limitations and work practice standards must I meet for my copper concentrate dryers, smelting furnaces, slag cleaning vessels, and copper converter departments?

(a) *Copper concentrate dryers.* For each copper concentrate dryer, you must comply with the emission limitation in paragraph (a)(1) or (2) of this section that applies to you.

(1) For each existing copper concentrate dryer, you must not cause to be discharged to the atmosphere from the dryer vent any gases that contain total particulate matter in excess of 50 milligrams per dry standard cubic meter (mg/dscm) as measured using the test methods specified in § 63.1450(a).

(2) For each new copper concentrate dryer, you must not cause to be discharged to the atmosphere from the dryer vent any gases that contain total particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(b) *Smelting furnaces.* For each smelting furnace, you must comply with the emission limitations and work

practice standards in paragraphs (b)(1) and (2) of this section.

(1) For each smelting furnace, you must not cause to be discharged to the atmosphere any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b). Process off-gas from a smelting furnace is generated when copper ore concentrates and fluxes are being smelted to form molten copper matte and slag layers.

(2) For each smelting furnace, you must control the process fugitive emissions released when tapping copper matte or slag from the smelting furnace according to paragraphs (b)(2)(i) and (ii) of this section.

(i) At all times when copper matte or slag is tapped from the smelting furnace, you must operate a capture system that collects the gases and fumes released from the tapping port in use. The design and placement of this capture system must be such that the tapping port opening, launder, and receiving vessel (e.g., ladle, slag pot) are positioned within the confines or influence of the capture system's ventilation draft during those times when the copper matte or slag is flowing from the tapping port opening.

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (b)(2)(i) of this section any gases that contain total particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(c) *Slag cleaning vessels.* For each slag cleaning vessel, you must comply with the emission limitations and work practice standards in paragraphs (c)(1) through (3) of this section that apply to you.

(1) For each slag cleaning vessel, except as provided for in paragraph (c)(2) of this section, you must not cause to be discharged to the atmosphere any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b).

(2) As an alternative to complying with the emission limit for nonsulfuric acid particulate matter in paragraph (c)(1) of this section, for each existing slag cleaning vessel you may choose to comply with the emission limit for total particulate matter specified in this paragraph (c)(2). You must not cause to be discharged to the atmosphere any process off-gas that contains total particulate matter in excess of 46 mg/dscm as measured using the test methods specified in § 63.1450(a).

(3) For each slag cleaning vessel, you must control process fugitive emissions released when tapping copper matte or slag from the slag cleaning vessel according to paragraphs (c)(3)(i) and (ii) of this section.

(i) At all times when copper matte or slag is tapped from the slag cleaning vessel, you must operate a capture system that collects the gases and fumes released from the tapping port in use. The design and placement of this capture system must be such that the tapping port opening, launder, and receiving vessel (e.g., ladle, slag pot) are positioned within the confines or influence of the capture system's ventilation draft during those times when the copper matte or slag is flowing from the tapping port opening.

(ii) You must not cause to be discharged to the atmosphere from the capture system used to comply with paragraph (c)(3)(i) of this section any gases that contain total particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(d) *Existing copper converter departments.* For each existing copper converter department, you must comply with the emission limitations and work practice standards in paragraphs (d)(1) through (6) of this section that apply to you.

(1) You must operate a capture system that collects the process off gas vented from each batch copper converter. At all times when one or more batch copper converters are blowing, you must operate the capture system according to the written operation and maintenance plan that has been prepared according to the requirements in § 63.1447(b).

(2) If your copper converter department uses Pierce-Smith converters, the capture system design must include use of a primary hood that covers the entire mouth of the converter vessel when the copper converter is positioned for blowing. Additional hoods (e.g., secondary hoods) or other capture devices must be included in the capture system design as needed to achieve the opacity limit in paragraph (d)(4) of this section. The capture system design may use multiple intake and duct segments through which the ventilation rates are controlled independently of each other, and individual duct segments may be connected to separate control devices.

(3) If your copper converter department uses Hoboken converters, the capture system must collect all process off-gas vented during blowing through the side-flue intake on each converter vessel.

(4) You must operate the capture system such that any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department meet the opacity limit as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department must not exceed 4 percent as determined by a performance test conducted according to § 63.1450(c).

(ii) The opacity limit in paragraph (d)(4)(i) of this section applies only at those times when a performance test is conducted according to § 63.1450(c). The requirements for compliance with opacity and visible emission standards specified in § 63.6(h) do not apply to this opacity limit.

(5) You must not cause to be discharged to the atmosphere from any Pierce-Smith converter primary hood capture system or Hoboken converter side-flue intake capture system any process off-gas that contains nonsulfuric acid particulate matter in excess of 6.2 mg/dscm as measured using the test methods specified in § 63.1450(b).

(6) You must not cause to be discharged to the atmosphere from any secondary capture system any gases that contain total particulate matter in excess of 23 mg/dscm as measured using the test methods specified in § 63.1450(a).

(e) *New copper converter departments.* For each new copper converter department for which construction commenced on or after April 20, 1998, the use of batch copper converters is prohibited.

(f) *Baghouses.* For each baghouse applied to meet any total particulate matter emission limit in paragraphs (a) through (d) of this section, you must operate the baghouse such that the bag leak detection system does not alarm for more than 5 percent of the total operating time in any semiannual reporting period.

(g) *Venturi wet scrubbers.* For each venturi wet scrubber applied to meet any total particulate matter emission limit in paragraphs (a) through (d) of this section, you must maintain the hourly average pressure drop and scrubber water flow rate at or above the minimum levels established during the initial or subsequent performance test.

(h) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber applied to meet any total particulate matter emission limit in paragraphs (a) through (d) of this section, you must operate the control device as specified in paragraphs (h)(1) and (2) of this section.

(1) You must select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) You must maintain the hourly average value for each of the selected parameters at or above the minimum level or at or below the maximum level, as appropriate for the selected parameter, established during the initial or subsequent performance test.

§ 63.1445 What work practice standards must I meet for my fugitive dust sources?

(a) You must control particulate matter emissions from fugitive dust sources at your primary copper smelter by operating according to a written fugitive dust control plan that has been approved by the designated authority. For the purpose of complying with this paragraph (a) you may use an existing fugitive dust control plan provided that the plan complies with the requirements of this section. A fugitive dust control plan is considered to be approved if the plan has been incorporated in your applicable State implementation plan, and the document addresses the fugitive dust sources specified in paragraph (b) of this section and includes the information specified in paragraph (c) of this section.

(b) Your fugitive dust control plan must address each of the fugitive dust emission sources listed in paragraphs (b)(1) through (6) of this section that are located at your primary copper smelter.

(1) On-site roadways used by trucks or other motor vehicles (e.g., front-end loaders) when transporting bulk quantities of fugitive dust materials. Paved roads and parking areas that are not used by these vehicles do not need to be included in the plan (e.g., employee and visitor parking lots).

(2) Unloading of fugitive dust materials from trucks or railcars.

(3) Outdoor piles used for storage of fugitive dust materials.

(4) Bedding areas used for blending copper concentrate and other feed constituents.

(5) Each transfer point in conveying systems used to transport fugitive dust materials. These points include, but are not limited to, transfer of material from one conveyor belt to another and transfer of material to a hopper or bin.

(6) Other site-specific sources of fugitive dust emissions that the Administrator or delegated permitting authority designate to be included in your fugitive dust control plan.

(c) Your fugitive dust control plan must describe the control measures you use to control fugitive dust emissions

from each source addressed in the plan, as applicable and appropriate for your site conditions. Examples of control measures include, but are not limited to, locating the source inside a building or other enclosure, installing and operating a local hood capture system over the source and venting the captured gas stream to a control device, placing material stockpiles below grade, installing wind screens or wind fences around the source, spraying water on the source as weather conditions require, applying appropriate dust suppression agents on the source, or combinations of these control measures.

(d) The requirement for you to operate according to a written fugitive dust control plan must be incorporated in your operating permit that is issued by the designated permitting authority under part 70 of this chapter. A copy of your fugitive dust control plan must be sent to the designated permitting authority on or before the compliance date for your primary copper smelter, as specified in § 63.1443.

§ 63.1446 What alternative emission limitation may I meet for my combined gas streams?

(a) For situations where you combine gas streams from two or more affected sources for discharge to the atmosphere through a single vent, you may choose to meet the requirements in paragraph (b) of this section as an alternative to complying with the individual total particulate matter emission limits specified in § 63.1444 that apply to you. This alternative emission limit for a combined gas stream may be used for any combination of the affected source gas streams specified in paragraphs (a)(1) through (5) of this section.

(1) Gas stream discharged from a copper concentrate dryer vent that would otherwise be subject to § 63.1444(a)(1) or (2);

(2) Gas stream discharged from a smelting furnace capture system that would otherwise be subject to § 63.1444(b)(2)(ii);

(3) Process off-gas stream discharged from a slag cleaning vessel that would otherwise be subject to § 63.1444(c)(2);

(4) Gas stream discharged from a slag cleaning vessel capture system that would otherwise be subject to § 63.1444(c)(3)(ii); and

(5) Gas stream discharged from a batch copper converter secondary capture system that would otherwise be subject to § 63.1444(d)(5).

(b) You must meet the requirements specified in paragraphs (b)(1) and (2) of this section for the combined gas stream discharged through a single vent.

(1) For each combined gas stream discharged through a single vent, you must not cause to be discharged to the atmosphere any gases that contain total particulate matter in excess of the emission limit calculated using the procedure in paragraph (b)(2) of this section and measured using the test methods specified in § 63.1450(a).

(2) You must calculate the alternative total particulate matter emission limit for your combined gas stream using Equation 1 of this section. The volumetric flow rate value for each of the individual affected source gas streams that you use for Equation 1 (i.e., the flow rate of the gas stream discharged from the affected source but before this gas stream is combined with the other gas streams) is to be the average of the volumetric flow rates measured using the test method specified in § 63.1450(a)(1)(ii):

$$E_{Alt} = \frac{E_d Q_d + E_{sv} Q_{sv} + E_{scvp} Q_{scvp} + E_{scvf} Q_{scvf} + E_{cc} Q_{cc}}{Q_d + Q_{sv} + Q_{scvp} + Q_{scvf} + Q_{cc}} \quad (\text{Eq. 1})$$

Where

E_{Alt} = Alternative total particulate matter emission limit for the combined gas stream discharged to atmosphere through a single vent (mg/dscm);

E_d = Total particulate matter emission limit applicable to copper concentrate dryer as specified in § 63.1444(a)(1) or (2) (mg/dscm);

Q_d = Copper concentrate dryer exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm);

E_{sv} = Total particulate matter emission limit for smelting furnace capture system as specified in § 63.1444(b)(2)(ii) (mg/dscm);

Q_{sv} = Smelting furnace capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm);

E_{scvp} = Total particulate matter emission limit for slag cleaning vessel process off-gas as specified in § 63.1444(c)(2) (mg/dscm);

Q_{scvp} = Slag cleaning vessel process off-gas volumetric flow rate before being combined with other gas streams (dscm);

E_{scvf} = Total particulate matter emission limit for slag cleaning vessel capture system as specified in § 63.1444(c)(3)(ii) (mg/dscm);

Q_{scvf} = Slag cleaning vessel capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm);

E_{cc} = Total particulate emission limit for the batch copper converter secondary capture system as specified in § 63.1544(d)(5) (mg/dscm); and

Q_{cc} = Batch copper converter capture system exhaust gas stream volumetric flow rate before being combined with other gas streams (dscm).

(c) For each baghouse applied to meet any total particulate matter emission limit in paragraph (b) of this section, you must operate the baghouse such that the bag leak detection system does not alarm for more than 5 percent of the total operating time in any semiannual reporting period.

(d) For each venturi wet scrubber applied to meet any total particulate matter emission limit in paragraph (b) of

this section, you must maintain the hourly average pressure drop and scrubber water flow rate at or above the minimum levels established during the initial or subsequent performance test.

(e) For each control device other than a baghouse or venturi wet scrubber applied to meet any total particulate matter emission limit in paragraph (b) of this section, you must operate the control device as specified in paragraphs (e)(1) and (2) of this section.

(1) You must select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) You must maintain the hourly average value for each of the selected parameters at or above the minimum level or at or below the maximum level, as appropriate for the selected parameter, established during the initial or subsequent performance test.

Operation and Maintenance Requirements

§ 63.1447 What are my operation and maintenance requirements?

(a) As required by § 63.6(e)(1)(i), you must always operate and maintain your affected source, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by this subpart.

(b) You must prepare and operate at all times according to a written operation and maintenance plan for each capture system and control device subject to standards in § 63.1444 or § 63.1446. The plan must address the requirements in paragraphs (b)(1) through (3) of this section as applicable to the capture system or control device.

(1) *Preventative maintenance.* You must perform preventative maintenance for each capture system and control device according to written procedures specified in your operation and maintenance plan. The procedures must include a preventative maintenance schedule that is consistent with the manufacturer's instructions for routine and long-term maintenance.

(2) *Capture system inspections.* You must conduct monthly inspections of the equipment components of the capture system that can affect the performance of the system to collect the gases and fumes emitted from the affected source (e.g., hoods, exposed ductwork, dampers, fans) according to written procedures specified in your operation and maintenance plan. The inspection procedure must include the requirements in paragraphs (b)(2)(i) through (iii) of this section as applicable to the capture system or control device.

(i) Observations of the physical appearance of the equipment to confirm the physical integrity of the equipment (e.g., verify by visual inspection no holes in ductwork or hoods, no flow constrictions caused by dents, or accumulated dust in ductwork).

(ii) Inspection, and if necessary testing, of equipment components to confirm that the component is operating as intended (e.g., verify by appropriate measures that flow or pressure sensors, damper plates, automated damper switches and motors are operating according to manufacture or engineering design specifications).

(iii) In the event that a defective or damaged component is detected during an inspection, you must initiate corrective action according to written procedures specified in your operation and maintenance plan to correct the

defect or deficiency as soon as practicable.

(3) *Copper converter department capture system operating limits.* You must establish, according to the requirements in paragraph (b)(3)(i) through (iii) of this section, operating limits for the capture system that are representative and reliable indicators of the performance of capture system when it is used to collect the process off-gas vented from batch copper converters during blowing.

(i) Select operating limit parameters appropriate for the capture system design that are representative and reliable indicators of the performance of the capture system when it is used to collect the process off-gas vented from batch copper converters during blowing.

At a minimum, you must use appropriate operating limit parameters that indicate the level of the ventilation draft and the damper position settings for the capture system when operating to collect the process off-gas from the batch copper converters during blowing. Appropriate operating limit parameters for ventilation draft include, but are not limited to, volumetric flow rate through each separately ducted hood, total volumetric flow rate at the inlet to control device to which the capture system is vented, fan motor amperage, or static pressure. Any parameter for damper position setting may be used that indicates the duct damper position relative to the fully open setting.

(ii) For each operating limit parameter selected in paragraph (b)(3)(i) of this section, designate the value or setting for the parameter at which the capture system operates during batch copper converter blowing. If your blister copper production operations allow for more than one batch copper converter to be operating simultaneously in the blowing mode, designate the value or setting for the parameter at which the capture system operates during each possible batch copper converter blowing configuration that you may operate at your smelter (i.e., the operating limits with one converter blowing, with two converters blowing, with three converters blowing, as applicable to your smelter).

(iii) Include documentation in the plan to support your selection of the operating limits established for the capture system. This documentation must include a description of the capture system design, a description of the capture system operation during blister copper production, a description of each selected operating limit parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter

according to the requirements in § 63.1452(a), and the data used to set the value or setting for the parameter for each of your batch copper converter configurations.

(4) *Baghouse leak detection corrective actions.* In the event a bag leak detection system alarm is triggered, you must initiate corrective action according to written procedures specified in your operation and maintenance plan to determine the cause of the alarm within 1 hour of the alarm, initiate corrective action to correct the cause of the problem within 24 hours of the alarm, and complete the corrective action as soon as practicable. Corrective actions may include, but are not limited to, the activities listed in paragraphs (b)(3)(i) through (vi) of this section.

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in emissions.

(ii) Sealing off defective bags or filter media.

(iii) Replacing defective bags or filter media or otherwise repairing the control device.

(iv) Sealing off a defective baghouse compartment.

(v) Cleaning the bag leak detection system probe, or otherwise repair the bag leak detection system.

(vi) Shutting down the process producing the particulate emissions.

General Compliance Requirements

63.1448 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, work practice standards, and operation and maintenance requirements in this subpart at all times, except during periods of startup, shutdown, and malfunction as defined in § 63.2.

(b) During the period between the compliance date specified for your affected source in § 63.1443, and the date upon which continuous monitoring systems have been installed and certified and any applicable operating limits have been set, you must maintain a log detailing the operation and maintenance of the process and emissions control equipment.

(c) You must develop and implement a written startup, shutdown, and malfunction plan according to the provisions in § 63.6(e)(3).

Initial Compliance Requirements

§ 63.1449 By what dates must I conduct performance tests or other initial compliance demonstrations?

(a) As required in § 63.7(a)(2), you must conduct a performance test within

180 calendar days of the compliance date that is specified in § 63.1443 for your affected source to demonstrate initial compliance with each emission and opacity limit in § 63.1443 and § 63.1446 that applies to you.

(b) For each work practice standard and operation and maintenance requirement that applies to you where initial compliance is not demonstrated using a performance test or opacity observation, you must demonstrate initial compliance within 30 calendar days after the compliance date that is specified for your affected source in § 63.1443.

§ 63.1450 What test methods and other procedures must I use to demonstrate initial compliance with the emission limitations?

(a) *Total particulate matter emission limits.* You must conduct each performance test to determine compliance with the total particulate matter emission limits in § 63.1444 or § 63.1446 that apply to you according to the requirements for representative test conditions specified in § 63.7(e)(1) and using the test methods and procedures in paragraphs (a)(1) through (5) of this section.

(1) Determine the concentration of total particulate matter according to the test methods in appendix A to part 60 of this chapter as specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 5, 5D, or 17, as applicable, to determine the concentration of total particulate matter. You can also use ASTM D4536-96 incorporated by reference in § 63.14 as an alternative to the sampling equipment and operating procedures in Method 5 or 17 when testing a positive pressure baghouse, but you must use the sample traverse location and number of sampling points described in Method 5D.

(2) As an alternative to using the applicable method specified in paragraph (a)(1)(v) of this section, you may determine total particulate matter emissions from the control device using Method 29 in appendix A of part 60 of this chapter provided that you follow the procedures and precautions

prescribed in Method 29. If the control device is a positive pressure baghouse, you must also follow the measurement procedure specified in sections 4.1 through 4.3 of Method 5D.

(3) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 60 minutes and a minimum sampling volume of 0.85 dscm. For the purpose of determining compliance with the applicable total particulate matter emission limit, the arithmetic mean of the results for the three separate test runs is used.

(4) For a venturi wet scrubber applied to emissions from an affected source and subject to operating limits in § 63.1444(g) or § 63.1446(d) for pressure drop and scrubber water flow rate, you must establish site-specific operating limits according to the procedures in paragraph (a)(4)(i) and (ii) of this section.

(i) Using the continuous parameter monitoring system (CPMS) required in § 63.1452, measure and record the pressure drop and scrubber water flow rate during each run of the particulate matter performance test.

(ii) Compute and record the hourly average pressure drop and scrubber water flow rate for each individual test run. Your operating limits are the lowest average pressure drop and scrubber water flow rate value in any of the three runs that meet the applicable emission limit.

(5) For a control device other than a baghouse or venturi wet scrubber applied to emissions from an affected source and subject to site-specific operating limit(s) in § 63.1444(h) or § 63.1446(e) for appropriate, site-specific operating parameters that are representative and reliable indicators of the control device performance, you must establish a site-specific operating limit(s) according to the procedures in paragraph (a)(5)(i) through (iv) of this section.

(i) Select one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(ii) Using the CPMS required in § 63.1452, measure and record the selected operating parameters for the control device during each run of the total particulate matter performance test.

(iii) Compute and record the hourly average value for each of the selected operating parameters for each individual test run. Your operating limits are the lowest value or the highest value, as appropriate for the selected operating parameter, measured in any of

the three runs that meet the applicable emission limit.

(iv) You must prepare written documentation to support your selection of the operating parameters used for the control device. This documentation must include a description of each selected parameter, a rationale for why you chose the parameter, a description of the method used to monitor the parameter, and the data recorded during the performance test and used to set the operating limit(s).

(b) *Nonsulfuric acid particulate matter emission limits.* You must conduct each performance test to determine compliance with the nonsulfuric acid particulate matter emission limits in § 63.1444 that apply to you according to the requirements for representative test conditions specified in § 63.7(e)(1) and using the test methods and procedures in paragraphs (b)(1) and (2) of this section.

(1) Determine the concentration of nonsulfuric acid particulate matter according to the test methods in appendix A to part 60 of this chapter as specified in paragraphs (b)(1)(i) through (v) of this section.

(i) Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

(ii) Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

(iii) Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

(iv) Method 4 to determine the moisture content of the stack gas.

(v) Method 5B to determine the nonsulfuric acid particulate matter emissions.

(2) You must conduct three separate test runs for each performance test. Each test run must have a minimum sampling time of 240 minutes and a minimum sampling volume of 3.4 dscm. For the purpose of determining compliance with the nonsulfuric acid particulate matter emission limit, the arithmetic mean of the results for the three separate test runs is used.

(c) *Copper converter department capture system opacity limit.* You must conduct each performance test to determine compliance with the opacity limit in § 63.1444 using the test methods and procedures in paragraphs (c)(1) through (9) of this section.

(1) You must conduct the performance test during the period when the primary copper smelter is operating under conditions representative of the smelter's normal blister copper production rate. You may

not conduct a performance test during periods of startup, shutdown, or malfunction. Before conducting the performance test, you must prepare a written test plan specifying the copper production conditions to be maintained throughout the opacity observation period and including a copy of the written documentation you have prepared according to paragraph (a)(3) of this section to support the established operating limits for the copper converter department capture system. You must submit a copy of the test plan for review and approval by the Administrator or delegated authority. During the observation period, you must collect appropriate process information and copper converter department capture system operating information to prepare documentation sufficient to verify that all opacity observations were made during the copper production and capture system operating conditions specified in the approved test plan.

(2) You must notify the Administrator or delegated authority before conducting the opacity observations to allow the Administrator or delegated authority the opportunity to have authorized representatives attend the test. Written notification of the location and scheduled date for conducting the opacity observations must be received by the Administrator on or before 30 calendar days before this scheduled date.

(3) You must gather the data needed for determining compliance with the opacity limit using qualified visible emission observers and process monitors as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) Opacity observations must be performed by a sufficient number of qualified visible emission observers to obtain two complete concurrent sets of opacity readings for the required observation period. Each visible emission observer must be certified as a qualified observer by the procedure specified in section 3 of Method 9 in appendix A of part 60 of this chapter. The entire set of readings during the required observation period does not need to be made by the same two observers. More than two observers may be used to allow for substitutions and provide for observer rest breaks. The owner or operator must obtain proof of current visible emission reading certification for each observer.

(ii) A person (or persons) familiar with the copper production operations conducted at the smelter must serve as the indoor process monitor. The indoor process monitor is stationed at a location inside the building housing the batch copper converters such that he or

she can visually observe and record operations that occur in the batch copper converter aisle during the times that the visible emission observers are making opacity readings. More than one indoor process monitor may be used to allow for substitutions and provide for rest breaks.

(4) You must make all opacity observations using Method 9 in appendix A to part 60 of this chapter and following the procedures described in paragraphs (c)(4)(i) and (ii) of this section.

(i) Each visible emission observer must make his or her readings at a position from the outside of the building that houses the copper converter department such that the observer's line-of-sight is approximately perpendicular to the longer axis of the converter building, and the observer has an unobstructed view of the building roof monitor sections or roof exhaust fan outlets that are positioned over each of the batch copper converters inside the building. Opacity readings can only be made during those times when the observer's position meets the sun orientation and other conditions specified in section 2.1 of Method 9.

(ii) At 15-second intervals, each visible emission observer views the building roof monitor sections or roof exhaust fan outlets that are positioned over each of the batch copper converters inside the building and reads the opacity of the visible plumes. If no plume is visible, the observer records zero as the opacity value for the 15-second interval. In situations when it is possible for an observer to distinguish two or more visible emission plumes from the building roof monitor sections or roof exhaust fan outlets, the observer must identify, to the extent feasible, the plume having the highest opacity and record his or her opacity reading for that plume as the opacity value for the 15-second interval.

(5) You must make opacity observations for a period of sufficient duration to obtain a minimum of 120 1-minute intervals during which at least one copper converter is blowing and no interferences have occurred from other copper production events, as specified in paragraph (c)(7) of this section, which generate visible emissions inside the building that potentially can interfere with the visible emissions from the converter capture systems as seen by the outside observers. To obtain the required number of 1-minute intervals, the observation period may be divided into two or more segments performed on the same day or on different days if conditions prevent the required number of opacity readings from being obtained

during one continuous time period. Examples of these conditions include, but are not limited to, changes in the sun's orientation relative to visible emission observers' positions such that the Method 9 conditions are no longer met or an unexpected thunder storm. If the total observation period is divided into two or more segments, all opacity observations must be made during the same set of copper production conditions described in your approved test plan as required by paragraph (c)(1) of this section.

(6) You must gather indoor process information during all times that the visible emission observers are making opacity readings outside the building housing the copper converter department. The indoor process monitor must continually observe the operations occurring in the copper converter department and prepare a written record of his or her observations using the procedure specified in paragraphs (c)(6)(i) through (iv) of this section.

(i) At the beginning of each observation period or segment, the clock time setting on the watch or clock to be used by the indoor process monitor must be synchronized with the clock time settings for the timepieces to be used by the outdoor opacity observers.

(ii) During each period or segment when opacity readings are being made by the visible emission observers, the indoor process monitor must continuously observe the operations occurring in the copper converter department and record his or her observations in a log book, on data sheets, or other type of permanent written format.

(iii) When a batch copper converter is blowing, a record must be prepared for the converter that includes, but is not limited to, the clock times for when blowing begins and when blowing ends and the converter blowing rate. This information may be recorded by the indoor process monitor or by a separate, automated computer data system.

(iv) The process monitor must record each event other than converter blowing that occurs in or nearby the converter aisle that he or she observes to generate visible emissions inside the building. The recorded entry for each event must include, but is not limited to, a description of the event and the clock times when the event begins and when the event ends.

(7) You must prepare a summary of the data for the entire observation period using the information recorded during the observation period by the outdoor visible emission observers and the indoor process monitor and the

procedure specified in paragraphs (c)(7)(i) through (iv) of this section.

(i) Using the field data sheets, identify the 1-minute clock times for which a total of eight opacity readings were made and recorded by both observers at 15-second intervals according to the test procedures (i.e., a total of four opacity values have been recorded for the 1-minute interval by each of the two observers). Calculate the average of the eight 15-second interval readings recorded on the field data sheets by the two observers during the clock time minute interval (add the four consecutive 15-second interval opacity readings made by Observer A during the specified clock time minute, plus the four consecutive 15-second interval opacity readings made by Observer B during the same clock time minute, and divide the resulting total by eight). Record the clock time and the opacity average for the 1-minute interval on a data summary sheet. Figure 1 of this subpart shows an example of the format for the data summary sheet you may use, but are not required to use.

(ii) Using the data summary sheets prepared according to paragraph (c)(7)(i) of this section and the process information recorded according to paragraph (c)(6)(iii) of this section, identify those 1-minute intervals for which at least one of the batch copper converters was blowing.

(iii) Using the data summary sheets prepared according to paragraph (c)(7)(ii) of this section and the process information recorded according to paragraph (c)(6)(iv) of this section, identify the 1-minute intervals during which at least one copper converter was blowing but none of the interference events listed in paragraphs (c)(7)(iii)(A) through (F) of this section occurred. Other ancillary activities not listed but conducted in or adjacent to the converter aisle during the opacity observations are not considered to be interference events (e.g., converter aisle cleaning, placement of smoking ladles or skulls on the converter aisle floor).

(A) Charging of copper matte, reverts, or other materials to a batch copper converter;

(B) Skimming slag or other molten materials from a batch copper converter;

(C) Pouring of blister copper or other molten materials from a batch copper converter;

(D) Return of slag or other molten materials to the flash smelting furnace or slag cleaning vessel;

(E) Roll-out or roll-in of the batch copper converter; or

(F) Smoke and fumes generated inside the converter building by operation of the smelting furnace, the slag cleaning

vessel (if used), anode refining and casting processes that drift into the copper converter department.

(iv) Using the data summary sheets prepared according to paragraph (c)(7)(iii) of this section, up to five 1-minute intervals following an interference event may be eliminated from data used for the compliance determination calculation specified in paragraph (c)(8) of this section by applying a time delay factor. The time delay factor must be a constant number of minutes not to exceed 5 minutes that is added to the clock time recorded when cessation of the interference event occurs. The same time delay factor must be used for all interference events (i.e., a constant time delay factor for the smelter of 1 minute, 2 minutes, 3 minutes, 4 minutes, or 5 minutes). The number of minutes to be used for the time delay factor is determined based on the site-specific equipment and converter building configuration. An explanation of the rationale for selecting the value used for the time delay factor must be prepared and included in the test report.

(8) You must use the data summary prepared in paragraph (c)(7) of this section to calculate the average opacity value for a minimum of 120 1-minute intervals during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section. Average opacity is calculated using Equation 1 of this section:

$$VE_{ave} = \frac{1}{n} \sum_{i=1}^n VE_i \quad (\text{Eq. 1})$$

Where

VE_{ave} = Average opacity to be used for compliance determination (percent);

n = Total number of 1-minute intervals during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section (at least 120 1-minute intervals);

i = 1-minute interval "i" during which at least one copper converter was blowing with no interference events as determined according to paragraphs (c)(7)(iii) and (iv) of this section; and

VE_i = Average opacity value calculated for the eight opacity readings recorded during 1-minute interval "i" (percent).

(9) You must certify that the copper converter department capture system operated during the performance test at the operating limits established in your

capture system operation and maintenance plan using the procedure specified in paragraphs (c)(9)(i) through (iv) of this section.

(i) Concurrent with all opacity observations, measure and record values for each of the operating limit parameters in your capture system operation and maintenance plan according to the monitoring requirements specified in § 63.1452(a).

(ii) For any dampers that are manually set and remain in the same position at all times the capture system is operating, the damper position must be visually checked and recorded at the beginning and end of each opacity observation period segment.

(iii) Review the recorded monitoring data. Identify and explain any times during batch copper converter blowing when the capture system operated outside the applicable operating limits.

(iv) Certify in your performance test report that during all observation period segments, the copper converter department capture system was operating at the values or settings established in your capture system operation and maintenance plan.

§ 63.1451 How do I demonstrate initial compliance with the emission limitations, work practice standards, and operation and maintenance requirements that apply to me?

(a) *Total particulate matter emission limits.* For each copper concentrate dryer, smelting furnace, slag cleaning vessel, and copper converter department subject to a total particulate matter emission limits in § 63.1444 or § 63.1446 that applies to you, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (a)(1) and (2) of this section.

(1) The average concentration of total particulate matter from a control device applied to emissions from the affected source, measured according to the performance test procedures in § 63.1450(a), did not exceed the applicable emission limit.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e).

(b) *Nonsulfuric acid particulate matter emissions limits.* For each smelting furnace, slag cleaning vessel, and copper converter departments subject to the nonsulfuric acid particulate matter emissions limit in § 63.1444 as applies to you, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (b)(1) and (2) of this section.

(1) The average concentration of nonsulfuric acid particulate matter in the process off-gas discharged from the

affected source, measured according to the performance test procedures in § 63.1450(b), did not exceed 6.2 mg/dscm.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e).

(c) For each existing copper converter department subject to the opacity limit in § 63.1444, you have demonstrated initial compliance if you meet both of the conditions in paragraphs (c)(1) and (2) of this section.

(1) The opacity of visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department measured according to the performance test procedures in § 63.1450(c), did not exceed 4 percent opacity.

(2) You have submitted a notification of compliance status according to the requirements in § 63.1454(e).

(d) *Copper converter department capture systems.* You have demonstrated initial compliance of the copper converter department capture system if you meet all of the conditions in paragraphs (d)(1) through (4) of this section.

(1) Prepared the capture system operation and maintenance plan according to the requirements of paragraph (a) of this section;

(2) Conducted an initial performance test according to the procedures of § 63.1450(c) demonstrating the opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department does not exceed 4 percent opacity;

(3) Included in your notification of compliance status a copy of your written capture system operation and maintenance plan and have certified in your notification of compliance status that you will operate the copper converter department capture system at all times during blowing at the values or settings established for the operating limits in that plan; and

(4) Submitted a notification of compliance status according to the requirements in § 63.1454(e).

(e) *Baghouses.* For each baghouse subject to operating limits in § 63.1444(f) or § 63.1446(c), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (e)(1) through (3) of this section.

(1) You have included in your written operation and maintenance plan required under § 63.1447(b) detailed descriptions of the procedures you use for inspection, maintenance, bag leak detection, and corrective action for the baghouse.

(2) You have certified in your notification of compliance status that you will operate the baghouse according to your written operation and maintenance plan.

(3) You have submitted the notification of compliance status according to the requirements in § 63.1454(e).

(f) *Venturi wet scrubbers.* For each venturi wet scrubber subject to operating limits in § 63.1444(g) or § 63.1446(d), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (f)(1) through (3) of this section.

(1) Established site-specific operating limits for pressure drop and scrubber water flow rate and have a record of the pressure drop and scrubber water flow rate measured during the performance test you conduct to demonstrate initial compliance with paragraph (a) of this section.

(2) Certified in your notification of compliance status that you will operate the venturi wet scrubber within the established operating limits for pressure drop and scrubber water flow rate.

(3) Submitted a notification of compliance status according to the requirements in § 63.1454(e).

(g) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber subject to operating limits in § 63.1444(h) or § 63.1446(e), you have demonstrated initial compliance if you meet all of the conditions in paragraphs (g)(1) through (4) of this section.

(1) Selected one or more operating parameters, as appropriate for the control device design, that can be used as representative and reliable indicators of the control device operation.

(2) Established site-specific operating limits for each of the selected operating parameters based on values measured during the performance test you conduct to demonstrate initial compliance with paragraph (a) of this section and have prepared written documentation according to the requirements in § 63.1450(a)(5)(iv).

(3) Included in your notification of compliance status a copy of the written documentation you have prepared to demonstrate compliance with paragraph (g)(2) of this section and have certified in your notification of compliance status that you will operate the control device within the established operating limits.

(4) Submitted a notification of compliance status according to the requirements in § 63.1454(e).

(h) *Fugitive dust sources.* For all fugitive dust sources subject to work practice standards in § 63.1445, you have demonstrated initial compliance if

you meet all of the conditions in paragraphs (i)(1) through (3) of this section.

(1) Prepared a written fugitive dust control plan according to the requirements in § 63.1454 and it has been approved by the designated authority.

(2) Certified in your notification of compliance status that you will control emissions from the fugitive dust sources according to the procedures in the approved plan.

(3) Submitted the notification of compliance status according to the requirements in § 63.1454(e).

(i) *Operation and maintenance requirements.* You have demonstrated initial compliance with the operation and maintenance requirements that apply to you if you meet all of the conditions in paragraphs (i)(1) through (3) of this section.

(1) Prepared an operation and maintenance plan according to the requirements in § 63.1454(b).

(2) Certified in your notification of compliance status that you will operate each capture system and control device according to the procedures in the plan.

(3) Submitted the notification of compliance status according to the requirements in § 63.1454(e).

Continuous Compliance Requirements

§ 63.1452 What are my monitoring requirements?

(a) *Copper converter department capture systems.* For each operating limit established under your capture system operation and maintenance plan, you must install, operate, and maintain an appropriate monitoring device according to the requirements in paragraphs (a)(1) through (6) of this section to measure and record the operating limit value or setting at all times the copper converter department capture system is operating during batch copper converter blowing. Dampers that are manually set and remain in the same position at all times the capture system is operating are exempted from the requirements of this paragraph (a).

(1) Install the monitoring device, associated sensor(s), and recording equipment according to the manufacturers' specifications. Locate the sensor(s) used for monitoring in or as close to a position that provides a representative measurement of the parameter being monitored.

(2) If a flow measurement device is used to monitor the operating limit parameter, you must meet the requirements in paragraph (a)(2)(i) through (iv) of this section.

(i) Locate the flow sensor and other necessary equipment such as

straightening vanes in a position that provides a representative flow.

(ii) Use a flow sensor with a minimum tolerance of 2 percent of the flow rate.

(iii) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(iv) Conduct a flow sensor calibration check at least semiannually.

(3) If a pressure measurement device is used to monitor the operating limit parameter, you must meet the requirements in paragraph (a)(3)(i) through (v) of this section.

(i) Locate the pressure sensor(s) in or as close to a position that provides a representative measurement of the pressure.

(ii) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(iii) Use a gauge with a minimum tolerance of 0.5 inch of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(iv) Check pressure tap pluggage daily.

(v) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(4) Conduct calibration and validation checks any time the sensor exceeds the manufacturer's specifications or you install a new sensor.

(5) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(6) Record the results of each inspection, calibration, and validation check.

(b) *Baghouses.* For each baghouse subject to the operating limit in § 63.1444(f) or § 63.1446(c) for the bag leak detection system alarm, you must at all times monitor the relative change in particulate matter loadings using a bag leak detection system according to the requirements in paragraph (b)(1) of this section and conduct regular inspections according to the requirements in paragraph (b)(2) of this section.

(1) You must install, operate, and maintain each bag leak detection system according to the requirements in paragraphs (b)(1)(i) through (vii) of this section.

(i) The system must be certified by the manufacturer to be capable of detecting emissions of particulate matter at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

(ii) The system must provide output of relative changes in particulate matter loadings.

(iii) The system must be equipped with an alarm that will sound when an

increase in relative particulate loadings is detected over a preset level. The alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) Each system that works based on the triboelectric effect must be installed, operated, and maintained in a manner consistent with the guidance document, "Fabric Filter Bag Leak Detection Guidance," EPA-454/R-98-015, September 1997. You may obtain a copy of this guidance document by contacting the National Technical Information Service (NTIS) at 800-553-6847. You may install, operate, and maintain other types of bag leak detection systems in a manner consistent with the manufacturer's written specifications and recommendations.

(v) To make the initial adjustment of the system, establish the baseline output by adjusting the sensitivity (range) and the averaging period of the device. Then, establish the alarm set points and the alarm delay time.

(vi) Following the initial adjustment, do not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in your operation and maintenance plan. Do not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless a responsible official certifies, in writing, that the baghouse has been inspected and found to be in good operating condition.

(vii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) You must conduct baghouse inspections at their specified frequencies according to the requirements in paragraphs (b)(2)(i) through (viii) of this section.

(i) Monitor the pressure drop across each baghouse cell each day to ensure pressure drop is within the normal operating range identified in the manual.

(ii) Confirm that dust is being removed from hoppers through weekly visual inspections or other means of ensuring the proper functioning of removal mechanisms.

(iii) Check the compressed air supply for pulse-jet baghouses each day.

(iv) Monitor cleaning cycles to ensure proper operation using an appropriate methodology.

(v) Check bag cleaning mechanisms for proper functioning through monthly visual inspection or equivalent means.

(vi) Make monthly visual checks of bag tension on reverse air and shaker-type baghouses to ensure that bags are not kinked (knead or bent) or laying on

their sides. You do not have to make this check for shaker-type baghouses using self-tensioning (spring-loaded) devices.

(vii) Confirm the physical integrity of the baghouse through quarterly visual inspections of the baghouse interior for air leaks.

(viii) Inspect fans for wear, material buildup, and corrosion through quarterly visual inspections, vibration detectors, or equivalent means.

(c) *Venturi wet scrubbers.* For each venturi wet scrubber subject to the operating limits for pressure drop and scrubber water flow rate in § 63.1444(g) or § 63.1446(d), you must at all times monitor the hourly average pressure drop and water flow rate using a CPMS. You must install, operate, and maintain each CPMS according to the requirements in paragraphs (c)(1) and (2) of this section.

(1) For the pressure drop CPMS, you must meet the requirements in paragraphs (c)(1)(i) through (vi) of this section.

(i) Locate the pressure sensor(s) in or as close to a position that provides a representative measurement of the pressure and that minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

(ii) Use a gauge with a minimum measurement sensitivity of 0.5 inch of water or a transducer with a minimum measurement sensitivity of 1 percent of the pressure range.

(iii) Check the pressure tap for pluggage daily.

(iv) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(v) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range, or install a new pressure sensor.

(vi) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(2) For the scrubber water flow rate CPMS, you must meet the requirements in paragraphs (c)(2)(i) through (iv) of this section.

(i) Locate the flow sensor and other necessary equipment in a position that provides a representative flow and that reduces swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(ii) Use a flow sensor with a minimum measurement sensitivity of 2 percent of the flow rate.

(iii) Conduct a flow sensor calibration check at least semiannually according to the manufacturer's instructions.

(iv) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(d) *Other control devices.* For each control device other than a baghouse or venturi wet scrubber subject to the operating limits for appropriate parameters in § 63.1444(h) or § 63.1446(e), you must at all times monitor the hourly average pressure drop and water flow rate using a CPMS. You must install, operate, and maintain each CPMS according to the equipment manufacturer's specifications and the requirements in paragraphs (d)(1) through (5) of this section.

(1) Locate the sensor(s) used for monitoring in or as close to a position that provides a representative measurement of the parameter being monitored.

(2) Determine the hourly average of all recorded readings.

(3) Conduct calibration and validation checks any time the sensor exceeds the manufacturer's specifications or you install a new sensor.

(4) At least monthly, inspect all components for integrity, all electrical connections for continuity, and all mechanical connections for leakage.

(5) Record the results of each inspection, calibration, and validation check.

(e) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times an affected source is operating.

(f) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels or to fulfill a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing compliance.

(g) A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitor to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

§ 63.1453 How do I demonstrate continuous compliance with the emission limitations, work practice standards, and operation and maintenance requirements that apply to me?

(a) *Particulate matter emission limits.* For each affected source subject to a

particulate matter emission limit § 63.1444 or § 63.1446 as applies to you, you must demonstrate continuous compliance according to the requirements in paragraphs (a)(1) and (2) of this section.

(1) For each copper concentrate dryer, smelting furnace, slag cleaning vessel, and copper converter department subject to a total particulate matter emission limit in § 63.1444 or § 63.1446 as applies to you, you must demonstrate continuous compliance by meeting the conditions in paragraphs (a)(1)(i) and (ii) of this section.

(i) Maintain the average concentration of total particulate matter in the gases discharged from the affected source at or below the applicable emission limit.

(ii) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(a).

(2) For each smelting furnace, slag cleaning vessel, and copper converter department subject to the nonsulfuric acid particulate matter emission limit in § 63.1444 as applies to you, you must demonstrate continuous compliance by meeting the conditions in paragraphs (a)(2)(i) and (ii) of this section.

(i) Maintain the average concentration of nonsulfuric acid particulate matter in the process off-gas discharged from the affected source at or below 6.2 mg/dscm.

(ii) Conduct subsequent performance tests following your initial performance test no less frequently than once per year according to the performance test procedures in § 63.1450(b).

(b) *Copper converter department capture systems.* You must demonstrate continuous compliance of the copper converter department capture system by meeting the requirements in paragraphs (b)(1) through (4) of this section.

(1) Operate the copper converter department capture system at all times during blowing at or above the lowest values or settings established for the operating limits and demonstrated to achieve the opacity limit according to the applicable requirements of this subpart;

(2) Inspect and maintain the copper converter department capture system according to the applicable requirements in § 63.1447 and recording all information needed to document conformance with these requirements;

(3) Monitor the copper converter department capture system according to the requirements in § 63.1452(a) and collecting, reducing, and recording the monitoring data for each of the operating limit parameters according to

the applicable requirements of this subpart; and

(4) Conduct subsequent performance tests according to the requirements of § 63.1450(c) following your initial performance test no less frequently than once per year to demonstrate that the opacity of any visible emissions exiting the roof monitors or roof exhaust fans on the building housing the copper converter department does not exceed 4 percent opacity.

(c) *Baghouses.* For each baghouse subject to the operating limit for the bag leak detection system alarm in § 63.1444(f) or § 63.1446(c), you must demonstrate continuous compliance by meeting the requirements in paragraphs (c)(1) through (3) of this section.

(1) Maintain the baghouse such that the bag leak detection system alarm does not sound for more than 5 percent of the operating time during any semiannual reporting period. To determine the percent of time the alarm sounded use the procedures in paragraphs (c)(1)(i) through (v) of this section.

(i) Alarms that occur due solely to a malfunction of the bag leak detection system are not included in the calculation.

(ii) Alarms that occur during startup, shutdown, or malfunction are not included in the calculation if the condition is described in the startup, shutdown, and malfunction plan, and all the actions you took during the startup, shutdown, or malfunction were consistent with the procedures in the startup, shutdown, and malfunction plan.

(iii) Count 1 hour of alarm time for each alarm when you initiated procedures to determine the cause of the alarm within 1 hour.

(iv) Count the actual amount of time you took to initiate procedures to determine the cause of the alarm if you did not initiate procedures to determine the cause of the alarm within 1 hour of the alarm.

(v) Calculate the percentage of time the alarm on the bag leak detection system sounds as the ratio of the sum of alarm times to the total operating time multiplied by 100.

(2) Maintain records of the times the bag leak detection system alarm sounded, and for each valid alarm, the time you initiated corrective action, the corrective action(s) taken, and the date on which corrective action was completed.

(3) Inspect and maintain each baghouse according to the requirements in § 63.1451(b)(2) and recording all information needed to document conformance with these requirements. If

you increase or decrease the sensitivity of the bag leak detection system beyond the limits specified in § 63.1451(b)(1)(vi), you must include a copy of the required written certification by a responsible official in the next semiannual compliance report.

(d) *Venturi wet scrubbers*. For each venturi wet scrubber subject to the operating limits for pressure drop and scrubber water flow rate in § 63.1444(g) or § 63.1446(d), you must demonstrate continuous compliance by meeting the requirements of paragraphs (d)(1) through (3) of this section.

(1) Maintain the hourly average pressure drop and scrubber water flow rate at levels no lower than those established during the initial or subsequent performance test;

(2) Inspect and maintain each venturi wet scrubber CPMS according to § 63.1452(c) and recording all information needed to document conformance with these requirements; and

(3) Collect and reduce monitoring data for pressure drop and scrubber water flow rate according to § 63.1452(e) and recording all information needed to document conformance with these requirements.

(e) *Other control devices*. For each control device other than a baghouse or venturi wet scrubber subject to the operating limits for site-specific operating parameters in § 63.1444(h) or § 63.1446(e), you must demonstrate continuous compliance by meeting the requirements of paragraphs (e)(1) through (3) of this section:

(1) Maintain the hourly average rate at levels no lower than those established during the initial or subsequent performance test;

(2) Inspect and maintain each venturi wet scrubber CPMS according to § 63.1452(d) and recording all information needed to document conformance with these requirements; and

(3) Collect and reduce monitoring data for selected parameters according to § 63.1452(e) and recording all information needed to document conformance with these requirements.

(f) *Fugitive dust sources*. For each fugitive dust source subject to work practice standards in § 63.1445, you must demonstrate continuous compliance by implementing all of fugitive control measures specified for the source in your written fugitive dust control plan.

Notifications, Reports and Records

§ 63.1454 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.6(h)(4) and (h)(5), 63.7(b) and (c), 63.8(f)(4), and 63.9(b) through (h) that apply to you by the specified dates.

(b) As specified in § 63.9(b)(2), if you start your affected source before June 12, 2002, you must submit your initial notification not later than October 10, 2002.

(c) As specified in § 63.9(b)(3), if you start your new affected source on or after June 12, 2002, you must submit your initial notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to conduct a performance test, you must submit a notification of intent to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(e) If you are required to conduct a performance test, opacity observation, or other initial compliance demonstration, you must submit a notification of compliance status according to § 63.9(h)(2)(ii) by the date specified in paragraph (e)(1) or (2) of this section as applies to you.

(1) For each initial compliance demonstration that does not include a performance test, you must submit the notification of compliance status before the close of business on the 30th calendar day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration that includes a performance test, you must submit the notification of compliance status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test according to § 63.10(d)(2).

§ 63.1455 What reports must I submit and when?

(a) You must submit each report in paragraphs (a)(1) and (2) of this section that applies to you.

(1) You must submit a compliance report semiannually according to the requirements in paragraph (b) of this section and containing the information in paragraph (c) of this section.

(2) You must submit an immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan. You must report the actions taken

for the event by fax or telephone within 2 working days after starting actions inconsistent with the plan. You must submit the information in § 63.10(d)(5)(ii) of this part by letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

(b) Unless the Administrator has approved a different schedule under § 63.10(a), you must submit each compliance report required in paragraph (a) of this section according to the applicable requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.1443 and ending on June 30 or December 31, whichever date comes first after the compliance date that is specified for your source in § 63.1443.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after your first compliance report is due.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A) of this chapter, you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) Each compliance report must contain the information in paragraphs (c)(1) through (3) of this section and, as applicable, paragraphs (c)(4) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, as defined in 40 CFR 63.2, with that official's name, title, and signature, certifying the accuracy and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a startup, shutdown or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i).

(5) If there are no deviations from any emission limitations (emission limit, operating limit, opacity limit) that applies to you and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limitations, work practice standards, or operation and maintenance requirements during the reporting period.

(6) If there were no periods during which an operating parameter monitoring system was out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the monitoring system was out-of-control during the reporting period.

(7) For each deviation from an emission limitation (emission limit, operating limit, opacity limit) and for each deviation from the requirements for work practice standards that occurs at an affected source where you are not using a continuous monitoring system to comply with the emission limitations or work practice standards in this subpart, the compliance report must contain the information in paragraphs (b)(1) through (4) of this section and the information in paragraphs (b)(7)(i) and (ii) of this section. This includes periods of startup, shutdown, and malfunction.

(i) The total operating time of each affected source during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(8) For each deviation from an emission limitation (emission limit, operating limit, opacity limit, and visible emission limit) occurring at an affected source where you are using a operating parameter monitoring system to comply with the emission limitation in this subpart, you must include the information in paragraphs (b)(1) through (4) of this section and the information in paragraphs (c)(8)(i) through (xi) of this section. This includes periods of startup, shutdown, and malfunction.

(i) The date and time that each malfunction started and stopped.

(ii) The date and time that each monitoring system was inoperative, except for zero (low-level) and high-level checks.

(iii) The date, time and duration that each monitoring system was out-of-control, including the information in § 63.8(c)(8).

(iv) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(v) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(vi) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(vii) A summary of the total duration of monitoring system downtime during the reporting period and the total duration of monitoring system downtime as a percent of the total source operating time during that reporting period.

(viii) A brief description of the process units.

(ix) A brief description of the monitoring system.

(x) The date of the latest monitoring system certification or audit.

(xi) A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

(d) If you have obtained a Title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If you submit a compliance report pursuant to paragraph (a) of this section along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limitation (including any operating limit), or work practice requirement in this subpart, submission of the compliance report is deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation you may have to report deviations from permit requirements to the permit authority.

§ 63.1456 What records must I keep and how long must I keep my records?

(a) You must keep the records listed in paragraphs (a)(1) through (7) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any initial notification or notification of compliance status that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) The records in § 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) For each monitoring system, you must keep the records specified in paragraphs (a)(4)(i) through (iv) of this section.

(i) Records described in § 63.10(b)(2)(vi) through (xi).

(ii) Monitoring data recorded by the monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(iii) Previous (i.e., superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(iv) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) For each performance test you conduct to demonstrate compliance with a opacity limit according to § 63.1450(c), you must keep the records specified in paragraphs (a)(5)(i) through (ix) of this section.

(i) Dates and time intervals of all opacity observation period segments;

(ii) Description of overall smelter operating conditions during each observation period. Identify, if any, the smelter copper production process equipment that was out-of-service during the performance test and explain why this equipment was not in operation;

(iii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test;

(iv) Name, title, and affiliation for each indoor process monitor participating in the performance test;

(v) Copies of all visible emission observer opacity field data sheets;

(vi) Copies of all indoor process monitor operating log sheets;

(vii) Copies of all data summary sheets used for data reduction;

(viii) Copy of calculation sheets of the average opacity value used to demonstrate compliance with the opacity limit; and

(ix) Documentation according to the requirements in § 63.1450(c)(9)(iv) to support your selection of the site-

specific capture system operating limits used for each batch copper converter capture system when blowing.

(6) For each baghouse subject to the operating limit in § 63.1444(f) or § 63.1446(c), you must keep the records specified in paragraphs (a)(6)(i) and (ii) of this section.

(i) Records of alarms for each bag leak detection system.

(ii) Description of the corrective actions taken following each bag leak detection alarm.

(7) For each control device other than a baghouse or venturi wet scrubber subject to site-specific operating limits in § 63.1444(g) or § 63.1446(f), you must keep documentation according to the requirements in § 63.1450(a)(5)(iv) to support your selection of the site-specific operating limits for the control device.

(b) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(c) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(d) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.1457 What part of the general provisions apply to me?

Table 2 to this subpart shows which parts of the general provisions in §§ 63.1 through 63.15 apply to you.

§ 63.1458 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by us, the United States Environmental Protection Agency (U.S. EPA), or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraph (c) of this section are retained by the U.S. EPA Administrator and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are as listed in paragraphs (c)(1) through (4) of this section.

(1) Approval of alternatives to the emission limitations and work practice standards in §§ 63.1444 through 63.1446 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

§ 63.1459 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2, and in this section as follows:

Bag leak detection system means a system that is capable of continuously monitoring relative particulate matter (dust) loadings in the exhaust of a baghouse in order to detect bag leaks and other upset conditions. A bag leak detection system includes, but is not limited to, an instrument that operates on triboelectric, light scattering, transmittance or other effect to continuously monitor relative particulate matter loadings.

Baghouse means a control device that collects particulate matter by filtering the gas stream through bags. A baghouse is also referred to as a "fabric filter."

Batch copper converter means a Pierce-Smith converter or Hoboken converter in which copper matte is oxidized to form blister copper by a process that is performed in discrete batches using a sequence of charging, blowing, skimming, and pouring.

Blowing means the operating mode for a batch copper converter during which air or oxygen-enriched air is injected into the molten converter bath.

Capture system means the collection of components used to capture gases and fumes released from one or more emission points, and to convey the captured gases and fumes to a control device. A capture system may include, but is not limited to, the following components as applicable to a given capture system design: duct intake devices, hoods, enclosures, ductwork, dampers, manifolds, plenums, and fans.

Charging means the operating mode for a batch copper converter during which molten or solid material is added into the vessel.

Control device means the air pollution control equipment used to collect particulate matter emissions. Examples of such equipment include, but are not

limited to, a baghouse, an electrostatic precipitator, and a wet scrubber.

Copper concentrate dryer means a vessel in which copper concentrates are heated in the presence of air to reduce the moisture content of the material. Supplemental copper-bearing feed materials and fluxes may be added or mixed with the copper concentrates fed to a copper concentrate dryer.

Copper converter department means the area at a primary copper smelter in which the copper converters are located.

Copper matte means a material predominately composed of copper and iron sulfides produced by smelting copper ore concentrates.

Deviation means any instance in which an affected source subject to this subpart or an owner or operator of such a source fails to meet any of the following:

(1) Any requirement or obligation established by this subpart including, but not limited to, any emission limitation (including any operating limit) or work practice standard;

(2) Any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Any emission limitation (including any operating limit) or work practice standard in this subpart during startup, shutdown, or malfunction, regardless whether or not such failure is permitted by this subpart.

Emission limitation means any emission limit, opacity limit, operating limit, or visible emission limit.

Fugitive dust material means copper concentrate, dross, reverts, slag, speiss, or other solid copper-bearing materials.

Fugitive dust source means a stationary source of particulate matter emissions resulting from the handling, storage, transfer, or other management of fugitive dust materials where the source is not associated with a specific process, process vent, or stack.

Examples of a fugitive dust source include, but are not limited to, on-site roadways used by trucks transporting copper concentrate, unloading of materials from trucks or railcars, outdoor material storage piles, and transfer of material to hoppers and bins.

Holding means the operating mode for a batch copper converter during which the molten bath is maintained in the vessel but no blowing is performed nor is material added into or removed from the vessel.

Opacity means the degree to which emissions reduce the transmission of light.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the specific reference method.

Pouring means the operating mode for a batch copper converter during which molten copper is removed from the vessel.

Primary copper smelter means any installation or any intermediate process engaged in the production of copper from copper sulfide ore concentrates through the use of pyrometallurgical techniques.

Responsible official means responsible official as defined in 40 CFR 70.2.

Skimming means the batch copper converter operating mode during which molten slag is removed from the vessel.

Slag cleaning vessel means a vessel that receives molten copper-bearing material and the predominant use of the vessel is to separate this material into molten copper matte and slag layers.

Smelting furnace means a furnace, reactor, or other type of vessel in which copper ore concentrate and fluxes are melted to form a molten mass of

material containing copper matte and slag. Other copper-bearing materials may also be charged to the smelting furnace.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

As required in § 63.1457, you must comply with the requirements of the NESHAP General Provisions (40 CFR part 63, subpart A) shown in the following table:

TABLE 1 TO SUBPART QQQ OF PART 63.—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART QQQ

Citation	Subject	Applies to subpart QQQ	Explanation
§ 63.1	Applicability	Yes.	
§ 63.2	Definitions	Yes.	
§ 63.3	Units and Abbreviations	Yes.	
§ 63.4	Prohibited Activities	Yes.	
§ 63.5	Construction and Reconstruction	Yes.	
§ 63.6(a)-(g)	Compliance with Standards and Maintenance requirements.	Yes.	
§ 63.6(h)	Determining compliance with Opacity and VE standards.	No	Subpart QQQ specifies the requirements and test protocol used to determine compliance with the opacity limits.
§ 63.6(i)-(j)	Extension of Compliance and Presidential Compliance Exemption.	Yes.	
§ 63.7(a)(1)-(2)	Applicability and Performance Test Dates.	No	Subpart QQQ specifies performance test applicability and dates.
§ 63.7(a)(3), (b)-(h)	Performance Testing Requirements	Yes.	
§ 63.8 except for (a)(4), (c)(4), and (f)(6).	Monitoring Requirements	Yes.	
§ 63.8(a)(4)	Additional Monitoring Requirements for Control devices in § 63.11.	No	Subpart QQ does not require flares.
§ 63.8(c)(4)	Continuous Monitoring System Requirements.	No	Subpart QQQ specifies requirements for operation of CMS.
§ 63.8(f)(6)	RATA Alternative	No	Subpart QQQ does not require continuous emission monitoring systems.
§ 63.9	Notification Requirements	Yes.	
§ 63.9(g)(5)	DATA reduction	No	Subpart QQQ specifies data reduction requirements
§ 63.10 except for (b)(2)(xiii) and (c)(7)-(8).	Recordkeeping and reporting Requirements.	Yes.	
§ 63.10(b)(2)(xiii)	CMS Records for RATA Alternative	No	Subpart QQQ does not require continuous emission monitoring systems.
§ 63.10(c)(7)-(8)	Records of Excess Emissions and Parameter Monitoring Accedences for CMS.	No	Subpart QQQ specifies record keeping requirements
§ 63.11	Control Device Requirements	No	Subpart QQQ does not require flares
§ 63.12	State Authority and Delegations	Yes.	
§§ 63.13–63.15	Addresses, Incorporation by Reference, Availability of Information.	Yes.	

FIGURE 1 TO SUBPART QQQ OF PART 63.—DATA SUMMARY SHEET FOR DETERMINATION OF AVERAGE OPACITY

Clock time	Number of converters blowing	Converter aisle activity	Average opacity for 1-minute interval (percent)	Visible emissions interference observed during 1-minute interval? (yes or no)	Average opacity for 1-minute interval blowing without visible emission interferences (percent)



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www.holbrookservco.com

Proposal Number: 072017-EMC-JH

Proposal Date: 07/20/17

Expiration Date: 08/20/17

BUDGETARY PRICING LETTER

To: Kennecott Utah Copper – Refinery
Adam Terry
11500 West 2100 South
Magna, UT 84044
Phone: 801-569-7358
Adam.Terry@riotinto.com



Re: **Boiler & Burner Emissions Upgrade Options – Kennecott Refinery**

Mr. Adam Terry,

Holbrook Servco would like to thank you for the opportunity to provide you with a **Budgetary Proposal** for the following boiler system upgrades per your request for quote during our meeting at your facility last month. The following options are priced per boiler. We have provided pricing for three options:

1. Replacement 70,000 lbs/hr Industrial Watertube Boiler with Ultra Lox NOx 9 PPM Burner – full boiler replacement, attachments include the following:
 - a. Boiler GA Dimensional Drawing
 - b. Boiler Detailed Proposal
2. Replacement Burner with Ultra Low NOx 9 PPM Technology – installation on existing boilers, attachments include the following:
 - a. Burner Technical Data
 - b. Burner Detailed Proposal
3. *Addition of an SCR System to the existing Boiler/Burner package to reduce emissions to 9 PPM NOx (**TBD – still working with manufacturers on this option**)*

Item No	Description	Unit Price	Qty	Total Price
1	Cleaver-Brooks NEBRASKA boiler model, NB-300D-55 (pricing includes delivery to the jobsite – offloading by others)	\$1,455,500.00	2	\$2,911,000.00
2	Installation of NB-300D-55 Boiler*	\$1,150,000.00	2	\$2,300,000.00
Total Boiler Option				\$5,211,000.00

Holbrook Servco – BURNER INSTALLATION PROPOSAL

1580 South Pioneer Road • Salt Lake City • Utah • 84104 • Tel: (801) 486-4300 • Fax: (801) 486-4399

3	Cleaver-Brooks Profire NTXL burner, model NTXLLG-924-3S-9PPM (pricing includes delivery to the jobsite – offloading by others)	\$285,650.00	2	\$571,300.00
4	Installation of Profire NTXL Burner**	\$565,250.00	2	\$1,130,500.00
Total Burner Retrofit Option				\$1,701,800.00
5	SCR System	TBD		
6	Installation of SCR System	TBD		
Total SCR Option				TBD

Other Comments or Clarifications:				
Payment Schedule: TBD Based Upon Options Selected				
Projected Lead Times (upon receipt of approved submittals):				
<ul style="list-style-type: none"> ▪ Boiler Production – 38-42 Weeks ▪ Burner Production – 18-20 Weeks 				

ADDITIONAL NOTES

- For this order to be processed a signed copy of this proposal and a copy of the purchase order must be provided.
- Cancellation of this order may result in cancellation charges for time and materials used up to the point of cancellation.
- Any additional materials or labor required for work outside the scope of this proposal will not be approved without written acceptance to proceed by the PURCHASER.
- Additional materials and labor will be billed out based upon current labor rates and prevailing material pricing at the time of the authorization.

BY SIGNING THIS PROPOSAL, the PURCHASER agrees that the services provided by Holbrook Servco, LP in accordance with this proposal will be subject to the current Holbrook Servco, LP Sales Terms and Conditions.

HOLBROOK SERVCO, LP

PURCHASER

Date: 07/20/17

Date: _____

By: Jason Hansen

By: _____
(Signature & printed name)

Title: New Equipment Sales Manager

Title: _____

Additional Documents Included:

- Boiler GA Dimensional Diagram
- Boiler Detailed Proposal
- Burner Technical Data
- Burner Detailed Proposal



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Calgary, Alberta, Canada T2G 5M4
Tel (403) 250-1075 Fax (403) 250-1076
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PROPOSAL

**Kennecott Utah Copper Corp.
Magna, Utah USA**

**NEW Low NOx Burner with Windbox
Gas Valve Train with BMS / CCS Retrofit
With SIL2 Components OPTION**

Foster Wheeler Boiler 580-BO-916

Proposal Ref. 9371-1 Rev. 2

Date: January 28, 2015

Prepared by:

Jim Kondziela – VP of Sales and Operations

Submitted To:

Katherine Marek
Graduate Project Engineer
Engineering Services: Kennecott Utah Copper Smelter

Rio Tinto

12000 West 2100 South, Magna, Utah 84044 USA
T: +1 (801) 569-7343 C: +1 (801) 201-9463
katherine.marek@riotinto.com



Process Combustion Systems Inc.

#13, 1515 HighField Crescent S.E.
Calgary, Alberta, Canada T2G 5M4
Tel (403) 250-1075 Fax (403) 250-1076
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1.0 Introduction

We are pleased to offer this proposal for a *NEW Low NOx Burner, Natural Gas Valve Train and BMS / CCS Control System* for the existing Foster Wheeler Boiler equipment number 580-BO-916 at the Kennecott Magna Utah Smelter Plant location.

Our proposal is based on our various information and drawings we have from the existing O&M manuals for this boiler which include the following:

- Foster Wheeler P&ID 3296-021-rC
- Foster Wheeler Burner GA drawings 60064/10-2-r1
- Foster Wheeler Wind-Box GA drawings 60064/10-1-r5
- TODD Combustion Engineering Data Sheets 60064-231-r1 (2 sheets)
- Fan Drawings Buffalo Forge – D2-55118RC
- Fan Curve Buffalo Forge – 890-L-25

The entire combustion system will be completely engineered and manufactured by Process Combustion Systems Inc.

Our proposal will have one (1) option case to consider and described as follows:

- **Re-use the following EXISTING components:**

- Existing Boiler and Super-Heater section in its entirety with all feed water pumps, feed water controls, etc.
- Existing Combustion air blower and motor
- Existing dampers for air flow and draft control and boiler related control elements.
- Existing control actuators for combustion air flow and FGR flow to be reused.

- **NEW Components as Follows:**

- Provide New Fives Pillard Low NOx Burner with windbox and HESI ignition system
- Provide entirely NEW skid mounted packaged gas train with fiberglass shed type enclosure with man access door.
- Provide entirely NEW Combustion control system (CCS) and burner management system (BMS) with PLC based controls (Allen Bradley Control Logix) with PC based HMI.
- Provide a NEW motorized damper for FGR system (actuator to be reused).
- Provide a NEW combustion air damper (actuator to be reused).
- Provide NEW oxygen analyzer.
- Provide NEW water level control relays in CCS panel.



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Installation and Site Engineering

The installation and the site engineering to facilitate the installation are **NOT** included in this proposal. I would suggest that these costs be used from the acid plant pre-heater for budgeting purposes.

2.0 Boiler Design Criteria

- **General Design**

- 1.) System Type: Direct Fired Water Tube D-Boiler with Super-Heater
- 2.) Production Rate: 80,000 lbs per hour steam
- 3.) Firing Rate Connected: 105.4 x 10⁶ Btu/hr Plus 20% XSair Design
- 4.) FGR Rate: 15% Design
- 5.) Site Elevation: 4,250 feet ASL
- 6.) Burner Differential Pressure: 7.0" wc
- 7.) Utilities
 - a.) Fuel: Natural Gas @ 50 psig
 - b.) Electricity: 120/1/60 Hz control voltage @ 15 amps
- 8.) No. of Burners: One (1)
- 9.) No. of Control Zones: One (1)
- 10.) Paint: Coating per Kennecott specifications



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- **Piping and Valve Standards**

- 1.) Fuel Safety Standards: NFPA 86A for ovens and furnaces
NEC Electrical
NFPA 8501
- 2.) Piping Fabrication ASME B31.3 Typical schedule 80 A106
- 3.) Fuel Safety Valves: FM and NFPA
ANSI 221.1
- 4.) Electrical: Non – Classified Electrical Area
(40 deg F to +100 deg F ambient conditions)

- **Performance Expectations (at operating steam pressure and normal flows)**

- 1.) Control: Within the original TODD burners' capabilities as described in the TODD specification sheets. The burner is expected to be stable and control from startup to normal operating steam production rate up to 80,000 lbs/hr.
- 2.) Heat Release: 105.4 x 10⁶ Btu/hr
- 3.) NOx Emissions: Existing with no change
- 4.) CO Emissions: Existing with no change



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3.0 Existing System Items to be Replaced

- Existing Control Panel and Valve Train Assembly

The existing combustion control panel and natural gas valve train for the Foster Wheeler Boiler will be replaced as part of the retrofit.

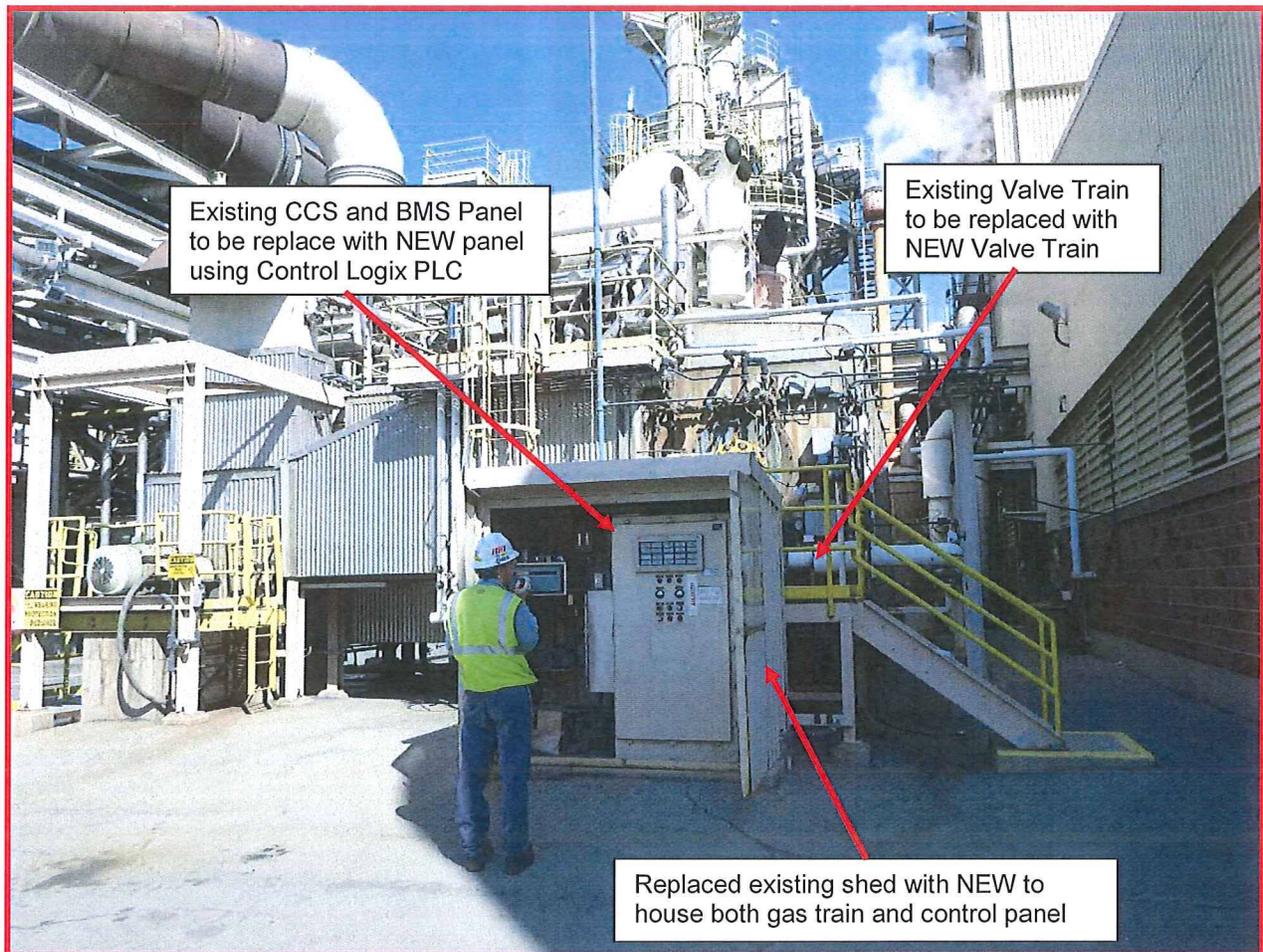


Fig No. 3.1: Existing System Overview



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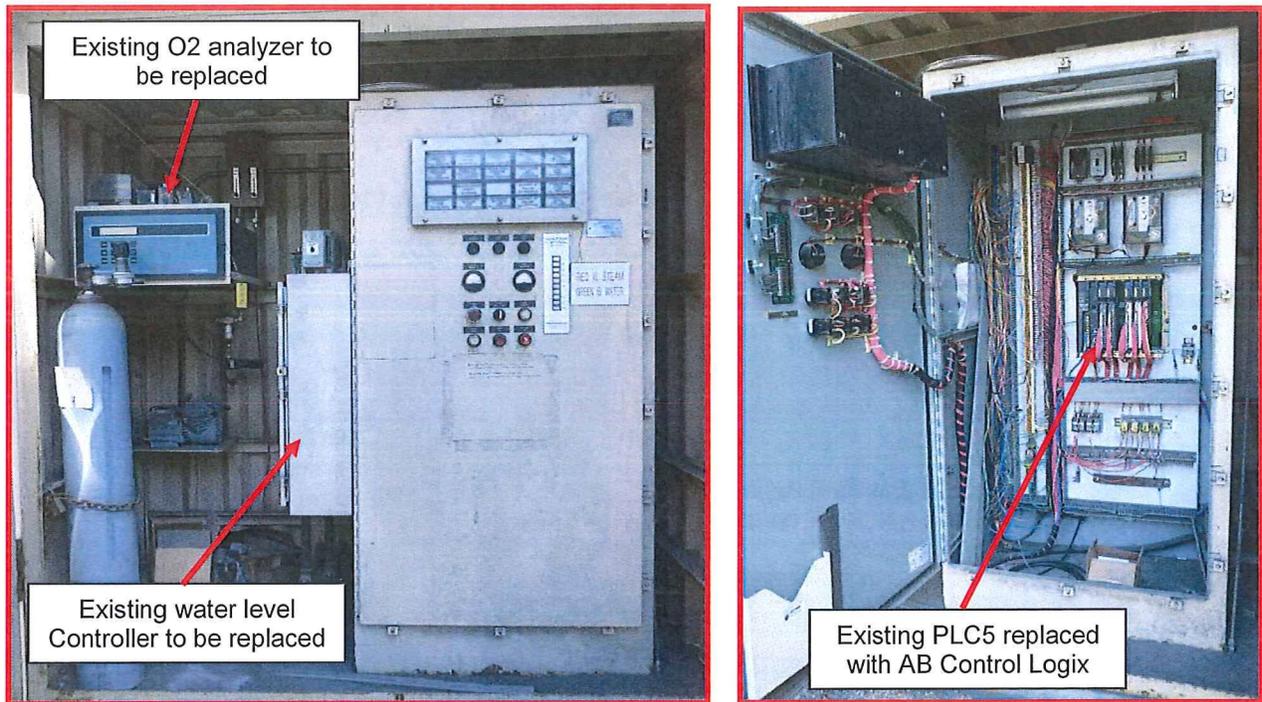


Fig No. 3.2: Existing Combustion Control Panel

The existing combustion control panel (CCS) with burner management system (BMS) will be replaced in its entirety.



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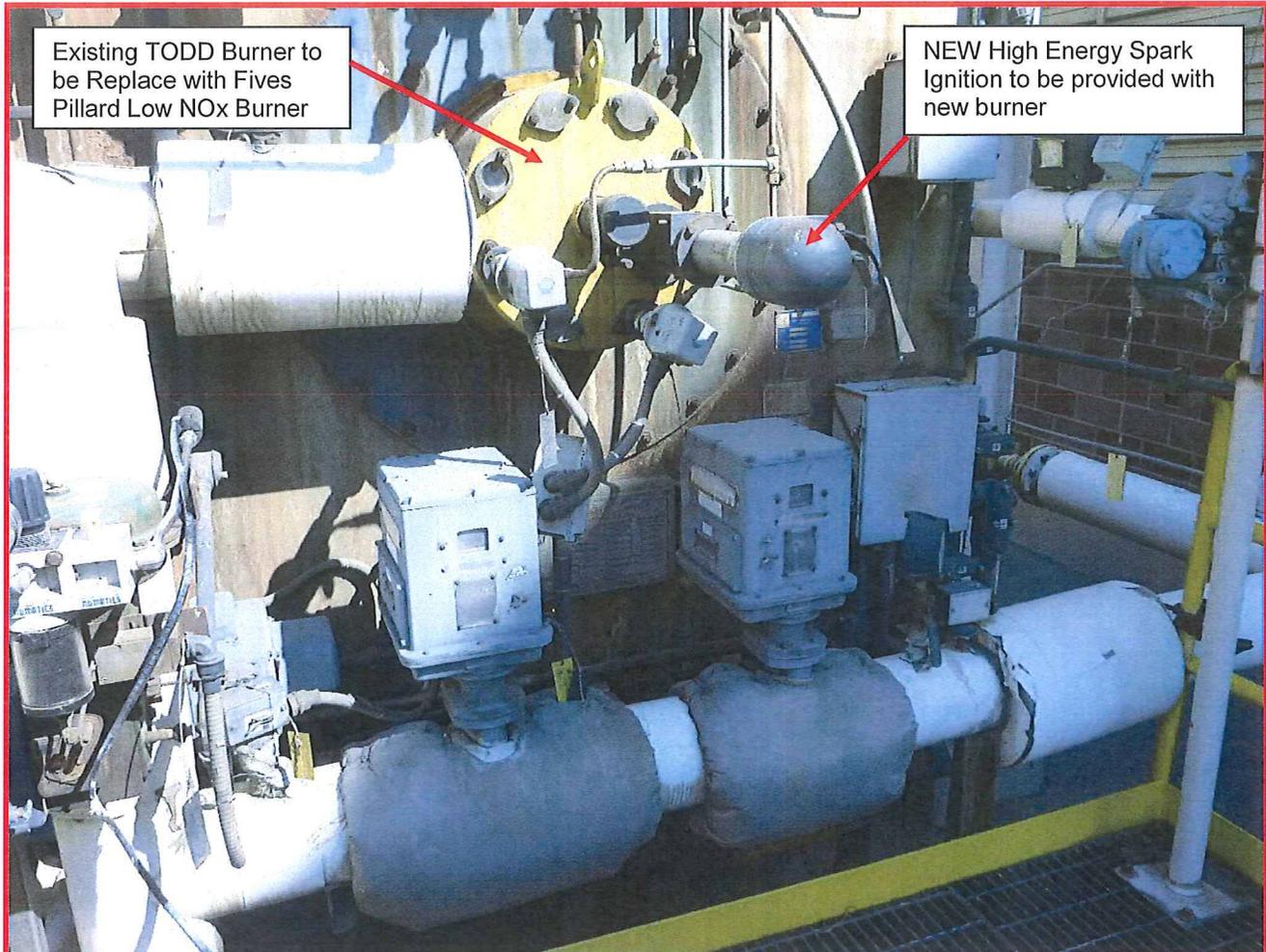


Fig No. 3.3 Existing Burner and Wind-box along with Gas Valve Train to be Replaced

The Existing TODD Burner will be Replaced along with the wind-box with a New Fives North American PILLARD G2 Low NOx burner.

The NEW skid mounted gas valve train will include Maxon type of safety shutoff valve, Fisher control valves, orifice plates for metered gas flows and Rosemount 3051 series DP transmitters.

The NEW gas flow control valve will be pneumatic type with a V-Ball type control valve (Fisher).

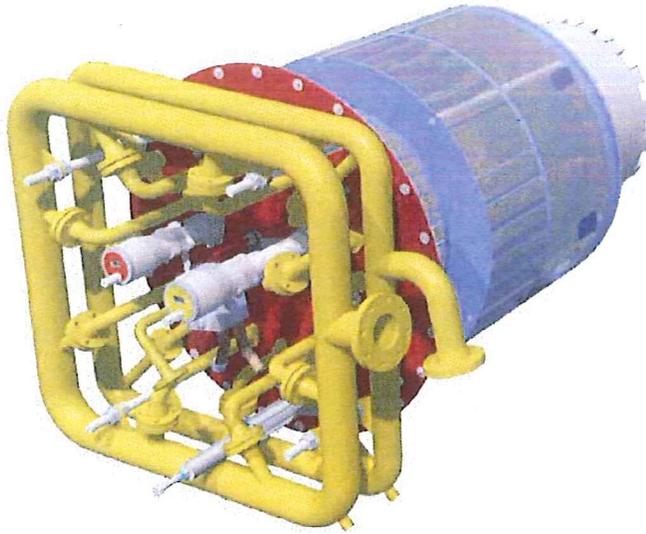
The NEW gas train skid to be installed at ground level which will free up space in front of the burner to improve maintenance access.



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GRC LONOXFLAM® G2 gas burners



fives north american

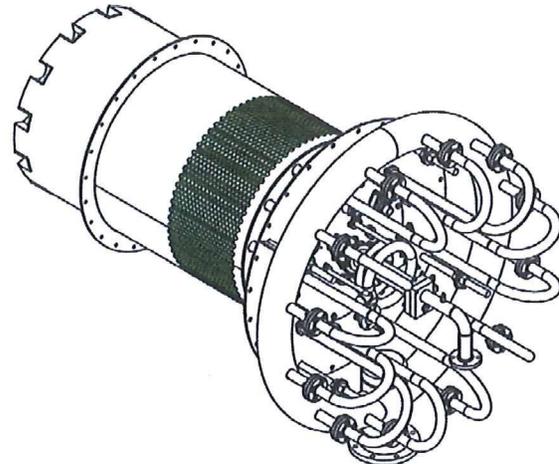
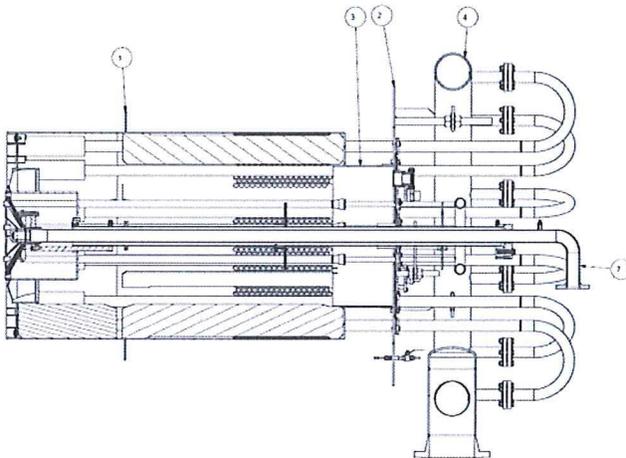


Fig No. 3.4 Conceptual Fives North American / Pillard Burner Cross Section View
(wind-box provided but not shown)



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4.0 NEW Valve Train and Combustion Control Panel

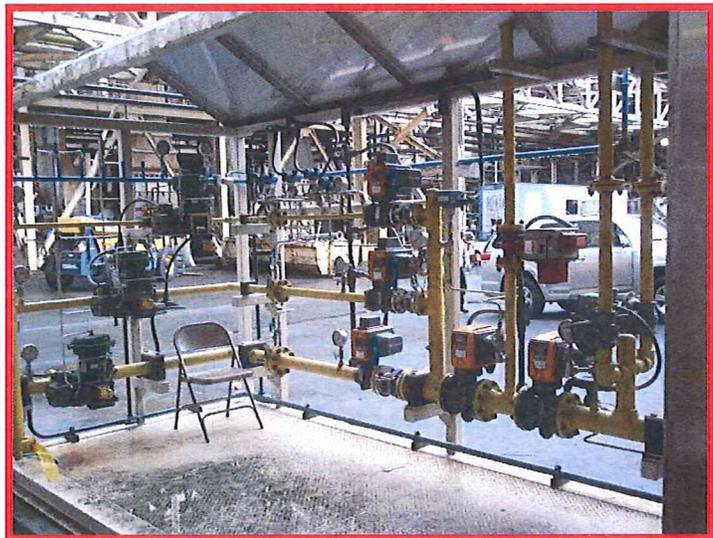
The NEW valve train will have a similar supply scope as the one(s) PCSI supplied for the steam super-heater or the acid plant pre-heater retrofit shown in the photos below.



Fig No. 4.1
Rear view of the super-heater valve train shown to the left.

Fig No. 4.2

Front view of super-heater valve train, flow control valves located on the left of the view with the Maxon type double block and vent main gas train located to the right in the view.



It is anticipated that the new skid for the boiler can either be made to fit in a similar foot print as the super heater valve train and it can be designed to be installed adjacent to the existing to skid to allow it to be installed prior to the outage as was done with the super-heater project.



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- **Fiber Glass Valve Train Shed (Enclosure)**

The one primary change to the gas valve train skid is that it will be built with a fiberglass enclosure and man access door similar to that depicted in the following photos.

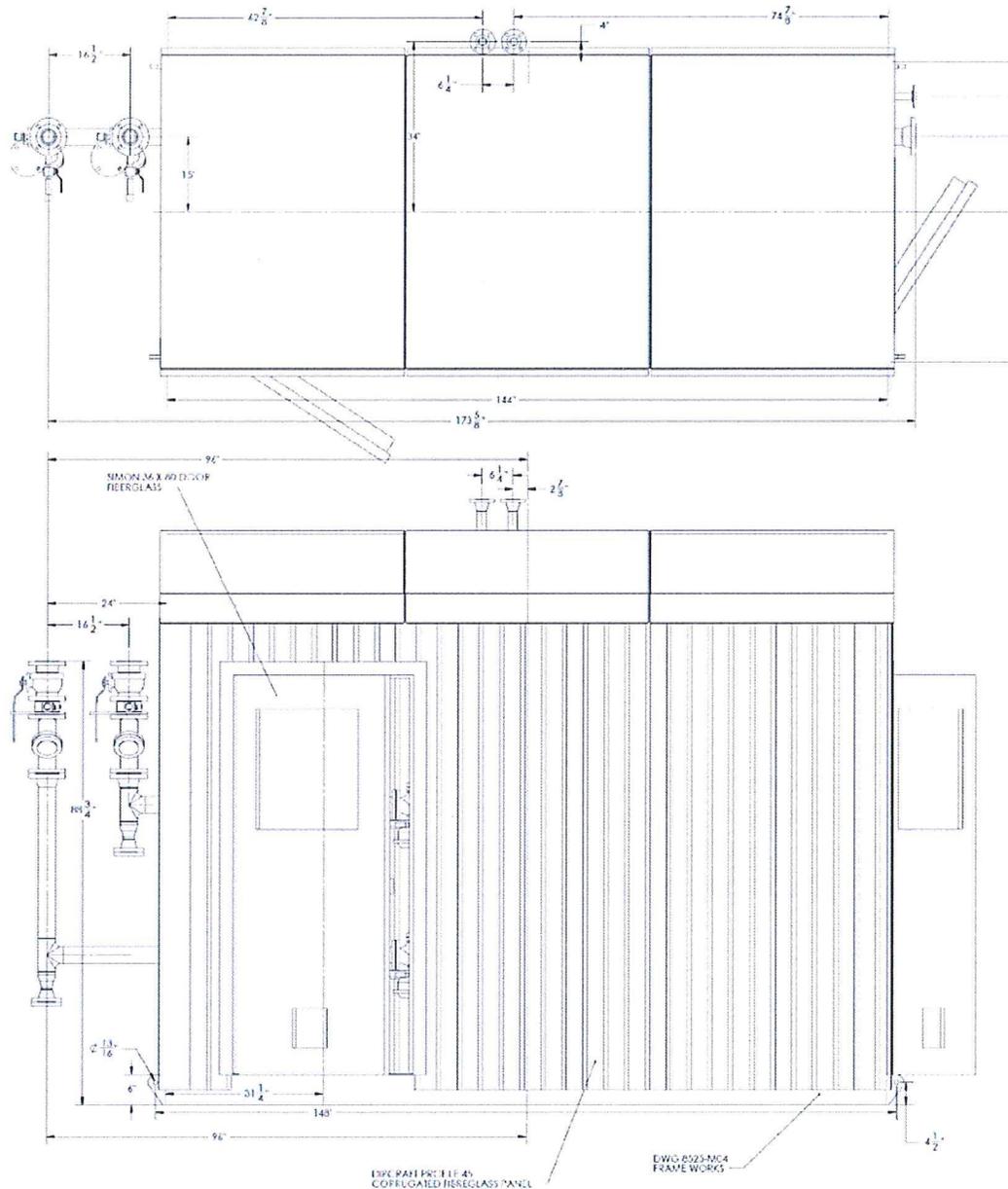


Fig No. 4.3A Typical Fiberglass Sided Gas Train Enclosure



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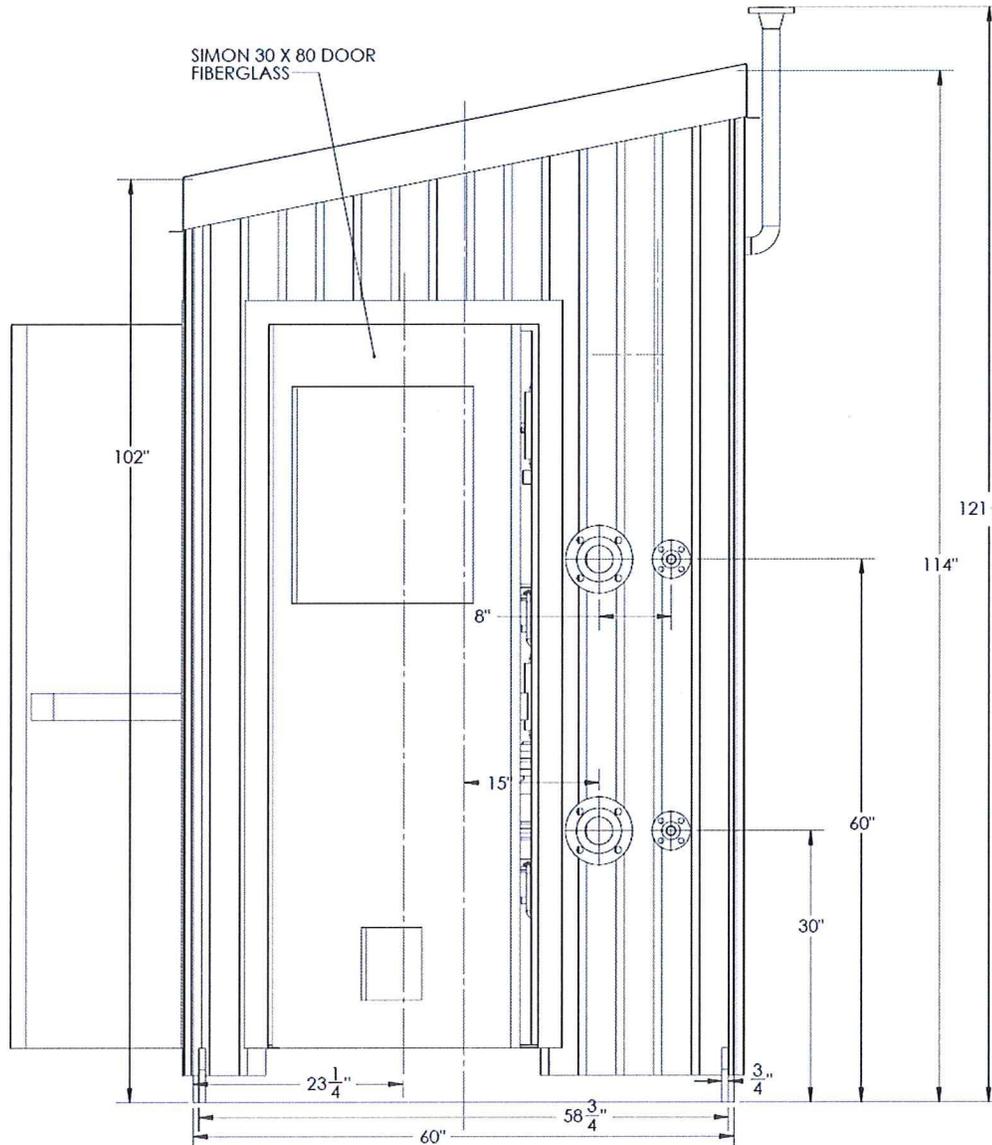


Fig No. 4.3B Fiberglass Sided Gas Train Enclosure



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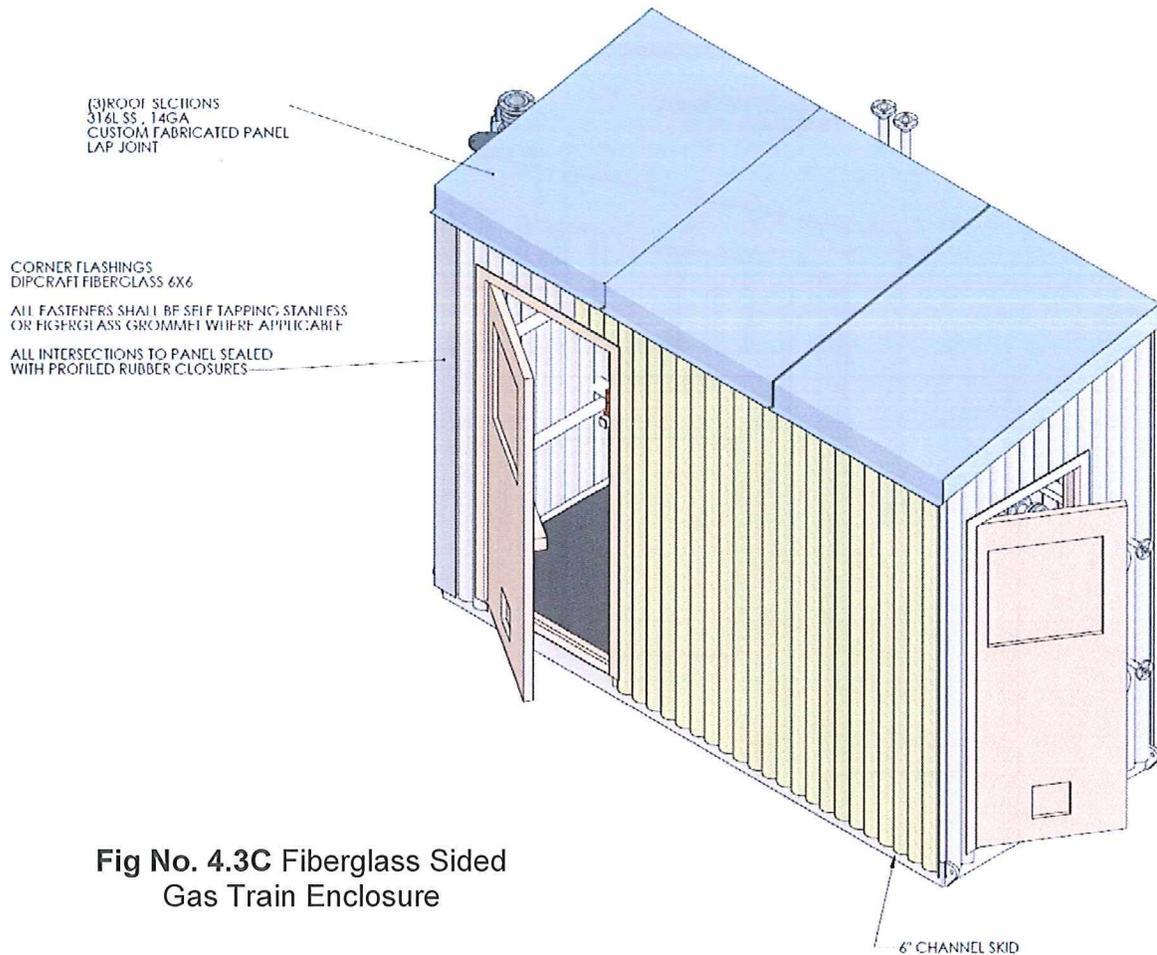


Fig No. 4.3C Fiberglass Sided
Gas Train Enclosure



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- **Gas Valve Train Description**

The existing burner has one (1) gas connection. Installed at the burner will be a new braided flexible hose and manual isolation ball valve. The nominal pipe size will be 4" for the gas connection.

The main gas train will be completely pre-piped and wired onto a seal welded structural steel box tubing skid.

The main gas train will be designed following NFPA and FM regulations for this type of application.

The double block and vent safety shutoff valve system will be via Maxon type motorized electric actuated valves with proof of closure switches.

The new pressure control regulator will be a Fisher series model 1098EGR.

The main gas flow control valve will be a Fisher series 1052 V200 "V" Ball control valve with 6020 series I/P positioner.

Differential pressure transmitters will be Fisher Rosemont series 3051 and the gas pressure transmitter is a Rosemont 2088.

The pressure switches for both low gas and high gas pressure will be provided by UE.

The pilot gas train is NOT required as we will use a high energy spark ignition system (HESI).

The nominal pipe size of the main gas train is 4", all joints larger than 2" will be flange using schedule 80 A106 pipe. The main gas train piping will be painted safety yellow and the support skid painted Kennecott standard "Dunes Tan" color.



Typical Maxon 5000 Series
SSOV Valve



Typical Fisher V-Ball
Control Valve



Typical Rosemont
DP Transmitter



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- Ignition System

The burner is supplied complete with a PCSI Chentronics "HESI" high energy direct spark retractable igniter. The exciter is Solid State and provides a high power output spark.

Separate gas pilot is NOT required.

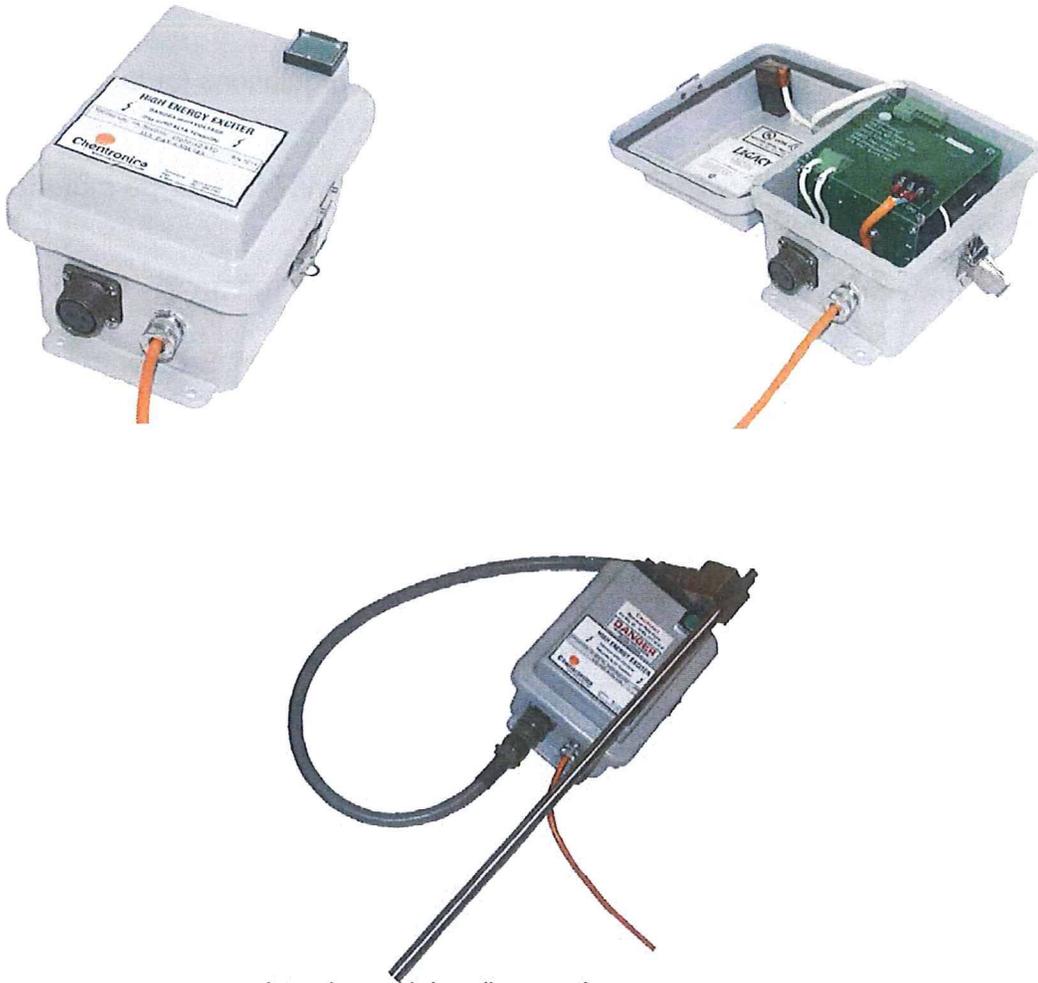


Fig No. 4.4 Typical High Energy Spark Ignition.



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- **Combustion Control System**

The Combustion Control System (CCS) LOCAL control panel will use a freestanding stainless steel NEMA 4X rated enclosure; it will be skid mounted with the valve train near the burner system.

The nominal size of the enclosure will be 84" H x 60" W x 18" D.

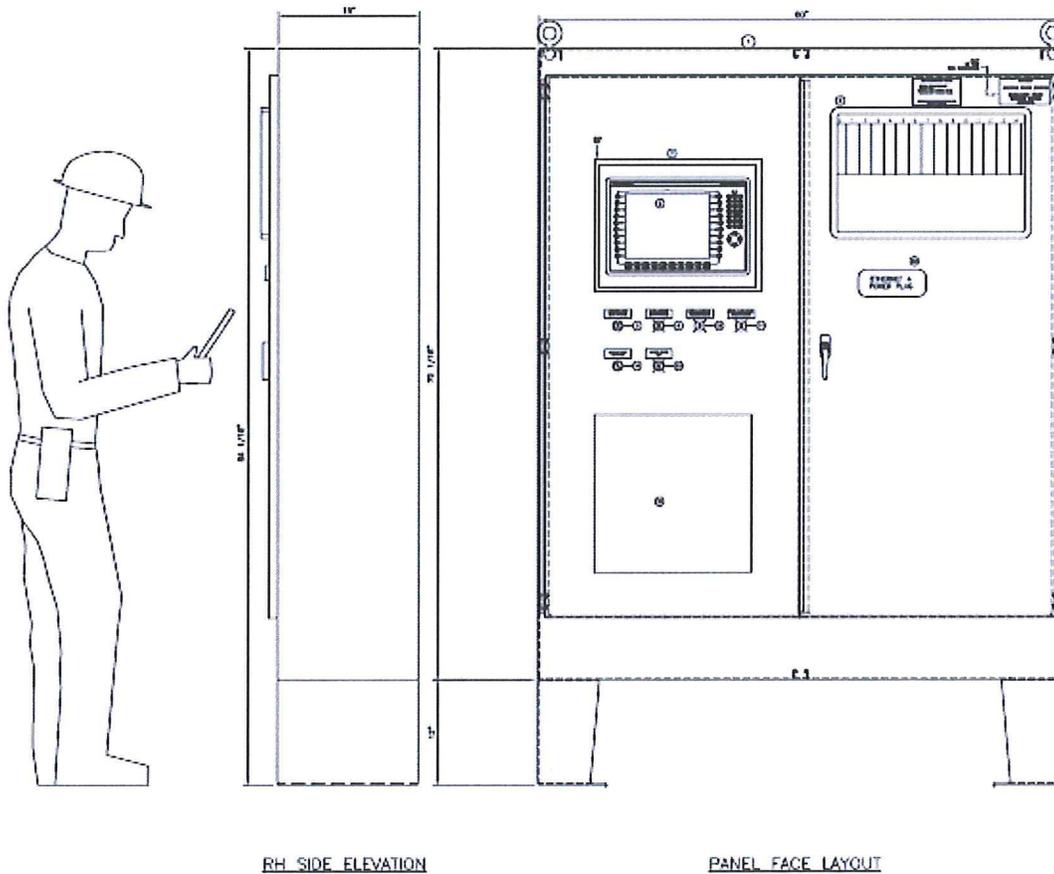


Fig No. 4.6A Typical Control Panel Layout (for reference only)



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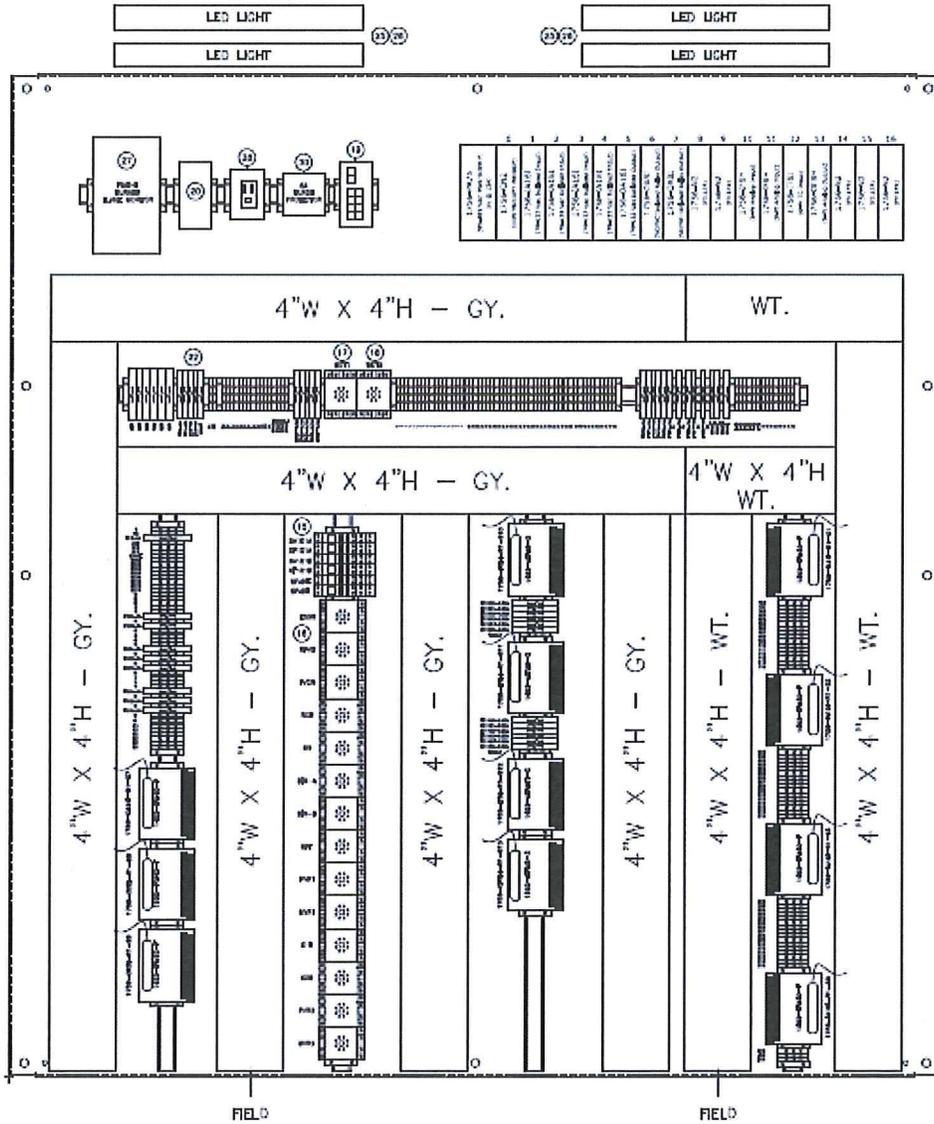


Fig No. 4.6B Typical Control Panel "Back Pan" Layout (for reference only)



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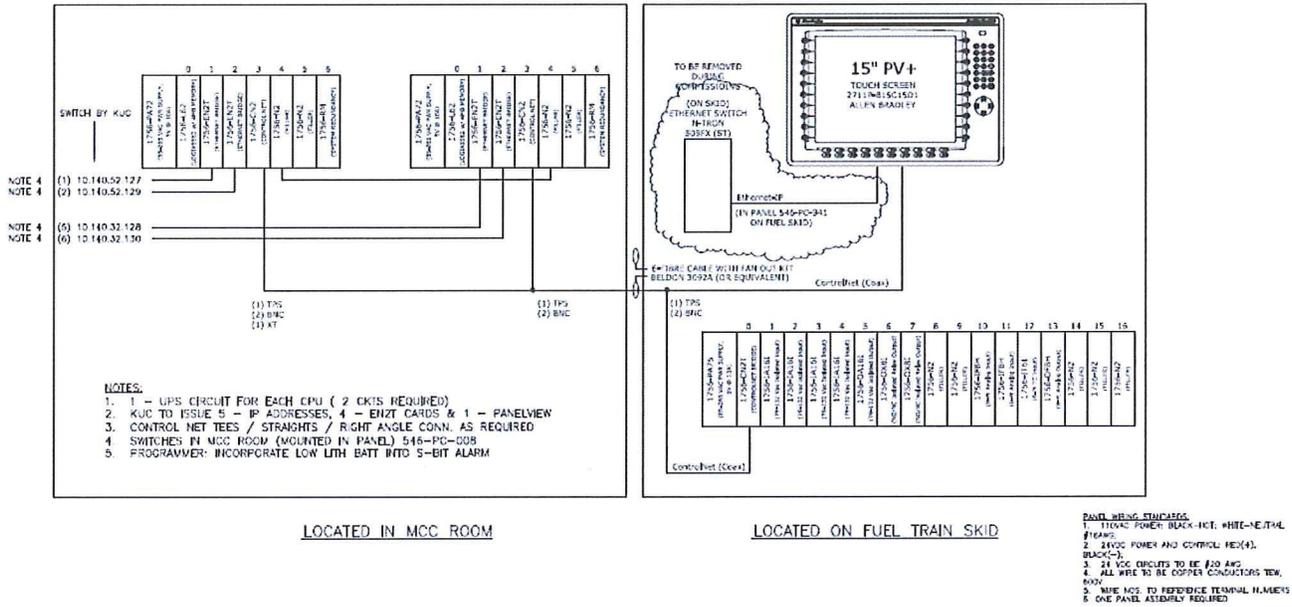


Fig No. 4.6C Typical PLC Configuration Layout (for reference only)



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An Allen Bradley Control Logix based PLC is included to perform the combustion control logic (CCS) for the burner (same system as the super-heater combustion system). The common CCS and BMS control panel will be mounted local to the main gas train control skid.



Fig No. 4.7 Typical Operator Interface (for reference only)



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The field instrumentation relative to combustion control - IE: DP transmitters for gas, metering orifices for gas and the gas flow control valves and operators for the burner air fuel ratio control are included.

The CCS will include the following control loops:

- Boiler Steam Pressure Control
- Boiler Water Level Control
- De-Super Heater Control
- Air fuel ratio control
- FGR flow control
- Draft pressure control

The BMS will receive a 4-20 ma signal from the boiler control system (DCS) to modulate the burner firing rate after the burner has sequenced through a safe startup.



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Fig No. 4.8

The new combustion control panel and BMS for the boiler is anticipated to be nearly identical to the super-heater or preheater control panel (except for the foot print), using the same program throughout (as much as possible though modified for the boiler) to maintain similar compatibility and functionality between the two systems.

The HMI will be a PC based HMI discussed later in this proposal.



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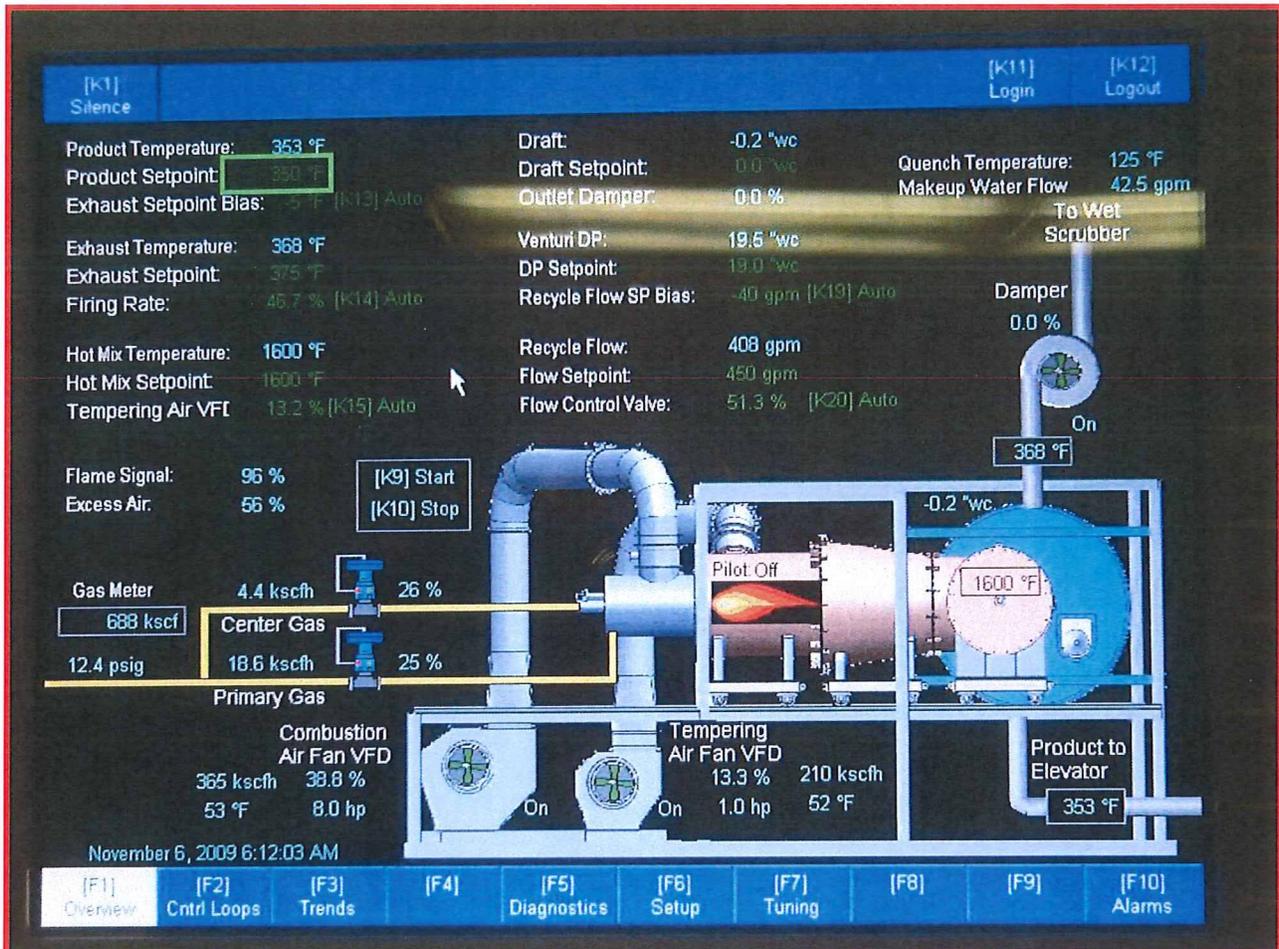


Fig No. 4.9 Typical HMI Overview Screen (for reference only)



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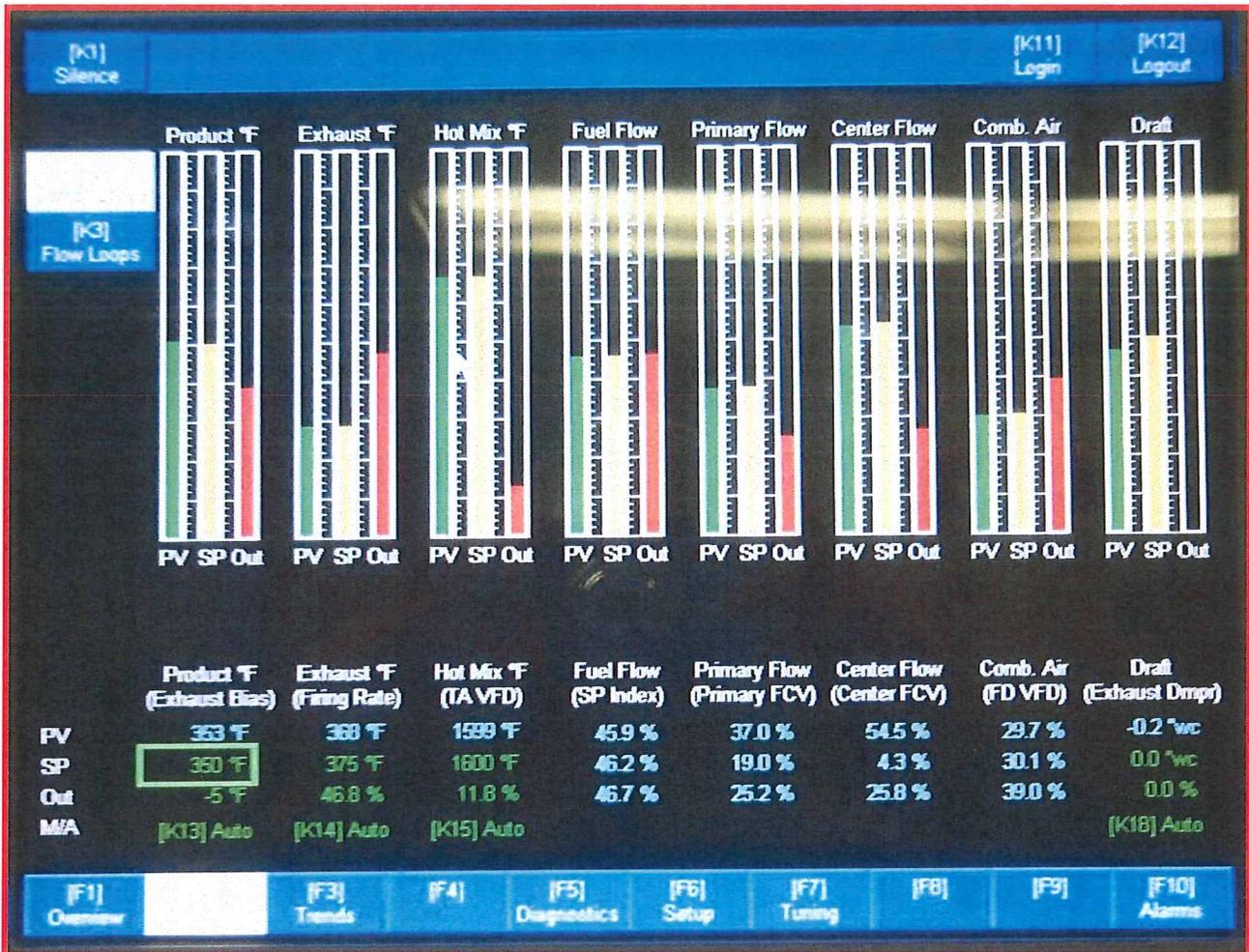


Fig No. 4.10 Typical HMI Controller Screen (for reference only)



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Transduction

Intel ATOM 1.6GHz Processor

TR-5195F

TR-5195F Fanless Industrial PC w/ Touch Screen



Features

- Intel ATOM 1.6GHz N270 processor.
- 19" TFT LCD touch screen with resolution 1280 x 1024.
- Enclosure with NEMA 4 epoxy finish.
- 2GB DDR2 533MHz memory.
- High speed, high temperature flash SATA SSD 32 ~ 128GB.
- System reset programmable watchdog timer, 1-255sec.
- 2 x Realtek RT8111C Dual Gigabit LAN.
- 4 x USB and 2 x Serial ports (optional up to 4 isolated RS-232 or RS-422/485 ports).
- Optional time sync IRIG A/B BNC port.
- Rectangular panel cut-out - easy mount clips.
- Operating temperature range 0°C - 50°C , 60°C for 2 hours at 100% system load.
- IEEE 1613 Class 2 Station Computer Compliance. CE tested with AC electrical safety approval.
- MTBF>50,000 hours, limited by LCD backlight.
- 5 year warranty.

Fig No. 4.11 Typical PC Based HMI Controller Proposed – Transduction Series

One change to the control panel when comparing to either the super heater or the pre-heater is that it is proposed with a PC based HMI instead of a panel view type as depicted above.



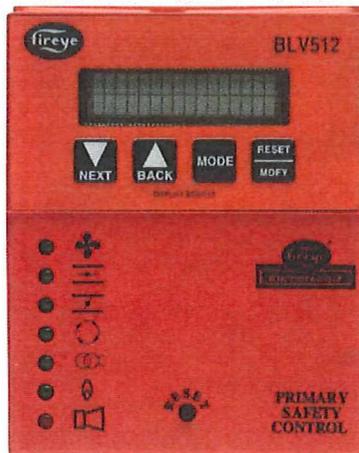
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- **Burner Management System**

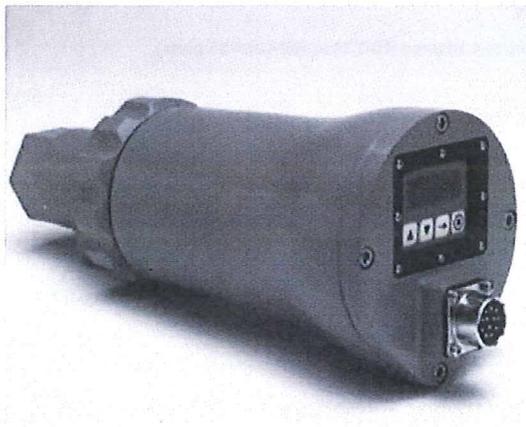
The burner will be fitted with a fully integrated burner management control system as part of the PLC based control system for the processing of a safe burner startup and operation. The flame relay will be a FIREYE Controls Company "Burner Logix" series flame safety relays.

Flame detection will be via a Qty of two (2) redundant Fireye 95UVS1 Insight self checking UV scanner.



YB110 FIREYE® BurnerLogix™

MICROPROCESSOR-BASED
INTEGRATED BURNER
MANAGEMENT CONTROL



INSIGHT
scanners

TYPE 95IR/95UV/95DS

MODEL S1,S2

Integrated Flame Scanner
with Internal Flame Relay

Fig No. 4.12 Typical Flame Relay and UV Detector



Process Combustion Systems Inc.

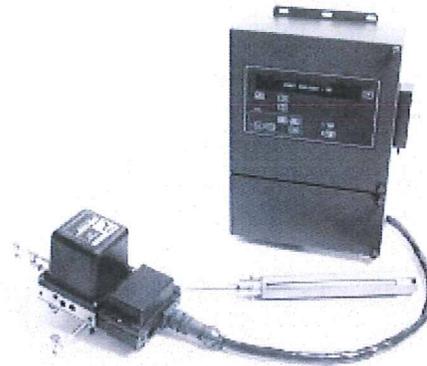
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Specification

Analyzers Smart Analyzer 90 Type SMA

[Main Menu](#)

- Oxygen Only or Optional Oxygen and Combustibles
- Rugged Industrial Design
- Easy Installation and Start-up.
- Highly Accurate Sensors
- Simplified In-house Maintenance
- Diagnostics and Alarming
- Patented Close Coupled Sample System
- Process Temperature Measurement
- Standard Combustion Efficiency Calculation
- Automatic Sensor Calibration-Standard
- Calibration Verification
- Distinctive Operator Interface
- Optional Filter Blowback
- High Temperature Operating Range
- Optional Dual Filtration System
- Probe & Cable Length Options
- Inherent Flashback Protection



Type SMA
Smart Analyzer 90

ABB Automation



Fig No. 4.13 Typical Oxygen Analyzer

Included with the system is a NEW ABB series PN SMA2.X.X.X.X Online Process O2 Analyzer, SMA series with probe, filter and accessories.



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- **Combustion Air and FGR System**

The existing combustion air system including the blower with intake silencer, all the ducting between the blower and burner and flexible connections are to be re-used at this point in time.

One (1) NEW combustion air flow control damper is included to utilize the existing actuator.

Air Flow measurement to the burner will be via a NEW KURZ thermal anemometer mass flow metering device. The existing annubar flow element will be used as a redundant air flow signal and a NEW differential pressure transmitter is included.

The existing FGR ducting will be reused. A NEW butterfly type control valve with new REXA actuator will be installed for FGR control along with a NEW KURZ thermal anemometer for FGR flow measurement to the burner.

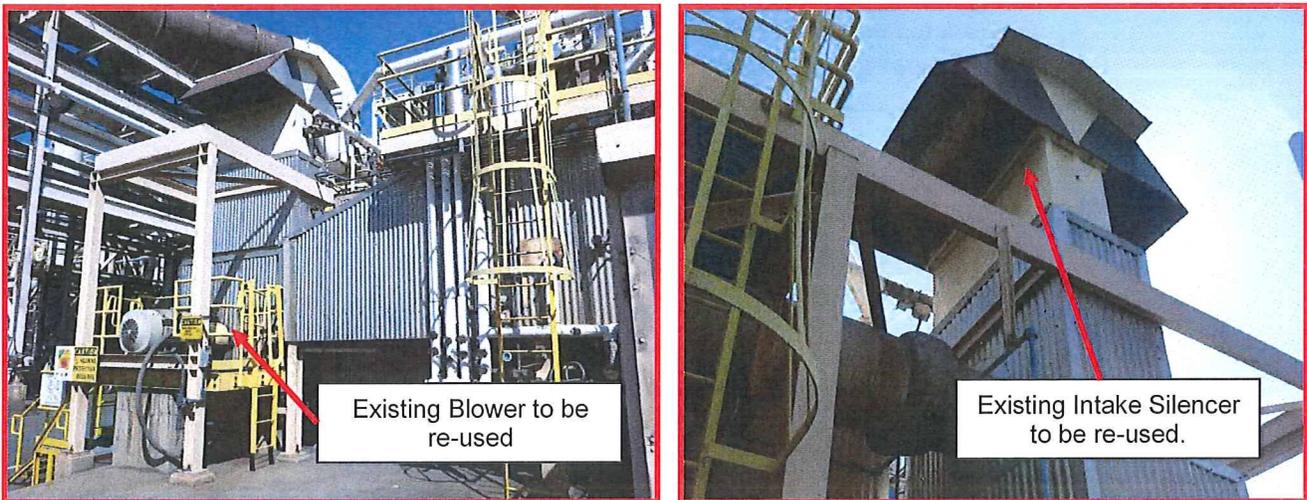


Fig No. 4.14 – Combustion Air Fan

Existing combustion air fan shown on the right will be reused this with NO modifications anticipated to the fan, ducting or silencer.



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5.0 Combustion Equipment List (Preliminary)

Item	Qty.	Description	Part No.
BURNER			
	1	Fives NA Pillard G2-105 Low NOx Burner	NEW G2 Burner
	1	HESI Ignition System	
COMBUSTION AIR TRAIN			
	1	KURZ Flow Meter	454FTB
	1	New Combustion Air Flow Damper	PCSI
	1	Existing Combustion Air Blower XX,000 scfm @ XX" wc	Buffalo Existing
FGR TRAIN			
	1	KURZ Flow Meter	454FTB
	1	18" BV Damper	PCSI
	1	REXA ElectroHydraulic Actuator	REXA
NATURAL GAS TRAIN			
	1	Flexible Connection - 4" x 24" Long	
	2	Manual Ball Valve	4" VCI
	1	Fisher I/P with air set regulator	Fisher 6020
	1	Fisher 200V (4") Flow Control Valve	Fisher 200V
	1	High Gas Pressure Switch	UE400
	1	Safety Shutoff Valve	MAXON -4"
	1	Safety Shutoff Valve	MAXON -4"
	1	Safety Shutoff Vent Valve	MAXON-2"
	1	Low Gas Pressure Switch	UE400
	1	Pressure Reducing Regulator	1098-EGR
	1	1/2" Meridian NPT Manual Ball Valve	Meridian
	1	1/2" Meridian NPT Manual Ball Valve	Meridian
	1	Pressure Gauge 4" Dial	Haenni
	1	Pressure Gauge 4" Dial	Haenni
	1	DP Transmitter	Fisher 3051
	1	3-Valve Manifold	Fisher 0305RC
	1	Metering Orifice & Flange Set	Orifice Plate
	2	1/2" Meridian NPT Manual Ball Valve	Meridian
	1	Filter Strainer	FIL



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Item Qty. Description Part No.

PILOT GAS TRAIN NOT REQUIRED

Pilot Gas Train NOT required, HESI is used with new burner.

Instrument Air Train

1	Manual Ball Valve	3/4" Meridan
5	Manual Ball Valve	1/2" Meridan
1	Safety Shutoff Valve	VCI 2"
1	Ashcroft	2-1/2" Gauge
1	Manual Ball Valve	3/4" Meridan
2	Ashcroft	B424B

BURNER MANAGEMENT AND PROCESS CONTROL SYSTEM (CCS/BMS)

Item Qty. Description Part No.

1	84 x 60 x18 Enclosure	PHW846018
1	Allen Bradley Control Logix CCS with HART Cards	
Lot	AB IFM Module Interface Cards	
1	Transdution TR5195F Touch Screen Color	HMI
Lot	ILLUMINATED PUSHBUTTONS	AB
1	ESD	AB
Lot	PUSHBUTTONS	AB
Lot	INDICATING LIGHTS	AB
1	FIREYE CHASSIS	E110
1	FIREYE PROGRAMMER	E160
1	FIREYE AMPLIFIER	EUVS4
1	FIREYE EXPANSION MODULE	E300
1	FIREYE SUBBASE	61-1466
1	FIREYE CONNECTING RIBBON CABLE	E350-3
1	FIREYE EXPANSION MODULE SUBBASE	60-1950
1	FIREYE REMOTE RESET CABLE	ED150-6
1	FIREYE REMOTE DISPLAY MTG KIT	129-145-2
Lot	OMRON RELAYS AND BASES	MK3
Lot	OMRON TIMERS	H3CA-8
1	EDWARDS ALARM HORN	846
1	ALARM BEACON	XXXX
1	FABRICATION	PC - FAB
1	TEST AND CHECK	PC - LABOUR
1	LOT of Approvals	PCSI
2	Fireye Flame Detector - Self Checking	95 Insight
1	Oxygen Analyzer	ABB



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6.0 Recommended Spare Parts (NOT Included in Price)

Item	Qty.	Description	Part No.
	1	HESI Ignition System	HESI
	1	KURZ Flow Meter	Kurz 454FTB
	1	Pressure Reducing Regulator	1098-28-EGR
	1	Safety Shutoff Valve	Maxon-4"
	1	Safety Shutoff Valve	Maxon-3/4"
	1	Pressure Gauge 4" Dial	Haenni
	1	Pressure Reducing Regulator	HSR
	1	FIREYE CHASSIS	E110
	1	FIREYE PROGRAMMER	E160
	1	FIREYE AMPLIFIER	EUVS4
	1	FIREYE EXPANSION MODULE	E300
	1	FIREYE SUBBASE	61-1466
	1	FIREYE CONNECTING RIBBON CABLE	E350-3
	1	FIREYE EXPANSION MODULE SUBBASE	60-1950
	1	FIREYE REMOTE RESET CABLE	ED150-6
	1	FIREYE REMOTE DISPLAY MTG KIT	129-145-2
	2	OMRON RELAYS AND BASES	MK3
	2	OMRON TIMERS	H3CA-8
	1	Fireye Flame Detector - Self Checking	95 Insight

Note: Spare parts BUDGET should be approximately 5%~7% of combustion system total.



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7.0 Design Standards

The complete combustion system will be designed by Process Combustion Systems (2000) Inc. It will meet all requirements of the provincial jurisdiction having authority. Process Combustion Systems (2000) Inc. is permitted to practice engineering as recognized by the APEGGA.

8.1 Engineering Services Scope of Supply

Engineering drawings and documentation to be supplied are as follows:

- P&ID (Process and Instrumentation Diagram)
- Overall burner and chamber layout drawings; (plan, side and front elevation)
- Detailed electrical schematic drawings of the control system
- Parts list drawings with bills of materials
- Qty of (3) copies and one (1) CD of Startup, service and maintenance manuals including product literature of all major components

Project Management Services – will be provided to coordinate the issuing of submittal drawings, materials ordering, scheduling, manufacturing, fabrication, assembly and offsite pretesting.

9.0 Pre-Testing

The air heater combustion control system will be completely pre-tested short of firing the burners with fuel. Each component will be pre-adjusted to the point practical, this to minimize the startup time on-site.

NDT on welded components for pressure welds may be performed at the subcontractors' facilities.

A final commissioning test report with device setting set-points will be provided.



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10.0 Site Commissioning

Startup service is available via per diem rates plus all expenses (see rate sheet attached).

COMBUSTION TECHNICIAN / ENGINEER RATE SHEET

Labor:

<u>Description</u>	<u>Hourly Regular</u>	<u>Hourly Overtime</u>
Senior Combustion / Process Application Specialist	\$200.00	\$300.00
Combustion Technician	\$175.00	\$262.50
Project Manager	\$175.00	\$262.50
Installation Supervision	\$160.00	\$240.00

- Regular Rate defined as Monday – Friday - based on a 10 hour day (7:00AM-17:00PM).
- Overtime Rate defined as any time outside of time shown, weekends and / or holidays.
- Minimum daily charge from Calgary Office 4 hours.
- Minimum out of town daily charge 8 hours subject to other standby arrangements / fees.
- Site specific safety training, meetings, related project discussions charged at same rate as above.
- Hotel cancellation fees due to cancelled work or changed schedules to be charge at cost plus 15%
- PCSI supplied Combustion Analyzer at \$250.00 / day flat rate.

Expenses:

Meals, Lodging, Taxi, Air Line Tickets, Rental Vehicle and Related Expenses:
 Cost plus 15%.
 If copy of receipts is required to be submitted with invoice, this must be stated on
 Purchase Order at time of ordering.

Mileage (Ground Transportation from Calgary Office):

..... \$0.85 / km

Terms of Payment:

Payable Net 30 Days on Submission of Invoice;
 All applicable Taxes Extra.



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11.0 Equipment Price and Terms of Payment

- a. **Price with NEW Low NOx Burner**- The price of the complete combustion system with new burner, windbox, combustion air control valve, new valve train and CCS / BMS control panel using the existing, blower, boiler and other components as described in the preceding sections, FOB Ex-works Calgary AB:

- **\$1,035,000.00 USD net excluding any applicable taxes**

- b. **OPTION SIL2 – Price ADD** – As an option we can offer the instrumentation and PLC using SIL2 rated components. This will have where possible “switches” replaced with transmitters; IE: low gas pressure, high gas pressure, valve positioner feedback etc. Air flow metering would use redundant DP transmitters; one for control and the other for the BMS. [The PLC will be either a Control Logix with diagnostic IO or AB AAdvance series or safety PLC (TBD later with discussion with KUC).] The Fireeye flame relay will be eliminated and the BMS logic will all be executed inside the PLC following the latest FM and NFPA 85 requirements:

Control Logix with safety controller (PLC > IO)

Safety: dependability, fault protection

- **\$75,000.00 ~ \$85,000.00 USD net excluding any applicable taxes**

*safer environment
by decreasing
chances of faults*

- **Note: BSM SIL2 Registration is NOT included at this point in time.**

- c. **Pre-Engineering Site Visit** – Site visit including expenses to measure and determine design gas train and components:

*SIL2
1/10M*

- **Included in above amount**

- d. **Payment Terms** – Prices are quoted herein are based in US Dollars with the following payment terms.

- 10% of Price upon receipt of Purchase Order by Supplier
- 20% due with GA drawing submittal
- 30% due with receipt of major components in our shop
- 20% due upon completion of FAT of system in PCS shop (to the extent reasonably possible)
- 10% due upon shipping.
- 10% due upon commissioning.

- e. **Validity** – this proposal is a firm proposal and pricing is valid for 60 days.



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- f. **Spare Parts** – are **NOT** included in the above total price, please allow **5%~7%** additional for commissioning and operating spares.
- g. **Commissioning** – is **NOT** included in the above total, please allow the following:
- Allow between **\$75,000 and \$85,000** for site supervision and commissioning services (including expenses).

12.0 Schedule

Upon receipt of an actionable purchase order from the Buyer, PCSI will assign a project engineer and the design phase will commence immediately.

- Engineering and design: 8~10 weeks
- Submittal for approval process: 2 weeks
- Equipment procurement: (14~16 weeks, running in parallel to manufacturing schedule)
- Manufacturing and assembly: 18~20 weeks
- Testing: 1~2 weeks
- Total Schedule from ARO: 28~32 weeks

13.0 Freight Terms

The control system and valve train will be built entirely in our Calgary shop. The prices quoted are FOB Ex-works Calgary AB.

14.0 Equipment and / or Services NOT Included in this Proposal Offering

- Unloading at Job Site
- Freight to Job Site
- Startup service
- Installation of the burner at the Buyers site
- Storage of any part of the equipment (or complete air heater) upon delay of delivery outside of the Sellers responsibility
- Any and all applicable taxes
- Permit Fee's other than submittal of design drawings to the gas inspection for approval.
- Local gas site inspection (site arrangements and costs are by the installing contractor. Process Combustion Systems can supply the field submittals at extra cost if required).



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15.0 Insurance

Process Combustion Systems (2000) Inc. is insured for \$5,000,000.00 of commercial general liability insurance. Our policy number is 042302402 c/o Lombard Canada.

16.0 Warranty

Warranty applies to the hardware components and fabrication of said hardware provided to this project as listed on the final engineering submittal documents. Our warranty does NOT cover in any way; hardware not supplied by Process Combustion Systems (2000) Inc.

Duration – the warranty duration is a maximum of 20 months from the shipping date, or 15 months from the time of start up / FAT test, which ever occurs first.

Equipment warranty is limited to providing the Buyer with replacement hardware of a like or similar model, suitable for its intended purpose. If it is determined that the subject hardware has failed during normal operation and usage and has not be damaged otherwise, replacement hardware will be provided FOB Calgary at no cost to the Buyer.

Defective hardware must be returned to Process Combustion Systems (2000) Inc. for evaluation in a timely manner (2~3 weeks) and the final decision to warranty an item is at the sole discretion of PCSI.

PCSI reserves the right to repair any item or component at its discretion rather than replace said component.

The warranty provided by Process Combustion Systems (2000) Inc. will under no circumstances extend to any defect, failure or non-performance caused by normal wear or by Buyers / Owners failure to follow instructions or other negligent misuse of the equipment or any part of the equipment. The warranty covers newly supplied material and installation.

We thank you again for this opportunity to present this proposal and we stand ready to answer any questions that you may have.

Sincerely Yours;

Jim Kondziela

Jim Kondziela
Principal - VP of Sales and Operations
Process Combustion Systems Inc.



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17.0 Message from the Principal Partners Of Process Combustion Systems Inc.

Process Combustion Systems (2000) Inc. was established in 1981 by Mr. Dale Paschinski and Mr. Dave Skoropad and they remain today as active working principal partners in the company.

Today PCSI has matured to be the most diversified combustion systems, industrial furnace design and process control firm in Canada. We are highly respected in the industries we serve as a high quality engineering design and combustion system supply company.

PCSI is closely affiliated with some of the best combustion, controls and energy services companies in the world, these including:

- Fives North American Mfg. CO Ltd.
- Hamworthy Peabody
- Chentronics
- Fireye Company
- Kentube Heat Exchangers
- Victory Energy (Boilers)

Over the last 25 years we have provided a variety of high temperature furnace and process equipment to such companies as:

- Pot Ash Corporation since 1980
- IMC Kalium / Mosaic since 1985
- Cargill since 1990
- Canadian Fertilizer since 1990



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Some of our recent work included the complete design for three (3) of the world's largest powder coating ovens (for continuous coating of pipe) for Shaw Pipes facility in Jubail, Saudi Arabia, this including the supply of the complete combustion and control systems including all the field commissioning. Also for Shaw we designed, built and commissioned three (3) additional systems for locations in Dubai and Thailand.

Another project included the supply of the combustion system for the world's largest sulfuric acid furnace for BHP located in Ravensthorpe, Australia.

PCSI has also grown in the last 25 years to be the largest steam power boiler combustion system upgrade company in Western Canada. These along with our continuing growth in Canada's burgeoning Oil Sands sector and strong growth from the potash, uranium and other precious metals mining sectors with a mix of agricultural processing maintains a strong light for the our future.

In 2007 Jim Kondziela partnered into the PCSI organization, Jim brings with him a combined 30 years of combustion and industrial furnace experience. He spent 25 years with North American Mfg. CO on the west coast as the Western Regional Sales Manager for them and the last 4 years with Bloom Engineering Company as the International Sales Manager working primarily in the burgeoning metals industries (steel and aluminum) throughout China and Asia in general.

In 2008 ~ 2009 we added support to our engineering, construction and service divisions with now approaching 20 full time direct and contract employees.



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PCS Organizational Chart

Principal Partners

Jim Kondziela
VP Sales / Operations

Dave Skoropad
General Manager
President

Dale Paschinski
Manager Boiler
Sales

Sandi Paschinski
Secretary
Treasurer

Todd Gilbert
Engineering
Manager

Robert Peddle
Engineering

Roger Mills
Sales Manager

Mark Skovmose
Engineering

Lee Mielke
Engineering

Chuck Archibald
Controls
Engineering

Dwight Bishop
Parts Manager
Shipping / Receiving

Rochelle Morozoff
Office Manager

Dustin MacPherson
Office Assistant
Shipping / Receiving

Rellie Maget
Instrumentation
Controls Mfg.

James Sandland
Service Manager

Glen Kraychy
Service Technician

Chris Paschinski
Construction
Manager

Thomas Jefferson
Construction

Leina Mai
Documentation

Only through internal growth, by adding key individuals and facilities will we maintain our industry strengths and pro-active designs to supply our client base the "Future Technologies" today.

Sincerely Yours;

Dale Paschinski
Dave Skoropad
Jim Kondziela

End of Proposal

WRAP Fugitive Dust Handbook



Prepared for:

**Western Governors' Association
1515 Cleveland Place, Suite 200
Denver, Colorado 80202**

Prepared by:

**Countess Environmental
4001 Whitesail Circle
Westlake Village, CA 91361
(WGA Contract No. 30204-111)**

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PREFACE

In 2004 the Western Regional Air Partnership's (WRAP) Dust Emissions Joint Forum (DEJF) selected Countess Environmental to prepare a fugitive dust handbook and an associated website (www.wrapair.org/forums/dejf/fdh) for accessing the information contained in the handbook. The material presented in the original handbook released on November 15, 2004 addressed the estimation of uncontrolled fugitive dust emissions and emission reductions achieved by demonstrated control techniques for eight major fugitive dust source categories. In 2006 WRAP hired Countess Environmental to update the handbook. The updates included revising each chapter in the handbook to reflect the new PM_{2.5}/PM₁₀ ratios developed for WRAP by the Midwest Research Institute (MRI) in 2005, addressing four additional major fugitive dust source categories as well as several minor source categories, and updating the existing chapters.

The material in this handbook focuses on fugitive dust emissions "at the source" and does not evaluate factors related to the transport and impact of emissions on downwind locations where ambient air monitoring occurs. The methods for estimation of dust emissions rely primarily on AP-42 with additional references to alternative methods adopted by state and local control agencies in the WRAP region. With regard to emission factor correction parameters, source extent/activity levels, control efficiencies for demonstrated control techniques, and emission reductions by natural mitigation and add-on control measures, sources of data are identified and default values are provided in tables throughout the handbook. Graphs, charts, and tables are provided throughout the handbook to assist the end user.

The handbook:

- (a) compiles technical and policy evaluations for the benefit of WRAP members, stakeholders, and other interested parties when addressing specific air quality issues and when developing regional haze implementation plans;
- (b) incorporates available information from both the public (federal, state and local air quality agencies) and private sectors (e.g., reports addressing options to reduce fugitive dust emissions in areas of the country classified as nonattainment for PM₁₀); and
- (c) serves as a comprehensive reference resource tool of currently available technical information on emission estimation methodologies and control measures for the following twelve fugitive dust source categories: agricultural tilling, agricultural harvesting, construction and demolition, materials handling, paved roads, unpaved roads, mineral products industry, abrasive blasting, livestock husbandry, and windblown dust emissions from agricultural fields, material storage piles, and exposed open areas.

This handbook is not intended to suggest any preferred method to be used by stakeholders in preparation of SIPs and/or Conformity analyses but rather to outline the most commonly adopted methodologies currently used in the US. The information contained in this handbook has been derived from a variety of sources each with its own accuracy and use limitations. Because many formulae and factors incorporate default values that have been derived for average US conditions, area specific factors should be used whenever they are available. Additionally, the

input terms (commonly referred to as “correction factors”) used in any given emission factor equation presented in this handbook were obtained using a specific test methodology and are designed to give an estimate of the emission from a specific activity or source under specific conditions. As a result the emission estimate must be used appropriately in any downstream application such as dispersion modeling of primary PM emissions.

It is important to note that EPA’s criteria for exceedances, violations, and model calibration and validation are based on ambient data from the National Ambient Air Monitoring Sites. It should be further noted that estimates of the relative contribution of fugitive dust to ambient PM concentrations based on chemical analysis of exposed filters are usually much lower than that based on emission inventory estimates, in some cases by a factor of 4. Part of this discrepancy between ambient measurements and emission estimates is due to the near source deposition losses of freshly generated fugitive dust emissions. It is not an objective of this handbook to resolve this modeling discrepancy issue. It is the role of modelers to incorporate deposition losses into their dispersion models and to account for the formation of secondary PM, which in many areas of the country are responsible for an overwhelming contribution to exceedances of the federal PM NAAQS.

Applicability to Tribes

The Regional Haze Rule explicitly recognizes the authority of tribes to implement the provisions of the Rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act §301(d) and the Tribal Authority Rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.
2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.
3. The Regional Haze Rule expressly provides that tribal visibility programs are “not dependent on the strategies selected by the state or states in which the tribe is located” (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12).
4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003; rather they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).
5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a

government-to-government basis in developing tribe-specific or generally applicable TIPs where necessary (see, e.g., 63 Fed. Reg.7263-64).

It is our hope that the findings and recommendations of this handbook will prove useful to tribes, whether they choose to submit full or partial 308 or 309 TIPs, or work with EPA to develop FIPs. We realize that the amount of modification necessary will vary considerably from tribe to tribe and we have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the “stakeholders” (private interest) which participate on Forums and Committees but are not eligible for the Board. Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members, Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this handbook as a consensus document.

EXECUTIVE SUMMARY

This fugitive dust handbook addresses the estimation of uncontrolled fugitive dust emissions and emission reductions achieved by demonstrated control techniques for twelve major and several minor fugitive dust source categories. The handbook focuses on fugitive dust emissions “at the source” and does not evaluate factors related to the transport and impact of emissions on downwind locations where ambient air monitoring occurs. The methods for estimating emissions draw (a) from established methods published by the USEPA, specifically AP-42: Compilation of Air Pollutant Emission Factors that are available from the Internet (www.epa.gov/ttn/chief/ap42), and (b) from alternate methods adopted by state and local air control agencies in the WRAP region such as the California Air Resources Board (www.arb.ca.gov/ei/areasrc/areameth.htm), Clark County, Nevada (www.co.clark.nv.us/air_quality), and Maricopa County, Arizona (www.maricopa.gov/envsvc/air). Sources of data are identified and default values for emission factor correction parameters, source extent/activity levels, control efficiencies, and emission reductions by natural mitigation and add-on control measures are provided in tables throughout the handbook.

The handbook has several distinct features that give it a major advantage over the use of AP-42 or other resource documents. The handbook is a comprehensive document that contains all the necessary information to develop control strategies for major sources of fugitive dust. These features include:

- (a) extensive documentation of emission estimation methods adopted by both federal and state agencies as well as methods in the “developmental” stage;
- (b) detailed discussion of demonstrated control measures;
- (c) lists of published control efficiencies for a large number of fugitive dust control measures;
- (d) example regulatory formats adopted by state and local agencies in the WRAP region;
- (e) compliance tools to assure that the regulations are being followed; and
- (f) a detailed methodology for calculating the cost-effectiveness of different fugitive dust control measures, plus sample calculations for control measure cost-effectiveness for each fugitive dust source category.

The handbook and associated website (www.wrapair.org/forums/dejf/fdh) are intended to:

- (a) support technical and policy evaluations by WRAP members, stakeholders, and other interested parties when addressing specific air quality issues and when developing regional haze implementation plans;
- (b) incorporate available information from both the public and private sectors that address options to reduce fugitive dust emissions in areas of the country classified as nonattainment for PM₁₀; and

- (c) provide a comprehensive resource on emission estimation methodologies and control measures for the following twelve fugitive dust source categories: agricultural tilling, agricultural harvesting, construction and demolition, materials handling, paved roads, unpaved roads, minerals products industry, abrasive blasting, livestock husbandry, and windblown dust emissions from agricultural fields, material storage piles, and exposed open areas.

The handbook contains separate, stand-alone chapters for each of the twelve major fugitive dust source categories identified above. Because the chapters are meant to stand alone, there is some redundancy between chapters. Each chapter contains a discussion of characterization of the source emissions, established emissions estimation methodologies, demonstrated control techniques, regulatory formats, compliance tools, a sample control measure cost-effectiveness calculation, and references. A separate chapter addressing several minor fugitive dust source categories and several appendices are also included in the handbook. Appendix A contains a discussion of test methods used to quantify fugitive dust emission rates. Appendix B contains cost information for demonstrated control measures. Appendix C contains a step-wise method to calculate the cost-effectiveness of different fugitive dust control measures. Appendix D contains a brief discussion of fugitive PM₁₀ management plans and record keeping requirements mandated by one of the air quality districts within the WRAP region.

A list of fugitive dust control measures that have been implemented by jurisdictions designated by the USEPA as nonattainment for federal PM₁₀ standards is presented in the table below. The published PM₁₀ control efficiencies for different fugitive dust control measures vary over relatively large ranges as reflected in the table. The user of the handbook is cautioned to review the assumptions included in the original publications (i.e., references identified in each chapter of the handbook) before selecting a specific PM₁₀ control efficiency for a given control measure. It should be noted that Midwest Research Institute (MRI) found no significant differences in the measured control efficiencies for the PM_{2.5} and PM₁₀ size fractions of unpaved road emissions based on repeated field measurements of uncontrolled and controlled emissions. Thus, without actual published PM_{2.5} control efficiencies, the user may wish to utilize the published PM₁₀ values for both size fractions.

Many control cost-effectiveness estimates were reviewed in preparation of this handbook. Some of these estimates contain assumptions that are difficult to substantiate and often appear unrealistic. Depending on which assumptions are used, the control cost-effectiveness estimates can vary by one to two orders of magnitude. Thus, rather than presenting existing cost-effectiveness estimates, the handbook presents a detailed methodology to calculate the cost-effectiveness of different fugitive dust control measures. This methodology is presented in Appendix C. The handbook user is advised to calculate the cost-effectiveness values for different fugitive dust control options based on current cost data and caveats that are applicable to the particular situation.

Fugitive Dust Control Measures Applicable for the WRAP Region

Source Category	Control Measure	Published PM10 Control Efficiency
Agricultural Tilling	Reduce tilling during high winds	1 – 5%
	Roughen surface	15 – 64%
	Modify equipment	50%
	Employ sequential cropping	50%
	Increase soil moisture	90%
	Use other conservation management practices	25 - 100%
Agricultural Harvesting	Limited activity during high winds	5 – 70%
	Modify equipment	50%
	Night farming	10%
	New techniques for drying fruit	25 –60%
Construction/Demolition	Water unpaved surfaces	10 – 74%
	Limit on-site vehicle speed to 15 mph	57%
	Apply dust suppressant to unpaved areas	84%
	Prohibit activities during high winds	98%
Materials Handling	Implement wet suppression	50 – 90%
	Erect 3-sided enclosure around storage piles	75%
	Cover storage pile with a tarp during high winds	90%
Paved Roads	Sweep streets	4 – 26%
	Minimize trackout	40 – 80%
	Remove deposits on road ASAP	> 90%
Unpaved Roads	Limit vehicle speed to 25 mph	44%
	Apply water	10 – 74%
	Apply dust suppressant	84%
	Pave the surface	>90%
Mineral Products Industry	Cyclone or muliclone	68 –79%
	Wet scrubber	78 –98%
	Fabric filter	99 – 99.8%
	Electrostatic precipitator	90 – 99.5%
Abrasive Blasting	Water spray	50 – 93%
	Fabric filter	> 95%
Livestock Husbandry	Daily watering of corrals and pens	> 10%
	Add wood chips or mulch to working pens	> 10%
Wind Erosion (agricultural, open area, and storage piles)	Plant trees or shrubs as a windbreak	25%
	Create cross-wind ridges	24 – 93%
	Erect artificial wind barriers	4 – 88%
	Apply dust suppressant or gravel	84%
	Revegetate; apply cover crop	90%
	Water exposed area before high winds	90%

Chapter 1. Introduction

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This chapter describes the purpose for the preparation of this fugitive dust handbook; presents a summary of WRAP's fugitive dust definition and dust emissions categorization scheme; provides a brief overview/primer on fugitive dust that includes a summary of factors affecting dust emissions, an overview of emission calculation procedures (including a discussion of emission factors), and a discussion of options for controlling emissions; and summarizes the organizational structure of the handbook.

This handbook does not address particulate emissions from wildfires or prescribed fires that are discussed in Section 13.1 of EPA's Compilation of Air Pollutant Emission Factors (AP-42). For more information on particulate emissions from fires, the reader is directed to the WRAP's Fire Emissions Joint Forum at www.wrapair.org/forums/fejf.

1.1 Background

Most of the more than 70 areas of the United States that have been unable to attain the national ambient-air quality standards (NAAQS) for PM₁₀ (particles smaller than 10 µm in aerodynamic diameter) are in western states with significant emission contributions from fugitive dust sources. Fugitive dust sources may be separated into two broad categories: process sources and open dust sources. Process sources of fugitive emissions are those associated with industrial operations such as rock crushing that alter the characteristics of a feed material. Open dust sources are those that generate non-ducted emissions of solid particles by the forces of wind or machinery acting on exposed material. Open dust sources include industrial sources of particulate emissions associated with the open transport, storage, and transfer of raw, intermediate, and waste aggregate materials, and nonindustrial sources such as unpaved roads and parking lots, paved streets and highways, heavy construction activities, and agricultural tilling.

On a nationwide basis, fugitive dust consists mostly of soil and other crustal materials. However, fugitive dust may also be emitted from powdered or aggregate materials that have been placed in open storage piles or deposited on the ground or roadway surfaces by spillage or vehicle trackout. Dust emissions from paved roadways contain tire and break wear particles in addition to resuspended road surface dust composed mostly of crustal geological material.

Generic categories of open dust sources include:

- Agricultural Tilling and Harvesting
- Construction and Demolition (Buildings, Roads)
- Materials Handling
- Paved Travel Surfaces
- Unpaved Travel Surfaces
- Minerals Products Industry (Metallic Ores, Non-metallic Ores, Coal)
- Abrasive Blasting
- Livestock Husbandry (Dairies, Cattle Feedlots)
- Wind Erosion of Exposed Areas (Agricultural Fields, Open Areas, Storage Piles)

1.2 Purpose of the Handbook

In early 2004 the Western Regional Air Partnership's (WRAP) Dust Emissions Joint Forum (DEJF) selected the Countess Environmental project team composed of senior scientists/consultants from Countess Environmental and Midwest Research Institute to prepare a fugitive dust handbook and a website (www.wrapair.org/forums/dejf/fdh) for accessing the information contained in the handbook. The handbook and website are intended to:

- (a) be used for technical and policy evaluations by WRAP members, stakeholders, and other interested parties when addressing specific air quality issues and when developing regional haze implementation plans;
- (b) incorporate available information from both the public and private sectors that address options to reduce fugitive dust emissions in areas of the country classified as nonattainment for PM₁₀; and
- (c) serve as a comprehensive reference resource tool that will provide technical information on emission estimation methodologies and control measures for all of the major and several minor fugitive dust source categories.

The material presented in the original handbook released on November 15, 2004 addressed the estimation of uncontrolled fugitive dust emissions and emission reductions achieved by demonstrated control techniques for eight major fugitive dust source categories. In 2006 WRAP hired Countess Environmental to update the handbook. The updates included revising each chapter in the handbook to reflect the new PM_{2.5}/PM₁₀ ratios developed for WRAP by the Midwest Research Institute (MRI) in 2005, addressing four additional major fugitive dust source categories as well as several minor source categories, and updating the existing chapters.

1.3 Dust Definition and Categorization Scheme

The WRAP Dust Emissions Joint Forum (DEJF) adopted a definition of dust and fugitive dust on October 21, 2004 that included developing criteria for separating anthropogenic dust from dust of natural origin.¹ Dust was defined as particulate matter which is or can be suspended into the atmosphere as a result of mechanical, explosive, or windblown suspension of geologic, organic, synthetic, or dissolved solids, and does not include non-geologic particulate matter emitted directly by internal and external combustion processes. Fugitive dust was defined as dust that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. The purpose of these definitions is to provide consistency when using the terms dust, fugitive dust, anthropogenic dust, and natural dust in the context of the federal regional haze rule. The distinction between anthropogenic dust and natural dust is made to: (a) clarify how the WRAP defines dust, its sources, and causes; (b) provide an operational definition for use in receptor- and emissions-based source apportionment techniques; and (c) identify and prioritize sources of dust which are most appropriate to control for purposes of improving visibility in Class I areas.

Natural and anthropogenic dust will often be indistinguishable and may occur simultaneously. For example, natural, barren areas will emit some dust during high wind events, but will emit more when the surface is disturbed by human activities. Hence, the dust from a disturbed, naturally barren area on a given day could be part natural and part anthropogenic. Any mitigation of dust for regional haze control would likely be focused on those anthropogenic sources which are most likely to contribute to visibility impairment in Class I areas and which are technically feasible and cost-effective to control. Sources that are already controlled or partially controlled may be technically infeasible or not cost-effective to control further. According to the WRAP’s definition of dust, anthropogenic emissions do not include any emissions that would occur if the surface were not disturbed or altered beyond a natural range. Such emissions should be subtracted, if practicable, from the total dust emissions to determine the precise anthropogenic emission quantity.

Examples of anthropogenic and natural dust categories in accordance with the WRAP’s dust definition are provided in Tables 1-1 and 1-2. All mechanically suspended dust from human activities is classified as anthropogenic emissions, and windblown dust from lands not disturbed or altered by humans beyond a natural range is classified as natural emissions. For emissions from other sources, the emissions may be categorized as either anthropogenic or natural, depending on whether the mechanically-suspended emissions are due to indigenous or non-indigenous animals, and whether the windblown emissions are from surfaces disturbed by humans beyond a natural range or from surfaces which have not been disturbed by humans beyond a natural range.

Table 1-1. WRAP Fugitive Dust Categorization Scheme for Mechanically Generated Dust

Anthropogenic Dust	Natural Dust
Mechanically- and explosively-suspended solids and dissolved solids from activities including but not limited to: <ul style="list-style-type: none"> • Agriculture • Construction, mining, and demolition • Material handling, processing, and transport • Vehicular movement on paved and unpaved surfaces • Animal movement on surfaces which have been disturbed or altered by humans beyond a natural range • Animal movement on undisturbed or unaltered surfaces by a number of animals which is greater than native populations • Cooling towers 	<ul style="list-style-type: none"> • Movement of a number of indigenous animals on surfaces which have not been disturbed or altered by humans beyond a natural range • Natural landslides, rockslides, and avalanches • Solids and dissolved solids emitted by volcanoes, geysers, waterfalls, rapids, and other types of splashing • Extraterrestrial material and impacts

Table 1-2. WRAP Fugitive Dust Categorization Scheme for Windblown Dust

Anthropogenic Dust	Natural Dust
<p>Solids and dissolved solids entrained by wind passing over surfaces that have been disturbed or altered by humans beyond a natural range. Such surfaces may include, but are not limited to:</p> <ul style="list-style-type: none"> • Undeveloped lands • Construction and mining sites • Material storage piles, landfills, and vacant lots • Agricultural crop, range, and forest lands • Roadways and parking lots • Artificially-exposed beds of natural lakes and rivers • Exposed beds of artificial water bodies • Areas burned by anthropogenic fires (as defined by the WRAP Policy for Categorizing Fire Emissions) which have yet to be revegetated or stabilized 	<p>Solids and dissolved solids entrained by wind passing over surfaces that have not been disturbed or altered by humans beyond a natural range. Such surfaces may include, but are not limited to:</p> <ul style="list-style-type: none"> • Naturally-dry river and lake beds • Barren lands, sand dunes, and exposed rock • Natural water bodies (e.g., sea spray) • Non-agricultural grass, range, and forest lands • Areas burned by natural fires (as defined by the WRAP Policy for Categorizing Fire Emissions) which have yet to be revegetated or stabilized
<p>Wind-blown particulate matter from sources created by natural events over 12 months ago, similar to EPA's natural events policy</p>	

The WRAP's original dust characterization scheme broke down fugitive dust emissions into five categories ranging from 100% anthropogenic emissions (i.e., all mechanically-suspended dust from human activities except animal movement) to 100% natural emissions (i.e., windblown dust from lands not disturbed or altered by humans beyond a natural range), with three categories between these two extremes representing a mixture of anthropogenic and natural emissions. Environ developed an alternative dust characterization scheme for WRAP in 2005 that broke down fugitive dust emissions into three categories based on activity rather than a description of spatial location since very different dust sources may spatially co-exist at the same site.² Environ's three categories are:

Category 1: Purely anthropogenic sources (e.g., construction, mining, wind erosion and vehicle traffic on paved and unpaved roads, agricultural tilling and harvesting, wind erosion of agricultural fields, particle emissions from cooling towers).

Category 2: Purely natural sources (e.g., volcanic ash emissions, wind erosion of unstable soil following landslides, mineral particle emissions from wave action/sea spray).

Category 3: Natural sources that may be anthropogenically influenced (e.g., wind erosion and mechanical suspension of soil due to animal movement [both native and non-native], wind erosion of bare areas on natural lands [undisturbed versus previously disturbed], wind erosion of sediment from dried ephemeral water bodies [natural or anthropogenic]).

1.4 Factors Affecting Dust Emissions

1.3.1 Mechanically Generated Dust

Mechanically generated emissions from open dust sources exhibit a high degree of variability from one site to another, and emissions at any one site tend to fluctuate widely. The site characteristics that cause these variations may be grouped into (a) properties of the exposed surface material from which the dust originates, and (b) measures of energy expended by machinery interacting with the surface. These site characteristics are discussed below.

Surface Material Texture and Moisture. The dry-particle size distribution of the exposed soil or surface material determines its susceptibility to mechanical entrainment. The upper size limit for particles that can become suspended has been estimated at $\sim 75 \mu\text{m}$ in aerodynamic diameter.³ Conveniently, $75 \mu\text{m}$ in physical diameter is also the smallest particle size for which size analysis by dry sieving is practical.⁴ Particles passing a 200-mesh screen on dry sieving are termed “silt”. Note that for fugitive dust particles, the physical diameter and aerodynamic diameter are roughly equivalent because of the offsetting effects of higher density and irregular shape. Dust emissions are known to be strongly dependent on the moisture level of the mechanically disturbed material.³ Water acts as a dust suppressant by forming cohesive moisture films among the discrete grains of surface material. In turn, the moisture level depends on the moisture added by natural precipitation, the moisture removed by evaporation, and moisture movement beneath the surface. The evaporation rate depends on the degree of air movement over the surface, material texture and mineralogy, and the degree of compaction or crusting. The moisture-holding capacity of the air is also important, and it correlates strongly with the surface temperature. Vehicle traffic intensifies the drying process primarily by increasing air movement over the surface.

Mechanical Equipment Characteristics. In addition to the material properties discussed above, it is clear that the physical and mechanical characteristics of materials handling and transport equipment also affect dust emission levels. For example, visual observation suggests (and field studies have confirmed) that vehicle emissions per unit of unpaved road length increase with increasing vehicle speed.³ For traffic on unpaved roads, studies have also shown positive correlations between emissions and (a) vehicle weight and (b) number of wheels per vehicle.⁵ Similarly, dust emissions from materials-handling operations have been found to increase with increasing wind speed and drop distance.

1.3.2 Wind Generated Dust

Wind-generated emissions from open dust sources also exhibit a high degree of variability from one site to another, and emissions at any one site tend to fluctuate widely. The site characteristics that cause these variations may be grouped into (a) properties of the exposed surface material from which the dust originates, and

(b) measures of energy expended by wind interacting with the erodible surface. These site characteristics are discussed below.

Surface Material Texture and Moisture. As in the case of mechanical entrainment, the dry-particle size distribution of the exposed soil or surface material determines its susceptibility to wind erosion. Wind forces move soil particles by three transport modes: saltation, surface creep, and suspension. Saltation describes particles, ranging in diameter from about 75 to 500 μm , that are readily lifted from the surface and jump or bounce within a layer close to the air-surface interface. Particles transported by surface creep range in diameter from about 500 to 1,000 μm . These large particles move very close to the ground, propelled by wind stress and by the impact of small particles transported by saltation. Particles smaller than about 75 μm in diameter move by suspension and tend to follow air currents. As stated above, the upper size limit of silt particles (75 μm in physical diameter) is roughly the smallest particle size for which size analysis by dry sieving is practical. The threshold wind speed for the onset of saltation, which drives the wind erosion process, is also dependent on soil texture, with 100-150 μm particles having the lowest threshold speed. Saltation provides energy for the release of particles in the PM10 size range that typically are bound by surface forces to larger clusters. Dust emissions from wind erosion are known to be strongly dependent on the moisture level of the erodible material.⁶ The mechanism of moisture mitigation is the same as that described above for mechanical entrainment.

Nonerodible Elements. Nonerodible elements, such as clumps of grass or stones (larger than about 1 cm in diameter) on the surface, consume part of the shear stress of the wind which otherwise would be transferred to erodible soil. Surfaces impregnated with a large density of nonerodible elements behave as having a “limited reservoir” of erodible particles, even if the material protected by nonerodible elements is itself highly erodible. Wind-generated emissions from such surfaces decay sharply with time, as the particle reservoir is depleted. Surfaces covered by unbroken grass are virtually nonerodible.

Crust Formation. Following the wetting of a soil or other surface material, fine particles will move to form a surface crust. The surface crust acts to hold in soil moisture and resist erosion. The degree of protection that is afforded by a soil crust to the underlying soil may be measured by the modulus of rupture (roughly a measure of the hardness of the crust) and thickness of the crust.⁷ Exposed soil that lacks a surface crust (e.g., a disturbed soil or a very sandy soil) is much more susceptible to wind erosion.

Frequency of Mechanical Disturbance. Emissions generated by wind erosion are also dependent on the frequency of disturbance of the erodible surface. A disturbance is defined as an action that results in the exposure of fresh surface material. This would occur whenever a layer of aggregate material is either added to or removed from the surface. The disturbance of an exposed area may also result from the turning of surface material to a depth exceeding the size of the largest material present. Each time that a surface is disturbed, its erosion potential is increased by destroying the mitigative effects of crusts, vegetation, and friable nonerodible elements, and by exposing new surface fines.

Wind Speed. Under high wind conditions that trigger wind erosion by exceeding the threshold velocity, the wind speed profile near the erodible surface is found to follow a logarithmic distribution:⁶

$$u(z) = \frac{u^*}{0.4} \ln \frac{z}{z_0} \quad (z > z_0) \quad (1)$$

where: u = wind speed (cm/s)
 u^* = friction velocity (cm/s)
 z = height above test surface (cm)
 z_0 = roughness height (cm)
0.4 = von Karman's constant (dimensionless)

The friction velocity (u^*) is a measure of wind shear stress on the erodible surface, as determined from the slope of the logarithmic velocity profile. The roughness height (z_0) is a measure of the roughness of the exposed surface as determined from the y-intercept of the velocity profile (i.e., the height at which the wind speed is zero) on a logarithmic-linear graph. Agricultural scientists have established that total soil loss by continuous wind erosion of highly erodible fields is dependent roughly on the cube of wind speed above the threshold velocity.⁶ More recent work has shown that the loss of particles in suspension mode follows a similar dependence. Soils protected by nonerodible elements or crusts exhibit a weaker dependence of suspended particulate emissions on wind speed.⁹

Wind Gusts. Although mean atmospheric wind speeds may not be sufficient to initiate wind erosion from a particular "limited-reservoir" surface, wind gusts may quickly deplete a substantial portion of its erosion potential. In addition, because the erosion potential (mass of particles constituting the "limited reservoir") increases with increasing wind speed above the threshold velocity, estimated emissions should be related to the gusts of highest magnitude. The current meteorological variable which appropriately reflects the magnitude of wind gusts is the fastest 2-minute wind speed from the "First Order Summary of the Day," published by the U.S. Weather Service for first order meteorological stations.¹⁰ The quantity represents the wind speed corresponding to the largest linear passage of wind movement during a 2-minute period. Two minutes is approximately the same duration as the half-life of the erosion process (i.e., the time required to remove one-half the erodible particles on the surface). It should be noted that instantaneous peak wind speeds can significantly exceed the fastest 2-minute wind speed. Because the threshold wind speed must be exceeded to trigger the possibility of substantial wind erosion, the dependence of erosion potential on wind speed cannot be represented by any simple linear function. For this reason, the use of an average wind speed to calculate an average emission rate is inappropriate.

Wind Accessibility. If the erodible material lies on an exposed area with little penetration into the surface wind layer, then the material is uniformly accessible to the wind. If this is not the case, it is necessary to divide the erodible area into subareas representing different degrees of exposure to wind. For example, the results of physical modeling show that the frontal face of an elevated materials storage pile is exposed to

surface wind speeds of the same order as the approach wind speed upwind of the pile at a height matching the top of the pile;¹¹ on the other hand, the leeward face of the pile is exposed to much lower wind speeds.

1.5 Use of Satellite Imagery to Inventory Erodible Vacant Land

Windblown dust from arid soils in the West contributes to exceedances of national air quality standards for inhalable particulate matter. This problem is intensifying because of increasing land disturbance associated with rapid population growth in areas such as the Las Vegas Valley. The rates of fine particle emissions from open areas are strongly dependent on the type and frequency of land disturbance that destroys the mitigative stabilization effects of natural crusting and vegetation. Satellite imagery has been shown to be a useful tool in tracking land disturbances (source activity levels) and the resultant degree of soil vulnerability to high wind events. This method has recently been used to develop an inventory of native desert, disturbed vacant land, stabilized vacant land and private unpaved roads in the Las Vegas Valley.¹² Wind tunnel studies have shown that each of these land categories have distinctly different potentials for wind-generated dust emissions. For example, native desert is essentially non-erodible because of the high stability of the undisturbed soil surface. Conversely, disturbed vacant land such as active grading areas at construction sites has the highest erodibility among the inventoried land categories.

In this study funded by Clark County, Nevada, multi-spectral satellite imagery was used to inventory vacant land and private unpaved roads throughout the Las Vegas Valley. Landsat TM imagery was found to be appropriate for classifying surface areas as a measure of activity level. Although Landsat TM imagery has much lower spatial resolution (30 meter pixel size) than commercial satellite imagery (10 times smaller pixel size), it has higher spectral resolution (an additional two IR wavelength bands) and costs only about 1 percent of the cost of commercial satellite imagery. In the surface classification process, it was found useful to define additional land categories that could be profiled with the satellite imagery, as follows: barren/shadow (areas with steep slopes); concrete; urban vegetation (golf courses and irrigated parks); natural drainage (rocky surfaces); and urban structures (rooftops, asphalt surfaces, etc.). Ground-truthing test sites were used to develop and verify the applicability of distinctive multi-spectral reflectance patterns for each land category. A classification error matrix showed that the method has an 89 percent reliability for this application. This method can be applied at regular intervals to track the effect of land development on emissions from open areas.

1.6 Emission Calculation Procedure

A calculation of the estimated emission rate for a given source requires data on source extent, uncontrolled emission factor, and control efficiency. The mathematical expression for this calculation is given as follows:

$$R = SE e (1 - c) \quad (2)$$

where: R = estimated mass emission rate in the specified particle size range
 SE = source extent
 e = uncontrolled emission factor in the specified particle size range (i.e., mass of uncontrolled emissions per unit of source extent)
 c = fractional efficiency of control

The source extent (activity level) is the appropriate measure of source size or the level of activity that is used to scale the uncontrolled emission factor to the particular source in question. For process sources of fugitive particulate emissions, the source extent is usually the production rate (i.e., the mass of product per unit time). Similarly, the source extent of an open dust source entailing a batch or continuous drop operation is the rate of mass throughput. For other categories of open dust sources, the source extent is related to the area of the exposed surface that is disturbed by either wind or mechanical forces. In the case of wind erosion, the source extent is simply the area of erodible surface. For emissions generated by mechanical disturbance, the source extent is also the surface area (or volume) of the material from which the emissions emanate. For vehicle travel, the disturbed surface area is the travel length times the average daily traffic (ADT) count, with each vehicle having a disturbance width equal to the width of a travel lane.

If an anthropogenic control measure (e.g., treating the surface with a chemical binder which forms an artificial crust) is applied to the source, the uncontrolled emission factor in Equation 2 must be multiplied by an additional term to reflect the resulting fractional control. In broad terms, anthropogenic control measures can be considered as either continuous or periodic, as the following examples illustrate:

Continuous controls	Periodic controls
Wet suppression at conveyor transfer points	Watering or chemical treatment of unpaved roads
Enclosures/wind fences around storage piles	Sweeping of paved travel surfaces
Continuous vegetation of exposed areas	Chemical stabilization of exposed areas

The major difference between the two types of controls is related to the time dependency of performance. For continuous controls, the efficiency of the control measure is essentially constant with respect to time. On the other hand, the efficiency associated with periodic controls tends to decrease (decay) with time after application until the next application, at which time the cycle repeats but often with some residual effects from the previous application.

In order to quantify the performance of a specific periodic control, two measures of control efficiency are required. The first is “instantaneous” control efficiency and is defined by:

$$c(t) = \left(1 - \frac{e_c(t)}{e_u}\right) \times 100 \quad (3)$$

where: $c(t)$ = instantaneous control efficiency (percent)
 $e_c(t)$ = instantaneous emission factor for the controlled source
 e_u = uncontrolled emission factor
 t = time after control application

The other important measure of periodic control performance is average efficiency, defined as:

$$C(T) = \frac{1}{T} \int_0^T c(t) dt \quad (4)$$

where: $c(t)$ = instantaneous control efficiency at time t after application (percent)
 T = time period over which the average control efficiency is referenced

The average control efficiency is needed to estimate the emission reductions due to periodic applications.

1.7 Emission Factors

Early in the USEPA field testing program to develop emission factors for fugitive dust sources, it became evident that uncontrolled emissions within a single generic source category may vary over two or more orders of magnitude as a result of variations in source conditions (equipment characteristics, material properties, and climatic parameters). Therefore, it would not be feasible to represent an entire generic source category in terms of a single-valued emission factor, as traditionally used by the USEPA to describe average emissions from a narrowly defined ducted source operation. In other words, it would take a large matrix of single-valued factors to adequately represent an entire generic fugitive dust source category. In order to account for emissions variability, therefore, the approach was taken that fugitive dust emission factors be constructed as mathematical equations for sources grouped by the dust generation mechanisms. The emission factor equation for each source category would contain multiplicative correction parameter terms that explain much of the variance in observed emission factor values on the basis of variances in specific source parameters. Such factors would be applicable to a wide range of source conditions, limited only by the extent of experimental verification. For example, the use of the silt content as a measure of the dust generation potential of a material acted on by the forces of wind or machinery proved to be an important step in extending the applicability of the emission factor equations to a wide variety of aggregate materials of industrial importance.

A compendium of predictive emission factor equations for fugitive dust sources is maintained on a CD-ROM by the U.S. EPA.¹³ These emission factor equations are also published in Volume I of the U.S. EPA's Compilation of Air Pollutant Emission Factors commonly referred to as AP-42.¹⁴ A set of particle size multipliers for adjusting the calculated emission factors to specific particle size fractions is provided with each equation. The ratios of PM_{2.5} to PM₁₀ for fugitive dust sources published in Section 13 of AP-42 typically range from 0.10 to 0.20.

Example: Vehicle Traffic on Unpaved Roads. For the purpose of estimating uncontrolled emissions, the U.S. EPA emission factor equation applicable to vehicle traffic on publicly accessible unpaved roads takes source characteristics into consideration:

$$E = [1.8 (s/12)^{1.8} (S/30)^{0.5} / (M/0.5)^{0.2}] - C \quad (5)$$

where: E = PM10 emission factor (lb/VMT)
s = surface material silt content (%)
S = mean vehicle speed (mph)
M = surface material moisture content (%)
C = emission factor for 1980's vehicle fleet exhaust, plus break/tire wear

The denominators in each of the multiplicative terms of the equation constitute normalizing default values, in case no site-specific correction parameter data are available. The default moisture content represents dry (worst-case) road conditions. Extrapolation to annual average uncontrolled emission estimates (including natural mitigation) is accomplished by assuming that emissions are occurring at the estimated rate on days without measurable precipitation and, conversely, are absent on days with measurable precipitation.

1.8 Emission Control Options

Typically, there are several options for the control of fugitive particulate emissions from any given source. This is clear from Equation 2 used to calculate the emission rate. Because the uncontrolled emission rate is the product of the source extent and the uncontrolled emission factor, a reduction in either of these two variables produces a proportional reduction in the uncontrolled emission rate. In the case of open sources, the reduction in the uncontrolled emission factor may be achieved by adjusted “work practices”. The degree of the reduction of the uncontrolled emission factor can be estimated from the known dependence of the factor on source conditions that are subject to alteration. For open dust sources, this information is embodied in the predictive emission factor equations for fugitive dust sources as presented in Section 13 of AP-42. The reduction of source extent and the incorporation of adjusted work practices that reduce the amount of exposed dust-producing material are preventive measures for the control of fugitive dust emissions.

Add-on controls can also be applied to reduce emissions by reducing the amount (areal extent) of dust-producing material, other than by cleanup operations. For example, the elimination of mud/dirt carryout onto paved roads at construction and demolition sites is a cost-effective preventive measure. On the other hand, mitigative measures involve the periodic removal of dust-producing material. Examples of mitigative measures include: cleanup of spillage on travel surfaces (paved and unpaved) and cleanup of material spillage at conveyor transfer points. Mitigative measures tend to be less favorable from a cost-effectiveness standpoint.

Periodically applied control techniques for open dust sources begin to decay in efficiency almost immediately after implementation. The most extreme example of this is the watering of unpaved roads, where the efficiency decays from nearly 100% to 0% in a matter of hours. On the other hand, the effects of chemical dust suppressants applied to unpaved roads may last for several months. Consequently, to describe the performance of most intermittent control techniques for open dust sources, the “time-weighted average” control efficiency must be reported along with the time period over which the value applies. For continuous control systems (e.g., wet suppression for continuous drop materials transfer), a single control efficiency is usually appropriate.

Table 1-3 lists fugitive dust control measures that have been judged to be generally cost-effective for application to metropolitan areas unable to meet PM10 standards. The most highly developed performance models available apply to application of chemical suppressants on unpaved roads. These models relate the expected instantaneous control efficiency to the application parameters (application intensity and dilution ratio) and to the number of vehicle passes (rather than time) following the application. More details on available dust control measure performance and cost are presented in two MRI documents.^{15, 16}

Table 1-3. Controls for Fugitive Dust Sources

Source category	Control action
Agricultural Tilling and Harvesting, Livestock Husbandry	Conservation management practices
Construction/Demolition	Paving permanent roads early in project Covering haul trucks Access apron construction and cleaning Watering of graveled travel surfaces
Abrasive Blasting, Materials Handling, Mineral Products Industry	Wet suppression
Paved Roads	Water flushing/sweeping Improvements in sanding/salting applications and materials Covering haul trucks Prevention of trackout Curb installation Shoulder stabilization
Unpaved Roads	Paving Chemical stabilization Surface improvement (e.g., gravel) Vehicle speed reduction
Wind Erosion (agricultural, open area, and storage pile)	Revegetation Limitation of off-road vehicle traffic

1.9 Document Organization

The handbook contains separate, stand-alone chapters for each fugitive dust source category with chapters arranged in the following order:

- Chapter 2: Agricultural Tilling
- Chapter 3: Construction and Demolition
- Chapter 4: Materials Handling
- Chapter 5: Paved Roads
- Chapter 6: Unpaved Roads
- Chapter 7: Agricultural Wind Erosion
- Chapter 8: Open Area Wind Erosion
- Chapter 9: Storage Pile Wind Erosion
- Chapter 10: Agricultural Harvesting
- Chapter 11: Mineral Products Industry
- Chapter 12: Abrasive Blasting
- Chapter 13: Livestock Husbandry
- Chapter 14: Miscellaneous Minor Fugitive Dust Sources

Each chapter contains the following subsections:

- (a) Characterization of Source Emissions
- (b) Emissions Estimation: Primary Methodology (generally from AP-42)
- (c) Emissions Estimation: Alternate Methodology (if available; e.g., CARB)
- (d) Demonstrated Control Techniques
- (e) Regulatory Formats
- (f) Compliance Tools
- (g) Sample Cost-Effectiveness Calculation
- (h) References

A glossary and a series of Appendices are included in the handbook. Appendix A contains a discussion of two basic test methods used to quantify fugitive dust emission rates, namely:

- (a) The upwind-downwind method that involves the measurement of upwind and downwind particulate concentrations, utilizing ground-based samplers under known meteorological conditions, followed by a calculation of the source strength (mass emission rate) with atmospheric dispersion equations; and
- (b) The exposure-profiling method that involves simultaneous, multipoint measurements of particulate concentration and wind speed over the effective cross section of the plume, followed by a calculation of the net particulate mass flux through integration of the plume profiles.

Appendix B contains cost information for demonstrated control measures. Appendix C contains a step-wise methodology to calculate the cost-effectiveness of different fugitive dust control measures. Appendix D contains a brief discussion of fugitive PM10 management plans and record keeping requirements mandated by one of the air quality districts within the WRAP region.

In compiling information regarding control cost-effectiveness estimates (i.e., \$ per ton of PM₁₀ reduction) of different control options for the fugitive dust handbook, we discovered that many of the estimates provided in contractor reports prepared for air quality agencies for PM₁₀ SIPs contain either hard to substantiate assumptions or unrealistic assumptions. Depending on what assumptions are used, the control cost-effectiveness estimates can range over one to two orders of magnitude. Consequently, the end user of the handbook would get a distorted view if we published these estimates. Rather than presenting these published cost-effectiveness estimates, we have prepared a detailed methodology containing the steps to calculate cost-effectiveness that is included in Appendix C. We recommend that the handbook user calculate the cost-effectiveness values for different fugitive dust control options based on current cost data and assumptions that are applicable for their particular situation.

1.10 References

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Chapter 2. Agricultural Tilling

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2.1 Characterization of Source Emissions

The agricultural tilling source category includes estimates of the airborne soil particulate emissions produced during the preparation of agricultural lands for planting and after harvest activities. Operations included in this methodology are discing, shaping, chiseling, leveling, and other mechanical operations used to prepare the soil. Dust emissions are produced by the mechanical disturbance of the soil by the implement used and the tractor pulling it. Soil preparation activities tend to be performed in the early spring and fall months. Particulate emissions from land preparation are computed by multiplying a crop specific emission factor by an activity factor. The crop specific emission factors are calculated using operation specific (i.e., discing or chiseling) emission factors which are combined with the number of operations provided in the crop calendars. The activity factor is based on the harvested acreage of each crop for each county in the state. In addition, acre-passes are computed, which are the number of passes per acre that are typically needed to prepare a field for planting a particular crop. The particulate dust emissions produced by agricultural land preparation operations are estimated by combining the crop acreage and the operation specific emission factor.

The current version of AP-42 (i.e., the 5th edition) does not address agricultural tilling even though an earlier edition (i.e., the 4th edition) included a PM10 emission factor equation for this fugitive dust source category expressed as follows:

$$EF = 1.01 s^{0.6}$$

where, EF is the PM10 emission factor (lb/acre-pass) and s is the silt content of surface soil (%). Thus, the methodology adopted by the California Air Resources Board (CARB) is presented below as the primary emissions estimation methodology in lieu of an official EPA methodology for this fugitive dust source category.

2.2 Emission Estimation: Primary Methodology¹⁻⁵

This section was adapted from Section 7.4 of CARB's Emission Inventory Methodology. Section 7.4 was last updated in January 2003.

The particulate dust emissions from agricultural land preparation are estimated for each crop in each county using the following equation.

$$\text{Emissions}_{\text{crop}} = \text{Emission Factor}_{\text{crop}} \times \text{Acres}_{\text{crop}}$$

Then the crop emissions for each county are summed to produce the county and statewide PM10 and PM2.5 emission estimates. The remainder of this section discusses each component of the above equation.

Acres. The acreage data used for estimating land preparation emissions are based on the state summary of crop acreage harvested. The acreage data are subdivided by county and crop type for the entire state, and are compiled from individual county agricultural commissioner reports.

Crop Calendars and Acre-Passes. Acre-passes (the total number of passes typically performed to prepare land for planting during a year) are used in computing crop specific emission factors for land preparation. These land preparation operations may occur following harvest or closer to planting, and can include discing, tilling, land leveling, and other operations. Each crop is different in the type of soil operations performed and when they occur. For the crops that are not explicitly updated, an updated crop profile from a similar crop can be used. For updating acre-pass data, it is also useful to collect specific information on when agricultural operations occur. Using these data, it is possible to create detailed temporal profiles that help to indicate when PM emissions from land preparations may be highest.

Emission Factor. The operation specific PM10 emission factors used to estimate the crop specific emission factor for agricultural land preparations were initially extracted from a University of California Davis report.⁴ After discussions with regulators, researchers, and industry representatives, the emission factors were adjusted based on a combination of scientific applicability, general experience, and observations. Five emission factors were developed by UC Davis using 1995 to 1998 test data measured in cotton and wheat fields in California. The operations tested included root cutting, discing, ripping and subsoiling, land planing and floating, and weeding, which produced emission factors that are summarized in Table 2-1 below. CARB has recently proposed adopting a PM2.5/PM10 ratio for fugitive dust from agricultural tilling and related land preparation activities of 0.15 based on the analysis conducted by MRI on behalf of WRAP.^{5, 6}

Table 2-1. Land Preparation Emission Factors

Land preparation operations	Emission factor (lbs PM10/acre-pass)
Root cutting	0.3
Discing, Tilling, Chiseling	1.2
Ripping, Subsoiling	4.6
Land Planing & Floating	12.5
Weeding	0.8

There are more than thirty different land preparation operations commonly used. With five emission factors available, the other operations can be assigned “best-fit” factors based on similar potential emission levels. The assignment of emission factors for operations are based on the expertise and experience of regulators, researchers, and industry representatives. For each crop, the emission factor is the sum of the acre-pass weighted emission factors for each land preparation operation.

Assumptions and Limitations. The CARB methodology is subject to the following assumptions and limitations:

1. The land preparation emission factors for discing, tilling, etc., are assumed to produce the same level of emissions, regardless of the crop type.
2. The land preparation emission factors do not change geographically for counties.

3. A limited number of emission factors are assigned to all land preparation activities.
4. Crop calendar data collected for test area (i.e., San Joaquin) crops and practices were extrapolated to the same crops in the remainder of the state. Existing crop profiles were used for the small percentage of crops in which update information was not collected.
5. In addition to the activities provided in the crop calendars, it is also assumed that field and row crop acreage receive a land-planing pass once every five years.

Temporal Activity. Temporal activity for agricultural tilling (and other land preparation activities) is derived by summing, for each county, the monthly emissions from all crops. For each crop, the monthly emissions are calculated based on its monthly crop calendar profile, which reflects the percentage of activities that occurs in that month. An example of the monthly activity profile for almonds, cotton, and wine grapes is shown below in Table 2-2. Because the mix of crops varies by county, composite temporal profiles combining all of the other county crops vary by county. An example of a composite land preparation profile by month for Fresno County, showing the combined temporal profile for all of the land preparation activities in the county, is shown in Table 2-3.

Table 2-2. Monthly Activity Profile of Selected Crops

Crops	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEP	OCT	NOV	DEC
Almonds	0	0	0	0	0	0	0	0	0	0	50	50
Cotton	0	9	9	0	0	0	0	0	0	0	41	41
Grapes-wine	0	0	0	4	16	16	12	12	12	28	0	0

Table 2-3. County Land Preparation Profile Composite

County	JAN	FEB	MAR	APR	MAY	JUN	JULY	AUG	SEP	OCT	NOV	DEC
Fresno	3	6	6	2	2	1	3	4	2	12	30	29

2.3 Demonstrated Control Techniques

The emission potential of agricultural land preparation operations, including soil tilling, is affected by the soil management and cropping systems that are in place. Table 2-4 presents a summary of demonstrated control measures and the associated PM10 control efficiencies. It is readily observed that reported control efficiencies for many of the control measures are highly variable. This may reflect differences in the operations as well as the test methods used to determine control efficiencies. A list of control measures for agricultural tilling operations is available from the California Air Pollution Control Officers' Association's (CAPCOA) agricultural clearinghouse website (http://capcoa.org/ag_clearinghouse.htm). The list of control measures for land preparation activities for field and orchard crops include: ceasing activities under very windy conditions, combining operations to reduce the number of passes, application of chemicals through an irrigation system, fallowing land, use cover crops and/or mulch/crop residue to reduce wind erosion of soil, operating at night when moisture levels are higher and winds tend to be lighter, precision farming with a GPS system to

reduce overlap of passes, roughening the soil or establishing ridges perpendicular to the prevailing wind direction, and using wind barriers.

Table 2-4. Control Efficiencies for Control Measures for Agricultural Tilling⁷⁻¹¹

Control measure	PM10 control efficiency	References/Comments
Equipment modification	50%	MRI, 1981. Control efficiency is for electrostatically charged fine-mist water spray.
Limited activity during a high-wind event	1 - 5%	SCAQMD, 1997. Control efficiency assumes no tilling when wind speed exceeds 25 mph.
Reduced tillage system (Conservation Tilling)	35 - 50%	Coates, 1994. This study identified total PM10 emissions generated for five different cotton tillage systems, including conventional tilling. Four of the systems combine several tillage operations (e.g., shredding, discing, mulching).
	60%	MRI, 1981. Control efficiency is for a minimum tillage technique that confines farm equipment and vehicle traffic to specific areas (for cotton and tomatoes).
	25 - 100%	MRI, 1981; U.S. EPA, 1992. Control efficiency is for application of herbicide that reduces need for cultivation (i.e., 25% for barley, alfalfa, and wheat; 100% for cotton, corn, tomatoes, and lettuce).
	30%	MRI, 1981; U.S. EPA, 1992. Control efficiency is for laser-directed land plane that reduces the amount of land planing.
	50%	MRI, 1981; U.S. EPA, 1992. Control efficiency is for using "punch" planter instead of harrowing (for cotton, corn, and lettuce).
	50%	MRI, 1981. Control efficiency is for using "plug" planting that places plants more exactly and eliminates the need for thinning (for tomatoes, only).
	50%	MRI, 1981; U.S. EPA, 1992. Control efficiency is for aerial seeding which produces less dust than ground planting (for alfalfa and wheat).
	91 - 99%	Grantz, et al. 1998. Control efficiency is for revegetation of fallow agricultural lands by direct seeding.
Tillage based on soil moisture	90%	MRI, 1981; U.S. EPA, 1992. Control efficiency is for sprinkler irrigation as a fugitive dust control measure. Also, sprinkler irrigation could reduce the need for extensive land planing associated with surface irrigation.
Sequential cropping	50%	MRI, 1981. Control efficiency is for double cropping corn.
Surface roughening	15 - 64%	Grantz et al, 1998. Control efficiency is for increasing surface roughness using rocks and soil aggregates.

2.4 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. However, most air quality districts currently exempt agricultural operations from controlling fugitive dust. Air quality districts that regulate fugitive dust emissions from agricultural operations include Clark County, NV and several districts in California such as the Imperial County APCD, the San Joaquin Valley APCD and the South Coast AQMD. Imperial County APCD's Rule 806 prohibits fugitive dust emissions from farming activities for farms over 40 acres. The San Joaquin Valley APCD and the South Coast AQMD prohibit fugitive dust emissions for the larger farms defined as farms with areas where the combined disturbed surface area within one continuous property line and not separated by a paved public road is greater than 10 acres. The San Joaquin Valley APCD's Rule 4550 (Conservation Management Practices, CMPs) requires farmers with 100 acres or more of contiguous or adjacent farmland to implement and document a biennial CMP plan to reduce fugitive dust emissions from on-farm sources, such as unpaved roads and equipment yards, during land preparation and harvesting activities. The District's rule requires farmers to implement a separate CMP for each crop for the following source categories: land preparation and cultivation, harvesting, unpaved roads, unpaved equipment yards, and other cultural practices. Example regulatory formats downloaded from the Internet are presented in Table 2-5. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- San Joaquin Valley APCD, CA: valleyair.org/SJV_main.asp
- South Coast AQMD, CA: aqmd.gov/rules
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/aq

CAPCOA's agricultural clearinghouse website (capcoa.org/ag_clearinghouse.htm) provides links to rules of different air quality agencies within California that regulate fugitive dust emissions from agricultural operations.

Table 2-5. Example Regulatory Format for Agricultural Tilling

Control measure	Agency
Any person engaged in agricultural operations shall take all reasonable precautions to abate fugitive dust from becoming airborne from such activities.	Clark County Reg. 41 7/10/04
Limit visible dust emissions to 20% opacity by pre-watering, phasing of work, applying water during active operations	SJVAPCD Rule 8021 11/15/2001
Implement one of following during inactivity: restricting vehicle access or applying water or chemical stabilizers	SJVAPCD Rule 8021 11/15/2001
Use mowing or cutting instead discing and maintain at least 3" stubble above soil (Also requires pre-application of watering if discing for weed abatement)	SCAQMD Rule 403 12/11/1998
Cease activities when wind speeds are greater than 25 mph	SCAQMD Rule 403.1 4/02/04

2.5 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations (e.g., observation of visible dust plume). An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Compliance tools applicable to agricultural tilling are summarized in Table 2-6.

Table 2-6. Compliance Tools for Agricultural Tilling

Record keeping	Site inspection/monitoring
Maintain daily records to document the specific dust control options taken; maintain such records for a period of not less than three years; and make such records available to the Executive Officer upon request.	Observation of dust plumes during periods of agricultural tilling; observation of dust plume opacity (visible emissions) exceeding a standard; observation of high winds (e.g., >25 mph).

2.6 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for agricultural tilling. A sample cost-effectiveness calculation is presented below for a specific control measure (conservation tilling) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for agricultural tilling, the same procedure is used to evaluate each candidate control measure (utilizing the control

measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Agricultural Tilling

Step 1. Determine source activity and control application parameters.

Field size (acres)		320
Frequency of operations per year		4
Control Measure	Conservation tilling	
Control application/frequency	Reduce 4 passes to 3 passes	
Control Efficiency		25%

The field size and frequency of operations are assumed values, for illustrative purposes. Conservation tilling has been chosen as the applied control measure. The control application/frequency and control efficiency are values determined from the proportional reduction in tilling frequency.

Step 2. Obtain PM10 Emission Factor.

The PM10 emission factor for agricultural tilling dust is 1.2 (lb/acre-pass).¹²

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor, EF, (given in Step 2) is multiplied by the field size and the frequency of operations (both under activity data) and then divided by 2,000 lbs to compute the annual PM10 emissions in tons per year, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (\text{EF} \times \text{Field Size} \times \text{Frequency of Ops}) / 2,000 \\ \text{Annual PM10 emissions} &= (1.2 \times 320 \times 4) / 2,000 = 0.768 \text{ tons} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= (\text{PM2.5/PM10}) \times \text{PM10 emissions} \\ \text{CARB proposed PM2.5/PM10 ratio for agricultural operations}^5 &= 0.15 \\ \text{Annual PM2.5 emissions} &= (0.15 \times 0.768 \text{ tons}) = 0.115 \text{ tons} \end{aligned}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, we have selected conservation tilling as our control measure. Based on a control efficiency estimate of 25%, the annual controlled PM emissions are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM10 emissions} &= (0.768 \text{ tons}) \times (1 - 0.25) = 0.576 \text{ tons} \\ \text{Annual Controlled PM2.5 emissions} &= (0.115 \text{ tons}) \times (1 - 0.25) = 0.086 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

In this example, eliminating one tilling pass actually reduces the annual tilling costs. The annual cost savings of this control measure is calculated by multiplying the number of acres by the tilling cost per acre. The cost of tilling is assigned a value of \$10 per acre (WSU, 1998¹³). Thus, the annual cost savings from eliminating one tilling pass is estimated to be: $320 \times 10 = \$3,200$.

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annual cost (in this case annual cost savings) by the emissions reduction (i.e., uncontrolled emissions minus controlled emissions), as follows:

Cost-effectiveness = Annual Costs Savings / (Uncontrolled emissions – Controlled emissions)

Cost-effectiveness for PM10 emissions = $-\$3,200 / (0.687 - 0.576) = -\$16,667/\text{ton}$

Cost-effectiveness for PM2.5 emissions = $-\$3,200 / (0.115 - 0.086) = -\$111,111/\text{ton}$

[Note: The negative cost-effectiveness values indicate a net cost savings for this control measure.]

2.7 References

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Chapter 3. Construction and Demolition

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3.1 Characterization of Source Emissions

Heavy construction is a source of dust emissions that may have a substantial temporary impact on local air quality. Building and road construction are two examples of construction activities with high emissions potential. Emissions during the construction of a building or road can be associated with land clearing, drilling and blasting, ground excavation, cut and fill operations (i.e., earth moving), and construction of a particular building or road. Dust emissions often vary substantially from day to day, depending on the level of activity, the specific operations, and the prevailing meteorological conditions. A large portion of the emissions results from construction vehicle traffic over temporary roads at the construction site.

The temporary nature of construction differentiates it from other fugitive dust sources as to estimation and control of emissions. Construction consists of a series of different operations, each with its own duration and potential for dust generation. In other words, emissions from any single construction site can be expected (1) to have a definable beginning and an end, and (2) to vary substantially over different phases of the construction process. This is in contrast to most other fugitive dust sources where emissions are either relatively steady or follow a discernable annual cycle. Furthermore, there is often a need to estimate areawide construction emissions without regard to the actual plans of any individual construction project. For these reasons, methods by which either areawide or site-specific emissions may be estimated are presented below.

The quantity of dust emissions from construction operations is proportional to the area of land being worked and to the level of construction activity. By analogy to the parameter dependence observed for other similar fugitive dust sources, one can expect emissions from construction operations to be positively correlated with the silt content of the soil (i.e., particles smaller than 75 micrometers [μm] in diameter), as well as with the speed and weight of the construction vehicle, and to be negatively correlated with the soil moisture content.

Table 3-1 displays the dust sources involved with construction. In addition to the on-site activities shown in Table 3-1, substantial emissions are possible because of material tracked out from the site and deposited on adjacent paved streets. Because all traffic passing the site (i.e., not just that associated with the construction) can resuspend the deposited material, this “secondary” source of emissions may be far more important than all the dust sources located within the construction site. Furthermore, this secondary source will be present during all construction operations. Persons developing construction site emission estimates must consider the potential for increased adjacent emissions from off-site paved roadways (see Chapter 5). High wind events also can lead to emissions from cleared land and material stockpiles. Chapters 8 and 9 present estimation methodologies that can be used for such sources at construction sites.

Table 3-1. Emission Sources for Construction Operations

Construction phase	Dust-generating activities
I. Demolition and debris removal	<ol style="list-style-type: none"> 1. Demolition of buildings or other (natural) obstacles such as trees, boulders, etc. <ol style="list-style-type: none"> a. Mechanical dismemberment (“headache ball”) of existing structures b. Implosion of existing structures c. Drilling and blasting of soil d. General land clearing 2. Loading of debris into trucks 3. Truck transport of debris 4. Truck unloading of debris
II. Site Preparation (earth moving)	<ol style="list-style-type: none"> 1. Bulldozing 2. Scrapers unloading topsoil 3. Scrapers in travel 4. Scrapers removing topsoil 5. Loading of excavated material into trucks 6. Truck dumping of fill material, road base, or other materials 7. Compacting 8. Motor grading
III. General Construction	<ol style="list-style-type: none"> 1. Vehicular Traffic 2. Portable plants <ol style="list-style-type: none"> a. Crushing b. Screening c. Material transfers 3. Other operations

3.2 Emissions Estimation: Primary Methodology¹⁻⁶

This section was adapted from: Estimating Particulate Matter Emissions from Construction Operations, report prepared for USEPA by Midwest Research Institute dated September 15, 1999.¹

Note that AP-42 Section 13.2.3, “Heavy Construction Operations,” was not adopted for the primary emission estimation methodology because it relies on a single-valued emission factor for TSP of 1.2 tons/acre-month based on only one set of field tests.²

3.2.1 PM Emissions from Construction

Construction emissions can be estimated when two basic construction parameters are known: the acres of land disturbed by the construction activity, and the duration of the activity. A general emission factor for all types of construction activity is 0.11 tons PM₁₀/acre-month and is based on a 1996 BACM study conducted by Midwest Research (MRI) Institute for the California South Coast Air Quality Management District (SCAQMD).³ The single composite factor of 0.11 tons PM₁₀/acre-month assumes that all construction activity produces the same amount of dust on a per acre basis. In other words, the amount of dust produced is not dependent on the type of construction but merely on the area of land being disturbed by the construction activity. A second

assumption is that land affected by construction activity does not involve large-scale cut and fill operations. Factors for the conversion of dollars spent on construction to acreage disturbed, along with the estimates for the duration of construction activity, were originally developed by MRI in 1974.⁴

Separate emission factors segregated by type of construction activity provide better estimates of PM10 emissions that are more accurate estimate than are obtained using a general emission factor. The factors from the 1996 MRI BACM study³ are summarized in Table 3-2. Specific emission factors and activity levels for residential, nonresidential, and road construction activities are described below.

Table 3-2. Recommended PM10 Emission Factors for Construction Operations¹

Basis for emission factor	Recommended PM10 emission factor
Level 1 Only area and duration known	0.11 ton/acre-month (average conditions) 0.42 ton/acre-month (worst-case conditions) ^a
Level 2 Amount of earth moving known, in addition to total project area and duration	0.011 ton/acre-month for general construction (for each month of construction activity) <u>plus</u> 0.059 ton/1,000 cubic yards for on-site cut/fill ^b 0.22 ton/1,000 cubic yards for off-site cut/fill ^b
Level 3 More detailed information available on duration of earth moving and other material movement	0.13 lb/acre-work hr for general construction <u>plus</u> 49 lb/scrapper-hr for on-site haulage ^c 94 lb/hr for off-site haulage ^d
Level 4 Detailed information on number of units and travel distances available	0.13 lb/acre-work hr for general construction <u>plus</u> 0.21 lb/ton-mile for on-site haulage 0.62 lb/ton-mile for off-site haulage ^c

- ^a Worst-case refers to construction sites with active large-scale earth moving operations.
- ^b These values are based on assumptions that one scrapper can move 70,000 cubic yards of earth in one month and one truck can move 35,000 cubic yards of material in one month. If the on-site/off-site fraction is not known, assume 100% on-site.
- ^c If the number of scrapers in use is not known, MRI recommends that a default value of 4 be used. In addition, if the actual capacity of earth moving units is known, the user is directed to use the following emission rates in units of lb/scrapper-hour for different capacity scrapers: 19 for 10 yd³ scrapper, 45 for 20 yd³ scrapper, 49 for 30 yd³ scrapper, and 84 for 45 yd³ scrapper.
- ^d Factor for use with over-the-road trucks. If "off-highway" or "haul" trucks are used, haulage should be considered "on-site."

3.2.2 Residential Construction

Residential construction emissions can be calculated for three basic types of residential construction:

- Single-family houses
- Two-family houses
- Apartment buildings

Housing construction emissions are calculated using an emission factor of 0.032 tons PM10/acre-month. Also required are: the number of housing units created, a units-to-acres conversion factor, and the duration of construction activity. The formula for calculating emissions from residential construction is:

$$\text{Emissions} = (0.032 \text{ tons PM10/acre-month}) B \times f \times m$$

where, B = the number of houses constructed
f = building to acres conversion factor
m = the duration of construction activity in months

Following the California methodology, residential construction acreage is based on the number of housing units constructed rather than the dollar value of construction.

An alternative methodology is recommended for residential construction in areas in which basements are constructed or the amount of dirt moved at a residential construction site is known. The F.W. Dodge reports (www.fwdodge.com/newdodgenews.asp) give the total square footage of homes for both single-family and two-family homes. These values can be used to estimate the volume in cubic yards of dirt moved. Multiplying the total square footage of the homes by an average basement depth of 8 ft, and adding 10% additional volume to account for peripheral dirt removed for footings, space around the footings, and other backfilled areas adjacent to the basement, produces an estimate of the total volume in cubic yards of earth moved during residential construction.

The information needed to determine activity levels of residential construction may be based either on the dollar value of construction or the number of housing units constructed. Construction costs vary throughout the United States. The average home cost can vary from the low to upper \$100,000s depending on where the home is located in the United States. Because residential construction characteristics do not show as much variance as the cost does, the number of units constructed is a better indicator of activity level. The amount of land impacted by residential construction is determined to be about the same on a per house basis. The number of housing units for the three types of residential construction (single family, two-family, and apartments) for a county or state are available from the F.W. Dodge's "Dodge Local Construction Potentials Bulletin."

A single-family house is estimated to occupy 1/4 acre. The "building to acres" conversion factor for a single-family house was determined by finding the area of the base of a home and estimating the area of land affected by grading and other construction activities beyond the "footprint" of the house. The average home is around 2,000 sq. ft. Using a conversion factor of 1/4 acre/house indicates that five times the base of the house is affected by the construction of the home. The "building to acres" conversion factor for two-family housing was found to be 1/3 acre per building. The 1/3 acre was derived from the average square footage of a two-family home (approximately 3,500 sq. ft.) and the land affected beyond the base of the house, about 4 times the base for two-family residences.

For comparison purposes, residential construction emission factor calculations are calculated below for BACM Level 1 and Level 2 scenarios. The PM10 construction emission factor for one single-family home is based on typical parameters for a single-family home:

- area of land disturbed 1/4 acre
- area of home 2,000 sq. ft.
- duration 6 months
- basement depth 8 ft.
- moisture level 6%
- silt content 8%

The BACM Level 1 emission calculation is estimated as follows:

$$0.032 \text{ tons PM10/acre-month} \times 1/4 \text{ acre} \times 6 \text{ months} = 0.048 \text{ tons PM10} = 96 \text{ lb PM10}$$

The BACM Level 2 emission calculation is estimated as follows:

$$\begin{aligned} \text{Cubic yards of dirt moved} &= 2,000 \text{ ft}^2 \times 8 \text{ ft.} \times 110\% = 17,600 \text{ ft}^3 = 652 \text{ yd}^3 \\ \text{PM10} &= (0.011 \text{ tons/acre-month} \times 1/4 \text{ acre} \times 6 \text{ months}) + (0.059 \text{ tons}/1000 \text{ yd}^3 \text{ dirt} \times 652 \text{ yd}^3 \text{ dirt}) \\ &= 0.016 \text{ tons} + 0.038 \text{ tons} = 0.0545 \text{ tons PM10} = 109 \text{ lb PM10} \end{aligned}$$

The emission factor recommended for the construction of apartment buildings is 0.11 tons PM10/acre-month because apartment construction does not normally involve a large amount of cut-and-fill operations. Apartment buildings vary in size, number of units, square footage per unit, floors, and many other characteristics. Because of these variations and the fact that most apartment buildings occupy a variable amount of space, a “dollars-to-acres” conversion is recommended for apartment building construction rather than a “building-to-acres” conversion factor. An estimate of 1.5 acres/\$10⁶ (in 2004 dollar value) is recommended to determine the acres of land disturbed by the construction of apartments. This “dollars-to-acres” conversion factor is based on updating previous conversion factors developed by MRI^{4, 5} using cost of living adjustment factors.

3.2.3 Nonresidential Construction

Nonresidential construction includes building construction (commercial, industrial, institutional, governmental) and also public works. The emissions produced from the construction of nonresidential buildings are calculated using the dollar value of the construction. The formula for calculating the emissions from nonresidential construction is:

$$\text{PM10 Emissions} = (0.19 \text{ tons PM10/acre-month}) \times \$ \times f \times m$$

where, \$ = dollars spent on nonresidential construction in millions

f = dollars to acres conversion factor

m = duration of construction activity in months

The emission factor of 0.19 tons PM10/acre-month was developed by MRI in 1999 using a method similar to a procedure originated by Clark County, Nevada and the emission factors recommended in the 1996 MRI BACM Report.³ A quarter of all nonresidential construction is assumed to involve active earthmoving in which the recommended emission factor is 0.42 tons PM10/acre-month. The 0.19 tons PM10/acre-month was calculated by taking 1/4 of the heavy emission factor, (0.42 tons PM10/acre-month) plus 3/4 of the general emission factor (0.11 tons/acre-month). The 1/4:3/4 apportionment is based on a detailed analysis of a Phoenix airport construction where specific unit operations had been investigated for PM10 emissions.⁶ The proposed emission factor of 0.19 tons/acre-month for nonresidential building construction resulted in a total uncontrolled PM10 emissions estimate that was within 25% of that based on a detailed unit operation emissions inventory using detailed engineering plans and “unit-operation” emission factors.

Extensive earthmoving activities will produce higher amounts of PM10 emissions than the average construction project. Thus, a worst-case BACM “heavy construction emission factor” of 0.42 tons PM10/acre-month should provide a better emissions estimate for areas in which a significant amount of earth is disturbed.

The dollar amount spent on nonresidential construction is available from the U.S. Census Bureau (www.census.gov/prod/www/abs/cons-hou), and the Dodge Construction Potentials Bulletin (www.fwdodge.com/newdodge/news.asp). Census data are delineated by SIC Code, whereas the Potentials Bulletin divides activity by the types of building being constructed rather than by SIC Code. It is estimated that for every million dollars spent on construction (in 2004 dollars), 1.5 acres of land are impacted. The “dollars to acres” conversion factor reflects the current dollar value using the Price and Cost Indices for Construction that are available from the Statistical Abstract of the United States, published yearly. The estimate for the duration of nonresidential construction is 11 months.

3.2.4 Road Construction

Road construction emissions are highly correlated with the amount of earthmoving that occurs at a site. Almost all roadway construction involves extensive earthmoving and heavy construction vehicle travel, causing emissions to be higher than found for other construction projects. The PM10 emissions produced by road construction are calculated using the BACM recommended emission factor for heavy construction¹ and the miles of new roadway constructed. The formula used for calculating roadway construction emissions is:

$$\text{PM10 Emissions} = (0.42 \text{ tons PM10/acre-month}) \times M \times f \times d$$

where, M = miles of new roadway constructed
f = miles to acres conversion factors
d = duration of roadway construction activity in months

The BACM worst case scenario emission factor of 0.42 tons/acre-month is used to account for the large amount of dirt moved during the construction of roadways. Since most road construction consists of grading and leveling the land, the higher emission factor more accurately reflects the high level of cut and fill activity that occurs at road construction sites.

The miles of new roadway constructed are available at the state level from the *Highway Statistics* book published yearly by the Federal Highway Administration (FHWA; www.fhwa.dot.gov/ohim/hs97/hm50.pdf) and the Bureau of Census Statistical Abstract of the United States. The miles of new roadway constructed can be found by determining the change in the miles of roadway from the previous year to the current year. The amount of roadway constructed is apportioned from the state to the county level using housing start data that is a good indicator of the need for new roads.

The conversion of miles of roadway constructed to the acres of land disturbed is based on a method developed by the California Air Resources Board. This calculation is performed by estimating the overall width of the roadway, then multiplying the width by a mile to determine the acres affected by one mile of roadway construction. The California “miles to acres disturbed” conversion factors are available for freeway, highway and city/county roads. In the Highway Statistics book, roadways are divided into separate functional classes. MRI developed a “miles-to-acres” conversion factor in 1999¹ according to the roadway types found in the “Public Road Length, Miles by Functional System” table of the annual *Highway Statistics*. The functional classes are divided into four groups. Group 1 includes Interstates and Other Principal Arterial roads and is estimated to occupy 15.2 acres/mile. Group 2 includes Other Freeways and Expressways (Urban) and Minor Arterial Roads and is estimated at 12.7 acres/mile. Group 3 has Major Collectors (Rural) and Collectors (Urban) and a conversion factor of 9.8 acres/mile. Minor Collectors (Rural) and Local roads are included in Group 4 and converted at 7.9 acres/mile. Table 3-3 shows the data used to calculate the acres per mile of road constructed.

Table 3-3. Conversion of Road Miles to Acres Disturbed

	Group 1	Group 2	Group 3	Group 4
Lane Width (feet)	12	12	12	12
Number of Lanes	5	5	3	2
Average Shoulder Width (feet)	10	10	10	8
Number of Shoulders	4	2	2	2
Roadway Width* (feet)	100	80	56	40
Area affected beyond road width	25	25	25	25
Width Affected (feet)	125	105	81	65
Acres Affected per Mile of New Roadway	15.2	12.7	9.8	7.9

* Roadway Width= (Lane Width x # of Lanes) + (Shoulder Width x # of Shoulders).

The amount of new roadway constructed is available on a yearly basis and the duration of the construction activity is determined to be 12 months. The duration accounts for the amount of land affected during that time period and also reflects the fact that construction of roads normally lasts longer than a year. The duration of construction of a new roadway is estimated at 12 to 18 months.

3.3 Emission Estimation: Alternate Methodology for Building Construction

This section was adapted from Section 7.7 of CARB's Emission Inventory Methodology. Section 7.7 was last updated in September 2002.

The building construction dust source category provides estimates of the fugitive dust particulate matter caused by construction activities associated with building residential, commercial, industrial, institutional, or governmental structures. The emissions result predominantly from site preparation work, which may include scraping, grading, loading, digging, compacting, light-duty vehicle travel, and other operations. Dust emissions from construction operations are computed by using a PM10 emission factor developed by MRI during 1996.³ The emission factor is based on observations of construction operations in California and Las Vegas. Activity data for construction is expressed in terms of acre-months of construction. Acre-months are based on estimates of the acres disturbed for residential construction, and project valuation for other non-residential construction.

3.3.1 Emission Estimation Methodology

Emission Factor. The PM10 emission factor used for estimating geologic dust emissions from building construction activities is based on work performed by MRI³ under contract to the PM10 Best Available Control Measure (BACM) working group. For most parts of the state, the emission factor used is 0.11 tons PM10/acre-month of activity. This emission factor is based on MRI's observation of the types, quantity, and duration of operations at eight construction sites (three in Las Vegas and five in California). The bulk of the operations observed were site preparation-related activities. The observed activity data were then combined with operation-specific emission factors provided in AP-42² to produce site emissions estimates. These site estimates were then combined to produce the overall average emission factor of 0.11 tons PM10/acre-month. The PM2.5/PM10 ratio for fugitive dust from construction and demolition activities is 0.1 based on the analysis conducted by MRI on behalf of WRAP.⁷

The construction emission factor is assumed to include the effects of typical control measures such as routine watering. A dust control effectiveness of 50% is assumed from these measures, which is based on the estimated control effectiveness of watering.⁸ Therefore, if this emission factor is used for construction activities where watering is not used, it should be doubled to more accurately reflect the actual emissions. The MRI document³ lists their average emission factor values as uncontrolled. However, it can be argued that the activities observed and the emission estimates do include the residual effects of control. All of the test sites observed were actual operations that used watering controls as part of their standard industry practice in California and Las Vegas. So, even if in some cases watering was not performed during MRI's actual site visits, the residual decreases in emissions from the watering controls and raising the soil moisture are included in the MRI estimates.

The 1996 MRI report³ also includes an emission factor for worst-case emissions of 0.42 tons PM10/acre-month. This emission factor is appropriate for large-scale construction operations, which involve substantial earthmoving operations. The South Coast Air Quality Management District (SCAQMD) estimated that 25% of their construction projects involve these types of operations. For the remainder of the state, such detailed information is not readily available, so the average emission factor of 0.11 tons PM10/acre-month is used by CARB for these other areas of California..

Activity Data. For the purpose of estimating emissions, it is assumed that the fugitive dust emissions are related to the acreage affected by construction. Because regionwide estimates of the acreage under construction may not be directly available, other construction activity data can be used to derive acreage estimates. Activity data are estimated separately for residential construction and the other types of construction (commercial, industrial, institutional, and governmental).

For residential construction, the number of new housing units estimated by the California Department of Finance⁹ are used to estimate acreage disturbed. It is estimated that single family houses are built on 1/7 of an acre in heavily populated counties, and 1/5 of an acre in less populated counties.¹⁰⁻¹² It is also estimated that multiple living units such as apartments occupy 1/20 of an acre per living unit. For all of these residential construction activities, a project duration of 6 months is assumed.¹⁰ Applying these factors to the reported number of new units in each county results in an estimate of acre-months of construction. This estimate of acre-months of construction combined with the construction emission factor is used to estimate residential construction particulate emissions.

For commercial, industrial, and institutional building construction, construction acreage is based on project valuations. Project valuations for additions and alterations are not included. According to the Construction Industry Research Board,¹³ most additions and alterations would be modifications within the existing structure and normally would not include the use of large earthmoving equipment. Most horizontal additions would usually be issued a new building permit. The valuations are 3.7, 4.0 and 4.4 acres per million dollars of valuation for the respective construction types listed.¹² Valuations were corrected from 1999 values to 1977 values using the Annual Average Consumer Price Index (CPI-U-RS) provided by the U.S. Census Bureau.¹⁴ The Census Bureau uses the Bureau of Labor Statistics' experimental Consumer Price Index (CPI-U-RS) for 1977 through 2000.¹⁵ Valuations were corrected from 1999 values to 1977 values because the acres per dollar valuation values are based on 1977 valuations. For example, the CPI-U-RS for 1999 is 244.1 and the CPI-U-RS for 1977 is 100.0. The ratio of 1977 to 1999 dollars is 100.0/244.1 or 0.41. Inflation from 1999 to 2004 is estimated to be 12%. Thus, updating the 1977 valuation results to 2004 dollars produces a ratio of 1977 to 2004 dollars of 0.41/1.12 or 0.37. CARB assumes that each acre is under construction for 11 months for each project type.¹⁰

3.3.2 Assumptions and Limitations

1. The current methodology assumes that all construction operations in all parts of the state emit the same levels of PM10 on a per acre basis.
2. It is assumed that watering techniques are used statewide, reducing emissions by 50% and making it valid to apply the MRI emission factor without correction.
3. The methodology assumes that valuation is proportional to acreage disturbed, even for high-rise type building construction.
4. The methodology assumes that construction dust emissions are directly proportional to the number of acres disturbed during construction.
5. The estimates of acreage disturbed are limited in their accuracy. New housing units and project valuations do not provide direct estimates of actual acreage disturbed by construction operations in each county.
6. The methodology assumes that the Consumer Price Index (CPI-U-RS) provides an accurate estimate of 1977 and current values.

3.3.3 Temporal Activity

The temporal activity is assumed to occur five days a week between the hours of 8:00 AM and 4:00 PM. The table below shows the percentage of construction activity that is estimated to occur during each month. The monthly activity increases during the spring and summer months. Some districts may use a different profile that has a larger peak during the summer months.

JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
6.4	6.4	8.3	9.2	9.2	9.2	9.2	9.2	9.2	8.3	8.3	7.3

3.4 Emission Estimation: Alternate Methodology for Road Construction

This section was adapted from Section 7.8 of CARB's Emission Inventory Methodology. Section 7.8 was last updated in August 1997.

The road construction dust source category provides estimates of the fugitive dust particulate matter due to construction activities while building roads. The emissions result from site preparation work that may include scraping, grading, loading, digging, compacting, light-duty vehicle travel, and other operations. Dust emissions from road construction operations are computed by using a PM10 emission factor developed by MRI.³ The emission factor is based on observations of construction operations in California and Las Vegas. Activity data for road construction is expressed in terms of acre-months of construction. Acre-months are based on estimates of the acres disturbed for road construction. The acres disturbed are computed based on: estimates of the annual difference in road mileage; estimates of road width (to compute acres disturbed); and an assumption of 18 months as the typical project duration.

3.4.1 Emissions Estimation Methodology

Emission Factor. The PM10 emission factor used for estimating geologic dust emissions from road construction activities is based on work performed by MRI under contract to the PM10 Best Available Control Measure working group.³ For most parts of the State, the emission factor used is 0.11 tons PM10/acre-month of activity. This emission factor is based on MRI's observation of the types, quantity, and duration of operations at eight construction sites (three in Las Vegas, and five in California). The bulk of the operations observed were site preparation related activities. The observed activity data were then combined with operation specific emission factors provided in U.S. EPA's AP-42 (5th Edition)² document to produce site emissions estimates. These site estimates were then combined to produce the overall average emission factor of 0.11 tons PM10/acre-month. The PM2.5/PM10 ratio for fugitive dust from construction and demolition activities is 0.1 based on the analysis conducted by MRI on behalf of WRAP.⁷

The construction emission factor is assumed to include the effects of routine dust suppression measures such as watering. A dust control effectiveness of 50% is assumed from these measures, which is based on the estimated control effectiveness of watering.⁸ Therefore, if this emission factor is used for road construction activities where watering is not used, it should be doubled to more accurately reflect the actual emissions. The MRI document³ lists their average emission factor values as uncontrolled. However, it can be argued that the activities do include the effects of controls. All of the test sites were actual operations that used watering controls, even if in some cases they were not used during the actual site visits. It is believed that the residual effects of controls are reflected in the MRI emission estimates.

The MRI report³ also includes an emission factor for worst-case construction emissions of 0.42 tons of PM10/acre-month. This emission factor is appropriate for large scale construction operations that involve substantial earthmoving operations. The South Coast Air Quality Management District (SCAQMD) estimated that a percentage of their construction projects involve these types of operations, and applied the larger emission factor to these activities. For the remainder of the state, such detailed information is not readily available, so the average emission factor of 0.11 tons PM10 per acre-month is used by CARB.

Activity Data. For the purpose of estimating emissions, it is assumed that the fugitive dust emissions are related to the acreage affected by construction. Regionwide estimates of the acreage disturbed by roadway construction may not be directly available. Therefore, the miles of road built and the acreage disturbed per mile of construction can be used to estimate the overall acreage disturbed.

The miles of road built are based on the annual difference in the road mileage. These data, from the California Department of Finance⁹ and Caltrans¹⁶, are split for each county into freeways, state highways, and city and county road. The acreage of land disturbed

per mile of road construction is based on the number of lanes, lane width, and shoulder width for each listed road type. The assumptions used are provided in Table 3-4. Because most projects will probably also disturb land outside of the immediate roadway corridor, these acreage estimates are somewhat conservative.

The final parameter needed is project duration, which is assumed to be an average of 18 months.¹⁰ Multiplying the road mileage built by the acres per mile and the months of construction provides the acre-months of activity for road building construction. This, multiplied by the emission factor, provides the emissions estimate.

Table 3-4. Roadway Acres per Mile of Construction Estimates

Road Type	Freeway	Highway	City & County
Number of Lanes	5	5	2
Width per Lane (feet)	12	12	12
Shoulder Width (feet)	10'x4 = 40'	20'x2 = 40'	20'x2 = 40'
Roadway Width* (feet)	100	76	64
Roadway Width* (miles)	0.019	0.014	0.012
Area per Mile** (acres)	12.1	9.2	7.8

*Roadway Width (miles) = [(Lanes x Width per Lane) + Shoulder Width] x (1 mile/5,280 feet)

**Area per Mile (acres) = Length x Width = 1 Mile x Width x 640 acres/mile²

3.4.2 Temporal Activity

Temporal activity is assumed to occur five days a week between the hours of 8 AM and 4 PM. The table below shows the percentage of construction activity that is estimated to occur during each month. The monthly activity increases during the spring and summer months as shown below. Some districts use a slightly different profile that has a larger peak during the summer months.

ALL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
100	7.7	7.7	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	7.7

3.4.3 Assumptions and Limitations

1. The current methodology assumes that all construction operations in all parts of the state emit the same levels of PM10 on a per acre basis.
2. It is assumed that watering techniques are used statewide, reducing emissions by 50% and making it valid to apply the MRI emission factor without correction.
3. The methodology assumes that the acreage disturbed per mile for road building is similar statewide, and the overall disturbed acreage is approximately the same as the finished roadway's footprint.
4. The methodology assumes that construction dust emissions are directly proportional to the number of acres disturbed during construction.

3.5 Supplemental Emission Factors

AP-42 lists uncontrolled TSP emission factors for specific activities at construction sites.² These TSP emission factors as well as references to the relevant chapters of this handbook that provide PM10 and/or TSP emission factors for similar activities are presented in Table 3-5.

Table 3-5. TSP Emission Factors for Specific Construction Site Activities

Construction Phase	Activity	TSP Emission Factor*
Demolition and Debris Removal	Drilling soil	1.3 lb/hole
	Land clearing with bulldozer	$5.7 (s)^{1.2} / M^{1.3}$ lb/hr
	Loading debris into trucks and subsequent unloading	See Chapter 4
	Truck transport of debris on paved or unpaved roads	See Chapters 5 and 6
Site Preparation (earth moving)	Bulldozing and compacting	$5.7 (s)^{1.2} / M^{1.3}$ lb/hr
	Scrapers unloading topsoil	0.04 lb/ton
	Scrapers in travel mode	See Chapter 6
	Scrapers removing topsoil	20.2 lb/mile
	Grading	$0.040 (S)^{2.5}$ lb/mile
	Loading excavated material into trucks and subsequent unloading	See Chapter 4
General Construction	Vehicular traffic	See Chapters 5 and 6
	Crushing and screening aggregate	See Chapter 11
	Material transfer	See Chapter 4

* Symbols for equations: M = material moisture content (%), s = material silt content (%), S = mean vehicle speed (mph).

3.6 Demonstrated Control Techniques

Because of the relatively short-term nature of construction activities, some control measures are more cost-effective than others. Frank Elswick of Midwest Industrial Supply Inc. presented an extensive summary of control measures for construction activities and their associated costs at a WRAP sponsored fugitive dust workshop in Palm Springs, CA in May 2005.¹⁷ Elswick concluded that dust suppressant methods fall into the following six categories:

1. Watering

- * Watering works by agglomerating surface particles together.
- * No negative environmental impacts from using water.
- * Normally readily available.
- * Evaporates quickly, therefore typically only effective for short periods of time.
- * Frequency of application depends on temperature and humidity.
- * Generally labor intensive due to frequent application.
- * Costs associated with pre-watering and as needed watering are \$55 to \$80/hour.

2. **Chemical Stabilizers**

- (a) Water absorbing products (e.g., calcium chloride brine or flakes, magnesium chloride brine, sodium chloride)
- * These products work by significantly increasing surface tension of water between dust particles, helping to slow evaporation and further tighten compacted soil.
 - * Products ability to absorb water from the air is a function of temperature and humidity.
 - * These products work best in low humidity environments.
 - * Frequent re-application in dry climates.
 - * Must be watered to activate during dry months.
 - * Potential costly environmental impacts to fresh water aquatic life, plants and water quality
 - * Corrosive to metal and steel.
 - * Not suitable for non-traffic areas.
 - * Costs associated with traffic area program are \$.03 - \$.05 per square foot.
- (b) Organic Petroleum Products (e.g. asphalt emulsions, cut/liquid asphalt, dust oils, petroleum resins)
- * These products work by binding and/or agglomerating surface particles together because of asphalt adhesive properties.
 - * Potentially costly environmental due to presence of polycyclic aromatic hydrocarbons that are “hazardous air and water pollutants” that may be subject to reporting requirements.
 - * Can fragment under traffic conditions.
 - * Not suitable for non-traffic areas.
 - * Costs associated with traffic area program are \$.05 - \$.075 per square foot.
- (c) Organic Non-Petroleum Products (e.g., ligninsulfonates, tall oil emulsions, vegetable oils)
- * These products work by binding and/or agglomerating surface particles together.
 - * Surface binding for these product may be reduced or destroyed by rains.
 - * Generally limited availability of non-petroleum products.
 - * Ligninsulfonates can impact freshwater aquatic life due to high B.O.D. and C.O.D.
 - * Not suitable for non-traffic areas.
 - * Costs associated with traffic area program are \$.04 - \$.08 square foot.
- (d) Polymer Products (e.g., polyvinyl acetates, vinyl acrylics)
- * These products work by binding soil particles together because of the polymer’s adhesive properties.
 - * Polymers also increase the load-bearing strength of all types of soils.
 - * Polymers are non-toxic, non-corrosive, and do not pollute ground water.
 - * Polymers dry virtually clear to create an aesthetically pleasing result.
 - * Polymers create a tough yet flexible crust to prevent wind and water erosion.
 - * Costs associated with traffic areas are \$.05 - \$.08 per square foot.
 - * Costs associated with disturbed non-traffic areas are \$300 - \$800 per acre depending on longevity desired.

- * Costs associated with slopes and inactive stockpiles are \$500 to \$1,000 per acre.

(e) Synthetic Products (e.g., iso-alkane compounds)

- * Synthetic fluids work as a dust suppressing ballasting mechanism, while also acting as a durable re-workable binder.
- * Formulated with safe and environmentally friendly synthetic fluids; non-hazardous per OSHA, EPA and US DOT; contains no asphalt, oil or PAH's.
- * Easy application; no water required.
- * Costs associated with traffic area program are \$.05 - \$.10 per square foot.

3. **Sand Fences**

- * Fabric on chain link fence.
- * Redwood slat fence.
- * Mylar sand fence.
- * Most effective when used in conjunction with chemical stabilizers.

4. **Perimeter Sprinklers**

- * Most effective when used in conjunction with other methods.

5. **Tire Cleaning Systems at Site Exit**

- * Rumble strips to prevent track-out from site onto pavement.
- * Washed rock 100' prior to exit onto pavement.

6. **On- Site Speed Control**

- * Limiting on-site vehicle speed to 15mph.

Wet suppression and wind speed reduction are the two most common methods used to control open dust sources at construction sites because a source of water and material for wind barriers tend to be readily available on a construction site. However, several other forms of dust control are available. Table 3-6 displays each of the preferred control measures by dust source.^{18, 19}

Table 3-6. Control Options for General Construction Sources of PM10

Emission source	Recommended control methods(s)
Debris handling	Wind speed reduction; wet suppression ^a
Truck transport ^b	Wet suppression; paving; chemical stabilization ^c
Bulldozers	Wet suppression ^d
Pan scrapers	Wet suppression of travel routes
Cut/fill material handling	Wind speed reduction; wet suppression
Cut/fill haulage	Wet suppression; paving; chemical stabilization
General construction	Wind speed reduction; wet suppression; early paving of permanent roads

^a Dust control plans should contain precautions against watering programs that confound trackout problems.

^b Loads could be covered to avoid loss of material in transport, especially if material is transported offsite.

^c Chemical stabilization is usually cost-effective for relatively long-term or semipermanent unpaved roads.

^d Excavated materials may already be moist and not require additional wetting. Furthermore, most soils are associated with an "optimum moisture" for compaction.

One of the dustiest construction operations is cutting and filling using scrapers, with the highest emissions occurring during scraper transit. In a 1999 MRI field study,⁵ it was found that watering can provide a high level of PM10 control efficiency for scraper transit emissions. Average control efficiency remained above 75% approximately 2 hours after watering. The average PM10 efficiency decay rate for water was found to vary from approximately 3% to 14% hour. The decay rate depended upon relative humidity in a manner consistent with the effect of humidity on the rate of evaporation. Test results for watered scraper transit routes showed a steep increase in control efficiency with a doubling of surface moisture and little additional control efficiency at higher moisture levels. This is in keeping with past studies that found that control efficiency data can be successfully fitted by a bilinear function. In another recent MRI field study (MRI, 2001),²⁰ tests of mud and dirt trackout indicated that a 10% soil moisture content represents a reasonable first estimate of the point at which watering becomes counter productive. The control efficiencies afforded by graveling or paving of a 7.6 m (25 ft) access apron were in the range of 40% to 50%.

Table 3-7 summarizes tested control measures and reported control efficiencies for dust control measures applied to construction and demolition operation.

Table 3-7. Control Efficiencies for Control Measures for Construction/Demolition^{20, 21}

Control measure	Source component	PM10 control efficiency	References/Comments
Apply water every 4 hrs within 100 feet of a structure being demolished	Active demolition and debris removal	36%	MRI, April 2001, test series 701. 4-hour watering interval (Scenario: lot remains vacant 6 mo after demolition)
Gravel apron, 25' long by road width	Trackout	46%	MRI, April 2001
Apply dust suppressants (e.g., polymer emulsion)	Post-demolition stabilization	84%	CARB April 2002; for actively disturbed areas
Apply water to disturbed soils after demolition is completed or at the end of each day of cleanup	Demolition Activities	10%	MRI, April 2001, test series 701. 14-hour watering interval.
Prohibit demolition activities when wind speeds exceed 25 mph	Demolition Activities	98%	Estimated for high wind days in absence of soil disturbance activities
Apply water at various intervals to disturbed areas within construction site	Construction Activities	61%	MRI, April 2001, test series 701. 3.2-hour watering interval
		74%	MRI, April 2001, test series 701. 2.1-hour watering interval
Require minimum soil moisture of 12% for earthmoving	Scraper loading and unloading	69%	AP-42 emission factor equation for materials handling due to increasing soil moisture from 1.4% to 12%
Limit on-site vehicle speeds to 15 mph (Scenario: radar enforcement)	Construction traffic	57%	Assume linear relationship between PM10 emissions and uncontrolled vehicle speed of 35 mph

3.7 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats downloaded from the Internet for several local air quality agencies in the WRAP region are presented in Table 3-8. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/envsvc/air/ruledsc.asp

3.8 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations (e.g., whether an unpaved road has been paved, graveled, or treated; whether haul truck beds are covered; whether water trucks are being used during construction activities). An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 3-9 summarizes the compliance tools that are applicable to construction and demolition.

Table 3-8. Example Regulatory Formats for Construction and Demolition

Source	Control measure	Goal	Threshold	Agency
Paved Roads- Public and Private Track-out and Carryout	Install track-out ctrl device	Prevent/remove track-out from haul trucks and tires	Paved roads within construction sites, where haul trucks traverse; with disturbed surface area >2 acres, with 100 cubic yards of bulk material hauled	Maricopa County Rule 310 04/07/2004
	Either immediately cleanup track-out (>50ft) and nightly clean-up of rest; install grizzly/wheel wash system; install gravel pad--30ftx50ft, 6" deep; pave intersection--100ftx20ft; route traffic over track-out ctrl devices; limit access to unprotected routes; pave construction roadways ASAP	Control track-out on paved construction roads	Immediate track-out clean-up after 50ft, at end of workday for less; gravel pad standards are min; paved intersection also min and must be accessible to public; limit access to unprotected routes with barriers	Maricopa County Rule 310 04/07/2004
	Track-out control device must be installed at all access points to public roads and there must be mud/dirt removal from interior paved roads with sufficient frequency	Allow mud/dirt to drop off before leaving site and prevent track-out	For sites greater than 5 acres or those with more than 100 yd3 of daily import/export	SJVAPCD Rule 8041 11/15/2001
	Removal of track-out within one hour or selecting a track-out prevention option and removing track-out at the end of the day		For sites greater than 5 acres or those with more than 100 yd3 of daily import/export and track-out is less than 50ft	SCAQMD Rule 403 12/11/1998
	Removing track-out ASAP		Track-out greater than 50 ft	SCAQMD Rule 403 12/11/1998
Require road surface paved or chemically stabilized from point of intersection with a public paved road to distance of at least 100 ft by 20 ft or installation of track-out control device from point of intersection with a public paved road to a distance of at least 25 ft by 20 ft	Prohibits material from extending more than 25 ft from a site entrance	For sites greater than 5 acres or those with more than 100 yd3 of daily import/export	SCAQMD Rule 403 12/11/1998	
Bulk Materials Transport	Establishes speed limits. Requires at least 6" freeboard when crossing paved public road, water applied to top of load. Haul trucks need tarp or suitable cover and truck interior must be cleaned before leaving site	Limit visible dust emissions to 20% opacity and prevent spillage from holes	Trucks entering paved public roads (6" freeboard); leaving work site; specific haul trucks need covering	SJVAPCD Rule 8031 11/15/2001
	Requires covering haul trucks or to use bottom-dumping if possible and maintain minimum 6" freeboard (in high winds)			SCAQMD Rule 403 12/11/1998
	Freeboard at least 3"; prevent spillage from holes; install track-out ctrl devices	Prevent/remove track-out onto paved roads	Within the work site; removes possible track-out from tires, exterior of trucks that traverse work site	Maricopa County Rule 310 04/07/2004
Construction and Demolition Earthmoving	Require water and chemical stabilizers (dust suppressants) be applied, in conjunction with optional wind barrier	Limit visible dust emissions to 20% opacity		SJVAPCD Rule 8021 11/15/2001
	Specifies Dust Control Plan must be submitted	Limit visible dust emissions to 20% opacity	For areas 40 acres or larger where earth movement of 2500 yd3 or more on at least 3 days is intended	SJVAPCD Rule 8021 11/15/2001

**Table 3-8. Example Regulatory Formats for Construction and Demolition
(Continued)**

Source	Control measure	Goal	Threshold	Agency
	Requires implementation of Best Available Control Measures (BACM)	Prohibit visible dust emissions beyond property line and limit an upwind/downwind PM10 differential to 50 ug/m3. Limit visible dust emissions to 100 ft from origin		SCAQMD Rule 403 12/11/1998
Construction and Demolition Demolition	Application of dust suppressants	Limit visible dust emissions to 20% opacity		SJVAPCD Rule 8021 11/15/2001
	Application of best available control measures (BACM)	Prohibits visible dust emissions beyond property line. Limits downwind PM10 levels to 50 ug/m3	For projects greater than 5 acres or 100 yd3 of daily import/export	SCAQMD Rule 403 12/11/1998
Construction and Demolition Grading Operations	Requires pre-watering and phasing of work	Limit VDE to 20% opacity		SJVAPCD Rule 8021 11/15/2001
	Requires water application and chemical stabilizers	Increase moisture content to proposed cut	For graded areas where construction will not begin for more than 60 days after grading	SCAQMD Rule 403 12/11/1998
	Preapplication of water to depth of proposed cuts and reapplication of water as necessary. Also stabilization of soils once earth-moving is complete	Ensure visible emissions do not extend more than 100 ft from sources		SCAQMD Rule 403 12/11/1998

Table 3-9. Compliance Tools for Construction and Demolition

Record keeping	Site inspection/monitoring
Site map; description of work practices; duration of project activities; locations and methods for demolition activities; locations and amounts of all earthmoving and material (types) handling operations; dust suppression equipment (types) and maintenance; frequencies, amounts, times, and rates of watering or dust suppressant application; mud/dirt carryout prevention and remediation requirements; wind shelters; meteorological log.	Observation of earthmoving and demolition activities, considering timeframe of project; observation of operation of dust suppression systems, vehicle/ equipment operation and disturbance areas; surface material sampling and analysis for silt and moisture contents; observation of truck spillage onto adjacent paved roads; mud/dirt carryout prevention and remediation; inspection of wind sheltering; real-time portable monitoring of PM; observation of dust plume opacity exceeding a standard.

3.9 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for construction and demolition. A sample cost-effectiveness calculation is presented below for a specific control measure (gravel apron at trackout egress points) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for construction and demolition, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Construction and Demolition (Mud/Dirt Egress Points)	
<u>Step 1. Determine source activity and control application parameters.</u>	
Egress traffic rate (veh/day)	100
Number of egress points	2
Duration of construction activity (month)	24
Wet days/year	10
Number of workdays/year	260
Number of emission days/yr (workdays without rain)	250
Control Measure	Gravel apron 25 ft long by road width
Economic Life of Control System (yr)	2
Control Efficiency	46%
Reference	MRI, 2001 ²⁰

The number of vehicles per day, wet days per year, workdays per year, and the economic life of the control are determined from climatic and industrial records. The number of emission days per year are calculated by subtracting the number of annual wet days from the number of annual workdays as follows:

$$\text{Number of workdays/year} - \text{Wet days/year} = 260 - 10 = 250$$

Gravel aprons at the two construction site egress points have been chosen as the applied control measure. The control efficiency was obtained from MRI, 2001.¹⁹

Step 2. Obtain PM10 Emission Factor. The PM10 emission factor for construction and demolition dust is 6 g/vehicle.²²

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor, EF, (given in Step 2) is multiplied by the number of vehicles per day and by the number of emission days per year (both under activity data) and divided by 454 grams/lb and 2000 lb/ton to compute the annual PM10 emissions, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (\text{EF} \times \text{Veh/day} \times \text{Emission days/year}) / (454 \times 2,000) \\ \text{Annual PM10 emissions} &= (6 \times 100 \times 250) / (454 \times 2,000) = 0.165 \text{ tons/year} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= 0.1 \times \text{PM10 emissions}^7 \\ \text{Annual PM2.5 emissions} &= (0.1 \times 0.165 \text{ tons/year}) = 0.0165 \text{ tons/year} \end{aligned}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, we have selected gravel aprons at egress points as our control measure. Based on a control efficiency estimate of 46% for a gravel apron, the annual PM emissions are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM10 emissions} &= (0.165 \text{ tons/yr}) \times (1 - 0.46) = 0.089 \text{ tons/yr} \\ \text{Annual Controlled PM2.5 emissions} &= (0.0165 \text{ tons/yr}) \times (1 - 0.46) = 0.0089 \text{ tons/yr} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	500
Annual Operating/Maintenance costs (\$)	3,150
Annual Interest Rate	5%
Capital Recovery Factor	0.54
Annualized Cost (\$/year)	3,419

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated as follows:

$$\begin{aligned} \text{Capital Recovery Factor} &= \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1 \\ \text{Capital Recovery Factor} &= 5\% \times (1 + 5\%)^2 / (1 + 5\%)^2 - 1 = 0.54 \end{aligned}$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor and the Capital costs to the annual Operating and Maintenance costs:

Annualized Cost = (CRF x Capital costs) + Annual Operating and Maintenance costs
Annualized Cost = (0.54 x \$500) + \$3,150 = \$3,419

Step 6. Calculate Cost Effectiveness. Cost effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

Cost effectiveness = Annualized Cost / (Uncontrolled emissions – Controlled emissions)

Cost effectiveness for PM10 emissions = \$3,420 / (0.165 - 0.089) = \$44,991/ton

Cost effectiveness for PM2.5 emissions = \$3,420 / (0.0165 - 0.0089) = \$449,908/ton

3.10 References

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4.1 Characterization of Source Emissions

Inherent in operations that use minerals in aggregate form is the handling and transfer of materials from one process to another (e.g., to and from storage). Outdoor storage piles are usually left uncovered, partially because of the need for frequent material transfer into or out of storage. Dust emissions occur at several points in the storage cycle, such as material loading onto the pile, disturbances by strong wind currents, and loadout from the pile. The movement of trucks and loading equipment in the storage pile area is also a substantial source of dust. Dust emissions also occur at transfer points between conveyors or in association with vehicles used to haul aggregate materials

4.2 Emissions Estimation: Primary Methodology¹⁻¹⁴

This section was adapted from Section 13.2.4 of EPA's *Compilation of Air Pollutant Emission Factors (AP-42)*. Section 13.2.4 was last updated in January 1995.

The quantity of dust emissions from aggregate storage operations varies with the volume of aggregate passing through the storage cycle. Emissions also depend on the age of the pile, moisture content, and proportion of aggregate fines. When freshly processed aggregate is loaded onto a storage pile, the potential for dust emissions is at a maximum. Fines are easily disaggregated and released to the atmosphere upon exposure to air currents, either from aggregate transfer itself or from high winds. However, as the aggregate pile weathers the potential for dust emissions is greatly reduced. Moisture causes aggregation and cementation of fines to the surfaces of larger particles. Any significant rainfall soaks the interior of the pile, and then the drying process is very slow.

Table 4-1 summarizes measured moisture and silt content values for industrial aggregate materials. Silt (particles equal to or less than 75 micrometers [μm] in diameter) content is determined by measuring the portion of dry aggregate material that passes through a 200-mesh screen, using ASTM-C-136 method.¹

Total dust emissions from aggregate storage piles result from several distinct source activities within the storage cycle:

1. Loading of aggregate onto storage piles (batch or continuous drop operations).
2. Equipment traffic in storage area.
3. Wind erosion of pile surfaces and ground areas around storage piles (see Chapter 9).
4. Loadout of aggregate for shipment or for return to the process stream (batch or continuous drop operations).

Either adding aggregate material to a storage pile or removing it usually involves dropping the material onto a receiving surface. Truck dumping on the pile or loading out from the pile to a truck with a front-end loader are examples of batch drop operations. Adding material to the pile by a conveyor stacker is an example of a continuous drop operation.

Table 4-1. Typical Silt and Moisture Contents of Materials at Various Industries^a

Industry	No. of facilities	Material	Silt content (%)			Moisture content (%)		
			No. of samples	Range	Mean	No. of samples	Range	Mean
Iron and steel production	9	Pellet ore	13	1.3-13	4.3	11	0.64-4.0	2.2
		Lump ore	9	2.8-19	9.5	6	1.6-8.0	5.4
		Coal	12	2.0-7.7	4.6	11	2.8-11	4.8
		Slag	3	3.0-7.3	5.3	3	0.25-2.0	0.92
		Flue dust	3	2.7-23	13	1	–	7
		Coke breeze	2	4.4-5.4	4.9	2	6.4-9.2	7.8
		Blended ore	1	–	15	1	–	6.6
		Sinter	1	–	0.7	0	–	–
		Limestone	3	0.4-2.3	1.0	2	ND	0.2
Stone quarrying and processing	2	Crusted limestone	2	1.3-1.9	1.6	2	0.3-1.1	0.7
		Various limestone products	8	0.8-14	3.9	8	0.46-5.0	2.1
Taconite mining and processing	1	Pellets	9	2.2-5.4	3.4	7	0.05-2.0	0.9
		Tailings	2	ND	11	1	–	0.4
Western surface coal mining	4	Coal	15	3.4-16	6.2	7	2.8-20	6.9
		Overburden	15	3.8-15	7.5	0	–	–
		Exposed ground	3	5.1-21	15	3	0.8-6.4	3.4
Coal-fired power plant	1	Coal (as received)	60	0.6-4.8	2.2	59	2.7-7.4	4.5
Municipal solid waste landfills	4	Sand	1	–	2.6	1	–	7.4
		Slag	2	3.0-4.7	3.8	2	2.3-4.9	3.6
		Cover	5	5.0-16	9.0	5	8.9-16	12
		Clay/dirt mix	1	–	9.2	1	–	14
		Clay	2	4.5-7.4	6.0	2	8.9-11	10
		Fly ash	4	78-81	80	4	26-29	27
		Misc. fill materials	1	–	12	1	–	11

^a References 1-10. ND = no data.

The quantity of particulate emissions generated by either type of drop operation, expressed as a function of the amount of material transferred, may be estimated using the following empirical expression:¹¹

$$\begin{aligned}
 \text{Metric Units} \quad E &= k(0.0016) \frac{\left(\frac{U}{2.2}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \quad (\text{kg/megagram [Mg]}) \\
 \text{English Units} \quad E &= k(0.0032) \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}} \quad (\text{pound [lb]/ton})
 \end{aligned}
 \tag{1}$$

where:

- E = emission factor
- k = particle size multiplier (dimensionless)
- U = mean wind speed (meters per second, m/s, or miles per hour, mph)
- M = material moisture content (%)

The particle size multiplier in the equation, k, varies with aerodynamic particle size range. For PM10, k is 0.35.¹¹ There are two sources of fugitive dust associated with materials handling activities, namely particulate emissions from aggregate handling and storage piles, which typically consists of loader and truck traffic around the storage piles, and fugitive dust associated with the transfer of aggregate by buckets or conveyors. The PM2.5/PM10 ratios for these two sources of fugitive dust are 0.1 and 0.15, respectively.¹² In general, particulate emissions from loader and truck traffic around the storage piles predominates over particulate emissions from transfer of aggregate by buckets or conveyors. Equation 1 retains the assigned quality rating of A if applied within the ranges of source conditions that were tested in developing the equation; see table below. Note that silt content is included, even though silt content does not appear as a correction parameter in the equation. While it is reasonable to expect that silt content and emission factors are interrelated, no significant correlation between the two was found during the derivation of the equation, probably because most tests with high silt contents were conducted under lower winds, and vice versa. It is recommended that estimates from Equation 1 be reduced one quality rating level if the silt content used in a particular application falls outside the following range:

Ranges of Source Conditions for Equation 1			
Silt content (%)	Moisture content (%)	Wind speed	
		m/s	mph
0.44 - 19	0.25 - 4.8	0.6 - 6.7	1.3 - 15

For Equation 1 to retain the quality rating of A when applied to a specific facility, reliable correction parameters must be determined for the specific sources of interest. The field and laboratory procedures for aggregate sampling are given in Reference 3. In the event that site-specific values for correction parameters cannot be obtained, the

appropriate mean values from Table 4-1 may be used, but the quality rating of the equation is reduced by one letter.

For emissions from trucks, front-end loaders, dozers, and other vehicles traveling between or on piles, it is recommended that the equations for vehicle traffic on unpaved surfaces be used (see Chapter 6). For vehicle travel between storage piles, the silt value(s) for the areas among the piles (which may differ from the silt values for the stored materials) should be used.

Worst-case emissions from storage pile areas occur under dry, windy conditions. Worst-case emissions from materials-handling operations may be calculated by substituting into the equation appropriate values for aggregate material moisture content and for anticipated wind speeds during the worst-case averaging period, usually 24 hours. A separate set of nonclimatic correction parameters and source extent values corresponding to higher than normal storage pile activity also may be justified for the worst-case averaging period.

4.3 Demonstrated Control Techniques

Watering and the use of chemical wetting agents are the principal means for control of emissions from materials handling operations involving transfer of bulk minerals in aggregate form. The handling operations associated with the transfer of materials to and from open storage piles (including the traffic around piles) represent a particular challenge for emission control. Dust control can be achieved by: (a) source extent reduction (e.g., mass transfer reduction), (b) source improvement related to work practices and transfer equipment such as load-in and load-out operations (e.g., drop height reduction, wind sheltering, moisture retention)), and (c) surface treatment (e.g., wet suppression).

In most cases, good work practices that confine freshly exposed material provide substantial opportunities for emission reduction without the need for investment in a control application program. For example, loading and unloading can be confined to leeward (downwind) side of the pile. This statement also applies to areas around the pile as well as the pile itself. In particular, spillage of material caused by pile load-out and maintenance equipment can add a large source component associated with traffic-entrained dust. Emission inventory calculations show, in fact, that the traffic dust component may easily dominate over emissions from transfer of material and wind erosion. The prevention of spillage and subsequent spreading of material by vehicles traversing the area is essential to cost-effective emission control. If spillage cannot be prevented because of the need for intense use of mobile equipment in the storage pile area, then regular cleanup should be employed as a necessary mitigative measure.

Fugitive emissions from aggregate materials handling systems are frequently controlled by wet suppression systems. These systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material

by the liquid and the ability of the liquid to “wet” small particles. There are two types of wet suppression systems—liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems that supply foams as the wetting agent.

Liquid spray wet suppression systems can be used to control dust emissions from materials handling at conveyor transfer points. The wetting agent can be water or a combination of water and a chemical surfactant. This surfactant, or surface-active agent, reduces the surface tension of the water. As a result, the quantity of liquid needed to achieve good control is reduced.

Watering is also useful to reduce emissions from vehicle traffic in the storage pile area. Continuous chemical treating of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90%.^{13, 14}

Table 4-2 presents a summary of control measures and reported control efficiencies for materials handling that includes the application of a continuous water spray at a conveyor transfer point and two control measures for storage piles.

Table 4-2. Control Efficiencies for Control Measures for Materials Handling

Control measure	PM10 control efficiency	References/comments
Continuous water spray at conveyor transfer point	62%	The control efficiency achieved by increasing the moisture content of the material from 1% to 2% is calculated utilizing the AP-42 emission factor equation for materials handling which contains a correction term for moisture content.
Require construction of 3-sided enclosures with 50% porosity for storage pile	75%	Sierra Research, 2003. ¹⁵ Determined through modeling of open area windblown emissions with 50% reduction in wind speed and assuming no emission reduction when winds approach open side.
Water the storage pile by hand or apply cover when wind events are declared	90%	Fitz et al., April 2000. ¹⁶

4.4 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats for several local air quality agencies in the WRAP region are presented in Table 4-3. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: <http://www.maricopa.gov/envsvc/air/ruledesc.asp>

Table 4-3. Example Regulatory Formats for Materials Handling

Control Measure	Goal	Threshold	Agency
Establishes wind barrier and watering or stabilization requirements and bulk materials must be stored according to stabilization definition and outdoor materials covered	Limit visible dust emissions to 20% opacity		SJVAPCD Rule 8031 11/15/2001
Best available control measures: wind sheltering, watering, chemical stabilizers, altering load-in/load-out procedures, or coverings	Prohibits visible dust emissions beyond property line and limits upwind/downwind PM10 differential to 50 µg/m3		SCAQMD Rule 403 12/11/1998
Watering, dust suppressant (when loading, stacking, etc.); cover with tarp, watering (when not loading, etc.); wind barriers, silos, enclosures, etc.	Limit VDE to 20% opacity; stabilize soil	For storage piles with >5% silt content, 3ft high, >=150 sq ft; work practices for stacking, loading, unloading, and when inactive; soil moisture content min 12%; or at least 70% min for optimum soil moisture content; 3 sided enclosures, at least equal to pile in length, same for ht, porosity </=50%	Maricopa County Rule 310 04/07/2004
Watering, clean debris from paved roads and other surface after demolition	Stabilize demolition debris and surrounding area; establish crust and prevent wind erosion	Immediately water and clean-up after demolition	Maricopa County Rule 310 04/07/2004
Utilization of dust suppressants other than water when necessary; prewater; empty loader bucket slowly	Prevent wind erosion from piles; stabilize condition where equip and vehicles op	Bulk material handling for stacking, loading, and unloading; for haul trucks and areas where equipment op	Maricopa County Rule 310 04/07/2004

4.5 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 4-4 summarizes the compliance tools that are applicable to materials handling.

Table 4-4. Compliance Tools for Materials Handling

Record keeping	Site inspection/monitoring
Site map; work practices and locations; material throughputs; type of material and size characterization; typical moisture content when fresh; vehicle/equipment disturbance areas; material transfer points and drop heights; spillage and cleanup occurrences; wind fence/enclosure installation and maintenance; dust suppression equipment and maintenance records; frequencies, amounts, times, and rates for watering and dust suppressants; meteorological log.	Observation of material transfer operations and storage areas (including spills), operation of wet suppression systems, vehicle/ equipment operation and disturbance areas; surface material sampling and analysis for silt and moisture contents; inspection of wind sheltering including enclosures; real-time portable monitoring of PM; observation of dust plume opacities exceeding a standard.

4.6 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for materials handling. A sample cost-effectiveness calculation is presented

below for a specific control measure (continuous water spray at conveyor transfer point) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for materials handling, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Materials Handling (Conveyor Transfer Point)

Step 1. Determine source activity and control application parameters.

Material throughput (tons/hr)	25
Operating cycle (hours/day)	12
Number of workdays/year	312
Number of transfer points	1
Moisture content of material, M (%)	1
Mean wind speed, U (mph)	6
Control Measure	Water spray located at conveyor transfer point
Control application/frequency	Continuous
Economic Life of Control System (yr)	10

The material throughput, operating cycle, number of workdays per year, number of transfer points, material moisture content, wind speed, and economic life of the control system are assumed values for illustrative purposes. A continuous water spray located at a conveyor transfer point has been chosen as the applied control measure to increase the moisture content of the material from 1% to 2%.

Step 2. Calculate Uncontrolled PM10 Emission Factor. The PM10 emission factor, EF, is calculated from the AP-42 equation utilizing the appropriate correction parameters (mean wind speed U = 6 mph and moisture content M = 1%), as follows:

$$EF = (0.35) \times (0.0032) \times (6/5)^{1.3} / (1/2)^{1.4} = 0.00377 \text{ lb/ton}$$

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (calculated in Step 2) is multiplied by the material throughput, operating cycle, and workdays per year (all under activity data) and then divided by 2,000 lbs to compute the annual PM10 emissions in tons per year, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (EF \times \text{Material Throughput} \times \text{Operating Cycle} \times \text{Workdays/yr}) / 2,000 \\ \text{Annual PM10 emissions} &= (0.00377 \times 25 \times 12 \times 312) / 2000 = 0.175 \text{ tons} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= 0.15 \times \text{PM10 emissions}^{12} \\ \text{Annual PM2.5 emissions} &= (0.15 \times 0.175 \text{ tons}) = 0.0263 \text{ tons} \end{aligned}$$

Step 4. Calculate Controlled PM Emission Factor. The PM emission factor for controlled emissions, EF, is calculated from the AP-42 equation utilizing the appropriate correction parameters (mean wind speed U = 6 mph and moisture content M = 2%), as follows:

$$EF=(0.35) \times (0.0032) \times (6/5)^{1.3} / (2/2)^{1.4} = 0.00142 \text{ lb/ton}$$

Step 5. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) is calculated by multiplying the PM10 emission factor (calculated in Step 4) by the material throughput, operating cycle, and workdays per year (all under activity data) and then divided by 2,000 lbs to compute the annual emissions in tons per year, as follows:

$$\text{Annual emissions} = (EF \times \text{Material Throughput} \times \text{Operating Cycle} \times \text{Workdays/yr}) / 2,000$$

$$\text{Annual PM10 Emissions} = (0.00142 \times 25 \times 12 \times 312) / 2000 = 0.0664 \text{ tons}$$

$$\text{Annual PM2.5 emissions for material transfer} = 0.15 \times \text{PM10 emissions}^{12}$$

$$\text{Annual PM2.5 Emissions} = (0.15 \times 0.0665 \text{ tons}) = 0.0100 \text{ tons}$$

Note: The control efficiency of using a water spray to increase the material moisture content from 1% to 2% is 62% $(100 \times (0.175 - 0.0664) / 0.175)$

Step 6. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	16,000
Annual Operating/Maintenance costs (\$)	12,200
Annual Interest Rate	3%
Capital Recovery Factor	0.1172
Annualized Cost (\$/yr)	14,076

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$\text{Capital Recovery Factor} = \text{AIR} \times (1+\text{AIR})^{\text{Economic life}} / ((1+\text{AIR})^{\text{Economic life}} - 1)$$

$$\text{Capital Recovery Factory} = 3\% \times (1+3\%)^{10} / (1+3\%)^{10} - 1 = 0.1172$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor by the Capital costs with the annual Operating/Maintenance costs as follows:

$$\text{Annualized Cost} = (\text{CRF} \times \text{Capital costs}) + \text{Operating/Maintenance costs}$$

$$\text{Annualized Cost} = (0.1172 \times 16,000) + 12,200 = \$14,076$$

Step 7. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost-effectiveness for PM10 emissions} = \$14,076 / (0.175 - 0.0664) = \$129,267/\text{ton}$$

$$\text{Cost-effectiveness for PM2.5 emissions} = \$14,076 / (0.0263 - 0.0100) = \$861,779/\text{ton}$$

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Chapter 5. Paved Roads

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5.1 Characterization of Source Emissions

Particulate emissions occur whenever vehicles travel over a paved surface such as a road or parking lot. Particulate emissions from paved surfaces are due to direct emissions from vehicles in the form of exhaust, brake wear and tire wear emissions, and resuspension of loose material on the road surface. In general terms, resuspended particulate emissions from paved surfaces originate from, and result in the depletion of the loose material present on the surface (i.e., the surface loading). In turn, that surface loading is continuously replenished by other sources. At industrial sites, surface loading is replenished by spillage of material and trackout from unpaved roads and staging areas.

Various field studies have found that public streets and highways as well as roadways at industrial facilities can be major sources of the atmospheric particulate matter within an area.¹⁻⁹ Of particular interest in many parts of the United States are the increased levels of emissions from public paved roads when the equilibrium between deposition and removal processes is upset. This situation can occur for various reasons, including application of granular materials for snow and ice control, mud/dirt carryout from construction activities in the area, and deposition from wind and/or water erosion of surrounding unstabilized areas. In the absence of continuous addition of fresh material (through localized trackout or application of antiskid material), paved road surface loading should reach an equilibrium value in which the amount of material resuspended matches the amount replenished. The equilibrium surface loading value depends upon numerous factors. It is believed that the most important factors are: the mean speed of vehicles traveling the road, the average daily traffic (ADT), the number of lanes and ADT per lane, the fraction of heavy vehicles (buses and trucks), and the presence or absence of curbs, storm sewers and parking lanes.¹⁰

5.2 Emissions Estimation: Primary Methodology¹⁻²⁹

This section was adapted from Section 13.2.1 of EPA's <i>Compilation of Air Pollutant Emission Factors (AP-42)</i> . Section 13.2.1 was last updated in December 2003.
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Dust emissions from paved roads have been found to vary with what is termed the “silt loading” present on the road surface as well as the average weight of vehicles traveling the road. The term silt loading (sL) refers to the mass of silt-size material (equal to or less than 75 micrometers [μm] in physical diameter) per unit area of the travel surface. The total road surface dust loading consists of loose material that can be collected by broom sweeping and vacuuming of the traveled portion of the paved road. The silt fraction is determined by measuring the proportion of the loose dry surface dust that passes through a 200-mesh screen using the ASTM-C-136 method. Silt loading is the product of the silt fraction and the total loading, and is abbreviated “sL.” Additional details on the sampling and analysis of such material are provided in Appendices C.1 and C.2 of AP-42.

The surface silt loading (sL) provides a reasonable means of characterizing seasonal variability in a paved road emission inventory. In many areas of the country, road surface silt loadings are heaviest during the late winter and early spring months when the residual loading from snow/ice controls is greatest.¹¹⁻²¹ As noted earlier, once replenishment of fresh material is eliminated, the road surface silt loading can be expected to reach an equilibrium value, which is substantially lower than the late winter/early spring values.

The quantity of particulate emissions from resuspension of loose material on the road surface due to vehicle travel on a dry paved road may be estimated using the following empirical expression:

$$E = k \left(\frac{sL}{2} \right)^{0.65} \times \left(\frac{W}{3} \right)^{1.5} - C \quad (1)$$

where,

- E = particulate emission factor (having units matching the units of k),
- k = particle size multiplier for particle size range,
- sL = road surface silt loading (grams per square meter, g/m^2),
- W = average weight (tons) of the vehicles traveling the road, and
- C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.²⁷

It is important to note that Equation 1 calls for the average weight of all vehicles traveling the road. For example, if 99% of traffic on the road are 2-ton cars/trucks while the remaining 1% consists of 20-ton trucks, then the mean weight "W" is 2.2 tons. More specifically, Equation 1 is not intended to be used to calculate a separate emission factor for each vehicle weight class. Instead, only one emission factor should be calculated to represent the "fleet" average weight of all vehicles traveling the road. The particle size multiplier (k) varies with aerodynamic size range. For PM10, k equals 0.016 lb/VMT (i.e., 7.3 g/VMT or 4.6 g/VKT). The PM2.5/PM10 ratio for fugitive dust from travel on paved roads is 0.15.²⁸

The PM2.5 and PM10 emission factors for the exhaust, brake wear and tire wear of a 1980's vehicle fleet (C) were obtained from EPA's MOBILE6.2 model.²⁹ The emission factor also varies with aerodynamic size range as shown in Table 5-1. Equation 1 is based on a regression analysis of numerous emission tests, including 65 tests for PM10.¹⁰ Sources tested include public paved roads, as well as controlled and uncontrolled industrial paved roads. All sources tested were of freely flowing vehicles traveling at constant speed on relatively level roads. No tests of "stop-and-go" traffic or vehicles under load were available for inclusion in the database. The equation retains the quality rating of A, if applied within the range of source conditions that were tested in developing the equation, as follows:

- Silt loading: 0.03 - 400 g/m^2 ; 0.04 - 570 grains/square foot
- Mean vehicle weight: 1.8 - 38 megagrams; 2.0 - 42 tons
- Mean vehicle speed: 16 - 88 kilometers per hour; 10 - 55 miles per hour

Table 5-1. Emission Factors for 1980's Vehicle Fleet Exhaust, Brake Wear, and Tire Wear

Particle size	C, Emission factor for exhaust, brake wear, and tire wear ^a		
	g/VMT	g/VKT	lb/VMT
PM2.5	0.1617	0.1005	0.00036
PM10	0.2119	0.1317	0.00047

^a Units shown are grams per vehicle mile traveled (g/VMT), grams per vehicle kilometer traveled (g/VKT), and pounds per vehicle mile traveled (lb/VMT).

NOTE: There may be situations where low silt loading and/or low average weight will yield calculated negative emissions from Equation 1. If this occurs, the emissions calculated from Equation 1 should be set to zero.

Users are cautioned that application of Equation 1 outside of the range of variables and operating conditions specified above (e.g., application to roadways or road networks with speeds below 10 mph and with stop-and-go traffic) will result in emission estimates with a higher level of uncertainty. To retain the quality rating of A for PM10 for the emission factor equation when it is applied to a specific paved road, it is necessary that reliable correction parameter values for the specific road in question be determined. With the exception of limited access roadways, which are difficult to sample, the collection and use of site-specific silt loading (sL) data for public paved road emission inventories are strongly recommended. The field and laboratory procedures for determining surface material silt content and surface dust loading are summarized in Appendices C.1 and C.2 of AP-42. In the event that site-specific silt loading values cannot be obtained, an appropriate value for a paved public road may be selected from the default values given in Table 5-2, but the quality rating of the equation should be reduced by two levels. Also, recall that Equation 1 refers to emissions due to freely flowing (not stop-and-go) traffic at constant speed on level roads.

Equation 1 may be extrapolated to average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual (or other long-term) average emissions are inversely proportional to the frequency of measurable (at least 0.254 mm [0.01 inch]) precipitation by application of a precipitation correction term. The precipitation correction term can be applied on a daily or an hourly basis.²⁶

For the daily basis, Equation 1 becomes:

$$E_{ext} = \left[k \left(\frac{sL}{2} \right)^{0.65} \left(\frac{W}{3} \right)^{1.5} - C \right] \left(1 - \frac{P}{4N} \right) \quad (2)$$

where k , sL , W , and C are as defined in Equation 1 and

- E_{ext} = annual or other long-term average emission factor in the same units as k ,
- P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and
- N = number of days in the averaging period (e.g., 365 for annual, 91 for seasonal, 30 for monthly)

Note that the assumption leading to Equation 2 is based by analogy with the approach used to develop long-term average unpaved road emission factors in Chapter 6. However, Equation 2 above incorporates an additional factor of “4” in the denominator to account for the fact that paved roads dry more quickly than unpaved roads and that the precipitation may not occur over the complete 24-hour day.

Table 5-2. Ubiquitous Silt Loading Default Values with Hot Spot Contributions from Anti-Skid Abrasives for Public Paved Roads (g/m²)

Average Daily Traffic (ADT) Category	< 500	500-5,000	5,000-10,000	> 10,000
Ubiquitous baseline (g/m ²)	0.6	0.2	0.06	0.03 0.015 limited access
Ubiquitous winter baseline multiplier during months with frozen precipitation	X4	X3	X2	X1
Initial peak additive contribution from application of antiskid abrasive (g/m ²)	2	2	2	2
Days to return to baseline conditions (assume linear decay)	7	3	1	0.5

For the hourly basis, Equation 1 becomes:

$$E_{ext} = \left[k \left(\frac{sL}{2} \right)^{0.65} \left(\frac{W}{3} \right)^{1.5} - C \right] \left(1 - \frac{1.2P}{N} \right) \quad (3)$$

where k , sL , and W , and C are as defined in Equation 1 and

- E_{ext} = annual or other long-term average emission factor in the same units as k ,
- P = number of hours with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and
- N = number of hours in the averaging period (e.g., 8,760 for annual; 2,124 for season; 720 for monthly).

Note that the assumption leading to Equation 3 is based by analogy with the approach used to develop long-term average unpaved road emission factors in Chapter 6. Also note that in the hourly moisture correction term $(1-1.2P/N)$ for Equation 3, the 1.2 multiplier is applied to account for the residual mitigative effect of moisture. For most applications, this equation will produce satisfactory results. However, if the time interval for which the equation is applied is short (e.g., 1 hour or 1 day), the application of this multiplier makes it possible for the moisture correction term to become negative. This will result in calculated negative emissions which is not realistic. Users should expand the time interval to include sufficient “dry” hours such that negative emissions are not calculated. For the special case where this equation is used to calculate emissions on an hour by hour basis, such as would be done in some emissions modeling situations, the moisture correction term should be modified so that the moisture correction “credit” is applied to the first hours following cessation of precipitation. In this special case, it is

suggested that this 20% “credit” be applied on a basis of one hour credit for each hour of precipitation up to a maximum of 12 hours.

Maps showing the geographical distribution of “wet” days on an annual basis for the United States based on meteorological records on a monthly basis are available in the *Climatic Atlas of the United States*.²³ Alternative sources include other Department of Commerce publications such as local climatological data summaries. The National Climatic Data Center (NCDC) offers several products that provide hourly precipitation data. In particular, NCDC offers a *Solar and Meteorological Surface Observation Network 1961-1990* (SAMSON) CD-ROM, which contains 30 years worth of hourly meteorological data for first-order National Weather Service locations. Whatever meteorological data are used, the source of that data and the averaging period should be clearly specified. It is emphasized that the simple assumption underlying Equations 2 and 3 has not been verified in any rigorous manner. For that reason, the quality ratings for Equations 2 and 3 should be downgraded one letter from the rating that would be applied to Equation 1.

Table 5-2 presents recommended default silt loadings for normal baseline conditions and for wintertime baseline conditions for public paved roads in areas that experience frozen precipitation with periodic application of antiskid material.²⁴ The winter baseline is represented as a multiple of the nonwinter baseline, depending on the average daily vehicle traffic count (ADT) value for the road in question. As shown, a multiplier of 4 is applied for low volume roads (< 500 ADT) to obtain a wintertime baseline silt loading of $4 \times 0.6 = 2.4 \text{ g/m}^2$.

It is suggested that an additional (but temporary) silt loading contribution of 2 g/m^2 occurs with each application of antiskid abrasive for snow/ice control. This was determined based on a typical application rate of 500 lb per lane mile and an initial silt content of 1%. Ordinary rock salt and other chemical deicers add little to the silt loading because most of the chemical dissolves during the snow/ice melting process.

To adjust the baseline silt loadings for mud/dirt trackout, the number of trackout points is required. It is recommended that in calculating PM10 emissions, six additional miles of road be added for each active trackout point from an active construction site, to the paved road mileage of the specified category within the county. In calculating PM2.5 emissions, it is recommended that three additional miles of road be added for each trackout point from an active construction site. It is suggested the number of trackout points for activities other than road and building construction areas be related to land use. For example, in rural farming areas, each mile of paved road would have a specified number of trackout points at intersections with unpaved roads. This value could be estimated from the unpaved road density (miles per square mile).

The use of a default value from Table 5-2 should be expected to yield only an order-of-magnitude estimate of the emission factor. Public paved road silt loadings are dependent upon: traffic characteristics (speed, ADT, and fraction of heavy vehicles); road characteristics (curbs, number of lanes, parking lanes); local land use (agriculture, new residential construction) and regional/seasonal factors (snow/ice controls, wind blown

dust). As a result, the collection and use of site-specific silt loading data is highly recommended. In the event that default silt loading values are used, the quality ratings for the equation should be downgraded two levels.

Limited access roadways (high speed freeways) pose severe logistical difficulties in terms of surface sampling, and few silt loading data are available for such roads. Nevertheless, the available data do not suggest great variation in silt loading for limited access roadways from one part of the country to another. For annual conditions, a default value of 0.015 g/m² is recommended for limited access roadways.^{9,22} Even fewer of the available data correspond to worst-case situations, and elevated loadings are observed to be quickly depleted because of high traffic speeds and high ADT rates. A default value of 0.2 g/m² is recommended for short periods of time following application of snow/ice controls to limited access roads.²²

The limited data on silt loading values for industrial roads have shown as much variability as public roads. Because of the variations of traffic conditions and the use of preventive mitigative controls, the data probably do not reflect the full extent of the potential variation in silt loading on industrial roads. However, the collection of site specific silt loading data from industrial roads is easier and safer than for public roads. Therefore, the collection and use of site-specific silt loading data is preferred and is highly recommended. In the event that site-specific values cannot be obtained, an appropriate value for an industrial road may be selected from the mean values given in Table 5-3, but the quality rating of the equation should be reduced by two levels.

AP-42 measurements of silt loading for paved roads involve periodic sampling from representative roads that are then used to calculate emissions. These silt loadings have been shown to be highly variable in time and space, and the labor required for their acquisition mitigates against frequent sampling that covers a wide spatial extent. Several groups – Desert Research Institute (DRI) and UC Riverside (CE-CERT) - have developed vehicle-based mobile sampling systems for PM₁₀ emissions of re-entrained paved road dust over the past several years.³⁰ Both systems (DRI's system is called TRAKER and CE-CERT's system is called SCAMPER) have been calibrated in Las Vegas against actual AP-42 silt loadings determined for samples taken in the study area for a complete range of paved roadway classifications and a large range of visible paved road surface loadings. The study results showed a reasonable relationship between the continuous vehicle-based PM₁₀ emission measurements and actual silt loadings.

Table 5-3 Typical Silt Content and Loading Values for Paved Roads at Industrial Facilities^a
(Metric And English Units).

Industry	No. of sites	No. of samples	Silt content (%)		No. of travel lanes	Total loading x 10 ⁻³			Silt loading (g/m ²)	
			Range	Mean		Range	Mean	Units ^b	Range	Mean
Copper smelting	1	3	15.4-21.7	19.0	2	12.9-19.5 45.8-69.2	15.9 55.4	kg/km lb/mi	188-400	292
Iron and steel production	9	48	1.1-35.7	12.5	2	0.006-4.77 0.020-16.9	0.495 1.75	kg/km lb/mi	0.09-79	9.7
Asphalt batching	1	3	2.6-4.6	3.3	1	12.1-18.0 43.0-64.0	14.9 52.8	kg/km lb/mi	76-193	120
Concrete batching	1	3	5.2-6.0	5.5	2	1.4-1.8 5.0-6.4	1.7 5.9	kg/km lb/mi	11-12	12
Sand and gravel processing	1	3	6.4-7.9	7.1	1	2.8-5.5 9.9-19.4	3.8 13.3	kg/km lb/mi	53-95	70
Municipal solid waste landfill	2	7	—	—	2	—	—	—	1.1-32.0	7.4
Quarry	1	6	—	—	2	—	—	—	2.4-14	8.2

^a References 1-2, 5-6, 11-13; dashes indicate information not available.

^b Multiply entries by 1,000 to obtain stated units: kilograms per kilometer (kg/km) and pounds per mile (lb/mi).

5.3 Emission Estimation: Alternate Methodology

This section was adapted from Section 7.9 of CARB's Emission Inventory Methodology. Section 7.9 was last updated in July 1997.

The paved road dust category includes emissions of fugitive dust particulate matter entrained by vehicular travel on paved roads. The California Air Resources Board (CARB) estimates road dust emissions for the following four classes of roads: (1) freeways/expressways, (2) major streets/highways, (3) collector streets, and (4) local streets. Dust emissions from vehicle travel on paved roads are computed using the emission factor equation provided in AP-42 (see Section 5.2 of this document). Inputs to the paved road dust equation were developed from area-specific roadway silt loading and average vehicle weight data measured by Midwest Research Institute (MRI, 1996).³¹

Data from states and air districts are used to estimate county specific VMT (vehicle miles traveled) data.^{32, 33} State highway³⁴ data are used to estimate the fraction of travel on each of the four road types in each county.

The statewide average vehicle weight for California is assumed to be 2.4 tons. This estimate is based on an informal traffic count estimated by MRI while they were performing California silt loading measurements.³¹ CARB assumes the following silt loadings for the four road categories: 0.02 g/m² for freeways, 0.035 g/m² for major roads, and 0.32 g/m² for collector and local roads.³⁵

Temporal activity is assumed to be the same as on-road vehicle travel: uniform in spring and fall, increasing slightly in summer, and decreasing slightly in winter. The monthly temporal profile shown below in Table 5-4 shows this trend. The weekly and daily activities are estimated to have higher activities on weekdays and during daylight hours.

Table 5-4. Monthly Temporal Profile for On-road Vehicle Travel

ALL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
100	7.7	7.7	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	7.7

This alternative methodology utilized by CARB is subject to the following assumptions and limitations:

1. The current AP-42 emission factor assumes that road dust emissions are proportional to VMT, roadway silt loading, and average vehicle weight.
2. It may be necessary to assume that virtually the same silt loading values apply throughout the state because of lack of measured silt loadings.
3. The methodology assumes that roadway silt loading, and therefore the emission factor, varies by the type of road.
4. It is assumed that the EPA particle size multiplier (i.e., the 'k' factor in the AP-42 equation) reasonably represents the size distribution of paved road dust.

5. The average vehicle fleet weight is assumed to be 2.4 tons in California (except for the SCAQMD that assumes 3 tons).
6. For freeway and major roads, emissions growth is assumed to be proportional to changes in roadway centerline mileage. For collector and local roads, emissions growth is assumed proportional to changes in VMT.

5.4 Demonstrated Control Techniques

Because of the importance of road surface silt loading, control techniques for paved roads attempt either to prevent material from being deposited onto the surface (preventive controls) or to remove from the travel lanes any material that has been deposited (mitigative controls). Covering of loads in trucks and the paving of access areas to unpaved lots or construction sites are examples of preventive measures. Examples of mitigative controls include vacuum sweeping, water flushing, and broom sweeping and flushing. Actual control efficiencies for any of these techniques can be highly variable. Locally measured silt loadings before and after the application of controls is the preferred method to evaluate controls. It is particularly important to note that street sweeping of gutters and curb areas may actually increase the silt loading on the traveled portion of the road. Redistribution of loose material onto the travel lanes will actually produce a short-term increase in the emissions.

In general, preventive controls are usually more cost effective than mitigative controls. The cost-effectiveness of mitigative controls falls off dramatically as the size of an area to be treated increases. The cost-effectiveness of mitigative measures is also unfavorable if only a short period of time is required for the road to return to equilibrium silt loading condition. That is to say, the number and length of public roads within most areas of interest preclude any widespread and routine use of mitigative controls. On the other hand, because of the more limited scope of roads at an industrial site, mitigative measures may be used quite successfully (especially in situations where truck spillage occurs). Note, however, that public agencies could make effective use of mitigative controls to remove sand/salt from roads after the winter ends.

Because available controls will affect the silt loading, controlled emission factors may be obtained by substituting controlled silt loading values into the appropriate equation. (Note that emission factors from controlled industrial roads were used in the development of the equation.) The collection of surface loading samples from treated, as well as baseline (untreated) roads provides a means to track effectiveness of the controls over time.

Table 5-5 summarizes tested control measures and reported control efficiencies for measures that reduce the generation of fugitive dust from paved roads.

Table 5-5. Control Efficiencies for Control Measures for Paved Roads³⁶⁻³⁸

Control measure	Source component	PM10 control efficiency	References/Comments
Implement street sweeping program with non-efficient vacuum units (14-day frequency)	Local streets	7%	MRI, September 1992. For non-PM10 efficient sweepers based on 55% efficient sweeping, 5.5 day equilibrium return time and CA-VMT weighted sweeping frequency (7 to 30 days)
	Arterial/collector streets	11%	
Implement street sweeping program with PM10 efficient vacuum units (14-day frequency)	Local streets	16%	MRI, September 1992. For PM10 efficient sweepers, based on 86% efficient sweeping, 8.6 day return time, and CA-VMT weighted sweeping frequency (7 to 30 days)
	Arterial/collector streets	26%	
Require streets to be swept by non-efficient vacuum units (once per month frequency)	Local, arterial and collector streets	4%	MRI, September 1992. For non-PM10 efficient sweepers based on 55% efficient sweeping, 5.5 day equilibrium return time and CA-VMT weighted sweeping frequency (7 to 30 days)
Require streets to be swept by PM10 efficient vacuum units (once per month frequency)	Local, arterial and collector streets	9%	MRI, September 1992. For PM10 efficient sweepers, based on 86% efficient sweeping, 8.6 day return time, and CA-VMT weighted sweeping frequency (7 to 30 days)
Require wind- or water-borne deposition to be cleaned up within 24 hours after discovery	All Streets	100%	Assumes total cleanup of spill on roadway before traffic resumes
Install pipe-grid trackout-control device	Mud/dirt carryout	80%	Sierra Research, 2003.
Install gravel bed trackout apron (3 in deep, 25 ft long and full road width)	Mud/dirt carryout	46%	MRI, April 2001
Require paved interior roads to be 100 foot long and full road width, or add 4 foot shoulder for paved roads	Mud/dirt carryout	42%	MRI, April 2001

5.5 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Example regulatory formats for several local air quality agencies in the WRAP region are presented in Table 5-6. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/envsvc/air/ruledesc.asp

Table 5-6. Example Regulatory Formats for Paved Roads

Control Measure	Goal	Threshold	Agency
Limit speed limit to 15 mph or less	Limit track-out from bulk material transport; reduce particulate matter emissions from paved roads	Work site roads, crossing paved roads transporting bulk materials; during diskings and blading ops	Maricopa County Rule 310 04/07/2004
Requires paved travel section, and 4 ft of paved or stabilized shoulder on each side of travel section. Shoulders shall be paved with dust palliative or gravel (2"). Medians shall be constructed as follows: with curbing, solid paving; apply dust palliatives, or with material that prevent track-out such as landscaping or decorative rock.	Comply with stabilization standard: limit shoulder visible dust emissions to 20% opacity; limit silt loading to 0.33 oz/ft2	Newly constructed or modified paved roads	Clark County Hydrographic Basins 212, 216, 217 Sect. 93 Air Quality Reg. 07/01/04
Requires paved shoulders. As an option to paving or vegetation requirements, oils or chemical dust suppressants can be used and must be maintained	Limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) of 500 or more	SJVAPCD Rule 8061 11/15/2001
Require average shoulder width to be 4 ft. Curbing adjacent to and contiguous with a paved lane or shoulder can be used in lieu of shoulder width requirements. Intersections, auxiliary entry and exit lanes may be constructed adjacent to and contiguous with a paved roadway in lieu of shoulder requirements	Limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) 500-3000	SJVAPCD Rule 8061 11/15/2001
Require average shoulder width to be 8 ft. Curbing adjacent to and contiguous with a paved lane or shoulder can be used in lieu of shoulder width requirements. Intersections, auxiliary entry and exit lanes may be constructed adjacent to and contiguous with a paved roadway in lieu of shoulder requirements	Limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) greater than 3000	SJVAPCD Rule 8061 11/15/2001
Medians constructed with minimum 4 ft shoulder widths adjacent to traffic lanes, and landscaped. Medians constructed with curbing id speed limit < 45 mph.	Meet stabilized surface requirements and limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) of 500 or more and medians part of roadway	SJVAPCD Rule 8061 11/15/2001
Curbing and shoulder width requirements in event of contingency notification	Maintain stabilized surface; limit paved road dust	Roads with average daily vehicle trips (ADVT) of 500 or more	SCAQMD Rule 1186 9/10/1999
Require average shoulder width to be 4 ft.	Limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) 500-3000	SCAQMD Rule 1186 9/10/1999
Require average shoulder width to be 8 ft.	Limit visible dust emissions to 20% opacity	Roads with average daily vehicle trips (ADVT) > 3000	SCAQMD Rule 1186 9/10/1999
For speed limit >45 mph: pave median area with typical roadway materials. For speed limit <45 mph: medians must be landscaped or treated with chemical stabilizers.	Maintain stabilized surface	Roads with average daily vehicle trips (ADVT) of 500 or more	SCAQMD Rule 1186 9/10/1999

5.6 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 5-7 summarizes the compliance tools that are applicable to paved roads.

Table 5-7. Compliance Tools for Paved Roads

Record keeping	Site inspection/monitoring
Road map; traffic volumes, speeds, and patterns; vacuum sweeping, mud/dirt trackout precautions, spill cleanup, erosion control, tarping of haul trucks; curbing of roads; application of sand/salt for anti-skid operations; dust suppression equipment and maintenance records.	Sampling of silt loading on paved road surfaces; counting of traffic volumes; observations of vacuum sweeping, high dust emission areas (including track-on and wash-on points), road curbing/shoulders; observation of dust plume opacity (visible emissions) exceeding a standard; real-time portable monitoring of PM.

5.7 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for fugitive dust originating from paved roads. A sample cost-effectiveness calculation is presented below for a specific control measure (PM10 efficient street sweeper) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control

measure for paved roads, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Paved Roads (Arterial Road Through Industrial Area)

Step 1. Determine source activity and control application parameters.

Vehicles/day	200
Average vehicle speed (mph)	40
Length of road (miles)	10
Control Measure	Use of PM10 efficient street sweepers
Control application/frequency	Once per month
Economic Life of Control System (yr)	10
Control Efficiency	9.2%

The number of vehicles per day, the average vehicle speed, road length, and economic life are assumed values for illustrative purposes. Street sweeping, using PM10 efficient sweepers has been chosen as the applied control measure. The control application/frequency and control efficiency are default values provided by MRI.³⁷

Step 2. Calculate PM10 Emission Factor. The PM10 emission factor is calculated from the AP-42 equation.

$$E \text{ (lb/VMT)} = 0.016 (sL/2)^{0.65} (W/3)^{1.5} - C \times (1 - (P/1460))$$

sL—silt loading (g/m ²)	12
W—average vehicle weight (tons)	5
C—exhaust plus brake and tire wear (lb/VMT)	0.00047
P—wet days/yr (number/yr)	50

$$E = 0.106 \text{ lb/VMT}$$

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (calculated in Step 2) is multiplied by the number of vehicles per day and the road length (both under activity data) and then multiplied by 365/2,000 to compute the annual PM10 emissions, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (\text{Emission Factor} \times \text{Vehicles/day} \times \text{Road length} \times 365 / 2,000) \\ \text{Annual PM10 emissions} &= (0.106 \times 200 \times 10) \times 365 / 2,000 = 39 \text{ tons} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= 0.15 \times \text{PM10 emissions}^{28} \\ \text{Annual PM2.5 emissions} &= (0.15 \times 39) = 5.8 \text{ tons} \end{aligned}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, a PM10 efficient street sweeper with a control efficiency of 9.2% has been selected as the control measure. Thus, the annual controlled PM10 and PM2.5 emissions estimates are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM10 emissions} &= (39 \text{ tons}) \times (1 - 0.092) = 35 \text{ tons} \\ \text{Annual Controlled PM2.5 emissions} &= (5.8 \text{ tons}) \times (1 - 0.092) = 5.3 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	152,000
Annual Operating/Maintenance costs (\$)	16,000
Annual Interest Rate	3%
Capital Recovery Factor	0.1172
Annualized Cost (\$/yr)	33,819

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$\text{Capital Recovery Factor} = \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1$$

$$\text{Capital Recovery Factor} = 3\% \times (1 + 3\%)^{10} / (1 + 3\%)^{10} - 1 = 0.1172$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor and the Capital costs to the annual Operating/Maintenance costs:

$$\text{Annualized Cost} = (\text{CRF} \times \text{Capital costs}) + \text{Annual Operating/Maintenance costs}$$

$$\text{Annualized Cost} = (0.1172 \times 152,000) + 16,000 = \$33,819$$

Step 6. Calculate Cost Effectiveness. Cost effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost effectiveness for PM10 emissions} = \$33,819 / (39 - 35) = \$9,492/\text{ton}$$

$$\text{Cost effectiveness for PM2.5 emissions} = \$33,819 / (5.8 - 5.3) = \$63,283/\text{ton}$$

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Chapter 6. Unpaved Roads

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6.1 Characterization of Source Emissions

When a vehicle travels on an unpaved surface such as an unpaved road or unpaved parking lot, the force of the wheels on the road surface causes pulverization of surface material. Particles are lifted and dropped from the rolling wheels, and the road surface is exposed to strong air currents in turbulent shear with the surface. The turbulent wake behind the vehicle continues to act on the road surface after the vehicle has passed. The quantity of dust emissions from a given segment of unpaved road varies linearly with the volume of traffic. Field investigations also have shown that emissions depend on source parameters that characterize the condition of a particular road and the associated vehicle traffic. Characterization of these source parameters allow for “correction” of emission estimates to specific road and traffic conditions present on public and industrial roadways.

6.2 Emission Estimation: Primary Methodology¹⁻²⁶

This section was adapted from Section 13.2.2 of EPA's *Compilation of Air Pollutant Emission Factors (AP-42)*. Section 13.2.2 was last updated in December 2003.

Dust emissions from unpaved roads have been found to vary directly with the fraction of silt (particles smaller than 75 micrometers [μm] in physical diameter) in the road surface materials.¹ The silt fraction is determined by measuring the proportion of loose dry surface dust that passes a 200-mesh screen using the ASTM-C-136 method. A summary of this method is contained in Appendix C of AP-42. Table 6-1 summarizes measured silt values for industrial unpaved roads. Table 6-2 summarizes measured silt values for public unpaved roads. It should be noted that the ranges of silt content for public unpaved roads vary over two orders of magnitude. Therefore, the use of data from this table can potentially introduce considerable error. Use of this data is strongly discouraged when it is feasible to obtain locally gathered data.

Since the silt content of a rural dirt road will vary with geographic location, it should be measured for use in projecting emissions. As a conservative approximation, the silt content of the parent soil in the area can be used. Tests, however, show that road silt content is normally lower than in the surrounding parent soil, because the fines are continually removed by the vehicle traffic, leaving a higher percentage of coarse particles. Other variables are important in addition to the silt content of the road surface material. For example, at industrial sites, where haul trucks and other heavy equipment are common, emissions are highly correlated with vehicle weight. On the other hand, there is far less variability in the weights of cars and pickup trucks that commonly travel publicly accessible unpaved roads throughout the United States. For those roads, the moisture content of the road surface material may be more dominant in determining differences in emission levels between a hot desert environment and a cool moist location.

Table 6-1. Typical Silt Content Values of Surface Material on Industrial Unpaved Roads^a

Industry	Road use or surface material	Plant sites	No. of samples	Silt content (%)	
				Range	Mean
Copper smelting	Plant road	1	3	16-19	17
Iron and steel production	Plant road	19	135	0.2-19	6.0
Sand and gravel processing	Plant road	1	3	4.1-6.0	4.8
	Material storage area	1	1	–	7.1
Stone quarry and processing	Plant road	2	10	2.4-16	10
	Haul road to/from pit	4	20	5.0-15	8.3
Taconite mining and processing	Service road	1	8	2.4-7.1	4.3
	Haul road to/from pit	1	12	3.9-9.7	5.8
Western surface coal mining	Haul road to/from pit	3	21	2.8-18	8.4
	Plant road	2	2	4.9-5.3	5.1
	Scraper route	3	10	7.2-25	17
	Haul road (freshly graded)	2	5	18-29	24
Construction sites	Scraper routes	7	20	0.56-23	8.5
Lumber sawmills	Log yards	2	2	4.8-12	8.4
Municipal solid waste landfills	Disposal routes	4	20	2.2-21	6.4

^a References 1, 5-15.

Table 6-2. Typical Silt Content Values of Surface Material on Public Unpaved Roads^a

Industry	Road use or surface material	Plant sites	No. of samples	Silt content (%)	
				Range	Mean
Publicly accessible roads	Gravel/crushed limestone	9	46	0.1-15	6.4
	Dirt (i.e., local material compacted, bladed, and crowned)	8	24	0.83-68	11

^a References 1, 5-16.

6.2.1 Emission Factors

The PM10 emission factors presented below are the outcomes from stepwise linear regressions of field emission test results of vehicles traveling over unpaved surfaces. For vehicles traveling on unpaved surfaces at industrial sites, PM10 emissions are estimated from the following empirical equation:

$$E = 1.5 (s/12)^{0.9} (W/3)^{0.45} \quad (1a)$$

and, for vehicles traveling on publicly accessible roads, dominated by light duty vehicles, PM10 emissions may be estimated from the following equation:

$$E = \frac{1.8 (s/12)^{1.8} (S/30)^{0.5}}{(M/0.5)^{0.2}} - C \quad (1b)$$

where

- E = PM10 emission factor (lb/VMT)
- s = surface material silt content (%)
- W = mean vehicle weight (tons)
- M = surface material moisture content (%)
- S = mean vehicle speed (mph)
- C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.

The source characteristics s, W and M are referred to as correction parameters for adjusting the emission estimates to local conditions. The metric conversion from lb/VMT to grams (g) per vehicle kilometer traveled (VKT) is 1 lb/VMT = 281.9 g/VKT. Equations 1a and 1b have a quality rating of B if applied within the ranges of source conditions that were tested in developing the equations shown in Table 6-3.

Table 6-3. Range of Source Conditions Used in Developing Equations 1a and 1b

Emission factor	Surface silt content, %	Mean vehicle weight		Mean vehicle speed		Mean No. of wheels	Surface moisture content, %
		Mg	ton	km/hr	mph		
Industrial roads (Equation 1a)	1.8-25.2	1.8-260	2-290	8-69	5-43	4-17 ^a	0.03-13
Public roads (Equation 1b)	1.8-35	1.4-2.7	1.5-3	16-88	10-55	4-4.8	0.03-13

As noted earlier, the models presented as Equations 1a and 1b were developed from tests of traffic on unpaved surfaces, mostly performed in the 1980s. Unpaved roads have a hard, generally nonporous surface that usually dries quickly after a rainfall or watering, because of traffic-enhanced natural evaporation. Factors influencing how fast a road dries are discussed in Section 6.5 below. A higher mean vehicle weight and a higher than normal traffic rate may be justified when performing a worst-case analysis of emissions from unpaved roads.

The PM2.5/PM10 ratio for fugitive dust from vehicles traveling on unpaved roads is 0.1.²³ The PM2.5 and PM10 emission factors for the exhaust, brake wear, and tire wear of a 1980's vehicle fleet (C) are shown in Table 6-4. They were obtained from EPA's MOBILE6.2 model.²⁴

Table 6-4. Emission Factors for 1980's Vehicle Fleet Exhaust, Brake Wear, and Tire Wear

Particle size	C, Emission factor for exhaust, brake wear, and tire wear (lb/VMT)
PM2.5	0.00036
PM10	0.00047

A PM10 emission factor for the resuspension of fugitive dust from unpaved shoulders created by the wake of high-profile vehicles such as tractor-trailers traveling on paved roads at high speed has been developed by Desert Research Institute (DRI). A discussion of the emissions estimation methodology for fugitive dust originating from unpaved shoulders is presented in Chapter 14.

6.2.2 Source Extent

It is important to note that the vehicle-related source conditions refer to the average weight, speed, and number of wheels for all vehicles traveling the road. For example, if 98% of the traffic on the road are 2-ton cars and trucks while the remaining 2% consists of 20-ton trucks, then the mean weight is 2.4 tons. More specifically, Equations 1a and 1b are not intended to be used to calculate a separate emission factor for each vehicle class within a mix of traffic on a given unpaved road. That is, in the example, one should not determine one factor for the 2-ton vehicles and a second factor for the 20-ton trucks. Instead, only one emission factor should be calculated that represents the “fleet” average of 2.4 tons for all vehicles traveling the road. Moreover, to retain the quality ratings when addressing a group of unpaved roads, it is necessary that reliable correction parameter values be determined for the road in question. The field and laboratory procedures for determining road surface silt and moisture contents are given in Appendices C.1 and C.2 of AP-42. Vehicle-related parameters should be developed by recording visual observations of traffic. In some cases, vehicle parameters for industrial unpaved roads can be determined by reviewing maintenance records or other information sources at the facility.

In the event that site-specific values for correction parameters cannot be obtained, then default values may be used. In the absence of site-specific silt content information, an appropriate mean value from Tables 6-1 and 6-2 may be used as a default value, but the quality rating of the equation is reduced by two letters. Because of significant differences found between different types of road surfaces and between different areas of the country, use of the default moisture content value of 0.5 percent in Equation 1b is discouraged. The quality rating should be downgraded two letters when the default moisture content value is used. It is assumed that readers addressing industrial roads have access to the information needed to develop average vehicle information for their facility.

6.2.3 Natural Mitigation

The effect of routine watering to control emissions from unpaved roads is discussed below in Section 6.5. However, all roads are subject to some natural mitigation because of rainfall and other precipitation. The Equation 1a and 1b emission factors can be extrapolated to annual average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual average emissions are inversely proportional to the number of days with measurable (more than 0.254 mm [0.01 inch]) precipitation:

$$E_{\text{ext}} = E[(365 - P)/365] \quad (2)$$

where,

- E_{ext} = annual size-specific emission factor extrapolated for natural mitigation (lb/VMT)
- E = emission factor from Equation 1a or 1b
- P = number of days in a year with at least 0.254 mm (0.01 in) of precipitation

Maps showing the geographical distribution of “wet” days on an annual basis for the United States based on meteorological records on a monthly basis are available in the *Climatic Atlas of the United States*.¹⁶ Alternative sources include other Department of Commerce publications such as local climatological data summaries. The National Climatic Data Center (NCDC) offers several products that provide hourly precipitation data. In particular, NCDC offers a *Solar and Meteorological Surface Observation Network 1961-1990* (SAMSON) CD-ROM, which contains 30 years worth of hourly meteorological data for first-order National Weather Service locations. Whatever meteorological data are used, the source of that data and the averaging period should be clearly specified.

Equation 2 provides an estimate that accounts for precipitation on an annual average basis for the purpose of inventorying emissions. It should be noted that Equation 2 does not account for differences in the temporal distributions of the rain events, the quantity of rain during any event, or the potential for the rain to evaporate from the road surface. In the event that a finer temporal and spatial resolution is desired for inventories of public unpaved roads, estimates can be based on a more complex set of assumptions. These assumptions include:

1. The moisture content of the road surface material is increased in proportion to the quantity of water added;
2. The moisture content of the road surface material is reduced in proportion to the Class A pan evaporation rate;
3. The moisture content of the road surface material is reduced in proportion to the traffic volume; and
4. The moisture content of the road surface material varies between the extremes observed in the area.

The CHIEF Web site (www.epa.gov/ttn/chief/ap42/ch13/related/c13s02-2) has a file that contains a spreadsheet program for calculating emission factors that are temporally and spatially resolved. Information required for use of the spreadsheet program includes monthly Class A pan evaporation values, hourly meteorological data for precipitation, humidity and snow cover, vehicle traffic information, and road surface material information.

It is emphasized that the simple assumption underlying Equation 2 and the more complex set of assumptions underlying the use of the procedure which produces a finer

temporal and spatial resolution have not been verified in any rigorous manner. For this reason, the quality ratings for either approach should be downgraded one letter from the rating that would be applied to Equation 1.

6.3 Emission Estimation: Alternate Methodology for Non-Farm Roads

This section was adapted from Section 7.10 of CARB's Emission Inventory Methodology. Section 7.10 was last updated in August 1997.

This source category provides estimates of the entrained geologic particulate matter emissions that result from vehicular travel over non-agricultural unpaved roads. The emissions are estimated separately for three major unpaved road categories: city and county roads, U.S. forests and park roads, and Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA) roads. The emissions result from the mechanical disturbance of the roadway and the vehicle generated air turbulence effects. Agricultural unpaved road estimates are computed in a separate methodology; see Section 6.4.

6.3.1 Emission Factor

The PM10 emission factor used for estimates of geologic dust emissions from vehicular travel on unpaved roads is based on work performed by UC Davis²⁸ and the Desert Research Institute.²⁹ The emission factor used for all unpaved roads statewide is 2.27 lbs PM10/VMT.³⁰ Because the emission measurements were performed in California, this emission factor was used by CARB to replace the previous generic emission factor provided in EPA's AP-42 document.³¹ The new emission factor is slightly smaller than the factors derived with the AP-42 methodology. The PM2.5/PM10 ratio for unpaved road dust is 0.1.²³

6.3.2 Source Extent (Activity Level)

For the purpose of estimating emissions, it is assumed that the unpaved road dust emissions are primarily related to the vehicle miles traveled (VMT) on the roads. State highway data are used to estimate unpaved road miles for each roadway category in each county. It is assumed that 10 daily VMT (DVMT) are traveled on unpaved city and county roads as well as U.S. forest and parks roads and BLM and BIA roads. Road mileage, if needed, can be simply computed by dividing the annual VMT values by 3650 (which is 10 DVMT x 365 days).

Daily activity on unpaved roads occurs primarily during daylight hours. Activity is assumed to be the same each day of the week. Monthly activity varies by county and is based on estimates of monthly rainfall in each county. This is to reflect that during wet months there is less unpaved road traffic, and there are also lower emissions per mile of road when the road soils have a higher moisture content. Unpaved road growth is tied to on-road VMT growth for many counties. For other counties, growth is set to zero and VMT is not used.

6.3.3 Assumptions and Limitations

CARB's methodology is subject to the following assumptions and limitations:

1. This methodology assumes that all unpaved roads emit the same levels of PM10 per VMT during all times of the year for all vehicles and conditions.
2. It is assumed that all unpaved roads receive 10 VMT per day.
3. This methodology assumes that no controls are used on the roads.
4. It is assumed that the emission factors derived in a test county are applicable to the rest of California.

6.4 Emission Estimation: Alternative Methodology for Farm Roads

This section was adapted from Section 7.11 of CARB's Emission Inventory Methodology. Section 7.11 was last updated in August 1997.

This source category provides estimates of the entrained geologic particulate matter emissions that result from vehicular travel over unpaved roads on agricultural lands. The emissions result from the mechanical disturbance of the roadway and the vehicle generated air turbulence effects. This emission factor used is oriented towards dust emissions from light duty vehicle use, but the activity data implicitly include some larger vehicle use for harvest and other operations.

6.4.1 Emission Factor

The PM10 emission factor used for estimates of geologic dust emissions from vehicular travel on unpaved roads is based on work performed by UC Davis²⁸ and the Desert Research Institute.²⁹ The emission factor used for all unpaved roads statewide is 2.27 lbs PM10/VMT.³⁰ Because the emission measurements were performed in California, this emission factor was used by CARB to replace the previous generic emission factor provided in EPA's AP-42 document.³¹ CARB's emission factor is slightly smaller than the factors derived with the AP-42 methodology. The PM2.5/PM10 ratio for unpaved road dust is 0.1.²³

6.4.2 Source Extent (Activity Level)

For the purpose of estimating emissions, it is assumed that the unpaved road dust emissions are primarily related to the vehicle miles traveled (VMT) on the roads. In 1976 an informal survey was made of several county agricultural commissioners in the San Joaquin Valley, who estimated that each 40 acres of cultivated land receives approximately 175 vehicle passes per year on the unpaved farm roads.³² This value of 4.28 VMT/acre-year has been used in the past by CARB to calculate emissions from unpaved farm roads. CARB is now proposing the following estimates of source extent for unpaved farm roads for different crops: 0.38 VMT/acre-year for grapes, 0.40 VMT/acre-year for cotton, and 1.23 VMT/acre-year for citrus.³³

The crop acreage data used to estimate the road dust emissions are from the state agency summary of crop acreage harvested.^{34, 35} The acreage estimates do not include pasture lands because it is thought that the quantity of vehicular travel on these lands is minimal. Daily activity on unpaved roads occurs primarily during daylight hours. Activity is assumed to be the same each day of the week. Monthly activity varies by county and is based on estimates of monthly rainfall in each county. This is to reflect that during wet months there is less unpaved road traffic, and there are also lower emissions per mile of road when the road soils have a higher moisture content. Unpaved road growth for farm roads is based on agricultural crop acreage or agricultural production. This value is set to zero for many counties.

6.4.3 Assumptions and Limitations

CARB's methodology is subject to the following assumptions and limitations:

1. This methodology assumes that all unpaved farm roads emit the same levels of PM10 per VMT during all times of the year for all vehicles and conditions.
2. It is assumed that all unpaved farm roads receive 175 VMT per 40 acres per year for all crops and cultivation practices.
3. This methodology assumes that no controls are used on the roads.
4. It is assumed that the emission factors derived in the test area are applicable to the rest of California.
5. This methodology assumes that unpaved road travel associated with pasture lands is negligible.

6.5 Demonstrated Control Techniques

A wide variety of options exist to control emissions from unpaved roads. Options fall into the following three groupings:

1. Vehicle restrictions that limit the speed, weight or number of vehicles on the road
2. Surface improvement by measures such as (a) paving or (b) adding gravel or slag to a dirt road
3. Surface treatment such as watering or treatment with chemical dust suppressants

Available control options span broad ranges in terms of cost, efficiency, and applicability. For example, traffic controls provide moderate emission reductions (often at little cost) but are difficult to enforce. Although paving is highly effective, its high initial cost is often prohibitive. Furthermore, paving is not feasible for industrial roads subject to very heavy vehicles and/or spillage of material in transport. Watering and chemical suppressants, on the other hand, are potentially applicable to most industrial roads at moderate to low costs. However, these require frequent reapplication to

maintain an acceptable level of control. Chemical suppressants are generally more cost-effective than water but not in cases of temporary roads (which are common at mines, landfills, and construction sites). In summary, then, one needs to consider not only the type and volume of traffic on the road but also how long the road will be in service when developing control plans.

Vehicle restrictions. These measures seek to limit the amount and type of traffic present on the road, or to lower the mean vehicle speed. For example, many industrial plants have restricted employees from driving on plant property and have instead instituted bussing programs. This eliminates emissions due to employees traveling to/from their worksites. Although the heavier average vehicle weight of the busses increases the base emission factor, the decrease in vehicle-miles-traveled results in a lower overall emission rate.

Surface improvements. Control options in this category alter the road surface. As opposed to “surface treatments” discussed below, improvements are relatively “permanent” and do not require periodic retreatment. The most obvious surface improvement is paving an unpaved road. This option is quite expensive and is probably most applicable to relatively short stretches of unpaved road with at least several hundred vehicle passes per day. Furthermore, if the newly paved road is located near unpaved areas or is used to transport material, it is essential that the control plan address routine cleaning of the newly paved road surface. The control efficiencies achievable by paving can be estimated by comparing emission factors for unpaved and paved road conditions. The predictive emission factor equation for paved roads, given in Chapter 5, requires estimation of the silt loading on the traveled portion of the paved surface, which in turn depends on whether the pavement is periodically cleaned. Unless curbing is to be installed, the effects of vehicle excursion onto unpaved shoulders (berms) also must be taken into account in estimating the control efficiency of paving.

Other surface improvement methods involve covering the road surface with another material that has a lower silt content. Examples include placing gravel or slag on a dirt road. The control efficiency can be estimated by comparing the emission factors obtained using the silt contents before and after improvement. The silt content of the road surface should be determined after 3 to 6 months rather than immediately following placement. Control plans should address regular maintenance practices, such as grading, to retain larger aggregate on the traveled portion of the road.

Surface treatments. These measures refer to control options that require periodic reapplication. Treatments fall into the two main categories of:

- (a) wet suppression (i.e., watering, possibly with surfactants or other additives), which keeps the road surface wet to control emissions, and
- (b) chemical stabilization that attempts to change the physical characteristics of the surface.

The necessary reapplication frequency varies from minutes or hours for plain water under summertime conditions to several weeks or months for chemical dust suppressants.

Wet Suppression. Watering increases the moisture content, which in turn causes particles to conglomerate and reduces their likelihood of becoming suspended when vehicles pass over the surface. The control efficiency depends on how fast the road dries after water is added. This in turn depends on: (a) the amount (per unit road surface area) of water added during each application; (b) the period of time between applications; (c) the weight, speed and number of vehicles traveling over the watered road during the period between applications; and (d) meteorological conditions (temperature, wind speed, cloud cover, etc.) that affect evaporation during the period. Figure 6-1 presents a simple bilinear relationship between the instantaneous control efficiency due to watering and the resulting increase in surface moisture. The moisture ratio “M” (i.e., the x-axis in Figure 6-1) is found by dividing the surface moisture content of the watered road by the surface moisture content of the uncontrolled road. As the watered road surface dries, both the ratio M and the predicted instantaneous control efficiency (i.e., the y-axis in the figure) decrease. The figure shows that between the uncontrolled moisture content (M = 1) and a value twice as large (M = 2), a small increase in moisture content results in a large increase in control efficiency. Beyond that, control efficiency grows slowly with increased moisture content.

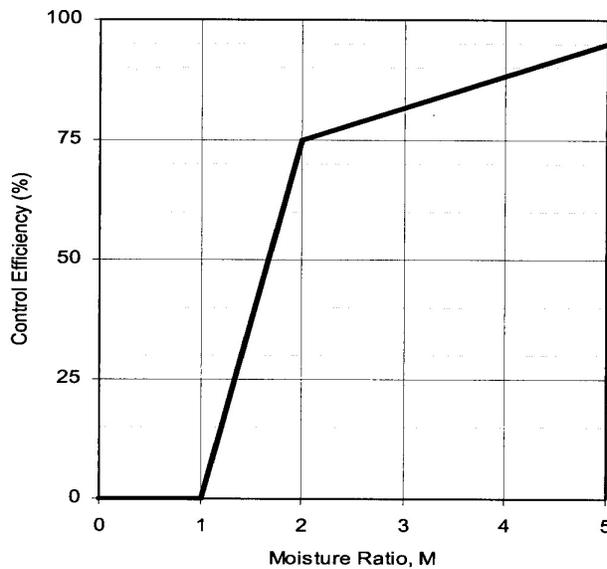


Figure 6-1. Watering Control Effectiveness for Unpaved Travel Surfaces

Given the complicated nature of how the road dries, characterization of emissions from watered roadways is best done by collecting road surface material samples at various times between water truck passes. AP-42 Appendices C.1 and C.2 present the recommended sampling and analysis procedures, respectively, for determining the surface/bulk dust loading. The moisture content measured can then be associated with a control efficiency by use of Figure 6-1. Samples that reflect average conditions during the watering cycle can take the form of either a series of samples between water applications or a single sample at the midpoint. It is essential that samples be collected during periods with active traffic on the road. Finally, because of different evaporation rates, it is recommended that samples be collected at various times during the year. If

only one set of samples is to be collected, these must be collected during hot, summertime conditions.

When developing watering control plans for roads that do not yet exist, it is strongly recommended that the moisture cycle be established by sampling similar roads in the same geographic area. If the moisture cycle cannot be established by similar roads using established watering control plans, the more complex methodology used to estimate the mitigation of rainfall and other precipitation can be used to estimate the control provided by routine watering. An estimate of the maximum daytime Class A pan evaporation (based upon daily evaporation data published in the monthly Climatological Data for the state by the National Climatic Data Center) should be used to insure that adequate watering capability is available during periods of highest evaporation. Hourly precipitation values are replaced by the equivalent inches of precipitation resulting from watering. One inch of precipitation is equivalent to an application of 5.6 gallons of water per square yard of road. Information on the long term average annual evaporation and on the percentage that occurs between May and October is available in the Climatic Atlas.¹⁶ This methodology should be used only for prospective analyses and for designing watering programs for existing roadways. The quality rating of an emission factor for a watered road that is based on this methodology should be downgraded two letters. Periodic road surface samples should be collected and analyzed to verify the efficiency of the watering program.

Chemical Dust Suppressants. As opposed to wet suppression (i.e., watering), chemical dust suppressants have much less frequent reapplication requirements. These materials suppress emissions by changing the physical characteristics of the existing road surface material. Many chemical dust suppressants applied to unpaved roads form a hardened surface that binds particles together. After several applications, a treated unpaved road often resembles a paved road except that the surface is not uniformly flat. Because the improved surface results in more grinding of small particles, the silt content of loose material on a highly controlled surface may be substantially higher than when the surface was uncontrolled. For this reason, the models presented as Equations 1a and 1b cannot be used to estimate emissions from chemically stabilized roads. Should the road be allowed to return to an uncontrolled state with no visible signs of large-scale cementing of material, the Equation 1a and 1b emission factors could then be used to obtain conservatively high emission estimates.

The control effectiveness of chemical dust suppressants appears to depend on: (a) the dilution rate used in the mixture; (b) the application rate (volume of solution per unit road surface area); (c) the time between applications; (d) the size, speed and amount of traffic during the period between applications; and (e) meteorological conditions (rainfall, freeze/thaw cycles, etc.) during the period. Other factors that affect the performance of chemical dust suppressants include other traffic characteristics (e.g., cornering, track-out from unpaved areas) and road characteristics (e.g., bearing strength, grade). The variability in these factors and differences between individual dust control products make the control efficiencies of chemical dust suppressants difficult to estimate. Past field testing of emissions from controlled unpaved roads has shown that chemical dust

suppressants provide a PM10 control efficiency of about 80% when applied at regular intervals of 2 weeks to 1 month.

Petroleum resin products historically have been the dust suppressants (besides water) most widely used on industrial unpaved roads. Figure 6-2 presents a method to estimate average control efficiencies associated with petroleum resins applied to unpaved roads.²⁰ The following items should be noted:

1. The term “ground inventory” represents the total volume (per unit area) of petroleum resin concentrate (not solution) applied since the start of the dust control season.
2. Because petroleum resin products must be periodically reapplied to unpaved roads, the use of a time-averaged control efficiency value is appropriate. Figure 6-2 presents control efficiency values averaged over two common application intervals, 2 weeks and 1 month. Other application intervals will require interpolation.
3. Note that zero efficiency is assigned until the ground inventory reaches 0.05 gallon per square yard (gal/yd²). Requiring a minimum ground inventory ensures that one must apply a reasonable amount of chemical dust suppressant to a road before claiming credit for emission control. Recall that the ground inventory refers to the amount of petroleum resin concentrate rather than the total solution.

As an example of the application of Figure 6-2, suppose that Equation 1a was used to estimate a PM10 emission factor of 7.1 lb/VMT from a particular road. Also, suppose that, starting on May 1, the road is treated with 0.221 gal/yd² of a solution (1 part petroleum resin to 5 parts water) on the first of each month through September. The average controlled PM10 emission factors calculated from Figure 6-2 are shown in Table 6-5.

Besides petroleum resins, other newer dust suppressants have also been successful in controlling emissions from unpaved roads. Specific test results for those chemicals, as well as for petroleum resins and watering, are provided in References 18 through 21.

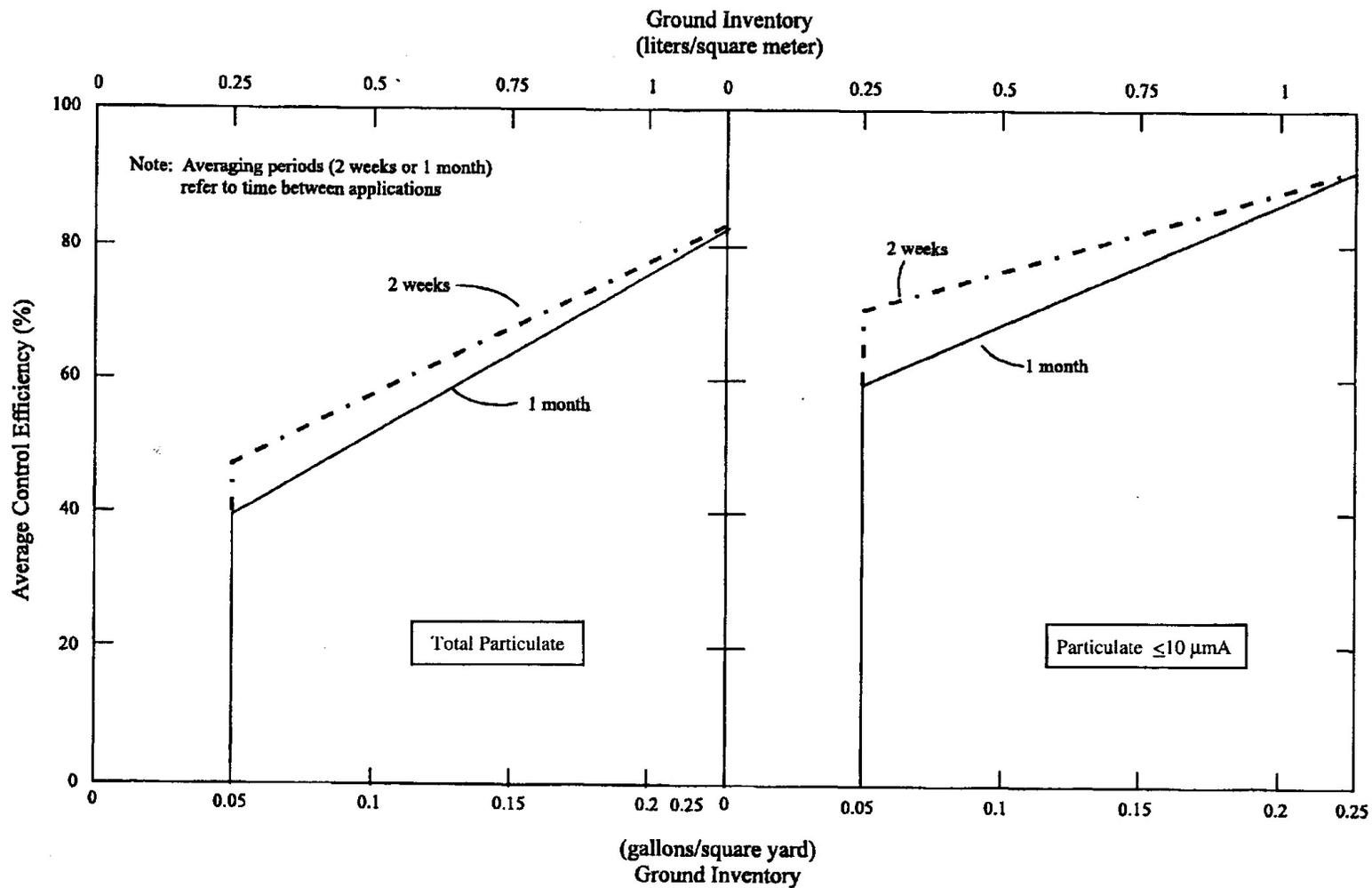


Figure 6-2. Average TSP and PM10 Control Efficiencies for Two Common Application Intervals

Table 6-5. Average Controlled PM10 Emission Factors for Specific Conditions

Period	Ground inventory, gal/yd ²	Average control efficiency, % ^a	Average controlled PM10 emission factor, lb/VMT
May	0.037	0	7.1
June	0.073	62	2.7
July	0.11	68	2.3
August	0.15	74	1.8
September	0.18	80	1.4

^a From Figure 6-2. Zero efficiency assigned if ground inventory is less than 0.05 gal/yd².

1 lb/VMT = 281.9 g/VKT. 1 gal/yd² = 4.531 L/m².

Table 6-6 summarizes tested control measures and reported control efficiencies for measures that reduce the generation of fugitive dust from unpaved roads.

Table 6-6. Control Efficiencies for Control Measures for Unpaved Roads^{36, 37}

Control measure	PM10 control efficiency	References/Comments
Limit maximum speed on unpaved roads to 25 miles per hour	44%	Assumes linear relationship between PM10 emissions and vehicle speed and an uncontrolled speed of 45 mph.
Pave unpaved roads and unpaved parking areas	99%	Based on comparison of paved road and unpaved road PM10 emission factors.
Implement watering twice a day for industrial unpaved road	55%	MRI, April 2001
Apply dust suppressant annually to unpaved parking areas	84%	CARB April 2002

6.6 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats downloaded from the Internet for several local air quality agencies in the WRAP region are presented in Table 6-7. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/envsvc/air/ruledesc.asp

Table 6-7. Example Regulatory Formats for Unpaved Roads

Control Measure	Goal	Threshold	Agency
<p>Requires annual treatment of unpaved public roads beginning in 1998 and continuing for each of 8 years thereafter by implementing one of the following: paving at least one mile with typical roadway material, applying chemical stabilizers to at least two miles to maintain stabilized surface, implementing at least one of the following on at least three miles of road surface: installing signage at 1/4 mile intervals limiting speed to 15 mph, installing speed control devices every 500 ft, or maintaining roadway to limit speed to 15 mph</p>		<p>Set applicability standard: unpaved road must be more than 50 ft wide at all points or must not be within 25 ft of property line, or have more than 20 vehicle trips per day. All roads with average daily traffic greater than average of all unpaved roads within its jurisdiction must be treated</p>	<p>SCAQMD Rule 1186 9/10/1999</p>
<p>Control measures implemented by June 1, 2003: pave, apply dust palliative, or other</p>	<p>Complies with stabilization standard: limit visible dust emissions to 20% opacity, limit silt loading to 0.33 oz/ft², and limit silt content to 6%</p>	<p>All unpaved roads with vehicular traffic 150 vehicles or more per day</p>	<p>Clark County Hydrographic Basins 212, 216, 217 Sect. 91 Air Quality Reg. 06/22/2000</p>
<p>Limit vehicle speed \leq15mph and \leq20 trips/day; BACM: watering, paving, apply/maintain gravel, asphalt, or dust suppressant; Dust control plan for construction site roads</p>	<p>Limit VDE to 20% opacity; limit silt loading to 0.33oz/ft², limit silt content to 6%</p>	<p>Construction site roads, inactive/active; limiting vehicle speed and trips is alternative to stabilization requirement and max number of trips each day in control plan (also number of vehicles, earthmoving equip, etc.); for roads with \geq150 vehicles/day implement BACM by 06/10/2004; same for \geq250 vehicles day (existing roads by 06/10/2000)</p>	<p>Maricopa County Rules 310 and 310.01 04/07/2004 and 02/16/2000</p>

6.7 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 6-8 summarizes the compliance tools that are applicable for unpaved roads.

Table 6-8. Compliance Tools for Unpaved Roads

Record keeping	Site inspection/monitoring
Road map; traffic volumes, speeds, and patterns; dust suppression equipment and maintenance records; frequencies, amounts, times, and rates for watering and dust suppressants (type); use of water surfactants; calculated control efficiencies; regrading, graveling, or paving of unpaved road segments; control equipment downtime and maintenance records; meteorological log.	Observation of water truck operation and inspection of sources of water; observation of dust plume opacity exceeding a standard; counting of traffic volumes; surface material sampling and analysis for silt and moisture contents; real-time portable monitoring of PM.

6.8 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for fugitive dust originating from unpaved roads. A sample cost-effectiveness calculation is presented below for a specific control measure (watering) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In

selecting the most advantageous control measure for unpaved roads, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Unpaved Roads at an Industrial Facility

Step 1. Determine source activity and control application parameters.

Road length (mile)	2
Vehicles/day	100
Wet days/year	20
Number of 8-hour workdays/year	260
Number of emission days/yr (workdays without rain)	240
Control Measure	Watering
Control Application/Frequency	Twice daily*
Economic Life of Control System (year)	10
Control Efficiency	55%

* No nighttime traffic.

The number of vehicles per day, wet days per year, workdays per year, and the economic life of the control measure are assumed values for illustrative purposes. Watering has been chosen as the applied control measure. The control application/frequency and control efficiency are default values provided by MRI, 2001.³⁵

Step 2. Calculate PM10 Emission Factor. The PM10 emission factor is calculated from the AP-42 equation utilizing the appropriate correction parameters.

$$E \text{ (lb/VMT)} = 1.5 \text{ (s/12)}^{0.9} \text{ (W/3)}^{0.45}$$

s—silt content (%)	15
W—vehicle weight (tons)	15

$$E = 3.8 \text{ lb/VMT}$$

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (calculated in Step 2) is multiplied by the number of vehicles per day, by the road length and by the number of emission days per year (see activity data) and divided by 2,000 lb/ton to compute the annual PM10 emissions, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (\text{EF} \times \text{Vehicles/day} \times \text{Miles} \times \text{Emission days/yr}) / 2,000 \\ \text{Annual PM10 emissions} &= (3.8 \times 100 \times 2 \times 240) / 2,000 = 91 \text{ tons} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= 0.1 \times \text{PM10 Emissions}^{23} \\ \text{Annual PM2.5 emissions} &= 0.1 \times 91 \text{ tons} = 9.1 \text{ tons} \end{aligned}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, we have selected watering as our control measure. Based on a control efficiency estimate of 55% for the application of water to unpaved roads, the annual controlled emissions estimate are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM}_{10} \text{ emissions} &= (91 \text{ tons}) \times (1 - 0.55) = 41 \text{ tons} \\ \text{Annual Controlled PM}_{2.5} \text{ emissions} &= (9.1 \text{ tons}) \times (1 - 0.55) = 4.1 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	30,000
Annual Operating/Maintenance costs (\$)	8,000
Annual Interest Rate	3%
Capital Recovery Factor	0.1172
Annualized Cost (\$/yr)	11,517

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$\begin{aligned} \text{Capital Recovery Factor} &= \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1 \\ \text{Capital Recovery Factor} &= 3\% \times (1 + 3\%)^{10} / (1 + 3\%)^{10} - 1 = 0.1172 \end{aligned}$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor and the Capital costs to the annual Operating/Maintenance costs:

$$\begin{aligned} \text{Annualized Cost} &= (\text{CRF} \times \text{Capital costs}) + \text{Annual Operating/Maintenance costs} \\ \text{Annualized Cost} &= (0.1172 \times 30,000) + 8,000 = \$11,517 \end{aligned}$$

Step 6. Calculate Cost Effectiveness. Cost effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\begin{aligned} \text{Cost effectiveness for PM}_{10} \text{ emissions} &= \$11,517 / (91 - 41) = \$231/\text{ton} \\ \text{Cost effectiveness for PM}_{2.5} \text{ emissions} &= \$11,517 / (9.1 - 4.1) = \$2,306/\text{ton} \end{aligned}$$

6.9 References

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Chapter 7. Agricultural Wind Erosion

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7.1 Characterization of Source Emissions

Wind blowing across exposed nonpasture agricultural land results in particulate matter (PM) emissions. Windblown dust emissions from agricultural lands are calculated by multiplying the process rate (acres of crop in cultivation) by an emission factor (tons of PM per acre per year).

7.2 Emission Estimation Methodology¹⁻¹³

This section was adapted from Section 7.12 of CARB's Emission Inventory Methodology. Section 7.12 was last updated in July 1997.

MRI developed a PM₁₀ emission factor for agricultural wind blown dust of 86.6 lb/acre on behalf of the EPA in 1992.¹ However this emission factor is not included in AP-42. Thus, the methodology adopted by the California Air Resources Board^{2,3} (CARB) is presented as the emissions estimation methodology in lieu of an official EPA methodology for this fugitive dust source category. The methodology for estimating fugitive dust emissions from open area wind erosion is presented in Chapter 8 of this handbook.

The standard methodology for estimating the emission factor for windblown emissions from agricultural lands is the wind erosion equation (WEQ). Although the WEQ is well established, it is controversial. The WEQ was developed by the United States Department of Agriculture-Agricultural Research Service (USDA-ARS) during the 1960s, for the estimation of wind erosion on agricultural land.^{4,5} The U.S. EPA adapted the USDA-ARS methodology for use in estimating windblown TSP emissions from agricultural lands in 1974⁵, and the California Air Resources Board (CARB) adopted the U.S. EPA methodology in 1989. The PM₁₀/TSP ratio for wind erosion is 0.5.⁶ The PM_{2.5}/PM₁₀ ratio for windblown fugitive dust posted on EPA's CHIEF website is 0.15 based on the analysis conducted by MRI on behalf of WRAP.⁷

The USDA-ARS has undertaken ambitious programs over the past decade to replace the WEQ with improved wind erosion prediction models such as the Revised Wind Erosion Equation (RWEQ)⁸ and the Wind Erosion Prediction System (WEPS)⁹ models. CARB does not consider these models feasible for use, although certain portions of the RWEQ were incorporated into the CARB methodology in 1997. According to CARB, the WEQ (with modifications) continues to be the best available, feasible method for estimating windblown agricultural emissions.

7.2.1 Summary of CARB's Wind Erosion Equation (ARBWEQ)

Much of the controversy surrounding the WEQ has related to its tendency to produce inflated emission estimates. Some of the reasons for the inflated emissions relate to the fact that it was developed in the Midwestern United States, and that it does not take into account many of the environmental conditions and farm practices specific to the West. In the revised methodology developed by CARB (referred to as the ARBWEQ), CARB staff added adjustments to the WEQ to improve its ability to estimate windblown emissions from western agricultural lands.

The U.S. EPA-modified version of the USDA-ARS derived wind erosion equation (WEQ) reads as follows:⁶

$$E_S = A I K C L' V' \quad (1)$$

where, E_S = total suspended particulate fraction of wind erosion losses of tilled fields (tons TSP/acre/year)
 A = portion of total wind erosion losses that would be measured as total suspended particulate, estimated to be 0.025
 I = soil erodibility (tons/acre/year)
 K = surface roughness factor (dimensionless)
 C = climatic factor (dimensionless)
 L' = unsheltered field width factor (dimensionless)
 V' = vegetative cover factor (dimensionless)

As an aid in understanding the mechanics of this equation, the soil erodibility factor I may be thought of as the basic erodibility of a flat, very large, bare field in a climate highly conducive to wind erosion (i.e., high wind speeds and high temperature with little precipitation). This factor was initially established for the WEQ for a large, flat, bare field in Kansas that has relatively high winds along with hot summers and low precipitation. The parameters K , C , L' and V' may be thought of as reduction factors for a ridged surface, a climate less conducive to wind erosion, smaller-sized fields, and vegetative cover, respectively, to adjust the equation for applicability to field conditions that differ from the original Kansas field. The A factor in Equation 1 has been used in the ARBWEQ without modification. There has been concern that this factor doesn't take into account finite dust loading. The RWEQ⁸ and WEPS⁹ models are attempting to address that concern.

Soil Erodibility, I. Soil erodibility by the wind is a function of the amount of erodible fines in the soil. The largest soil aggregate size normally considered to be erodible is approximately 0.84 mm equivalent diameter. The soil erodibility factor, I , is related to the percentage of dry aggregates greater than 0.84 mm as shown in Figure 7-1.⁶ The percentage of nonerodible aggregates (and by difference the amount of fines) in a soil sample can be determined experimentally by a standard dry sieving procedure, using a No. 20 U.S. Bureau of Standards sieve with 0.84 mm square openings. For areas larger than can be field sampled for soil aggregate size (e.g., a county) or in cases where soil particle size distributions are not available, a representative value of I can be obtained from the predominant soil type(s) for farmland in the area. Measured erodibilities, I (in units of tons/acre-year), of various soil textural classes are presented in Table 7-1 as a function of percent of dry soil aggregates greater than 0.84 mm in diameter.⁶ For California, the soil textural classes were determined by CARB staff from University of California soil maps.¹⁰ An additional level of detail was included in the ARBWEQ by using the United States Department of Agriculture-Natural Resources Conservation Service's (NRCS) State Geographic Data Base (STATSGO) of soil data.¹¹ In addition, the USDA-ARS recommended an adjustment for changes to long term erodibility due to irrigation.¹² This affects a property known as cloddiness, and refers to the increased tendency for a soil to form stable agglomerations after being exposed to irrigation water.

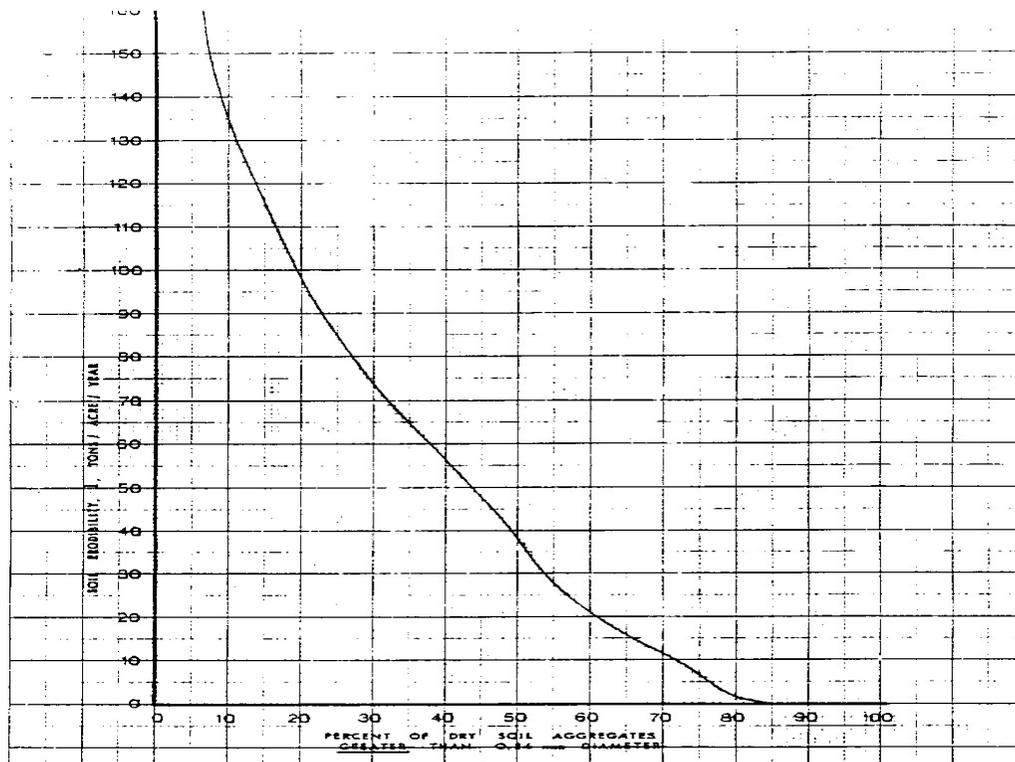


Figure 7-1. Soil Erodibility as a Function of Particle Size⁶

Table 7-1. Soil Erodibility, I, for Various Soil Textural Classes⁶

Predominant Soil Textural Class	Erodibility (tons/acre-year)
Sand	220
Loamy sand	134
Sandy loam, clay, silty clay	86
Loam, sandy clay loam, sandy clay	56
Silty loam, clay loam	47
Silty clay loam, silt	38

Surface Roughness Factor, K. The surface roughness factor, K, accounts for the resistance to wind erosion provided by ridges and furrows or large clods in the field and is crop specific. The surface roughness factor, K, is a function of the height and spacing of the ridges, and varies from 1.0 (no reduction) for a field with a smooth surface to a minimum of 0.5 for a field with the optimum ratio of ridge height (h) to ridge spacing (w). The relationship between K and h^2/w is shown in Figure 7-2.⁶ Average K values of common field crops are shown in Table 7-2. Similar crops are assigned similar surface roughness values.

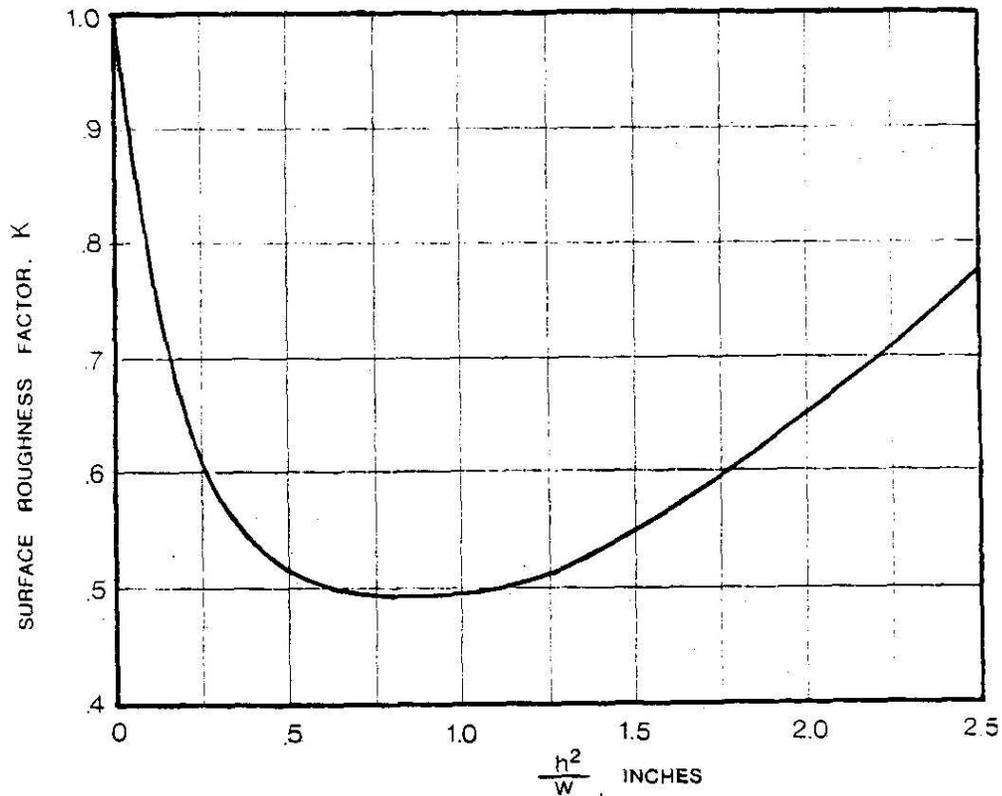


Figure 7-2. Determination of Surface Roughness Factor, K^6

Table 7-2. Surface Roughness Factor, K, for Common Field Crops⁶

Crop	K
Alfalfa, safflower	1.0
Grain hays, oats, potatoes, rice	0.8
Barley, corn, peanuts, rye, soybeans, sugar beets, vegetables, wheat	0.6
Beans, cotton, sorghum	0.5

Climatic Factor, C. The annual climatic factor, C, is based on data that show that erosion varies directly with the wind speed cubed, and as the inverse of the square of surface soil moisture. The C factor can be calculated from the following equation:

$$C = 0.345 W^3 / (PE)^2 \quad (2)$$

where, W = mean annual wind speed (mph), corrected to a standard height of 10 meters
 PE = Thornthwaite's precipitation-evaporation index (i.e., ratio of precipitation to evapotranspiration)

Monthly or seasonal climatic factors can be estimated from Equation 2 by substituting the mean wind speed of the period of interest for the mean annual wind speed. Climatic factors have been computed from National Weather Bureau data for

many locations throughout the country. The annual climatic factors for many areas of the US are shown in Figure 7-3. The monthly precipitation/evaporation ratio varies from <16 for arid deserts to >127 for rain forests. For the ARBWEQ, CARB staff improved the input data for calculating the factor C, as well as the methods associated with developing the county wide averaged annual climatic factor. Monthly climatic factors were obtained by modifying the annual climatic factor calculation method. Annual climatic factors for different counties within California range from 0.019 to 1.274.¹⁴ The reader is directed to CARB's website to obtain the list of climatic factors for counties within California (www.arb.ca.gov/emisinv/areasrc/fullpdf).

Unsheltered Field Width Factor, L' Soil erosion across a field is directly related to the unsheltered width along the prevailing wind direction. The rate of erosion is zero at the windward edge of the field and increases approximately proportionately with distance downwind until, if the field is large enough, a maximum rate of soil movement is reached. Correlation between the width of a field and its rate of erosion is also affected by the soil erodibility of its surface: the more erodible the surface, the shorter the distance in which maximum soil movement is reached. This relationship between the unsheltered width of a field (L), its surface erodibility (IK), and its relative rate of soil erosion (L') is shown graphically for different values of IK (ranging from IK = 20 to IK = 134) in Figure 7-4.⁶ If the curves of Figure 7-4 are used to obtain the L' factor for the windblown dust equation, values for the variables I and K must already be known and an appropriate value for L must be determined.

L is calculated as the distance across the field in the prevailing wind direction minus the distance from the windward edge of the field that is protected from wind erosion by a barrier. The distance protected by a barrier is equal to 10 times the height of the barrier, or 10H. For example, a row of 30-foot high trees along the windward side of a field reduces the effective width of the field by 300 feet. If the prevailing wind direction differs significantly (>25 degrees) from perpendicularity with the field, L should be increased to account for this additional distance of exposure to the wind. The distance across the field, L, is equal to the field width divided by the cosine of the angle between the prevailing wind direction and the perpendicularity to the field.

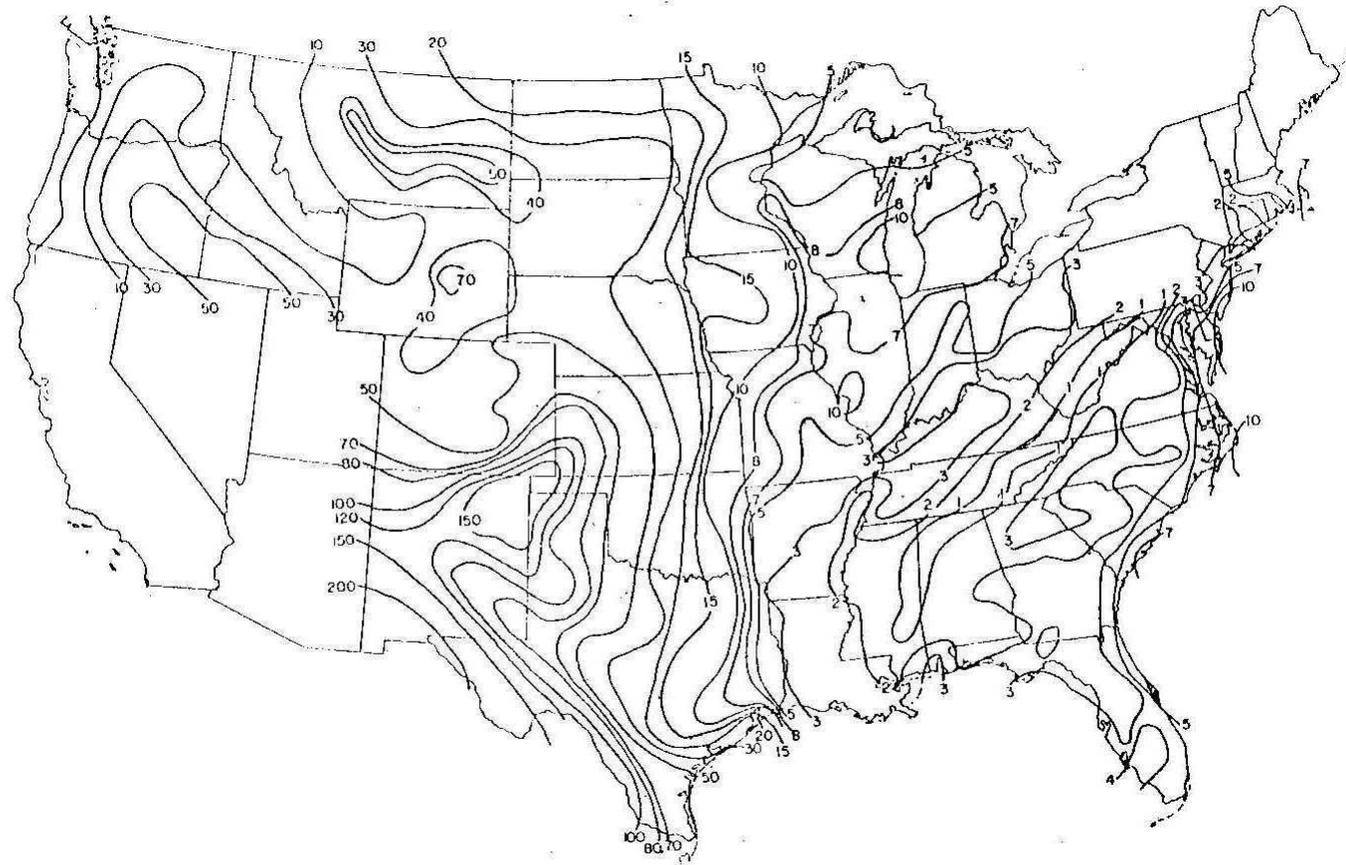


Figure 7-3. Annual Climatic Factor Used in Wind Erosion Equation⁶

[Note: Isopleths for several western and northeastern states were not available at the time this figure was prepared.]

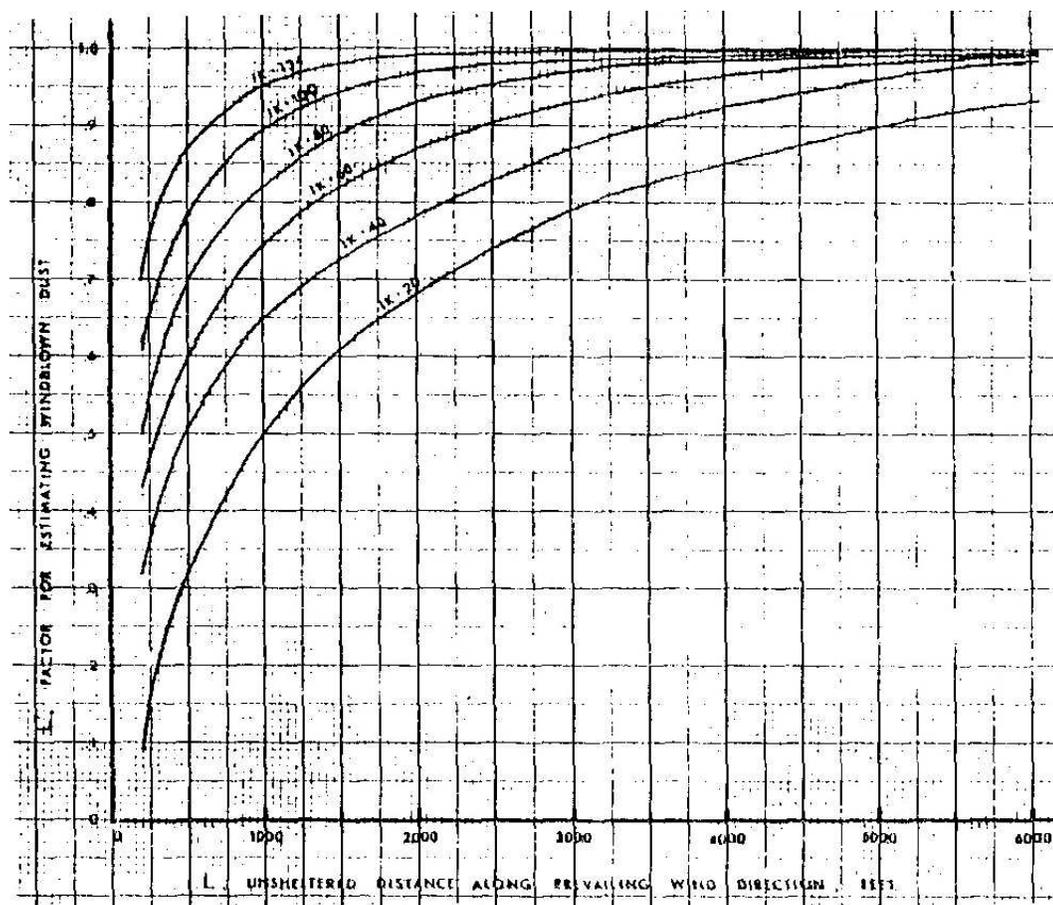


Figure 7-4. Effect of Field Length on Relative Soil Erosion Rate⁶

Vegetative Cover Factor, V' . Vegetative cover on agricultural fields during periods other than the primary crop season greatly reduces wind erosion of the soil. This cover most commonly is crop residue, either standing stubble or mulched into the soil. The effect of various amounts of residue, V , in reducing erosion is shown qualitatively in Figure 7-5, where $IKCL'$ is the potential annual soil loss (in tons/acre-year) from a bare field, and V' is the fractional amount of this potential loss which results when the field has a vegetative cover of V (in lb of air-dried residue/acre). The amount of vegetative cover on a single field can be ascertained by collecting and weighing clean residue from a representative plot or by visual comparison with calibrated photographs. The vegetative soil cover factor, V' , is especially problematic for California, and was completely replaced by a series of factors in the ARBWEQ (see analysis below). This factor assumes a certain degree of cover year round based upon post harvest soil cover, and does not account for barren fields from land preparation, growing canopy cover, or replanting of crops during a single annual cycle. All of these factors are very important in the estimation of windblown agricultural dust emissions. Therefore, CARB staff replaced the vegetative soil cover factor, V' , with separate crop canopy cover, post harvest soil cover, and post harvest replant factors.

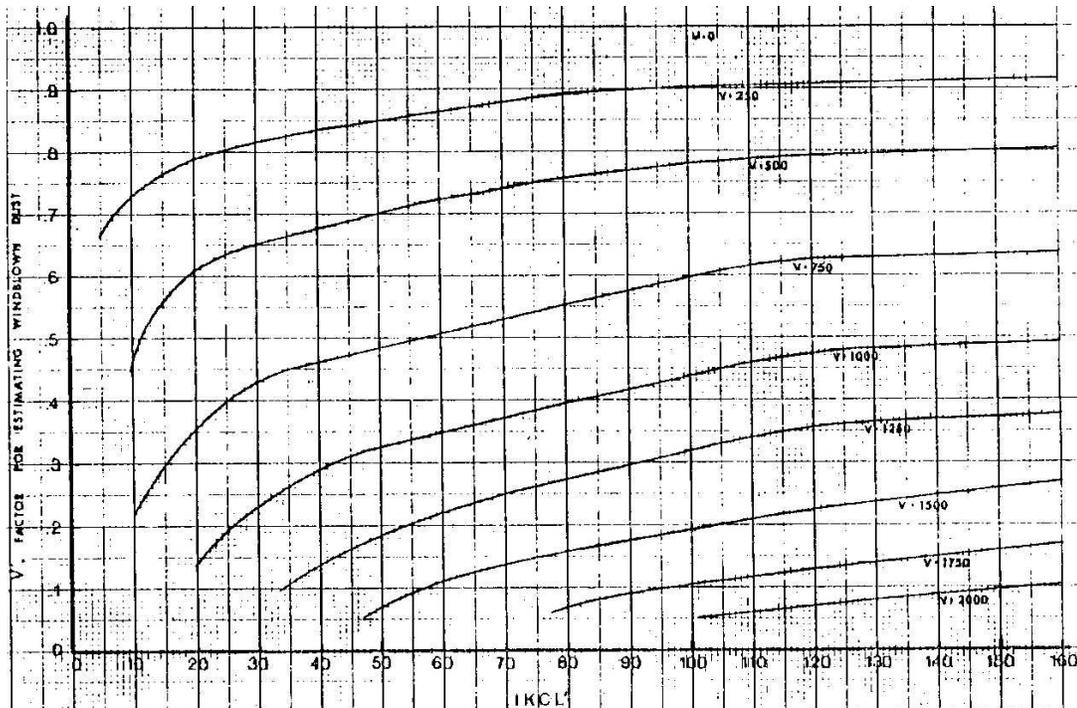


Figure 7-5. Effect of Vegetative Cover on Relative Emission Rate⁶

7.2.2 Climate-Based Improvements in the ARBWEQ

The calculation of the climatic factor C requires mean monthly temperature, monthly rainfall, and mean annual wind speed for a given location as data inputs. This factor is used to estimate climatic effects on an annual basis. In order to make estimates of emissions using the ARBWEQ that are specific to different seasons, it is necessary to estimate the climatic factor that would apply to each season. The changes to the agricultural windblown emissions inventory discussed here, include modifications to both the annual and the monthly climatic factor profile determination methodology included in the ARBWEQ.

The Annual Climatic Factor for the ARBWEQ. Reference 6 includes a definition of the climatic factor that agrees with the method utilized by the NRCS.¹³ It incorporates the monthly precipitation effectiveness derived from precipitation and temperature, along with monthly average wind speeds. Garden City, Kansas is assigned a factor of 1.0 and the climatic factors for all other sites are adjusted from this value.

The Monthly Climatic Factor for the ARBWEQ. There are several ways to create a climate-based monthly profile for the ARBWEQ. Because the ARBWEQ is an annual emission estimation model, CARB staff did not directly estimate monthly emissions using the monthly climatic factor. Instead, the annual climatic factor was used to determine annual emissions, and then the monthly-normalized climatic factors were multiplied by the annual emissions. This helped to limit the effect of extreme monthly values on the annual emissions estimate. CARB staff devised a method termed the “month-as-a-year” method which produced climatic factors that would apply if the

climate for a given month were instead the year round climate. These monthly numbers, once normalized, provided the climate-based temporal profile. The improvements arising from the use of the month-as-a-year method are due to the fact that it relies on temperature, and precipitation inputs, in addition to wind. The ARBWEQ further modified the temporal profile calculation, by also adding nonclimate-based temporal factors. The month-as-a-year method in the ARBWEQ produces pronounced curves with small climatic factors (resulting in lower emissions) in the cool, wet and more stagnant periods, and large climatic factors (and higher emissions) in the hot, dry, and windy periods. The U.S. EPA method yields gentler profiles, which are shifted into the cooler and wetter months from the ARBWEQ profiles. The 1989 CARB methodology established one erosive wind energy distribution statewide. This resulted in an unrealistic, nearly flat distribution, with very little seasonality. Therefore, the ARBWEQ month-as-a-year method provides a more realistic picture of the windblown dust temporal profile (see Reference 3 for comparison curves and supporting references).

7.2.3 Nonclimate-Based Improvements in the ARBWEQ

Among the nonclimate-based factors that influence windblown agricultural emissions are soil type, soil structure, field geometry, proximity to wind obstacles, crop, soil cover by crop canopy or post harvest vegetative material, irrigation, and replanting of the post harvest fallow land with a different crop. CARB has attempted to correct many of these limitations in the ARBWEQ. Many of the corrections are temporally based and rely upon the establishment of accurate crop calendars to reflect field conditions throughout the year. The long-term irrigation-based adjustment to erodibility, due to soil cloddiness, is not temporally based, and is therefore applied for the entire year.¹² The change in erodibility varies based on soil type, but often results in a reduction in the tons per acre value for irrigated crops of about one-third.

Crop Calendars: Quantifying Temporal Effects. Factors such as crop canopy cover, post harvest soil cover, irrigation, and replanting to another crop have a major effect on windblown emissions. Estimating the effects of these factors requires establishing accurate crop calendars. The planting and harvesting dates are principal components of the crop calendar. The list of references consulted to establish the planting and harvesting dates is included in Reference 3.

Each planting month for a given crop was viewed by CARB staff as a separate cohort (maturation class). Since a single planting cohort may be harvested in several months, each cohort was split into cohort-plant/harvest date pairs. The cohort-plant/harvest date pairs were then assigned based upon a first-in-first-out ordering. The fraction of the total annual crop assigned to a given cohort-plant/harvest date pair was derived by multiplying the fraction of the total annual crop planted in a given month (cohort) by the fraction of the cohort harvested in a given month. The fraction of a cohort-plant/harvest date pair that has been planted, but not harvested at any given time, is termed the growing canopy fraction, or GCF (although the canopy may or may not actually be increasing at any given time). The growing canopy fraction determines the fraction of the acreage that will have the crop canopy factor applied to its emission calculations. The acreage that is not assigned to the growing canopy fraction is the postharvest/preplant (PHPP) acreage. The PHPP acreage will have the post harvest soil

cover, and replanting to a different crop factors applied when calculating its emissions. The effect of using cohort-plant/harvest date pairs is to blend the crop canopy, soil cover, replanting, and irrigation effects over both the planting and harvesting periods. This approach provides a more realistic estimate of the temporal windblown emissions profile during these periods. All of the monthly factor profile adjustments described below are calculated for each month of the year, for each cohort-harvest/plant date pair, for each crop, for each county.

Adding a Short-Term Irrigation Factor for Wetness. This adjustment takes into account the overall soil texture, number of irrigation events, and fraction of wet days during the time period¹² (one month for the purposes of the CARB inventory). The list of references consulted to establish the irrigation profiles is included in Reference 3. The irrigation factor for months in which irrigations take place will typically be greater than 0.80. In other words, the irrigations will result in a reduction in erodibility of less than 20%. This is only an estimate for a typical case during the growing season. When averaged over the year, the overall reduction in erodibility is lower.

Replacement Factors to Address Problems with the Vegetative Soil Cover Factor in the WEQ. According to CARB, there are many problems with the vegetative soil cover factor, V. For example, this factor is applied to the acreage year round, even during the growing season, and ignores the effect of disk-down and other land preparation operations on post harvest vegetative soil cover. The factor also does not account for canopy cover during the growing season. In addition, the WEQ was derived based on agricultural practices typical of the Midwestern United States. Crops such as alfalfa have full canopy cover for nearly the entire year. There is also a large amount of acreage that is used for more than one crop per year, and there was no provision in the vegetative soil cover factor for estimating the effects on emissions of this replanting. Whether the land is to be immediately replanted to a different crop, or is going to remain fallow until the next planting of the same crop, it is common practice to disk under the harvested crop within a month or two of harvest. The vegetative soil cover factor for the most part assumes that the post harvest debris remains undisturbed. References to support this agricultural practice are included in Reference 3. CARB staff replaced the vegetative soil cover factor in the ARBWEQ with the three adjustments discussed below to approximate the effects on windblown agricultural PM emissions of: (a) crop canopy cover during the growing season; (b) changes to post harvest soil cover; and (c) post harvest planting of a different crop on the harvested acreage.

Crop Canopy Factor. Crop canopy cover is the fraction of ground covered by crop canopy when viewed directly from above. USDA-ARS staff provided CARB with methodology from the RWEQ for estimating the effects of crop canopy cover on windblown dust emissions.⁸ The soil loss ratio (SLRcc) is defined as the ratio of the soil loss for a soil of a given canopy cover divided by the soil loss from bare soil. SLRcc is the factor that is multiplied by the erodibility to adjust the erodibility for canopy cover. The greater the canopy cover, the smaller the SLRcc, and the greater the reduction in erodibility. SLRcc defines an exponential curve that demonstrates major differences in the erodibility reduction for the range of zero to 30 percent canopy cover (typically achieved within a few months after planting). Thereafter, reductions occur much more

slowly, and eventually the curve flattens out. This results in a rapid decrease in emissions during the first few months following planting, until the emissions are only a very small fraction of the bare soil emissions. The canopy cover then will remain, and the windblown emissions will consequently stay very low until harvest. Senescence effects (late growing season reduction in canopy) have been excluded from this model, and the rationale for that exclusion is discussed in Reference 3.

Post Harvest Soil Cover Factor. Post harvest soil cover is the fraction of ground covered by vegetative debris when viewed directly from above. USDA-ARS staff provided CARB with methodology from the RWEQ for estimating the effects of post harvest soil cover on windblown dust emissions.⁸ The soil loss ratio (SLRsc) is defined as the ratio of the soil loss for a soil of a given soil cover divided by the soil loss from bare soil. SLRsc is the factor that is multiplied by the erodibility to adjust the erodibility for post harvest soil cover. The greater the post harvest soil cover, the smaller the SLRsc, and the greater the reduction in erodibility. The list of references consulted to establish the post harvest soil cover profiles is included in Reference 3.

Post Harvest “Replant-to-Different-Crop” Factor. As discussed above, the vegetative soil cover factor does not include any adjustments for harvested acreages that are quickly replanted to a different crop. This multiple cropping is very common in California, and has been accounted for in this methodology by removing from the inventory calculation the fraction of the harvested acreage that is replanted, at the estimated time of replanting. This removed fraction is based on information provided by agricultural authorities (see reference list in Reference 3). The net result of the application of the fraction is that the post disk-down acreage (one to two months after harvest), and resultant emissions, is reduced by the fraction of harvested acreage converted to a new crop.

Bare and Border Soil Adjustments. Most fields will have some cultivated areas that are barren. These bare areas could be due to uneven ground (e.g., water accumulation), uneven irrigation, pest damage, soil salinity, etc. Most fields will have some type of border. In some cases there is a large barren border, in other cases it is overgrown with vegetation. Many border areas are relatively unprotected, and prone to wind erosion. CARB staff established approximate fractions of cultivated acreage that would be barren and border areas, respectively. These barren and border acreage adjustments result in emission increases disproportionate to the acreage involved. The reason that the bare acreage-based increase is so large is that the bare acreage does not have either a crop canopy or post harvest soil cover factor applied. The same reasons apply to the border adjustment, but the border region is also assumed not to be irrigated. Therefore, no irrigation factor (wetness), and no long-term irrigation adjustment to erodibility (cloddiness) are applied. No border adjustment was applied to the pasture acreage, since pasture areas frequently lack a barren border.

Temporal Activity. For the 1989 CARB methodology, the temporal profile was based on an estimated statewide erosive wind energy profile. The profile, implemented in the ARBWEQ included wind, precipitation and temperature climatic effects, along with the addition of the effects of crop canopy, postharvest soil cover, postharvest replanting to a different crop, and irrigation. In addition, the inclusion of bare ground and

field border effects also adjusted the profile in the ARBWEQ. The profile produced for the ARBWEQ is no longer a separate profile applied to annual emissions, but is now an intermediate output produced during the estimation of annual emissions.

7.3 Demonstrated Control Techniques

The emission potential of agricultural wind erosion is affected by the degree to which soil management and cropping systems provide adequate protection to the exposed soil surface during exposure periods. Table 7-3 presents a summary of demonstrated control measures and the associated PM10 control efficiencies. It is readily observed that reported control efficiencies for many of the control measures are highly variable. This may reflect differences in the operations as well as the test methods used to determine control efficiencies.

Table 7-3. Control Efficiencies for Control Measures for Agricultural Wind Erosion ^{1, 15-18}

Control measure	PM10 Control Efficiency	References/comments
Artificial wind barrier	64-88%	MRI, 1992. Assumes a 50% porosity fence.
	54-71%	Grantz et al, 1998. Control efficiency is for a wind fence.
	4-32%	Bilbro and Stout, 1999. Control efficiency based upon reduction in wind velocity by a wind fence made from plastic pipe with a range of optical density of from 12% to 75%.
Cover crop	90%	Washington State Univ., 1998.
Cross-wind ridges	24-93%	Grantz et al, 1998. Control efficiency is for furrows.
	40-80%	Washington State Univ., 1998.
Mulching	20-40%	Washington State Univ., 1998. Control efficiency is for straw.
Trees or shrubs planted as a windbreak	25%	Sierra Research, 1997. Control efficiency is for trees.

7.4 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats for several local air quality agencies in the WRAP region are presented in Table 7-4. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/envsvc/air/ruledesc.asp

(Note: The Clark County website did not include regulatory language specific to agricultural wind erosion at the time this chapter was written.)

Table 7-4. Example Regulatory Formats for Agricultural Wind Erosion

Control measure	Goal	Threshold	Agency
Requires producers to draft and implement fugitive dust plan with approved control methods	Limits fugitive dust from agricultural sources		SJVAPCD Rule 8081 11/15/2001
Exemption from Rule 403 general requirements.	Limit PM10 Levels to 50 µg/m ³	Voluntary implementation of district approved conservation practices and complete/maintain self-monitoring plan	SCAQMD Rule 403 12/11/1998
Requires dust plan that contains procedures assuring moisture factor between 20%-40% for manure in top 3" of occupied pens and outlines manure management practices and removal	Reduce fugitive dust from livestock feed yards		ICAPCD Rule 420 8/13/2002
Dust suppressants, gravel, install shrubs/trees	Limit fugitive dust plume to 20% opacity	Commercial feedlot/livestock area; shrubs/trees 50ft-100ft from animal pens; compliance with stabilization limitation	Maricopa County Rule 310.01 02/16/2000
Record keeping for all ctrl measure taken	Ensure that appropriate ctrl measures are implemented and maintained	All ops subject to Rule 310.01, provided within 48 hrs of ctrl officer request	Maricopa County Rule 310.01 02/16/2000

7.5 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 7-5 summarizes the compliance tools that are applicable to agricultural wind erosion.

Table 7-5. Compliance Tools for Agricultural Wind Erosion

Record keeping	Site inspection/monitoring
Land condition by date (e.g., vegetation; furrowing of fallow land; soil crusts), including residue management and percentages; meteorological log; establishment/maintenance of windbreaks.	Observation of land condition (crusts, furrows), especially during period of high winds.

7.6 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for fugitive dust originating from agricultural wind erosion. A sample cost-effectiveness calculation is presented below for a specific control measure (adding a straw mulch to the field) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous

control measure for agricultural wind erosion, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Agricultural Wind Erosion

Step 1. Determine source activity and control application parameters.

Field size (acres)	320
Control Measure	1,000 lb mulch per acre
Control application/frequency	Once post-harvesting
Control Efficiency	30%

The field size is an assumed value, for illustrative purposes. Adding a straw mulch to the field at a rate of 1,000 lbs per acre has been chosen as the applied control measure. The control application/frequency and control efficiency are default values provided by WSU, 1998.

Step 2. Calculate Pm10 Emission Factor. The PM10 emission factor is calculated from AP-42 equation utilizing the appropriate correction parameters:

$$E \text{ (tons/acre-year)} = 0.5 A I K C L' V'$$

A	0.025
I – soil erodibility (tons/acre-year)	86
K- surface roughness factor	0.50
Climatic factor	0.33
Unsheltered field width factor	0.70
Vegetative cover factor	0.25

$$E = 0.031 \text{ tons/acre-year}$$

[Note: the correction parameters above were selected for illustrative purposes.]

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (given in Step 2) is multiplied by the field size (under activity data) to compute the annual PM10 emissions in tons per year, as follows:

$$\begin{aligned} \text{Annual emissions} &= (\text{Emission Factor} \times \text{Field Size}) \\ \text{Annual PM10 emissions} &= (0.031 \times 320) = 9.9 \text{ tons} \end{aligned}$$

$$\text{Annual PM2.5 emissions} = 0.15 \times \text{PM10 emissions}^7 = 0.15 \times 9.9 \text{ tons} = 1.5 \text{ tons}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, we have selected conservation tilling as our control measure. Based on a control efficiency estimate of 30%, the annual controlled emissions are calculated to be:

$$\text{Annual Controlled PM}_{10} \text{ emissions} = (9.9 \text{ tons}) \times (1 - 0.3) = 6.9 \text{ tons}$$

$$\text{Annual Controlled PM}_{2.5} \text{ emissions} = (1.5 \text{ tons}) \times (1 - 0.3) = 1.0 \text{ tons}$$

Step 5. Determine Annual Cost to Control PM Emissions.

The Annual Cost of mulching is calculated by multiplying the number of acres by the cost per acre. The cost of mulching is assigned a value of \$40 per acre.¹⁷ Thus, the Annual Cost is estimated to be: $320 \times 40 = \$12,800$

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annual cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annual Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost-effectiveness for PM}_{10} \text{ emissions} = \$12,800 / (9.9 - 6.9) = \$4,295/\text{ton}$$

$$\text{Cost-effectiveness for PM}_{2.5} \text{ emissions} = \$12,800 / (1.5 - 1.0) = \$28,636/\text{ton}$$

7.7 References

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Chapter 8. Open Area Wind Erosion

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8.1 Characterization of Source Emissions

Dust emissions may be generated by wind erosion of open areas of exposed soils or other aggregate materials within an industrial facility. These sources typically are characterized by nonhomogeneous surfaces impregnated with nonerodible elements (particles larger than approximately 1 centimeter [cm] in diameter). Field testing of coal piles and other exposed materials using a portable wind tunnel has shown that: (a) threshold wind speeds exceed 5 meters per second (m/s) (11 miles per hour [mph]) at 15 cm above the surface or 10 m/s (22 mph) at 7 m above the surface, and (b) particulate emission rates tend to decay rapidly (half-life of a few minutes) during an erosion event. In other words, these aggregate material surfaces are characterized by finite availability of erodible material (mass/area) referred to as the erosion potential. Any natural crusting of the surface binds the erodible material, thereby reducing the erosion potential. Loose soils or other aggregate materials consisting of sand-sized materials act as an unlimited reservoir of erodible material and can sustain emissions for periods of hours without substantial decreases in emission rates.

If typical values for threshold wind speed at 15 cm are corrected to typical wind sensor height (7 to 10 m), the resulting values exceed the upper extremes of hourly mean wind speeds observed in most areas of the country. In other words, mean atmospheric wind speeds are not sufficient to sustain wind erosion from flat surfaces of the type tested. However, wind gusts may quickly deplete a substantial portion of the erosion potential. Because erosion potential has been found to increase rapidly with increasing wind speed, estimated emissions should be related to the gusts of highest magnitude. The routinely measured meteorological variable that best reflects the magnitude of wind gusts is the fastest mile. This quantity represents the wind speed corresponding to the whole mile of wind movement that has passed by the 1-mile contact anemometer in the least amount of time. Daily measurements of the fastest mile are presented in the monthly Local Climatological Data (LCD) summaries. The duration of the fastest mile, typically about 2 minutes (for a fastest mile of 30 mph), matches well with the half-life of the erosion process, which ranges between 1 and 4 minutes. It should be noted, however, that peak winds can significantly exceed the daily fastest mile.

The wind speed profile in the surface boundary layer is found to follow a logarithmic distribution as follows:

$$u(z) = \frac{u^*}{0.4} \ln \frac{z}{z_0} \quad (z > z_0) \quad (1)$$

where,

- u = wind speed (cm/s)
- u^* = friction velocity (cm/s)
- z = height above test surface (cm)
- z_0 = roughness height (cm)
- 0.4 = von Karman's constant (dimensionless)

The friction velocity (u^*) is a measure of wind shear stress on the erodible surface, as determined from the slope of the logarithmic velocity profile. The roughness height (z_0) is a measure of the roughness of the exposed surface as determined from the y-intercept

of the velocity profile, i.e., the height at which the wind speed is zero. These parameters are illustrated in Figure 8-1 for a roughness height of 0.1 cm.

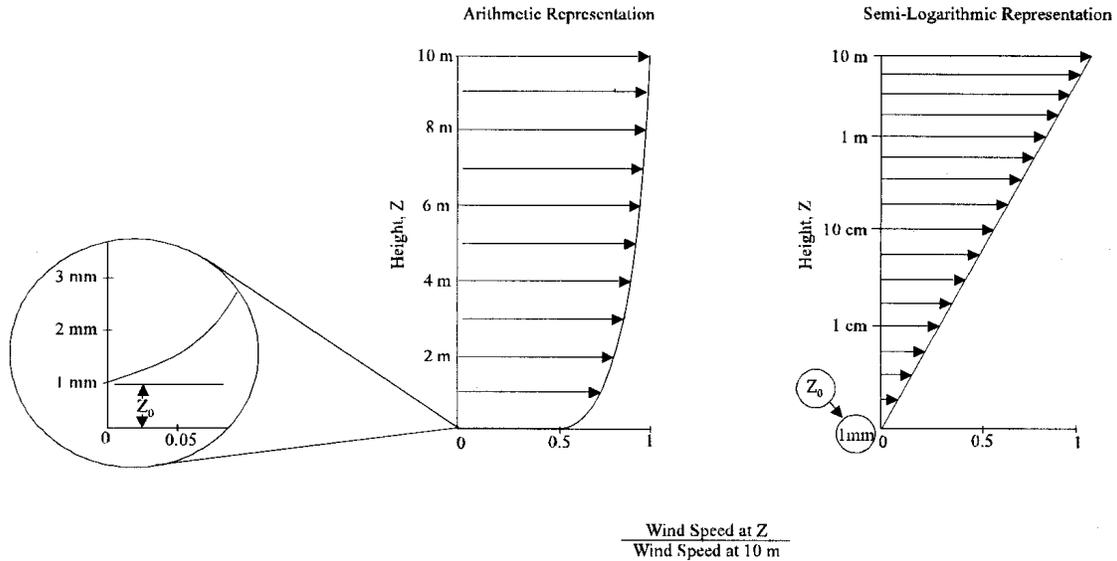


Figure 8-1. Illustration of Logarithmic Wind Velocity Profile

Emissions generated by wind erosion are also dependent on the frequency of disturbance of the erodible surface because each time that a surface is disturbed, its erosion potential is restored. A disturbance is defined as an action that results in the exposure of fresh surface material. On a storage pile, this would occur whenever aggregate material is either added to or removed from the old surface. A disturbance of an exposed area may also result from the turning of surface material to a depth exceeding the size of the largest pieces of material present.

8.2 Emission Estimation: Primary Methodology¹⁻¹¹

This section was adapted from Section 13.2.5 of EPA's *Compilation of Air Pollutant Emission Factors (AP-42)*. Section 13.2.5 was last updated in January 1995.

The PM₁₀ emission factor for wind-generated particulate emissions from mixtures of erodible and nonerodible surface material subject to disturbance may be expressed in units of grams per square meter (g/m²) per year as follows:

$$\text{PM}_{10} \text{ Emission Factor} = 0.5 \sum_{i=1}^N P_i \quad (2)$$

where,

N = number of disturbances per year

P_i = erosion potential corresponding to the observed (or probable) fastest mile of wind for the *i*th period between disturbances (g/m²)

In calculating emission factors, each area of an erodible surface that is subject to a different frequency of disturbance should be treated separately. For a surface disturbed

daily, $N = 365$ per year, and for a surface disturbance once every 6 months, $N = 2$ per year. The erosion potential function for a dry, exposed surface is given as:

$$P = 58 (u^* - u_t^*)^2 + 25 (u^* - u_t^*) \quad (3)$$

$$P = 0 \text{ for } u^* \leq u_t^*$$

where,

- u^* = friction velocity (m/s)
- u_t^* = threshold friction velocity (m/s)

Because of the nonlinear form of the erosion potential function, each erosion event must be treated separately. The PM_{2.5}/PM₁₀ ratio for windblown fugitive dust posted on EPA's CHIEF website is 0.15. This ratio is based on the analysis conducted by MRI on behalf of WRAP.¹¹

Equations 2 and 3 apply only to dry, exposed materials with limited erosion potential. The resulting calculation is valid only for a time period as long or longer than the period between disturbances. Calculated emissions represent intermittent events and should not be input directly into dispersion models that assume steady-state emission rates. For uncrusted surfaces, the threshold friction velocity is best estimated from the dry aggregate structure of the soil. A simple hand sieving test of surface soil can be used to determine the mode of the surface aggregate size distribution by inspection of relative sieve catch amounts, following the procedure described below.

FIELD PROCEDURE FOR DETERMINING THRESHOLD FRICTION VELOCITY

(from a 1952 laboratory procedure published by W. S. Chepil⁵)

- Step 1. Prepare a nest of sieves with the following openings: 4 mm, 2 mm, 1 mm, 0.5 mm, and 0.25 mm. Place a collector pan below the bottom (0.25 mm) sieve.
- Step 2. Collect a sample representing the surface layer of loose particles (approximately 1 cm in depth, for an encrusted surface), removing any rocks larger than about 1 cm in average physical diameter. The area to be sampled should be not less than 30 cm by 30 cm.
- Step 3. Pour the sample into the top sieve (4-mm opening), and place a lid on the top.
- Step 4. Move the covered sieve/pan unit by hand, using a broad circular arm motion in the horizontal plane. Complete 20 circular movements at a speed just necessary to achieve some relative horizontal motion between the sieve and the particles.
- Step 5. Inspect the relative quantities of catch within each sieve, and determine where the mode in the aggregate size distribution lies, i.e., between the opening size of the sieve with the largest catch and the opening size of the next largest sieve.
- Step 6. Determine the threshold friction velocity from Table 8-1.

The results of the sieving can be interpreted using Table 8-1. Alternatively, the threshold friction velocity for erosion can be determined from the mode of the aggregate size distribution using the graphical relationship described by Gillette.^{5,6} If the surface material contains nonerodible elements that are too large to include in the sieving (i.e., greater than about 1 cm in diameter), the effect of the elements must be taken into account by increasing the threshold friction velocity.¹⁰

Table 8-1 Field Procedure for Determination of Threshold Friction Velocity (Metric Units)

Tyler Sieve No.	Opening (mm)	Midpoint (mm)	u_t^* (cm/s)
5	4		
9	2	3	100
16	1	1.5	76
32	0.5	0.75	58
60	0.25	0.375	43

Threshold friction velocities for several surface types have been determined by field measurements with a portable wind tunnel. These values are presented in Table 8-2.

Table 8-2. Threshold Friction Velocities (Metric Units)

Material	Threshold friction velocity (m/s)	Roughness height (cm)	Threshold wind velocity at 10 m (m/s)	
			$z_o = \text{Actual}$	$z_o = 0.5 \text{ cm}$
Overburden ^a	1.02	0.3	21	19
Scoria (roadbed material) ^a	1.33	0.3	27	25
Ground coal (surrounding coal pile) ^a	0.55	0.01	16	10
Uncrusted coal pile ^a	1.12	0.3	23	21
Scraper tracks on coal pile ^{a,b}	0.62	0.06	15	12
Fine coal dust on concrete pad ^c	0.54	0.2	11	10

^a Western surface coal mine; reference 2.

^b Lightly crusted.

^c Eastern power plant; reference 3.

The fastest mile of wind for the periods between disturbances may be obtained from the monthly local climatological data (LCD) summaries for the nearest reporting weather station that is representative of the site in question.⁷ These summaries report actual fastest mile values for each day of a given month. Because the erosion potential is a highly nonlinear function of the fastest mile, mean values of the fastest mile are inappropriate. The anemometer heights of reporting weather stations are found in Reference 8, and should be corrected to a 10-m reference height using Equation 1. To convert the fastest mile of wind (u^+) from a reference anemometer height of 10 m to the equivalent friction velocity (u^*), the logarithmic wind speed profile may be used to yield the following equation:

$$u^* = 0.053 u_{10}^+ \quad (4)$$

where,

u^* = friction velocity (m/s)

u_{10}^+ = fastest mile of reference anemometer for period between disturbances (m/s)

This assumes a typical roughness height of 0.5 cm for open terrain. Equation 4 is restricted to large relatively flat exposed areas with little penetration into the surface wind layer.

8.3 Emission Estimation: Alternate Methodology

Duane Ono with the Great Basin Unified APCD and Dale Gillette developed a method called the Dust ID method to measure fugitive PM10 dust emissions due to wind erosion that has been approved for use in PM10 SIPs.^{12, 13} This method has been applied to the dry lake bed at Owens Lake, CA using an extensive sand flux monitoring network. Owens Lake is the largest single source of fugitive dust in the United States (estimated to be ~80,000 tons PM10/year). The network consisted of co-located electronic Sensits and passive Cox Sand Catchers (CSCs) deployed on a 1 km x 1 km grid covering 135 square kilometers of the lake bed with their sensor or inlet positioned 15 cm above the surface. Sensits measure the kinetic energy or the particle counts of sand-sized particles as they saltate across the surface. Due to differences in the electronic response of individual Sensits, these units had to be co-located with passive sand flux measurement devices to calibrate their electronic output and to determine the hourly sand flux. The battery powered Sensits were augmented with a solar charging system. A data logger recorded hourly Sensit data during inactive periods and switched to 5-minute data during active erosion periods. CSC's are passive instruments that are used to collect sand-sized particles that are blown across the surface during a dust event. These instruments were designed and built by the Great Basin Unified Air Pollution Control District as a reliable, low-cost instrument that could withstand the harsh conditions at Owens Lake. CSC's have no moving parts and can collect sand for a month at Owens Lake without overloading the collector. As an alternative to hourly sand (saltation) flux measurements relying on Sensits, Ono¹⁴ found that monthly sand flux measurements obtained with CSCs could be applied to a model developed by Gillette et al.¹⁵ to provide a good estimate of hourly sand flux rates.

Hourly PM10 emissions from each square kilometer of the lake bed were estimated from the following equation:

$$F_a = K_f \times q$$

where, F_a = PM10 emissions flux ($\text{g}/\text{cm}^2/\text{hr}$)

q = hourly sand flux ($\text{g}/\text{cm}^2/\text{hr}$) measured at 15 cm above the surface

K_f , called the K-factor, = proportionality factor relating the PM10 emissions flux to the sand flux measured at 15 cm above the surface.

K_f values were determined by comparing CALPUFF model predictions, based on meteorological data from thirteen 10-meter towers and an Upper Air Wind Profiler to generate wind fields using the CALMET model, to observed hourly PM10 concentrations measured at six PM10 monitoring sites utilizing TEOM PM10 monitors. A K-factor of 5×10^{-5} was used to initially run the model and to generate PM10 concentration values that were close to the monitored concentrations. Hourly K-factor values were later adjusted in a post-processing step to determine the K-factor value that would have made the modeled concentration match the monitored concentration at each of the six PM10 monitor sites using the following equation:

$$K_f = K_i [(C_{\text{obs}} - C_{\text{bac}})/C_{\text{mod}}]$$

where, K_i = initial K-factor (5×10^{-5})

$C_{\text{obs.}}$ = observed hourly PM10 concentration ($\mu\text{g}/\text{m}^3$)

$C_{\text{bac.}}$ = background PM10 concentration (assumed to be $20 \mu\text{g}/\text{m}^3$)

$C_{\text{mod.}}$ = model-predicted hourly PM10 concentration ($\mu\text{g}/\text{m}^3$)

The results showed that K_f changed spatially and temporally at Owens Lake and that the changes corresponded to different soil textures on the lake bed and to seasonal surface changes that affected erodibility. The results also showed that some source areas were active all year, while others were seasonal and sometimes sporadic. Wind tunnel tests at Owens Lake independently confirmed these seasonal and spatial changes in K_f . Ono et al.¹² concluded that the emission estimates using their Dust ID method were more accurate than the AP-42 method for estimating daily emissions, since the emissions estimates correspond to measured hourly wind erosion on the lake bed. For daily emissions, Ono and co-workers believe that AP-42 drastically overestimates the emissions at low wind speed conditions, and underestimates emissions at high wind speeds. This large discrepancy in the emission estimates is due to the use of a single threshold friction velocity for the entire erosion area in the AP-42 method. The AP-42 method and the Dust ID method of estimating emissions resulted in very close agreement for the annual emissions.

8.4 Emission Estimation: Other Methodologies

Several alternative emission estimation methods for open area wind erosion have been developed that are still in the developmental stage and have not yet been approved by federal or state agencies. Thus, the reader is cautioned in the use of these methods.

8.4.1 MacDougall Method

MacDougall developed a method for estimating fugitive dust emissions from wind erosion of vacant land.¹⁶ This method, which relies heavily on emission factors developed for different vacant land parcels using wind tunnels. The availability of wind tunnel results for the types of vacant land being assessed must be considered when deciding to use this method for other applications. It should be pointed out that in 2003 Environ (under contract to the Western Governors' Association) abandoned this approach due to the paucity of sufficient wind tunnel data for many different vacant land parcels in the western U.S.¹⁷ Also, the WRAP's fugitive dust expert panel had major reservations regarding the MacDougall method.¹⁸ Panel members were skeptical about using the proposed methodology since wind tunnels have shortcomings and do not represent actual conditions in nature. The panel concluded that determining emission factors in the manner proposed will result in significant underestimation of windblown dust for those cases where saltation plays a role. The six steps described in the MacDougall method are summarized below.

Step 1: Categorizing Vacant Land. Vacant land within the study area must be categorized based upon the potential of the parcels to emit fugitive dust during wind

events. Many wind tunnel studies have been conducted in the western United States, and the vacant land descriptions of the wind tunnel test areas should be used to categorize the vacant land within the study area. When categorizing vacant land, it is especially important whether the land has vegetation, rocks or other sheltering elements, whether the soil crust is intact or disturbed, and whether there are periodic activities on the vacant land such as vehicles or plowing that will change the land from fairly stable to unstable. Not every parcel of vacant land will necessarily fit into a category that has been wind tunnel tested. For parcels without a specific vacant land type wind tunnel test, assumptions will need to be made of the best representative land type and uncertainties noted.

Step 2: Identify Wind Tunnel Emission Factors. Based upon the vacant land categorization, wind tunnel results should be reviewed and applied appropriately to each category of vacant land. Wind tunnel results should be reviewed to determine if “spikes” from the initial portion of the test are presented separately or averaged into an hourly factor. Whenever possible, spikes should not be included in an hourly factor. The spike values should be included only at the beginning of each wind event.

Step 3: Develop Meteorological Data Set. For the area to be studied, hourly average wind speeds, rainfall, and if available peak wind gust data should be gathered. If a study area is particularly large, several different meteorological data sets may need to be gathered, and each land parcel matched with the meteorological data that impacts that parcel.

Step 4: Determine Land Type Reservoirs, Threshold Wind Velocities, Wind Events, and Rainfall Events. Based upon the wind tunnel results for each vacant land type, the wind speed when emissions were first measured for the vacant land type, should be set as the threshold wind speed. Most vacant land does not have an endless reservoir of fugitive dust; however, land that has a high degree of disturbance will continue to emit throughout a wind event. Therefore, for each vacant land type, the wind tunnel results should be reviewed and a determination made on the length of time the parcel will emit for a give wind event. It is recommended that an assumption be made that parcels with sheltering elements, vegetated parcels, or parcels with a soil crust will only emit during the first hour of a wind event. Parcels with a relatively high silt component or with frequent disturbance will probably continue to emit throughout a wind event. Because most threshold wind speeds are relatively high (i.e., sustained hourly winds of 25 to 30 mph), a wind event may be defined as any time period when winds reach the threshold wind velocities separated by at least 24 hours before a new wind event is defined. Depending on the soils in an area, rain may have a large impact on wind erosion. Days with rain should not be included in the inventory.

Step 5: Develop Emission Inventory Specific Emission Factors. Using the reservoir determination, threshold wind speeds, wind event determination and rainfall factors, determine hours when wind conditions produced emissions from each vacant land parcel for the time period of the emission inventory. The number of hours with wind speeds in each wind speed category should be totaled. The number of hours can then be multiplied by the wind tunnel emission factor and a total emission factor for the time period of the

inventory can be calculated. The emission factor equations for vacant land with and without sustained emissions are given as follows:

(a) With sustained emissions: $EF_1 = (\sum (H P))$

where, EF_1 = PM10 emission factor (lb/acre)

H = number of hours when wind conditions result in emissions

P = emission factor for a given vacant land category (lb/hour-acre)

(b) Without sustained emissions: $EF_1 = (\sum (W P))$

where, EF_1 = PM10 emission factor (lb/acre)

W = number of wind events when wind conditions result in emissions

P = emission factor for a given vacant land category (lb/acre)

The emission factor equation for spike emissions is given as:

$$EF_2 = (\sum (E S))$$

where, EF_2 = spike PM10 emission factor (lb/acre)

E = number of events producing spike emissions

S = spike mass for a given vacant land category (lb/acre)

Emission factors will vary from time period to time period and from vacant land type to vacant land type. Generally speaking, disturbed lands will have unlimited reservoirs and lower threshold wind velocities leading to much higher emissions than stable or sheltered parcels with one hour reservoirs. An emission factor should be developed for each vacant land category in the inventory.

Step 6: Apply Emission Inventory Specific Emission Factors to Vacant Land Categories. Once emission inventory emission factors have been developed, the number of acres in each category should be multiplied by the factor and the emissions totaled. It may be useful to develop certain factors over shorter time periods and then total the emissions over a longer time period. For example, one may want to develop winter factors and summer factors and then total them together for the annual inventory. For large areas, where vacant land categories will change over the duration of an inventory or different meteorological data sets will apply, it is advisable to subdivide the inventory by time period or area, and then total the inventory at the end. Annual emissions for each vacant land category are calculated as follows:

$$E = A (EF_1 + EF_2)$$

where, E = annual emissions for a given vacant land category

A = vacant land category acreage

EF_1 = annual emission factor for a given vacant land category

EF_2 = spike emission factor for a given vacant land category

8.4.2 Draxler Method

Based on an evaluation of available algorithms for calculating wind blown fugitive dust emissions, the WRAP expert fugitive dust panel¹⁸ recommended the use of the

algorithm developed by Draxler et al.¹⁹ that was based on the earlier work of Marticorena et al.²⁰ This algorithm received the highest score on the basis of extensive field verification test results and having undergone peer review. Draxler and coworkers developed their algorithm for estimating fugitive dust emissions during desert dust storms in Iraq, Kuwait, and Saudi Arabia using a Lagrangian transport and dispersion model where the vertical dust flux was proportional to the difference in the squares of the friction velocity and threshold friction velocity. A proportionality constant was used to relate the surface soil texture to the PM10 dust emissions, and is defined as the ratio of vertical flux of PM10 to total aeolian horizontal mass flux. PM10 emissions caused by wind erosion were estimated in a stepwise process as follows:

- Step I. Obtain large scale and small scale wind fields
- Step II. Estimate sand movement (horizontal flux of saltation particles $\geq 50 \mu\text{m}$)
- Step III. Calculate vertical resuspended dust emissions

The horizontal flux of sand, Q ($\mu\text{g}/\text{meter-second}$), was modeled as follows:

$$Q = A (\rho/g) u^* (u^{*2} - u_t^{*2})$$

where, A = a dimensionless constant

ρ = the density of air

g = the acceleration due to gravity

u^* = the friction velocity (m/s)

u_t^* = the threshold friction velocity (m/s) required for initiation of sand movement by the wind.

The value of A is not constant if there is wetting followed by crusting of the surface sediments, or if there is a depletion of loose particles on the surface for a “supply-limited” surface. The value of A ranges from a maximum of ~ 3.5 when the surface is covered with loose sand to ~ 0 when the surface has a smooth crust with few loose particles larger than 1 mm. Suspended dust is proportional to saltation or sandblasting as follows:

$$F = K Q$$

where, F = the vertical flux of dust ($\mu\text{g}/\text{m}^2\text{-second}$)

K = proportionality factor (m^{-1}) that relates the surface soil texture to PM10 dust emissions

Q = the horizontal flux of saltating particles ($\mu\text{g}/\text{m-second}$)

The value of K is not precisely known, but data sets of F versus Q are available so that estimates of K can be made for certain soils. For sand textured soils, K is estimated to be $\sim 5.6 \times 10^{-4} \text{ m}^{-1}$ and A is ~ 2.8 .

8.4.3 UNLV Method

James and co-workers with the University of Nevada Las Vegas (UNLV) developed a wind blown dust inventory for Clark County, NV based on wind tunnel measurements.²¹ The method involved deriving estimates of wind blown fugitive dust emission factors for three categories of vacant land: disturbed vacant land, stabilized vacant land, and

undisturbed native desert soils. The emission factors included geometric mean hourly “spike” corrected emission rates (tons/acre-hour) for disturbed vacant land, stabilized vacant land and undisturbed native desert soils as well as geometric mean spike emissions (ton/acre) for disturbed vacant land and undisturbed native desert soils as a function of wind speed and soil type. The emission inventory assumed that the particulate reservoir for disturbed vacant land had no limit. For every hour the sustained wind speeds were within a given wind speed category above the “spike” wind speed, the emissions were calculated. A single “spike” mass was added for each acre of vacant land for those days that the wind speed exceeded a threshold wind speed, assuming each day represented a single wind event and reservoir recharging would not have occurred during a 24-hour period. Wind speeds less than the “spike” speed were not included in the emission calculations. Because the native desert parcels have a limited PM10 reservoir, it was assumed that the reservoir would be depleted within one hour of sustained winds above the “spike” wind speed. Therefore, only one hour of emissions were calculated during each day that winds exceeded the threshold friction velocity (“spike” wind speed) for native desert parcels.

The wind speed threshold for generating fugitive dust emissions was estimated by James et al.²¹ to be 20 mph for disturbed vacant land and 25 mph for native desert parcels. Because the parcels stabilized with dust suppressants had been subjected to some disturbance by vehicle traffic that may have caused some dust palliatives to break down, the initial wind threshold for this category was lower than the other categories, namely 15 mph. However, the use of dust palliatives greatly reduced the overall emission factors. Spikes were generally not observed from the stabilized parcels, and emission factors without spike corrections were used for stabilized parcels. As with native desert, it was assumed that the stabilized parcels have a limited PM10 reservoir that would be depleted within one hour of sustained winds above the threshold wind velocity. Therefore, only one hour of emissions was calculated during each day for stabilized parcels.

For a sustained wind speed of 25 mph, the geometric mean hourly spike corrected emission factors across all soil types for Clark County were estimated to be $\sim 5 \times 10^{-3}$ ton/acre-hour for disturbed vacant land, $\sim 2 \times 10^{-3}$ ton/acre-hour for native desert, and $\sim 2 \times 10^{-4}$ ton/acre-hour for stabilized land. The geometric mean spike emissions for a sustained wind speed of 25 mph were estimated to be $\sim 2 \times 10^{-3}$ ton/acre for disturbed vacant land and $\sim 5 \times 10^{-4}$ ton/acre for undisturbed native desert parcels. It should be pointed out that there was significant scatter in the observed data, with within category variability ranging over 1 to 2 orders of magnitude.

8.4.4 WRAP RMC Method

The Dust Emissions Joint Forum (DEJF) of the Western Regional Air Partnership contracted with ENVIRON to develop a particulate emission calculation method for open area wind erosion in 2003. The DEJF extended ENVIRON’s original contract (Phase 2) to provide windblown dust emissions inventories, and perform modeling simulations of the effects of those emissions on regional haze for calendar year 2002 and future year projections. The purpose of this additional effort was to improve the windblown dust

emissions model developed as part of Phase 1. The results of the initial model runs and subsequent sensitivity simulations had demonstrated a need to revise and/or update various assumptions associated with the development of the emission inventory. To this end, revised estimation methodologies and algorithms were evaluated in Phase 2 in order to address various shortcomings and limitations of the Phase 1 version of the model. Many of the assumptions employed in the Phase 1 methodology were necessitated by a lack of specificity in the underlying data used to characterize vacant land types and soil conditions in relation to the potential for wind erosion. Even in Phase 2, it was necessary to rely on some assumptions where data were lacking.

Summary of the WRAP RMC Method

The WRAP RMC windblown dust method utilizes wind tunnel-based emission algorithms for different soils and accounts for land use and local meteorology. The complete set of documents that describe the method in full detail may be found at www.wrapair.org. The summary of the method presented below is based on ENVIRON's final report submitted to the DEJF on May 5, 2006.²²

There are two important factors for characterizing the dust emission process from an erodible surface. They are (a) the threshold friction velocity that defines the inception of the emission process as a function of the wind speed as influenced by the surface characteristics, and (b) the strength of the emissions that follow the commencement of particle movement. The two critical factors affecting emission strength are the wind speed (wind friction velocity) that drives the saltation system, and the soil characteristics.

Friction Velocities Surface friction velocities are determined from the aerodynamic surface roughness lengths and the 10-meter wind speeds based on MM5 model simulations. Friction velocity, u_* , is related to the slope of the velocity versus the natural logarithm of height through the relationship:

$$\frac{u_z}{u_*} = \frac{1}{\kappa} \ln \frac{z}{z_0}$$

where u_z = wind velocity at height z (m/s)

u_* = friction velocity (m/s)

κ = von Karman's constant (0.4)

z_0 = aerodynamic roughness height (m)

The threshold friction velocities, u_{*t} , are determined from the relationships developed by Marticorena et al.²⁰ as a function of the aerodynamic surface roughness length, z_0 . Figure 8-2 shows the comparison between Marticorena's modeled relationship of threshold friction velocity and aerodynamic surface roughness length and wind tunnel data obtained by different investigators.²³⁻²⁶

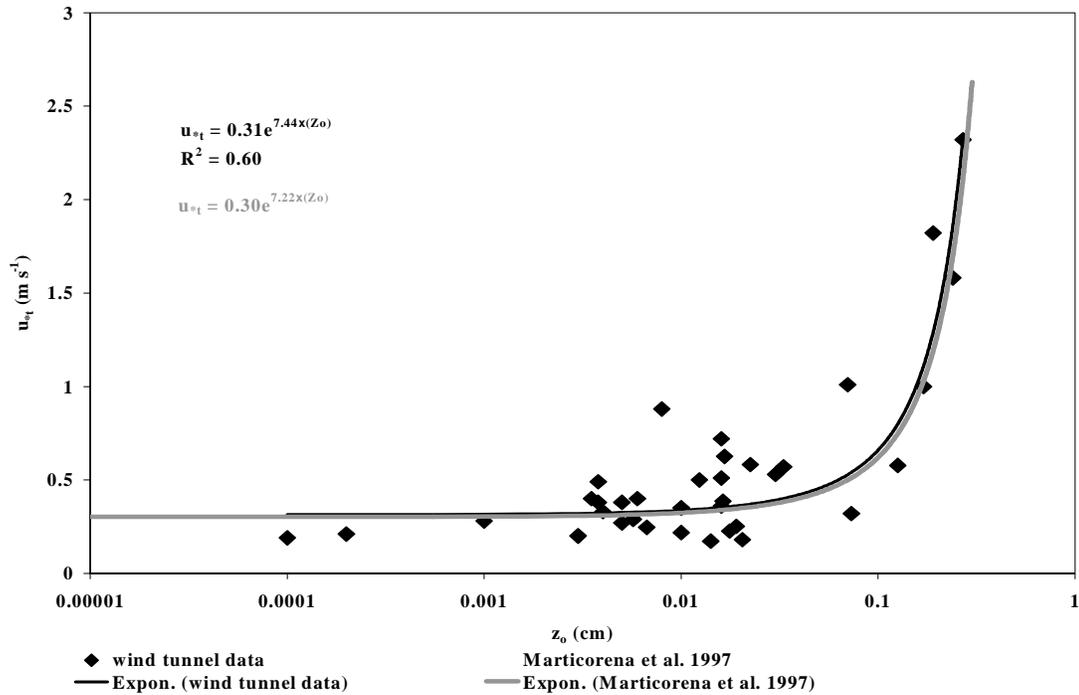


Figure 8-2. Threshold Friction Velocity vs. Aerodynamic Roughness Length

Surface friction velocities, including the threshold friction velocity, are a function of the aerodynamic surface roughness lengths. The surface friction velocities are in turn dependent on surface characteristics, particularly land use/land cover. While these values can vary considerable for a given land type, published data are available which provide a range of surface friction velocities for various land use types and vegetation cover. These data are presented in Table 8-3.

Table 8-3. Threshold Friction Velocities for Typical Surface Types ²³⁻²⁶

Site Type	Undisturbed u_{*t} (m/s)	Disturbed u_{*t} (m/s)	% change [1-(dist./undist.)]
agricultural fields	1.29	0.55	0.57
alluvial fan	0.72	0.60	0.17
desert flat	0.75	0.51	0.32
desert pavement	2.17	0.59	0.73
fan surface	1.43	0.47	0.67
playa, crusted	2.13	0.63	0.70
playa	1.46	0.58	0.60
prairie	2.90	0.24	0.92
sand dune	0.44	0.32	0.27

Emission Fluxes Emission fluxes, or emission rates, are determined as a function of surface friction velocity and soil texture. The relationships that Chatenet et al.²⁷ established between the 12 soil types in the classical soil texture triangle and their four dry soil types (silt [FSS], sandy silt [FS], silty sand [MS], and sand [CS]) are of key importance. The relationships developed by Alfaro and others^{28, 29} for each of the soil texture groups are used to estimate dust emission fluxes. These relationships are presented in Figure 8-3.

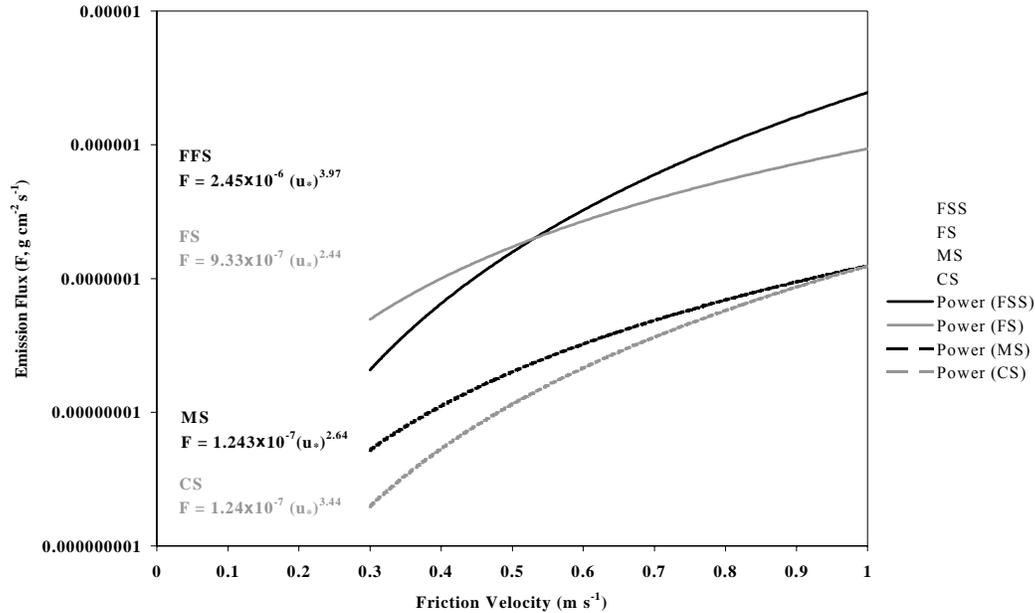


Figure 8-3. Emission Flux vs. Friction Velocity Predicted by the Alfaro and Gomes Model²⁸ Constrained by the Four Soil Classes of Alfaro et al.²⁹

Reservoir Characteristics Reservoirs are classified as limited for stable land parcels and unlimited for unstable land parcels. Classification of reservoirs as limited or unlimited has implications with respect to the duration of time over which the dust emissions are generated. In general, the reservoirs should be classified in terms of the type of soils, the depth of the soil layer, soil moisture content and meteorological parameters. Finally, the time required for a reservoir to recharge following a wind event is influenced by a number of factors including precipitation and snow events and freezing conditions of the soils. A recharge time of 24 hours is assigned to all surfaces. In addition, it is assumed that no surface will generate emissions for more than 10 hours in any 24-hour period.

The duration and amount of precipitation and snow and freeze events will also affect the dust emissions from wind erosion. Barnard³⁰ has compiled a set of conditions for treating these events based on seasons, soil characteristics and the amounts of rainfall and snow cover. The time necessary to re-initiate wind erosion after a precipitation event ranges from 1 to 10 days, depending on the soil type, season of the year and whether the rainfall amount exceeds 2 inches.

Soil Disturbance The disturbance level of a surface more appropriately has the effect of lowering the threshold surface friction velocity. Except for agricultural lands, which are treated separately in the model as described below, vacant land parcels are typically

undisturbed unless some activity is present such as to cause a disturbance (e.g., off-road vehicle activity in desert lands, or animal grazing on rangelands). It is recommended that all non-agricultural land types be considered undisturbed, since there is no *a priori* information to indicate otherwise for the regional scale modeling domain to be considered. Therefore, for the purpose of evaluating the sensitivity of the model to disturbance levels, all grassland, shrubland and barren land areas are assumed to have 10 % of their land area disturbed. Threshold surface friction velocities for these disturbed lands are assigned as follows: 3.1 m/s for grasslands and shrublands, and 0.82 m/s for barren land.

Soil Characteristics Application of the emission factor relations described above requires the characterization of soil texture in terms of the four soil groups considered by the model. The characteristics or type of soil is one of the parameters of primary importance for the application of the emission estimation relations derived from wind tunnel study results. The State Soil Geographic Database (STATSGO) available from the USDA³¹ is used to determine the type of soils present in the modeling domain for which the emission inventory is developed. The classification of soil textures and soil group codes is based on the standard soil triangle that classifies soil texture in terms of percent sand, silt and clay. Combining the soil groups defined by the work of Alfaro et al.²⁹ and Chatenet et al.²⁷ and the standard soil triangle provides the mapping of the 12 soil textures to the four soil groups considered in their study. The soil texture mappings are summarized in Table 8-4.

Table 8-4. STATSGO Soil Texture and Soil Group Codes

STATSGO Soil Texture	Soil Texture Code	Soil Group	Soil Group Code
No Data	0	N/A	0
Sand	1	CS	4
Loamy Sand	2	CS	4
Sandy Loam	3	MS	3
Silt Loam	4	FS	1
Silt	5	FSS	2
Loam	6	MS	3
Sandy Clay Loam	7	MS	3
Silty Clay Loam	8	FSS	1
Clay Loam	9	MS	3
Sandy Clay	10	MS	3
Silty Clay	11	FSS	1
Clay	12	FS	2

Surface Roughness Lengths Surface roughness lengths can vary considerably for a given land type, as evidenced by examination of the data in Table 8-5. Surface roughness lengths are assigned as a function of land use type based on a review of the information in Table 8-5. The disturbance level of various surfaces has the effect of altering the surface roughness lengths, which in turn impact the potential for vacant lands to emit dust from wind erosion

Table 8-5. Aerodynamic Surface Aerodynamic Roughness Lengths, Z_0

Site Type	Average z_0 (cm)	Reference(s)
agricultural fields (bare)	0.031	23 - 26
desert flat/pavement	0.133	23 - 26
fan surface	0.088	23 - 26
playa, crusted	0.059	23 - 26
playa	0.057	23 - 26
prairie	0.049	23 - 26
sand dune	0.007	23 - 26
scrub desert	0.045	26
sparse veg. (0.04% cover)	0.37	33
sparse veg. (8% cover)	5.4	33
sparse veg. (10.3% cover)	6.8	33
sparse veg. (13.5% cover)	7.2	33
sparse veg. (26% cover)	8.3	33
thick grass	2.3	34
thin grass	5	34
sparse grass	0.12	35
agricultural crops	2-4	35
orchards	50-100	35
decid. forests	100-600	35
conf. forests	100-600	35
agricultural crops	15	36
urban	100	36
decid. forests (closed canopy)	121	36
conif. forests (closed canopy)	134	36

An examination of Figure 8-2, which relates the threshold surface friction velocity to the aerodynamic surface roughness length, reveals that for surface roughness lengths larger than approximately 0.1 cm, the threshold friction velocities increase rapidly above values that can be realistically expected to occur in the meteorological data used in the model implementation. Therefore to simplify the model implementation, only those land types with roughness length less than or equal to 0.1 cm are considered as potentially erodible surfaces.

For a given surface roughness, as determined by the land use type³², the threshold friction velocity has a constant value. Thus, the land use data is mapped to an internal dust code used within the model to minimize computer resource requirements and coding efforts. The mapping of land use types to dust codes 3 and above (except for code 5 that applies to orchards and vineyards) is presented in Table 8-6, which summarizes the surface characteristics by dust code. [Note: Dust codes 1 and 2 refer to water/wetlands and forest/urban, respectively.]

Table 8-6. Surface Characteristics by Dust Code and Land Use Category

Dust Code	3	4	6	7
Land use category	Agricultural	Grassland	Shrubland	Barren
Surface roughness length, Z_0 (cm)	0.031	0.1	0.05	0.002
Threshold friction velocity (m/s)	3.72	6.17	4.30	3.04
Threshold wind velocity at 10 meter height (m/s [mph])	13.2 [29.5]	19.8 [44.3]	14.6 [32.8]	12.7 [28.5]

Meteorology Gridded hourly meteorological data, which is required for the dust estimation methodology is based on MM5 model simulation results. Data fields required include wind speeds, precipitation rates, soil temperatures and ice/snow cover.

Agricultural Land Adjustments Unlike other types of vacant land, windblown dust emissions from agricultural land are subject to a number of non-climatic influences, including irrigation and seasonal crop growth. As a result, several non-climatic correction or adjustment factors were developed for applicability to the agricultural wind erosion emissions. These factors included:

- Long-term effects of irrigation (i.e., soil “clodiness”)
- Crop canopy cover
- Post-harvest vegetative cover (i.e., residue)
- Bare soil (i.e., barren areas within an agriculture field that do not develop crop canopy for various reasons, etc.)
- Field borders (i.e., bare areas surrounding and adjacent to agricultural fields)

The methodology used to develop individual non-climatic correction factors was based upon previous work performed by the California Air Resources Board in their development of California-specific adjustment factors for the USDA’s Wind Erosion Equation.³⁷

Other Adjustments Two other adjustments to modeled air quality impacts relate to fugitive dust transportability and partitioning between fine and coarse fractions of PM10. Transportability fractions as a function of land use are assigned on the basis of the methodology described by Pace.³⁸ New fine fraction values developed by Cowherd³⁹ from controlled wind tunnel studies of western soils are applied to determine the fine and coarse fractions of wind-generated fugitive dust emissions.

Concerns Regarding the Method

ENVIRON’s methodology for calculating wind-generated fugitive dust emissions relies on several assumptions that may not be valid. As was mentioned above, many of the assumptions employed in Phase 1 were necessitated by a lack of specificity in the underlying data used to characterize vacant land types and soil conditions in relation to the potential for wind erosion. Even in Phase 2, it was necessary to rely on some assumptions where data were lacking.

The pertinent vacant land characteristics that are most difficult to characterize are the dust reservoir capacities and resuspension characteristics in relation to the levels of surface disturbance and the presence of protective surface elements (vegetation, rocks). Another complex feature is the recharge time needed to re-establish all or part of the reservoir after depletion by a wind erosion event.

Surface disturbance tends to have a much stronger impact than soil type in providing a high dust reservoir capacity. If the surface is disturbed in such a way that non-erodible

elements are minimized, it can be considered as having an “unlimited” erosion potential. This means that the reservoir is large enough to support hours of fine particle emissions during a high-wind event. Therefore, it is important any PM10 emission models or empirical relationships account for not only the soil type but also the state of aggregation of the exposed surface material.

After a surface disturbance that creates an unlimited reservoir of available particles, precipitation events can have a major effect in restoring a surface crust and place the surface in a stable condition for an indefinite period. When this occurs, typically a “limited” reservoir will be present on the surface. This reservoir contains only minor amounts of accumulated deposition from previous area-wide wind erosion events or from other more localized fugitive dust sources such as unpaved roads.

Because of the complexity of determining dust reservoir characteristics and their dynamic features, the Phase 2 methodology also tends to rely on assigned characteristics that do not appear to be well founded for most areas subject to wind erosion. For example, the assumed recharge period of only 24 hours is usually unrealistic. For example in the case of agricultural land, this would require a major disturbance to the soil such as a tilling operation that brings fresh, loose and dry soil to the surface. In the absence of a major surface disturbance, actual recharge times may extend to weeks and even months.⁴⁰ In some cases, however, a stable surface can transition to a highly erodible state in the absence of mechanical disturbance. The highly alkaline soils at Owens Lake, California for instance are fairly stable during summer months, but can change to a very unstable surface in the winter and spring following periods with precipitation and cold temperatures.¹²

Another example of concern is the value assumed in the Phase 2 model for the estimated time after a precipitation event that it takes to re-initiate wind erosion. The times given for full restoration of the dust reservoir are in the range of 1 to 4 days, depending on the soil type and whether the precipitation exceeded 2 inches. These values are at variance with the results of a multiyear field study conducted by Cowherd et al. in the western Mojave Desert.⁴¹ That study showed that precipitation events of that order could re-stabilize soil surfaces for indefinite periods pending the next major surface disturbance. In the study area, scattered reservoirs of loose sand were stabilized by the presence of desert vegetation.

Stable soils in windy areas tend to have limited reservoirs of erodible particles consisting of a thin surface layer of deposition from previous high wind events. These layers have been homogenized by successive resuspension and atmospheric mixing during wind erosion over many years. This is illustrated by a recently completed inventory of vacant lands in the Las Vegas Valley.⁴² This study showed that the vast majority of the land consisted of “native desert” as characterized by a single reflectance signature from satellite imagery with visible and infrared wavelength components. Landsat TM 5 with a 30-meter pixel size was found to provide a useful reflectance averaging that eliminated the effects of micro-features associated with uneven patterns of vegetation. The thin layers of erodible particles appear to exhibit a relatively uniform

chemistry. Therefore, the known soil chemistry differences below the surface layer were not a confounding factor in establishing a single spectral signature for this vacant land category. On the other hand, areas where the soil had been turned as part of land preparation processes for construction projects could not be fitted to a single spectral signature because of surface soil chemistry differences.

Due to the paucity of wind tunnel data, Mansell et al.¹⁷ developed fugitive dust emission factors for wind erosion of vacant land, based on soil texture rather than using area-specific wind tunnel data as recommended by MacDougall.¹⁶ The emission fluxes for four soil aggregate populations were expressed in terms of friction velocity, based on test data from a relatively large portable wind tunnel. It was assumed that the flux would remain constant at any friction velocity for a period of 1 hour or 10 hours depending on whether the surface was classified as having a limited or unlimited reservoir respectively. Mansell and coworkers did not rely on the wind tunnel emission factors derived for Clark County by James et al.²¹ because they appeared to be much greater than emission factors measured by other researchers using wind tunnels with a larger cross-section than the UNLV designed wind tunnel (6" wide by 6" high by 60" long).

It should be noted that because ENVIRON's methodology assigns a very short recovery time on (a) replenishing soil losses from high wind events, and on (b) losing the mitigating effects of precipitation, the estimated emissions are driven mostly by wind speed. There is little accounting for the natural tendency of most unlimited reservoir surfaces to re-stabilize for long periods of time in the absence of major surface disturbances or large supplies of available loose sand that can abrade stable crusts. As noted in the land inventory of the Las Vegas Valley cited above, a frequent land disturbance pattern is found only on regularly traveled surfaces, with few exceptions.

Recommendations

In order to use ENVIRON's methodology/model for calculating wind-generated fugitive dust emissions, it is strongly recommended that the user review the necessary inputs for the model, and refine the inputs if better information is available. If a wind blown dust inventory is needed for a planning area, local wind tunnel data, or erosion monitoring using CSC sand flux samplers based on the methodology described by Ono et al.¹² (see Section 8.3) is a very practical approach.

8.5 Demonstrated Control Techniques

Control measures for open area wind erosion are designed to stabilize the exposed surface (e.g., by armoring it with a less erodible cover material) or to shield it from the ambient wind. Table 8-7 presents a summary of control measures and reported control efficiencies for open area wind erosion.

Table 8-7. Control Efficiencies for Control Measures for Open Area Wind Erosion

Control measure	Source Component	PM10 Control Efficiency	References/comments
Apply dust suppressants to stabilize disturbed area after cessation of disturbance	Disturbed areas	84%	CARB, April 2002. ⁴³
Apply gravel to stabilize disturbed open areas	Disturbed areas	84%	CARB, April 2002. ⁴³ Estimated to be as effective as chemical dust suppressants.

8.6 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats for several local air quality agencies in the WRAP region are presented in Table 8-8. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/envsvc/air/ruledesc.asp

8.7 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Table 8-8. Example Regulatory Formats for Open Area Wind Erosion

Control measure	Goal	Threshold	Agency
Watering, fencing, paving, graveling, dust suppressant, vegetative cover, restrict vehicular access	Maintain soil moisture content min 12%; or 70% min of optimum soil moisture content; reduce windblown emissions	Construction sites; fences 3ft-5ft, adjacent to roadways/urban areas;	Maricopa County Rule 310 04/07/2004
Cease ops (wind speed >25mph); applying dust suppressant 2x hr; watering and fencing (as above); for after work hours: gravel, water 3x/day (possibly 4)	Reduce amt of windblown dust leaving site; maintain soil moisture content 12%	Wind speed must be >25mph for 60 min average; fencing must be 3ft-5ft with <50% porosity; watering for after work, holidays, weekends increase to 4x/day during wind event	Maricopa County Rule 310 04/07/2004
Use of one of following for dust control on all disturbed soil to maintain in damp condition: soil crusted over by watering or other, or graveling or treated with dust suppressant	Prevent visible fugitive dust from exceeding 20% opacity, and prevent dust plume from extending more than 100 yd		Clark County Sect. 94 Air Quality Reg. 06/22/2000
Requires application of water or chemical stabilizers prior to wind event 3 times a day (possible increase to 4 times a day if evidence of wind driven dust), or establish a vegetative cover within 21 days after active operations have ceased to maintain a stabilized surface for 6 months		For operations that remain inactive for not more than 4 consecutive days	SCAQMD Rule 403 12/11/1998

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 8-9 summarizes the compliance tools that are applicable to open area wind erosion.

Table 8-9. Compliance Tools for Open Area Wind Erosion

Record keeping	Site inspection/monitoring
Soil stabilization methods; application frequencies, rates, and times for dust suppressants; establishment/maintenance of wind breaks.	Crust strength determination (e.g., drop ball test); observation of operation of dust suppression systems; inspection of heights and porosities of windbreaks.

8.8 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for fugitive dust originating from open area wind erosion. A sample cost-effectiveness calculation is presented below for a specific control measure (apply gravel) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for open area wind erosion, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation For Open Area Wind Erosion (Dirt Parking Lot)

Step 1. Determine source activity and control application parameters.

Area of dirt parking lot	10,000 m ²
Disturbance frequency per day	1
Duration of exposure (months)	12
Roughness height (cm)	0.5
Threshold peak wind speed at height of 10 m (m/s)	10

Control Measure	Apply gravel
Control application/frequency	Once every years
Economic Life of Control System (yr)	5
Threshold friction velocity for gravel (m/s)	1.9
Control Efficiency (%)	84
Reference for Control Efficiency	Sierra Research (2003) ⁴⁴

The field size, source activity parameters, and control measure parameters are assumed values for illustrative purposes. Applying a 3” deep gravel bed over the dirt has been chosen as the applied control measure.

Step 2. Obtain PM10 Emission Factor.

The PM10 emission factor is obtained from AP-42: $PM10\ EF = 0.5 \sum_{i=1}^N P_i$

$$P = 58 (u^* - u_t^*)^2 + 25 (u^* - u_t^*)$$

$$P = 0 \text{ for } u^* \leq u_t^*$$

P—erosion potential (g/m²)

Threshold friction velocity u_t^* (m/s) = 0.053 u_{10}^+ 0.53

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (obtained in Step 2) is applied to each day for which the peak wind exceeds the threshold velocity for wind erosion. The following monthly climatic data are used for illustrative purposes and are assumed to apply to each month of the year.

Monthly erosion potential (P) ^a				
Day of Month	Peak Wind (u_{10}^+)		u^* m/s	P g/m ²
	mph	m/s		
6	29	13.0	0.69	5.36
7	30	13.4	0.71	6.41
11	38	17.0	0.90	17.21
22	25	11.2	0.59	1.78
Sum of P				30.77

^a Assumed to apply to 12 months of the year.

The annual PM10 emissions are equal to the PM10 emission factor (i.e., 0.5 times the monthly erosion potential) multiplied by 12 and then by the field size (under activity data) and then divided by 454 g/lb and 2,000 lb/ton to compute the annual PM10 emissions in tons per year, as follows:

$$\text{Annual PM10 emissions} = (\text{Emission Factor} \times \text{Field Size}) / (454 \times 2,000)$$

$$\text{Annual PM10 emissions} = (0.5 \times 0.77 \times 12 \times 10,000) / (454 \times 2,000)$$

$$\text{Annual PM10 emissions} = 2.03 \text{ tons}$$

$$\text{Annual PM2.5 emissions} = 0.15 \times \text{PM10 emissions}^{12} = 0.15 \times 2.03 = 0.30 \text{ tons}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, we have selected applying gravel over the dirt parking lot as our control measure. Based on a control efficiency estimate of 84% for this control measure, the annual controlled emissions estimate are calculated to be:

Annual Controlled PM10 emissions = 0.33 tons

Annual Controlled PM2.5 emissions = 0.049 tons

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	50,000
Annual Operating/Maintenance costs (\$)	4,000
Annual Interest Rate	3%
Capital Recovery Factor	0.2184
Annualized Cost (\$/yr)	13,173

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$\text{Capital Recovery Factor} = \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1$$

$$\text{Capital Recovery Factor} = 3\% \times (1 + 3\%)^5 / (1 + 3\%)^5 - 1 = 0.2184$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor and the Capital costs to the Annual Operating/Maintenance:

$$\begin{aligned} \text{Annualized Cost} &= (\text{CRF} \times \text{Capital costs}) + \text{Annual Operating/Maintenance costs} \\ \text{Annualized Cost} &= (0.2084 \times 50,000) + 4,000 = 14,918 \end{aligned}$$

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost-effectiveness for PM10 emissions} = \$14,918 / (2.03 - 0.33) = \$8,735/\text{ton}$$

$$\text{Cost-effectiveness for PM2.5 emissions} = \$14,918 / (0.30 - 0.049) = \$58,234/\text{ton}$$

8.9 References

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Chapter 9. Storage Pile Wind Erosion

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9.1 Characterization of Source Emissions

Dust emissions may be generated by wind erosion of open areas of exposed soils or other aggregate materials within an industrial facility. These sources typically are characterized by nonhomogeneous surfaces impregnated with nonerodible elements (particles larger than approximately 1 centimeter [cm] in diameter). Field testing of coal piles and other exposed materials using a portable wind tunnel has shown that:

(a) threshold wind speeds exceed 5 meters per second (m/s) (11 miles per hour [mph]) at 15 cm above the surface or 10 m/s (22 mph) at 7 m above the surface, and (b) particulate emission rates tend to decay rapidly (half-life of a few minutes) during an erosion event. In other words, these aggregate material surfaces are characterized by finite availability of erodible material (mass/area) referred to as the erosion potential. Any natural crusting of the surface binds the erodible material, thereby reducing the erosion potential. Loose soils or other aggregate materials consisting of sand-sized materials act as an unlimited reservoir of erodible material and can sustain emissions for periods of hours without substantial decreases in emission rates.

If typical values for threshold wind speed at 15 cm are corrected to typical wind sensor height (7 to 10 m), the resulting values exceed the upper extremes of hourly mean wind speeds observed in most areas of the country. In other words, mean atmospheric wind speeds are not sufficient to sustain wind erosion from flat surfaces of the type tested. However, wind gusts may quickly deplete a substantial portion of the erosion potential. Because erosion potential has been found to increase rapidly with increasing wind speed, estimated emissions should be related to the gusts of highest magnitude. The routinely measured meteorological variable that best reflects the magnitude of wind gusts is the fastest mile. This quantity represents the wind speed corresponding to the whole mile of wind movement that has passed by the 1 mile contact anemometer in the least amount of time. Daily measurements of the fastest mile are presented in the monthly Local Climatological Data (LCD) summaries. The duration of the fastest mile, typically about 2 minutes (for a fastest mile of 30 mph), matches well with the half-life of the erosion process, which ranges between 1 and 4 minutes. It should be noted, however, that peak winds can significantly exceed the daily fastest mile.

The wind speed profile in the surface boundary layer is found to follow a logarithmic distribution as follows:

$$u(z) = \frac{u^*}{0.4} \ln \frac{z}{z_0} \quad (z > z_0) \quad (1)$$

where,

- u = wind speed (cm/s)
- u* = friction velocity (cm/s)
- z = height above test surface (cm)
- z₀ = roughness height (cm)
- 0.4 = von Karman's constant (dimensionless)

The friction velocity (u*) is a measure of wind shear stress on the erodible surface, as determined from the slope of the logarithmic velocity profile. The roughness height (z₀) is a measure of the roughness of the exposed surface as determined from the y-intercept

of the velocity profile, i.e., the height at which the wind speed is zero. These parameters are illustrated in Figure 9-1 for a roughness height of 0.1 cm.

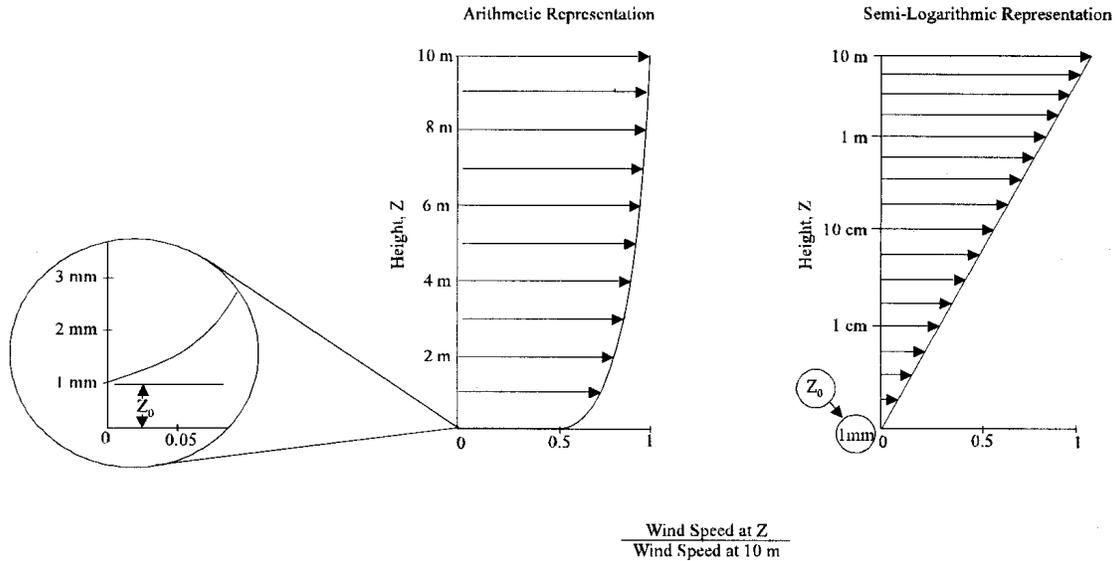


Figure 9-1. Illustration of Logarithmic Wind Velocity Profile

Emissions generated by wind erosion are also dependent on the frequency of disturbance of the erodible surface because each time that a surface is disturbed, its erosion potential is restored. A disturbance is defined as an action that results in the exposure of fresh surface material. On a storage pile, this would occur whenever aggregate material is either added to or removed from the old surface. A disturbance of an exposed area may also result from the turning of surface material to a depth exceeding the size of the largest pieces of material present.

9.2 Emission Estimation: Primary Methodology ¹⁻¹¹

This section was adapted from Section 13.2.5 of EPA's *Compilation of Air Pollutant Emission Factors (AP-42)*. Section 13.2.5 was last updated in January 1995.

The PM₁₀ emission factor for wind-generated particulate emissions from mixtures of erodible and nonerodible surface material subject to disturbance may be expressed in units of grams per square meter (g/m^2) per year as follows:

$$\text{PM}_{10} \text{ Emission Factor} = 0.5 \sum_{i=1}^N P_i \quad (2)$$

where,

N = number of disturbances per year

P_i = erosion potential corresponding to the observed (or probable) fastest mile of wind for the *i*th period between disturbances (g/m^2)

In calculating emission factors, each area of an erodible surface that is subject to a different frequency of disturbance should be treated separately. For a surface disturbed

daily, $N = 365$ per year, and for a surface disturbance once every 6 months, $N = 2$ per year. The erosion potential function for a dry, exposed surface is given as:

$$P = 58 (u^* - u_t^*)^2 + 25 (u^* - u_t^*) \quad (3)$$

$$P = 0 \text{ for } u^* \leq u_t^*$$

where,

- u^* = friction velocity (m/s)
- u_t = threshold friction velocity (m/s)

Because of the nonlinear form of the erosion potential function, each erosion event must be treated separately. The PM_{2.5}/PM₁₀ ratio for windblown fugitive dust posted on EPA's CHIEF website is 0.15 based on the analysis conducted by MRI on behalf of WRAP.¹¹

Equations 2 and 3 apply only to dry, exposed materials with limited erosion potential. The resulting calculation is valid only for a time period as long or longer than the period between disturbances. Calculated emissions represent intermittent events and should not be input directly into dispersion models that assume steady-state emission rates. For uncrusted surfaces, the threshold friction velocity is best estimated from the dry aggregate structure of the soil. A simple hand sieving test of surface soil can be used to determine the mode of the surface aggregate size distribution by inspection of relative sieve catch amounts, following the procedure described below.

FIELD PROCEDURE FOR DETERMINING THRESHOLD FRICTION VELOCITY

(from a 1952 laboratory procedure published by W. S. Chepil⁵)

- Step 1. Prepare a nest of sieves with the following openings: 4 mm, 2 mm, 1 mm, 0.5 mm, and 0.25 mm. Place a collector pan below the bottom (0.25 mm) sieve.
- Step 2. Collect a sample representing the surface layer of loose particles (approximately 1 cm in depth, for an encrusted surface), removing any rocks larger than about 1 cm in average physical diameter. The area to be sampled should be not less than 30 cm by 30 cm.
- Step 3. Pour the sample into the top sieve (4-mm opening), and place a lid on the top.
- Step 4. Move the covered sieve/pan unit by hand, using a broad circular arm motion in the horizontal plane. Complete 20 circular movements at a speed just necessary to achieve some relative horizontal motion between the sieve and the particles.
- Step 5. Inspect the relative quantities of catch within each sieve, and determine where the mode in the aggregate size distribution lies, i.e., between the opening size of the sieve with the largest catch and the opening size of the next largest sieve.
- Step 6. Determine the threshold friction velocity from Table 9-1.

The results of the sieving can be interpreted using Table 9-1. Alternatively, the threshold friction velocity for erosion can be determined from the mode of the aggregate size distribution using the graphical relationship described by Gillette.^{5,6} If the surface material contains nonerodible elements that are too large to include in the sieving (i.e., greater than about 1 cm in diameter), the effect of the elements must be taken into account by increasing the threshold friction velocity.¹⁰

Table 9-1. Field Procedure for Determination of Threshold Friction Velocity (Metric Units)

Tyler Sieve No.	Opening (mm)	Midpoint (mm)	u_t^* (cm/s)
5	4		
9	2	3	100
16	1	1.5	76
32	0.5	0.75	58
60	0.25	0.375	43

Threshold friction velocities for several surface types have been determined by field measurements with a portable wind tunnel. These values are presented in Table 9-2.

Table 9-2 Threshold Friction Velocities (Metric Units)

Material	Threshold friction velocity (m/s)	Roughness height (cm)	Threshold wind velocity at 10 m (m/s)	
			$z_o = \text{Actual}$	$z_o = 0.5 \text{ cm}$
Overburden ^a	1.02	0.3	21	19
Scoria (roadbed material) ^a	1.33	0.3	27	25
Ground coal (surrounding coal pile) ^a	0.55	0.01	16	10
Uncrusted coal pile ^a	1.12	0.3	23	21
Scraper tracks on coal pile ^{a,b}	0.62	0.06	15	12
Fine coal dust on concrete pad ^c	0.54	0.2	11	10

^a Western surface coal mine; reference 2.

^b Lightly crusted.

^c Eastern power plant; reference 3.

The fastest mile of wind for the periods between disturbances may be obtained from the monthly local climatological data (LCD) summaries for the nearest reporting weather station that is representative of the site in question.⁷ These summaries report actual fastest mile values for each day of a given month. Because the erosion potential is a highly nonlinear function of the fastest mile, mean values of the fastest mile are inappropriate. The anemometer heights of reporting weather stations are found in Reference 8, and should be corrected to a 10-m reference height using Equation 1. To convert the fastest mile of wind (u^+) from a reference anemometer height of 10 m to the equivalent friction velocity (u^*), the logarithmic wind speed profile may be used to yield the following equation:

$$u^* = 0.053 u_{10}^+ \quad (4)$$

where,

u^* = friction velocity (m/s)

u_{10}^+ = fastest mile of reference anemometer for period between disturbances (m/s)

This assumes a typical roughness height of 0.5 cm for open terrain. Equation 4 is restricted to large relatively flat exposed areas with little penetration into the surface wind layer.

If the pile significantly penetrates the surface wind layer (i.e., with a height-to-base ratio exceeding 0.2), it is necessary to divide the pile area into subareas representing different degrees of exposure to wind. The results of physical modeling show that the frontal face of an elevated pile is exposed to wind speeds of the same order as the approach wind speed at the top of the pile.

For two representative pile shapes (conical and oval with flattop, 37-degree side slope), the ratios of surface wind speed (u_s) to approach wind speed (u_r) have been derived from wind tunnel studies.⁹ The results are shown in Figure 9-2 corresponding to an actual pile height of 11 m, a reference (upwind) anemometer height of 10 m, and a pile surface roughness height (z_0) of 0.5 cm. The measured surface winds correspond to a height of 25 cm above the surface. The area fraction within each contour pair is specified in Table 9-3.

Table 9-3. Subarea Distribution for Regimes of u_s/u_r

Pile subarea	Percent of pile surface area			
	Pile A	Pile B1	Pile B2	Pile B3
0.2a	5	5	3	3
0.2b	35	2	28	25
0.2c	NA	29	NA	NA
0.6a	48	26	29	28
0.6b	NA	24	22	26
0.9	12	14	15	14
1.1	NA	NA	3	4

NA = not applicable.

The profiles of u_s/u_r in Figure 9-2 can be used to estimate the surface friction velocity distribution around similarly shaped piles, using the following procedure:

- Step 1.** Correct the fastest mile value (u^+) for the period of interest from the anemometer height (z) to a reference height of 10 m (u_{10}^+) using a variation of Equation 1:

$$u_{10}^+ = u^+ \frac{\ln(10/0.005)}{\ln(z/0.005)} \quad (5)$$

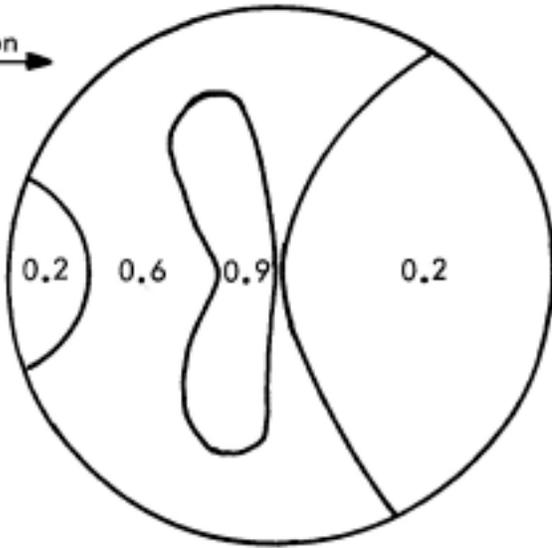
where a typical roughness height (z_0) of 0.5 cm (0.005 m) has been assumed. If a site-specific roughness height is available, it should be used.

- Step 2.** Use the appropriate part of Figure 9-2 based on the pile shape and orientation to the fastest mile of wind, to obtain the corresponding surface wind speed distribution (u_s^+):

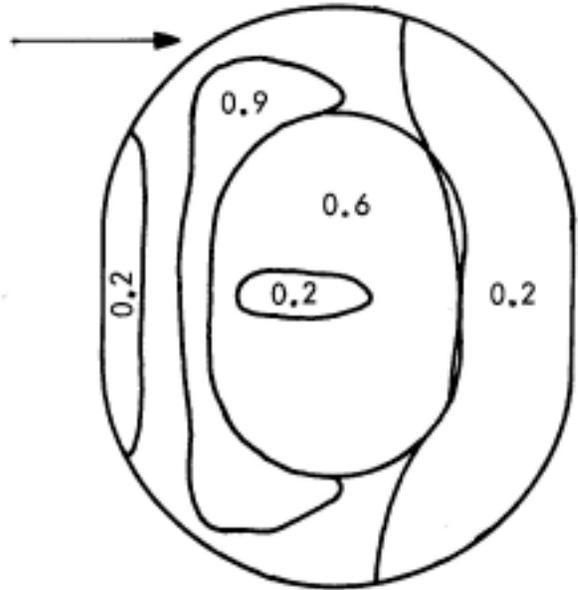
$$u_s^+ = \frac{(u_s)}{u_r} u_{10}^+ \quad (6)$$

- Step 3.** For any subarea of the pile surface having a narrow range of surface wind speed, use a variation of Equation 1 to calculate the equivalent friction velocity (u^*): $u^* = (0.4 u_s^+) / \ln(25 / 0.5) = 0.10 u_s^+$ (7)

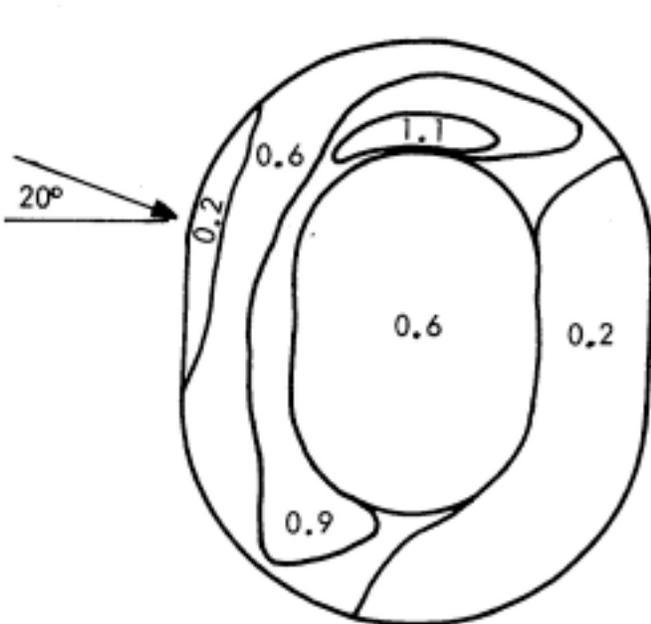
Flow
Direction →



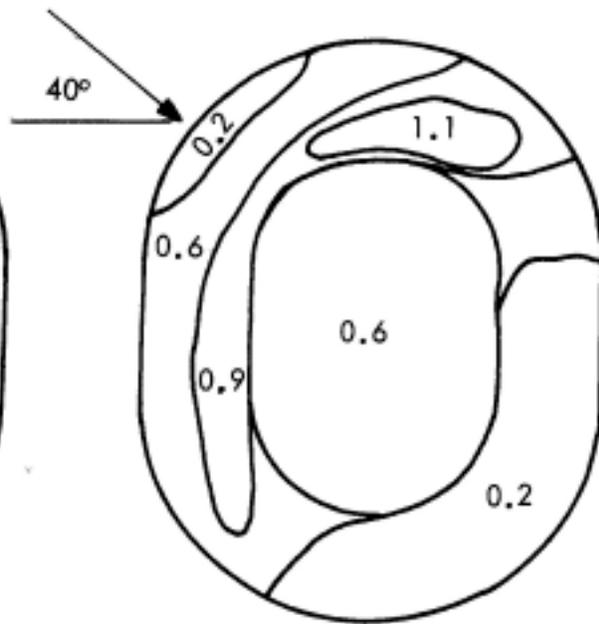
Pile A



Pile B1



Pile B2



Pile B3

Figure 9-2. Contours of Normalized Surface Wind Speed Ratios, u_s/u_r

From this point on, the procedure is identical to that used for a flat pile, as described above. Implementation of the above procedure is carried out in the following steps:

- Step 1. Determine threshold friction velocity for erodible material of interest (see Table 9-2 or determine from mode of aggregate size distribution).
- Step 2. Divide the exposed surface area into subareas of constant frequency of disturbance (N).
- Step 3. Tabulate fastest mile values (u^+) for each frequency of disturbance and correct them to 10 m (u_{10}^+) using Equation 5.
- Step 4. Convert fastest mile values (u_{10}^+) to equivalent friction velocities (u^*), taking into account (a) the uniform wind exposure of nonelevated surfaces, using Equation 4, or (b) the nonuniform wind exposure of elevated surfaces (piles), using Equations 6 and 7.
- Step 5. For elevated surfaces (piles), subdivide areas of constant N into subareas of constant u^* (i.e., within the isopleth values of u_s/u_r in Figure 9-2 and Table 9-3) and determine the size of each subarea.
- Step 6. Treating each subarea (of constant N and u^*) as a separate source, calculate the erosion potential (P_i) for each period between disturbances using Equation 3 and the emission factor using Equation 2.
- Step 7. Multiply the resulting emission factor for each subarea by the size of the subarea, and add the emission contributions of all subareas. Note that the highest 24-hour emissions would be expected to occur on the windiest day of the year. Maximum emissions are calculated assuming a single event with the highest fastest mile value for the annual period.

The recommended emission factor equation presented above assumes that all of the erosion potential corresponding to the fastest mile of wind is lost during the period between disturbances. Because the fastest mile event typically lasts only about 2 minutes, which corresponds roughly to the half-life for the decay of actual erosion potential, it could be argued that the emission factor overestimates particulate emissions. However, there are other aspects of the wind erosion process that offset this apparent conservatism as follows:

1. The fastest mile event contains peak winds that substantially exceed the mean value for the event.
2. Whenever the fastest mile event occurs, there are usually a number of periods of slightly lower mean wind speed that contain peak gusts of the same order as the fastest mile wind speed.

Of greater concern is the likelihood of over prediction of wind erosion emissions in the case of surfaces disturbed infrequently in comparison to the rate of crust formation.

9.3 Emission Estimation: Alternate Methodology

EPA published a total suspended particulate (TSP) emission factor equation for wind erosion of active storage piles in 1989 that is not included in AP-42.¹² For days when there was at least 0.01 inch of precipitation, the TSP emissions were zero. The TSP emission factor equation (in units of lb/day/acre of surface) for days when there was less than 0.01 inch of precipitation was given as:

$$E_{TSP} = 1.7 (s/1.5) (f/15)$$

where, s = silt content of material (weight %)

f = percentage of time the unobstructed wind speed is greater than 12 mph at the mean pile height

The annual TSP emissions factor equation for wind blown dust from active storage piles was given as follows:

$$\text{TSP (lb/year/acre of surface)} = 1.7 (s/1.5) (365 [365-p] / 235) (f/15)$$

where, s = silt content of material (weight %)

p = number of days per year with at least 0.01 inch of precipitation

f = percentage of time the unobstructed wind speed is greater than 12 mph at the mean pile height

Based on the PM10/TSP ratio of 0.5 for wind blown dust from active storage piles published in Section 13.2.5 of AP-42 and a PM2.5/PM10 ratio of 0.15 for wind blown dust¹¹, the PM10 and PM2.5 emission factor equations (in units of lb/day/acre) would be:

$$E_{PM10} = 0.85 (s/1.5) (f/15)$$

$$E_{PM2.5} = 0.13 (s/1.5) (f/15)$$

The short-term hourly TSP emission factor equation for wind blown dust from active storage piles (in units lb/acre-hour) given in the 1989 EPA report was equal to the wind speed (in units of mph) multiplied by a factor of 0.72. Thus for a wind speed that averaged 25 mph during a one-hour period, the TSP emission factor during that hour would be 18 lb/acre which is equal to 2.02 g/m². The corresponding PM10 and PM2.5 emission factors would be 1.01 g/m² and 0.15 g/m², respectively.

9.4 Demonstrated Control Techniques

Control measures for storage pile wind erosion are designed to stabilize the erodible surface (e.g., by increasing the moisture content of the aggregate material being stored) or to shield it from the ambient wind. Table 9-4 presents a summary of control measures and reported control efficiencies for storage pile wind erosion.

Table 9-4. Control Efficiencies for Control Measures for Storage Pile Wind Erosion

Control measure	PM10 control efficiency	References/comments
Require construction of 3-sided enclosures with 50% porosity	75%	Sierra Research, 2003. ¹³ Determined through modeling of open area windblown emissions with 50% reduction in wind speed and assuming no emission reduction when winds approach open side
Water the storage pile by hand or apply cover when wind events are declared	90%	Fitz et al., April 2000. ¹⁴

9.5 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Regulatory formats specify the threshold source size that triggers the need for control application. Example regulatory formats for several local air quality agencies in the WRAP region are presented in Table 9-5. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: <http://www.maricopa.gov/envsvc/air/ruledesc.asp>

(Note: The Clark County website did not include regulatory language specific to storage pile wind erosion at the time this chapter was written.)

9.6 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

Table 9-5. Example Regulatory Formats for Storage Pile Wind Erosion

Control Measure	Goal	Threshold	Agency
Establishes wind barrier and watering or stabilization requirements and bulk materials must be stored according to stabilization definition and outdoor materials covered	Limit visible dust emissions to 20% opacity		SJVAPCD Rule 8031 11/15/2001
Best available control measures: wind sheltering, watering, chemical stabilizers, altering load-in/load-out procedures, or coverings	Prohibits visible dust emissions beyond property line and limits upwind/downwind PM10 differential to 50 ug/m3		SCAQMD Rule 403 12/11/1998
Watering, dust suppressant (when loading, stacking, etc.); cover with tarp, watering (when not loading, etc.); wind barriers, silos, enclosures, etc.	Limit VDE to 20% opacity; stabilize soil	For storage piles with >5% silt content, 3ft high, >150 sq ft; work practices for stacking, loading, unloading, and when inactive; soil moisture content min 12%; or at least 70% min for optimum soil moisture content; 3 sided enclosures, at least equal to pile in length, same for height, porosity <50%	Maricopa County Rule 310 04/07/2004
Utilization of dust suppressants other than water when necessary; prewater; empty loader bucket slowly	Prevent wind erosion from piles; stabilize condition where equip and vehicles op	Bulk material handling for stacking, loading, and unloading; for haul trucks and areas where equipment op	Maricopa County Rule 310 04/07/2004

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 9-6 summarizes the compliance tools that are applicable to wind erosion from material storage piles.

Table 9-6. Compliance Tools for Storage Pile Wind Erosion

Record keeping	Site inspection/monitoring
Site map; work practices, including pile formation and removal times (throughputs); locations, sizes, and shapes of storage piles; moisture and silt contents of pile surface material; location/heights/densities of vegetation or other wind breaks, including maintenance times; dust suppression equipment and maintenance records; frequencies, amounts, times, and rates of watering or dust suppressant application; meteorological log.	Sampling and analysis of storage pile surface material for silt and moisture contents; observation of pile formation and removal, including wet suppression systems; observation of vehicle/ equipment operation and disturbance areas; inspection of wind sheltering including enclosures; real-time portable monitoring of PM; observation of dust plume opacity exceeding a standard.

9.7 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for fugitive dust originating from storage pile wind erosion. A sample cost-effectiveness calculation is presented below for a specific control measure (3-sided enclosure) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for storage pile wind erosion, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Storage Pile Wind Erosion

Step 1. Determine source activity and control application parameters.

Frequency of disturbance (days/yr)	365
Height of pile (m)	11
Base diameter (m)	29.2
Total surface area (m ²)	838
Portion of pile exposed to high winds (%)	12
Surface area exposed to high winds (m ²)	101
Threshold friction velocity u^*_t (m/s)	0.85
Control Measure	3-sided enclosure
Economic Life of Control System (yr)	10
Control Efficiency (%)	74.7
Reference for Control Efficiency	Sierra Research, 2003 ¹³

The pile size, source activity parameters and control measure parameters are assumed values for illustrative purposes. A 3-sided enclosure has been chosen as the applied control measure. The control efficiency is provided by Sierra Research.¹³

The pile surface area within each surface wind speed range (see AP-42, Section 13.2.5) is as follows:

Surface areas within each wind speed range			
Area ID	Pile surface		
	u_s / u_r	%	Area (m ²)
A	0.9	12	101
B	0.6	48	402
C	0.2	40	335
Total Area			838

Step 2. Obtain PM10 Emission Factor.

The PM10 emission factor is obtained from AP-42: $PM10\ EF = 0.5 \sum_{i=1}^N P_i$

P—erosion potential (g/m ²)	$P = 58 (u^* - u^*_t)^2 + 25 (u^* - u^*_t)$
	$P = 0$ for $u^* \leq u^*_t$

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor (given in Step 2) is applied to each day for which the peak wind exceeds the threshold velocity for wind erosion. The following monthly climatic data are used for illustrative purposes and are assumed to apply to each month of the year.

Day of month	Monthly erosion potential (P)				
	Peak wind (u^*_{10})		u^*_s (m/s)		
	mph	m/s	Area C $u_s / u_r: 0.2$	Area B $u_s / u_r: 0.6$	Area A $u_s / u_r: 0.9$
6	29	13.0	2.59	7.78	11.67
7	30	13.4	2.68	8.05	12.07
11	38	17.0	3.40	10.19	15.29
22	25	11.2	2.24	6.71	10.06
28	45	20.1	4.02	12.07	18.10

Monthly erosion potential (P) ^a						
Day of month	u* (m/s)			P (g/m ²)		
	Area C	Area B	Area A	Area C	Area B	Area A
6	0.26	0.78	1.17	0	0	13.74
7	0.27	0.80	1.21	0	0	16.32
11	0.34	1.02	1.53	0	5.89	43.70
22	0.22	0.67	1.01	0	0	5.30
28	0.40	1.21	1.81	0	16.32	77.52
Sum of P (g/m ²)				0	22.21	156.57
Area (m ²)				335	402	101
Monthly PM10 emissions (g) ^b				0	4,464	7,907

^a Assumed to apply to 12 months of the year.

^b Monthly PM10 emissions = 0.5 times monthly erosion potential times surface area for each area of the pile.

The annual PM10 emissions in units of tons for each section of the pile is equal to 12 times the monthly PM10 emissions for each section of the pile divided by 454 g/lb and 2,000 lb/ton as follows:

Annual PM10 emissions for Area A = $(12 \times 7,907) / (454 \times 2,000) = 0.104$ tons

Annual PM10 emissions for Area B = $(12 \times 4,464) / (454 \times 2,000) = 0.059$ tons

Annual PM10 emissions for Area C = 0 tons

Annual PM10 emissions for storage pile = $0.104 + 0.059 + 0 = 0.163$ tons

Annual PM2.5 Emissions = $0.15 \times \text{PM10 Emissions}^{11} = 0.15 \times 0.163 = 0.025$ tons

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

Controlled emissions = Uncontrolled emissions x (1 – Control Efficiency)

For this example we have selected a 3-sided enclosure as our control measure with a control efficiency of 74.7%. Thus, the annual controlled PM10 and PM2.5 emissions estimates are calculated to be:

Annual Controlled PM10 emissions = $(0.163 \text{ tons/yr}) \times (1 - 0.747) = 0.041$ tons

Annual Controlled PM2.5 emissions = $(0.025 \text{ tons/yr}) \times (1 - 0.747) = 0.006$ tons

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	2,000
Annual Operating/Maintenance costs (\$)	400
Annual Interest Rate	3%
Capital Recovery Factor	0.1172
Annualized Cost (\$/yr)	634

The Capital costs, Annual Operating/Maintenance (O & M) costs and Annual Interest Rate (AIR) are assumed values for illustrative purposes.

The Capital Recovery Factor (CRF) is calculated as follows:

$$\text{Capital Recovery Factor} = \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1$$

$$\text{Capital Recovery Factor} = 3\% \times (1 + 3\%)^{10} / (1 + 3\%)^{10} - 1 = 0.1172$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor and the Capital costs to the annual O & M costs as follows:

$$\text{Annualized Cost} = (\text{CRF} \times \text{Capital costs}) + \text{O \& M costs}$$

$$\text{Annualized Cost} = (0.1172 \times 2,000) + \$400 = \$634$$

Step 6. Calculate Cost Effectiveness. Cost effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost effectiveness for PM}_{10} \text{ emissions} = \$634 / (0.163 - 0.041) = \$5,195/\text{ton}$$

$$\text{Cost effectiveness for PM}_{2.5} \text{ emissions} = \$634 / (0.025 - 0.006) = \$34,635/\text{ton}$$

9.8 References

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Chapter 10. Agricultural Harvesting

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10.1 Characterization of Source Emissions

Harvesting emissions are generated by three different operations: crop handling by the harvest machine, loading of the harvested crop into trailers or trucks, and transport by trailers or trucks in the field. Emissions from these operations are in the form of solid particulates composed mainly of raw plant material and soil dust that is entrained into the air. These emissions may simply be due to the vehicles traveling over the soil, or via the mechanical processing of the plant material and underlying soil, or, as in the case of almonds, via the actual blowing or sweeping of the crop to remove waste materials and position it for pickup. Defoliant and/or desiccants are used on some crops several weeks before harvesting which can produce PM emissions from the drifting of these chemicals equal to about 1% of the product applied on the crop.¹

10.2 EPA's Emission Estimation Methodology

Section 9 of EPA's Compilation of Air Pollutant Emission Factors (AP-42) addresses emission factors for mechanical harvesting of three different crops (cotton, wheat and sorghum). This section of AP-42 was last updated in February 1980. However, it does not list TSP or PM10 emission factors for agricultural harvesting. Instead it lists PM7 emission factors for the three crops expressed in units of pounds per square mile for crop handling by the harvest machine, loading of the harvested crop into trailers or trucks, and transport by trailers or trucks in the field. The sum of the PM7 emission factor for these three separate operations total 0.0086 lb/acre for mechanical picking of cotton, 0.041 lb/acre for mechanical stripping of cotton, 0.0027 lb/acre for wheat, and 0.012 lb/acre for sorghum.¹ The PM7 emission factors for harvesting cotton are based on an average machine speed of 3 mph for pickers and 5 mph for strippers, a basket capacity of 240 lb, a trailer capacity of 6 baskets, a lint cotton yield of 1.17 bales/acre for pickers and 0.77 bales/acre for strippers, and a transport speed of 10 mph. The weighted average stripping factors assumes that 2% of all strippers are 4-row models with baskets and, of the remainder, 40% are 2-row models pulling trailers and 60% are 2-row models with mounted baskets. The PM7 emission factors for harvesting wheat and sorghum are based on an average combine speed of 7.5 mph, a combine swath width of 20 feet, a field transport speed of 10 mph, a truck loading time of 6 minutes, a truck capacity of 13 acres for wheat and 7 acres for sorghum, and a filled truck travel time of 2 minutes per load. These AP-42 PM7 emission factors developed more than 25 years ago for the entire US are much lower than CARB's PM10 emission factors developed in early 2003 for California.

10.3 CARB's Emission Estimation Methodology

This section was adapted from Section 7.5 of CARB's Emission Inventory Methodology. Section 7.5 was last updated in January 2003.

The California Air Resources Board (CARB) has published a PM10 emission estimation method for fugitive dust emissions originating from agricultural harvesting

operations.² Unlike the soil preparations activities (e.g., disking, tilling, etc.), harvest operations tend to be fairly unique for each crop. Because of this, harvest emission factors combine all of the operations that go into harvesting a commodity into a single factor that includes emissions from all of the relevant operations. PM10 emission factors have been measured in California by UC Davis for harvesting cotton, almonds and wheat.³ These emission factors are shown in Table 10-1. Using these emission factors as a baseline, harvesting emission factors were assigned to other major crops grown in California in consultation with agricultural experts. These PM10 emission factors are also included in Table 10-1.

Table 10-1. Harvesting PM10 Emission Factors

Crop	PM 10 Emission Factor (lbs/acre)
Almonds	40.8
Corn	1.7 ^a
Cotton	3.4
Fruit trees	0.085 ^b
Onions	1.7 ^a
Potatoes	1.7 ^a
Sugar beets	1.7 ^a
Tomatoes	0.17 ^c
Vine crops	0.17 ^c
Walnuts	40.8 ^d
Wheat	5.8

^a EF = 50% EF for cotton

^b EF = 2.5% EF for cotton

^c EF = 5% EF for cotton

^d EF = same EF as almonds

UC Davis has recently completed a study measuring PM10 emissions from almond harvesting that indicates that CARB's PM10 emission factor for almond harvesting may be over-estimated by 62%.⁴ The complete list of harvesting emission factors assigned to over 200 crops is presented in Attachment 10-1 at the end of this chapter. The acreage data used for estimating harvest emissions for different crops are available from each state's Department of Food and Agriculture as well as from individual county agricultural commissioner reports.

Crop Calendar and Temporal Activity. Harvesting is performed at very specific times each year, so crop calendar data, which tells when harvest activities occur, is important. Temporal activity for harvesting is derived by summing, for each county, the monthly emissions from all crops. For each crop, the monthly emissions are calculated based on its monthly profile, which reflects the percentage of harvesting activities occurring in that month. An example of the monthly harvesting profile for almonds, cotton, and wheat is shown in Table 10-2. Because the mix of crops varies by county, composite temporal profiles combining all of the other county crops vary by county. An example of a composite harvesting profile by month for Fresno County, showing the combined temporal profile for all of the harvesting activities in the county, is shown in Table 10-3.

Table 10-2. Sample Monthly Harvesting Profile of Crops

Crops	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Almonds	0	0	0	0	0	0	0	0	50	50	0	0
Cotton	0	0	0	0	0	0	0	0	0	50	50	0
Wheat	0	0	0	0	0	50	50	0	0	0	0	0

Table 10-3. Sample County Harvesting Profile Composite

County	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Fresno	0.1	0.1	0.2	0.2	0.1	5.6	5.9	0.8	30.7	42.8	13.6	0.1

Assumptions. The CARB methodology is subject to the following assumptions:

1. The current harvest emission factors assume that for each crop, harvesting produces the same level emissions under all conditions for all equipment.
2. The emission factors for crops other than almonds, cotton, and wheat were assigned to reflect the relative geologic PM10 generation potential of various harvest practices.
3. Crop calendar data collected for San Joaquin Valley crops and practices were extrapolated to the same crops in the remainder of California.

PM2.5 Emission Factors. In July 2006, EPA revised the PM2.5/PM10 ratios listed in AP-42 for fugitive dust resulting from different fugitive dust source categories based on MRI's controlled laboratory experiments conducted for WRAP in 2005.⁵ The revised PM2.5/PM10 ratios range from 0.1 for unpaved roads to 0.15 for paved roads, wind erosion, and transfer of aggregate material. CARB is considering adopting a PM2.5/PM10 ratio of 0.15 for both agricultural tilling and agricultural tilling based on MRI's findings.⁶

10.4 Demonstrated Control Techniques

Soil dust emissions from field transport can be reduced by lowering vehicle speed. Also, the use of terraces, contouring, and strip cropping to inhibit soil erosion will suppress the entrainment of harvested crop fragments in the wind. Shelterbelts, positioned perpendicular to the prevailing wind, will lower emissions by reducing the wind velocity across the field. By minimizing tillage and avoiding residue burning, the soil will remain consolidated and less prone to disturbance from transport activities.

Table 10-4 summarizes tested control measures and reported control efficiencies for measures that reduce the generation of fugitive dust from agricultural harvesting.⁷⁻⁹ A list of control measures for agricultural harvesting operations is available from the California Air Pollution Control Officers' Association's (CAPCOA) agricultural clearing house website (http://capcoa.org/ag_clearinghouse.htm). The list of control measures for harvesting field and orchard crops include: the use of balers to harvest crops that are traditionally harvested by chopping, new drying techniques for dried fruit, increasing equipment size to reduce the number of passes, fallowing land, green chop (i.e., harvesting a forage crop without allowing it to dry in the field), hand harvesting, night harvesting, switch to a crop that requires no waste/residue burning, applying a light

amount of water or other stabilizing material to the soil prior to harvest, packing commodities in an enclosed area, and utilizing a shuttle system to haul multiple trailers per trip.

Table 10-4. Control Efficiencies for Control Measures for Harvesting⁷⁻⁹

Control Measure	PM10 Control Efficiency	References / Comments
Equipment modification	50%	MRI, 1981. Control efficiency is for electrostatically charged fine-mist water spray.
Land set-aside/fallowing	100%	SJVAPCD, 2003.
Limited activity during high winds	5 - 70%	URS, 2001. Emissions reduction depends on wind speed.
Night farming	10%	SJVAPCD, 2003. Harvest when humidity and soil moisture is higher than during day.
New techniques for drying fruit		
Continuous tray	25%	SJVAPCD, 2003.
Dried on vine (DOV)	60%	
Precision farming	8%	SJVAPCD, 2003. Use of GPS system.
Reduced harvest activity	29 – 71 %	URS, 2001. Applicable to cotton, alfalfa, hay.
Soil moisture monitoring	30%	URS, 2001.

10.5 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. However, most air quality districts currently exempt agricultural operations from controlling fugitive dust. Air quality districts that regulate fugitive dust emissions from agricultural harvesting include Clark County, NV and several districts in California such as the Imperial County APCD, the San Joaquin Valley APCD and the South Coast AQMD. Imperial County APCD prohibits fugitive dust emissions from farming activities for farms over 40 acres. The San Joaquin Valley APCD and the South Coast AQMD prohibit fugitive dust emissions for the larger farms defined as farms with areas where the combined disturbed surface area within one continuous property line and not separated by a paved public road is greater than 10 acres. Example regulatory formats downloaded from the Internet are presented in Table 10-5. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- San Joaquin Valley APCD, CA: valleyair.org/SJV_main.asp
- South Coast AQMD, CA: aqmd.gov/rules
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/aq

CAPCOA's agricultural clearing house website (http://capcoa.org/ag_clearinghouse.htm) provides links to rules of different air quality agencies that regulate fugitive dust emissions from agricultural operations.

Table 10-5. Example Regulatory Formats for Harvesting

Control Measure	Agency
Any person engaged in agricultural operations shall take all reasonable precautions to abate fugitive dust from becoming airborne from such activities.	Clark County Reg. 41 7/01/04
Limit fugitive dust from off-field agricultural sources such as unpaved roads with more than 75 trips/day and bulk materials handling by requiring producers to develop and implement a Fugitive Dust Management Plan with district approved control methods.	SJVAPCD Rule 8081 11/15/01
Cease activities when wind speeds are greater than 25 mph.	SCAQMD Rule 403.1 4/02/04

10.6 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 10-6 summarizes the compliance tools that are applicable for harvesting.

Table 10-6. Compliance Tools for Harvesting

Record keeping	Site inspection/monitoring
Maintain daily records to document the specific dust control options taken; maintain such records for a period of not less than three years; and make such records available to the Executive Officer upon request.	Observation of dust plumes during periods of agricultural harvesting; observation of dust plume opacity (visible emissions) exceeding a standard; observation of high winds (e.g., >25 mph).

10.7 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for agricultural harvesting. A sample cost-effectiveness calculation is presented below for a specific control measure (precision farming utilizing a GPS system) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for agricultural harvesting, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Agricultural Harvesting

Step 1. Determine source activity and control application parameters.

Field size (acres)	320
Crop	Cotton
Frequency of operations per year	2 (picking & stalk cutting)
Control Measure	Precision farming
Control application/frequency	Reduce overlap of passes by 8%
Economic Life of Control System (yr)	5
Control Efficiency	8%

Precision farming utilizing a GPS system has been chosen as the applied control measure. The field size, frequency of operations, and control application/frequency are assumed values for illustrative purposes. The economic life of the control is determined from industrial records. The control efficiency of 8% is based on the proportional reduction in passes to harvest the cotton and cut the stalks after harvesting the cotton (SJVAPCD, 2003).⁸

Step 2. PM10 Emission Factor.

The PM10 emission factor for harvesting cotton includes the emissions from picking the cotton plus the emissions from cutting the stalks after picking the cotton. The PM10 emission factor for each operation is 1.7 lb/acre.²

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor, EF, (given in Step 2) is multiplied by the field size and the frequency of operations (both under activity data) and then divided by 2,000 lbs to compute the annual PM10 emissions in tons per year, as follows:

$$\text{Annual PM10 emissions} = (\text{EF} \times \text{Field Size} \times \text{Frequency of Ops}) / 2,000$$

- Annual PM10 Emissions = $(1.7 \times 320 \times 2) / 2,000 = 0.544$ tons

$$\text{Annual PM2.5 emissions} = (\text{PM2.5/PM10}) \times \text{PM10 emissions}$$

Assume PM2.5/PM10 ratio for agricultural harvesting is 0.15 (MRI, 2006).⁶

$$\text{Annual PM2.5 emissions} = 0.15 \times \text{PM10 emissions}$$

- Annual PM2.5 Emissions = $(0.15 \times 0.544 \text{ tons}) = 0.0816$ tons

Step 4. Calculate Controlled PM Emissions. The uncontrolled emissions (calculated in Step 3) are multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency})$$

For this example, we have selected precision farming as our control measure. Based on a control efficiency estimate of 8%, the annual controlled PM emissions are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM}_{10} \text{ emissions} &= (0.544 \text{ tons}) \times (1 - 0.08) = 0.500 \text{ tons} \\ \text{Annual Controlled PM}_{2.5} \text{ emissions} &= (0.0816 \text{ tons}) \times (1 - 0.08) = 0.075 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

The Annualized Cost of control is calculated by subtracting the cost savings from reducing the overlap of harvesting passes by 8% from the annualized cost of purchasing the GPS system.

Assuming that the cost of harvesting is equivalent to that of tilling, namely \$10/acre (WSU, 1998¹⁰), the cost savings using GPS precision farming is \$512 (i.e., $0.08 \times 320 \text{ acres} \times \$10/\text{acre} \times 2 \text{ harvesting passes}$ [i.e., one pass to harvest the cotton and a second pass to cut the stalks]).

GPS systems range in cost from \$200 to \$5,000 and have a lifetime of approximately five years (SJVAPCD, 2003⁸). Using an estimate of \$1,000 and an economic life (EL) of five years for the GPS system together with an annual interest rate (AIR) of 5%, the annualized cost of the GPS system is calculated by adding the product of the Capital Recovery Factor (CRF) and the capital costs to the annual operating and maintenance costs, which for this example are assumed to be \$200 per year.

The Capital Recovery Factor (CRF) is calculated as follows:

$$\text{CRF} = \text{AIR} \times (1 + \text{AIR})^{\text{EL}} / [(1 + \text{AIR})^{\text{EL}} - 1]$$

$$\text{CRF} = 5\% \times (1 + 5\%)^5 / [(1 + 5\%)^5 - 1] = 0.231$$

$$\text{Annualized capital cost} = \text{CRF} \times \text{capital cost} = 0.231 \times \$1,000 = \$231$$

$$\text{Annual cost of GPS system} = \text{Annualized capital costs} + \text{Annual O \& M costs}$$

$$\text{Annual cost of GPS system} = \$231 + \$200 = \$431$$

Annualized cost of control measure = Annual cost of GPS system minus the cost savings from reducing the overlap of harvesting passes

$$\text{Annualized Cost} = \$431 - \$512 = -\$81$$

The annualized cost is negative and represents a net savings.

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost-effectiveness for PM}_{10} \text{ emissions} = -\$81 / (0.544 - 0.500) = -\$1,862/\text{ton}$$

$$\text{Cost-effectiveness for PM}_{2.5} \text{ emissions} = -\$81 / (0.0816 - 0.075) = -\$12,412/\text{ton}$$

The negative cost-effectiveness values indicate cost savings.

10.8 References

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10.9 Attachment 10-1. PM10 Emission Factors for Harvesting Crops in CA

Crop Description	Crop Profile	Assumption	PM10 Emission Factor (lb/acre)
ALMOND HULLS	Almonds	Almonds/1	40.77
ALMONDS, ALL	Almonds	Almonds/1	40.77
ANISE (FENNEL)	Lettuce	Cotton/2	1.68
APPLES, ALL	Citrus	Cotton/40	0.08
APRICOTS, ALL	Citrus	Cotton/40	0.08
ARTICHOKES	Melon	Cotton/40	0.08
ASPARAGUS, FRESH MKT	Melon	Cotton/2	1.68
ASPARAGUS, PROC	Melon	Cotton/2	1.68
ASPARAGUS, UNSPECIFIED	Melon	Cotton/2	1.68
AVOCADOS, ALL	Citrus	Cotton/40	0.08
BARLEY, FEED	Wheat	Wheat/1	5.8
BARLEY, MALTING	Wheat	Wheat/1	5.8
BARLEY, UNSPECIFIED	Wheat	Wheat/1	5.8
BEANS FRESH UNSPECIFIED	Dry Beans	Cotton/20	0.17
BEANS, BLACKEYE (PEAS)	Dry Beans	Cotton/2	1.68
BEANS, FAVA	Dry Beans	Cotton/2	1.68
BEANS, GARBANZO	Garbanzo	Cotton/2	1.68
BEANS, GREEN LIMAS	Dry Beans	Cotton/2	1.68
BEANS, LIMAS, BABY DRY	Dry Beans	Cotton/2	1.68
BEANS, LIMAS, LG. DRY	Dry Beans	Cotton/2	1.68
BEANS, PINK	Dry Beans	Cotton/2	1.68
BEANS, RED KIDNEY	Dry Beans	Cotton/2	1.68
BEANS, SNAP FR MKT	Dry Beans	Cotton/20	0.17
BEANS, SNAP PROC	Dry Beans	Cotton/20	0.17
BEANS, UNSPECIFIED SNAP	Dry Beans	Cotton/20	0.17
BEANS, UNSPEC. DRY EDIBLE	Dry Beans	Cotton/2	1.68
BEETS, GARDEN	Sugar Beets	Cotton/2	1.68
BERRIES, BLACKBERRIES	Grapes-Table	Cotton/40	0.08
BERRIES, BOYSENBERRIES	Grapes-Table	Cotton/40	0.08
BERRIES, BUSH, UNSPECIFIED	Grapes-Table	Cotton/40	0.08
BERRIES, LOGANBERRIES	Grapes-Table	Cotton/40	0.08
BERRIES, RASPBERRIES	Grapes-Table	Cotton/40	0.08
BROCCOLI, FR MKT	Vegetables	Cotton/40	0.08
BROCCOLI, PROC	Vegetables	Cotton/40	0.08
BROCCOLI, UNSPECIFIED	Vegetables	Cotton/40	0.08
BROCCOLI, FOOD SERV	Vegetables	Cotton/40	0.08
BRUSSELS SPROUTS	Melon	Cotton/40	0.08
CABBAGE, CH. & SPECIALTY	Lettuce	Cotton/40	0.08
CABBAGE, HEAD	Lettuce	Cotton/40	0.08
CARROTS, FOOD SERV	Sugar Beets	Cotton/20	0.17
CARROTS, FR MKT	Sugar Beets	Cotton/20	0.17
CARROTS, PROC	Sugar Beets	Cotton/20	0.17
CARROTS, UNSPECIFIED	Sugar Beets	Cotton/20	0.17
CAULIFLOWER, FOOD SERV	Vegetables	Cotton/40	0.08

Crop Description	Crop Profile	Assumption	PM10 Emission Factor (lb/acre)
CAULIFLOWER, FR MKT	Vegetables	Cotton/40	0.08
CAULIFLOWER, PROC	Vegetables	Cotton/40	0.08
CAULIFLOWER, UNSPECIFIED	Vegetables	Cotton/40	0.08
CELERY, FOOD SERV	Lettuce	Cotton/40	0.08
CELERY, FR MKT	Lettuce	Cotton/40	0.08
CELERY, PROC	Lettuce	Cotton/40	0.08
CELERY, UNSPECIFIED	Lettuce	Cotton/40	0.08
CHERIMOYAS	Citrus	Cotton/40	0.08
CHERRIES, SWEET	Citrus	Cotton/40	0.08
CHESTNUTS	Almonds	Almonds/10	4.08
CHIVES	Lettuce	Cotton/40	0.08
CILANTRO	Lettuce	Cotton/40	0.08
CITRUS, MISC BY-PROD	Citrus	Cotton/40	0.08
CITRUS, UNSPECIFIED	Citrus	Cotton/40	0.08
CLOVER, UNSPECIFIED SEED	Alfalfa	Alfalfa/1	0
COLLARD GREENS	Lettuce	Cotton/40	0.08
CORN FOR GRAIN	Corn	Cotton/2	1.68
CORN FOR SILAGE	Corn	Cotton/20	0.17
CORN, SWEET ALL	Corn	Cotton/40	0.08
CORN, WHITE	Corn	Cotton/40	0.08
COTTON LINT, PIMA	Cotton	Cotton/1	3.37
COTTON LINT, UNSPEC	Cotton	Cotton/1	3.37
COTTON LINT, UPLAND	Cotton	Cotton/1	3.37
COTTONSEED	Cotton	Cotton/1	3.37
CUCUMBERS	Vegetables	Cotton/40	0.08
CUCUMBERS, GREENHOUSE	No Land Prep	Zero/1	0
DATES	Citrus	Almonds/20	2.04
EGGPLANT, ALL	Vegetables	Cotton/40	0.08
ENDIVE, ALL	Lettuce	Cotton/40	0.08
ESCAROLE, ALL	Lettuce	Cotton/40	0.08
FIELD CROP BY PRODUCTS	Cotton	Cotton/20	0.17
FIELD CROPS, UNSPEC.	Corn	Cotton/20	0.17
FIGS, DRIED	Citrus	Almonds/20	2.04
FOOD GRAINS, MISC	Corn	Cotton/2	1.68
FRUITS & NUTS, UNSPEC.	Citrus	Cotton/40	0.08
GARLIC, ALL	Garlic	Cotton/2	1.68
GRAPEFRUIT, ALL	Citrus	Cotton/40	0.08
GRAPES, RAISIN	Grapes-Raisin	Cotton/20	0.17
GRAPES, TABLE	Grapes-Table	Cotton/20	0.17
GRAPES, UNSPECIFIED	Grapes-Wine	Cotton/20	0.17
GRAPES, WINE	Grapes-Wine	Cotton/20	0.17
GREENS, TURNIP & MUSTARD	Lettuce	Cotton/40	0.08
GUAVAS	Citrus	Cotton/40	0.08
HAY, ALFALFA	Alfalfa	Alfalfa/1	0
HAY, GRAIN	Alfalfa	Cotton/2	1.68
HAY, GREEN CHOP	Alfalfa	Alfalfa/1	0

Crop Description	Crop Profile	Assumption	PM10 Emission Factor (lb/acre)
HAY, OTHER UNSPECIFIED	Alfalfa	Cotton/2	1.68
HAY, SUDAN	Alfalfa	Alfalfa/1	0
HAY, WILD	Alfalfa	Cotton/2	1.68
HORSERADISH	Onions	Cotton/40	0.08
JOJOBA	Melon	Cotton/40	0.08
KALE	Lettuce	Cotton/40	0.08
KIWIFRUIT	Citrus	Cotton/40	0.08
KOHLRABI	Lettuce	Cotton/40	0.08
KUMQUATS	Citrus	Cotton/40	0.08
LEEKs	Onions	Cotton/40	0.08
LEMONS, ALL	Citrus	Cotton/40	0.08
LETTUCE, BULK SALAD PRODS.	Lettuce	Cotton/40	0.08
LETTUCE, HEAD	Lettuce	Cotton/40	0.08
LETTUCE, LEAF	Lettuce	Cotton/40	0.08
LETTUCE, ROMAINE	Lettuce	Cotton/40	0.08
LETTUCE, UNSPECIFIED	Lettuce	Cotton/40	0.08
LIMA BEANS, UNSPECIFIED	Dry Beans	Cotton/2	1.68
LIMES, ALL	Citrus	Cotton/40	0.08
MACADAMIA NUT	Almonds	Almonds/10	4.08
MELON, CANTALOUPE	Melon	Cotton/40	0.08
MELON, HONEYDEW	Melon	Cotton/40	0.08
MELON, UNSPECIFIED	Melon	Cotton/40	0.08
MELON, WATER MELONS	Melon	Cotton/40	0.08
MUSHROOMS	No Land Prep	Zero/1	0
MUSTARD	Lettuce	Cotton/40	0.08
NECTARINES	Citrus	Cotton/40	0.08
NURSERY TURF	No Land Prep	Zero/1	0
OATS FOR GRAIN	Wheat	Wheat/1	5.8
OKRA	Lettuce	Cotton/40	0.08
OLIVES	Citrus	Cotton/40	0.08
ONIONS	Onions	Cotton/2	1.68
ONIONS, GREEN & SHALLOTS	Onions	Cotton/40	0.08
ORANGES, NAVEL	Citrus	Cotton/40	0.08
ORANGES, UNSPECIFIED	Citrus	Cotton/40	0.08
ORANGES, VALENCIAS	Citrus	Cotton/40	0.08
ORCHARD BIOMASS	Almonds	Cotton/40	0.08
PARSLEY	Lettuce	Cotton/40	0.08
PASTURE, IRRIGATED	No Land Prep	Zero/1	0
PASTURE, MISC. FORAGE	No Land Prep	Zero/1	0
PASTURE, RANGE	No Land Prep	Zero/1	0
PEACHES, CLINGSTONE	Citrus	Cotton/40	0.08
PEACHES, FREESTONE	Citrus	Cotton/40	0.08
PEACHES, UNSPECIFIED	Citrus	Cotton/40	0.08
PEANUTS, ALL	Safflower	Cotton/2	1.68
PEARS, ASIAN	Citrus	Cotton/40	0.08
PEARS, BARLETT	Citrus	Cotton/40	0.08

Crop Description	Crop Profile	Assumption	PM10 Emission Factor (lb/acre)
PEARS, UNSPECIFIED	Citrus	Cotton/40	0.08
PEAS, DRY EDIBLE	Dry Beans	Cotton/20	0.17
PEAS, EDIBLE POD (SNOW)	Dry Beans	Cotton/20	0.17
PEAS, GREEN, PROCESSING	Dry Beans	Cotton/20	0.17
PEAS, GREEN, UNSPECIFIED	Dry Beans	Cotton/20	0.17
PECANS	Almonds	Almonds/10	4.08
PEPPERS, BELL	Tomatoes	Cotton/40	0.08
PEPPERS, CHILI, HOT	Tomatoes	Cotton/40	0.08
PERSIMMONS	Citrus	Cotton/40	0.08
PISTACHIOS	Almonds	Almonds/10	4.08
PLUMCOTS	Citrus	Cotton/40	0.08
PLUMS	Citrus	Cotton/40	0.08
POMEGRANATES	Citrus	Cotton/40	0.08
POTATOES SEED	Sugar Beets	Cotton/2	1.68
POTATOES, IRISH ALL	Sugar Beets	Cotton/2	1.68
PRUNES, DRIED	Citrus	Cotton/40	0.08
PUMPKINS	Melon	Cotton/20	0.17
QUINCE	Citrus	Cotton/40	0.08
RADICCHIO	Lettuce	Cotton/40	0.08
RADISHES	Sugar Beets	Cotton/40	0.08
RAPINI	Sugar Beets	Cotton/40	0.08
RHUBARB	Lettuce	Cotton/40	0.08
RICE, FOR MILLING	Rice	Cotton/2	1.68
RICE, WILD	Rice	Cotton/2	1.68
RUTABAGAS	Sugar Beets	Cotton/2	1.68
RYE FOR GRAIN	Wheat	Wheat/1	5.8
SAFFLOWER	Safflower	Wheat/1	5.8
SALAD GREENS NEC	Lettuce	Cotton/40	0.08
SEED BARLEY	Wheat	Wheat/1	5.8
SEED BEANS	Dry Beans	Cotton/2	1.68
SEED OATS	Wheat	Wheat/1	5.8
SEED PEAS	Dry Beans	Cotton/20	0.17
SEED RICE	Rice	Cotton/2	1.68
SEED RYE	Wheat	Wheat/1	5.8
SEED WHEAT	Wheat	Wheat/1	5.8
SEED, ALFALFA	Alfalfa	Alfalfa/1	0
SEED, BERMUDA GRASS	Alfalfa	Alfalfa/1	0
SEED, COTTON FOR PLANTING	Cotton	Cotton/1	3.37
SEED, GRASS, UNSPECIFIED	Alfalfa	Alfalfa/1	0
SEED, MISC FIELD CROP	Corn	Cotton/20	0.17
SEED, OTHER (NO FLOWERS)	Alfalfa	Cotton/20	0.17
SEED, SAFFLOWER, PLANTING	Safflower	Wheat/1	5.8
SEED, SUDAN GRASS	Alfalfa	Alfalfa/1	0
SEED, VEG & VINECROP	Vegetables	Cotton/20	0.17
SILAGE	Wheat	Cotton/20	0.17
SORGHUM, GRAIN	Wheat	Wheat/1	5.8

Crop Description	Crop Profile	Assumption	PM10 Emission Factor (lb/acre)
SPICES AND HERBS	Lettuce	Cotton/40	0.08
SPINACH UNSPECIFIED	Lettuce	Cotton/40	0.08
SPINACH, FOOD SERV	Lettuce	Cotton/40	0.08
SPINACH, FR MKT	Lettuce	Cotton/40	0.08
SPINACH, PROC	Lettuce	Cotton/40	0.08
SPROUTS, ALFALFA & BEAN	Lettuce	Cotton/40	0.08
SQUASH	Melon	Cotton/20	0.17
STRAW	Alfalfa	Wheat/1	5.8
STRAWBERRIES, FRESH MKT	Melon	Cotton/40	0.08
STRAWBERRIES, PROC	Melon	Cotton/40	0.08
STRAWBERRIES, UNSPECIFIED	Melon	Cotton/40	0.08
SUGAR BEETS	Sugar Beets	Cotton/2	1.68
SUNFLOWER SEED	Corn	Wheat/1	5.8
SUNFLOWER SEED, PLANTING	Corn	Wheat/1	5.8
SWEET POTATOES	Sugar Beets	Cotton/2	1.68
SWISSCHARD	Lettuce	Cotton/40	0.08
TANGELOS	Citrus	Cotton/40	0.08
TANGERINES & MANDARINS	Citrus	Cotton/40	0.08
TOMATILLO	Tomatoes	Cotton/40	0.08
TOMATOES, CHERRY	Tomatoes	Cotton/40	0.08
TOMATOES, FRESH MARKET	Tomatoes	Cotton/40	0.08
TOMATOES, GREENHOUSE	No Land Prep	Zero/1	0
TOMATOES, PROCESSING	Tomatoes	Cotton/20	0.17
TOMATOES, UNSPECIFIED	Tomatoes	Cotton/20	0.17
TURNIPS, ALL	Sugar Beets	Cotton/2	1.68
VEGETABLES, BABY	Vegetables	Cotton/40	0.08
VEGETABLES, ORIENTAL, ALL	Vegetables	Cotton/40	0.08
VEGETABLES, UNSPECIFIED	Vegetables	Cotton/20	0.17
WALNUTS, BLACK	Almonds	Almonds/1	40.77
WALNUTS, ENGLISH	Almonds	Almonds/1	40.77
WHEAT ALL	Wheat	Wheat/1	5.8

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11.1 Characterization of Source Emissions

This chapter of the handbook addresses fugitive dust emissions from mineral products industries that involve the production and processing of various ores, as discussed in Chapter 11 of AP-42¹. In the mineral products industry, there are two major categories of emissions: ducted sources (those vented to the atmosphere through some type of stack, vent, or pipe), and fugitive sources (those not confined to ducts and vents but emitted directly from the source to the ambient air). Ducted emissions are usually collected and transported by an industrial ventilation system having one or more fans or air movers, eventually to be emitted to the atmosphere through some type of stack.

Many operations and processes are common to all mineral products industries, including extraction of aggregate materials from the earth, loading, unloading, conveying, crushing, screening, loadout, and storage. Other operations are restricted to specific industries. These include wet and dry fine milling or grinding, air classification, drying, calcining, mixing, and bagging. Sand and gravel is typically mined in a moist or wet condition such that negligible particulate emissions occur during the mining operation. Construction aggregate processing can produce large amounts of fugitive dust, which due to its generally larger particle sizes tends to settle out within the plant. Some of the individual operations such as wet crushing and grinding, washing, screening, and dredging take place with high moisture content (>4% by weight). Such wet processes do not generate appreciable particulate emissions. For those processing and manufacturing operations that are housed in enclosed buildings with the dust captured by a control device (e.g., product recovery cyclones, fabric filters, and wet scrubber/suppression systems), no uncontrolled fugitive dust emissions are emitted directly into the outdoor air.

The operations at a typical western surface coal mine include drilling and blasting, removal of the overburden with a dragline or shovel, loading trucks, bulldozing and grading, crushing, vehicle traffic, and storage of coal in active storage piles that are subject to wind erosion. All operations that involve movement of soil or coal, or exposure of erodible surfaces, generate some amount of fugitive dust. During mine reclamation, which proceeds continuously throughout the life of the mine, overburden spoils piles are smoothed and contoured by bulldozers. Topsoil is placed on the graded spoils, and the land is prepared for revegetation by furrowing and mulching. From the time an area is disturbed until the new vegetation emerges, all disturbed areas are subject to wind erosion.

11.2 Emission Estimation Methodology

This section was adapted from EPA's documentation of methods used for the National Emission Inventory (NEI)² and from Section 11, Mineral Products Industry, of EPA's *Compilation of Air Pollutant Emission Factors (AP-42)*.¹ Many of the categories addressed in AP-42 have not been updated by the EPA since the mid to late 1990's.

This section addresses three different mineral categories: (a) metallic ores (b) non-metallic ores and rock, and (c) coal. Fugitive dust emission factors for mining and quarrying activities are based on EPA's methodology used for the annual National

Emission Inventory that includes emissions from extraction of the ore or rock from the earth but not processing activities.² Fugitive dust emission factors for processing activities are taken from AP-42 and represent average values based on a number of tests made under a variety of conditions such as material silt content, moisture content, and wind speed. As such, the actual uncontrolled emission factors will vary depending upon actual site conditions.

The EPA methodology used to develop the annual National Emission Inventory (NEI) for fugitive PM10 dust emissions from mining and quarrying operations utilizes the sum of the emissions from the mining of metallic and nonmetallic ores and coal as well as rock quarrying, as follows:

$$E = E_m + E_n + E_c \quad (1)$$

where, E = PM10 emissions from mining and quarrying operations

E_m = PM10 emissions from metallic ore mining operations

E_n = PM10 emissions from non-metallic ore mining and rock quarrying operations

E_c = PM10 emissions from coal mining operations

The NEI PM10 emissions estimate for mining and rock quarrying operations involving extraction of ore or rock from the earth include three specific activities: (1) overburden removal, (2) drilling and blasting, and (3) loading and unloading. Ore processing activities that involve transfer and conveyance operations, crushing and screening operations, storage, and travel on haul roads are not included in the NEI emissions estimate since EPA assumes that the dust emissions from these activities are well controlled. Uncontrolled particulate emission factors for ore processing activities are presented in the subsections below for estimating fugitive dust emissions from these sources. Fugitive dust emissions from materials handling, travel on unpaved roads, and wind erosion of storage piles are addressed in Chapters 4, 6 and 9 of this handbook, respectively.

The NEI emissions estimation methodology assumes that the TSP emission factors developed for copper ore mining apply to the three activities listed above for all metallic ore mining. PM10 emission factors for each of these three activities for metallic ore mining are based on the following PM10/TSP ratios: 0.35 for overburden removal, 0.81 for drilling and blasting, and 0.43 for loading/unloading operations.³

In the NEI emission estimation methodology, non-metallic ore mining emissions are calculated by assuming that the PM10 emission factors for western surface coal mining apply to mining of all non-metallic ores. The PM10/TSP ratio for western surface coal mining is 0.40.⁴

Coal mining includes two additional sources of PM10 emissions compared to the sources considered for metallic and non-metallic ores, namely overburden replacement and truck loading and unloading of that overburden. EPA assumes that the amount of overburden material handled equals ten times the amount of coal mined.⁵

EPA Method 5 (or equivalent) source tests used to generate particulate emission factors include a filterable PM fraction that is captured on or prior to a filter and a condensable PM fraction that is collected in the impinger portion of the sampling train. PM emission factors presented below include the sum of the filterable and condensable PM fractions for those cases where information exists for both fractions. For those cases where information only exists for the filterable PM fraction, this is clearly identified in the text below.

Previous NEI PM emission inventories for fugitive dust from mineral products industries assumed a PM2.5/PM10 ratio of 0.29.² In July 2006 EPA adopted revised PM2.5/PM10 ratios for several fugitive dust source categories, including a ratio of 0.1 for heavy vehicle traffic on unpaved surfaces around aggregate storage piles and a ratio of 0.15 for transfer of aggregate associated with buckets or conveyors based on the recent findings of MRI.⁶ Thus, the PM2.5/PM10 ratio for fugitive dust from mineral products industries lies somewhere between 0.1 and 0.15.

Estimates of the amount of metallic and non-metallic ores handled at surface mines are available from the U.S. Geological Survey. Production figures for coal mining operations are available from the Energy Information Administration (EIA) in the U.S. Department of Energy.

11.2.1 Metallic Ores

EPA uses the following equation to calculate PM10 emissions from overburden removal, drilling and blasting, and loading and unloading from metallic ore mining operations:

$$E_m = A_m [EF_o + (B \times EF_b) + EF_l + EF_d] \quad (2)$$

where, A_m = metallic crude ore handled at surface mines (tons)

EF_o = PM10 open pit overburden removal emission factor for copper ore (lbs/ton)

B = fraction of total ore production that is obtained by blasting at metallic ore mines

EF_b = PM10 drilling/blasting emission factor for copper ore (lbs/ton)

EF_l = PM10 loading emission factor for copper ore (lbs/ton)

EF_d = PM10 truck dumping emission factor for copper ore (lbs/ton)

Utilizing the TSP emission factors and PM10/TSP ratios developed for copper ore mining operations, PM10 emissions from metallic ore mining operations are calculated as follows:

$$E_m = A_m [0.0003 + (0.57625 \times 0.0008) + 0.022 + 0.032] = 0.0548 A_m \quad (3)$$

Based on NEI's emission estimation methodology that excludes fugitive dust emissions from haul truck traffic on unpaved surfaces, PM10 emissions from loading and truck dumping account for 40% and 58%, respectively, of the total PM10 emissions from metallic ore mining operations.

Uncontrolled filterable TSP and PM10 emission factors for metallic ore processing operations are presented in Table 11-1. These emission factors are for emissions after product recovery cyclones. Uncontrolled PM emission factors for taconite ore processing are presented in Table 11-2.

Table 11-1. Filterable TSP and PM10 Emission Factors for Metallic Ore Processing^a

Source	TSP (lb/ton)	PM10 (lb/ton)
Low-moisture ores ^b		
Primary crushing	0.5	0.05
Secondary crushing	1.2	ND
Tertiary crushing	2.7	0.16
Material handling and transfer – all minerals except bauxite	0.12	0.06
Material handling and transfer – bauxite/alumina	1.1	ND
High-moisture ores ^b		
Primary crushing	0.02	0.009
Secondary crushing	0.05	0.02
Tertiary crushing	0.06	0.02
Material handling and transfer – all minerals except bauxite	0.01	0.004
Material handling and transfer – bauxite/alumina	ND	ND
Both low- and high-moisture ores ^b		
Wet grinding	Neg	Neg
Dry grinding with air conveying and/or air classification	28.8	26
Dry grinding without air conveying and/or air classification	2.4	0.31
Drying – all minerals except titanium/zirconium sands	19.7	12

^a Emission factors in units of lb/ton of material processed. One lb/ton is equivalent to 0.5 kg/Mg. Neg = negligible. ND = no data.

^b Low-moisture ore has a moisture content of less than 4% by weight; high-moisture ore has a moisture content of at least 4% by weight.

Table 11-2. TSP and PM10 Emission Factors for Taconite Ore Processing^a

Source	TSP (lb/ton)	PM10 (lb/ton)
Natural gas-fired grate/kiln	7.4	0.65
Gas-fired vertical shaft top gas stack	16	ND
Oil-fired straight grate	1.2	ND

^a Applicable to both acid pellets and flux pellets. Emission factors in units of lb/ton of fired pellets produced. One lb/ton is equivalent to 0.5 kg/Mg. ND = no data.

11.2.2 Non-metallic Ores

EPA uses the following equation to calculate the PM10 emissions from overburden removal, drilling and blasting, and loading and unloading from non-metallic ore mining and rock quarrying operations:

$$E_n = A_n [EF_v + (D \times EF_r) + EF_a + 0.5 (EF_e + EF_t)] \quad (4)$$

where, A_n = non-metallic crude ore handled at surface mines (tons)

EF_v = PM10 open pit overburden removal emission factor at western surface coal mining operations (lbs/ton)

- D = fraction of total ore production that is obtained by blasting at non-metallic ore mines
- EF_r = PM10 drilling/blasting emission factor at western surface coal mining operations (lbs/ton)
- EF_a = PM10 loading emission factor at western surface coal mining operations (lbs/ton)
- EF_e = PM-10 truck unloading: end dump-coal emission factor at western surface coal mining operations (lbs/ton)
- EF_t = PM10 truck unloading: bottom dump-coal emission factor at western surface coal mining operations (lbs/ton)

Utilizing the PM10 factors developed for western surface coal mining operations, PM10 emissions from non-metallic ore mining and rock quarrying operations are calculated as follows:

$$E_n = A_n [0.225 + (0.61542 \times 0.00005) + 0.05 + 0.5 (0.0035 + 0.033)] = 0.293 A_n \quad (5)$$

PM10 emissions from overburden removal account for 77% of the total PM10 emissions from non-metallic ore mining and rock quarrying operations.

Uncontrolled TSP and PM10 emission factors for non-metallic ore processing operations are presented in Table 11-3. The emission factors for mixer loading and truck loading for concrete batching operations were updated in June 2006.⁷ These new AP-42 emission factors are approximately double the previous emission factors. Excluding road dust and windblown dust, the plant wide PM10 emission factors per yard of concrete for an average concrete batch formulation at a typical facility are 0.058 lb/yd³ for truck mix concrete and 0.037 lb/yd³ for central mix concrete.

Table 11-3. TSP and PM10 Emission Factors for Non-metallic Ore Processing Operations^a

Industry	Source	TSP (lb/ton)	PM10 (lb/ton)
Sand and Gravel	Sand Dryer	2.0	ND
Crushed Stone	Tertiary crushing ^b	0.0054	0.0024
	Fines crushing	0.039	0.0150
	Screening	0.025	0.0087
	Fines screening	0.30	0.072
	Conveyor transfer point	0.0030	0.0011
	Wet drilling – unfragmented stone	ND	8.0×10^{-5}
	Truck unloading – fragmented stone	ND	1.6×10^{-5}
	Truck unloading – conveyor, crushed stone	ND	1.0×10^{-4}
Lightweight Aggregate	Rotary Kiln	131	ND
Concrete Batching	Aggregate transfer	0.0069	0.0033
	Sand transfer	0.0021	0.00099
	Cement unloading to storage silo	0.72	0.46
	Cement supplement unloading to silo	3.14	1.10
	Weigh hopper loading	0.0051	0.0024
	Mixer loading (central mix) ^c	0.524	0.156
	Truck loading (truck mix) ^c	1.122	0.311
Phosphate Rock	Dryer	5.7	4.8
	Grinder	1.5	ND
	Calciner	15	14.4
Kaolin ^d	Apron dryer	1.2	ND
	Multiple hearth furnace	34	16
	Flash calciner	1,100	560
Fire Clay ^d	Rotary dryer	65	16
	Rotary calciner	120	30
Bentonite ^d	Rotary dryer	290	20
Talc	Railcar unloading	0.00098	ND
Brick Manufacturing	Grinding and screening wet material ^e	0.025	0.0023
	Grinding and screening dry material ^f	8.5	0.53
	Brick dryer	0.077	ND
	Natural gas-fired kiln	0.96	0.87
	Coal-fired kiln	1.79	1.35
	Sawdust-fired kiln	0.93	0.85
	Sawdust-fired kiln and sawdust dryer	1.36	0.31
	Natural gas-fired kiln firing structural clay	1.0	ND
Portland Cement Manufacturing	Wet process kiln	130	31
	Preheater kiln	250	ND
Gypsum	Rotary ore dryers ¹	0.16(FFF) ^{1.7}	0.013(FFF) ^{1.7}
	Continuous kettle calciners and hot pit	41 ^d	26
	Flash calciners	37 ^d	14
Lime Manufacturing	Primary crusher	0.017 ^d	ND
	Secondary crusher	0.62 ^d	ND
	Product transfer and conveying	2.2 ^d	ND
	Product loading, enclosed truck	0.61 ^d	ND
	Product loading, open truck	1.5 ^d	ND
	Coal-fired rotary kiln	352	44
	Coal- and gas fired rotary kiln	80	ND
	Gas-fired calcimatic kiln	97	ND
	Product cooler	6.8	ND

^a Emission factors in units of lb/ton of material processed. One lb/ton is equivalent to 0.5 kg/Mg. ND = no data. FFF is the ratio of gas mass rate per unit dryer cross section area to the dry mass feed rate.¹

^b Emission factors for tertiary crushers can be used as an upper limit for primary or secondary crushing.

^c Emission factors for mixer loading and truck loading for concrete batching operations were updated June 2006.

^d Filterable PM emission factors.

^{e,f} Units are lb/ton of raw material processed based on a raw material moisture content of 13% and of 4%, respectively.

11.2.3 Coal

EPA uses the following equation to calculate the PM10 emissions from overburden removal, drilling and blasting, loading and unloading, and overburden replacement from coal mining operations:

$$E_c = A_c [10 (EF_{to} + EF_{or} + EF_{dt}) + EF_v + EF_r + EF_a + 0.5 (EF_e + EF_t)] \quad (6)$$

where, A_c = coal production at surface mines (tons)

EF_{to} = PM10 emission factor for truck loading overburden at western surface coal mining operations (lbs/ton of overburden)

EF_{or} = PM10 emission factor for overburden replacement at western surface coal mining operations (lbs/ton of overburden)

EF_{dt} = PM10 emission factors for truck unloading: bottom dump-overburden at western surface coal mining operations (lbs/ton of overburden)

EF_v = PM10 open pit overburden removal emission factor at western surface coal mining operations (lbs/ton)

EF_r = PM10 drilling/blasting emission factor at western surface coal mining operations (lbs/ton)

EF_a = PM10 loading emission factor at western surface coal mining operations (lbs/ton)

EF_e = PM10 truck unloading: end dump-coal emission factor at western surface coal mining operations (lbs/ton)

EF_t = PM10 truck unloading: bottom dump-coal emission factor at western surface coal mining operations (lbs/ton)

Utilizing the PM10 factors developed for western surface coal mining operations, PM10 emissions from coal mining operations are calculated as follows:

$$E_c = A_c [10 (0.015 + 0.001 + 0.006) + 0.225 + 0.00005 + 0.05 + 0.5 (0.0035 + 0.033)] = 0.514 A_c \quad (7)$$

PM10 emissions from loading overburden into trucks and overburden removal account for 29% and 44%, respectively, of the total PM10 emissions from coal mining operations.

PM10 emission factor equations for uncontrolled fugitive dust sources at western surface coal mines are presented in Table 11-4.

Table 11-4. PM10 Emission Factor Equations for Uncontrolled Fugitive Dust from Western Surface Coal Mines^a

Operation	Material	PM10 Emission Factor Equations	
		English Units	Metric Units
Truck loading	Coal	$0.089 / (M)^{0.9}$ lb/ton	$0.045 / (M)^{0.9}$ kg/Mg
Bulldozing	Coal	$14.0(s)^{1.5} / (M)^{1.4}$ lb/hr	$6.33(s)^{1.5} / (M)^{1.4}$ kg/hr
	Overburden	$0.75(s)^{1.5} / (M)^{1.4}$ lb/hr	$0.34(s)^{1.5} / (M)^{1.4}$ kg/hr
Dragline	Overburden	$0.0016(d)^{0.7} / (M)^{0.3}$ lb/yd ³	$0.0022(d)^{0.7} / (M)^{0.3}$ kg/m ³
Grading	Overburden	$0.031(S)^2$ lb/VMT	$0.0034(S)^2$ kg/VKT

^a Symbols for equations: VMT = vehicle miles traveled; VKT = vehicle kilometers traveled; ND = no data. M = material moisture content (%); s = material silt content (%); d = drop height (ft); S = mean vehicle speed (mph).

In using the equations presented in Table 11-4 to estimate emissions from sources found at a specific western surface mine, it is necessary that reliable values for correction parameters be obtained for the specific sources of interest. For example, the actual silt content of coal or overburden measured at a facility should be used instead of estimated values. In the event that site-specific values for correction parameters cannot be obtained, the appropriate geometric mean values from Table 11-5 may be used.

Table 11-5. Range and Geometric Mean of Correction Factors Used to Develop Emission Factor Equations Shown in Table 11-4.

Source	Correction Factor	Range (Geometric Mean)	
		English Units	Metric Units
Blasting	Area Blasted	1,100 – 73,000 ft ² (17,000 ft ²)	100 – 6,800 m ² (1,590 m ²)
Coal loading	Moisture	6.8 – 38% (17.8%)	
Bulldozers			
	Coal	4 – 22% (10.4%)	
	Silt	6 – 11.3% (8.6%)	
Overburden	Moisture	2.2 – 16.8% (7.9%)	
	Silt	3.8 – 15.1% (6.9%)	
Dragline	Drop Distance	5 – 100 ft (28.1 ft)	1.5 – 30 m (8.6 m)
	Moisture	0.2 – 16.3% (3.2%)	
Scraper	Silt	7.2 – 25.2% (16.4%)	
	Weight	36 – 70 ton (53.8 ton)	33 – 64 Mg (48.8 Mg)
Grader	Speed	5.0 – 11.8 mph (7.1 mph)	8 – 19 kph (11.4 kph)
Haul truck	Silt content	1.2 – 19.2% (4.3%)	
	Moisture	0.3 – 20.1% (2.4%)	
	Weight	23 – 290 ton (120 ton)	20.9 – 260 Mg (110 Mg)

TSP emission factors for fugitive dust sources not covered in Table 11-4 are presented in Table 11-6. These factors were determined through source testing at various western surface coal mines. It should be pointed out that AP-42 does not list PM10/TSP ratios for fugitive dust sources. Instead it lists TSP and PM15 emission factor equations and PM10/PM15 ratios that range from 0.52 for blasting and 0.60 for grading to 0.75 for other operations. Calculating TSP and PM15 emission factors using typical correction factors provided in Table 11-5 together with the published PM10/PM15 ratios produces PM10/TSP ratios ranging from 0.15 to 0.30 for open area fugitive dust sources at western surface coal mines.

Table 11-6. Uncontrolled TSP Emission Factors for Western Surface Coal Mines^a

Source	Material	TSP Emission Factor	
		English Units	Metric Units
Blasting	Coal or overburden	0.000014 (A) ^{1.5} lb/blast	0.00022 (A) ^{1.5} kg/blast
Drilling	Overburden	1.3 lb/hole	0.59 kg/hole
Topsoil removal by scraper	Topsoil	0.058 lb/ton	0.029 kg/Mg
Overburden replacement	Overburden	0.012 lb/ton	0.006 kg/Mg
Train loading by power shovel	Coal	0.028 lb/ton	0.014 kg/Mg
Bottom dump truck unloading	Overburden	0.066 lb/ton	0.033 kg/Mg
Wind erosion of exposed areas ^b	Seeded land, stripped or graded overburden	0.38 ton/acre-yr	0.85 Mg/hectare-yr
Wind erosion of storage pile	Coal	0.72 (u) lb/acre-hr	1.8 (u) kg/hectare-hr

^a A = horizontal area (ft² or m²) with blasting depth ≤ 70 ft (≤21 m); not for a vertical face of a bench. U = wind speed (mph or m/s)

^b To estimate wind erosion on a shorter time scale (e.g., worst-case day); see Chapter 8 of the handbook.

11.2.4 Supplemental Emission Factors

TSP and PM10 emission factors for operations associated with ten mineral products industries are published in the EPA's *National Air Pollutant Emission Trends Procedures Document for 1900-1996*.⁸ The PM10 emission factors and PM10/TSP ratios for these operations are presented in Table 11-7. It should be pointed out that several of the emission factors shown in Table 11-7 are not consistent with values presented in Tables 11-1 and 11-3. To be conservative, one may wish to adopt the higher of the two values.

Table 11-7. Supplemental PM10 Emission Factors for Mineral Products Industries^a

Mineral Product Industry	Operation	PM10 (lb/ton)	PM10/TSP Ratio
Copper Ore	Crushing	2.9 to 3.9	0.45
	Open pit overburden removal	0.0003	0.37
	Drill/blasting	0.0008	0.80
	Loading	0.022	0.44
	Truck dumping	0.032	0.80
	Transfer/conveying	0.08	0.53
	Storage	0.7	0.35
Iron Ore	Mining	0.18	0.41
Lead Ore	Crushing	5.1	0.85
Zinc Ore	Crushing	2.3	0.38
Sand and Gravel	Mining	0.029	0.29
Asphalt Concrete	Fugitives	0.15	0.50
Brick Manufacturing	Material Handling	1.4	0.31
Cement Manufacturing	Fugitives	10.4	0.58
Lime Manufacturing	Fugitives	1.75	0.37
Coal	Surface Mining	0.2	0.40
	Coal Handling	0.17	0.34
	Pneumatic Dryer	1.5	0.50

^a Emission factors in units of lb/ton of material processed. One lb/ton is equivalent to 0.5 kg/Mg.

The predictive emission factor presented in Chapter 4 may be used to calculate emissions for materials handling operations if source specific data (moisture content, wind speed, and silt content) is available.

11.3 Demonstrated Control Techniques

Emissions from mineral processing plants can be controlled by a variety of devices, including wet scrubbers, cyclones, venturi scrubbers, fabric filters, and electrostatic precipitators or baghouses. Rudimentary fallout chambers and cyclone separators can be used to control the larger particles. Conveyor belts moving dried rock may be covered and sometimes enclosed. Transfer points and bucket elevators are sometimes enclosed and evacuated to a control device. Dry rock is often stored in enclosed bins or silos, which are vented to the atmosphere, with fabric filters frequently used to control emissions. Cyclones are often used for product recovery from mechanical processes. In such cases, the cyclones are not considered to be an air pollution control device. Emissions from dryers and calciners can be controlled by a combination of a cyclone or a multiclone and a wet scrubber system. Fabric filters are used at some facilities to control emissions from mechanical processes such as crushing and grinding. Cyclones and fabric filters are used to control emissions from screening, milling, and materials handling and transfer operations.

For moderate to heavy uncontrolled emission rates from typical dry ore operations, a wet scrubber with a pressure drop of 6" to 10" of water will reduce TSP emissions by approximately 95%. With very low uncontrolled emission rates typical of high-moisture conditions, the percentage reduction will be lower (approximately 70%). Wet suppression techniques include application of water, chemicals and/or foam, usually at crusher or conveyor feed and/or discharge points. Such spray systems at transfer points and on material handling operations have been estimated to reduce TSP emissions by 70 to 95%. Spray systems can also reduce loading and wind erosion TSP emissions from storage piles of various materials by 80 to 90%. Venturi scrubbers with a relatively low pressure drop (12" of water) have reported PM10 collection efficiencies of 80 to 99%, whereas high-pressure-drop scrubbers (30" of water) have reported PM10 collection efficiencies of 96 to 99.9%, and electrostatic precipitators have PM10 collection efficiencies of 90 to 99%.

Over a wide range of inlet mass loadings, a well-designed and maintained baghouse will reduce emissions to a relatively constant outlet concentration. Such baghouses tested in the mineral processing industry consistently reduce emissions to less than 0.05 g/m^3 (0.02 grains/ft^3), with an average concentration of 0.015 g/m^3 ($0.006 \text{ grains/ft}^3$). Under conditions of moderate to high uncontrolled emission rates of typical dry ore facilities, this level of controlled emissions represents greater than 99% removal of PM emissions. Control efficiencies depend upon local climatic conditions, source properties and duration of control effectiveness.

Process fugitive emission sources include materials handling and transfer, raw milling operations in dry process facilities, and finish milling operations. Emissions from these processes can be controlled by fabric filtration (baghouses) with reported removal

efficiencies of approximately 95 to 99%. The industry uses shaker, reverse air, and pulse jet filters as well as some cartridge units, but most newer facilities use pulse jet filters.

Successful control techniques used for haul roads are dust suppressant application, paving, route modifications, and soil stabilization. Controls for conveyors include covering and wet suppression; for storage piles, wet suppression, windbreaks, enclosure, and soil stabilizers; for conveyor and batch transfer points, wet suppression and various methods to reduce freefall distances (e. g., telescopic chutes, stone ladders, and hinged boom stacker conveyors); and for screening and other size classification, covering and wet suppression. Additional information on these control measures can be found in other chapters of this handbook.

AP-42 lists both uncontrolled and controlled PM10 emission factors for different control devices for many mineral processing industries. Comparing the controlled emission factor for a specific control device to the uncontrolled emission factor provides the PM10 control efficiency for that control device presented in Table 11-8.

Table 11-8. PM10 Control Efficiencies for Mineral Processing Operations

Mineral Products Industry	Source	Control Device	PM10 Control Efficiency (%)
Taconite ore	Natural gas fired kiln	Multiclone	79
Crushed stone	Tertiary crushing	Wet scrubber	78
	Fines crushing	Wet scrubber	92
	Screening	Wet scrubber	91.6
	Fines screening	Wet scrubber	96.9
	Conveyor transfer point	Wet scrubber	95.9
Pulverized mineral	Grinding	Fabric filter	>99.5%
Lightweight aggregate	Rotary Kiln	Wet scrubber	99.4
	Rotary Kiln	Fabric filter	99.8
	Rotary Kiln	Electrostatic precipitator	99.5
Kaolin	Flash calciner	Fabric filter	99.99
Fire clay	Rotary dryer	Cyclone	68
	Rotary calciner	Multiclone and wet scrubber	99.8
Bentonite	Rotary dryer	Fabric filter	99.6
Hot mix asphalt	Dryer	Fabric filter	99.4
Brick manufacturing	Grinding and screening	Fabric filter	99.4
Portland cement	Wet process kiln	Electrostatic precipitator	97.9
Cement batching	Unloading into silo	Wet scrubber	99.9
	Mixer loading (central mix)	Wet scrubber	96.5
	Truck loading (truck mix)	Wet scrubber	91.6
Gypsum manufacturing	Flash calciner	Fabric filter	99.8
Lime manufacturing	Coal-fired rotary kiln	Fabric filter	99.6
	Coal-fired rotary kiln	Electrostatic precipitator	90

11.4 Regulatory Formats

PM stack emissions from taconite ore processing facilities constructed or modified after August 24, 1982 are regulated under 40 CFR 60, subpart LL to 0.05 g/m³ (0.022

grains/ft³). In addition, the opacity of stack emissions is limited to 7% unless the stack is equipped with a wet scrubber, and process fugitive emissions are limited to 10%. The standard does not affect emissions from indurating furnaces. Emissions from Portland cement plants constructed or modified after August 17, 1971 are regulated to limit PM emissions from kilns to 0.15 kg/Mg (0.30 lb/ton) of feed, and to limit PM emissions from clinker coolers to 0.050 kg/Mg (0.10 lb/ton) of feed. Emissions of filterable PM from rotary lime kilns constructed or modified after May 3, 1977 are regulated to 0.30 kg/Mg (0.60 lb/ton) of stone feed under 40 CFR Part 60, subpart HH.

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. Example regulatory formats downloaded from the Internet for several local air quality agencies in the WRAP region are presented in Table 11-9. The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- San Joaquin Valley APCD, CA: valleyair.org/SJV_main.asp
- South Coast AQMD, CA: aqmd.gov/rules
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/aq

Table 11-9. Example Regulatory Formats for Mineral Processing Operations

Control Measure	Agency
Limits PM emissions from cement kilns to 30 pounds per hour for kiln feed rates of 75 tons per hour or greater. Limits PM emissions to 0.40 pound per ton of kiln feed for kiln feed rates less than 75 tons per hour.	SCAQMD Rule 1112.1 02/07/86
Limits opacity from cement manufacturing facilities to 20 % for open storage piles and unpaved roads and to 10 % for all other operations, Specifies covers for conveying systems and enclosures for conveying system transfer points, and loading/unloading through an enclosed system.	SCAQMD Rule 1156 11/04/05
Limits opacity from an aggregate handling facility to 20% based on an average of 12 consecutive readings, or 50% based on five individual, consecutive readings, using the SCAQMD Opacity Test Method No. 9B.	SCAQMD Rule 1157 01/07/05
Limits (a) PM emissions from stacks at a nonmetallic mineral processing plant to 0.02 grains/dry standard cubic foot (gr/dscf) (50 mg/dscm), (b) opacity of fugitive dust emissions from any transfer point on a conveying system to 7%, and (c) opacity of fugitive dust emissions from any crusher to 15%.	Maricopa Co. Rule 316 6/08/05
No owner or operator of an existing tunnel kiln at a brick or structural product manufacturing facility shall emit more than 0.42 lbs. of particulate matter per ton of fired product from a tunnel kiln with a capacity throughput \geq 1 ton/hour.	Maricopa Co. Rule 325 8/10/05
Limits the opacity of fugitive dust emissions at metallic or non-metallic mineral mining and processing facilities (based on an aggregate of at least 3 minutes in any 1-hour period) to (a) 10% for grinding mills, screening equipment, conveyors, conveyor transfer points, bagging equipment, storage bin, storage piles, stacker, enclosed truck, or rail car loading stations, (b) 15% for crushers, and (c) 7% for emissions from a stack or exhaust from a control device or building vent.	Clark Co. Rule 34 7/01/04

11.5 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 11-10 summarizes the compliance tools that are applicable for mineral processing industries.

Table 11-10. Compliance Tools for Mineral Processing Industries

Record keeping	Site inspection/monitoring
Maintain daily records onsite for a period of five years, and make such records available to the Executive Officer upon request for: (a) hours of operation, (b) volume of ore or aggregate mined, (c) watering and sweeping schedule for internal paved roads, (d) number of haul trucks exiting the facility, (e) Fugitive Dust Advisories, (f) Dust Control Plan, (g) Operation and Maintenance Plan for the on-site emission control system (ECS), and (h) twice daily moisture results of aggregate material.	Observation of dust plumes during periods of mining and processing operations; observation of dust plume opacity (visible emissions) exceeding a standard; tests of surface soil stabilization and aggregate moisture content; monitoring device to record pressures, flow rates and other ECS operating conditions; posting of signs restricting speeds to 15 mph; observation of high winds (e.g., >25 mph).

11.6 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for mineral processing operations. The reader is directed to Sections 4.6, 6.8, and 9.6 of the handbook for examples of calculating the cost effectiveness of specific control

measures for several minerals processing operations, namely materials handling, haul trucks traveling on unpaved industrial roads, and storage pile wind erosion, respectively.

A sample cost-effectiveness calculation is presented below for a specific control measure (wet scrubber for tertiary crushing of crushed stone) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for mineral processing, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Tertiary Crushing at Crushed Stone Processing Plant

Step 1. Determine source activity and control application parameters.

Material throughput (tons/year)	2,000,000
Control Measure	Wet scrubber
Control application/frequency	Continuous
Economic Life of Control System (yr)	10
Control Efficiency (Reference)	78% (AP-42)

The material throughput and economic life are assumed values for illustrative purposes. A wet scrubber system has been chosen as the control measure for reducing fugitive dust emissions. The moisture content of the crushed stone averages 0.21 to 1.3% for facilities without a wet suppression system and 0.55 to 2.88% for facilities with a wet suppression system.¹

Step 2. Obtain Uncontrolled PM Emission Factors. The uncontrolled PM10 emission factor for tertiary crushing of crushed stone published in AP-42 is 0.0024 lb/ton of material throughput. The PM2.5/PM10 ratio for crushed stone aggregate is 0.15 (MRI, 2006).⁶

Step 3. Calculate Uncontrolled PM Emissions. The annual uncontrolled PM10 emissions are calculated by multiplying the PM10 emission factor by the material throughput and then divided by 2,000 lbs to compute the annual emissions in tons per year, as follows:

$$\text{Annual emissions} = (\text{EF} \times \text{Material Throughput})/2,000$$

$$\text{Annual PM10 Emissions} = (0.0024 \times 2,000,000)/2000 = 2.4 \text{ tons}$$

$$\text{Annual PM2.5 Emissions} = 0.15 (\text{Annual PM10 Emissions}) = 0.36 \text{ tons}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

For this example, a wet scrubber/suppression system with a control efficiency of 78% has been selected as the control measure. Thus, the annual controlled PM10 and PM2.5 emissions estimates are calculated to be:

Annual Controlled PM10 emissions = (2.4 tons) x (1 – 0.78) = 0.53 tons
 Annual Controlled PM2.5 emissions = (0.36 tons) x (1 – 0.78) = 0.079 tons

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	16,000
Operating/Maintenance costs (\$)	12,200
Annual Interest Rate	3%
Capital Recovery Factor	0.12
Annualized Cost (\$/yr)	14,076

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$CRF = AIR \times (1 + AIR)^{\text{Economic life}} / (1 + AIR)^{\text{Economic life}} - 1$$

$$CRF = 3\% \times (1 + 3\%)^{10} / (1 + 3\%)^{10} - 1 = 0.1172$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor (CRF) multiplied by the Capital costs to the sum of the Operating and Maintenance costs, as follows:

$$\text{Annualized Cost} = (CRF \times \text{Capital costs}) + \text{Operating/Maintenance costs}$$

$$\text{Annualized Cost} = (0.1172 \times \$16,000) + \$12,200 = \$14,076$$

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\text{Cost-effectiveness for PM10 emissions} = \$14,075 / (2.4 - 0.53) = \$7,519/\text{ton}$$

$$\text{Cost-effectiveness for PM2.5 emissions} = \$14,075 / (0.36 - 0.079) = \$50,127/\text{ton}$$

11.7 References

1. USEPA, 2006. *Compilation of Air Pollutant Emission Factors*, AP-42 Section 11 (Minerals Products Industry), Fifth Edition.
2. USEPA, 2004. *Documentation for the Final 1999 National Emissions Inventory (Version 3.0) for Criteria Pollutants and Ammonia: Area Sources*, report prepared by E. H. Pechan and Associates for the USEPA OAQPS, January 31.
3. USEPA, 1986. *Generalized Particle Size Distributions for Use in Preparing Size-Specific Particulate Emissions Inventories*, EPA-450/4-86-013, July.
4. USEPA, 1990. *AIRS Facility Subsystem Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants*, EPA-450/4-90-003, March.
5. USEPA, 2001. *Procedures Document for National Emission Inventory, Criteria Air Pollutants, 1985-1999*, EPA-454/R-01-006, March.

6. MRI, 2006. *Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Emission Factors*, prepared for the WRAP by Midwest Research Institute, Feb. 1.
7. USEPA, 2006. *AP-42 Section 11.12: Concrete Batching*, updated in June.
8. USEPA, 1998. *National Air Pollutant Emission Trends Procedure Document for 1900-1996*, EPA-454/R-98-008, May.

Chapter 12. Abrasive Blasting

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12.1 Emission Estimation Methodology

This section was adapted from Section 13.2.6 of EPA's Compilation of Air Pollutant Emission Factors (AP-42). Section 13.2.6 was last updated in September 1997.

Abrasive blasting is the use of abrasive material to clean and prepare metal or masonry surfaces prior to painting. Sand is the most widely used blasting abrasive.¹ Other abrasive materials include coal slag, smelter slag, cast iron grit, cast iron shot, steel shot, garnet, walnut shells, carbon dioxide pellets, as well as synthetic abrasives such as silicon carbide, aluminum oxide, and glass or plastic beads. The PM10 and PM2.5 emission factors listed in AP-42 for sand blasting of mild steel are 13 lb/1,000 lb abrasive and 1.3 lb/1,000 lb abrasive, respectively, giving a PM2.5/PM10 ratio of 0.1. Using grit or shot instead of sand as the abrasive media reduces total PM emissions by 76% and 90%, respectively.

12.2 Demonstrated Control Techniques

A number of different methods have been used to control the emissions from abrasive blasting. These methods include: blast enclosures; vacuum blasters; drapes; water curtains; wet blasting; and reclaim systems. Wet blasting controls include not only traditional wet blasting processes but also high pressure water blasting, high pressure water and abrasive blasting, and air and water abrasive blasting. For wet blasting, control efficiencies between 50 and 93 percent have been reported. Fabric filters are typically used to control emissions from enclosed abrasive blasting operations with reported control efficiencies in excess of 95%.¹

Muleski and Downing recently tested the use of a polyurethane sponge material impregnated with different abrasive materials and compared the particulate emissions from this new sponge media with that from traditional abrasive materials.² The pliable nature of the sponge material allows it to surround the point of abrasive impact, thus capturing airborne dust emissions. The most commonly sold sponge media is a product containing 30 grit aluminum oxide known as "Silver 30". Using recycled sponge media mixed with fresh abrasive material per the manufacturer's recommendations reduced TSP emissions by 94% and PM10 emissions by 96% compared to traditionally used abrasives such as coal slag and silica sand. In other words, when used as recommended (i.e., recycled sponge media with fresh abrasive material added), the foam-based blasting media achieved a control level essentially identical to that of fabric filtration.

12.3 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. As an example, Maricopa County's Rule 312 states that all abrasive blasting operations shall be performed in a confined enclosure, unless one of the following conditions are met, in which case unconfined blasting may be performed: (a) the item to be blasted exceeds 8 ft. in any one dimension, or (b) the

surface being blasted is fixed in a permanent location, cannot easily be moved into a confined enclosure, and the surface is not normally dismantled or moved prior to abrasive blasting.³ Dry abrasive blasting in a confined enclosure with a forced air exhaust requires the use of either a certified abrasive (i.e., an abrasive certified by the California Air Resources Board), or venting to an emission control system (ECS) for which the operator must maintain an operation and maintenance plan. A list of abrasives currently certified by CARB as permissible for dry outdoor blasting can be obtained from Maricopa County's website (maricopa.gov/aq/divisions/planning.aspx#rules). For unconfined blasting, at least one of the following control measures shall be used: wet abrasive blasting, vacuum blasting, or dry abrasive blasting, provided that all of the following conditions are met: performed only on a metal substrate, use of certified abrasive for dry unconfined blasting, blasting paint that has a lead content of less than 0.1 percent, abrasive blasting operation directed away from unpaved surfaces, and the certified abrasive may only be used once unless contaminants are separated from the abrasive after each use. No dry unconfined abrasive blasting operation shall be conducted when the 1-hour average wind speed is greater than 25 miles per hour.

Maricopa County Rule 312 states no owner or operator shall discharge into the atmosphere from any abrasive blasting operation any air contaminant for an observation period or periods aggregating more than three minutes in any sixty minute period an opacity conducted in accordance with EPA Reference Method 9 ("Visual Determination of the Opacity of Emissions from Stationary Sources," 40 CFR 60, Appendix A) equal to or greater than 20 percent. At the end of the work shift the owner or operator shall clean up spillage, carryout, and/or track out of any spent abrasive material with a potential to be transported during periods where the wind exceeds 25 mph.

The South Coast AQMD's Rule 1140 states that before blasting all abrasives used for dry unconfined blasting shall contain no more than 1% by weight material passing a No. 70 U.S. Standard sieve, and after blasting the abrasive shall not contain more than 1.8% by weight material five microns or smaller.⁴ Rule 1140 states that visible emission evaluation of abrasive blasting operations shall be conducted in accordance with the following provisions:

1. Emissions shall be read in opacities and recorded in percentages.
2. The light source should be behind the observer during daylight hours.
3. The light source should be behind the emission during hours of darkness.
4. The observer position should be at approximately right angles to wind direction and at a distance no less than twice the height of the source but not more than a quarter mile from the base of the source.
5. Emissions from unconfined abrasive blasting shall be read at the densest point in the plume, which point shall be at least 25 feet from the source.

6. Where the presence of uncombined water is the only reason for failure to comply with opacity limits, the opacity limits shall not apply. The burden of proof in establishing that opacity limits shall not apply shall be upon the operator.
7. Emissions from unconfined abrasive blasting employing multiple nozzles shall be evaluated as a single source unless it can be demonstrated by the operator that each nozzle, evaluated separately, meets the requirements of this rule.
8. Emissions from confined abrasive blasting shall be read at the densest point after the air contaminant leaves the enclosure.

The website addresses for obtaining information on fugitive dust regulations for local air quality districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- San Joaquin Valley APCD, CA: valleyair.org/SJV_main.asp
- South Coast AQMD, CA: aqmd.gov/rules
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/aq

12.4 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Maricopa County Rule 312 states that as a minimum each owner or operator subject to this rule shall keep the following records onsite for at least 5 years at permitted Title V

sources and for at least 2 years at Non-Title V sources: (a) the type and amount of solid abrasive material consumed on a monthly basis, including the name of the certified abrasive used, as applicable; and (b) Material Safety Data Sheets (MSDS) or results of any lead testing that was performed on paint that is to be removed via unconfined blasting, as applicable. In addition if blasting operations occur daily or are a part of a facility's primary work activity, then records shall be kept of the blasting equipment including a description of the type of blasting (e.g., confined, unconfined, sand, wet, etc.), the location of the blasting equipment or specify if the equipment is portable, a description of the emission control system (ECS) associated with the blasting operations, the days of the week blasting occurs, and the normal hours of operation. If blasting operations occur periodically, then records shall be kept of the dates the blasting occurs, the blasting equipment that is operating including a description of the type of blasting, and a description of the ECS associated with the blasting operations.

12.5 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for abrasive blasting operations. A sample cost-effectiveness calculation is presented below for a specific control measure (fabric filtration used to capture particulates from sand blasting of mild steel) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for abrasive blasting, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Sand Blasting of Mild Steel

Step 1. Determine source activity and control application parameters.

Silica sand abrasive use (tons/year)	10
Control Measure	Fabric Filter
Control application/frequency	Continuous
Economic Life of Control System (yr)	10
Control Efficiency (Reference)	95% (AP-42)

The amount of abrasive material used on a yearly basis and the economic life of the control system are assumed values for illustrative purposes. A fabric filter filtration system has been chosen as the control measure for reducing fugitive dust emissions from abrasive blasting of mild steel.

Step 2. Obtain Uncontrolled PM Emission Factors. The uncontrolled PM10 and PM2.5 emission factors for sand blasting of mild steel published in AP-42 are 26 lb/ton of abrasive and 2.6 lb/ton of abrasive.

Step 3. Calculate Uncontrolled PM Emissions. The annual uncontrolled PM emissions are calculated by multiplying the PM emission factors by the amount of abrasive material used per year divided by 2,000 lb/ton to produce emission estimates in tons per year, as follows:

- Annual PM10 Emissions = (26 lb/ton x 10 tons/year) / 2,000 lb/ton = 0.13 tons
- Annual PM2.5 Emissions = (2.6 lb/ton x 10 tons/year) / 2,000 lb/ton = 0.013 tons

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

Controlled emissions = Uncontrolled emissions x (1 – Control Efficiency).

For this example, fabric filters with a control efficiency of 95% has been selected as the control measure. Thus, the annual controlled PM10 and PM2.5 emissions estimates are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM10 emissions} &= (0.13 \text{ tons}) \times (1 - 0.95) = 0.0065 \text{ tons} \\ \text{Annual Controlled PM2.5 emissions} &= (0.013 \text{ tons}) \times (1 - 0.95) = 0.00065 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

Capital costs (\$)	10,000
Annual operating and maintenance costs (\$)	1,000
Annual Interest Rate	3%
Capital Recovery Factor	0.12
Annualized Cost (\$/yr)	2,200

The capital costs, annual operating and maintenance costs, and annual interest rate (AIR) are assumed values for illustrative purposes. The Capital Recovery Factor (CRF) is calculated from the Annual Interest Rate (AIR) and the Economic Life of the control system, as follows:

$$\begin{aligned} \text{CRF} &= \text{AIR} \times (1 + \text{AIR})^{\text{Economic life}} / (1 + \text{AIR})^{\text{Economic life}} - 1 \\ \text{CRF} &= 3\% \times (1 + 3\%)^{10} / (1 + 3\%)^{10} - 1 = 0.1172 \end{aligned}$$

The Annualized Cost is calculated by adding the product of the Capital Recovery Factor (CRF) multiplied by the Capital costs to the sum of the operating and maintenance costs, as follows:

$$\begin{aligned} \text{Annualized Cost} &= (\text{CRF} \times \text{Capital costs}) + \text{Operating and Maintenance costs} \\ \text{Annualized Cost} &= (0.1172 \times \$10,000) + \$1,000 = \$2,172 \end{aligned}$$

Step 6. Calculate Cost-effectiveness. Cost-effectiveness is calculated by dividing the annualized cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions:

$$\text{Cost-effectiveness} = \text{Annualized Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

$$\begin{aligned} \text{Cost-effectiveness for PM10 emissions} &= \$2,172 / (0.13 - 0.0065) = \$17,590/\text{ton} \\ \text{Cost-effectiveness for PM2.5 emissions} &= \$2,172 / (0.013 - 0.00065) = \\ &= \$175,895/\text{ton} \end{aligned}$$

12.6 References

1. USEPA, 1997. *Abrasives Blasting*, Section 13.2.6 of Compilation of Air Pollutant Emission Factors, September.
2. Muleski, G. E., and Downing, J., 2006. *Control of Abrasive Blasting Emissions through Improved Materials*, paper presented at the EPA 15th International Emission Inventory Conference, New Orleans, LA, May 16-18.
3. Maricopa County, 2003. *Rule 312 - Abrasive Blasting*, July 2.
4. South Coast AQMD, 1985. *Rule 1140 – Abrasive Blasting*, August 2.

Chapter 13. Livestock Husbandry

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13.1 Emission Estimation Methodology

This section was adapted from Section 7.6 of CARB's Emission Inventory Methodology. Section 7.6 was last updated in May 2004.

AP-42 does not address livestock husbandry. Thus, the methodology adopted by the California Air Resources Board (CARB) is presented here as the primary emissions estimation methodology for this fugitive dust source category.¹ The CARB methodology only provides estimates of PM10 emissions from cattle feedlot and dairy operations. For each category, the emissions are calculated by multiplying a per animal emission factor by the population of each animal type. The livestock population is available from the US Department of Agriculture. Livestock emissions research is ongoing.

CARB's PM10 emission factor for cattle feedlots is 28.9 lbs PM10/1000 head/day (i.e., 10.55 lb/head-year) based on a work performed by UC Davis.² The corresponding PM10 emission factor for dairy cattle is 6.72 lbs PM10/1000 head/day (i.e., 2.45 lb/head-year) based on an emission factor of 4.4 lbs PM10/1000 lactating head/day, developed by Texas A&M.³ To make the Texas emission factor more California specific, it was multiplied by a scaling factor based on the ratio of the California feedlot PM10 emission factor to a Texas feedlot PM10 emission factor. This ratio is 29:19; thus, the scaling factor is 1.53. The PM10/TSP and PM2.5/PM10 ratios for this source category are 0.48 and 0.11, respectively.

The CARB methodology is subject to the following assumptions:

1. Population data and residence time data adequately represent average animal population values for each county.
2. All animals within a single class produce the same emissions (e.g., dairy cows, calves, and heifers).
3. It is assumed that all dairies or feedlots produce the same PM10 emissions on a per-head basis.
4. For dairies, the baseline PM10 emission factor includes the effects of support stock such as calves and heifers. This is because the emissions testing included these animals within its analysis.
5. For feedlots, the baseline PM10 emission factor represents the population mix at a typical feedlot.
6. The method does not include emissions for animal waste composting or land application.

7. Due to insufficient temporal information, it is assumed that air emissions occur evenly throughout the year seven days a week and 24 hours a day.

The San Joaquin Valley APCD has developed separate emission factors for different operations associated with dairies and cattle feedlots based on CARB's PM10 emission factors of 2.45 lb/head-year for dairies and 10.55 lb/head-year for cattle feedlots.⁴ These emission factors are shown in Table 13-1.

Table 13-1. PM10 Emission Factors for Cattle Feedlot and Dairy Operations

Source Category	Operation	PM10 Emission Factor
Dairies	Corral/Manure Handling	1.845 lb/head-yr (freestall) 4.6 lb/head-yr (open corral)
	Overall Management/Feeding	1.845 lb/head-yr (freestall) 4.6 lb/head-yr (open corral)
	Unpaved Road	0.369 lb/head-yr
	Unpaved Area	0.123 lb/head-yr
Cattle Feedlots	Pens/Manure Handling	7.94 lb/head-yr
	Overall Management/Feeding	0.53 lb/head-yr
	Unpaved Road	1.59 lb/head-yr
	Unpaved Area	0.53 lb/head-yr

13.2 Demonstrated Control Techniques

CARB does not list any control measures for this fugitive dust source category. However, the San Joaquin Valley APCD (District) has been very proactive in identifying potential control measures for cattle feedlots and dairies. For example, fugitive dust emissions originating from the disturbance of dry and loose surface material (e.g., feed, bedding material, and manure) caused by animal movement and mechanical disturbances by vehicles can be controlled by sprinkling water on the surface of the open corral or pen, removing manure before it dries, using a layer of wood chips in dusty areas, housing dairy cattle in stalls with concrete floors rather than dirt floors, and adopting a feeding schedule when animals are less active. Wind blown fugitive dust originating from uncovered bulk materials can be controlled by applying water or chemical suppressants, covering the material with tarps or storing the material in enclosure, and erecting wind barriers. Since no data could be found in the literature on which to base a control efficiency factor for these practices, the District has conservatively assumed a minimal 10% control effectiveness. Control measures identified by the District for cattle feedlots and dairies are shown in Table 13-2. A list of control measures for cattle feedlots and dairies is available from the California Air Pollution Control Officers' Association's (CAPCOA) agricultural clearing house website (http://capcoa.org/ag_clearinghouse.htm).

Control measures for unpaved roads and unpaved parking/traffic areas include application of chemical dust suppressants, paving the surface or placing a layer of gravel over the unpaved surface, speed reduction, access restriction, and track out control measures. These control measures and their associated control efficiencies are listed in Chapter 6 of the handbook. Control measures for storage piles of bulk materials other than manure include dust suppressants, watering, covering and wind barriers. These

control measures and their associated control efficiencies are listed in Chapter 9 of the handbook.

Table 13-2. Control Measures for Cattle Feedlots and Dairies^a

Source Category	Control Measure
Manure management	Frequent manure removal (every 6 months) with equipment that leaves an evenly corral surface of compacted manure on top of the soil.
	Insert the manure directly beneath the soil.
Dust entrainment by animal	Daily water sprinkling, and timing of watering around 6PM or before sunset.
	Use of freestalls with concrete surface for animal housing/feeding areas to allow frequent manure removal.
	Stocking density adjustment in accordance to the moisture found in the unit area to reduce dust.
	Removal of loose material on surface and maintain a compacted layer of manure 1 to 2 inches thick.
	Addition of fibrous material such as wood chips to working pens.
	Delaying the last daily feeding to reduce end-of-day spike in livestock activity.
Other	Adding moisture to hay
	Using a totally enclosed delivery system and covered feeders, and using palletized feed.
	Planting rows of vegetation around a building to create a barrier for air exiting from the building.

^a Since no data could be found in the literature on which to base a control efficiency factor for these practices, the SJVAPCD has conservatively assumed a minimal 10% control effectiveness for each control measure.

13.3 Regulatory Formats

Fugitive dust control options have been embedded in many regulations for state and local agencies in the WRAP region. However, most air quality districts currently exempt agricultural operations from controlling fugitive dust. Air quality districts that regulate fugitive dust emissions from agricultural operations include Clark County, NV and several districts in California such as the Imperial County APCD, the San Joaquin Valley APCD and the South Coast AQMD. Imperial County APCD prohibits fugitive dust emissions from farming activities for farms over 40 acres. The San Joaquin Valley APCD and the South Coast AQMD prohibit fugitive dust emissions for the larger farms defined as farms with areas where the combined disturbed surface area within one continuous property line and not separated by a paved public road is greater than 10 acres. SJVAPCD's Rule 4550 applies to animal feeding operations (AFOs) that house animals for a total of at least 45 days in any 12 month period for agricultural parcels exceeding 100 acres excluding the AFO. Example regulatory formats downloaded from the Internet for several local air quality agencies in the WRAP region are presented in Table 13-3. CAPCOA's agricultural clearing house website (http://capcoa.org/ag_clearinghouse.htm) provides links to rules of different air quality agencies that regulate fugitive dust emissions from agricultural operations. The website addresses for obtaining information on fugitive dust regulations for local air quality

districts within California, for Clark County, NV, and for Maricopa County, AZ, are as follows:

- Districts within California: www.arb.ca.gov/drdb/drdb.htm
- San Joaquin Valley APCD, CA: valleyair.org/SJV_main.asp
- South Coast AQMD, CA: aqmd.gov/rules
- Clark County, NV: www.co.clark.nv.us/air_quality/regs.htm
- Maricopa County, AZ: www.maricopa.gov/aq

Table 13-3. Example Regulatory Formats for Cattle Feedlots and Dairies

Control Measure	Agency
Limit fugitive dust from animal feeding operations for facilities exceeding 100 acres excluding the AFO by requiring owner/operator to implement a Conservation Management Practice (CMP) Plan with district approved control methods.	SJVAPCD Rule 4550 5/20/04
Limit fugitive dust from off-field agricultural sources such as unpaved roads with more than 75 trips/day and bulk materials handling by requiring producers to draft and implement a Fugitive Dust Management Plan with district approved control methods.	SJVAPCD Rule 8081 9/16/04
Producers that voluntarily implement district approved conservation practices and complete and maintain the self-monitoring plan can maintain an exemption from the Rule 403 general requirements.	SCAQMD Rule 403 4/02/04
Cease tilling/mulching activities when wind speeds are greater than 25 mph.	SCAQMD Rule 403.1 4/02/04
Limit fugitive dust from paved and unpaved roads and livestock operations by ceasing all hay grinding activities between 2 and 5 PM if visible emissions extend more than 50 feet from a hay grinding source, and treating all unpaved access connections to livestock operations and unpaved feed lane access areas with either pavement, gravel (maintained to a depth of 4 inches), or asphaltic road-base.	SCAQMD Rule 1186 4/02/04
Reduce fugitive dust from livestock feed yards by requiring that the moisture content in the top three inches of manure piles for occupied pens be maintained between 20% and 40%. This rule also outlines manure management practices, including removal.	SCAQMD Rule 1186 4/02/04
Reduce fugitive dust from livestock feed yards by requiring that the moisture content for manure piles be maintained between 20% and 40%.	ICAPCD Rule 420 8/13/02

13.4 Compliance Tools

Compliance tools assure that the regulatory requirements, including application of dust controls, are being followed. Three major categories of compliance tools are discussed below.

Record keeping: A compliance plan is typically specified in local air quality rules and mandates record keeping of source operation and compliance activities by the source owner/operator. The plan includes a description of how a source proposes to comply with all applicable requirements, log sheets for daily dust control, and schedules for compliance activities and submittal of progress reports to the air quality agency. The purpose of a compliance plan is to provide a consistent reasonable process for documenting air quality violations, notifying alleged violators, and initiating enforcement action to ensure that violations are addressed in a timely and appropriate manner.

Site inspection: This activity includes (1) review of compliance records, (2) proximate inspections (sampling and analysis of source material), and (3) general observations. An inspector can use photography to document compliance with an air quality regulation.

On-site monitoring: EPA has stated that “An enforceable regulation must also contain test procedures in order to determine whether sources are in compliance.” Monitoring can include observation of visible plume opacity, surface testing for crust strength and moisture content, and other means for assuring that specified controls are in place.

Table 13-4 summarizes the compliance tools that are applicable for cattle feedlots and dairies.

Table 13-4. Compliance Tools for Cattle Feedlot and Dairies

Record keeping	Site inspection/monitoring
Maintain daily records to document the specific dust control options taken; maintain such records for a period of not less than three years; and make such records available to the APCO upon request. Submit a Conservation Management Practice (CMP) Plan to the APCO listing the selected CMPs for implementation, contact information for the owner/operator, a site plan or map of the site.	Observation of dust plumes and dust plume opacity (visible emissions) exceeding a standard; observation of high winds (e.g., >25 mph).

13.5 Sample Cost-Effectiveness Calculation

This section is intended to demonstrate how to select a cost-effective control measure for cattle feedlots and dairies. A sample cost-effectiveness calculation is presented below for cattle feedlots for a specific control measure (frequent scraping and manure removal) to illustrate the procedure. The sample calculation includes the entire series of steps for estimating uncontrolled emissions (with correction parameters and source extent), controlled emissions, emission reductions, control costs, and control cost-effectiveness values for PM10 and PM2.5. In selecting the most advantageous control measure for cattle feedlots and dairies, the same procedure is used to evaluate each candidate control measure (utilizing the control measure specific control efficiency and cost data), and the control measure with the most favorable cost-effectiveness and feasibility characteristics is identified.

Sample Calculation for Cattle Feedlots	
<u>Step 1. Determine source activity and control application parameters.</u>	
Number of cattle at the feedlot	1,000
Control Measure	Scraping and manure removal

Frequency of operations per year	2
Control Efficiency	10%

Scraping and removal of manure from feedlot pens every six months has been chosen as the applied control measure. The number of cattle at the feedlot is an assumed value for illustrative purposes. Since no data could be found in the literature on which to base a control efficiency factor for control measures for cattle feedlots and dairies, the SJVAPCD has conservatively assumed a minimal 10% control effectiveness for each control measure (SVAPCD, 2004⁴).

Step 2. Obtain Uncontrolled PM10 Emission Factor.

The uncontrolled PM10 emission factor for cattle feedlots is 10.55 lb/head/year (CARB, 2004¹).

Step 3. Calculate Uncontrolled PM Emissions. The PM10 emission factor, EF, (given in Step 2) is multiplied by the number of cattle (see activity data) and then divided by 2,000 lb/ton to compute the annual PM10 emissions in tons per year, as follows:

$$\begin{aligned} \text{Annual PM10 emissions} &= (\text{EF} \times \text{Number of Cattle}) / 2,000 \\ \text{Annual PM10 Emissions} &= (10.55 \times 1,000) / 2,000 = 5.28 \text{ tons} \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= (\text{PM2.5/PM10}) \times \text{PM10 emissions} \\ \text{where the PM2.5/PM10 ratio for cattle feedlots} &= 0.11 \text{ (CARB, 2004}^1\text{)}. \end{aligned}$$

$$\begin{aligned} \text{Annual PM2.5 emissions} &= 0.11 \times \text{PM10 emissions} \\ \text{Annual PM2.5 Emissions} &= (0.11 \times 5.28 \text{ tons}) = 0.58 \text{ tons} \end{aligned}$$

Step 4. Calculate Controlled PM Emissions. The controlled PM emissions (i.e., the PM emissions remaining after control) are equal to the uncontrolled emissions (calculated above in Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency})$$

For this example, we have selected frequent scraping and removal of manure as our control measure. Based on a control efficiency estimate of 10%, the annual controlled PM emissions are calculated to be:

$$\begin{aligned} \text{Annual Controlled PM10 emissions} &= (5.28 \text{ tons}) \times (1 - 0.10) = 4.75 \text{ tons} \\ \text{Annual Controlled PM2.5 emissions} &= (0.58 \text{ tons}) \times (1 - 0.10) = 0.52 \text{ tons} \end{aligned}$$

Step 5. Determine Annual Cost to Control PM Emissions.

The SJVAPCD assumes that the cost for scraping and removal of manure is \$3 per head.⁴ Thus, the annualized cost of scraping and removal of manure from feedlot pens holding 1,000 head of cattle every six months is calculated as follows:

$$\begin{aligned} \text{Annual Costs} &= \text{Cost per head to remove manure} \times \text{Head of Cattle} \times \text{Frequency of Ops/year} \\ \text{Annual Costs} &= \$3/\text{head} \times 1,000 \text{ head} \times 2/\text{year} = \$6,000 \end{aligned}$$

Step 6. Calculate Cost-effectiveness. The cost-effectiveness is calculated by dividing the annual cost by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions from the uncontrolled emissions as follows:

$$\text{Cost-effectiveness} = \text{Annual Cost} / (\text{Uncontrolled emissions} - \text{Controlled emissions})$$

Cost-effectiveness for PM10 emissions = $\$6,000 / (5.28 - 4.75) = \$11,374/\text{ton}$
Cost-effectiveness for PM2.5 emissions = $\$6,000 / (0.58 - 0.52) = \$103,404/\text{ton}$

Note: The actual cost-effectiveness values for this control measure are lower than the calculated values shown here since the SJVAPCD assumes that the control efficiency is at least 10%.

13.6 References

1. CARB, 2004. *Livestock Husbandry*, Section 7.6 of CARB's Emission Inventory Procedural Manual, Volume III: Methods for Assessing Area Source Emissions, May.
2. Flocchini, R.G., James, T.A., et. al., 2001. *Sources and Sinks of PM10 in the San Joaquin Valley*, Interim Report prepared by the Air Quality Group, Crocker Nuclear Laboratory, University of California, Davis. August 10.
3. Goodrich, L.B., Parnell, C.B., Mukhtar, S., Lacey, R.E., Shaw, B.W., 2002. *Preliminary PM10 Emission Factor for Freestall Dairies*, Department of Biological and Agricultural Engineering, Texas A&M University, paper presented at the 2002 ASAE Annual International Meeting, Chicago, IL, July 28-31.
4. SJVAPCD, 2005. *Emission Reduction Calculation Methodology for Dairies and Feedlot Conservation Management Practices*, Draft Report prepared by San Joaquin Valley APCD, November 24.

Chapter 14. Miscellaneous Minor Fugitive Dust Sources

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14.1 Introduction

This Chapter identifies emission estimation methods for several minor fugitive dust source categories not addressed in other chapters of the handbook. Because several of these methods have not been approved by federal or state agencies, the reader is cautioned in the use of the emission factors included in these emission estimation methods. The emission estimation methods discussed here address:

- windblown dust from unpaved roads
- uncovered haul trucks,
- unpaved shoulders,
- leaf blowers, and
- explosives detonation.

14.2 Windblown Dust from Unpaved Roads

The California Air Resources Board adopted the U.S. EPA-modified version of the USDA-ARS derived wind erosion equation (WEQ) used to estimate windblown dust from agricultural fields¹ to estimate windblown dust from unpaved roads² as follows:

$$E_s = a I K C L' V' \quad (1)$$

where, E_s = the quantity of unpaved road dust entrained to the air by wind erosion (tons TSP/acre/year)

a = portion of total roadway wind erosion losses that are assumed to be suspended into the air; estimated to be 0.038 for TSP

I = soil erodibility (tons/acre/year)

K = surface roughness factor (dimensionless)

C = climatic factor (dimensionless)

L' = unsheltered width factor (dimensionless)

V' = vegetative cover factor (dimensionless)

In summary, the 'I' term in the windblown dust equation provides an estimate of the soil erosion from an area that is large, flat, bare, and highly erodible. The additional terms in the equation reduce emissions from this worst-case scenario. The climatic, C, factor helps to account for regional differences in wind and rainfall. If a surface is rough, as represented by K, soil erosion is decreased. If the length of the erodible area parallel to the wind is short, then the erosion is decreased, as represented by the L' factor. If there is crop residue on the erodible area, then erosion is further decreased by the V' factor. A detailed discussion of the parameters I, K, C, L', and V' is presented in Chapter 7 of the Handbook.

Soil Erodibility – I. The soil erodibility, I, of an unpaved road is related to the soil type of the road surface. Because roadway soil types are not readily available, the county specific, average soil types are used to estimate the erodibility. The county soil types are computed using a geographic information system (GIS) to average detailed county soil profile maps provided by the Natural Resources Conservation Service. This approach

assumes that unpaved road surfaces have the same soil characteristics as the base soils in the vicinity of the roadway.

Climatic Factor - C. The rate of soil erosion varies directly with the wind velocity and inversely with the soil surface moisture. The climatic factor is used to adjust for these parameters. CARB staff computed the county ‘C’ factors based on regional rainfall and wind speed data measured in California.

Surface Roughness - K. Surface roughness can help to reduce soil erosion. The ‘K’ factor is used to account for ridges or furrows that help to minimize wind related erosion. Because most unpaved roads are flat, the surface roughness factor is assumed to be 1.0, indicating no reduction in emissions due to surface texture.

Unsheltered Width Factor - L’. Soil erosion is directly related to the unprotected width of the area in the prevailing wind direction. For unpaved roads, depending on the wind direction, the width of the erosive area parallel to the wind direction could be very narrow, very long, or somewhere in between. CARB assumes that the wind direction is equally distributed for all roads and that the average value of L’ is 0.32.

Vegetative Cover Factor - V’. Vegetative cover reduces soil erosion. For unpaved roads, it is assumed that there is no vegetative cover, therefore a value of 1.0 is used.

Based on analysis of resuspended California soil samples, CARB estimated that the PM10/TSP ratio for windblown dust from unpaved roads is 0.5. Windblown dust emissions from unpaved roads are calculated for each county by multiplying the PM10 emission rate (i.e., 50% of the TSP emission rate calculated from the TSP emission factor equation, Equation 1) by the unpaved road mileage and the average width of the unpaved roads assumed to average 20 feet. CARB’s estimates does not include windblown dust from agricultural unpaved roads since they assume that windblown emissions from agricultural unpaved roads are included in the source category for windblown dust from agricultural lands.

The CARB methodology is subject to the following assumptions and limitations:

1. It is assumed that the unpaved road soil characteristics are approximately the same as the soils in the vicinity of the unpaved road that are not used for vehicular travel. This implies that no additional gravel or other treatments have been applied to the unpaved roads.
2. It is assumed that the soil wind erosion equation may be reasonably applied to estimate windblown dust from unpaved roads. Because of the large differences between unpaved road surfaces and agricultural lands, the validity of this assumption is questionable.
3. Using the soil erosion equation, it is assumed that 3.8% of the total eroded material is entrained to the air. (‘a’ factor = 0.038).

4. It is assumed that the county average soil erodibility, 'I', and climatic, 'C', factors are representative (on average) of the overall county conditions.
5. It is assumed that a value of 0.32 for the unsheltered width factor, L', is valid.
6. It is assumed that unpaved roads have no vegetative cover and are essentially flat.
7. The typical unpaved road width is 20 feet.
8. This methodology assumes no extraordinary windstorm activity; only average annual conditions are estimated.

CARB is aware that their methodology for estimating windblown dust from unpaved roads is built on a foundation of dubious assumptions. Because of the differences between unpaved roads and agricultural lands, it is unlikely that the agricultural soil erosion equation provides very accurate estimates of windblown road dust. The emissions estimates could be improved by performing wind tunnel tests on unpaved roads, and then extrapolating the resulting emission factors to the remainder of the State. With the use of geographic information systems, it is also possible to incorporate localized climatological and soil texture properties into the emission estimates. In addition, the mileage of unpaved roads could be improved using available digital maps which include public, as well as private unpaved roads.

14.3 Uncovered Haul Trucks

A total suspended particulate (TSP) emission factors for uncovered haul trucks was included in a USEPA report published in 1989.³ The hourly TSP emission estimate for uncovered haul trucks was estimated from the following equation:

$$\text{TSP (lb/yd}^2\text{/hour)} = 0.00015 u$$

where, u = sum of wind speed and vehicle speed (mph)

To estimate PM10 and PM2.5 emissions, PM10/TSP and PM2.5/TSP ratios will need to be obtained for this source category.

14.4 Unpaved Shoulders

DRI developed a PM10 emission factor for the resuspension of fugitive dust from unpaved shoulders created by the wake of high-profile vehicles such as tractor-trailers (semis) traveling on paved roads at high speed (50-65 mph).⁴ The emission factor for unpaved shoulder with surface loadings of 4,500 to 5,500 g/m², silt content of 3 to 6%, and a surface moisture content under 1% was given as:

$$\text{EF} = 0.028 \pm 0.014 \text{ lb/VMT}$$

DRI concluded that emissions from unpaved shoulders due to smaller vehicles such as cars, vans and SUVs were negligible. It should be pointed out that the PM10

emissions were estimated utilizing nephelometers that are not quantitative for coarse particles. Thus, PM10 emissions may be underestimated.

14.5 Leaf Blowers

Dennis Fitz and other researchers from CE-CERT at UC Riverside recently completed a study on behalf of the San Joaquin Valley APCD to determine PM2.5 and PM10 emissions from leaf blowing/vacuuming, raking and sweeping activities.⁵ Real-time PM2.5 and PM10 measurements were obtained with DustTrak aerosol monitors calibrated against Arizona road dust (NIST SRM 8632). The precision of the DustTrak PM2.5 and PM10 measurements were determined to be 19% and 27%, respectively, based on collocated DustTrak monitors. The accuracy of the DustTrak measurements was determined by comparing the DustTrak measurements to the filter-based measurements. In general the two data sets agreed to within 50%, which was similar to the variability between replicate tests. The PM2.5 and PM10 emission factors determined by DustTrak monitors for different cleaning activities and surfaces are summarized in Table 14-1. The DustTrak results for blowing leaves on asphalt and concrete surfaces as a function of power blower type are presented in Table 14-2.

Table 14-1. PM Emission Factors for Leaf Blowing/Vacuuming, Raking and Sweeping Activities (mg/m²)

Cleaning Action and Surface Cleaned	PM2.5	PM10
Power blowing/vacuuming over concrete surfaces	30	80
Power blowing/vacuuming over asphalt surfaces	20	60
Push broom to sweep asphalt surfaces	0	20
Push broom to sweep concrete surfaces	20	80
Raking asphalt surfaces	0	0
Raking on concrete surfaces	0	0
Raking lawns	0	1
Power blowing on lawns	1	2
Power blowing from gutters	9	30
Power blowing on packed dirt	80	120
Power blowing cut grass on walkways	2	6

Table 14-2. PM Emission Factors by Power Blower Type and Surface (mg/m²)

Power Blower Type	Surface	PM2.5	PM10
Electric	Asphalt	20	60
Gas Hand Held	Asphalt	10	40
Gas Backpack	Asphalt	20	60
Electric: vacuum mode	Asphalt	40	120
Electric: vacuum mode, full bag	Asphalt	20	70
Electric	Concrete	40	130
Gas Hand Held	Concrete	10	40
Gas Backpack	Concrete	30	70
Electric: vacuum mode	Concrete	30	80

14.6 Explosives Detonation

Emissions from the detonation of industrial explosives and firing of small arms (excluding military operations) are addressed in Section 13.3 of AP-42.⁶ This section of AP-42 was last updated in February 1980 (and reformatted in January 1995). Such large quantities of particulate are generated in the shattering of rock and earth by the explosive that the quantity of particulates from the explosive charge cannot be distinguished. With the exception of a few studies in underground mines, most studies have been performed in laboratory test chambers that differ substantially from the actual environment. Any estimates of emissions from explosives use must be regarded as approximations that cannot be made more precise because explosives are not used in a precise, reproducible manner.

14.7 References

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GLOSSARY

Areal extent—Fraction (or percentage) of the source area that is affected by the control measure.

Aerodynamic particle size—Diameter of a sphere of unit density, which behaves aerodynamically as a particle with different sizes, shapes, and densities.

Aggregate material—Mineral particles, such as sand or stone, typically derived from a mechanical process.

Agricultural tilling—Mechanical disturbance of agricultural soil by discing, shaping, chiseling, and leveling using a tractor or implement.

Annual interest rate—The yearly cost of borrowing money, expressed as a percentage of the amount borrowed.

Annualized cost of control—Average yearly costs of a control system including annual operating costs such as labor, materials, utilities and maintenance items, and annualized costs of the capital costs of purchase and installation. Annualized costs are dependent on the interest rate paid on borrowed money or collectable by the plant as interest (if available capital is used), the useful life of the control equipment, and depreciation rates of the equipment.

AP-42—Abbreviation for the U.S. EPA’s publication “Compilation of Air Pollutant Emission Factors.”

BACM—Abbreviation for Best Available Control Measures—techniques that achieve the maximum degree of emissions reduction from a source, as determined on a case-by-case basis considering technological and economic feasibility.

Bare soil adjustment—Adjustment to windblown emissions for the planted acreage on which plants do not establish.

Base year—Year for which the pre-control emissions inventory was performed.

Baseline Emissions—Emissions (total or source) in the base year.

Batch drop—Materials handling process involving free fall of aggregate, as from a bucket.

Border adjustment—Adjustment to windblown emissions for the nonplanted regions of the acreage dedicated to a given crop that separate it from surrounding regions.

CAPCOA—Acronym for California Air Pollution Control Officers’ Association.

Capital recovery factor—Amount of money per dollar of machinery investment required to pay annual interest costs on unrecovered investment and to recover the costs of the investment within a specified number of years at the given interest rate.

Chemical wetting agent—Compound added to water in order to enhance the penetration of water into dusty material and prevent dust emissions.

Clay—Cohesive soil with individual particles not visible to the unaided human eye (less than 0.002 mm in diameter). Clay can be molded into a ball that will not crumble.

Climatic factor “C,” annual—Parameter used to estimate the effects of climate on soil erodibility. Garden City, Kansas is set to 1.0 and temperature, wind, and precipitation are used to adjust the factor.

Climatic factor “C,” monthly—Parameter used to modify the annual “C” factor equation for a particular month of the year. The U.S. EPA uses mean monthly wind speed in place of the annual wind speed. The ARB methodology uses the month-as-a-year method.

Cloddiness—Level of relatively stable agglomerations in soil caused by exposure to water cohort (maturation class).

Compliance tool—Means for checking whether a facility is meeting legal requirements for control of a pollutant. Compliance tools include record keeping logs, databases, and site inspection methods.

Continuous drop—Materials handling process involving continual release of aggregate, such as from a conveyor.

Control application rate/frequency—Amount of pollutant suppressant applied over a particular area and the number of times per period that the suppressant is applied.

Control efficiency—Degree (e.g., percentage) to which a control measure is effective in limiting the release of a pollutant.

Control efficiency decay rate—Decrease in control efficiency for a control measure with a limited life span.

Control extent—Fraction of emissions from a source category that will be affected by a control method.

Control measure—Procedure or course of action taken to reduce air pollution. Preventive measures reduce source extent or incorporate process modifications or adjust work practices to reduce the amount of pollutants. Mitigative measures involve the periodic removal of pollutant causing materials, such as the cleanup of

spillage on travel surfaces and cleanup of material spillage at conveyor transfer points.

Controlled emissions—Estimated emissions (total or by source category) after application of control measures, i.e., remaining emissions.

Cost effectiveness—Control cost divided by the mass of emissions reduced (most typically expressed in terms of “dollars per ton”).

Crop calendar—Temporal distribution of agricultural activities (e.g., planting and harvesting dates).

Crop canopy cover factor—Adjustment to windblown emissions based on the crop canopy cover.

Crop canopy cover—Fraction of land sheltered by vegetation, as viewed directly from above.

Crust—The hard outer surface of soil (or other dust producing material) that inhibits the wind erosion of underlying fine particles.

Cut and fill—The activities of earthmoving equipment where soil or rock is removed from one area (cut) and deposited elsewhere on shallow ground (fill).

***De Minimis* source**—Facility or operation with emissions that are below a certain threshold, classifying them as insignificant sources of emissions; refer to 40 CFR, Part 52 for more details.

Demonstrated control technique—A control measure that is supported by verifiable tests as to the control efficiency the measure will achieve.

Deposition—Accumulation of airborne particles on ground-level surfaces through gravitational settling and other physical phenomena.

Disturbance—Destabilization of a land surface from its undisturbed natural condition thereby increasing the potential for fugitive dust emissions.

Dunes—Ridges or mounds of loose, wind-blown material, usually sand.

Dust—Fine, dry particles of matter able to be suspended in the air.

Dust Control Plan—Legally mandated plan for a geographical area or dust-producing operation that identifies how emissions will be controlled to attain the requirements of the Clean Air Act and Amendments.

Dust suppressants—Water, hygroscopic materials, solution of water and chemical surfactant, foam, or non-toxic chemical/ organic stabilizers not prohibited for use by the U.S. Environmental Protection Agency or any applicable law, rule or regulation, as a treatment material to reduce fugitive dust emissions.

Economic Life—Length of time during which a product or piece of property may be put to profitable use. (Usually less than its physical life)

Emission activity level—A numerical measure of the intensity of a process that emits pollutants (e.g., miles traveled by a vehicle, tons of transferred material). Also referred to as source extent or process rate.

Emission factor—A representative value that relates the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant.

Emission parameters—Values that affect pollutant emissions, such as moisture level and silt content of the emitting material.

Emission reduction—Amount (mass or percent) of emissions eliminated by control application.

Enforcement/Compliance costs—Expenses associated with enforcing control measures, including government agency and source facility expenditures.

Erosion potential—Value representing the potential for suspension of surface dust by wind erosion. Depending on the presence of a surface crust or surface disturbance, particle size distribution, and moisture content, a site is characterized as having 1) unlimited erosion potential, 2) limited erosion potential, or 3) no erosion potential.

Fastest mile of wind—The highest wind speed over a specified period (usually the 24-hour observational day) of any “mile” of wind. The fastest mile of wind is the reciprocal of the shortest interval (in 24 hours) that it takes one mile of air to pass a given point.

Fetch—Distance over which soil is eroded by a wind having a relatively constant direction and speed.

Friction velocity—Measure of shear stress of the wind on the exposed surface of soil or other aggregate material, causing loose particles to be lifted from the surface.

Fugitive dust source—Emitter of airborne particles where the particulate emissions cannot reasonably be passed through a stack, chimney, vent, or other functionally equivalent opening. Fugitive dust sources include roadways, construction

(earthmoving and demolition), material handling operations, soil tillage, and wind erosion.

Gravel—Soil particles ranging from 1/5 inch to 3 inches in diameter.

Grid counting method—Method used to estimate areas contained between contour lines on maps.

Ground inventory—A measurement of the amount of dust suppressant applied to an unpaved surface, usually expressed as gallons of suppressant per square yard of road surface.

Growing canopy fraction (GCF)—The proportion of the acreage that will have the crop canopy cover factor applied to it.

Half life of control—The time required for control efficiency to fall to half its initial value.

Irrigation factor (wetness)—Adjustment to the erodibility due to surface wetness from irrigation.

Long-term irrigation-based erodibility adjustment—Adjustment that takes into account changes in cloddiness of the soil, based upon differences between irrigated and nonirrigated soils.

Material throughput—Output rate of processed material.

Mitigative control—Control measure that periodically removes exposed dust-producing material.

MOBILE model—Software tool developed by EPA to predict gram per mile emissions of hydrocarbons, carbon monoxide, oxides of nitrogen, carbon dioxide, particulate matter, and toxics from cars, trucks, and motorcycles under various conditions.

Mode—The most frequent value in a group of values. The approximate mode of a particle size distribution (i.e., particle size diameter) can be found by sieving a surface material sample to find the threshold friction velocity using a modification to W.S. Chepil's method.

Moisture content—A measurement, usually expressed as a percent, of the mass of water in a material sample. Moisture content is obtained by weighing the original sample and then drying the sample to obtain the mass of vaporized water.

Month-as-a-year—Term used by California Air Resources Board (ARB) staff to describe method of calculating the climatic "C" factor profile by assuming that each month's data for a given site describes a unique annual climatic regime.

Most cost-effective—Having the lowest cost per mass of PM emissions reduced.

Most efficient—Having the highest control efficiency (note that preventive controls are usually addressed before mitigative controls).

Mulch—Any material used to cover a soil surface to conserve soil moisture and prevent erosion.

Nonattainment area—Geographic area that is not in compliance with federal health-based air quality standards for an air pollutant (e.g., PM-10).

Nonerodible material—Objects larger than 1 centimeter in diameter that are not susceptible to movement even on windy days (e.g., gravel, hard-packed soil clods).

Operating/Maintenance costs—Expenses associated with personnel, materials, consumables, equipment repair, and other types of continuing expenses.

Overhead costs—A broad category of costs associated with administration.

Pan evaporation rate—The rate of evaporation from a US Class-A pan that is filled with water, with daily measurements made of the water level to compute the resulting daily water loss.

Peak wind gust—A maximum wind speed defined by U.S. weather observing practice, with gusts reported when the peak wind speed reaches at least 16 knots and the variation in wind speed between the peaks and lulls is at least 9 knots. The duration of a gust is usually less than 20 seconds.

Plant/harvest date pair—Methodology that uses planting cohorts split between harvest months, using the fraction of the total crop planted in a given month with the fraction of the total crop harvested in a given month.

PM_x—Airborne particulate matter with aerodynamic diameters equal to or less than x μm (e.g. PM₁₀, PM_{2.5})

Portable wind tunnel—Moveable air channel with an open bottom through which air is drawn at different velocities. This type of wind tunnel with a backend sampling system is used to investigate particle emissions by wind erosion, as a function of wind speed.

Postharvest soil cover factor—Adjustment to windblown emissions based on the fraction of land covered after harvest when viewed directly from above.

- Precipitation effectiveness (PE)**—See “Thornthwaite’s precipitation-evaporation index”; the sum of 12 monthly values (ratios of precipitation to actual evapotranspiration).
- Preventive control**—Control measure that inhibits or minimizes the accumulation of exposed dust-producing material.
- Prewatering**—Application of water during construction and earthmoving operations to excavation areas and borrow pits before earth is excavated. The areas to be excavated are moistened to the full depth from the surface to the bottom of the excavation to achieve an optimum moisture content for fugitive dust control.
- Quality rating**—An assessment level of A through E as assigned by EPA to each emission factor in AP-42, with A being the best. A factor's rating is a general indication of the reliability, or robustness, of that factor.
- Replant-to-different-crop factor**—Adjustment to windblown emissions for harvested acreages that are quickly replanted to a different crop.
- Reservoir**—Amount of surface particles available for sustaining wind erosion. Surface soil properties determine the duration of dust events, and limited reservoirs will emit dust for a shorter duration of time (i.e., minutes) than unlimited reservoirs (i.e., days).
- Revegetation**—Vegetative cover that has been established on previously disturbed ground, such as a construction site.
- Revised Wind Erosion Equation (RWEQ)**—Model that is intermediate in complexity between the wind erosion equation (WEQ) and the wind erosion prediction system (WEPS).
- Rock**—Soil particles greater than 3 inches in diameter.
- Roughness height**—Height above ground level where the wind speed is theoretically reduced to zero because of surface obstructions; a measure of surface protrusion into the boundary layer wind flow.
- Sand**—Soil particles ranging from 0.05 to 2.0 mm in diameter; individual particles are visible to the unaided human eye.
- Senescence**—Process of plant aging and dying that is characterized by decreasing growth rates, chlorophyll breakdown, and mobilization of nitrogen out of leaves and into other plant organs.
- Sheltering elements**—Blockages to wind that inhibit wind erosion of soil. Examples include wind fences and trees.

SIC code—Abbreviation for Standard Industrial Classification code. A numbering system established by the Office of Management and Budget that identifies companies by industry.

Sieving—Process of passing a material through a series of woven square meshes of decreasing size to separate particles into different particle size classes. For agricultural soil classification, wet sieving disperses the material in a liquid before passing the suspension through one or more sieves. Dry sieving is used to characterize material dustiness levels and can be performed either by a mechanical sieve shaker or by rotational hand sieving.

Silt content—Percentage of particles less than 74 μm in physical diameter (i.e., fraction passing a standard 200-mesh sieve).

Silt—Noncohesive soil whose individual particles are not visible to the unaided human eye (0.002 to 0.05 mm). Silt will crumble when rolled into a ball.

Soil classes (types)—Classifications used by soil scientists: representative erodibilities have been measured, which allow soil maps to be used to estimate erodibilities for agricultural land.

Soil cover deterioration—Reduction in postharvest soil cover due to the effects of weather, sunlight, insects, microbes, etc.

Soil loss ratio (SLR)—The ratio of the soil loss for a soil of a given cover divided by the soil loss from bare soil.

Soil texture—The relative proportions of clay, silt, and sand in soil.

Soil—Surface material consisting of disintegrated rock and organic material.

Source Extent—See “Emission activity level.”

State Geographic Data Base (STATSGO)—Database of soil data produced and maintained by the NRCS.

Stepwise linear regression—Process of determining best-fit polynomials for a predictive mathematical model. The procedure involves least squares regression analysis in a forward stepping procedure

Surface disturbance—See “Disturbance.”

Surface loading—Mass of loose material per paved road surface area. Total surface loading is measured by vacuuming a known area of paved road surface to obtain all material regardless of particle size. Silt surface loading is obtained by sieving the

total surface loading and refers only to particles with physical diameters less than 74 μm .

Surface stabilization/treatment/improvement—The paving, graveling, chemical stabilization, or watering of a dust-emitting surface to prevent dust emissions due to mechanical disturbance and wind erosion.

Thornthwaite’s precipitation-evaporation index—A measure of soil aridity, calculated as the ratio of precipitation to evapotranspiration.

Threshold friction velocity—Friction velocity that closely corresponds to the threshold wind speed for wind erosion of a specific surface. See “Friction velocity.”

Threshold source size—An emission level below which a facility or dust-emitting activity is not regulated.

Threshold wind speed—Wind speed (measured at a reference height of 10 m) below which wind erosion does not occur from the exposed surface being considered.

Tillage—Practice of producing a soil surface to maintain surface residue, prepare a seed bed, conserve soil moisture, and reduce wind erosion.

Trackout—Accumulation of mud/dirt on paved roads, as deposited by vehicles that exit unpaved sites such as construction areas, agricultural fields, quarries, dumps, or batch plants.

Traffic volume—Measure of the number of vehicles traveling over a road segment. Vehicle miles traveled (VMT) on a road equals the average daily traffic (ADT) times the roadway length.

Uncontrolled emissions—Total emissions before application of any control measures.

Unit-operation emission factors—Emission factors that represent sub-processes or separate activities associated with an emission source.

Vegetative cover/residue—Organic matter, either growing or dead, that protects the soil surface from the erosive force of wind.

Visible dust—For regulatory purposes, means airborne particles that obscure an observer’s view to a degree equal to or greater than a specified opacity limit.

Wet stabilization/watering—See “Surface stabilization.”

Wind barrier/Wind sheltering—See “Sheltering element.”

Wind erosion equation (WEQ)—Methodology originally developed to estimate wind erosion from agricultural lands. Later modified by U.S. EPA to use for estimating PM emissions.

Wind Erosion Prediction System (WEPS)—Detailed simulation model to predict wind erosion emissions; currently in development. May be useful in future, especially for episodic modeling.

Wind erosion—Removal of dry soil particles from the ground surface by wind, causing airborne particulate matter downwind of the emitting soil area.

Wind shear—Force of wind parallel to a surface that can remove loose particles, as opposed to wind directly impacting the surface.

Worst-case emissions—See “Uncontrolled emissions.”

Appendix A

Emission Quantification Techniques

EMISSION QUANTIFICATION TECHNIQUES

Fugitive dust emission rates and particle size distributions are difficult to quantify because of the diffuse and variable nature of such sources and the wide range of particle sizes, including particles that deposit immediately adjacent to the source. Standard source testing methods, which are designed for application to confined flows under steady-state, forced-flow conditions, are not suitable for the measurement of fugitive emissions unless the plume can be drawn into a forced-flow system. The available source testing methods for fugitive dust sources are described in the following paragraphs.

Mechanical Entrainment Processes

Because it is usually impractical to enclose open dust sources or to capture the entire emissions plume, only two methods are suitable for the measurement of particulate emissions from most open dust sources:

1. The upwind-downwind method involves the measurement of upwind and downwind particulate concentrations, utilizing ground-based samplers under known meteorological conditions, followed by a calculation of the source strength (mass emission rate) with atmospheric dispersion equations.¹
2. The exposure-profiling method involves simultaneous, multipoint measurements of particulate concentration and wind speed over the effective cross section of the plume, followed by a calculation of the net particulate mass flux through integration of the plume profiles.²

In both cases it is customary to use high-volume air samplers, so that quantifiable sample mass can be accumulated in sampling periods no longer than about six hours.

Upwind-Downwind Method. The upwind-downwind method involves the measurement of airborne particulate concentrations both upwind and downwind of the pollutant source. The number of upwind sampling instruments depends on the degree of isolation of the source operation of concern (i.e., the absence of interference from other sources upwind). Increasing the number of downwind instruments improves the reliability in determining the emission rate by providing better plume definition. In order to reasonably define the plume emanating from a point source, instruments need to be located at a minimum of two downwind distances and three crosswind distances. The same sampling requirements pertain to line sources except that measurements need not be made at multiple crosswind distances.

Net downwind (i.e., downwind minus upwind) concentrations are used as input to atmospheric dispersion equations (normally of the Gaussian type) to back-calculate the particulate emission rate (i.e., source strength) required to generate the pollutant concentrations measured. Emission factors are obtained by dividing the calculated emission rate by the source extent. A number of meteorological parameters must be concurrently recorded for input to this dispersion equation. As a minimum, the wind direction and speed must be recorded on-site.

While the upwind-downwind method is applicable to virtually all types of sources, it has significant limitations with regard to the development of source-specific emission factors. Because of the impracticality of adjusting the locations of the sampling array for shifts in wind direction during sampling, it may be questionable to assume that the plume position is fixed in the application of the dispersion model. In addition, the usual assumption that a line or area source is uniformly emitting may not allow for a realistic representation of spatial variation in source activity.

Exposure-Profiling Method As an alternative to conventional upwind-downwind sampling, the exposure-profiling technique utilizes the emission profiling concept, which is the basis for the conventional ducted source testing method (i.e., USEPA Method 5³), except that, in the case of exposure-profiling, the ambient wind directs the plume to the sampling array. The passage of airborne particulate matter immediately downwind of the source is measured directly by means of a simultaneous, multipoint sampling of particulate concentration and wind velocity over the effective cross section of the fugitive emissions plume.

For the measurement of nonbuoyant fugitive emissions using exposure profiling, sampling heads are distributed over a vertical network positioned just downwind (usually about 5 m) from the source. Particulate sampling heads should be symmetrically distributed over the concentrated portion of the plume containing at least 80% of the total mass flux. A vertical line grid of at least three samplers is sufficient for the measurement of emissions from line or moving point sources (see Figure A-1), while a two-dimensional array of at least five samplers is required for quantification of the fixed virtual point source of emissions. For quantifying emissions of particles larger than about 10 μm , the particulate samplers should have directional intakes, as discussed below. At least one upwind sampler must be operated to measure the background concentration, and wind speed and direction must be measured concurrently on-site.

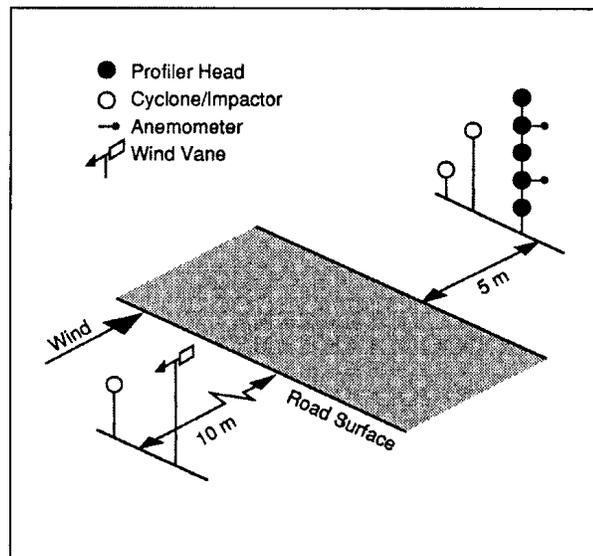


Figure A-1. Exposure Profiling Method—Roadway

The particulate emission rate is obtained by a spatial integration of the distributed measurements of exposure (accumulated mass flux), which is the product of mass concentration and wind speed:

$$R = \int_A C(h, w)u(h, w)dhdw \quad (1)$$

where, R = emission rate, (g/s)
 C = net particulate concentration, (g/m³)
 u = wind speed, (m/s)
 h = vertical distance coordinate, (m)
 w = lateral distance coordinate, (m)
 A = effective cross-sectional area of plume, (m²)

Usually, a numerical integration scheme is used to calculate the emission rate. This mass-balance calculation scheme requires no assumptions about plume dispersion phenomena.

Isokinetic Sampling Regardless of which method is used, isokinetic sampling is required for a representative collection of particles larger than about 10 μm in aerodynamic diameter. The directional sampling intakes are pointed into the mean wind direction and the intake velocity of each sampler is periodically adjusted (usually with intake nozzles) to closely match the mean wind velocity approaching the sampling intake. Because of natural fluctuations in wind speed and direction, some anisokinetic sampling effects will always be encountered. If the angle α between the mean wind direction and the direction of the sampling axis equals 30°, the sampling error is about 10%.⁴ For an isokinetic flow ratio of sampling intake speed to approach wind speed between 0.8 and 1.2, the sampling error is about 5%.⁴

Wind Erosion

The two wind erosion source testing methods of interest are the upwind-downwind method as described above and the portable wind tunnel method. The wind tunnel method involves the use of a portable open-floored wind tunnel for *in situ* measurement of emissions from representative surfaces under predetermined wind conditions.⁵

Upwind-Downwind Method The upwind-downwind method is burdened with practical difficulties for the study of wind erosion, in that the onset of erosion and its intensity is beyond the control of the investigator. In addition, background (upwind) particulate concentrations tend to be high during erosion events, making source isolation very difficult.

Wind Tunnel Method The most common version of the wind tunnel method utilizes a pull-through wind tunnel with an open-floored test section placed directly over the surface to be tested. Air is drawn through the tunnel at controlled velocities. The exit air stream from the test section passes through a circular duct fitted with a directional sampling probe at the downstream end. Air is drawn isokinetically through the probe by

a high-volume sampling train. The wind tunnel method incorporates the essential features of the USEPA Method 5 stack sampling method.³ The one prime difference, the use of single-point sampling, is justified by the high turbulence levels in the sampling module. The measurement uncertainty inherent in this method is of the same order as that in Method 5, which has been subjected to extensive collaborative testing by EPA. The wind tunnel method relies on a straightforward mass-balance technique for the calculation of emission rate. By sampling under light ambient wind conditions, background interferences from upwind erosion sources can be avoided. Although a portable wind tunnel does not generate the larger scales of turbulent motion found in the atmosphere, the turbulent boundary layer formed within the tunnel simulates the smaller scales of atmospheric turbulence. It is the smaller-scale turbulence, which penetrates the wind flow in direct contact with the erodible surface and contributes to the particle entrainment mechanisms.⁶

Particle Sizing

Concurrent with the measurement of mass emissions, the aerodynamic particle size distribution should be characterized. Chemical, biological, and morphological analyses may also be performed to characterize the nature and origin of the particles. For particle sizing, a high-volume cyclone/cascade impactor featuring isokinetic sample collection has been used.⁷ A cyclone preseparator (or other device) is needed to remove the coarse particles, which otherwise would bounce off the greased substrate stages within the impactor, causing fine-particle bias. Once again, the sampling intake is pointed into the wind and the sampling velocity adjusted to the mean local wind speed by fitting the intake with a nozzle of appropriate size. This system offers the advantage of a direct determination of aerodynamic particle size.

Another particle sizing option includes an analysis of the particulate deposit by optical or electron microscopy. Disadvantages include: (a) potential artificial disaggregation of particle clusters during sample preparation, and (b) uncertainties in converting physical size data to equivalent aerodynamic diameters. In a collaborative field test of the exposure-profiling method, the cyclone/impactor method was judged to be more suitable than microscopy for the particle sizing of fugitive dust emissions.⁸

Control Efficiency Estimation

Field evaluation of the control efficiency requires that the study design include not only adequate emission measurement techniques but also a proven “control application plan.” In the past, two major types of plans have been used. Under the Type-1 plan, controlled and uncontrolled emission measurements are obtained simultaneously. Under the Type-2 plan, uncontrolled tests are performed initially, followed by controlled tests.

In order to ensure comparability between the operating characteristics of the controlled and uncontrolled sources, many evaluations are forced to employ Type-2 plans. An example would be a wet suppression system used on a primary crusher. One important exception to this; however, is unpaved-road dust control. In this instance,

testing under a Type-1 plan may be conducted on two or more contiguous road segments. One segment is left untreated and the others are treated with the dust suppressant. Under a Type-2 plan, a normalization of emissions may be required to allow for potential differences in source characteristics during the uncontrolled and controlled tests because they do not occur simultaneously.

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Appendix B

Estimated Costs of Fugitive Dust Control Measures

Source Category	Control Measure	Estimated Costs	Comments/Assumptions
Paved Roads	4' Paved Shoulders	\$8,200/mile-year	Useful life of 20 years
	Polymer emulsion to stabilize shoulders	\$0.92/square yard	
	Purchase PM10 efficient sweeper	\$190/mile-year	Useful life of 8 years; sweep 15 centerline miles per day
	Clean up spills	\$640/cleanup	
Unpaved Roads and Parking Areas	Pave unpaved roads	\$44,100/mile-year	Useful life of 25 years
	Pave section 100' long before facility exit	\$716/year	30' wide with 3" of asphalt; useful life of 25 years
	Pave unpaved parking lots	\$0.23/ft ² -year	Useful life of 25 years
	Pipe grid trackout control device	\$1,820/year	Useful life of 8 years
	Gravel bed to reduce trackout	\$1,360/year	50' x 30' x 3" thick
	Post speed limit sign	\$53/year for two signs	Useful life of 15 years
	Apply water to unpaved parking lot once a day	\$68-\$81/acre-day	
	Chemical dust suppressant	\$5,340/acre-year	Useful life of 1 year
Construction and Demolition	Chemical dust suppressant	\$5,340/acre-year	Useful life of 1 year
	Apply water once a day	\$68-\$81/acre-day	
	Apply water during high winds	\$272/acre	
	Prohibit activities during high winds	\$1,360 per 8 hour day idled	Demolition of 1,000 ft ² structure on 1.2 acres
	Require air quality monitoring	\$7,500/month	
	Onsite dust control coordinator	\$100/day	
	Sprinkler system to maintain minimum soil moisture of 12%	\$138/acre	
	Limit speed to 15 mph	\$22/inspection	Radar gun = \$700
	Post speed limit signs	\$180/sign	
Bulk Materials	3-sided enclosure with 50% porosity	\$109/year	Useful life of 15 years; pile volume = 5 yd ³
Disturbed Open Areas	Polymer emulsion dust suppressant	\$2,140/acre	Surface stabilized for 3 years if no vehicle disturbance
	Gravel, 1" deep	\$490/acre-year	Useful life of 15 years
	Post no trespassing signs	\$53/sign	Useful life of 15 years
Windblown Dust	Prohibit activities at construction sites during high winds	\$3,100 per high wind day	40 acre construction site
	Water storage pile each hour during high winds	\$22/day	100 cubic yard pile

Reference: Sierra Research, Inc., *Final BACM Technological and Economic Feasibility Analysis*, prepared for the San Joaquin Valley APCD, March 21, 2003.

Appendix C

Methodology for Calculating Cost-Effectiveness of Fugitive Dust Control Measures

INTRODUCTION

In compiling information on control cost-effectiveness estimates for the fugitive dust handbook, we discovered that many of the estimates provided in contractor reports prepared for air quality agencies for PM10 SIPs contain either hard to substantiate assumptions or unrealistic assumptions. Depending on which assumptions are used, the control cost-effectiveness estimates can range over one to two orders of magnitude. Rather than presenting existing cost-effectiveness estimates, we have prepared a detailed methodology containing the steps to calculate cost-effectiveness that is presented below. We recommend that the handbook user calculate the cost-effectiveness values for different fugitive dust control options based on current cost data and assumptions that are applicable to their particular situation.

Based on field measurements of uncontrolled and controlled unpaved road emissions conducted by Midwest Research Institute, there were no significant differences in the measured control efficiencies for the PM2.5 and PM10 size fractions. Thus, the cost-effectiveness for PM2.5 reduction can be calculated by dividing the cost-effectiveness estimate for PM10 reduction by the PM2.5/PM10 ratio for that fugitive dust source.

TECHNICAL APPROACH

The steps necessary to calculate the cost-effectiveness for different fugitive dust control measures are listed below. This methodology was employed to calculate the cost-effectiveness for each control application case study for the different fugitive dust source categories addressed in the handbook.

Step 1: Select a specific control measure for the fugitive dust source category of interest.

Step 2: Specify the basic parameters required to calculate uncontrolled and controlled emissions for the specific source:

- (a) applicable emission factor equation
- (b) parameters used in the emission factor equation
- (c) source extent (activity level)
- (d) characteristics of the source
- (e) control measure implementation schedule (frequency, application rate)

Step 3: Calculate the annual uncontrolled emission rate as the product of the emission factor and the source extent (from Step 2).

Step 4: Determine the control efficiency for the selected control measure. This may involve either (a) using a published value, (b) calculating the control efficiency based on comparing the controlled emissions estimate derived from the applicable emission factor equation with the uncontrolled emissions estimate derived from the same emission factor equation, or (c) specifying the desired control efficiency which then will entail determining the appropriate level of control to achieve the desired control efficiency.

Step 5: Calculate the annual controlled emissions rate (i.e., the emissions remaining after control) as the product of the annual uncontrolled emission rate (from Step 3) multiplied by the percentage that uncontrolled emissions are reduced, as follows:

$$\text{Controlled emissions} = \text{Uncontrolled emissions} \times (1 - \text{Control Efficiency}).$$

Step 6: Calculate the reduction in emissions as the difference between the annual uncontrolled emission rate (from Step 3) and the annual controlled emission rate (from Step 5).

Step 7: Gather cost estimates for implementing the selected control measure for the following items:

- (a) annualized capital costs (total capital costs/lifetime of the control)
- (b) annual operating and maintenance costs that include overhead, enforcement, and compliance costs

Step 8: Calculate the annualized capital investment cost as the product of the annual capital cost and the capital recovery factor. The capital recovery factor is calculated as follows:

$$\text{CRF} = [i (1 + i)^n] / [(1 + i)^n - 1]$$

where, CRF = capital recovery factor

i = annual interest rate (fraction)

n = number of payment years

Step 9: Calculate the total annualized cost by combining the annualized capital investment cost (from Step 8) with annual operating and maintenance costs (from Step 7).

Step 10: Calculate the cost-effectiveness of the selected control measure by dividing the total annualized costs (from Step 9) by the emissions reduction. The emissions reduction is determined by subtracting the controlled emissions (from Step 5) from the uncontrolled emissions (from Step 3).

Appendix D

Fugitive PM10 Management Plan

Overview

The San Joaquin Valley APCD's Regulation VIII that addresses fugitive dust specifies two general control methods for controlling fugitive dust: (1) limiting visible dust emissions and (2) maintaining a stabilized surface. Visible dust emissions (VDE) may not exceed 20 percent opacity during periods when soil or other dust-producing materials are being disturbed by vehicles, equipment, or the forces of wind. "Opacity" is a visual evaluation of the amount of one's view that is obscured by a dust plume. The VDE limit applies to construction sites, the handling and storage of bulk materials, and to unpaved roads and traffic areas. A stabilized surface is a treated surface that is resistant to wind effects. This requirement applies to vacant open areas that have previously been disturbed, unpaved roads and traffic areas, and outdoor bulk storage piles. Methods for creating and maintaining a stabilized surface may include applying chemical or organic stabilizers, road-mix or paving materials, vegetative materials, or water for soaking the soil or forming a visible crust.

For unpaved roads and unpaved traffic areas, a Fugitive PM10 Management Plan (FPMP) may be implemented as a compliance alternative to the Visible Dust Emission standard and the requirement to maintain a stabilized unpaved road surface. The FPMP identifies the control measures to be implemented whenever vehicular traffic reaches and exceeds the applicable thresholds i.e., ≥ 75 vehicles per day or ≥ 26 vehicles per day with 3 or more axles). Acceptable control measures are those that have demonstrated to achieve at least 50 percent PM10 control efficiency when properly applied to an unpaved surface.

A FPMP may not be prepared for unpaved haul roads and access roads as well as traffic areas at construction projects nor as an alternative to a Conservation Management Practice (CMP) Plan for agricultural sources. Non-agricultural sources choosing to implement a FPMP are required to submit a plan to the District for approval. Once approved, the owner or operator is required to implement the District-approved FPMP on all days where traffic exceeds the applicable minimum thresholds. An approved plan remains active until the District notifies the owner or operator that it is no longer valid, or until the owner or operator notifies the District that plan implementation has been permanently discontinued.

Required Information

The FPMP must include the following information:

1. The names, addresses, and phone numbers of persons responsible for the preparation, submittal, and implementation of the FPMP, and of the persons responsible for the unpaved road or traffic area.

2. A plot plan or map showing the location of each unpaved road or traffic area to be covered by the FPMP, the total length in miles of unpaved roads, and the total area in acres of unpaved traffic areas that will be subject to the plan.

3. The months (and weeks, if known) of the year when vehicle traffic is expected to exceed the minimum thresholds described in the applicable rules, and the types of vehicles (i.e. passenger vehicles, trucks, mobile equipment, etc.).

4. The control methodologies to be applied, including:
- a. Product specifications;
 - b. Manufacturer’s usage instructions (method, frequency, and intensity of application);
 - c. Application equipment (type, number, and capacity); and
 - d. Environmental impact information and approvals or certificates related to appropriate and safe use for ground application.

5. The condition of the treated surfaces to be achieved as a result of the use of suppressants or other dust control material.

Record Keeping Requirements

Owners and operators are required to maintain records and any other supporting documents to demonstrate compliance for those days when control measures were implemented. Records are to include the type of control measure implemented, the location and extent of coverage, and the date, amount and frequency of applying dust suppressants.

Record keeping forms developed by the District or a facsimile that provides the necessary information may be used for record keeping purposes. Records are to be kept for a minimum of one year following termination of dust generating activities. Title V stationary sources are required to keep the records for a minimum of five years. Records must be made available to the District inspector upon request. The matrix below lists the forms to be used for Regulation VII record keeping.

Industry	Activity at site and corresponding record keeping forms					
	Bulk Materials	Unpaved Roads	Equip & Vehicle Storage	Open Areas	Earth Moving	Trackout and Carryout
Construction	A C	A C D	A C D	A C	A	B
Oilfields	A C	A C D	A C D	A C	A	B
Off-field Ag Ops	A C	A C D	A C D			
Ag Product Processing	A C	A C D	A C D			B
Bulk Materials	A C	A C D	A C D			B
Equipment & Vehicle Storage	A C	A C D	A C D	A C		B
Truck Stops	A C	A C D	A C D	A C		B

Form A = Daily watering schedule

Form B = Sweeping/cleanup schedule for trackout and carryout

Form C = Permanent control measure (e.g., paving, gravel, a grizzly, chemical dust suppressants)

Form D = Daily schedule for water application onto unpaved roads and equipment areas

0157 44.1

**Alternative Control
Techniques Document--
NO_x Emissions from
Industrial/Commercial/Institutional
(ICI) Boilers**

Emission Standards Division

**U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
March 1994**

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ALTERNATIVE CONTROL TECHNIQUES DOCUMENT

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1. INTRODUCTION

Congress, in the Clean Air Act Amendments (CAAA) of 1990, amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

[W]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of . . . oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Industrial, commercial, and institutional (ICI) boilers have been identified as a category that emits more than 25 tons of oxides of nitrogen (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from ICI boilers. Additional ACT documents are being developed for other stationary source categories.

ICI boilers include steam and hot water generators with heat input capacities from 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). These boilers are used in a variety of applications, ranging from commercial space heating to process steam generation, in all major industrial sectors. Although coal, oil, and natural gas are the primary fuels, many ICI boilers also burn a variety of industrial, municipal, and agricultural waste fuels.

It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable to every ICI boiler application. The furnace design, method of fuel firing, condition of existing equipment, operating duty cycle, site conditions, and other site-specific factors must be taken into consideration to properly evaluate the applicability and performance of any given control technique. Therefore, the feasibility of a retrofit should be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by ICI boiler manufacturers, control equipment vendors, ICI boiler

users, and regulatory agencies. Chapter 2 summarizes the findings of this study. Chapter 3 presents information on the ICI boiler types, fuels, operation, and industry applications. Chapter 4 discusses NO_x formation and uncontrolled NO_x emission factors. Chapter 5 covers alternative control techniques and achievable controlled emission levels. Chapter 6 presents the cost and cost effectiveness of each control technique. Chapter 7 describes environmental and energy impacts associated with implementing the NO_x control techniques. Finally, Appendices A through G provide the detailed data used in this study to evaluate uncontrolled and controlled emissions and the costs of controls for several retrofit scenarios.

2. SUMMARY

This chapter summarizes the information presented in more detail in Chapters 3 through 7 of this document. Section 2.1 reviews the diversity of equipment and fuels that make up the ICI boiler population. The purposes of this section are to identify the major categories of boiler types, and to alert the reader to the important differences that separate the ICI boiler population from other boiler designs and operating practices. This diversity of combustion equipment, fuels, and operating practices impacts uncontrolled NO_x emission levels from ICI boilers and the feasibility of control for many units. Section 2.2 reviews baseline NO_x emission reported for many categories of ICI boilers and highlights the often broad ranges in NO_x levels associated with boiler designs, firing methods, and fuels.

The experience in NO_x control retrofits is summarized in Section 2.3. This information was derived from a critical review of the open literature coupled with information from selected equipment vendors and users of NO_x control technologies. The section is divided into a subsection on combustion controls and another on flue gas treatment controls. As in the utility boiler experience, retrofit combustion controls for ICI boilers have targeted principally the replacement of the original burner with a low- NO_x design. When cleaner fuels are burned, the low- NO_x burner (LNB) often includes a flue gas recirculation (FGR) system that reduces the peak flame temperature producing NO_x . Where NO_x regulations are especially stringent, the operating experience with natural gas burning ICI boilers also includes more advanced combustion controls and techniques that can result in high fuel penalties, such as water injection (WI). As in the case of utility boilers, some boiler designs have shown little adaptability to combustion controls to reduce NO_x . For these units, NO_x reductions are often achievable only with flue gas treatment technologies for which experience varies.

Section 2.4 summarizes the cost of installing NO_x controls and operating at lower NO_x levels. The data presented in this document are drawn from the reported experience of technology users coupled with costs reported by selected technology vendors. This information is offered only as a guideline because control costs are always greatly influenced by numerous

site factors that cannot be taken fully into account. Finally, Section 2.5 summarizes the energy and environmental impacts of low-NO_x operation. Combustion controls are often limited in effectiveness by the onset of other emissions and energy penalties. This section reviews the emissions of CO, NH₃, N₂O, soot and particulate.

2.1 ICI BOILER EQUIPMENT

The family of ICI boilers includes equipment type with heat input capacities in the range of 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). Industrial boilers generally have heat input capacities ranging from 10 to 250 MMBtu/hr (2.9 to 73 MWt). This range encompasses most boilers currently in use in the industrial, commercial, and institutional sectors. The leading user industries of industrial boilers, ranked by aggregate steaming capacity, are the paper products, chemical, food, and the petroleum industries. Those industrial boilers with heat input greater than 250 MMBtu/hr (73 MWt) are generally similar to utility boilers. Therefore, many NO_x controls applicable to utility boilers are also candidate control for large industrial units. Boilers with heat input capacities less than 10 MMBtu/hr (2.9 MWt) are generally classified as commercial/institutional units. These boilers are used in a wide array of applications, such as wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, government buildings, airports, primarily providing steam and hot water for space heating. Boilers used in this sector generally range in size from 0.4 to 12.5 MMBtu (0.11 to 3.7 MWt) heat input capacity, although some are appreciably larger.

Table 2-1 lists the various equipment and fuel combinations, the range in heat input capacity, and the typical applications. Passed boiler inventory studies were used to estimate the relative number and total firing capacity of each boiler-fuel category. Many of these boilers vary greatly in age and use patterns. Older units have outdated furnace configurations with greater refractory area and lower heat release rates. Newer designs focus on compact furnaces with tangent tube configurations for greater heat transfer and higher heat release rates. Newer furnaces also tend to have fewer burners, because of improvements in combustion control and better turndown capability, and better economics. This diversity of equipment requires a careful evaluation of applicable technologies. Many smaller ICI boilers often operate with little supervision, and are fully automated. Application of NO_x controls that would limit this operational flexibility may prove impractical. They can be found fully enclosed inside commercial and institutional buildings and in industry steam plants or completely outdoors in several industrial applications at refineries and chemical plants. The location of these boilers often

TABLE 2-1. ICI BOILER EQUIPMENT, FUELS, AND APPLICATIONS

Heat transfer configuration	Design and fuel type	Capacity range, MMBtu/hr ^a	% of ICI boiler units ^{b,c}	% of ICI boiler capacity ^{b,c}	Application ^d
Watertube	Pulverized coal	100-1,500+	** ^e	2.5	PH, CG
	Stoker coal	0.4-550+ ^f	**	5.0	SH, PH, CG
	FBC ^g coal	1.4-1,075	**	**	PH, CG
	Gas/oil	0.4-1,500+	2.3	23.6	SH, PG, CG
	Oil field steamer	20-62.5	N.A. ^h	N.A.	PH
	Stoker nonfossil	1.5-1,000 ^f	**	1.1	SH, PH, CG
	FBC nonfossil	40-345	**	**	PH, CG
	Other nonfossil	3-800	**	**	SH, PH, CG
Firetube	HRT coal	0.5-50	**	**	SH, PH
	Scotch coal	0.4-50	**	**	SH, PH
	Vertical coal	<2.5	**	**	SH, PH
	Firebox coal	0.4-15	**	**	SH, PH
	HRT gas/oil	0.5-50	1.5	1.5	SH, PH
	Scotch gas/oil	0.4-50	4.8	4.6	SH, PH
	Vertical gas/oil	<2.5	1.0	**	SH, PH
	Firebox gas/oil	<20	6.5	48	SH, PH
	HRT nonfossil	2-50	N.A.	N.A.	SH, PH
	Firebox nonfossil	2-20	N.A.	N.A.	SH, PH
Cast iron	Coal	<0.4-14	9.9	1.3	SH, PH
	Gas/oil	<0.4-14	72	9.6	SH, PH
Tubeless	Gas/oil	<0.4-4	N.A.	N.A.	SH, PH

^aTo convert to MWt, multiply by 0.293.

^bIncludes all units used in the ICI sector, regardless of capacity.

^c1991 FBC data; other data are from 1977-1978.

^dSH = Space heat; PH = Process heat; CG = Cogeneration.

^e** indicates less than 1 percent.

^fDesign capacities can be higher.

^gFBC = fluidized bed combustion.

^hN.A. = Not available. No data are available.

influences the feasibility of retrofit for some control technologies because poor access and limited available space.

ICI boiler equipment is principally distinguished by the method of heat transfer of heat to the water. The most common ICI boiler types are the watertube and firetube units. Firetube boilers are generally limited in size to about 50 MMBtu/hr (15 MWt) and steam pressures, although newer designs tend to increase the firing capacity. All of these firetubes are prefabricated in the shop, shipped by rail or truck, and are thus referred to as packaged. Watertube boilers tend to be larger in size than firetube units, although many packaged single burner designs are well within the firetube capacity range. Larger, multi-burner watertubes tend to be field erected, especially older units. Newer watertubes also tend to be single burners and packaged. Steam pressures and temperatures for watertubes are generally higher than firetube units. Combustion air preheat is never used for firetube boiler configuration. Higher capacity watertube ICI boilers often use combustion air preheat. This is an important distinction because air preheat units tend to have higher NO_x levels.

As the type and sizes of ICI boilers are extremely varied, so are the fuel types and methods of firing. The most commonly used fuels include natural gas, distillate and residual fuel oils, and coal in both crushed and pulverized form. Natural gas and fuel oil are burned in single or multiple burner arrangements. Many ICI boilers have dual fuel capability. In smaller units, the natural gas is normally fed through a ring with holes or nozzles that inject fuel in the air stream. Fuel oil is atomized with steam or compressed air and fed via a nozzle in the center of each burner. Heavy fuel oils must be preheated to decrease viscosity and improve atomization. Crushed coal is burned in stoker and fluidized bed (FBC) boilers. Stoker coal is burned mostly on a grate (moving or vibrating) and is fed by various means. Most popular are the spreader and overfeed methods. Crushed coal in FBC boilers burns in suspension in either a stationary bubbling bed of fuel and bed material or in a circulating fashion. The bed material is often a mixture of sand and limestone for capturing SO₂. Higher fluidizing velocities are necessary for circulating beds which have become more popular because of higher combustion and SO₂ sorbent efficiencies. Where environmental emissions are strictly controlled and low grade fuels are economically attractive, FBC boilers have become particularly popular because of characteristically low NO_x and SO₂ emissions.

Although the primary fuel types are fossil based, there is a growing percentage of nonfossil fuels being burned for industrial steam and nonutility power generation. These fuels

include municipal and agricultural wastes, coal mining wastes, and petroleum coke and special wastes such as shredded tires, refuse derived fuel (RDF), tree bark and saw dust, and black liquor from the production of paper. Solid waste fuels are typically burned in stoker or FBC boilers which provide for mass feed of bulk material with minimal pretreatment and the handling of large quantities of ash and other inorganic matter. Some industries also supplement their primary fossil fuels with hazardous organic chemical waste with medium to high heating value. Some of these wastes can contain large concentrations of organically bound nitrogen that can be converted to NO_x emissions. The practice of burning hazardous wastes in boilers and industrial furnaces is currently regulated by the EPA under the Resource Conservation and Recovery Act (RCRA).

2.2 NO_x FORMATION AND BASELINE EMISSIONS

NO_x is the high-temperature byproduct of the combustion of fuel and air. When fuel is burned with air, nitric oxide (NO), the primary form of NO_x , is formed mainly from the high temperature reaction of atmospheric nitrogen and oxygen (thermal NO_x) and from the reaction of organically bound nitrogen in the fuel with oxygen (fuel NO_x). A third and less important source of NO formation is referred to as "prompt NO," which forms from the rapid reaction of atmospheric nitrogen with hydrocarbon radical to form NO_x precursors that are rapidly oxidized to NO at lower temperatures. Prompt NO is generally minor compared to the overall quantity of NO generated from combustion. However, as NO_x emissions are reduced to extremely low limits, i.e., with natural gas combustion, the contribution of prompt NO becomes more important.

The mechanisms of NO_x formation in combustion are very complex and cannot be predicted with certainty. Thermal NO_x is an exponential function of temperature and varies with the square root of oxygen concentration. Most of the NO_x formed from combustion of natural gas and high grade fuel oil (e.g., distillate oil or naphtha) is attributable to thermal NO_x . Because of the exponential dependence on temperature, the control of thermal NO_x is best achieved by reducing peak combustion temperature. Fuel NO_x results from the oxidation of fuel-bound nitrogen. Higher concentrations of fuel nitrogen typically lead to higher fuel NO_x and overall NO_x levels. Therefore, combustion of residual oil with 0.5 percent fuel-bound nitrogen, will likely result in higher NO_x levels than natural gas or distillate oil. Similarly, because coal has higher fuel nitrogen content higher baseline NO_x levels are generally measured from coal combustion than either natural gas or oil combustion. This occurs in spite of the fact that the conversion of fuel nitrogen to fuel NO_x typically diminishes with increasing nitrogen

concentration. Some ICI boilers, however, that operate at lower combustion temperature, as in the case of an FBC, or with reduced fuel air mixing, as in the case of a stoker, can have low NO_x emissions because of the suppression of the thermal NO_x contribution.

Test data were compiled from several sources to arrive at reported ranges and average NO_x emission levels for ICI boilers. Baseline data were compiled from test results on more than 200 ICI boilers described in EPA documents and technical reports. These data, representative of boiler operation at 70 percent capacity or higher, are detailed in Appendix A. Table 2-2 summarizes the range and average NO_x emissions from the various categories of ICI boilers investigated in this study. On an average basis, coal-fired ICI boilers emit the highest level of NO_x, as anticipated. Among the higher emitters are the wall-fired boilers with burners on one or two opposing walls of the furnace. Average NO_x levels were measured at approximately 0.70 lb/MMBtu. Next highest emitters are tangential boilers burning pulverized coal (PC). The burners on these units are located in the corners of the furnace at several levels and firing in a concentric direction.

Among the stokers, the spreader firing system has the highest NO_x levels than either the overfeed or underfeed designs. This is because a portion of the coal fines burn in suspension in the spreader design. This method of coal combustion provides for the greatest air-fuel mixing and consequently higher NO_x formation. FBC boilers emit significantly lower NO_x emissions than PC-fired units and are generally more efficient than stokers. The large variations in baseline NO_x levels for the FBC units are generally the result of variations in air distribution among FBC units. Newer FBC designs incorporate a staged air addition that suppresses NO_x levels. Also the type of bed material and SO₂ sorbent influence the level of NO_x generated. FBC units are, on average, the lowest NO_x emitters among coal burning ICI equipment.

Large variations in baseline NO_x levels are also shown for ICI boilers burning residual oil. For example, boilers with a capacity of less than 100 MMBtu/hr (29 MWt) can have emissions in the range of 0.20 to 0.79 lb/MMBtu, a factor of nearly 4. This is attributable predominantly to large variations in fuel nitrogen content of these fuel oils. NO_x emissions from distillate-oil- and natural-gas-fired ICI boilers are significantly lower due by and large to the burning of cleaner fuel with little or no fuel-bound nitrogen. It is also important to note that baseline emission levels for the larger boilers tend to be somewhat higher, on average. This is attributable to the higher heat release rate that generally accompanies the larger units in order to minimize the size of the furnace and the cost of the boiler. Also, another factor is the use

TABLE 2-2. SUMMARY OF BASELINE NO_x EMISSIONS

Fuel	Boiler type	Uncontrolled NO _x range, lb/MMBtu	Average, lb/MMBtu
Pulverized coal	Wall-fired	0.46-0.89	0.69
	Tangential	0.53-0.68	0.61
	Cyclone	1.12 ^a	1.12
Coal	Spreader stoker	0.35-0.77	0.53
	Overfeed stoker	0.19-0.44	0.29
	Underfeed stoker	0.31-0.48	0.39
	Bubbling FBC	0.11-0.81	0.32
	Circulating FBC	0.14-0.60	0.31
Residual oil	Firetube	0.21-0.39	0.31
	Watertube:		
	10 to 100 MMBtu/hr > 100 MMBtu/hr	0.20-0.79 0.31-0.60	0.36 0.38
Distillate oil	Firetube	0.11-0.25	0.17
	Watertube:		
	10 to 100 MMBtu/hr > 100 MMBtu/hr	0.08-0.16 0.18-0.23	0.13 0.21
Crude oil	TEOR steam generator	0.30-0.52	0.46
Natural gas	Firetube	0.07-0.13	0.10
	Watertube:		
	≤ 100 MMBtu/hr > 100 MMBtu/hr	0.06-0.31 0.11-0.45	0.14 0.26
	TEOR steam generator	0.09-0.13	0.12
Wood	< 70 MMBtu/hr	0.010-0.050	0.022
	≥ 70 MMBtu/hr	0.17-0.30	0.24
Bagasse		0.15 ^b	0.15
MSW	Mass burn	0.40 ^b	0.40
	Modular	0.49 ^b	0.49

^aSingle data point.

^bAP-42 emission factor.

of preheated combustion air with the larger boilers. Higher heat release rate and preheated combustion air increase the peak temperature of the flame and contribute to higher baseline NO_x levels. The AP-42 emission factors were used for some of the ICI boilers for which little or no data were available in this study.

2.3 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

The reduction of NO_x emissions from ICI boilers can be accomplished with combustion modification and flue gas treatment techniques or a combination of these. The application of a specific technique will depend on the type of boiler, the characteristic of its primary fuel, and method of firing. Some controls have seen limited application, whereas certain boilers have little or no flexibility for modification of combustion conditions because of method of firing, size, or operating practices. Table 2-3 lists the applicability of candidate NO_x control techniques for ICI boiler retrofit. Each "X" marks the applicability of that control to the specific boiler/fuel combination. Although applicable, some techniques have seen limited use because of cost, energy and operational impacts, and other factors.

NO_x emissions can be controlled by suppressing both thermal and fuel NO_x. When natural gas or distillate oil is burned, thermal NO_x is the only component that can be practically controlled due to the low levels of fuel N₂ in the distillate oil. The combustion modification techniques that are most effective in reducing thermal NO_x are particularly those that reduce peak temperature of the flame. This is accomplished by quenching the combustion with water or steam injection (WI/SI), recirculating a portion of the flue gas to the burner zone (FGR), and reducing air preheat temperature (RAP) when preheated combustion air is used. The use of WI/SI has thus far been limited to small gas-fired boiler applications in Southern California to meet very stringent NO_x standards. Although very effective in reducing thermal NO_x, this technique has not been widely applied because of its potential for large thermal efficiency penalties, safety, and burner control problems. FGR, on the other hand, has a wide experience base. The technique is implemented by itself or in combination with LNB retrofits. In fact, many LNB designs for natural-gas-fired ICI boilers incorporate FGR. LNB controls are available from several ICI equipment vendors. RAP is not a practicable technique because of severe energy penalties associated with its use, and for this reason it was not considered further in this document.

Thermal NO_x can also be reduced to some extent by minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and reducing the firing capacity of the boiler. The

TABLE 2-3. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

NO _x control technique	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X ^a	X	X	X ^b		X ^a	X	X ^a
LNB	X			X	X	X			
FGR				X	X	X			X ^b
NGR	X ^b								X ^b
SNCR	X ^b	X	X	X	X ^b		X	X	X
SCR	X ^b		X ^b	X ^b					

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BT/OT = Burner tuning/oxygen trim

WI/SI = Water injection/steam injection

SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)

LNB = Low-NO_x burners

FGR = Flue gas recirculation

NGR = Natural gas reburning

SNCR = Selective noncatalytic reduction

SCR = Selective catalytic reduction

MSW = Municipal solid waste

^aSCA is designed primarily for control of smoke and combustible fuel rather than NO_x. Optimization of existing SCA (OFA) ports can lead to some NO_x reduction.

^bLimited experience.

first technique is often referred to as oxygen trim (OT) or low excess air (LEA) and can be attained by optimizing the operation of the burner(s) for minimum excess air without excessive increase in combustible emissions. The effect of lower oxygen concentration on NO_x is partially offset by some increase in thermal NO_x because of higher peak temperature with lower gas volume. OT and LEA are often impractical on packaged watertube and firetube boilers due to increased flame lengths and CO, and can lead to rear wall flame impingement, especially when fuel oil is fired. The second technique reduces flame temperature and oxygen availability by staging the amount of combustion air that is introduced in the burner zone. Staged combustion air (SCA) can be accomplished by several means. For multiple burner boiler, the most practical approach is to take certain burners out of service (BOOS) or biasing the fuel flow to selected burners to obtain a similar air staging effect. The third technique involves reducing the boiler firing rate to lower the peak temperature in the furnace. This approach is not often considered because it involves reducing steam generation capacity that must be replaced elsewhere. Also, with some fuels, gains in reduction of thermal NO_x are in part negated by increases in fuel NO_x that result by increases in excess air at reduced boiler load.

The reduction of fuel NO_x with combustion modifications is most effectively achieved with the staging of combustion air. By suppressing the amount of air below that required for complete combustion (stoichiometric conditions), the conversion of fuel nitrogen to NO_x can be minimized. This SCA technique is particularly effective on high nitrogen fuels such as coal and residual oil fired boilers, which may have high baseline emissions and would result in high reduction efficiencies. For PC, BOOS for NO_x reduction is not practical. Therefore, SCA is usually accomplished with the retrofit of internally air staged burner or overfire air ports. The installation of low- NO_x burners for PC- and residual-oil-fired boilers is a particularly effective technique because it involves minimal furnace modifications and retained firing capacity. Staged fuel burners in some packaged watertube boilers without membrane convective side furnace wall(s) may cause an increase in CO emissions at the stack, due to short circuiting of incomplete combustion products to the convective section. The installation of OFA ports for some boilers is not practicable. These boilers are principally firetube and watertube packaged designs and most PC-fired units. Large field-erected gas- and low-sulfur oil-fired ICI boilers are the best candidates for the application of OFA because these fuels are least susceptible to the adverse effects of combustion staging, such as furnace corrosion and unburned fuel emissions.

Another combustion modification technique involves the staging of fuel, rather than combustion air. By injecting a portion of the total fuel input downstream of the main combustion zone, hydrocarbon radicals created by the reburning fuel will reduce NO_x emission emitted by the primary fuel. This reburning technique is best accomplished when the reburning fuel is natural gas. Natural gas reburning (NGR) and cofiring have been investigated primarily for utility boilers, especially coal-fired units that are not good candidates for traditional combustion modifications such as LNB. Examples of these boilers are cyclones and stoker fired furnaces. Application of these techniques on ICI boilers has been limited to some municipal solid waste (MSW) and coal-fired stokers.

NO_x control experience for ICI boilers with flue gas treatment controls has been limited to the selective noncatalytic and catalytic reduction techniques (SNCR and SCR). Both techniques involve the injection of ammonia or urea in a temperature window of the boiler where NO_x reduction occurs by the selective reaction of NH_2 radicals with NO to form water and nitrogen. The reaction for the SNCR process must occur at elevated temperatures, typically between 870 and 1,090°C (1,600 and 2,000°F) because the reduction proceeds without a catalyst. At much lower flue gas temperatures, typically in the range of 300 to 400°C (550 to 750°F), the reaction requires the presence of a catalyst. SNCR is particularly effective when the mixing of injected reagent and flue gas is maximized and the residence time of the gas within the reaction temperature is also maximized. These favorable conditions are often encountered in retrofit applications of SNCR on FBC boilers. The reagent is injected at the outlet of the furnace (inlet to the hot cyclone), where mixing is promoted while flue gas temperature remains relatively constant. Other applications of SNCR on stoker boilers burning a variety of fuels and waste fuels have also shown promise. SCR retrofit ICI applications in this country have been limited to a few boilers in California, although the technology is widely used abroad and several vendors are currently marketing several systems.

2.3.1 Combustion Modification Controls

Table 2-4 summarizes control efficiency and NO_x levels achieved with the retrofit of combustion modification techniques for watertube ICI boilers. The data base includes primarily commercial facilities that were retrofit to meet regulated NO_x limits. In addition, the data base also includes result obtained from controls installed for research and development of specific techniques. Details and references for this data base can be found in Appendices B and C of this document.

TABLE 2-4. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL PERFORMANCE ON ICI WATERTUBE BOILERS

ICI boiler and fuel	NO _x control	Percent NO _x reduction	Controlled NO _x level, lb/MMBtu	Comments
PC, wall-fired	SCA	15-39	0.33-0.93	Limited applicability because of potential side effects.
	LNB	49-67	0.26-0.50	Technology transfer from utility applications.
	NGR	N.A. ^a	0.23-0.52	Limited experience. Technology transfer from utility applications.
	LNB+SCA	42-66	0.24-0.49	Technology transfer from utility applications.
PC, T-fired	SCA	25	0.29-0.38	Effective technique. Technology transfer from utility applications.
	LNB	18	0.36	LNCFS ^b utility firing system design with closed coupled OFA.
	NGR	30	0.23	Limited experience.
	LNB+SCA	55	0.20	LNCFS utility firing system design. Technology transfer from utility applications.
Spreader stoker	SCA	-1-35	0.22-0.52	Potential grate problems and high CO emissions.
	FGR+SCA	0-60	0.19-0.47	Limited applicability.
	RAP	32	0.30	Limited applicability.
	Gas cofiring	20-25	0.18-0.20	Only recent exploratory tests. NO _x reduction via lower O ₂ .
Coal-fired BFBC	SCA	40-67	0.10-0.14	SCA often incorporated in new designs.
Circulating coal-fired FBC	SCA	N.A.	0.05-0.45	SCA often incorporated in new designs.
	SCA+FGR	N.A.	0.12-0.16	Limited application for FGR.
Residual-oil-fired	LNB	30-60	0.09-0.23	Staged air could result in operational problems.
	FGR	4-30	0.12-0.25	Limited effectiveness because of fuel NO _x contribution.
	SCA	5-40	0.22-0.74	Techniques include BOOS ^c and OFA. Efficiency function of degree of staging.
	LNB+FGR	N.A.	0.23	Combinations are not additive in effectiveness.
	LNB+SCA	N.A.	0.20-0.40	Combinations are not additive in effectiveness.
Distillate-oil-fired	LNB	N.A.	0.03-0.33	Low-excess air burner designs.
	FGR	20-68	0.04-0.15	Widely used technique because of effectiveness.
	SCA	30	0.09-0.12	Limited applications except BOOS ^c , Bias and selected OFA for large watertube.
	LNB+FGR	N.A.	0.03-0.13	Most common technique. Many LNB include FGR.
	LNB+SCA	N.A.	0.20	SCA also included in many LNB designs.
Natural-gas-fired	SCA	17-46	0.06-0.24	Technique includes BOOS ^c and OFA. Many LNB include SCA technique.
	LNB	39-71	0.03-0.17	Popular technique. Many designs and vendors available.
	FGR	53-74	0.02-0.10	Popular technique together with LNB.
	LNB+FGR	55-84	0.02-0.09	Most popular technique for clean fuels.
	LNB+SCA	N.A.	0.10-0.20	Some LNB designs include internal staging.

^aN.A. = Not available. No data are available to determine control efficiency. See Appendix B for detailed individual test data.

^bLNCFS = Low-NO_x Concentric Firing System by ABB-Combustion Engineering.

^cBOOS is not applicable to single-burner packaged boilers and some multiburner units.

The most effective NO_x control techniques for PC-fired ICI boilers are LNB, NGR, and LNB+SCA. The average reduction achieved with the retrofit of LNB on seven ICI boilers was 55 percent with a controlled level of 0.35 lb/MMBtu. A combination of LNB plus overfire air (OFA) also achieved an average of 0.35 lb/MMBtu on eight ICI boilers. Lower NO_x emissions were achieved for tangentially fired boilers. Evaluation of retrofit combustion controls for coal-fired stokers revealed control efficiencies in the range of 0 to 60 percent. This wide range in control efficiency is attributed to the degree of staging implemented and method of staging. Typically, existing OFA ports on stokers are not ideal for effective NO_x staging. Furthermore, the long term effectiveness of these controls for stokers was not evaluated in these exploratory tests. The average NO_x reduction for eight stokers with enhanced air staging was 18 percent with a corresponding controlled NO_x level of 0.38 lb/MMBtu. Largest NO_x reductions were accompanied by large increases in CO emissions. Gas cofiring in coal-fired stokers, only recently explored, achieves NO_x reductions in the 20 to 25 percent range only by being able to operate at lower excess air.

Air staging in coal-fired FBC boilers is very effective in reducing NO_x from these units. FBCs are inherently low NO_x emitters because low furnace combustion temperatures preclude the formation of thermal NO_x. Furthermore, the in-bed chemistry between coal particles, CO, and bed materials (including SO₂ sorbents) maintains fuel nitrogen conversion to NO at a minimum. The control of NO_x is further enhanced by operating these boilers with some air staging. In fact, many new FBC designs, including circulating FBCs, come equipped with air staging capability especially for low NO_x emissions. Excessive substoichiometric conditions in the dense portion of the fluidized bed can result in premature corrosion of immersed watertubes used in bubbling bed design. Circulating FBC boilers are better suited for deep staging because these units do not use in-bed watertubes.

NO_x reductions and controlled levels for residual oil combustion are influenced by the nitrogen content of the oil, the degree of staging implemented, and other fuel oil physical and chemical characteristics. Because of these factors, NO_x control performance on this fuel is likely to vary, as shown in Table 2-4. Data on LNB for residual-oil-fired ICI boilers were obtained primarily from foreign applications. The average controlled NO_x level reported with LNB for residual-oil-fired ICI boilers is 0.19 lb/MMBtu based on 17 Japanese installations and one domestic unit equipped with Babcock and Wilcox (B&W) XCL-FM burner for industrial boilers.

The data base for distillate-oil- and natural-gas-fired boilers is much larger than that for residual-oil-fired units. This is because many of the distillate-oil- and natural-gas-fired applications are in California, where current regulations have imposed NO_x reductions from such units. Among the controls more widely used are LNB, FGR, and LNB with FGR. Many LNB designs also incorporate low excess air and FGR, internal to the burner or external in a more conventional application. The average NO_x reduction for FGR on natural-gas-fired boilers is approximately 60 percent from many industrial boilers, nearly all located in California. The average controlled NO_x level for FGR-controlled ICI watertube boilers is 0.05 lb/MMBtu or approximately 40 ppm corrected to 3 percent O₂. For distillate oil, the average FGR-controlled level from watertube boilers is 0.08 lb/MMBtu or approximately 65 ppm corrected to 3 percent O₂. Average NO_x emissions controlled with LNB plus FGR are slightly lower than these levels.

Table 2-5 summarizes results of controls for firetube units. Controlled NO_x levels achieved on these boiler types are generally slightly lower than levels achieved on watertube

TABLE 2-5. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL PERFORMANCE ON ICI FIRETUBE BOILERS

Fuel type	NO _x control	Percent NO _x reduction	Controlled NO _x level, lb/MMBtu	Comments
Residual-oil-fired	LNB	30-60	0.09-0.25	Staged air could result in operational problems.
	SCA	49	0.11	Technique generally not practical unless incorporated in new burner design.
Distillate-oil-fired	LNB	15	0.15	Several LNB designs are available. Most operate on low excess air.
	FGR	N.A. ^a	0.04-0.16	Effective technique for clean fuels.
Natural-gas-fired	SCA	5	0.08	Technique not practical unless incorporated in new burner design.
	LNB	32-78	0.02-0.08	Several LNB designs are available. Some include FGR or internal staging.
	FGR	55-76	0.02-0.08	Effective technique. Used in many applications in California.
	LNB+FGR	N.A.	0.02-0.04	Most popular technique for very low NO _x levels. Some LNB designs include FGR.
	Radiant LNB	53-82	0.01-0.04	Commercial experience limited to small firetubes.

^aN.A. = Not available. No data are available to determine control efficiency. See Appendix B for detailed individual test data.

units. For example, LNB + FGR recorded an average of about 0.033 lb/MMBtu or approximately 35 ppm corrected to 3 percent O₂. FGR by itself is also capable to achieve these low NO_x levels when burning natural gas. In addition to these combustion controls, both OT and WI have been retrofitted in combination on selected packaged industrial boilers in California to meet very low NO_x levels. These controls offer the potential for economic NO_x control because of low initial capital investment compared to either FGR or LNB. NO_x reduction efficiencies and controlled levels have been reported in the range of about 55 to 75 percent depending on the amount of water injected and the level of boiler efficiency loss acceptable to the facility.

2.3.2 Flue Gas Treatment Controls

Application of flue gas treatment controls in the United States is generally sparse. Table 2-6 summarizes the range in NO_x reduction performance and controlled NO_x levels achieved with the application of SNCR and SCR. The data base assembled to produce these results includes both domestic and foreign installation whose results have been reported in the literature or were available from selected technology vendors. References and details are available in Appendix B.

The NO_x reduction efficiency of SNCR for PC-fired boilers is based on results from four boilers, one a small utility unit. For these boilers, NO_x reductions ranged from 30 to 83 percent and averaged 60 percent, with controlled NO_x levels in the range of 0.15 to 0.40 lb/MMBtu. SNCR performance is known to vary with boiler load because of the shifting temperature window. SNCR has been reported to be quite more effective for FBC and stoker boilers. In circulating FBC boilers in California, SNCR with either urea or ammonia injection, achieved an average NO_x reduction and controlled level of nearly 75 percent and 0.08 lb/MMBtu, respectively. SNCR results for 13 coal-fired stokers ranged from 40 to 74 percent reduction, with controlled NO_x levels between 0.14 and 0.28 lb/MMBtu. For stokers burning primarily waste fuels, including MSW mass burning equipment, several applications of SNCR resulted in NO_x reductions in the range of 25 to 80 percent, averaging about 60 percent, with controlled levels in the range of 0.035 to 0.31 lb/MMBtu.

2.4 COST AND COST EFFECTIVENESS OF NO_x CONTROL TECHNIQUES

A simplified costing methodology, based primarily on the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, was developed for this study. The capital control costs were based on costs reported by vendors and users of the NO_x control technologies and from data available in the open literature. The total capital investment was

TABLE 2-6. SUMMARY OF FLUE GAS TREATMENT NO_x CONTROL PERFORMANCE ON ICI BOILERS

ICI boiler and fuel	NO _x control	Percent NO _x reduction	Controlled NO _x level, lb/MMBtu	Comments
PC, wall-fired	SNCR-Urea	30-83	0.15-0.40	Experience relies primarily on utility retrofits. Because of relatively higher NO _x , higher control efficiency is frequently achieved.
Coal-fired FBC	SCR	53-63	0.10-0.15	Limited applications to few foreign installations. No domestic experience.
Coal-Stoker	SNCR-Ammonia	50-66	0.15-0.18	Control levels achieved in combination with OFA controls.
Coal-Stoker	SNCR-Urea	40-74	0.14-0.28	Control levels achieved in combination with OFA controls.
Wood-fired stoker	SNCR-Ammonia	50-80	0.04-0.23	Vendors of technology report good efficiency for stoker applications irrespective of fuels.
	SNCR-Urea	25-78	0.09-0.17	
MSW stokers and mass burn	SNCR-Ammonia	45-79	0.07-0.31	Vendors of technology report good efficiency for stokers applications, irrespective of fuels.
	SNCR-Urea	41-75	0.06-0.30	
	SCR	53	0.05	
Coal-fired FBC	SNCR-Ammonia	76-80	0.04-0.09	Technique is particularly effective for FBC boilers. Applications limited to California sites.
	SNCR-Urea	57-88	0.03-0.14	
Wood-fired FBC	SNCR-Ammonia	44-80	0.03-0.20	Technique is particularly effective for FBC boilers irrespective of fuel type. Applications limited to California sites.
	SNCR-Urea	60-70	0.06-0.07	
Wood-fired Watertube	SNCR-Urea	50-52	0.14-0.26	Limited application and experience.
	SCR	80	0.22	Only two known installations in the United States.
Natural-gas- and distillate-oil-fired watertube	SNCR-Ammonia	30-72	0.03-0.20	Limited application and experience.
	SNCR-Urea	50-60	0.05-0.10	
	SCR	53-91	0.01-0.05	

annualized using a 10-percent interest rate and an amortization period of 10 years. Cost effectiveness was calculated by dividing the total annualized cost by an NO_x reduction for each retrofit cost case using boiler capacity factors in the range of 0.33 to 0.80.

Table 2-7 summarizes the total investment cost and cost effectiveness of several retrofit scenarios. Overall, the total investment of controls varies from a minimum of about \$100/MMBtu/hr for oxygen trim with operation of the boiler with BOOS for multi-burner watertubes, to an estimated \$20,000/MMBtu/hr for the installation of SCR on a 400 MMBtu/hr (120 MWt) PC-fired boiler. The high costs of SCR retrofit were derived from estimates developed for small utility boilers, and are meant to be estimates because no domestic application of this technology was available at the time of this printing. Furthermore, costs of SCR systems have recently shown a downward trend because of improvements in the technology, increased number of applications, and competitiveness in the NO_x retrofit market.

Control techniques with the lowest investment cost are those that require minimum equipment modification or replacement. For example, the installation of an OT system coupled with WI for gas-fired firetubes and packaged watertube is typically much less than \$35,000. Also the application of BOOS in multi-burner units may be a relatively low investment cost approach in reducing NO_x. These costs, however, do not consider the installation of emission monitoring instrumentation. The cost of CEM systems can easily outweigh the cost of NO_x controls for these packaged boilers. The cost effectiveness of WI controls for packaged boilers is anticipated to be low in spite of the associated efficiency losses. This is because an efficiency improvement was credited with the combined application of oxygen trim controls that can compensate for some of the losses of WI.

The installation of FGR, LNB, and LNB with FGR controls for both packaged and multi-burner field erected boilers burning natural gas or oil was estimated to range between \$650/MMBtu/hr and \$4,700/MMBtu/hr with cost effectiveness as low as \$240/ton to as high as \$6,300/ton, depending on fuel type and boiler capacity. The cost of SNCR is based on estimates provided by two vendors of the technology. For a 400 MMBtu/hr boiler, the investment cost can be as low as \$1,100/MMBtu/hr for a stoker boiler burning coal, to \$3,300/MMBtu/hr for an MSW unit burning stoker. The cost effectiveness of SNCR was calculated to range from as low as \$1,010/ton to \$2,400/ton depending on fuel and boiler type. SNCR costs are not likely to vary with type of reagent used (aqueous ammonia or urea).

**TABLE 2-7. ESTIMATED COST AND COST EFFECTIVENESS OF NO_x CONTROLS
(1992 DOLLARS)**

Fuel type	Boiler type and size, MMBtu/hr	NO _x control technique	Estimated NO _x control level, lb/MMBtu ^a	NO _x reduction, tons/yr	Total capital investment, \$/MMBtu/hr	Cost effectiveness, \$/ton of NO _x
Pulverized coal	Watertube (400)	LNB	0.35	310	5,300	1,170-1,530
		SNCR	0.39	270	1,600-2,100	1,010-1,400
		SCR	0.14	490	20,000	3,400-4,200
Coal	FBC (400)	SNCR	0.08	210	1,600	890-1,030
	S. Stoker (400)	SNCR	0.22	270	1,100	1,300-1,500
Natural gas	Single burner packaged watertube (50)	OT+WI	0.06	5.8	530	710-820
		LNB	0.08	4.3	650-2,300	570-2,400
		LNB+FGR	0.06	5.8	2,100-4,700	1,600-4,400
		SCR	0.02	8.7	2,400-6,900	4,800-6,900
	Packaged firetube (10.5)	OT+WI	0.04	1.3	2,400	3,100-3,700
		OT+FGR	0.07	0.65	5,300	8,000-11,000
	Multiburner field-erected watertube (300)	OT+SCA ^b	0.15	53	190	210-240
		LNB	0.12	60	5,100-8,300	2,100-4,200
Distillate oil	Single burner packaged watertube (50)	LNB	0.10	3.3	2,300	460-1,900
		LNB+FGR	0.07	6.6	2,100-4,700	1,000-3,300
		SCR	0.03	25	2,400-6,900	3,900-5,500
	Packaged firetube (10.5)	OT+FGR	0.12	1.6	5,400	4,500-6,200
	Multiburner watertube (300)	LNB	0.10	72	5,100-8,300	3,100-6,300
Residual oil	Single burner packaged watertube (50)	LNB	0.19	19	2,300	240-1,000
		LNB+FGR	0.15	23	2,100-4,700	760-2,000
		SCR	0.06	33	2,400-6,900	2,000-2,900
	Firetube (10.5)	LNB	0.17	4.6	5,400	2,700-3,600
	Multiburner watertube (300)	LNB	0.19	120	5,100-8,300	1,600-3,300
Wood waste	Stoker (150)	SNCR	0.11	43	2,100-2,500	1,300-2,400
	FBC (400)	SNCR	0.11	61	970	1,500-1,600
MSW	Stoker (500)	SNCR	0.18	240	2,100-3,300	1,500-2,100

^aAverage levels calculated from the data base available to this study. Average levels do not necessarily represent what can be achieved in all cases.

^bSCA is burners out of service.

Notes: Boiler capacity factor between 0.50 and 0.66. See Appendices D, E, F, and G for details of costing. Costs do not include installation of continuous emission monitoring (CEM) system. Annual NO_x reduction based on 0.50 capacity factor. Total capital investment from Appendices E through G.

Figures 2-1 through 2-4 illustrate how the cost effectiveness of these controls varies with boiler capacity. As anticipated, the larger the boiler size the more cost effective is the control. Also, costs increase much more rapidly for boilers below 50 MMBtu/hr in size.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

Combustion modification controls to reduce NO_x emissions from ICI boilers can result in either increase or decreases in the emissions of other pollutants, principally CO emissions. The actual effect will depend on the operating conditions of the boiler's existing equipment and the sophistication of burner management system. As discussed earlier, many of these boilers especially the smaller packaged units are operated relatively with little supervision and with combustion safety margin which includes excessive amounts of combustion air to ensure efficient combustion. For these boilers, the installation of burner controls to reduce excess oxygen is likely to reduce NO_x emissions with some increase in CO emissions. For those boilers, that have poor air distribution to the active burners, a program of burner tuning with oxygen trim is likely to achieve both some reduction in NO_x and CO as well.

Table 2-8 lists CO emissions changes that were recorded with the application of combustion modification controls. The information shows that high CO emission are more prevalent when burning coal, especially with combustion controls such as LNB and SCA. Highest CO levels were recorded from the application of SCA for FBC boilers. CO emissions from combustion modifications for natural-gas- and oil-fired boilers are usually less than 200 ppm. Higher CO levels are likely to be recorded with the attainment of strict NO_x emission levels. In recognition of this, the South Coast Air Quality Management District (SCAQMD) in California permits 400-ppm CO levels for low NO_x permits under its Rule 1146. Also, the American Boiler Manufacturers Association (ABMA) recommends 400-ppm CO levels when NO_x emissions from ICI boilers are lowered. Increases in particulate emissions and unburned carbon are other potential impacts of combustion modification NO_x control retrofits on oil- and coal-fired ICI boilers. Insufficient data are available to quantify these potential impacts, however.

Other potential environmental impacts can result from the application of SNCR and SCR control techniques. Both techniques can have ammonia emissions released to the atmosphere from the boiler's stack. Ammonia-based SNCR or SCR can result in ammonia releases from the transport, storage, and handling of the chemical reagent. Data from technology vendors show that the level of unreacted ammonia emitted from the boiler's stack

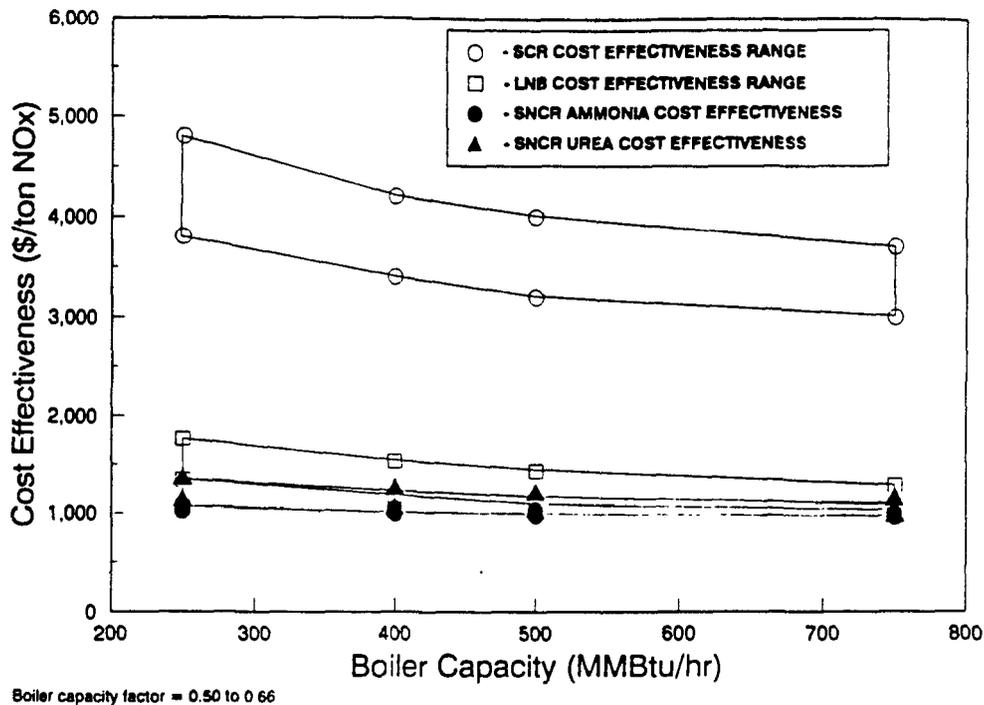


Figure 2-1. Cost effectiveness versus boiler capacity, PC wall-fired boilers.

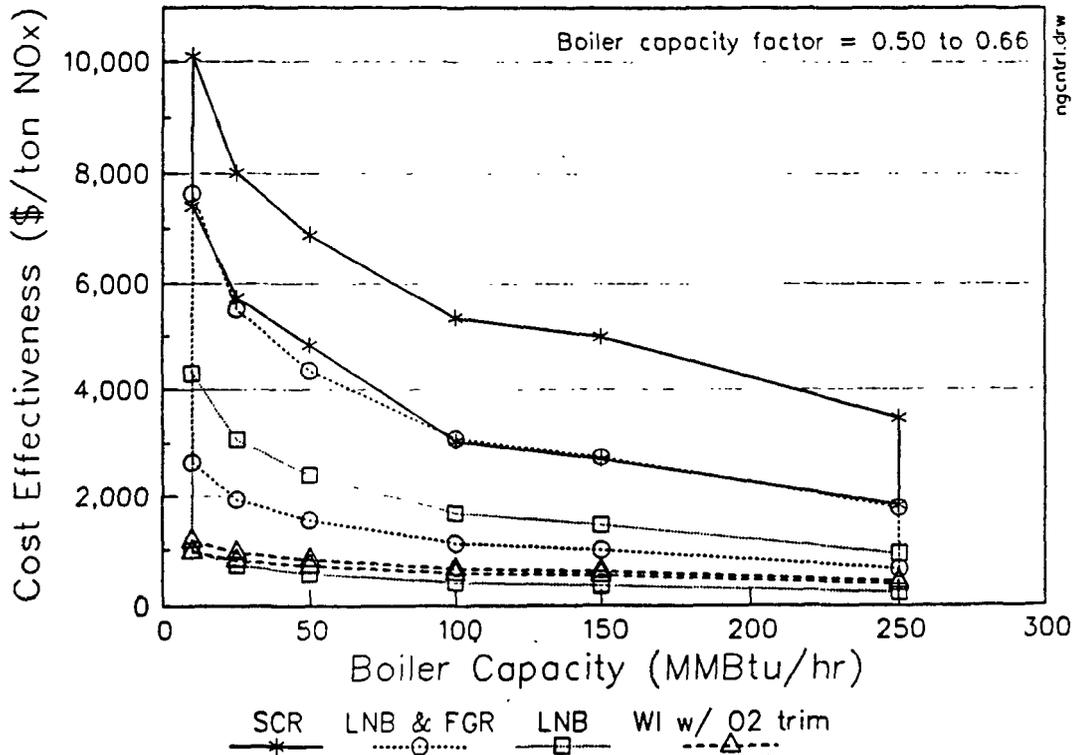


Figure 2-2. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers.

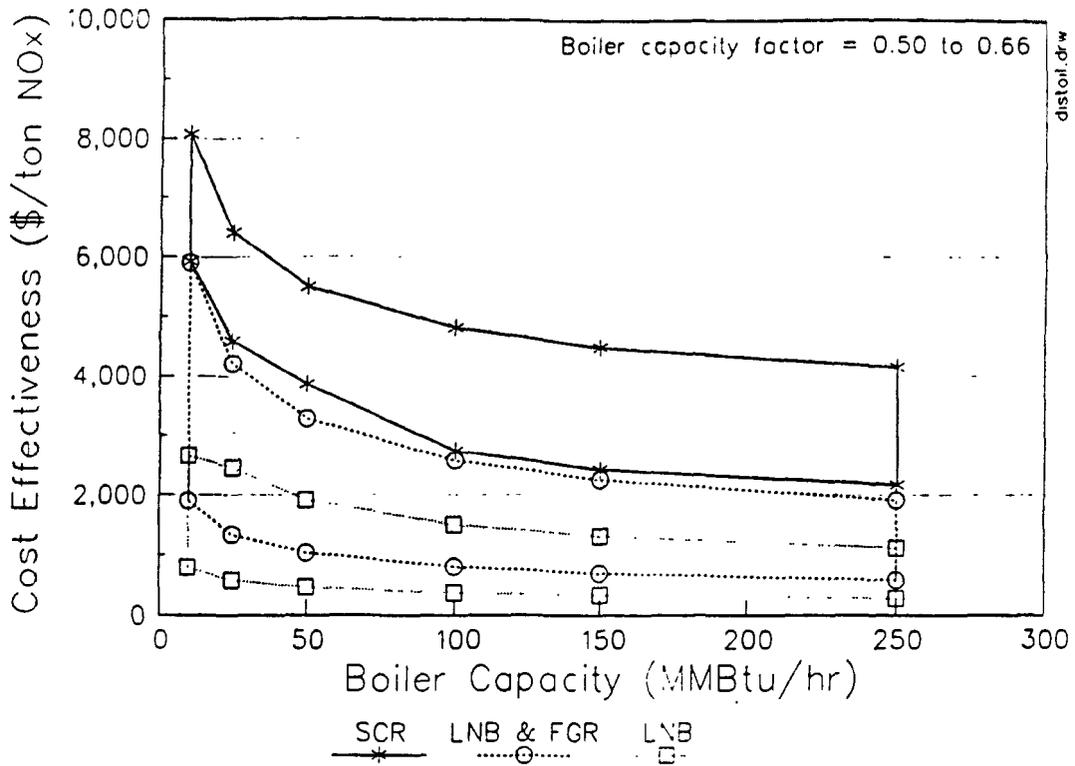


Figure 2-3. Cost effectiveness versus boiler capacity, distillate-oil-fired boilers.

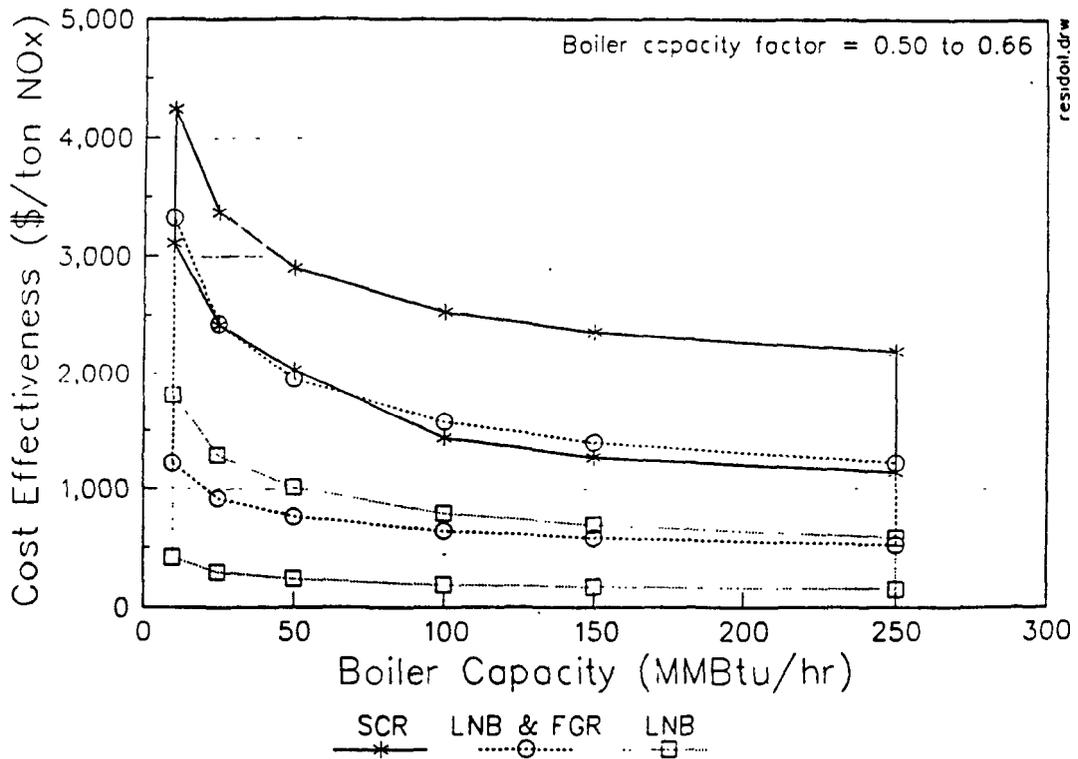


Figure 2-4. Cost effectiveness versus boiler capacity, residual-oil-fired boilers.

TABLE 2-8. EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM ICI BOILERS

Boiler and fuel type	NO _x control	NO _x reduction, %	CO emissions impact	
			Emissions at low NO _x , ppm	Average change, %
Coal-fired watertube	LNB	67	13-430	+800
	LNB+SCA	66	60-166	+215
Coal-fired stoker	SCA	31	429	+80
Coal-fired FBC	SCA	67	550-1,100	+86
Gas-fired packaged firetube	FGR	59-74	3-192	-93 - -6.3
	LNB	32-82	0-30	-100 - -53
Gas-fired packaged watertube	FGR	53-78	20-205	-70 - +450
	LNB+FGR	55	2	-98
Distillate oil packaged watertube	FGR	20-68	24-46	+20 - +1,000
Distillate oil packaged firetube	LNB	15	13	+120
Residual oil watertube	FGR	4-30	20-145	0 - +1,400
	SCA	8-40	20-100	N.A. ^a

^aN.A. = Not available.

when either urea and ammonia-based processes are used is less than 40 ppm. The actual level of ammonia breakthrough will depend on how well the reagent feedrate is controlled with variable boiler loads and on the optimization of injection location and mixing of reagent with the flue gas. For some retrofits, especially packaged boilers, the injection of reagents at SNCR temperatures and the retrofit of SNCR reactors are difficult if not completely impractical.

Increased energy consumption will result from the retrofit of most NO_x control techniques. For example, the injection of water or steam to chill the flame and reduce thermal NO_x will reduce the thermal efficiency of the boiler by 0.5 to 2 percent depending on the quantity of water used. Increases in CO emissions that can result from the application of certain controls such as WI, SCA, and LNB will also translate to increased fuel consumption. The application of FGR will require auxiliary power to operate the flue gas recirculation fan. Both

SNCR and SCR have auxiliary power requirements to operate reagent feed and circulating pumps. Also, anhydrous ammonia-based SNCR and SCR require auxiliary power to operate vaporizers and for increased combustion air fan power to overcome higher pressure drop across catalysts. Additionally, increases in flue gas temperatures, often necessary to maintain the SCR reactor temperature constant over the boiler load, can translate into large boiler thermal efficiency losses. Oxygen trim and burner tuning will, on the other end, often result in an efficiency improvement for the boiler. This is because lower oxygen content in the flue gas translates to lower latent heat loss at the stack. Estimates of increases and potential decreases in energy consumption are presented in Chapter 7.

3. ICI BOILER EQUIPMENT PROFILE

ICI boilers span a broad range of equipment designs, fuels, and heat input capacities. The feasibility of retrofitting existing ICI boilers with NO_x controls, and the effectiveness and costs of these controls, depend on many boiler design characteristics such as heat transfer configuration, furnace size, burner configuration, and heat input capacity. Many of these design characteristics are influenced by the type of fuel used such as natural gas, fuel oil, pulverized and stoker coal, and solid waste fuels. Uncontrolled NO_x emissions also vary significantly among the various fuels and boiler design types. Combustion modifications are the most common approach to reducing NO_x, but experience with many ICI boiler types is limited. FGT controls can substitute for combustion modifications or can provide additive NO_x reductions from controlled-combustion levels.

This chapter presents an overview of ICI boiler equipment to aid in the assessment of NO_x control technologies. A boiler is defined here as a combustion device, fired with fossil or nonfossil fuels, used to produce steam or to heat water. In most ICI boiler applications, the steam is used for process heating, electrical or mechanical power generation, space heating, or a combination of these. Smaller ICI boilers produce hot water or steam primarily for space heating. The complete boiler system includes the furnace and combustion system, the heat exchange medium where combustion heat is transferred to the water, and the exhaust system. There are roughly 54,000 industrial boilers currently in operation in the United States today, with new units being added at the rate of about 200 per year. Of these new units, nearly 80 percent are sold as replacement units, thus the nation's industrial boiler population is growing only slightly. The leading user industries, ranked on the basis of aggregate steaming capacity, are the paper products industry, the chemical products industry, the food industry, and the petroleum industry.¹

As a whole, ICI boilers span the range of heat input capacities from 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt). Table 3-1 gives the distribution of the major ICI boiler

TABLE 3-1. ICI BOILER EQUIPMENT, FUELS, AND APPLICATIONS

Heat transfer configuration	Design and fuel type	Capacity range, MMBtu/hr ^a	% of ICI boiler units ^{b,c}	% of ICI boiler capacity ^{b,c}	Application ^d
Watertube	Pulverized coal	100-1,500+	**	2.5	PH, CG
	Stoker coal	0.4-550+ ^e	** ^f	5.0	SH, PH, CG
	FBC ^g coal	1.4-1,075	**	**	PH, CG
	Gas/oil	0.4-1,500+	2.3	23.6	SH, PH, CG
	Oil field steamer	20-62.5	N.A. ^h	N.A.	PH
	Stoker nonfossil	1.5-1,000 ^e	**	1.1	SH, PH, CG
	FBC nonfossil	40-345	**	**	PH, CG
	Other nonfossil	3-800	**	**	SH, PH, CG
Firetube	HRT coal	0.5-50	**	**	SH, PH
	Scotch coal	0.4-50	**	**	SH, PH
	Vertical coal	<2.5	**	**	SH, PH
	Firebox coal	0.4-25	**	**	SH, PH
	HRT gas/oil	0.5-50	1.5	1.5	SH, PH
	Scotch gas/oil	0.4-50	4.8	4.6	SH, PH
	Vertical gas/oil	<2.5	1.0	**	SH, PH
	Firebox gas/oil	<20	6.5	48	SH, PH
	HRT nonfossil	2-50	N.A.	N.A.	SH, PH
	Firebox nonfossil	2-20	N.A.	N.A.	SH, PH
Cast iron	Coal	<0.4-14	9.9	1.3	SH, PH
	Gas/oil	<0.4-14	72	9.6	SH, PH
Tubeless	Gas/oil	<0.4-4	N.A.	N.A.	SH, PH

^aTo convert to MWt, multiply by 0.293.

^bIncludes all units used in the ICI sector, regardless of capacity.

^c1991 FBC data²; other data are from 1977-1978.^{3,4}

^dSH = Space heat; PH = Process heat; CG = cogeneration.

^eDesign capacities can be higher.

^f** indicates less than 1 percent.

^gFBC = fluidized bed combustion

^hN.A. = Not available. No data are available.

types currently in use. Figures 3-1 and 3-2 illustrate the range of heat input capacities applicable to various fuels, heat transfer configurations, and equipment types. Industrial boilers generally have heat input capacities ranging from 10 to 250 MMBtu/hr (2.9 to 73 MWt). This range encompasses most boilers currently in use in the industrial, commercial, and institutional sectors. Those industrial boilers with heat input capacities greater than 250 MMBtu/hr (73 MWt) are generally similar to utility boilers.⁵ Therefore, many of the NO_x controls applicable to utility boilers are also candidate controls for large industrial boilers.

Boilers with heat input capacities less than 10 MMBtu/hr are generally classified as commercial/institutional units. These boilers are used in a wide array of applications, such as wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, and government facilities, primarily providing steam and hot water for space heating.³ Boilers used in this sector generally range in size from 0.4 to 12.5 MMBtu/hr (0.11 to 3.7 MWt) heat input capacity, although some are appreciably larger.⁶

As the types and sizes of ICI boilers are extremely varied, so too are the fuel types burned in these units. The most commonly used fuels include natural gas, distillate and residual fuel oils, and coal in both crushed and pulverized form. Although the primary fuel types used are fossil based, there is a growing percentage of nonfossil fuels being burned for industrial steam and nonutility power generation. The fuels' physical and chemical composition greatly influence the quantity and type of emissions produced, and the feasibility of certain types of NO_x controls, as will be discussed in Chapters 4 and 5.

The following sections describe the main characteristics of ICI boiler types used in the United States. Section 3.1 describes the three main heat transfer configurations of boilers. Section 3.2 addresses those units primarily fueled by coal. Section 3.3 discusses oil- and natural-gas-fired boilers. Finally, Section 3.4 describes nonfossil-fueled boilers.

3.1 BOILER HEAT TRANSFER CONFIGURATIONS

An important way of classifying boilers is by heat transfer configuration. The four major configurations are watertube, firetube, cast iron, and tubeless. In a watertube boiler (Figures 3-3 and 3-4), combustion heat is transferred to water flowing through tubes lining the furnace walls and boiler passes. The furnace watertubes absorb primarily radiative heat, while the watertubes in the boiler passes gain heat by convective heat transfer. ICI watertube boilers span the entire range of ICI boiler capacities: 0.4 to 1,500 MMBtu/hr (0.11 to 440 MWt) heat input capacity.^{7,8} They can be either packaged or field-erected, depending on their size. In general, most units

3-4

PARAMETER	Boiler Heat Input Capacity Range, MMBtu/hr *								
	0.4	1.0	3.0	10	25	50	100	250	1500
<u>Fuel</u>									
Coal	—————								
Oil	—————								
Natural Gas	—————								
Wood			—————						
Bagasse				—————					
MSW **				—————					
ISW **				—————					
<u>Heat Transfer Configuration</u>									
Watertube	—————								
Firetube					—————				
Cast Iron				—————					
Tubeless			—————						

* To convert MMBtu/hr to MW multiply by 0.293

** MSW - municipal solid waste; ISW - industrial solid waste

Figure 3-1. Occurrence of fuel types and heat transfer configurations by capacity.

PARAMETER	Boiler Heat Input Capacity Range, MMBtu/hr *									
	0.4	1.0	3.0	10	25	50	100	250	1500	
<u>Equipment Type</u>										
Coal Watertube Stoker	—————									
PC-Fired										
FBC			—————	—————	—————	—————	—————	—————	—————	—————
Coal Firetube										
Coal Cast Iron				—————						
Oil/Gas Watertube	—————									
Oil/Gas Firetube										
Oil/Gas Cast Iron				—————						
Oil/Gas Tubeless			—————							
Wood Stoker			—————	—————	—————	—————	—————	—————	—————	—————
Wood FBC										
Wood-Other			—————	—————	—————	—————				
Bagasse Stoker										
Bagasse-Other										
MSW Mass Burn**										
MSW Modular**										
ISW Modular**										

* To convert MMBtu/hr to MW multiply by 0.293

** MSW - municipal solid waste; ISW - industrial solid waste

Figure 3-2. Occurrence of ICI boiler equipment types by capacity.

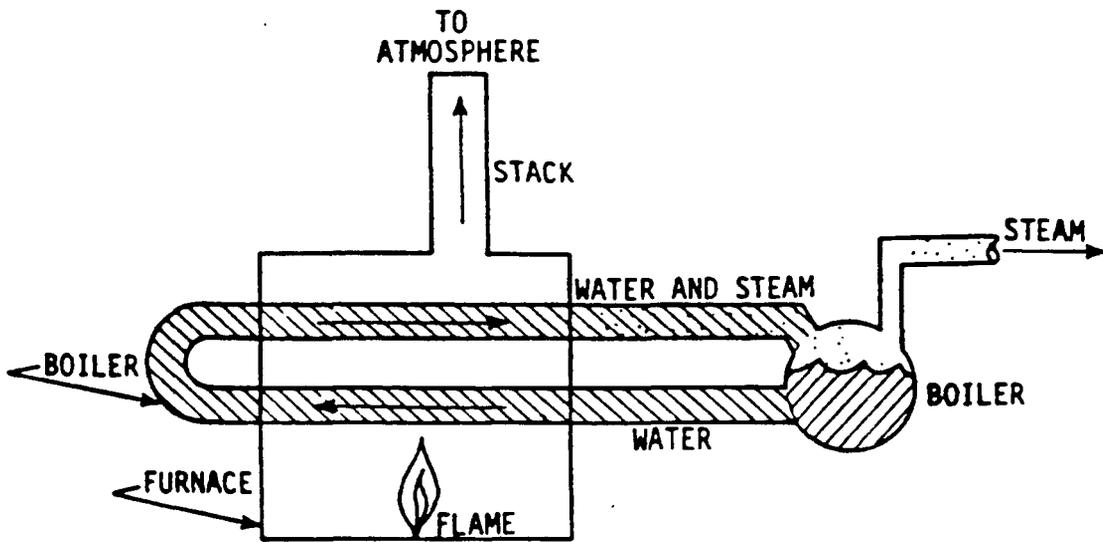


Figure 3-3. Simplified diagram of a watertube boiler.⁹

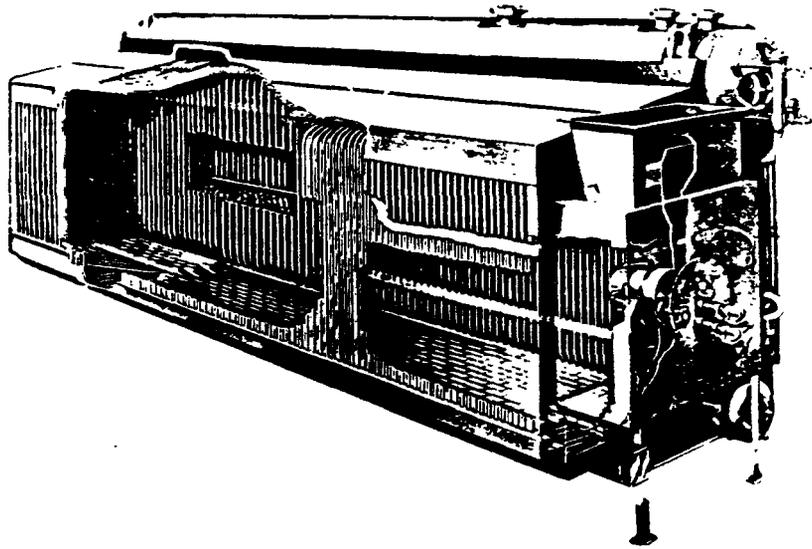


Figure 3-4. Watertube boiler.¹⁰

greater than 200 MMBtu/hr heat input capacity are field-erected. Field-erected units are assembled onsite; these include all large multi-burner gas- and oil-fired boilers and most PC and stoker units. Packaged boilers are shipped by rail or flatbed truck as complete units. New gas- and oil-fired boilers as large as 150 MMBtu/hr (44 MWt) heat input capacity are typically shop-assembled and shipped as packaged units. Demand for packaged boilers peaked in the 1970s, when premium fuel restrictions and the rapidly escalating prices of oil and gas caused their decline. However, with government's repeal of its premium fuel use restrictions, and with greater availability and lowered prices of oil and gas, the packaged boiler is becoming increasingly popular.¹¹

In a firetube boiler (Figures 3-5 and 3-6), the hot combustion gases flow through tubes immersed in the boiler water, transferring heat to the water. The firebox itself is also often immersed in the water. At high pressures, and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers, since, in the firetube units, the high-pressure steam is contained by the boiler walls rather than by multiple small diameter watertubes, which are inherently stronger.⁶ As a consequence, ICI firetube boilers are typically small, with heat input capacities limited to less than 50 MMBtu/hr (15 MWt)¹², and steam pressures limited to 300 psig, although high-end steam pressures of 150 psig are more common. Firetubes are used primarily where loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

In a cast iron boiler, combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low-pressure steam or hot water, and generally burn oil or natural gas.¹³ They are used primarily in the residential and commercial sectors, and have heat input capacities up to 14 MMBtu/hr (4.1 MWt).¹⁴

The tubeless design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

3.2 COAL-FIRED BOILER EQUIPMENT TYPES

In 1977, 12 percent of all ICI boilers in the United States were coal-fired.³ Coal has not been utilized in ICI boilers as extensively as oil or natural gas, chiefly due to cost-effectiveness considerations for the smaller units. Although the majority of coal-fired ICI boilers are smaller cast iron units, coal-fired firetube or cast iron boilers are not as common as oil- or natural-gas-

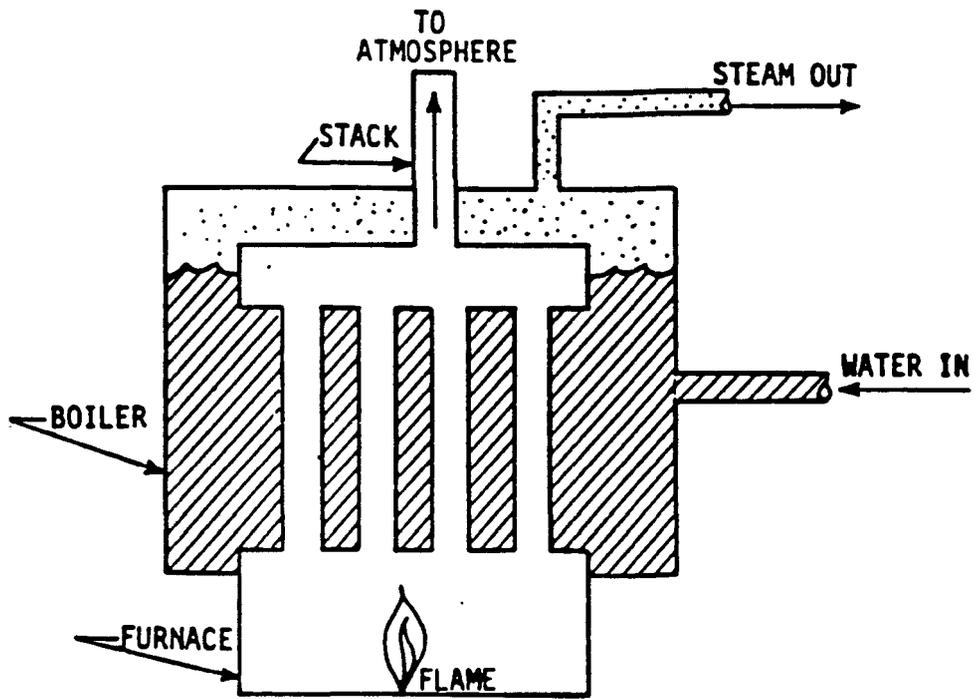


Figure 3-5. Simplified diagram of a firetube boiler.¹⁵

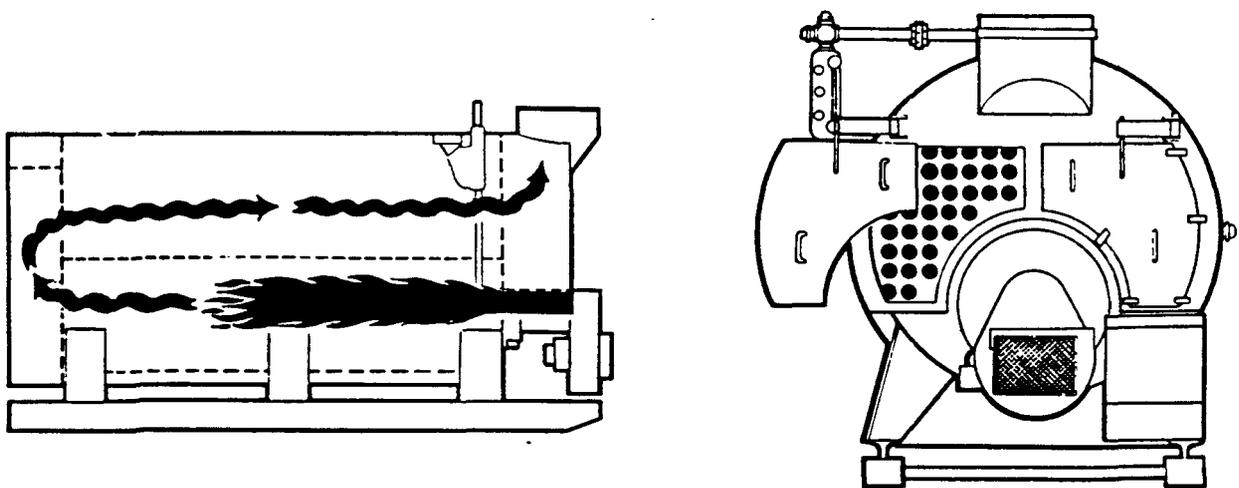


Figure 3-6. Firetube boiler.¹⁶

fired firetube units. As discussed above, this is because firetube boilers are usually limited to 50 MMBtu/hr (15 MWt) heat input capacity. For smaller industrial and commercial units below this capacity, coal has not been a popular fuel because of the high capital cost of coal handling equipment relative to the costs of the boilers. Thus, most ICI boilers are fueled with oil or natural gas.

Nevertheless, there has been a market percentage increase in coal-fired boilers since the early 1970s. Of the total industrial boiler units purchased in 1971, only 0.5 percent were designed primarily for coal use. By 1980, coal-fired boilers claimed 13.7 percent of the new boiler market. With regards to the application of these coal-fired boilers, five industry groups consumed 66 percent of the total industrial coal used in 1980. These groups included the chemical products industry, the paper products industry, the food and kindred products industry, the primary metals industry, and the transportation equipment industry.¹⁷

3.2.1 Coal-fired Watertube Boilers

Coal-fired watertube boilers made up less than 1 percent of the total United States ICI boiler population in 1977, the last time an industrial boiler inventory was taken. Yet, due to their larger capacities, these units accounted for 14 percent of the total operating capacity.¹⁸ Coal-fired watertube ICI boilers can be classified into three major categories: stokers, PC-fired units, and FBC boilers. The following subsections describe these types of boilers.

3.2.1.1 Stoker-firing Watertube Boilers

Stoker-firing systems account for approximately 90 percent of coal-fired watertube ICI boilers.¹⁹ Stoker systems can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. These systems differ in how fuel is supplied to either a moving or stationary grate for burning. One important similarity among all stokers is that all design types use underfeed air to combust the coal char on the grate, combined with one or more levels of overfire air introduced above the grate. This helps ensure complete combustion of volatiles and low combustion emissions. Most stokers also utilize flyash reinjection to minimize the unburned carbon content in the flyash. Underfeed stokers were once the primary stoker type used in industrial and utility steam generation, but the high costs of maintenance and these units' slow response to varying loads have made them less competitive in the present market. Spreader stokers, however, are extremely popular in industry today, due in part to their wide fuel capability, discussed further below.²⁰

Underfeed stokers are generally of two types: the horizontal-feed, side-ash-discharge type, shown in Figure 3-7; and the gravity-feed, rear-ash-discharge type, shown in Figure 3-8. The horizontal-feed, side-ash-discharge type of stoker is used primarily in small boilers supplying relatively constant steam loads of less than 30,000 lb/hr (~30 MMBtu/hr input).²¹ As shown in Figure 3-7, coal is supplied from below the air-admitting surface of the grate into the bottom of a fuel bed, usually via a longitudinal channel called a retort. As additional coal is fed into the boiler with a ram or screw, the coal is forced to the top of the retort, where it spills onto a grate located on either side. Combustion air is supplied through tuyeres at the side grates, where combustion is completed. Overfire air is often supplied to the flame zone above the bed to provide more combustion air and turbulence for more complete combustion.²² These smaller underfeed stokers typically have one or two retorts. Maximum allowable burning rates are typically 425,000 Btu/hr per square foot of grate area.²¹ Allowable burning rates determine the size of the grate area for a given heat input rate. The higher the burning rate the higher the intensity of combustion and thickness of the burning bed. The gravity-feed, rear-ash-discharge underfeed stoker often has multiple retorts. Typically, this type of stoker has a maximum 500 MMBtu/hr (146 MWt) heat input capacity.²¹ In this type of stoker, coal is introduced through a coal hopper and is ram-fed to the inclined retorts and grates. The retorts and grates are typically inclined 20 to 25°. Maximum allowable fuel burning rates are 600,000 Btu/ft²-hr.²¹

An overfeed stoker, shown in Figure 3-9, uses a moving grate assembly. Coal is fed from a hopper onto a continuous grate that conveys the coal into the furnace. As coal moves through the furnace on the grate, it passes over several air zones for staged burning. The air serves a dual purpose; it is used for combustion as well as for cooling the fuel bed and grate, preventing fusing of the coal. At the far end of the moving grate, combustion is completed and ash discharged to the bottom of the furnace. An adjustable gate at the coal feed point allows regulation of the depth of the fuel bed.^{23,24} The three types of grates used with overfeed coal stokers are the chain, travelling, and water-cooled vibrating grates. These overfeed stoker systems are often referred to by the type of grate employed. Overfeed coal-fired systems typically range up to 350 MMBtu/hr (100 MWt) heat input capacity. Maximum fuel burning rates for overfeed stokers are roughly 500,000 Btu/ft²-hr.²¹

In a spreader stoker, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. In a typical spreader stoker boiler, shown in Figure 3-10, primary air is admitted evenly throughout the active grate area, providing some fuel bed cooling, while above

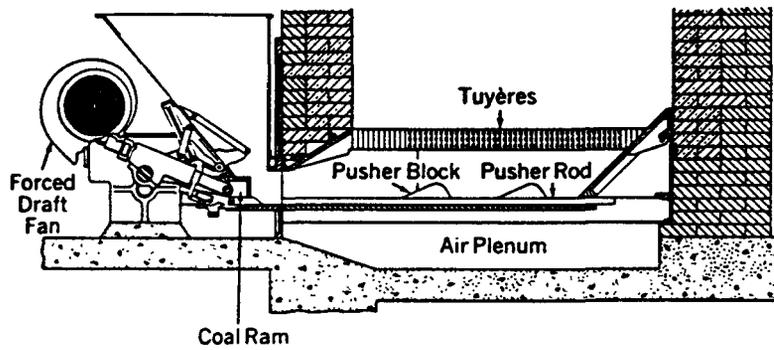


Figure 3-7. Single-retort horizontal-feed underfeed stoker.²¹

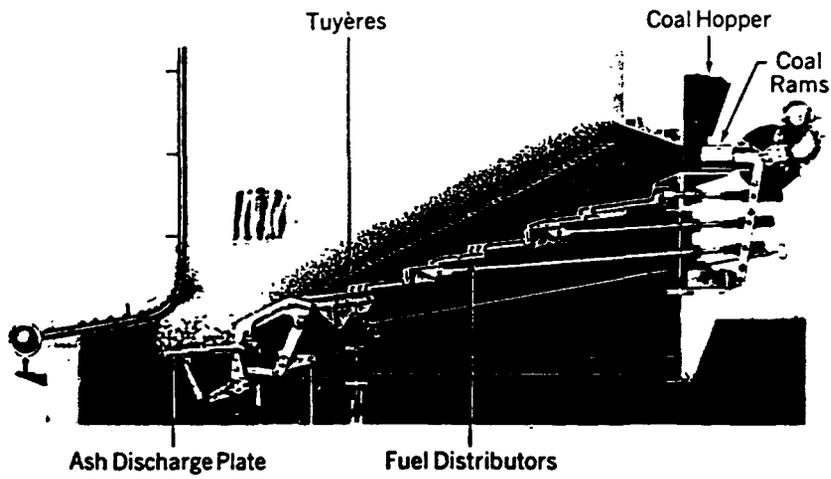


Figure 3-8. Multiple-retort gravity-feed underfeed stoker.²¹

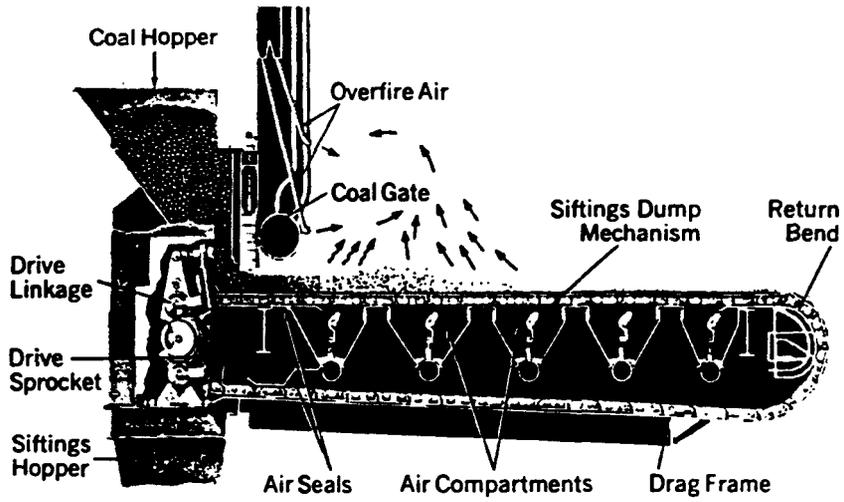


Figure 3-9. Overfeed chain-grate stoker.²¹

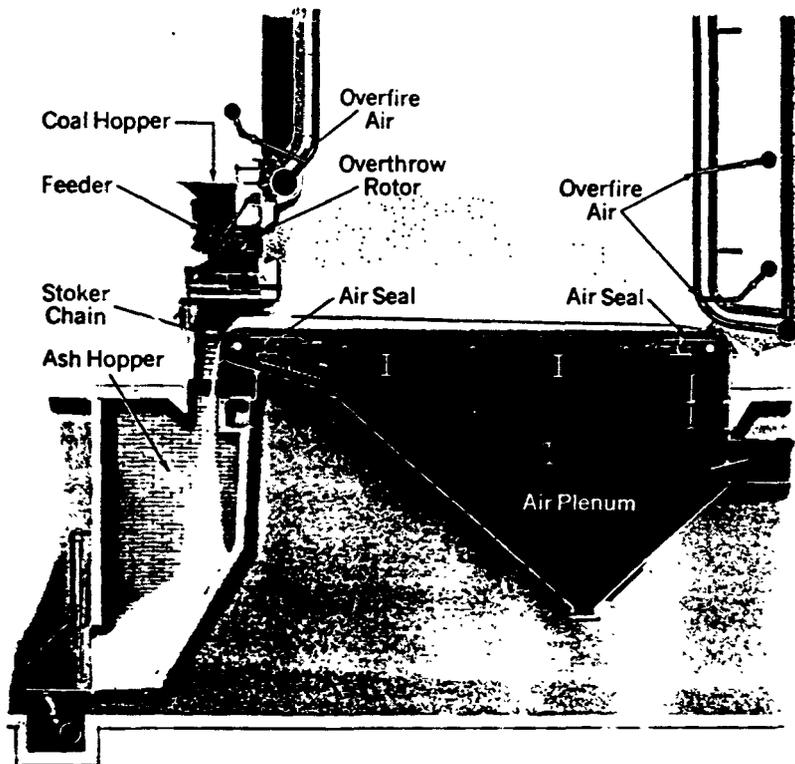


Figure 3-10. Spreader stoker.²¹

the grate an overfire air system provides secondary air and turbulence. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, among other factors. Generally, the finer the fuel and/or the higher its volatile matter content, the more energy released in suspension; the higher the moisture content, the more energy released on the grate.²⁴ Many spreader stoker units incorporate a flyash recirculation system, whereby unburned solids in the flyash are collected and recirculated back into the primary combustion chamber. Heat input capacities of spreader stokers typically range from 5 to 550 MMBtu/hr (1.5 to 160 MWt), although there are a few units of 1,500 MMBtu/hr (440 MWt) or more.¹⁸ Maximum fuel burning rates are highest for this stoker design, often reaching a maximum of 750,000 Btu/ft²-hr.²¹

In general, stoker coal is fed crushed with a nominal size less than 2 inches. Overfeed and spreader stokers can be used to burn almost any type of coal or solid fuel, including wood, wood waste, and bagasse. Coking bituminous coals, however, are not used in overfeed stokers to avoid matting and restricting the airflow through the grate. Coking has little effect on the performance of spreader stokers.⁸ Most packaged stoker units designed for coal firing are less than 100 MMBtu/hr (29 MWt) capacity.²⁵ Larger units are typically field-erected.

3.2.1.2 PC-fired Watertube Boilers

PC-fired boilers account for a small percentage of the ICI watertube boiler population. In 1977, they accounted for less than 1/10th of 1 percent of all installed ICI boiler units. However, they accounted for approximately 2.5 percent of total ICI boiler capacity.¹⁸ This disparity is due to the fact that PC-fired boilers are almost entirely limited to sizes larger than 100 MMBtu/hr (29.3 MWt) heat input capacity. Below this level, the required coal-handling and pulverizing equipment can increase the capital cost of PC-fired units to as high as 10 times that of an oil- or natural-gas-fired industrial boiler of the same size.²⁶ Thus, when coal is the fuel of choice, stoker firing dominates in units below about 150 MMBtu/hr (44 MWt) heat input capacity. PC firing and FBC are usually the choices for larger boilers.²⁷ PC-fired ICI boilers are nearly all of watertube configuration, and the majority are field-erected.²⁶

Combustion in PC-fired units takes place almost entirely while the coal is suspended, unlike in stoker units, in which most, if not all, of the coal burns on a grate. Finely ground coal (70 percent through 200 mesh) is typically mixed with primary combustion air and fed to the burner or burners, whereupon it is ignited and mixed with secondary combustion air. Depending

upon the location of the burners and the direction of coal injection into the furnace, PC-fired boilers can be classified into three different firing types

- Single- and opposed-wall, also known as face firing
- Tangential, also known as corner firing
- Cyclone

Of these types, wall and tangential configurations are the most common.²⁶

Figure 3-11 shows a schematic of a single-wall-fired boiler. Wall-fired boilers can be either single-wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed-wall-fired, with burners mounted on two opposing walls. However, opposed-wall boilers are usually much larger than 250 MMBtu/hr heat input capacity, and are much more common in utility rather than in industrial applications.²⁶

Figure 3-12 shows a plan view of a tangential-firing configuration, with the burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that enhances air/fuel mixing. Larger flame volumes and flame interaction contribute to characteristically lower NO_x levels from tangential firing. Tangential boilers, like opposed-wall boilers, are commonly used in utility applications.²⁶

Cyclone furnaces are often categorized as PC-fired systems even though the coal burned in cyclones is crushed and not pulverized. These furnaces burn low-fusion-temperature coal crushed to a maximum particle size of about 4.75 mm (95 percent through 1/4 inch mesh).⁸ The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension, while larger particles adhere to a molten layer of slag on the combustion chamber wall. The larger particles remain in the slag until they are burned. Because of their intense furnace heat release rates, cyclones emit high levels of NO_x, and are generally more difficult to control with combustion modifications. Cyclone furnaces are not as widely used in the industrial sector as wall, tangential, or stoker systems.⁸

PC-fired boilers are also classified as either dry bottom or wet bottom, depending on whether the ash is removed in solid or molten state. This is an important differentiation with respect to NO_x emissions, as wet-bottom boilers generally operate at higher furnace temperatures and subsequently emit greater amounts of NO_x. Boiler designs in wet- and dry-bottom furnaces hinge on coal quality and ash fusion properties. Wet-bottom furnaces are also referred to as slag tap furnaces. In the ICI sectors, dry-bottom PC-fired boilers are much more widely used than wet-bottom boilers.^{6,8}

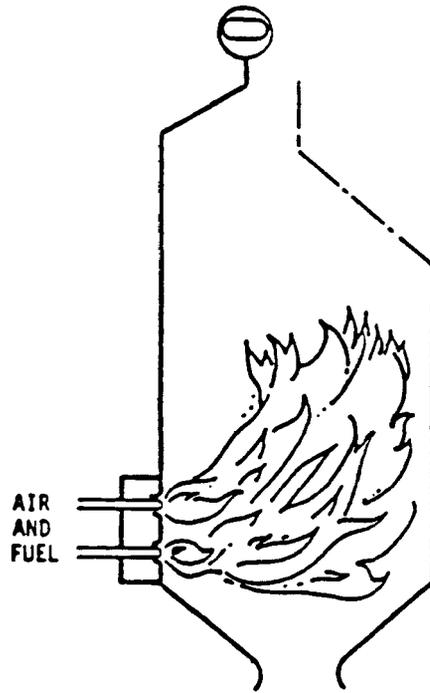


Figure 3-11. Wall firing.²⁶

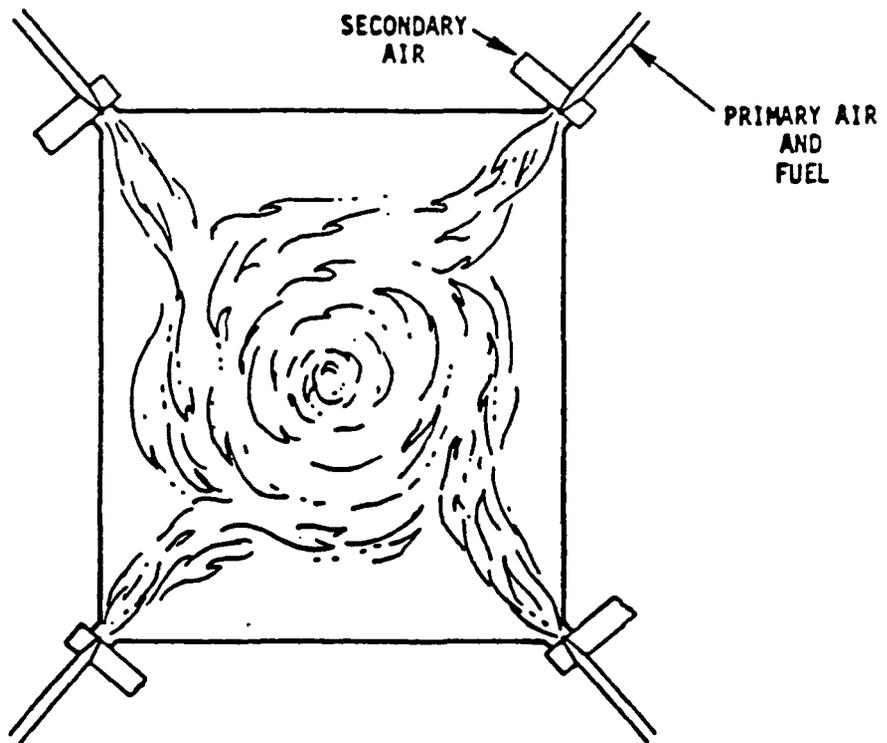


Figure 3-12. Tangential firing.²⁶

3.2.13 FBC Watertube Boilers

FBC boilers, while not constituting a large percentage of the total ICI boiler population, have nonetheless gained popularity in the last decade, due primarily to their capabilities to burn a wide range of solid fuels and to use combined NO_x/SO_x controls within the furnace. FBC units generate steam for ICI facilities, cogenerators, independent power producers, and utilities. In the United States, FBCs in use in the industrial sector account for less than 10 percent of the total installed FBC generating capacity.²⁸

There are two major categories of FBC systems: (1) atmospheric, operating at a slight negative draft, and (2) pressurized, operating at from 4 to 30 atmospheres (60 to 450 psig). Pressurized FBC (PFBC) systems are being demonstrated at two utility sites in the United States. No PFBC units are currently in operation in the ICI sector, and it is unlikely that such systems will be used for industrial applications in the near future, due to the developmental status of this technology. A recent market assessment report concluded that PFBCs are several years away from full commercialization in the utility industry, and that near-term opportunities for large industrial applications rest with atmospheric FBC technology.²⁸ Currently, only atmospheric FBC systems are used in the ICI sector.²⁹ Therefore, the remainder of this section describes atmospheric FBCs.

In a typical FBC boiler, solid, liquid, or gaseous fuel or fuels, together with a mixture of inert material (e.g., sand, silica, ash) and/or a sorbent such as limestone, are kept suspended by a steady upward flow of primary air through the fuel bed. This fuel bed fluidization promotes turbulence, which improves mixing of fuel and air, allowing the FBC to combust solid fuel at a substantially lower and more uniformly distributed temperature—typically 815 to 870°C (1,500 to 1,600°F) — compared to stoker or PC-fired boilers, where furnace temperatures can peak at 1,590°C (2,900°F).

This lower temperature range provides two of the three main advantages of FBCs over conventional boiler units:

- Lower combustion temperatures result in less formation of thermal NO_x and allow use of sorbent to reduce SO₂ emissions
- Lower combustion temperatures are generally below the ash fusion temperatures of most fuels, resulting in less slagging and fouling of heat transfer surfaces
- FBCs are able to burn many types of fuels besides coal, including low-grade fuels such as petroleum coke, waste coal, municipal waste, and biomass materials

Flexible-fuel capability is inherent in FBC design, and the ability to efficiently burn low-grade fuels would generally be impractical without FBC technology. High combustion efficiencies are generally due to the long retention times of solids in the fluidized beds.³⁰

FBCs are primarily watertube boilers, especially among the larger units, although firetube units are also available. In some FBCs — bubbling bed units, described below — additional watertubes are located within the fuel bed itself, oriented either horizontally or vertically. Steam output is controlled by manipulating the primary bed parameters of height, temperature, fuel input, and fluidization velocity—the velocity of the primary air through the bed.

Firetube FBC boilers are also available and in use. However, of the more than 50 FBC manufacturers worldwide, only 12 offer firetube designs in addition to the more conventional watertube systems.³¹ This indicates the relative popularity of watertube FBC systems as compared to the less common firetube units.

Figures 3-13 and 3-14 show the two principal types of atmospheric FBC boilers, the bubbling bed and the circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling-bed design, the fluidization velocity is relatively slow, ranging between 5 and 12 ft/s, the idea being to minimize solid carryover into the convective passes of the boiler. In some units, relatively slow fluidization velocities allow watertubes to be placed within the bed itself, as long as tube erosion is not a problem. Circulating FBCs, however, employ fluidization velocities as high as 30 ft/s and actually promote the carryover or circulation of solids—fuel and bed material. Solids leaving the primary combustion zone are trapped by high-temperature cyclones and recirculated back to the primary combustion chamber. In some circulating-bed designs, a secondary combustion chamber is used to complete combustion of the fuel. The circulating FBC maintains a continuous, high-volume recycle rate that increases the fuel residence time compared to the bubbling-bed design. Because of this, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization in the control of SO₂ emissions than bubbling-bed units.³³ This is one reason why the bubbling bed FBC, still favored for small-scale boilers, is not as favored for large-scale industrial and utility applications.³³ Circulating FBCs have their heat exchange tubes downstream of the recirculating cyclone.

Of atmospheric FBCs currently in use in all sectors, including industrial, utility, independent power production, and cogeneration applications, coal is the primary fuel used, followed in descending order by biomass, coal waste, and municipal waste. Coal waste and

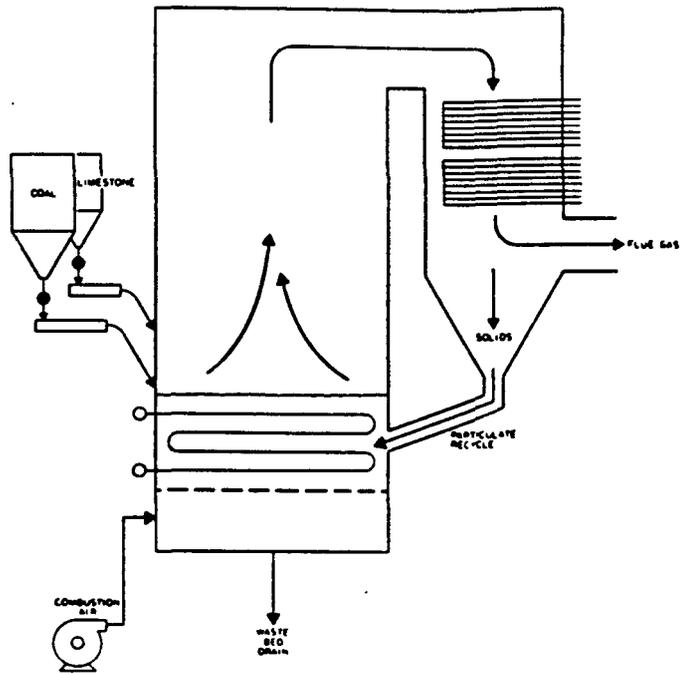


Figure 3-13. Bubbling FBC schematic.³²

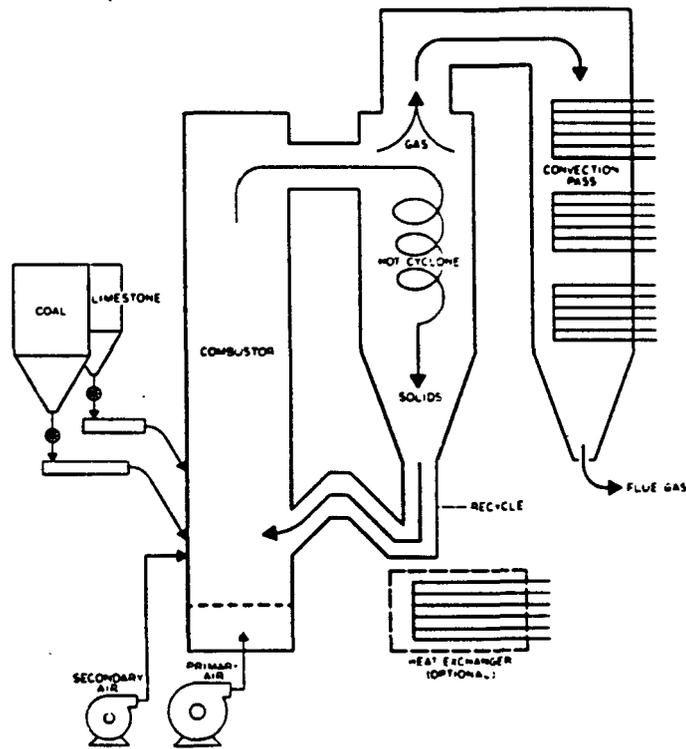


Figure 3-14. Circulating FBC schematic.³²

municipal waste are not significant fuel types for larger FBC plants.³³ Of 157 non-utility FBC boilers in operation in the United States in 1991, 116 were of heat input capacities below 250 MMBtu/hr (73 MWt or 37 MWe), and of these, 51 burned coal exclusively.² Another 18 units burned coal in combination with wood, sludge, coke, or biomass. The coal-burning FBCs ranged between 8.4 and 235 MMBtu/hr heat input capacity (2.5 to 69 MWt, or 1.25 to 35 MWe output), and accounted for a relatively small amount of the total capacity of coal-fired ICI boilers. The largest coal-fired FBC unit in non-utility application in the United States has an approximate heat input capacity of 1,070 MMBtu/hr (315 MWt), generating 160 MWe of electric power at a cogeneration facility.²

From an economic standpoint, ICI FBC boilers that burn coal do not compete strongly with gas-fired units. For example, in the 200- to 600-MMBtu/hr (59- to 175-MWt or 30- to 90-MWe) size range, the capital costs of a coal-fired FBC boiler are 2 to 3 times higher than a conventional natural-gas-fired unit. The use of lower cost opportunity fuels, such as coke, biomass, wood waste, and low-grade coals, can provide sufficient economic incentive to offset higher initial capital costs. When used in electric power generating applications, FBC coal-fired power plants produce electricity at 1.5 to 3 times the cost of gas-based power generation.³⁴ Future growth in the ICI FBC boiler market is expected to occur mainly among units that burn fuels other than coal, such as waste fuels like wood and manure.

3.2.2 Coal-fired Firetube Boilers

Coal-fired firetube boilers represent a small portion of the ICI boiler population. In 1977, coal-fired firetube boilers accounted for only 10 percent of the industrial and commercial firetube boiler population in the United States, and only 1.5 percent of all ICI boilers.³⁵ The four most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox; however, the HRT boiler is generally used with gas or oil instead of coal. Virtually all coal-fired firetube boilers are packaged units. The following sections discuss these boiler types as well as other less common firetube boilers.

3.2.2.1 HRT Firetube Boilers

In a typical HRT boiler, the firetubes are horizontal and self-contained, with the combustion chamber separate. When solid fuel such as coal is used, it is fed through a feed chute onto grates in the primary combustion chamber. The combustion gases then pass through the firetubes of the boiler.

Most coal- and other solid-fuel-fired HRT boilers are two-pass designs. In a two-pass HRT boiler, shown in Figure 3-15, primary and secondary combustion chambers are located beneath the boiler tank. The combustion gases flow over the bridge wall towards the rear of the boiler, heating the outer shell of the tank. At the rear of the boiler, the combustion gases then enter the firetubes. The gases flow through the firetubes, transferring additional heat to the water, and are then exhausted through the boiler stack.

HRT boilers come in various sizes, ranging from 0.5 to 50 MMBtu/hr (0.15 to 15 MWt) heat input capacity, with pressures of 15 to 250 psig. Some larger units are available that supply saturated steam at 300 psig. Firing of coal in HRT boilers is not as common as firing liquid or gaseous fuels, due to the possibility of scaling or slagging.

3.2.2.2 Scotch Firetube Boilers

A Scotch, or shell, boiler differs from the HRT boiler in that the boiler and furnace are contained in the same shell. In a two-pass unit, combustion occurs in the lower half, with the flue gases passing beneath the bottom of the water basin occupying the upper half. The gases then pass through the firetubes running through the basin. Scotch boilers also come in three- or four-pass configurations. The capacity of Scotch boilers ranges up to 50 MMBtu/hr (15 MWt) heat input, with pressures up to 300 psig, although more typical pressures are approximately 200 psig. Like HRT boilers, coal is not as commonly used in Scotch boilers due to slagging and scaling.³⁶ More common gas- and oil-fired Scotch units are shown in Figures 3-6 and 3-16.

3.2.2.3 Vertical Firetube Boilers

Another common firetube design is the vertical boiler. A vertical firetube boiler is a single-pass unit in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. Figure 3-17 depicts an exposed-tube vertical boiler in which the firetubes extend from the top of the furnace into the steam space. This causes the steam to be superheated and reduces carryover of moisture.³⁷

Figure 3-18 shows a submerged-tube vertical boiler in which the firetubes extend from the furnace to the tube sheet, which is below the water level. This design prevents the ends of the firetubes from overheating. A conical flue gas collector directs the flue gases to an exhaust stack. The submerged-tube boiler has essentially been discontinued, however, because the collector is difficult to build and tends to leak.³⁷

Vertical boilers are small, with heat input capacities under 2.5 MMBtu/hr (0.73 MWt). However, they are capable of burning all types of fuels, including coal.

3-21

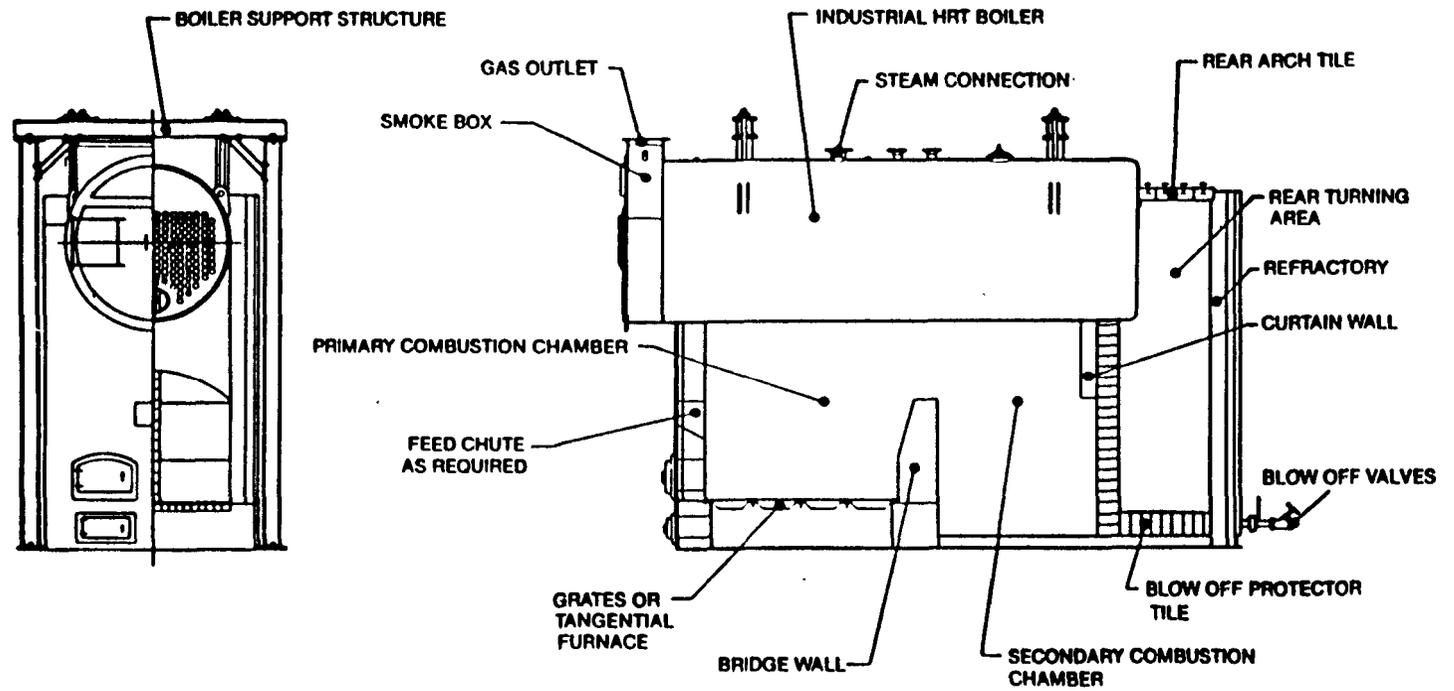


Figure 3-15. Two-pass HRT boiler.³⁸

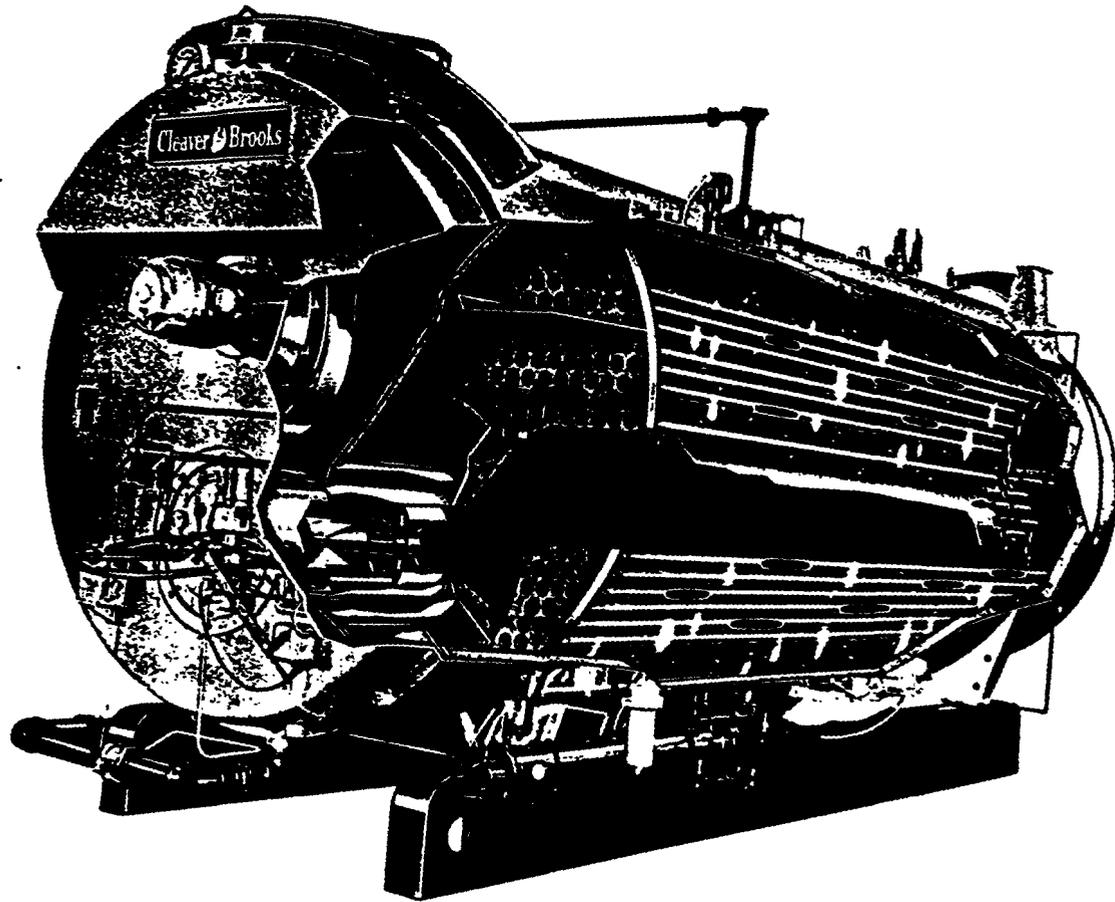


Figure 3-16. Four-pass gas-/oil-fired scotch boiler.³⁹

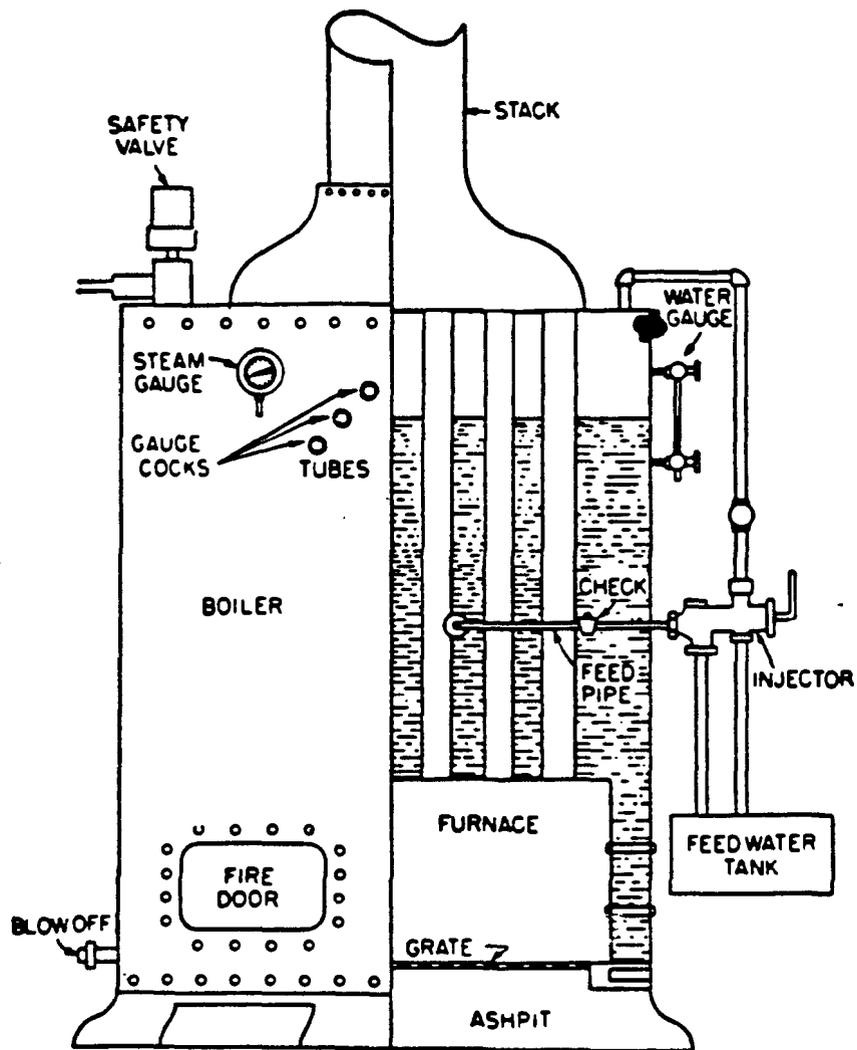


Figure 3-17. Exposed-tube vertical boiler.³⁷

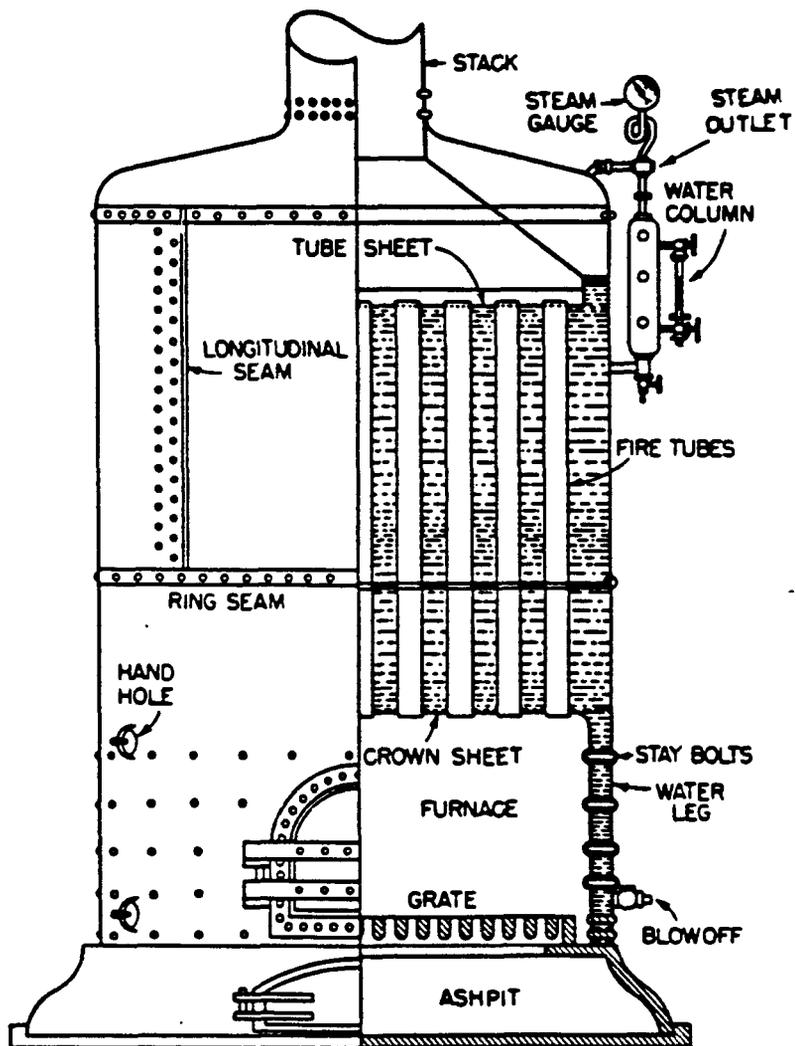


Figure 3-18. Submerged-tube vertical boiler.³⁷

3.2.2.4 Firebox Firetube Boilers

Another type of firetube boiler is the firebox boiler. These units are constructed with an internal steel-encased, water-jacketed firebox. Firebox boilers are compact and employ, at most, three passes of combustion gases. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers. A locomotive boiler is a single-pass horizontal firetube boiler; a short firebox boiler is a two-pass horizontal firetube unit; and a compact firebox boiler is a three-pass horizontal unit.³⁷

Currently available coal-fired firebox units either employ mechanical underfeed stokers, or are capable of being hand-fired. They are generally limited in size to below 25 MMBtu/hr (7.3 MWt) heat input capacity.⁴⁰

3.2.3 Cast Iron Boilers

Commercial cast iron boilers consist of several vertical sections of heat exchange tubes mounted above a firebox. Water enters each section at the bottom, and is heated or converted to steam as it passes upward through the heat exchange tubes. The capacity of a commercial cast iron boiler is determined by the number of heat exchange sections in the boiler.

In 1977, only 12 percent of the 1.5 million cast iron boilers in the United States were coal fired, and of these, 37 percent had heat input capacities of 0.4 MMBtu/hr (0.1 MWt) or higher.⁴¹ The majority of cast iron boilers are below 0.4 MMBtu/hr (0.1 MWt) heat input capacity and are fueled by natural gas or fuel oil. All cast iron boilers are packaged units, as they are usually no greater than 14 MMBtu/hr (4.1 MWt) in heat input capacity, and, hence, are relatively small.

3.3 OIL- AND NATURAL-GAS-FIRED ICI BOILER EQUIPMENT TYPES

Oil- and natural-gas-fired ICI boilers accounted for 88 percent of the ICI boiler population in 1977.³ These boilers are generally similar to coal-fired units, with the exception of stoker systems, which are not used to burn liquid or gaseous fuels. However, some boilers are designed with oil/gas burners and a solid fuel stoker system, to allow use of the most economically available fuel. Oil- and natural-gas-fired ICI boilers are similar; in fact, many are capable of firing both fuels either separately or in combination.

In smaller packaged units, single burners are usually employed, while larger field-erected boilers often have multiple burners. In older boilers, multiple-burner arrangements provided a means of controlling heat input in lieu of burner turndown capability. With advances in burner control and turndown capability—most new burners can maintain stable flames as low as

10 percent of capacity—the use of multiple burners in smaller units has declined. Most newer units smaller than 200 MMBtu/hr (59 MWt) heat input capacity have only one burner. Oil- and natural-gas-fired boiler types can be categorized as watertube, firetube, cast iron, or tubeless, and as either packaged or field-erected. Watertube boilers can either be shop-assembled (packaged) or field-erected. Firetube and cast iron boilers are nearly all packaged because of their smaller sizes.

In the smaller sizes and most commercial applications of ICI boilers, the packaged gas/oil fired Scotch firetube boiler predominates.⁴² Almost all of these applications are for heating where loads do not fluctuate quickly. Boilers designed for low temperature (250°F or less) and low pressure (15 psig and less) steam are the most widely used in residential, apartment, and commercial construction.⁴²

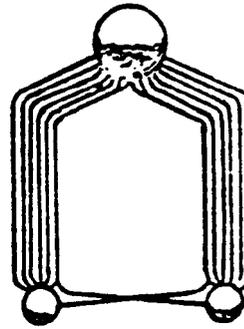
3.3.1 Oil- and Natural-gas-fired Watertube Boilers

Oil- and natural-gas-fired watertube boilers come in a wide range of capacities, from small commercial units of 0.4 MMBtu/hr (0.1 MWt) heat input capacity, to very large industrial boilers of 1,500 MMBtu/hr (440 MWt) or heat input capacity or higher. However, in the ICI sector, most are smaller than 250 MMBtu/hr (73 MWt). Larger oil- and natural-gas-fired watertube boilers that are field-erected are similar to PC-fired units in firing configuration, but with smaller furnace volumes (higher heat release rate per unit volume or waterwall surface area). Units with heat input capacities greater than 150 MMBtu/hr (44 MWt) are typically wall-fired or tangential-fired with multiple burners. Field-erected watertube boilers strictly designed for oil firing are more compact than coal-fired boilers with the same heat input, because of the more rapid combustion characteristics of fuel oil. Field-erected watertube boilers fired by natural gas are even more compact due to the rapid combustion rate of the gaseous fuel, the low flame luminosity, and the ash-free content of natural gas.⁴³

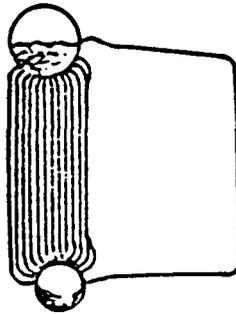
In general, field-erected watertube boilers are much more common than packaged units in the boiler size category above 100 MMBtu/hr (29 MWt) heat input capacity, whereas below this capacity, watertube boilers are usually packaged. There are, however, packaged watertube units as large as 250 MMBtu/hr (73 MWt) heat input capacity.

The major type of watertube design used in packaged oil/natural-gas-fired ICI boilers is the horizontal bent tube, classified by the number of drums, headers, and tube configuration, with the latter being the most distinguishing factor. Figure 3-19 shows the three most common tube configurations used in packaged units. The "A" type has two small lower drums, or headers,

A-type has two small lower drums or headers. Upper drum is larger to permit separation of water and steam. Most steam production occurs in center furnace-wall tubes entering drum.



D-type allows much flexibility. Here the more active steaming risers enter drum near water line. Burners may be located in end walls or between tubes in buckle of the D, right angles to drum.



O-type is also a compact steamer. Transportation limits height of furnace, so, for equal capacity, longer boiler is often required. Floors of D and O types are generally tile-covered.

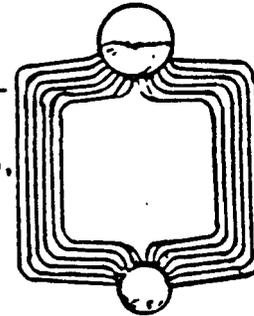


Figure 3-19. Watertube design configurations.⁴⁴

and a large upper drum for steam and water separation. Most steam production occurs in the center furnace wall tubes entering the drum. The "D" type, the most flexible design and the most widespread, has two drums and a large-volume combustion chamber that is easy to outfit with a superheater or economizer. The "O" configuration's symmetry exposes the least amount of tube surface to radiant heat.¹¹ Figure 3-20 depicts a typical D-type packaged boiler, and its watertubes, equipped with a single oil/natural gas burner at the end.

3.3.2 Oil- and Natural-gas-fired Firetube Boilers

The most common types of firetube boilers used for oil and natural gas firing are the Scotch, the HRT, the vertical, and the firebox boilers. Available units range from 0.4 MMBtu/hr (0.1 MWt) to 50 MMBtu/hr (15 MWt) heat input capacity, although most in use in the ICI sector have capacities below 25 MMBtu/hr (7.3 MWt).³⁵ These firetube boilers almost always employ a single burner rather than multiple burners, and nearly all are packaged units.

Of these four types of firetube designs, the Scotch firetube boiler is the most common. In a four-pass Scotch boiler, such as that shown in Figure 3-16, the burner is located at the end of the unit. Combustion gases pass first through the furnace tube, which is an extension of the

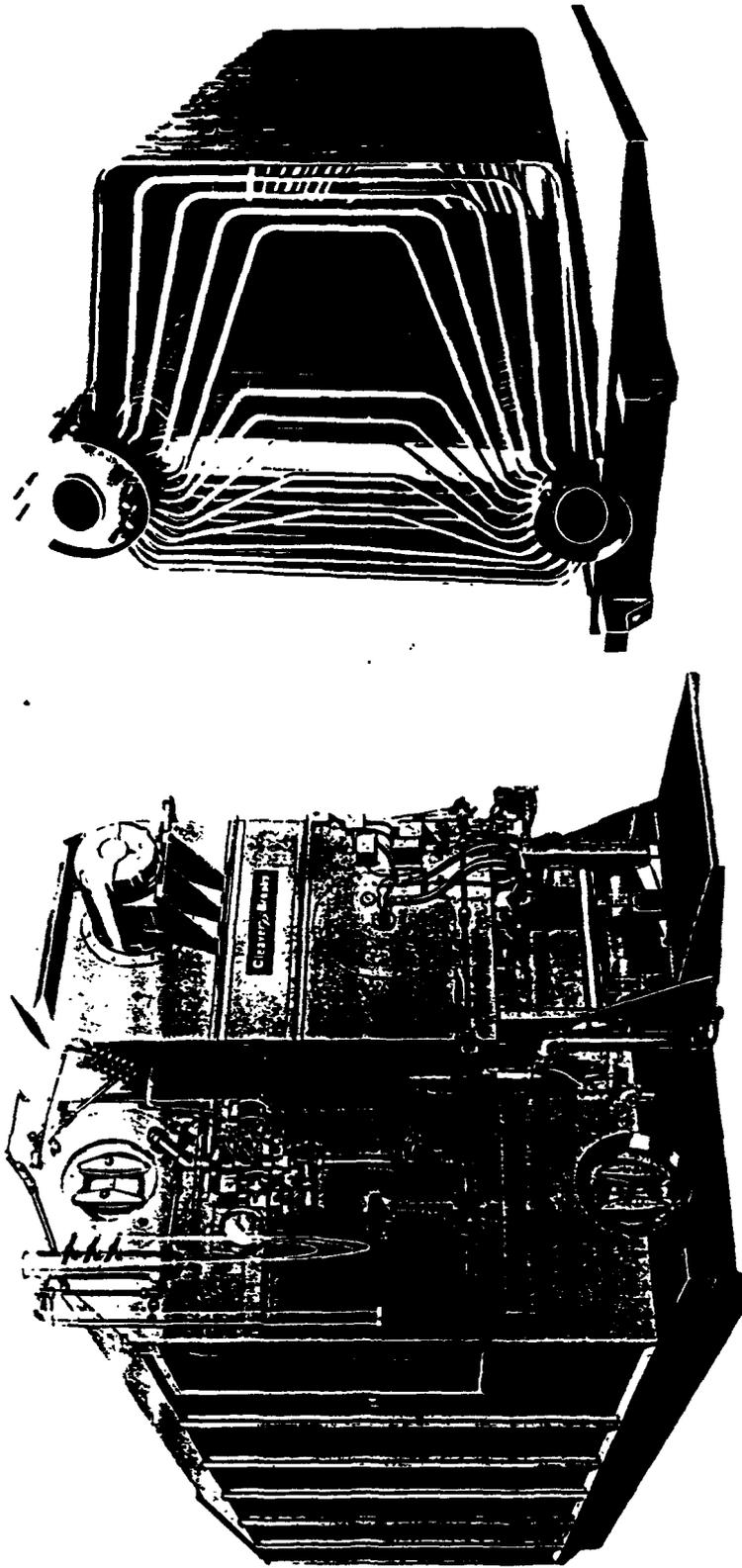


Figure 3-20. D-type packaged boiler and watertubes.⁴⁵

combustion chamber, to the end of the boiler, and then enter firetubes at the bottom of the unit. The flue gases then flow back toward the front of the unit, and then enter two more systems of firetubes located above the combustion chamber, before finally exhausting through the stack. A two-pass Scotch boiler is shown in Figure 3-6; this type of unit ranges from 1 MMBtu/hr to 30 MMBtu/hr (0.3 to 9 MWt) heat input capacity.

Oil- and natural-gas-fired HRT, vertical, and firetube boilers are similar in designs and capacities to the coal-fired units discussed earlier. They are essentially the same as the coal-fired firetube units, but differ in that burners rather than stoker systems are used.

3.3.3 Oil- and Natural-gas-fired Cast Iron Boilers

Although approximately 70 percent of ICI boilers are oil- or natural-gas-fired cast iron units, these systems comprise only about 10 percent of the total United States ICI boiler capacity. Two-thirds of these boilers are rated below 0.4 MMBtu/hr (0.1 MWt) heat input capacity. Most of them are used in the commercial and institutional sectors to provide low-pressure steam or hot water. Cast iron boilers using oil or natural gas are similar in design to those described in Section 3.2.3.

3.3.4 Other Oil- and Natural-gas-fired Boilers

Another oil- and natural-gas-fired boiler currently in use is the three-pass vertical tubeless boiler, shown in Figure 3-21. This boiler consists of a vertical, rigid steel pressure vessel enclosed inside another pressure vessel, with water in between. This assembly is itself enclosed within an insulated outer shell. The burner is mounted horizontally at the bottom of the boiler assembly, firing into the inner pressure vessel, which serves as a large primary radiant furnace. Flue gases pass up through the inner vessel, and then make second and third passes over convection fins mounted on the outside of the outer pressure vessel. Heat is transferred to the water located between the two pressure vessels. This type of boiler is packaged and is available in heat input capacities ranging from 0.25 to 4.2 MMBtu/hr (0.07 to 1.23 MWt). The largest units are roughly 6 feet in diameter and 9 feet in height.⁴⁶

Boilers used in thermally enhanced oil recovery (TEOR) operations are referred to as TEOR steam generators. These units are typically packaged watertube boilers with heat input capacities from about 20 to 62.5 MMBtu/hr (5.9 to 18.3 MWt). Steam generators are typically cylindrical in shape and horizontally oriented, with watertubes arranged in a coil-like design. For a given size, there is little variability in the design or configuration of oil field steam generators.⁴⁷ Figure 3-22 shows a typical oil field steam generator.

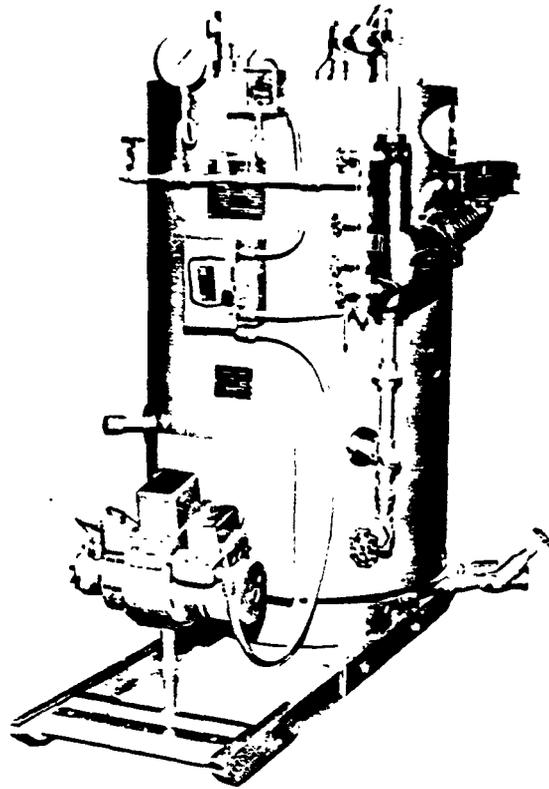


Figure 3-21. Vertical tubeless boiler.⁴⁶

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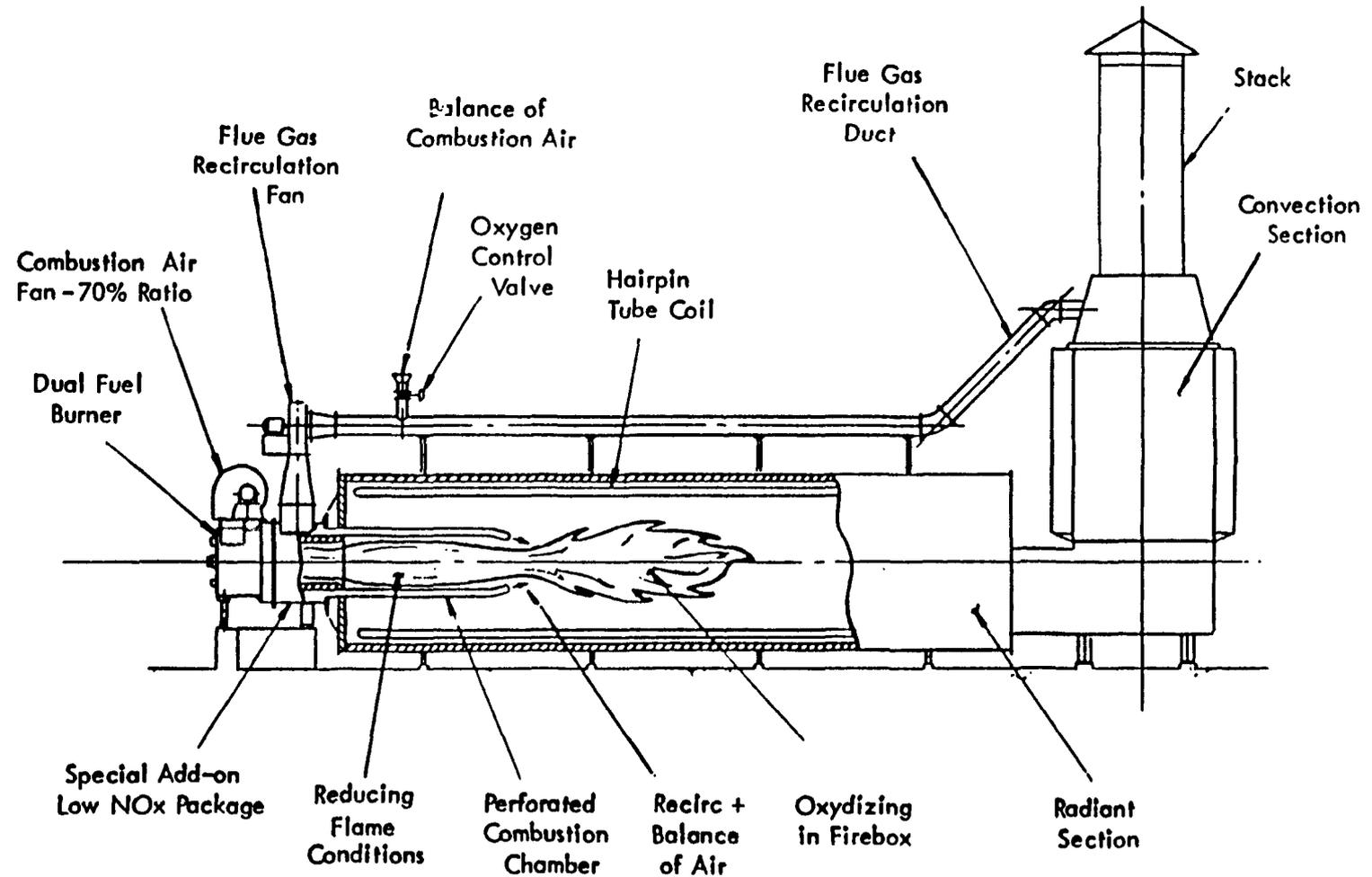


Figure 3-22. TEOR steam generator.⁴⁹

FBC boilers rely on coal, biomass, wood, and other solid fuels. Natural gas or oil is used primarily as either a startup fuel to preheat the fluidized bed, or as an auxiliary fuel when additional heat is required.^{31,48}

3.3.5 Oil Burning Equipment

Natural-gas- and oil-fired boilers often use similar combustion equipment, and in fact, many units are capable of firing either fuel. The use of fuel oil, however, generally requires special equipment to "atomize" the fuel before combustion. In some installations, this atomization equipment may play a key role in the combustion performance of the boiler unit. To burn fuel oil at the high rates required in most ICI boiler applications, it is necessary that the oil be atomized or dispersed into the furnace as a fine mist. This exposes a larger amount of oil particle surface for contact with the combustion air, assuring prompt ignition and rapid combustion.⁵⁰ The most common types of atomizers are steam and mechanical atomizers.

Steam atomizers, which may also be used with moisture-free compressed air, are the most widely used.⁵⁰ These types of atomizers produce a steam-fuel emulsion which, when released into a furnace, atomizes the oil through rapid expansion of the steam. Steam atomizers are available in sizes up to 300 MMBtu/hr (88 MWt) input. The steam and oil pressure required are dependent on the design of the steam atomizer, although maximum oil pressures can be as high as 300 psi and maximum steam pressures as much as 150 psi.⁵⁰ Oil pressures are much lower than for mechanical atomizers. The steam atomizer performs more efficiently over a wider load range than do mechanical atomizers.

In mechanical atomizers the pressure of the fuel oil itself is used as the means for atomization. The oil pressure required at the atomizer for maximum capacity typically ranges from 600 to 1,000 psi, depending on capacity, load range, and fuel grade.⁵⁰ Mechanical atomizers are available in sizes up to 180 MMBtu/hr (53 MWt) input.

The viscosity of the oil is the most important property affecting atomization in mechanical atomizers.⁵¹ As viscosity increases, larger viscous forces must be overcome by the energy supplied to the nozzle. This detracts from the energy available for droplet breakup, resulting in coarser atomization and possible adverse effects on combustion efficiency.⁵¹ Thus, for proper atomization and combustion, oil of grades higher than No. 2 must usually be heated to reduce its viscosity to 135 to 150 Saybolt Universal Seconds.⁵⁰ Figure 3-23 shows the effect of temperature on viscosity for No. 2 (distillate) through No. 6 (residual) fuel oils.

3-33

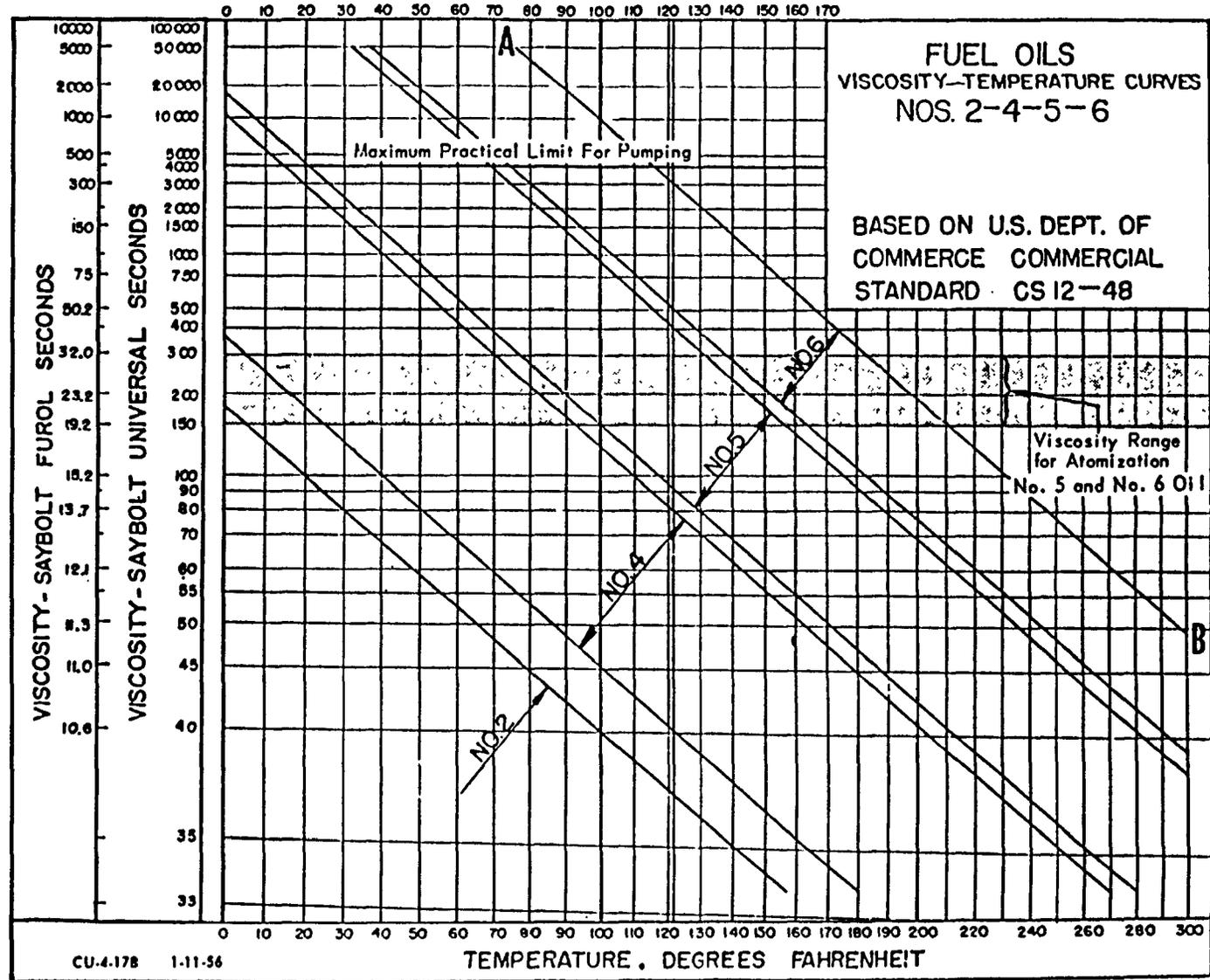


Figure 3-23. Effect of temperature on fuel oil viscosity.⁵¹

3.4 NONFOSSIL-FUEL-FIRED ICI BOILER EQUIPMENT TYPES

Nonfossil-fuel-fired boilers are commonly used in industries that generate combustible wastes from their industrial processes. In general, nonfossil-fuel-fired boilers include any boiler used in the production of steam or hot water from biomass, including wood wastes and bagasse, and general solid waste, including MSW, industrial solid waste (ISW), and RDF. The following subsections briefly describe the types of fuels burned and the most common types of nonfossil-fuel-fired boilers currently in use.

3.4.1 Wood-fired Boilers

Wood wastes are typically burned in boilers used in the paper and allied products industry, the forest products industry, and the furniture industry. Types of wood wastes are sawdust, sanderdust, wood chips, slats, and bark. Other sources of wood for fuel include discarded packing crates, wood pallets, and wood waste from construction or demolition activities.⁵² Wood is often cofired with an auxiliary fossil fuel in larger boilers.

Stokers are the most common type of wood-firing systems in the United States. There are three types of wood-fired stokers: spreader, overfeed, and underfeed. In design, they are similar to the coal-fired stokers described earlier, and range from 1.5 MMBtu/hr (0.44 MWt) to greater than 1,430 MMBtu/hr (420 MWt) heat input capacity. Of larger wood-fired units of 150 MMBtu/hr (44 MWt) heat input capacity or greater, spreader stokers are the most widespread.⁵³ As in the coal-fired spreader stoker described earlier, fuel enters the furnace through a chute and is spread pneumatically or mechanically across the furnace, where part of the wood burns in suspension. The remainder of the fuel lands on a stationary or moving grate, where it is burned in a thin, even bed. A portion of the combustion air is injected under the grate to drive off the volatiles and burn the char, while the remainder is fed above the grate to complete combustion. Most stoker units are equipped with a flyash reinjection system.

Other methods used to fire wood are overfeed and underfeed stoker firing, gasification, pyrolysis, fuel cell firing, suspension firing, and FBC, though to a lesser degree than spreader stoker firing. Another type of boiler combustion system, the Dutch oven, is also in use, but has been essentially discontinued from new construction due to its low efficiency, high construction costs, and inability to follow load swings.⁵³ The overfeed stoker is the second most common method of wood firing after the spreader stoker.

Gasification is a method of firing wood waste or other biomass whereby the fuel is partially combusted to generate a combustible fuel gas rich in carbon monoxide and hydrogen,

which is then burned. Heat to sustain the process is derived from exothermic chemical reactions, while the combustible components of the resulting gas are generated by endothermic reactions.⁵⁴ In essence, a gasification system behaves as a type of biomass burner. One manufacturer offers flyash gasification systems ranging from 4.2 to 33.5 MMBtu/hr (1.2 to 9.8 MWt) heat input capacity.

In pyrolysis, an organic fuel is introduced into a high-temperature environment with little oxygen. Thermal cracking of the fuel occurs, producing combustible gases that are then burned. One system uses a moving variable-speed grate to introduce the waste fuel to the pyrolytic gasification chamber, where the fuel is thermally cracked between 1,500°F and 1,850°F. The resulting combustible gases are then fired in an afterburner and the flue gases directed to the boiler passes. This system is available in heat input capacities from 14 to 57 MMBtu/hr (4.1 to 16.7 MWt).

In a fuel cell boiler, wood is piled on a stationary grate in a refractory-lined cell. Forced draft air is supplied to drive off the volatiles in the wood and burn the carbon. The volatiles are mixed with secondary and tertiary combustion air and pass into a second chamber where combustion is completed.⁵³ Fuel cell boilers range in heat input capacity from 3 MMBtu/hr (0.9 MWt) to 60 MMBtu/hr (17.6 MWt).

In suspension firing boilers, small-sized wood fuel, such as sanderdust, is typically blown into the furnace and combusted in mid-air. The small-sized fuels required by these boilers are typically cleaner and drier than other wood wastes, which can result in increased combustion efficiency and less ash entering the furnace. However, most of the ash that does enter the furnace is usually entrained in the flue gas. Most newer boilers utilize a flyash reinjection system to minimize the amount of unburned carbon in the flyash.

Wood is also fired in FBC boilers, which are detailed in Section 3.2.1.3. In 1991, 10 nonutility FBC boilers below 250 MMBtu/hr (73 MWt) heat input capacity and exclusively firing wood wastes were in use in the United States.² These ranged from a 40-MMBtu/hr (12-MWt or 6-MWe) boiler, at a timber company's cogeneration plant, to a 180-MMBtu/hr (53-MWt or 27-MWe) unit, used by an independent power producer. In an additional 29 units below 250 MMBtu/hr (73 MWt) heat input capacity, wood was fired in combination with other fuels, such as coal, oil, plastic, and other agricultural wastes. The largest single wood-fired FBC boiler had an electrical generating capacity of 220 MWe, roughly equivalent to 1,500 MMBtu/hr (440 MWt) heat input capacity. This unit was operated by an independent power producer, and

is atypical in size. The next largest wood-fired FBC in the ICI sector was 345 MMBtu/hr (100 MWt or 51 MWe) heat input capacity. This is more typical of the ICI wood-fired FBC boiler range.²

It is fairly common practice to use an auxiliary fuel, particularly fossil fuel, in all types of wood-fired boilers. Approximately 50 percent of wood-fired boilers have some type of fossil fuel firing capability.⁵³ Fossil fuels are fired during startup operation, as an augmentation fuel, or alone when wood fuel is unavailable. Fossil fuels are used more frequently in larger wood-fired boilers than in smaller boilers below 100 MMBtu/hr (29 MWt) heat input capacity.

Wood-fired boilers are available in both firetube and watertube designs, and are packaged or field-erected. Typical firetube boilers used in wood firing are the HRT and the firebox. Wood-fired HRT boilers are usually no larger than 40 MMBtu/hr (12 MWt) heat input capacity, although some as large as 50 MMBtu/hr (15 MWt) have been built. Wood-fired firebox units generally range between 2 and 20 MMBtu/hr (0.6 to 6 MWt) heat input capacity. The firing methods discussed above are used with both firetube and watertube boilers.

Packaged watertube boilers are the most difficult of all boilers to fire with wood waste. This is because the furnaces of these boilers are relatively cold, with water walls on all sides, and because the furnaces are very narrow due to shipping requirements. Because of this cold environment, it is essential that the dry wood particles be small enough to burn out completely during the time it takes the particles to pass through the furnace. For most packaged watertube units, the particles should be no larger than 1/64 to 1/32 of an inch, depending upon the heat release rate.⁵⁵

3.4.2 Bagasse-fired Boilers

Bagasse, an agricultural waste, is the fibrous residue left after processing sugar cane. It is used in sugar industry boilers in Hawaii, Florida, Louisiana, Texas, and Puerto Rico.⁵² This fuel is available on a seasonal basis. Other agricultural wastes include nut hulls, rice hulls, corn cobs, olive pits, and sunflower seed hulls.

The earliest type of bagasse-burning furnace was the Dutch oven with flat grates. In this type of furnace, the bagasse was burned in a pile on a refractory hearth and combustion air admitted to the pile around its circumference through tuyeres. However, this type of furnace resulted in high maintenance costs and was essentially discontinued from new installation. A more commonly used pile burning boiler is the fuel cell, described earlier. In one type of fuel cell boiler system, the Ward furnace, shown in Figure 3-24, bagasse is gravity-fed through chutes

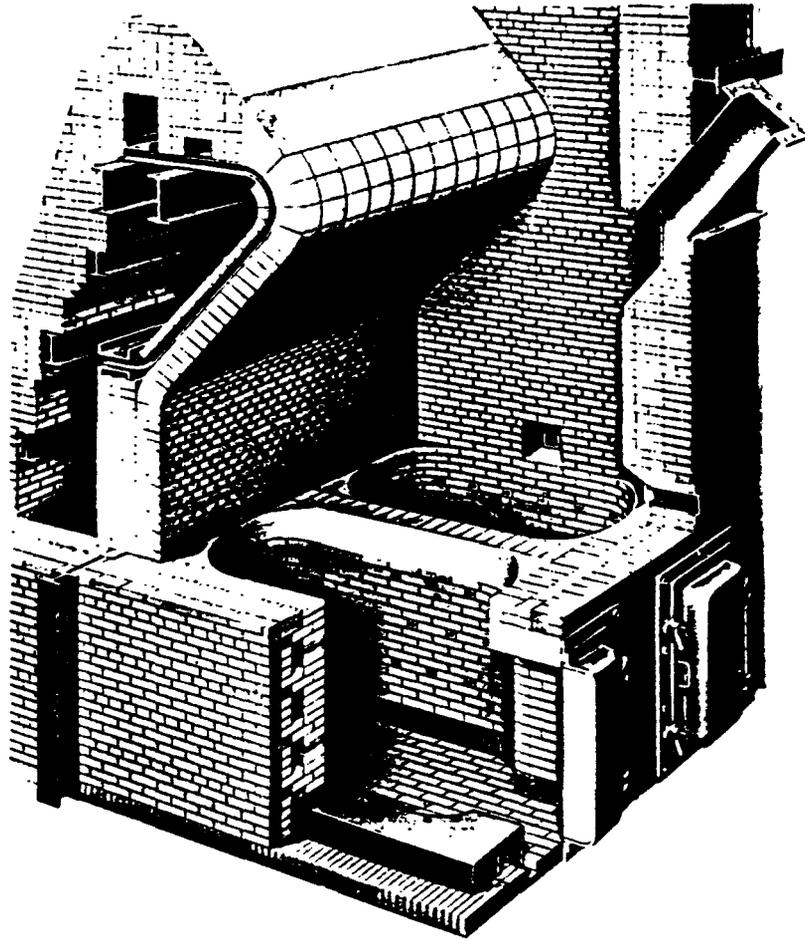


Figure 3-24. Ward fuel cell furnace.⁵⁶

into individual cells, where it is burned from the surface of the pile with air injected into the sides of the pile. Additional heat is radiated to the pile from hot refractory, and combustion is completed in a secondary furnace. This type of design is considered one of the most reliable, flexible, and simple methods of burning bagasse.⁵⁶

Recent trends in bagasse firing have been toward using spreader stoker systems. Bagasse spreader stoker boilers are similar in design to wood-fired spreader stokers, except that flyash reinjection is not normally used.⁵⁷ Spreader stokers require bagasse with a high percentage of fines and a moisture content not over 50 percent.⁵⁶

Like most other waste-fueled boilers, bagasse-fired units typically use auxiliary fuels such as natural gas or fuel oil during startup or when additional capacity is required. Most operators minimize the amount of auxiliary fuel used, and typically less than 15 percent of the total annual

fuel heat input to bagasse boilers comes from fossil fuels.⁵⁷ Bagasse-fired boilers range from 13 to 800 MMBtu/hr (3.8 to 230 MWt) heat input capacity.

3.4.3 Municipal Solid Waste (MSW)-fired Boilers

General solid waste consists of refuse and garbage from municipalities and industries. Boilers that fire general solid waste are found in manufacturing plants, district heating plants, municipal heating plants, and electric utilities. As mentioned earlier, general solid waste can be further classified as MSW, ISW, or as RDF.

MSW is made up of food wastes, rubbish, demolition and construction wastes, treatment plant wastes, and other special wastes. Combustible rubbish consists of material such as paper, cardboard, plastics, textiles, rubber, leather, wood, furniture, and garden trimmings. Treatment plant waste consists of sludge from water, wastewater, and industrial wastewater treatment facilities. Special wastes are roadside litter, dead animals, and abandoned vehicles. The exact makeup of MSW varies both seasonally and geographically. For example, more organic material is usually contained in MSW during the fall, especially in areas such as the northeast where many trees are deciduous. Typically, over one third of MSW in the United States is paper, with the next most abundant constituents being food wastes and garden trimmings.⁵⁸

MSW-fired boilers can be categorized by heat input capacity as either small modular units or large mass-burning facilities. Small modular MSW-fired boilers range from 4.5 MMBtu/hr (1.3 MWt) to 38 MMBtu/hr (11 MWt) heat input capacity, while mass-burning units are as large as 290 MMBtu/hr (85 MWt).⁵⁹ Modular units have been in operation in the United States since the late 1960s, while most existing mass-burning facilities have been constructed since 1970.

A typical large mass-burning facility rated at 150 MMBtu/hr (44 MWt) heat input capacity and MSW throughput of 15 tons per hour is shown in Figure 3-25. The facility includes a waterwall furnace and an overfeed stoker system. MSW is loaded by overhead crane into the feed chute, which deposits the waste onto the first grate, known as the "dry-out" grate. Ignition starts at the bottom of the dry-out grate and is continued on a second "combustion" grate. A third grate, the "burn-out" grate, provides final combustion of the waste before dumping the ash into the ash pit. Typical thermal efficiencies for this size of mass-burning boiler range between 60 and 70 percent.^{60,61} Other variations of mass burn systems besides the waterwall furnace type are controlled air (pyrolysis) and refractory furnaces. Controlled-air MSW units

3-39

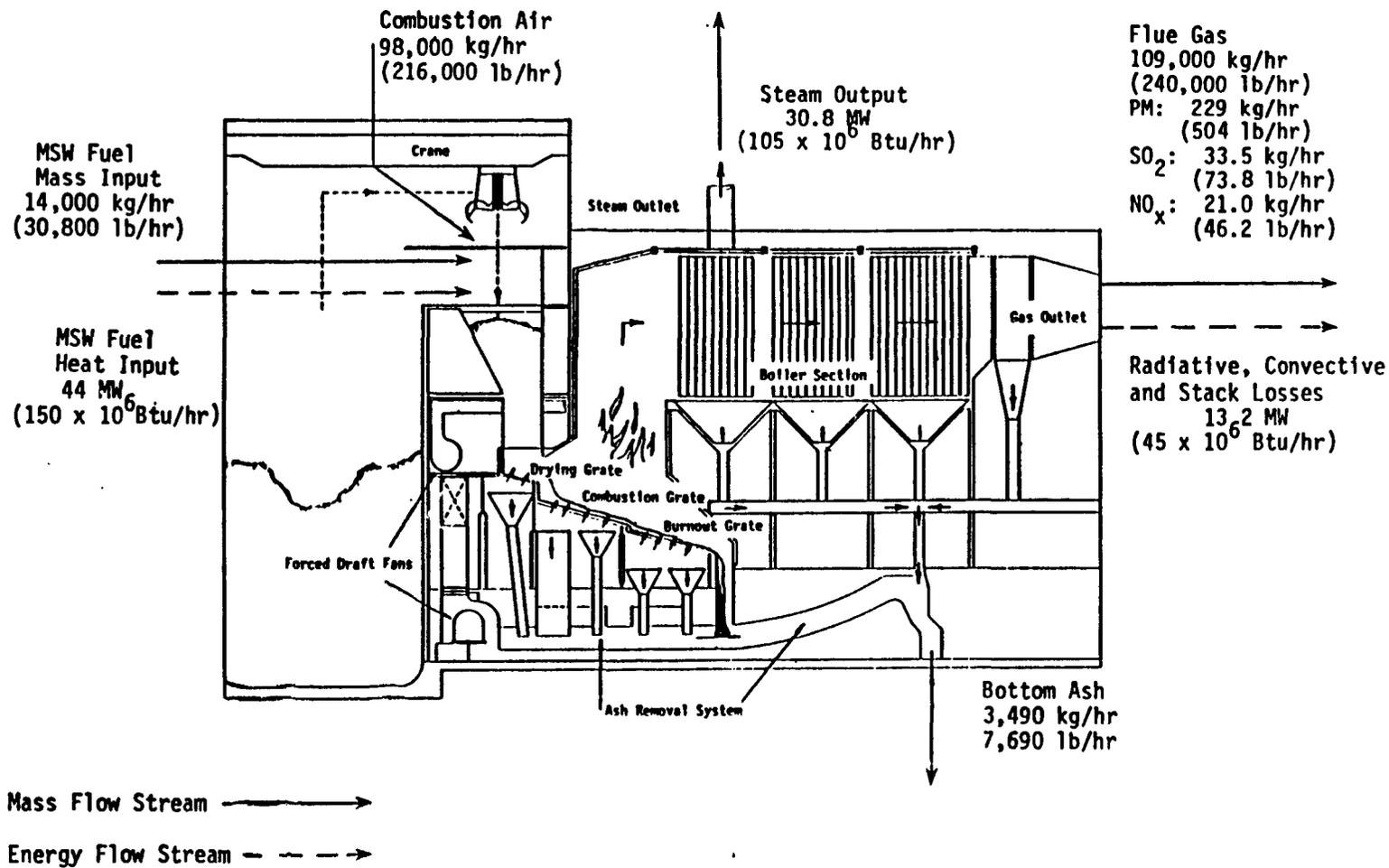


Figure 3-25. Large MSW-fired boiler.⁶⁰

received much developmental attention during the 1970s. Many of these units, however, were subsequently shut down due to operational or economic problems.⁶²

Small modular units differ from the mass-burning boilers in that they are typically hopper- and ram-fed instead of crane-fed. These units are packaged and designed to allow installation of additional units as the need for further capacity increases. A typical modular boiler, shown in Figure 3-26, utilizes a furnace with a primary and secondary combustion chamber. MSW is fired at approximately 820°C (1,500°F) in the primary chamber and at 1,040°C (1,900°F) in the secondary chamber. An auxiliary burner is used in the secondary chamber whenever additional heat is required. This particular type of unit is an example of a controlled-air or "starved-air" boiler, as the air in the primary combustion chamber is below stoichiometric levels to reduce ash and fuel entrainment.⁶³

3.4.4 Industrial Solid Waste (ISW)-fired Boilers

ISW is composed of those wastes, typically paper, cardboard, plastic, rubber, textiles, wood, agricultural waste, and trash, arising from industrial processes. The composition of ISW fuel at any one site is usually relatively constant because the industrial activities that generate the waste are usually well regulated. The average heating value of ISW is higher than MSW, about 17,000 kJ/kg (7,100 Btu/lb) compared to 11,000 kJ/kg (4,875 Btu/lb) as fired, and the ash content is less.⁶⁴

ISW is fired in the same type of boiler systems as the modular units described above. These units encompass the same capacity range of the modular MSW-fired boilers, but can also be as large as 60 MMBtu/hr (17.6 MWt) heat input capacity. Large-mass burning boilers are not commonly used at industrial facilities; thus, ISW is usually only fired in mass-burning boilers when it is collected as part of MSW.⁶⁴

3.4.5 Refuse-derived Fuel (RDF)-fired Boilers

RDF is fuel processed from general solid waste. Unlike MSW and ISW fuels, which are burned in the same form as they are received at the boiler site, RDF is generated by the sorting and processing of the general solid waste. Usually, noncombustibles, such as glass and metal, are removed and recycled, and the remainder of the refuse processed into pelletized or powdered form. RDF can be burned alone or in combination with coal or oil.⁵⁴ The most common use of RDF is as a substitute for part of the coal used in coal-fired stoker and PC boilers. However, a few stoker units burn RDF alone; these units are similar to standard coal-fired boilers.⁶⁴

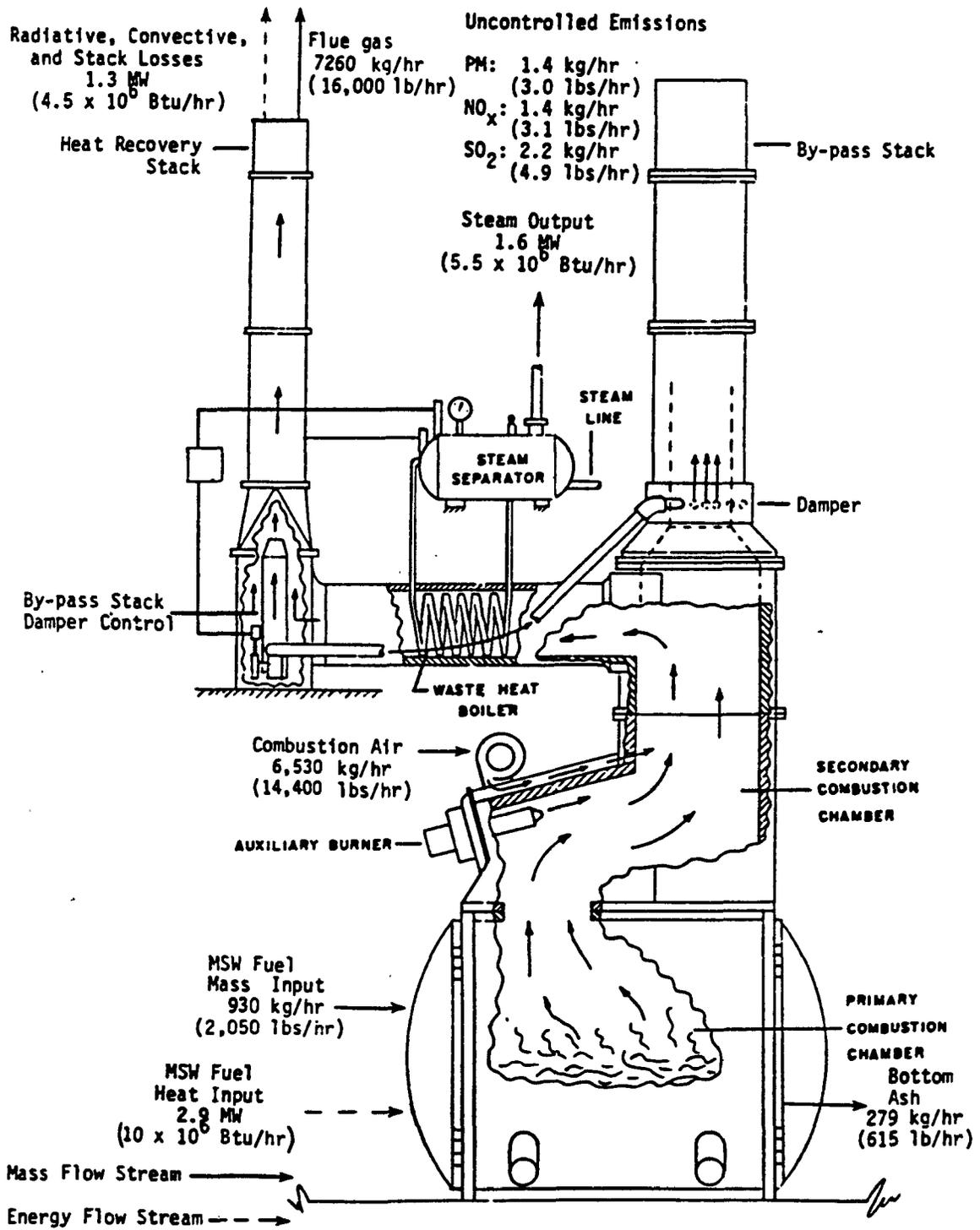


Figure 3-26. Modular MSW-fired boiler.⁶³

Both RDF-firing and mass burn systems were commonly used in early U.S. resource recovery plants. Currently, the majority of U.S. MSW firing units utilize mass burn and not RDF firing, due in part to the successful experience of mass burn plants in Germany, Switzerland, Japan, and a number of U.S. locations. Based on the number of plants in operation and the number being planned in the near future, mass burn is the MSW-firing system of choice, although RDF firing is still considered a viable technique, especially when refuse throughput is low to moderate, on the order of a few thousand tons per day.^{62,65}

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4. BASELINE EMISSION PROFILES

NO_x is a high-temperature byproduct of the combustion of fuels with air. NO_x formation in flames has two principal sources. Thermal NO_x is that fraction of total NO_x that results from the high-temperature reaction between the nitrogen and oxygen in the combustion air. The rate of thermal NO_x formation varies exponentially with peak combustion temperature and oxygen concentration. Fuel NO_x is that fraction of total NO_x that results from the conversion of organic-bound nitrogen in the fuel to NO_x via a high-temperature reaction with oxygen in the air. The amount of nitrogen in the fuel, peak combustion temperature, oxygen concentration, and mixing rate of fuel and air influence the amount of fuel NO_x formed. When low-nitrogen fuels such as natural gas, higher grade fuel oils, and some nonfossil fuels are used, nearly all the NO_x generated is thermal NO_x . When coal, low-grade fuel oils, and some organic wastes are burned, fuel NO_x generally becomes more of a factor because of the higher levels of fuel-bound nitrogen available.

Aside from the physical and chemical characteristics of the fuels, many boiler design and operating parameters influence the formation of NO_x because they impact peak flame temperatures, fuel-air mixing rates, and oxygen concentrations. Principal among these are the heat release rates and absorption profiles in the furnace, fuel feed mechanisms, combustion air distribution, and boiler operating loads. For example, steam pressure and temperature requirements may mandate a certain heat release rate and heat absorption profile in the furnace which changes with the load of the boiler. Solid fuels can be introduced into the furnace in several ways, each influencing the rate of mixing with combustion air and the peak combustion temperature. These parameters are very unit specific and vary according to the design type and application of each individual boiler. As described in Chapter 3, ICI boilers include a broad range of furnace types operating in a variety of applications and burning a variety of fuels ranging from clean burning natural gas to several types of nonfossil and waste fuels. Thus, NO_x emissions from ICI boilers tend to be highly variable.

This chapter discusses the primary factors influencing baseline NO_x levels and summarizes the baseline (uncontrolled) NO_x emission levels measured from a variety of ICI boiler and fuel combinations. Parameters affecting NO_x emissions from ICI boilers are discussed in Section 4.1, while compiled baseline emissions for ICI boilers are presented in Section 4.2 on the basis of boiler fuel type. Section 4.3 presents a summary of the information presented in this chapter.

4.1 FACTORS AFFECTING NO_x EMISSIONS FROM ICI BOILERS

The ranges in baseline NO_x emissions for ICI boilers are due to several factors including boiler design, fuel type, and boiler operation. These factors usually influence baseline NO_x in combination with each other, and often to different degrees depending on the particular ICI boiler unit. Thus, wide variations among ICI boiler NO_x emissions are common, even among similar boiler designs or fuel types. These factors are discussed in the following subsections.

4.1.1 Boiler Design Type

The firing type of the boiler influences the overall NO_x emission level. For example, for a given fuel, tangential field-erected units typically have a baseline level less than wall-fired boilers because of their inherent staging of fuel and air in a concentric fireball: This trend has been documented for utility-sized boilers.¹ Conversely, cyclone units generally have higher NO_x levels than wall-fired units due to their inherent turbulent, high-temperature combustion process, which is conducive to NO_x formation.² Even within a particular type of boiler, other design details may influence baseline NO_x. For example, in field erected PC wall-fired units, NO_x may vary depending upon whether a wet bottom or dry bottom furnace is used. Wet bottom furnaces have higher furnace temperatures to maintain the slag in a molten state, leading to greater thermal NO_x formation.³

In comparison, coal stokers have lower NO_x emissions than PC-fired units since the stokers inherently operate in a "staged combustion" configuration.⁴ Staged combustion, which is discussed in greater detail in Chapter 5, relies on the reduction of the peak flame zone oxygen level to reduce formation of fuel NO_x, and is achieved by delaying — or staging — the addition of combustion air. Higher NO_x levels reported for spreader stokers are due to a portion of the fuel burning in suspension with more effective fuel/air mixing and higher combustion temperatures. In comparison, overfeed and underfeed stokers combust more of the coal on a grate where combustion is naturally staged, with a fuel rich zone close to the grate and a more fully mixed zone above the grate. Additionally, underfeed and overfeed units tend to have larger

fireboxes and, consequently, lower heat release rates, resulting in lower peak temperatures and lower levels of thermal NO_x formation.⁵

The other major design type of solid-fuel-fired units, FBC boilers, report lower baseline NO_x emissions than similarly-sized wall-, tangential-, or cyclone-fired units, due mostly to the lower combustion temperatures used in FBCs. In FBC boilers, NO_x formation generally peaks in the lower part of the furnace and is reduced in the freeboard zone, where heterogeneous reducing reactions between char and NO_x occur.⁶ Also, newer FBC designs are incorporating combustion air staging in their original configuration to achieve low emissions for permitting in strict environmental areas. In staged configurations, the lower part of the fluidized bed and furnace are kept at or below stoichiometry. The staged addition of combustion air results in lower NO_x levels compared to unstaged designs.

Regarding smaller packaged natural-gas- or oil-fired boilers, NO_x emissions generally depend more on fuel, heat release rate and capacity characteristics. In general, ICI boilers with higher heat release rates and higher capacities tend to have higher levels of NO_x. This is discussed in more detail in Section 4.1.3. For a given heat release rate and fuel type, however, there is no strong correlation between NO_x emissions and whether a packaged boiler is a firetube or a watertube design.

4.1.2 Fuel Characteristics

ICI boiler baseline NO_x emissions are highly influenced by the properties of the fuels burned. NO_x and other emissions will vary depending on whether natural gas, oil, coal, or nonfossil fuels are used. Additionally, among each of these fuel types, emissions will depend on highly variable factors such as fuel grade and fuel source. In particular, studies have shown that fuel nitrogen content — and for coal the oxygen content and the ratio of fixed carbon to volatile matter — are key factors influencing NO_x formation.^{3,7-9}

Much attention has been given to the role of fuel-bound nitrogen in NO_x formation. For any given fuel, only a portion of the available fuel nitrogen is converted during combustion to fuel NO_x. Published data indicate that for coal burning, anywhere from 5 to 60 percent of the nitrogen is converted, whereas for other fuels as much as 80 percent of the fuel bound nitrogen is routinely converted.^{10,11} In general, higher nitrogen fuels such as coal and residual oil have lower conversion rates, as shown in Figure 4-1, but higher overall NO_x rates than lower nitrogen fuels such as distillate oil.³ The nitrogen content of bituminous coals can vary from as low as 0.8 to as high as 3.5 percent by weight. Fuel oil is normally divided into distillate oil and residual

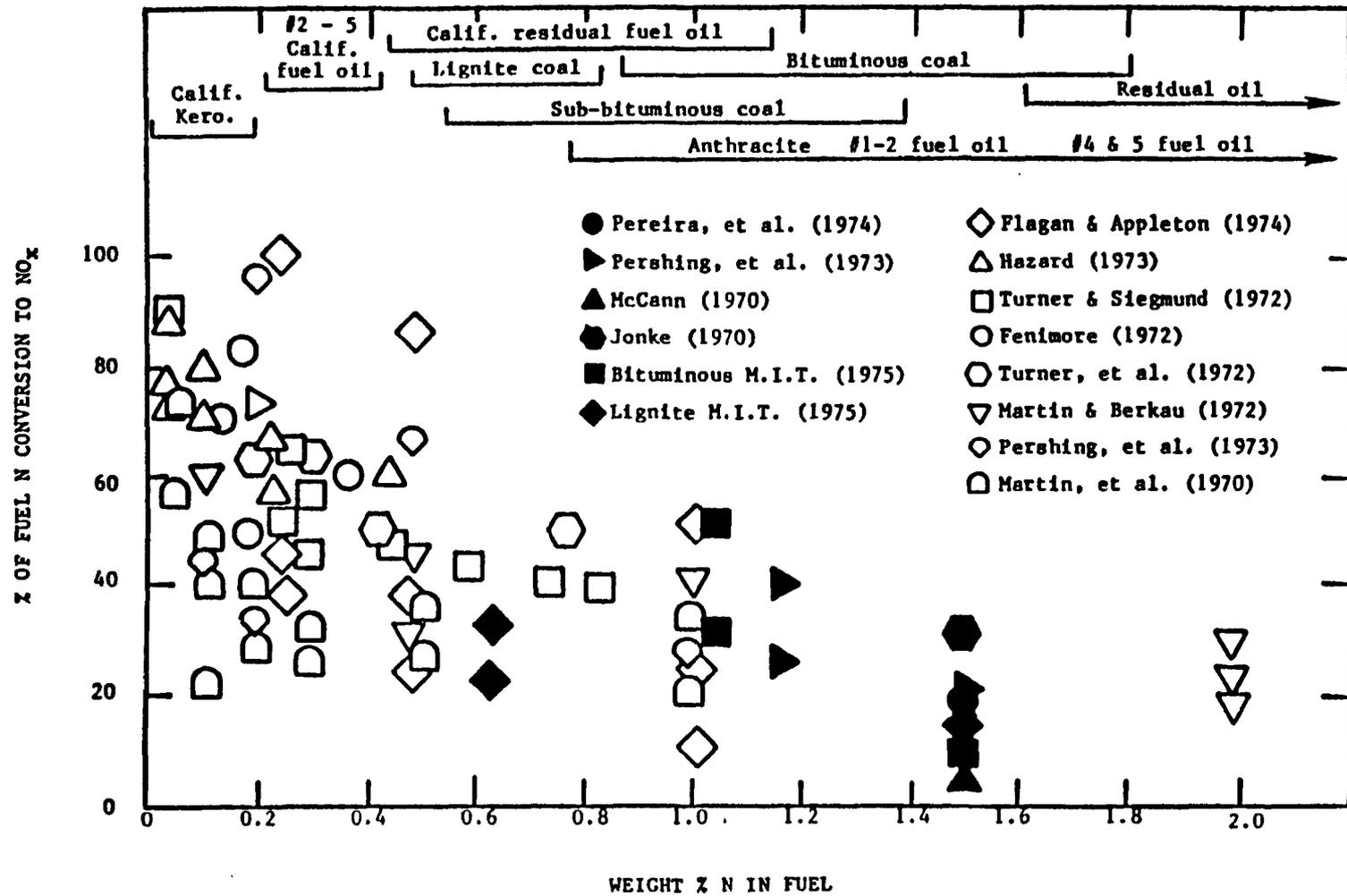


Figure 4-1. Conversion of fuel nitrogen.¹¹

oil. Distillate oil represents the lighter fraction of the distillation process, including No. 2 oil and diesel oil normally used in residential and commercial heating, internal combustion engines, and sometimes in larger boilers strictly regulated for SO₂ and NO_x emissions. Residual oil consists of the higher temperature fractions and still bottoms from the distillation process, including No. 4, 5, and 6 fuel oils often used in industrial and some commercial boilers.

Table 4-1 lists the range and average concentrations of nitrogen and sulfur in distillate, residual, and crude oils. The data were compiled from various sources, including emission test reports, to illustrate the variability of these fuel properties. Many areas will have oils with different values, these depending on many factors such as the type of crude, refinery processes (e.g., hydrodesulfurization), and blending. Clearly, the lighter oils contain much lower levels of fuel nitrogen and sulfur, thereby contributing significantly lower NO_x and SO₂ emissions. Distillate oil normally has less than 0.01-percent nitrogen content, whereas the fuel nitrogen content of residual oils typically ranges from 0.1 to 0.8 percent by weight, with an average of 0.36 percent based on the data used to compile Table 4-1.

Sulfur content is typically specified when residual oil is purchased. This is done to meet environmental regulations and to safeguard boiler equipment from acid corrosion. Although lower sulfur content generally means lower nitrogen, there is no apparent direct relationship between these two fuel oil parameters, as illustrated in Figure 4-2. Because the deliberate denitrification of fuel oil is not a refinery practice, significant swings in the nitrogen content of residual oil occur even when sulfur content is limited to low levels.

The nitrogen content of natural gas can vary over a wide range, from zero to as high as 12.9 percent, depending on the source of the gas. Nitrogen in natural gas, however, does not contribute as much to the production of fuel NO_x as with liquid or solid fuels, the reason being that the nitrogen in natural gas is in its molecular form (N₂), as in the combustion air. In contrast, nitrogen in liquid or solid fuels is released in its atomic form (N) and reacts at relatively low temperatures with oxygen to form fuel NO_x.¹²

Figure 4-3 shows the effect of fuel nitrogen content on total NO_x emissions for 26 oil-fired and 15 coal-fired industrial boiler tests. For the oil-fired tests, in which both residual and distillate oils were burned, a clear correlation was seen between nitrogen content and NO_x, with higher NO_x levels reported for the higher nitrogen content oils. The field tests of coal-fired units, however, showed no direct correlation between total NO_x emissions and coal fuel nitrogen content, per se.⁹ Similar results were also reported in a study comparing the use of low-sulfur

TABLE 4-1. TYPICAL RANGES IN NITROGEN AND SULFUR CONTENTS OF FUEL OILS^a

	Distillate oil (No. 2)		Residual oil (No. 6)	
	Nitrogen	Sulfur	Nitrogen	Sulfur
Average	<0.01	0.72	0.36	1.3
Low	<0.001	0.20	0.10	0.10
High	0.01	0.70	0.80	3.5
Standard deviation	0.005	0.20	0.17	0.90
Reference	13-15		9, 14, 16-20	

^aAll concentrations are percent by weight.

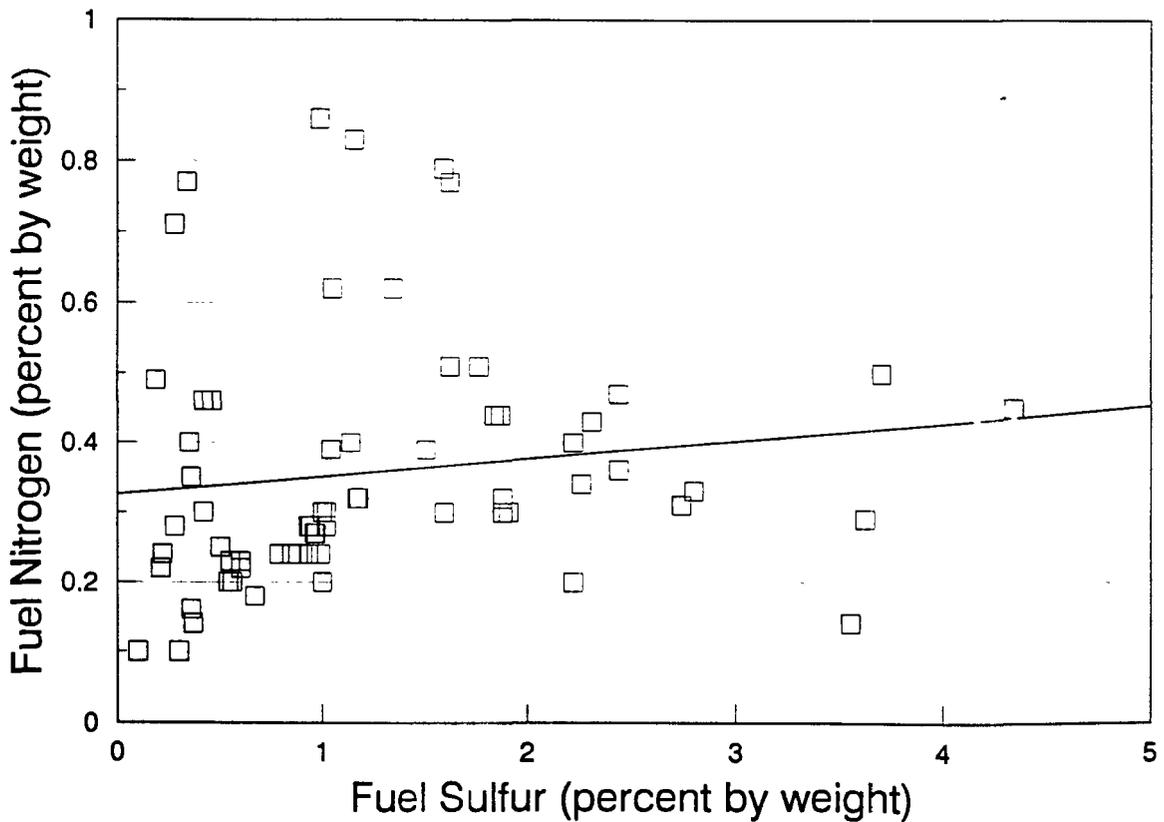


Figure 4-2. Fuel oil nitrogen versus sulfur for residual oil. (Data from several EPA- and EPRI-sponsored tests; see Table 4-1.)

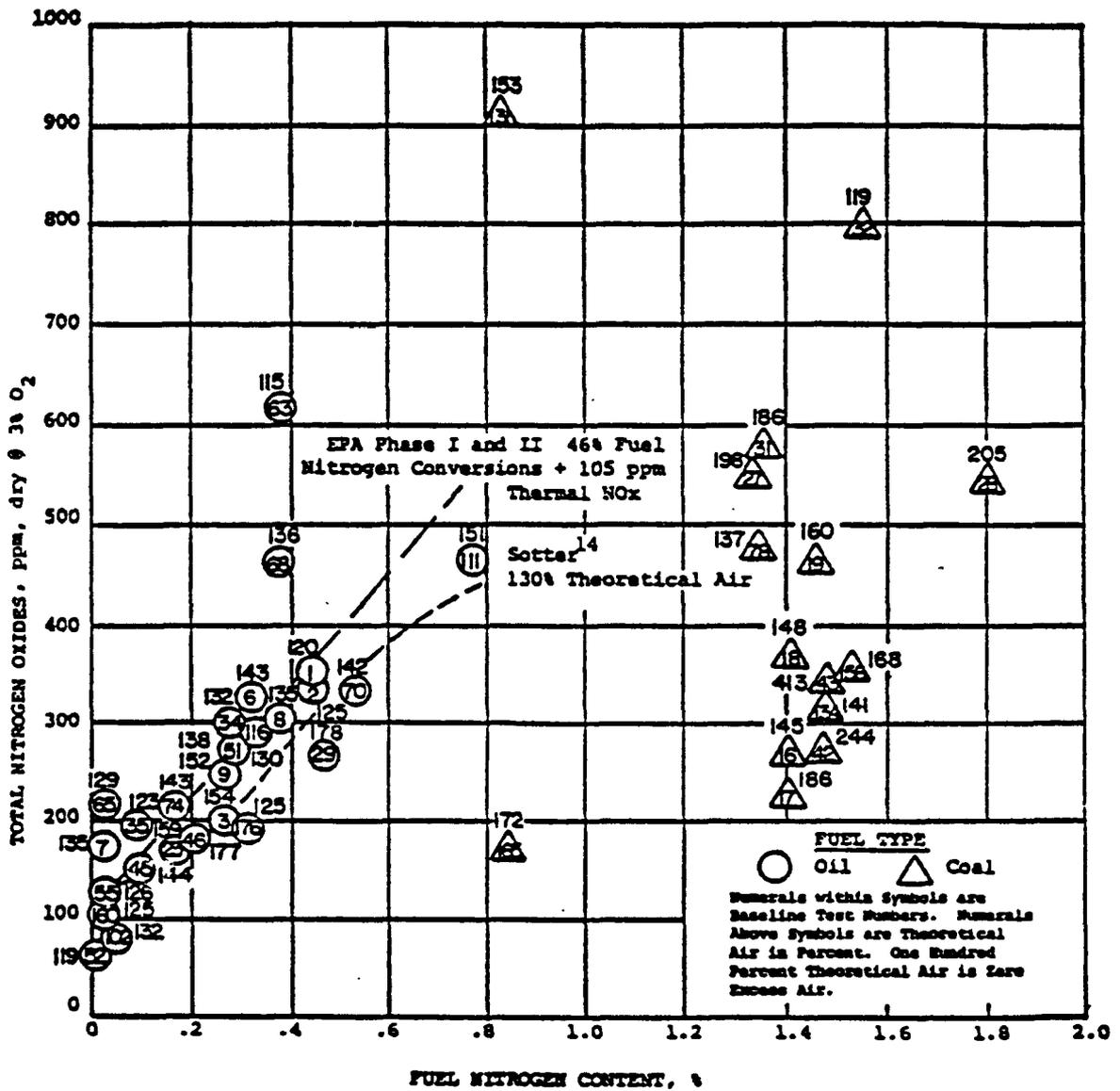


Figure 4-3. Effect of fuel nitrogen content on total NO_x emissions.⁹

western coal to the use of eastern bituminous coal in ICI boilers.⁸ It is believed that while nitrogen content does play a key role in NO_x formation, as was seen in the oil tests, other coal fuel factors such as oxygen content also influence NO_x formation concurrently, masking any obvious correlation between coal fuel nitrogen and NO_x.

This was suggested by test results showing a possible linkage between the ratio of coal oxygen to coal nitrogen and the amount of NO_x formed. Figure 4-4 shows the results of a study of the effects of the coal oxygen/nitrogen ratio on fuel NO_x formation in tangential PC-fired boilers. The figure shows the relationship between fuel NO_x, coal nitrogen content, and the coal oxygen/nitrogen ratio. The data indicate slightly higher NO_x emissions for western sub-bituminous coal due to the higher coal oxygen/nitrogen ratio, despite the coal's lower fuel nitrogen content. On a broader scale, coal property data show that coals with high oxygen/nitrogen ratios generally have lower nitrogen contents. Thus, the two influences — higher NO_x due to higher oxygen content, and lower NO_x due to lower nitrogen content — would tend to balance one another resulting in reasonably similar fuel NO_x emissions for a variety of coal types.^{7,21}

Another major coal factor influencing baseline NO_x formation is the fuel ratio, defined as the ratio of a coal's fixed carbon to volatile matter. Typically, under unstaged combustion conditions, lower fuel ratios (i.e. higher volatile content of the coal) correlate to higher levels of NO_x, because with higher volatile content coals, greater amounts of volatile nitrogen are released in the high temperature zone of the flame where sufficient oxygen is present to form NO_x.³ Thus, considered by itself, higher volatile coal firing will tend to result in higher baseline NO_x levels.²² It has been shown, however, that firing coal with high volatile content and lower fixed carbon generally results in less solid carbon to be burned out in the post-flame gases, meaning that the coal can be fired at lower excess air before combustible losses became a problem.⁸ As discussed in Section 4.1.4, lower excess air requirements generally result in lower NO_x emissions. Thus, the higher NO_x levels associated with higher volatile coals may be balanced to a certain degree by the lower excess air capability provided.

The difference between average NO_x emission levels reported among various fuel oil types (i.e., residual versus distillate) lies primarily in the fact that residual oils are produced from the residue left after lighter fractions (gasoline, kerosene, and distillate oils) have been removed from crude oil. Residual oils thus contain high quantities of nitrogen, sulfur, and other impurities. As discussed, fuels with high nitrogen contents generally produce higher levels of

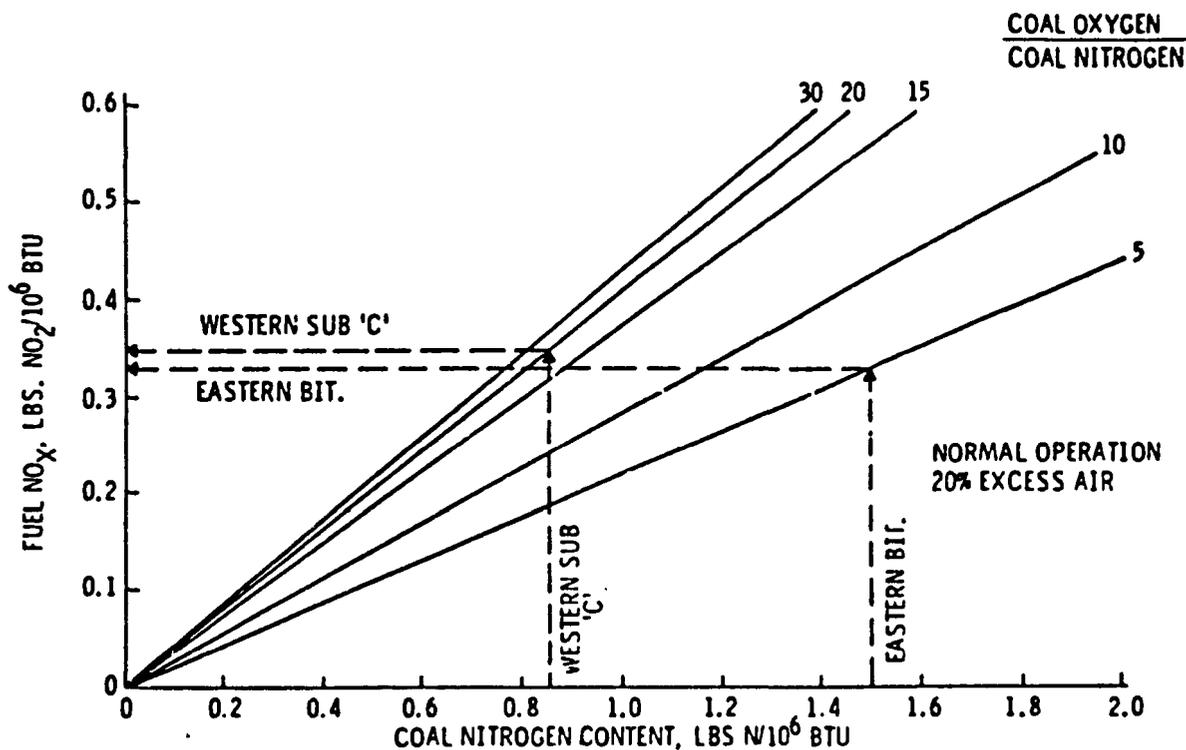


Figure 4-4. Fuel NO_x formation as a function of coal oxygen/nitrogen ratio and coal nitrogen content.²¹

fuel-bound NO_x than fuels with low nitrogen contents. Thus, with residual oil in particular, fuel NO_x makes up a greater portion of the total NO_x emitted. For any particular class of boilers, the range in NO_x emissions for residual oil is often wider than the range of emissions for distillate oil. The larger amount and variation of fuel nitrogen in the residual oil accounts for this.²³ Even within one type of fuel oil, large variations in NO_x emissions can be recorded due to the other factors discussed in this chapter. The variability in NO_x emissions between the boilers listed in Appendix A burning the same type of oil is chiefly due to variations in boiler heat release rates and operating conditions.

Besides distillate oil, many nonfossil fuel types are low-nitrogen-content fuels. Thus, NO_x emissions from ICI boilers fired on these fuels and on natural gas are almost entirely thermal NO_x, and the major factors which influence their NO_x levels are furnace heat release rate (related to capacity and operating load) and excess air level, both of which are discussed below.²⁴ While most wood burning boilers are stokers and are similar in design to coal-fired

units, the relatively low nitrogen content of wood contributes to much lower fuel-bound NO_x formation than with coal. In general, with wood wastes the generation of particulates and other unburned combustibles is more of a concern than NO_x formation. The wood moisture content and wood fuel size are the two most important fuel quality factors influencing those emissions.²⁵

Moisture content also plays an important role in the formation of uncombustible emissions in MSW firing. By its nature, MSW composition is highly dependent on the net waste contributions of residential and commercial waste producers, and on seasonal factors which may impact the amount and type of organic waste produced. For example, a period of high rainfall can result in increased moisture content in the MSW, with larger quantities of yard waste. These variables result in wide ranges in MSW composition and corresponding fuel properties. Studies have shown that the non-combustible content of MSW can range from 5 to 30 percent, the moisture content from 5 to 50 percent, and the heating value from about 7,000 to 15,000 kJ/kg (3,000 to 6,500 Btu/lb).²⁶ Nitrogen contents, too, are often highly variable depending on the source of MSW. Ultimate analyses of MSW from different parts of the United States have shown nitrogen contents ranging between 0.2 and 1.0 percent.²⁷⁻³¹ Thus, emissions from MSW-fired boilers will also tend to be highly variable.

4.1.3 Boiler Heat Release Rate

Boiler heat release rate per furnace area is another influential variable affecting NO_x formation. As heat release rate increases, so does peak furnace temperature and NO_x formation, as illustrated in Figure 4-5. Boiler heat release rate varies primarily with the boiler firing type, the primary fuel burned, and the operating load.³ Additionally, boiler heat release rate per unit volume is often related to boiler capacity, as illustrated in Figure 4-6. For example, among coal-fired boilers, PC-fired units are typically the largest in capacity. The data in Appendix A include PC-fired units from 111 to 640 MMBtu/hr (32.5 to 188 MWt) heat input capacity, whereas the coal stokers listed in Appendix A are generally smaller, ranging in size from 3 to 444 MMBtu/hr (0.88 to 130 MWt), with the vast majority being below 200 MMBtu/hr (59 MWt) capacity. These ranges are fairly representative of the capacity ranges discussed in Chapter 3. Compared to other coal-fired boiler designs, PC-fired units tend to have larger capacities, heat release rates, and, as shown by the data in Appendix A, generally higher baseline NO_x levels.

Among stoker units, the largest capacity stokers are spreader stokers as reflected in the Appendix A data. The majority of spreader stoker data came from units greater than

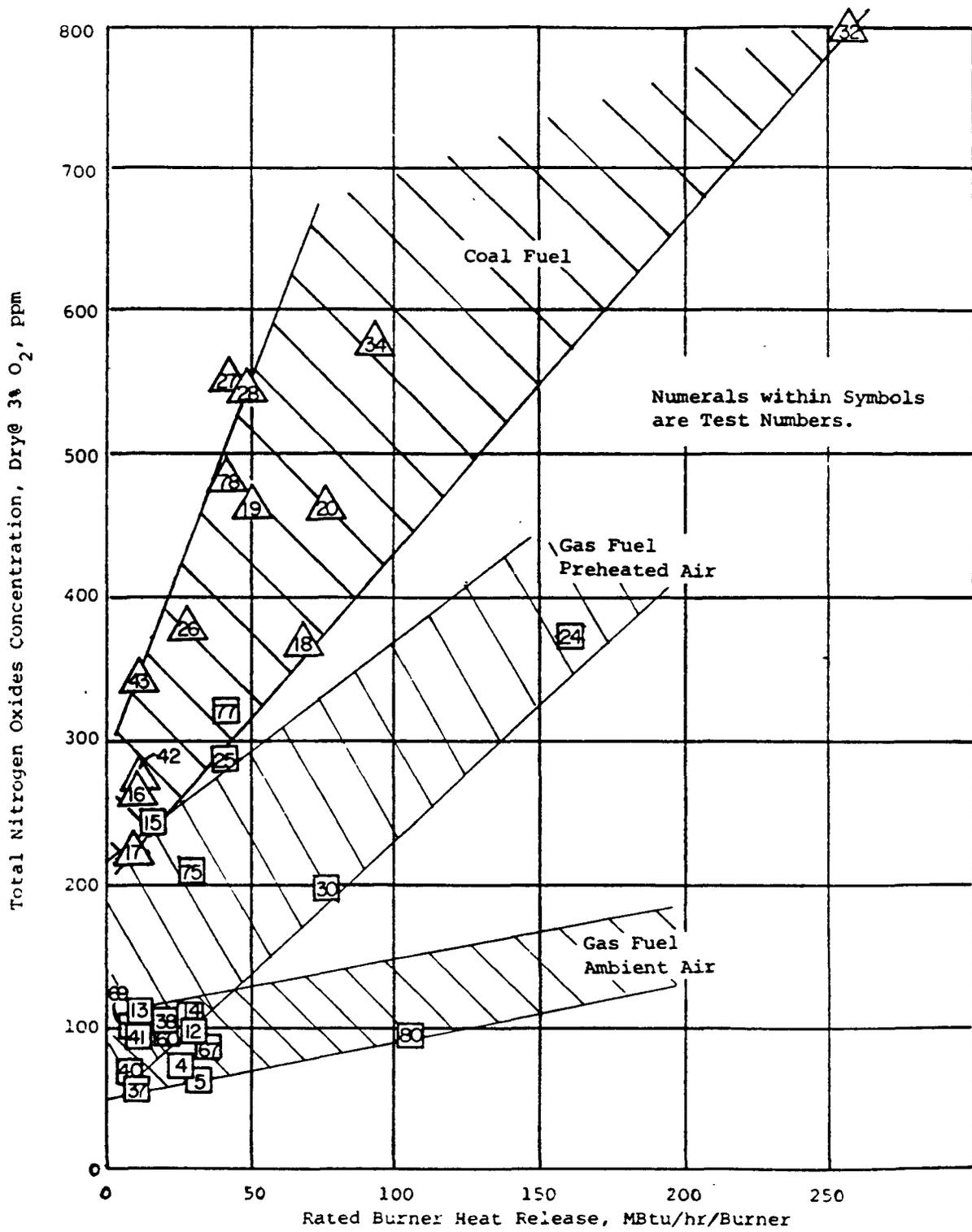


Figure 4-5. Effect of burner heat release rate on NO_x emissions for coal and natural gas fuels.¹⁶

4-12

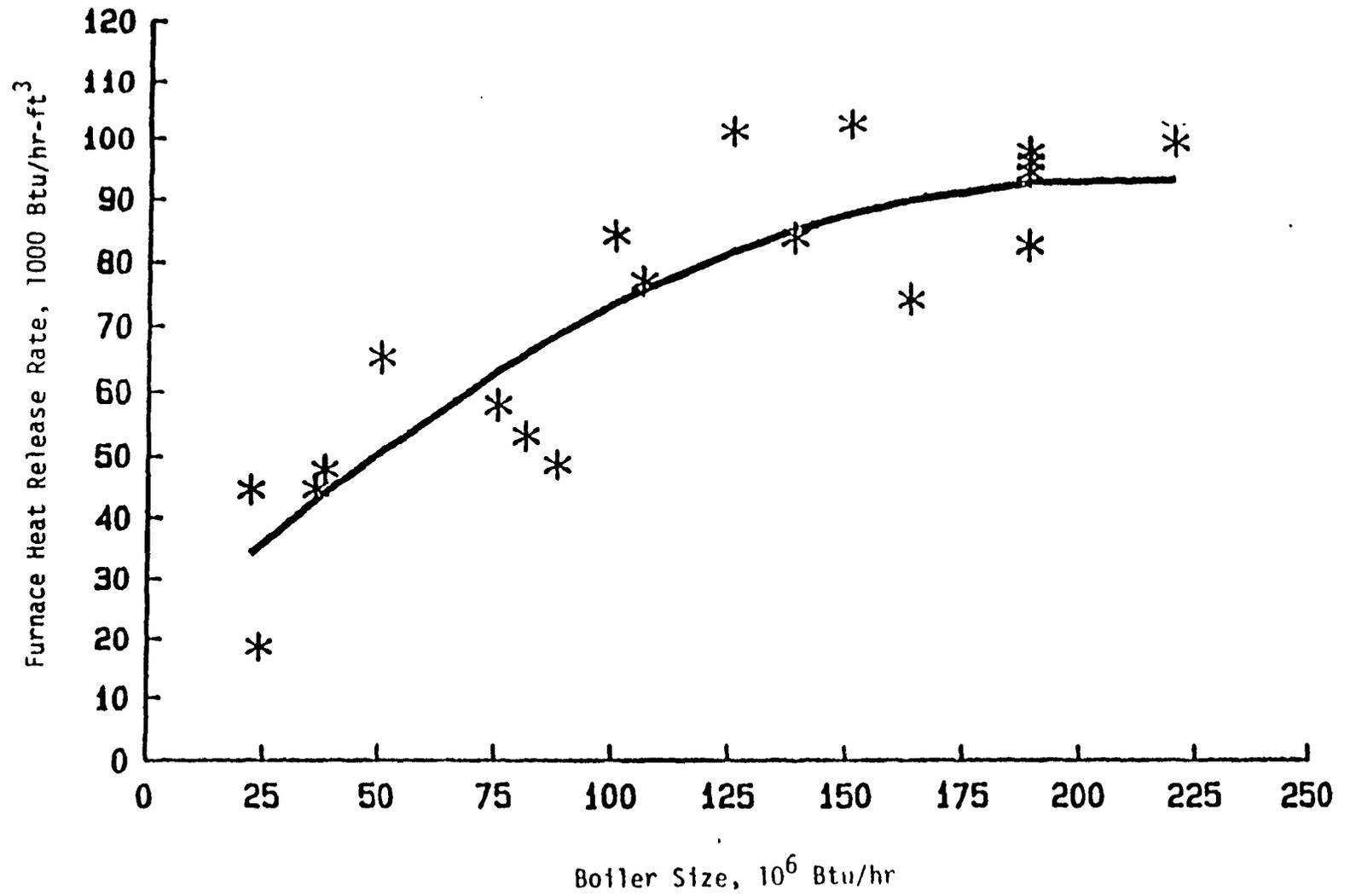


Figure 4-6. Furnace heat release rate versus boiler size.³²

100 MMBtu/hr (29 MWt) in capacity, while the other two stoker types were usually less than 100 MMBtu/hr (29 MWt). While some large underfeed and overfeed stokers are in use in the ICI sector, these types of stokers commonly have lower heat input capacities, and, as indicated earlier, tend to have larger fireboxes. Consequently, overfeed and underfeed stokers generally have lower heat release rates per unit area, resulting in lower peak temperatures and lower levels of thermal NO_x formation than spreaders.⁵

Because packaged natural-gas- or oil-fired watertube boilers are available in higher capacities and heat release rates than firetubes, the high end of the ranges of reported baseline NO_x tends to be greater for the watertube designs. However, as noted in Section 4.1.1, there is no obvious correlation per se between NO_x emissions and whether a boiler is a firetube or a watertube.

4.1.4 Boiler Operational Factors

In addition to boiler design and fuel factors, the conditions under which a unit is operated also influence baseline NO_x levels. Chief among these operational factors are the amount of excess oxygen in the flue gases and the combustion air temperature. Excess oxygen refers to the oxygen concentration in the stack gases, and is dependent on the amount of excess air provided to the boiler for combustion.³³ Combustion air temperature, meanwhile, is dependent on the degree of air preheat used before the air is introduced into the furnace or burner. Air preheat is usually used to increase furnace thermal efficiency.

Numerous sources have discussed the typical relationship of excess oxygen levels and NO_x, wherein as excess oxygen increases, so does NO_x.³⁴⁻³⁷ This relationship is shown in Figure 4-7, which presents data for natural-gas-fired watertube and firetube boilers. The thermal efficiency advantages of operating boilers at low excess oxygen levels have long been known, as long as the boiler is operated with a certain margin of excess air above the minimum level required to avoid excessive combustible emissions formation (CO, particulate). Operation on low excess oxygen or air is therefore considered a fundamental part of good combustion management of boilers. However, many ICI boilers are typically fired with excess oxygen levels which are more than adequate to assure complete combustion and provide a margin of safety to the operator.³⁸ Thus, these units often are operated at unnecessarily high excess oxygen levels that result in unnecessarily high NO_x emissions and losses in efficiency. Utility boilers, on the other hand, are typically fired with a smaller safety margin of excess air, but these units are more

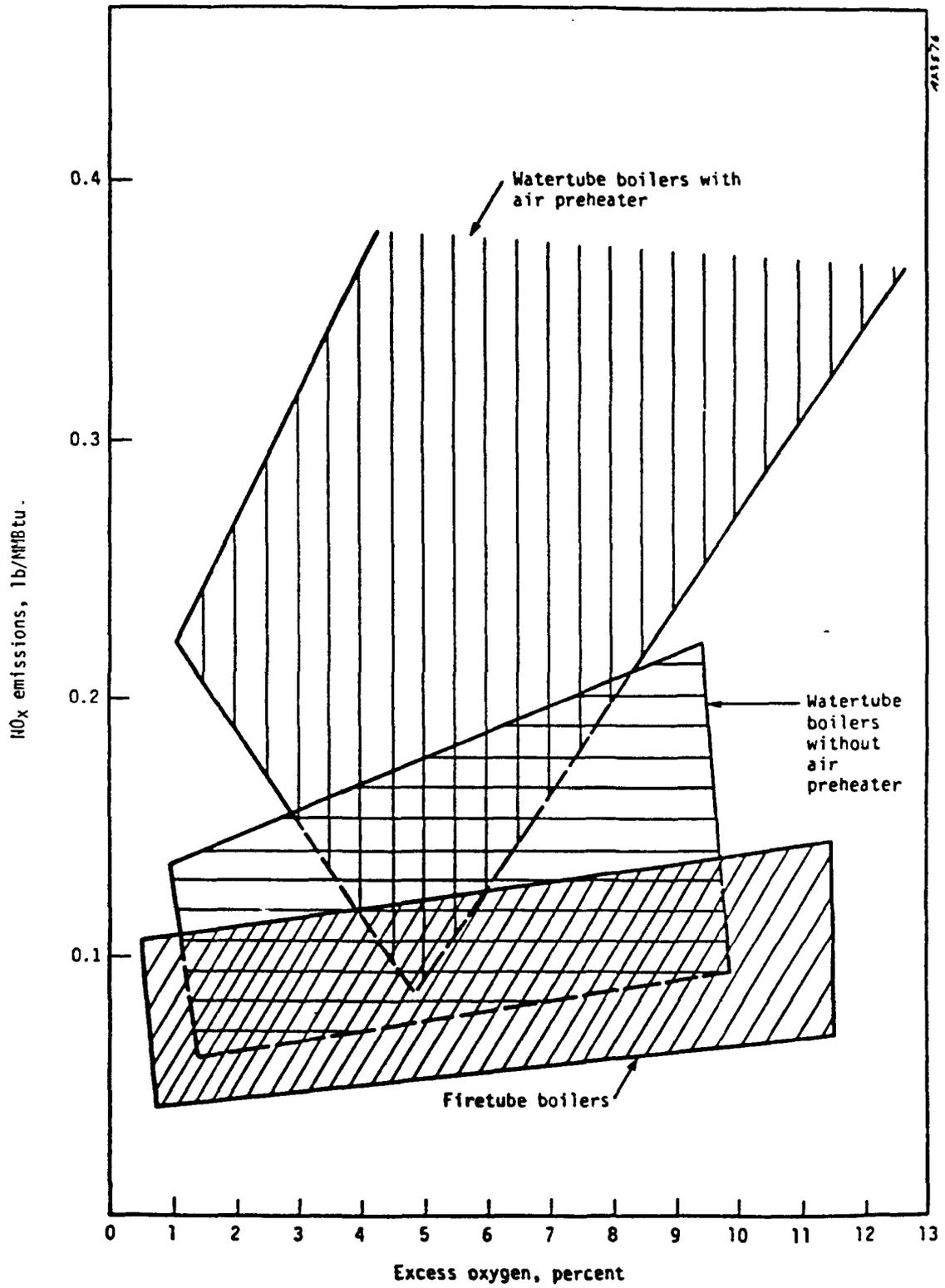


Figure 4-7. Effect of excess oxygen and preheat on NO_x emissions, natural-gas-fired boilers.³⁹

closely monitored by operating personnel and are not as subject to such wide variations in load as ICI boilers.³⁸

Figure 4-7 also shows the effect of using combustion air preheat. As shown, use of air preheat generally results in higher levels of NO_x. The level of combustion air preheat has a direct effect on the temperatures in the combustion zone, which, in turn, has a direct impact on the amount of thermal NO_x formed. More specifically, the greater degree that the air is preheated, the higher the peak combustion temperature and the higher the thermal NO_x.⁴⁰ Because the air preheat temperature primarily affects thermal NO_x formation, the use of air preheat has its greatest NO_x impact on fuels such as natural gas and distillate oils.^{40,41} Boilers with combustion air preheat systems are usually larger than 50 MMBtu/hr in capacity, with preheat temperatures in the range of 120 to 340°C (250° to 650°F).⁴¹ In particular, many stoker boilers are equipped with air preheat.

4.2 COMPILED BASELINE EMISSIONS DATA — ICI BOILERS

This section presents compiled uncontrolled NO_x emissions data for ICI boilers. Where data were available, CO and total unburned hydrocarbon (THC) emissions are also reported. These baseline data were compiled from test results on more than 200 boilers described in EPA documents and technical reports. These data are detailed in Appendix A. Emission tests on these boilers were performed at greater than 70-percent boiler load in most cases.

4.2.1 Coal-fired Boilers

Table 4-2 summarizes reported baseline NO_x, CO, and THC emission ranges for coal-fired boilers, and lists current AP-42 emission factors for comparison.⁴²⁻⁴⁵ Industrial PC-fired boilers were among the highest emitters of NO_x. The emission level from a wet bottom cyclone fired industrial boiler was recorded at 1.12 lb/MMBtu. The data for dry-bottom boilers compiled for this study show a range in NO_x emissions from 0.46 to 0.89 lb/MMBtu. In comparison, AP-42 shows NO_x emissions for dry-bottom boilers in the range of 0.58 to 0.81 lb/MMBtu. However, the AP-42 factors include several utility boilers as no distinction is made among application for this class of boilers. For wet-bottom industrial PC-fired boilers, only one data point was obtained in this study.

Spreader stoker units averaged 0.60 lb/MMBtu (450 ppm) NO_x from a range of 0.40 to 1.08 lb/MMBtu (300 to 800 ppm). The other two stoker types, overfeed and underfeed, averaged 0.29 and 0.36 lb/MMBtu respectively (215 and 265 ppm). Emission data for spreader

TABLE 4-2. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, COAL-FIRED BOILERS

Boiler type	NO _x , lb/MMBtu ^a		CO, lb/MMBtu ^a		THC, lb/MMBtu ^a	
	Compiled data ^b	AP-42	Compiled data	AP-42	Compiled data	AP-42
PC wall-fired	0.46-0.89	0.58-0.81 ^{c,d}	0.0-0.05	0.02-0.04	0.001-0.019	0.004-0.007
PC tangential	0.53-0.68	0.58-0.81 ^{c,d}	0.0-0.14	0.02-0.04	0.004-0.009	0.004-0.007
Cyclone	1.12 ^e	1.31 ^{c,d}	0.0 ^e	0.02-0.04	N.A. ^f	0.004-0.007
Spreader stoker	0.35-0.77	0.42-0.54	0.0-0.53	0.19-0.35	0.0-0.018	0.004-0.007
Overfeed stoker	0.19-0.44	0.29-0.41	0.001-1.65	0.35-0.42	0.022-0.024	0.004-0.007
Underfeed stoker	0.31-0.48	0.37-0.42	0.0-0.94	0.42-0.76	0.010 ^e	0.081-0.150
Bubbling FBC	0.11-0.81	N.A.	0.17-0.49	N.A.	N.A.	N.A.
Circulating FBC	0.14-0.60	N.A.	0.02-0.25	N.A.	N.A.	N.A.

^aTo convert to ppm @ 3% O₂, multiply by the following: NO_x, 740; CO, 1,215; THC, 2,130.

^bSee Appendix A for compiled data.

^cCurrent AP-42 does not distinguish PC units by firing configuration, but by dry- versus wet-bottom.

^dIncludes utility boilers.

^eSingle data point.

^fN.A. = Not available. No data available.

stokers compiled for this study show generally higher emission levels than suggested by current AP-42 emission factors.

FBC boilers are typically low NO_x emitters compared to PC-fired boilers and most spreader stokers, as the data indicate. This is due to several reasons, one of which is the lower combustion temperatures, as discussed in Chapter 3, and the use of staged combustion, as discussed in Section 4.1. As shown in Appendix A, available industrial coal-fired FBC data indicate an average NO_x emission level of 0.27 lb/MMBtu (200 ppm), for bubbling bed units, and 0.32 lb/MMBtu (240 ppm), for circulating FBC boilers. NO_x emissions ranged from 0.11 to 0.81 lb/MMBtu (80 to 600 ppm), for bubbling bed FBC units, and from 0.14 to 0.60 lb/MMBtu (105 to 445 ppm), for circulating FBC units. No AP-42 factors are currently available for industrial FBC boilers.

CO and THC emission data for all types of coal-fired boilers are highly variable. Average CO emission levels for PC wall-fired and spreader stoker units were generally in agreement with the AP-42 factors. For PC wall-fired units, CO ranged between 0 and 0.05 lb/MMBtu (0 to 60 ppm), while for spreader stokers, CO ranged between 0 and 0.53 lb/MMBtu (0 to 645 ppm). However, the measured CO emission levels for overfeed and underfeed stokers encompassed much wider ranges than reported in AP-42, ranging from 0 to 1.65 lb/MMBtu (0 to 2,000 ppm). Likewise, the THC emissions for overfeed stokers also differed greatly from the AP-42 values, averaging roughly 0.023 lb/MMBtu (50 ppm). Overfeed stoker THC data were available for only two units, however. This and the wide range of reported emission values indicates that available baseline CO and THC data from overfeed and underfeed stokers are generally inadequate. Circulating FBC boilers tend to have lower CO emissions than bubbling bed units, ranging from 0.02 to 0.25 lb/MMBtu (24 to 300 ppm). The bubbling bed units' CO levels were higher at 0.17 to 0.49 lb/MMBtu (205 to 595 ppm). The higher fluidization velocities and recirculation used in the circulating FBC units generally increase air/fuel mixing and combustion efficiency.

PC-fired boilers tend to emit less CO than stoker units. The data in Table 4-2 show CO emissions from PC wall-fired and tangential boilers ranging from 0 to 0.14 lb/MMBtu (0 to 170 ppm). CO emissions from the stoker units listed were higher, ranging from 0 to 1.65 lb/MMBtu (0 to 2,000 ppm). The use of pulverized coal allows better air/fuel mixing, increasing the combustion efficiency in the furnace which is evidenced by lower CO. In stoker units, however, coal combustion takes place on grates, and the combustion air supplied to the

fuel bed generally does not allow as high combustion efficiencies. Spreader stokers, which burn some fuel in suspension and the remainder on grates, generally emit less CO than overfeed and underfeed stokers, although the CO data in Appendix A for underfeed stokers is suspect, as mentioned above. The combustion temperatures in stokers are also lower than in PC-fired units, contributing to higher levels of CO.

4.2.2 Oil-fired Boilers

Table 4-3 gives baseline emission data for oil-fired ICI boilers, categorized by type of oil, boiler capacity, and heat transfer configuration. Residual-oil-fired boilers averaged approximately 0.36 lb/MMBtu (280 ppm) of NO_x, regardless of capacity, with NO_x ranging from 0.20 to 0.79 lb/MMBtu (160 to 625 ppm). Average baseline NO_x levels for distillate-oil-fired units were lower at approximately 0.15 lb/MMBtu (120 ppm). NO_x from the distillate-oil-fired units ranged from 0.08 to 0.25 lb/MMBtu (63 to 200 ppm). These data are in general agreement with AP-42 emission factors.

Reported CO emission levels for residual oil boilers were low, with the majority of units reporting CO levels below 0.030 lb/MMBtu (40 ppm). The baseline CO data for distillate-oil-fired watertube boilers, however, show wide variability, with units in the large capacity (greater than 100 MMBtu/hr) category emitting anywhere from 0 to 0.84 lb/MMBtu (0 to 1,090 ppm), while in the 10 to 100 MMBtu/hr capacity range, units emitted between 0 and 1.18 lb/MMBtu (0 and 1,530 ppm). CO emissions from distillate-oil-fired firetube units were low, under 0.015 lb/MMBtu (20 ppm). High levels of CO emissions from industrial boilers indicate, in part, poor burner tuning and maintenance levels for many of these units, which are often operated with little supervision and required maintenance.

Reported unburned THC emissions for residual-oil-fired boilers ranged from 0 to 0.031 lb/MMBtu (0 to 70 ppm), while for distillate-oil-fired units the range was between 0 and 0.022 lb/MMBtu (0 to 50 ppm). These are in general agreement with current AP-42 THC emission factors.

4.2.3 Natural-gas-fired Boilers

The data base compiled for this study indicated that baseline NO_x emission levels for natural-gas-fired firetube boilers ranged from 0.07 to 0.13 lb/MMBtu (58 to 109 ppm). For watertube units, NO_x ranged from 0.06 to 0.31 lb/MMBtu (50 to 260 ppm) for units less than or equal to 100 MMBtu/hr capacity, and from 0.11 to 0.45 lb/MMBtu (95 to 375 ppm) for units greater than 100 MMBtu/hr capacity. As shown in Table 4-4, the low end of the emission range

TABLE 4-3. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, OIL-FIRED BOILERS

Oil type and boiler capacity	NO _x , lb/MMBtu ^a		CO, lb/MMBtu ^a		THC, lb/MMBtu ^a	
	Compiled data ^b	AP-42	Compiled data	AP-42	Compiled data	AP-42
Residual Oil:						
Firetube units	0.21-0.39	0.37	0.0-0.023	0.033	0.002-0.014	0.011
Watertube units:						
10 to 100 MMBtu/hr	0.20-0.79	0.37	0.0-0.114	0.003	0.0-0.031	0.009
>100 MMBtu/hr	0.31-0.60	0.28-0.45	0.0-0.066	0.033	0.002-0.016	0.007
Distillate Oil:						
Firetube units	0.11-0.25	0.14	0.0-0.014	0.036	0.012 ^c	0.004
Watertube units:						
10 to 100 MMBtu/hr	0.08-0.16	0.14	0.0-1.177	0.036	0.0-0.003	0.002
> 100 MMBtu/hr	0.18-0.23	N.A. ^d	0.0-0.837	N.A.	0.001-0.009	N.A.

^aTo convert to ppm @ 3% O₂, multiply by the following: NO_x, 790; CO, 1,300; THC, 2,270.

^bSee Appendix A for compiled data.

^cSingle data point.

^dN.A. = Not available. No data available.

TABLE 4-4. COMPARISON OF COMPILED UNCONTROLLED EMISSIONS DATA WITH AP-42 EMISSION FACTORS, NATURAL-GAS-FIRED BOILERS

Boiler type and capacity	NO _x , lb/MMBtu ^a		CO, lb/MMBtu ^a		THC, lb/MMBtu ^a	
	Compiled data ^b	AP-42	Compiled data	AP-42	Compiled data	AP-42
Firetube units	0.07-0.13	0.095	0.0-0.784	0.019	0.004-0.117	0.0076
Watertube units:						
≤ 100 MMBtu/hr	0.06-0.31	0.13	0.0-1.449	0.033	0.0-0.023	0.0055
> 100 MMBtu/hr	0.11-0.45	0.26-0.52	0.0-0.233	0.038	0.0-0.051	0.0016

^aTo convert to ppm @ 3% O₂, multiply by the following: NO_x, 835; CO, 1,370; THC, 2,400.

^bSee Appendix A for compiled data.

is well below the current AP-42 emission factors. This is due in part to emissions data obtained at reduced boiler load and emissions from smaller capacity boilers. As illustrated in Appendix A, NO_x emissions from natural-gas-fired boilers tend to increase with increasing boiler capacity.

Baseline CO emission levels show wide variability, ranging from 0 to 1.45 lb/MMBtu (0 to 1,990 ppm). The data indicate that for natural-gas-fired boilers less than or equal to 100 MMBtu/hr in capacity, CO emissions are often higher than in the current AP-42 emission factors. THC emissions ranged from 0 to 0.117 lb/MMBtu (0 to 280 ppm).

4.2.4 Nonfossil-fuel-fired Boilers

Table 4-5 shows AP-42 uncontrolled emission factors for wood waste-, bagasse-, and general solid waste-fired boilers. AP-42 NO_x emission factors for wood-fired units are 0.27 lb/MMBtu (190 ppm), for larger boilers, and 0.065 lb/MMBtu (50 ppm), for smaller units. The limited emissions data for wood-fired boilers in Appendix A show an NO_x range of 0.010 to 0.30 lb/MMBtu (7 to 220 ppm corrected to 3 percent O₂). Many of these boilers operate inefficiently with very high excess air levels, at times greater than 5 times the amount required for complete combustion. Bagasse-fired boilers generally emit low levels of NO_x, roughly 0.15 lb/MMBtu (105 ppm).

Boilers that burn general solid waste typically show higher NO_x levels than biomass-fueled units. The current AP-42 NO_x emission factors for MSW-fired units and RDF-fueled units are 0.4 to 0.49 lb/MMBtu (280 to 350 ppm) and 0.36 lb/MMBtu (250 ppm), respectively.

TABLE 4-5. AP-42 UNCONTROLLED EMISSION FACTORS FOR NONFOSSIL-FUEL-FIRED BOILERS

Fuel and equipment type	NO _x , lb/MMBtu	CO, lb/MMBtu	THC, lb/MMBtu
Wood Waste:			
Units with 50,000 to 400,000 lb/hr steam output (~70 to 580 MMBtu/hr heat input)	0.27 (0.17-0.30) ^a	0.38-4.52	0.16
Units with less than 50,000 lb/hr steam output (<70 MMBtu/hr heat input)	0.022 (0.010-0.050) ^a	0.38-4.52	0.16
Bagasse	0.15	N.A. ^b	N.A.
General Solid Waste:			
Mass burn municipal solid waste	0.4	0.24	0.012
Modular municipal solid waste	0.49	0.38	N.A.
Refuse derived fuel	0.36	0.26	N.A.

^aCompiled data range, Appendix A.

^bN.A. = Not available. No data available.

Uncontrolled CO emissions from these boilers are relatively high, 0.24 to 0.38 lb/MMBtu (280 to 440 ppm). Table 4-6 presents a detailed breakdown of NO_x emissions for municipal waste combustors (MWCs) by major equipment types. The data come from 52 combustion sources, each tested over a period of 1 to 3 hours. The average NO_x level of 210 ppm corrected to 7 percent O₂ translates into approximately 0.4 lb/MMBtu.

Nonfossil-fuel-fired FBC boilers burning wood waste, manure, and other agricultural waste byproducts had NO_x emissions ranging from 0.10 to 0.42 lb/MMBtu (70 to 300 ppm). This is lower than the coal-fired FBC emission levels because of the lower nitrogen contents of the nonfossil fuels.

AP-42 CO emission factors for all wood-fired boilers span a wide range, from 0.38 to 4.52 lb/MMBtu (440 to 5,200 ppm), due to several factors, including wood composition and boiler design type. Unburned THC emissions are significantly higher than levels measured in fossil-fuel-fired boilers. Reported AP-42 levels are 0.16 lb/MMBtu (327 ppm), on average.

TABLE 4-6. AVERAGE NO_x EMISSIONS FROM MUNICIPAL WASTE COMBUSTORS^a

Combustor type	Capacity (tons/day)	Uncontrolled NO _x emissions, ppm @ 7% O ₂	
		Range	Average
Mass burn/refractory	56-375	59-240	155
Mass burn/rotary waterwall	100-165	146-165	156
Mass burn/waterwall	100-1,000	68-370	243
Refuse derived fuel (RDF)	300-1,000	195-345	270
Modular, excess air	50-120	105-280	140
Modular, starved air	36-90	86-280	215
All types	36-1,000	59-370	210

^aSource of data: Reference 20.

4.2.5 Other ICI Boilers

There are limited baseline NO_x emissions data for small commercial and institutional boilers such as cast iron and tubeless units. This is due in part to the virtual lack of regulations on boilers in the capacity range below 10 MMBtu/hr (2.9 MWt), with the exception of recent rules adopted in Southern California in 1988 and 1990. Natural gas is the predominant fuel in this area for these combustion sources. Units of this capacity range, while numerous, have not historically been regulated due to their size; hence, little testing has been done to characterize their emissions.

Uncontrolled NO_x emissions from natural-gas-fired TEOR steam generators range between 0.09 and 0.13 lb/MMBtu (75 and 110 ppm), while for crude-oil-fired steam generators, baseline NO_x emissions generally range from 0.30 to 0.52 lb/MMBtu (240 to 400 ppm), depending on the nitrogen content of the crude oil.^{46,47} Because there is less variability in the designs and configurations of TEOR steam generators, their NO_x emissions, for a given fuel, are usually less variable than other boilers.

4.3 SUMMARY

Table 4-7 summarizes baseline NO_x emissions for the major ICI boiler equipment categories discussed in Chapter 3. Coal-fired cyclone boilers generally emit the highest levels

TABLE 4-7. SUMMARY OF BASELINE NO_x EMISSIONS

Fuel	Boiler type	Uncontrolled	
		NO _x range, lb/MMBtu	Average, lb/MMBtu
Pulverized coal	Wall-fired	0.46-0.89	0.69
	Tangential	0.53-0.68	0.61
	Cyclone	1.12 ^a	1.12
Coal	Spreader stoker	0.35-0.77	0.53
	Overfeed stoker	0.19-0.44	0.29
	Underfeed stoker	0.31-0.48	0.39
	Bubbling FBC	0.11-0.81	0.32
	Circulating FBC	0.14-0.60	0.31
Residual oil	Firetube	0.21-0.39	0.31
	Watertube:		
	10 to 100 MMBtu/hr	0.20-0.79	0.36
> 100 MMBtu/hr	0.31-0.60	0.38	
Distillate oil	Firetube	0.11-0.25	0.17
	Watertube:		
	10 to 100 MMBtu/hr	0.08-0.16	0.13
> 100 MMBtu/hr	0.18-0.23	0.21	
Crude oil	TEOR steam generator	0.30-0.52	0.46
Natural gas	Firetube	0.07-0.13	0.10
	Watertube:		
	≤ 100 MMBtu/hr	0.06-0.31	0.14
	> 100 MMBtu/hr	0.11-0.45	0.26
	TEOR steam generator	0.09-0.13	0.12
Wood	< 70 MMBtu/hr	0.010-0.050	0.022
	≥ 70 MMBtu/hr	0.17-0.30	0.24
Bagasse		0.15 ^b	0.15
MSW	Mass burn	0.40 ^b	0.40
	Modular	0.49 ^b	0.49

^aSingle data point.

^bAP-42 emission factor.

of NO_x , followed by PC wall-fired units, PC tangential boilers, coal-fired stokers, MSW-burning units, and crude-oil-fired TEOR steam generators. The lowest NO_x emissions are from boilers fired on natural gas, distillate oil, and wood fuels. NO_x emissions from coal-fired FBC and stoker boilers are generally lower than from PC-fired boiler types. In general, few data are available for ICI boilers less than 10 MMBtu/hr (2.9 MWt) in thermal capacity, which includes many fossil- and nonfossil-fuel-fired firetube units, cast iron units, and tubeless types.

With the exception of distillate-oil-fired units, the data show that for a given fuel, NO_x emissions from firetube boilers are lower than from watertube boilers. This is likely due to the fact that most watertube boilers have larger capacities than firetube units. As discussed above, as boiler capacity increases, NO_x emissions also increase in most cases.

Actual emissions from individual boilers vary widely by boiler heat release rate, fuel quality and type, boiler design type, and operating factors such as excess air level or load. Fuel type is a major factor influencing baseline NO_x levels. Listed in descending order of NO_x emissions, the fuels are pulverized coal, stoker coal, MSW, crude oil, residual oil, distillate oil, natural gas, wood, and bagasse. It is important to recognize that large variations in baseline (uncontrolled) NO_x levels are possible due to several boiler design and operational factors, including variations in the chemical makeup of the fuel. The most important fuel property that influences NO_x is the fuel nitrogen content, which determines to a large degree the amount of fuel NO_x that may be formed during combustion.

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5. NO_x CONTROL TECHNOLOGY EVALUATION

This chapter presents a survey of applicable control technologies to reduce NO_x emissions from ICI boilers. A review of current knowledge on the effectiveness, applicability, and limitations of specific control techniques is presented for each major fuel/equipment category discussed in Chapter 3. These categories are as follows:

- Coal-fired:
 - PC, field-erected watertube
 - Stoker coal, packaged and field-erected
 - FBC
- Oil-fired:
 - Residual oil, packaged and field-erected watertube
 - Residual oil, packaged firetube
 - Distillate oil, packaged and field-erected watertube
 - Distillate oil, packaged firetube
 - Crude oil, TEOR steam generator
- Natural-gas-fired:
 - Packaged and field-erected watertube
 - Packaged firetube
- Nonfossil-fuel-fired:
 - Stoker-fed
 - FBC

NO_x emissions data from more than 200 boilers were compiled from technical reports, NO_x control equipment manufacturer literature, and compliance and rule development records available at California's South Coast Air Quality Management District (SCAQMD). These data are tabulated in Appendix B. Most of the data were obtained from boilers operating in the ICI sectors. However, some small utility boilers were included in the data base of Appendix B

because their heat input capacities are characteristic of large industrial boilers. The largest unit for which data are listed is a 1,250 MMBtu/hr PC-fired boiler. However, more than 90 percent of the units listed in Appendix B have heat capacities less than 400 MMBtu/hr. Most of the emissions data were obtained during short-term tests. Where noted, test data were collected from long-term tests based on 30-day continuous monitoring.

The control of NO_x emissions from existing ICI boilers can be accomplished either through combustion modification controls, flue gas treatment controls, or a combination of these technologies. Combustion modification NO_x controls such as SCA, LNB, and FGR modify the conditions under which combustion occurs to reduce NO_x formation. Flue gas treatment controls—principally SNCR and SCR — are applied downstream of the combustion chamber and are based upon chemical reduction of already formed NO_x in the flue gas. Other gas treatment controls, besides SNCR and SCR, that combine NO_x and SO₂ reduction are being developed. However, these controls are generally expensive and are currently targeted primarily for coal-fired utility boilers. Several demonstrations of these technologies are underway at electrical power plants under the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) demonstration program and other programs sponsored by industry. With the exception of reburning and SCR-based technologies, these advanced controls are not discussed here because they are not likely to be applied to the ICI boiler population in the foreseeable future.

In this section, the main discussion of NO_x controls for ICI boilers is preceded by Section 5.1, which presents a brief overview of NO_x formation and basic concepts for its reduction by combustion modifications. Sections 5.2, 5.3, and 5.4 discuss combustion modification NO_x controls for coal-fired boilers, oil- and natural-gas-fired units, and nonfossil-fuel-fired boilers, respectively. Section 5.5 discusses flue gas treatment controls for ICI boilers.

5.1 PRINCIPLES OF NO_x FORMATION AND COMBUSTION MODIFICATION NO_x CONTROL

NO_x is formed primarily from the thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_x) or from the conversion of chemically bound nitrogen in the fuel (fuel NO_x). Additionally, a third type of NO_x, known as prompt NO, is often present, though to a lesser degree than fuel or thermal NO_x. For natural gas, distillate oil, and nonfossil fuel firing, nearly all NO_x emissions result from thermal fixation. With coal, residual oil, and crude oil firing, the proportion of fuel NO_x can be significant and, under certain boiler operating conditions, may be predominant.

The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel bound nitrogen, if any, and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels or the particle fineness of solid fuels.¹ Additionally, thermal NO_x is greatly increased by increased residence time at high temperature, as mentioned earlier. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control strategies:

- Decrease primary flame zone O_2 level:
 - Decreased overall O_2 level
 - Controlled (delayed) mixing of fuel and air
 - Use of fuel-rich primary flame zone
- Decrease residence time at high temperature:
 - Decreased peak flame temperature:
 - Decreased adiabatic flame temperature through dilution
 - Decreased combustion intensity
 - Increased flame cooling
 - Controlled mixing of fuel and air
 - Use of fuel-rich primary flame zone
 - Decreased primary flame zone residence time

Table 5-1 shows the relationship between these control strategies and currently available combustion modification NO_x control techniques, which are categorized as either operational adjustments, hardware modifications, or techniques requiring major boiler redesign. The use of a secondary NO_x reduction combustion zone is also included in the table. This strategy is based on a secondary low oxygen reducing zone where NO_x is reduced to N_2 . This is accomplished with secondary injection of fuel downstream of the primary combustion zone. This control technique is referred to as fuel staging, or reburning, and is discussed in greater detail in the following subsections. Additionally, fuel switching is also considered a viable combustion control because of the reduction or elimination of fuel NO_x with the burning or cofiring of cleaner fuels. Table 5-2 identifies combinations of NO_x controls and major boiler fuel type categories for which retrofit experience is available and documented.

TABLE 5-1. SUMMARY OF COMBUSTION MODIFICATION NO_x CONTROL APPROACHES

NO _x control approach	Control concept	Effect on thermal NO _x	Effect on fuel NO _x	Primary control techniques		
				Operational adjustments	Hardware modification	Major redesign
Decrease primary flame zone O ₂ level	Decrease overall O ₂ level	Reduces O ₂ rich, high NO _x pockets in the flame	Reduces exposure of fuel N intermediaries to oxygen	LEA firing and OT	FGR	Low excess air burners
	Delayed mixing of fuel and air	Flame cooling and dilution during delayed mixing reduces peak temperature	Volatile fuel N reduces to N ₂ in absence of oxygen	Burner adjustments and timing	LNB	Optimum burner/firebox design
	Primary fuel-rich flame zone	Flame cooling in low O ₂ , low temperature primary zone reduces peak temperature	Volatile fuel N reduces to N ₂ in absence of oxygen	BOOS; biased burner firing	OFA ports	Burner/firebox design for SCA
Decrease peak flame temperature	Decrease adiabatic flame temperature	Direct suppression of thermal NO _x mechanism	Minor	RAP	FGR, LNB, water injection	
	Decrease combustion intensity	Increased flame cooling; yields lower peak temperature	Minor direct effect; indirect effect on mixing	Load reduction	Enlarged firebox, increased burner spacing	Enlarged firebox, increased burner spacing
	Increase flame cooling; reduce residence time	Increased flame zone cooling; yields lower peak temperature	Minor	Burner tilt	WI or SI	Redesign heat transfer surface, firebox aerodynamics
Create secondary NO _x reducing zone	Use of low O ₂ secondary combustion zone	Primary zone NO _x reduces to N ₂ in absence of O ₂	Primary zone NO _x reduces to N ₂ in absence of O ₂		OFA ports	Install reburning burners, OFA ports; replace tube wall panels, piping ductwork
Fuel switching	Burn higher quality fuel with low or no nitrogen content	Minor or slight increase because of higher temperature flame	Large NO _x reduction due to reduced fuel nitrogen conversion	Minor if dual-fuel capability exists		Only for installation of burner and fuel delivery system

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TABLE 5-2. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

NO _x control technique	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X ^a	X	X	X ^b		X ^a	X	X ^a
LNB	X			X	X	X			
FGR				X	X	X			X ^b
NGR	X ^b								X ^b
SNCR	X ^b	X	X	X	X ^b		X	X	X
SCR	X ^b		X ^b	X ^b					

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BT/OT = Burner tuning/oxygen trim

WI/SI = Water injection/steam injection

SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)

LNB = Low-NO_x burners

FGR = Flue gas recirculation

NGR = Natural gas reburning

SNCR = Selective noncatalytic reduction

SCR = Selective catalytic reduction

MSW = Municipal solid waste

^aSCA is designed primarily for control of smoke and combustible fuel rather than for NO_x control. Optimization of existing SCA (OFA) ports

can lead to some NO_x reduction.

^bLimited experience.

Typically, the simplest boiler operational adjustments rely on the reduction of excess oxygen used in combustion, often referred to as BT/OT. Figure 5-1 shows the results of several tests to determine the effect of excess air levels on NO_x emissions from natural-gas and oil-fired firetube boilers.² These test results show that NO_x emissions can be reduced 10 to 15 percent when the stack excess oxygen concentration is lowered from 5 to 3 percent, measured in the flue gas on a dry basis. The actual amount of NO_x reduced by decreasing excess air varies significantly based on fuel and burner conditions. These reductions are due mainly to lower oxygen concentration in the flame, where NO_x formation is highest.

Although LEA operation can produce measurable reductions in NO_x, in this study, LEA will not be considered a separate control technology but a part of other retrofit technologies, since it accompanies the application of low NO_x combustion hardware such as low NO_x burners. Additionally, boiler operation with LEA is considered an integral part of good combustion air management that minimizes dry gas heat loss and maximizes boiler efficiency.³ Therefore, most boilers should be operated on LEA regardless of whether NO_x reduction is an issue. However, excessive reduction in excess air can be accompanied by significant increases in CO. As illustrated in Figure 5-2, when excess air is reduced below a certain level, CO emissions increase exponentially. This rapid increase in CO is indicative of reduced mixing of fuel and air that results in a loss in combustion efficiency. Each boiler type has its own characteristic "knee" in the CO versus excess oxygen depending on several factors such as fuel type and burner maintenance. In general, along with LEA, the application of combustion modifications that reduce NO_x often result in reduced combustion efficiency (manifested by increased CO).

Another operational adjustment listed in Table 5-1, load reduction, when implemented, decreases the combustion intensity, which, in turn, decreases the peak flame temperature and the amount of thermal NO_x formed. However, test results have shown that with industrial boilers, there is only slight NO_x reduction available from this technique as the NO_x reduction effect of lowering the load is often tempered by the increase in excess air required at reduced load.⁴ Higher excess air levels are often required with older single-burner units because high burner velocity promotes internal gas recirculation and stable combustion. Multiple-burner boilers generally provide a greater load turndown capability. Operating at reduced load is often infeasible for many ICI boilers because steam load is dictated by process steam demands and cannot be controlled independently. Reduced load on one boiler must be compensated for by increased load on another boiler, unless energy conservation measures permit a net reduction

L-5

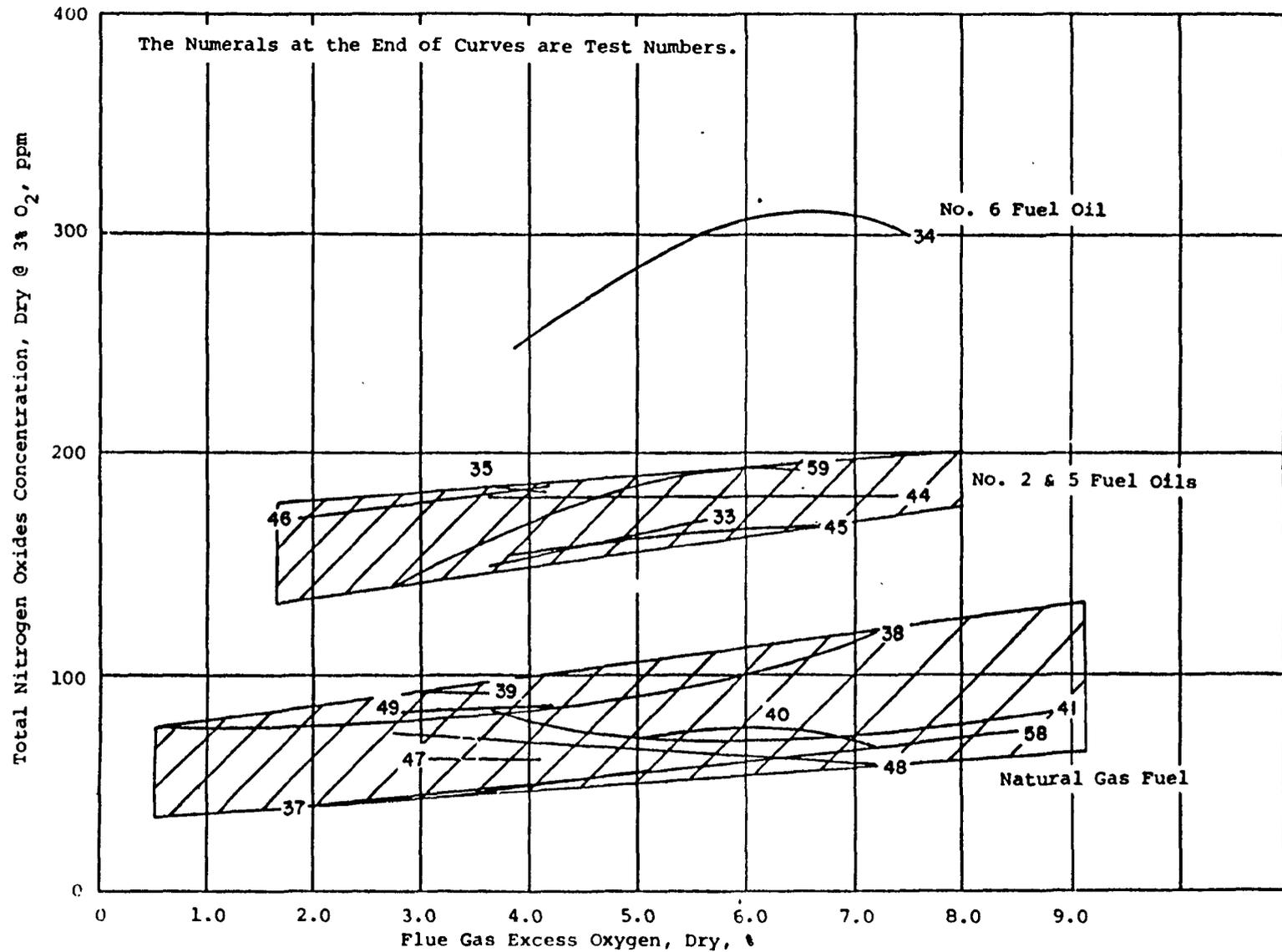


Figure 5-1. Effect of excess O₂ on NO_x emissions for firetube boilers at baseline operating conditions, natural gas and oil fuels.^{2x}

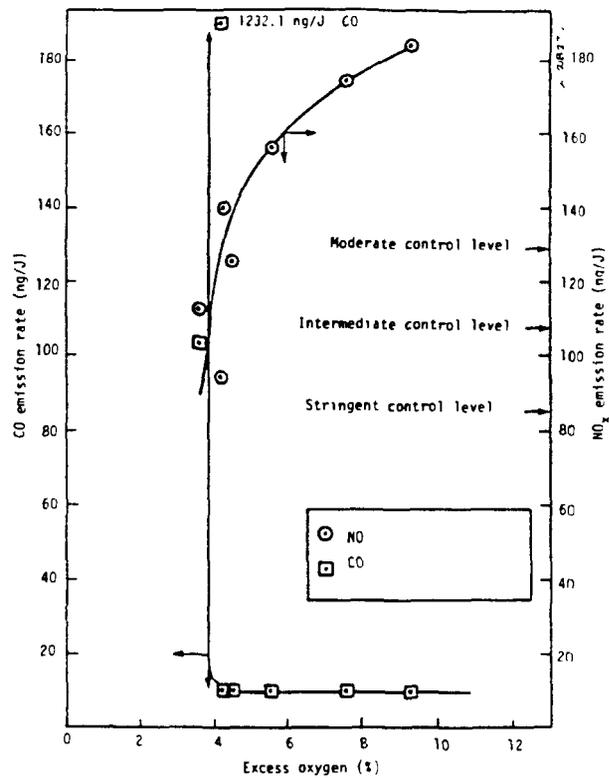


Figure 5-2. Changes in CO and NO_x emissions with reduced excess oxygen for a residual oil-fired watertube industrial boiler.⁵

in fuel consumption. Therefore, reduced load operation is not considered as a viable retrofit NO_x control technology and will not be discussed further in this report.

Although the formations of fuel and thermal NO_x are generally predominant, a third type of NO_x, known as prompt NO, has also been reported. Prompt NO is so termed because of its early formation in the flame zone where the fuel and air first react, at temperatures too low to produce thermal NO_x. C₂ and CH radicals present in hydrocarbon flames are believed to be the primary sources of prompt NO because they react with atmospheric nitrogen to form precursors such as HCN and NH₃, which are rapidly oxidized to NO. The formation of prompt NO is greater in fuel-rich flames, and decreases with the increase in local O₂ concentrations.⁶ Like fuel and thermal NO_x formation, prompt NO formation has been shown to be a function of flame temperature and stoichiometry. Prompt NO, however, generally accounts for smaller levels of NO_x than are due to thermal or fuel NO_x. For example, in utility boiler systems, prompt NO is assumed to be less than 50 ppm, while the thermal NO_x contribution can be as

high as 125 to 200 ppm.⁶ In ICI boilers, prompt NO is believed to account for the first 15 to 20 ppm of NO_x formed during combustion.⁷ The control of prompt NO is not typically targeted because of prompt NO's minor combustion to total NO_x. However, as NO_x limits for ICI boilers grow stricter, especially in areas such as the South Coast Air Basin of Southern California, the control of prompt NO is gaining more importance as evidenced by the development of new techniques, such as fuel induced recirculation, as discussed in Section 5.5.

The following sections discuss retrofit NO_x controls that are commercially available and the documented experience in NO_x reduction performance for each major ICI boiler and fuel category mentioned earlier.

5.2 COMBUSTION MODIFICATION NO_x CONTROLS FOR COAL-FIRED ICI BOILERS

Coal rank plays an important role in the NO_x reduction performance of combustion control technologies. Typically, controlled limits for low volatile bituminous coal differ from those attainable when burning high volatile subbituminous coal or lignites. However, the data available on coal-fired ICI boilers are insufficient to warrant a breakdown of achievable control levels based on coal type. Nearly all data compiled in this study were for boilers fired on bituminous coal. In comparison with ICI boilers fired on natural gas or oil, discussed in Section 5.3, there are relatively few reported emissions data for ICI coal-fired units operating with NO_x controls. This section includes data from 18 field operating PC-fired units, 11 stoker units, and 10 field operating FBC boilers. Large PC-fired industrial boilers are similar in design to utility boilers.⁸ Thus, control techniques applicable to many utility boilers can often be applied to large industrial boilers as well. Data from three pilot-scale PC-fired facilities are also included in Appendix B, because their firing capacities are in the ICI boiler range and test results are considered indicative of the ICI boiler population. Additionally, combustion modification tests for bubbling bed FBC (BFBC) units include results obtained at pilot-scale facilities. Pilot-scale research on retrofit combustion modification NO_x control for FBC far exceeds published data on full-scale FBC installations. This is because commercial FBC boilers are relatively new, the majority having been installed after 1985, and many new units come already equipped with these controls. Little research on full-scale NO_x control retrofit technologies has been undertaken. Pilot-scale research provides an in-depth view into the mechanisms of NO_x formation and control in FBC. These data are used in this study to support conclusions with respect to NO_x reduction efficiencies and controlled limits.

Sections 5.2.1 through 5.2.3 summarize the combustion modification techniques applicable to the three major coal-fired industrial boiler types: PC, stokers, and FBC units.

5.2.1 Combustion Modification NO_x Controls for Pulverized Coal (PC)-fired ICI Boilers

Table 5-3 summarizes test results of combustion modification techniques applicable to ICI PC-fired boilers. The table provides the ranges of percent NO_x reduction and the controlled NO_x levels achieved in these tests. More detailed data are contained in Appendix B. The following are brief discussions of each applicable control, the attained NO_x reduction efficiency attained and potential operational limits and impacts of retrofit on existing ICI boilers.

5.2.1.1 SCA

One approach to reducing NO_x, discussed in Section 5.1, is to decrease the primary flame zone oxygen level. The intent of SCA controls is to achieve a primary fuel-rich flame zone, where both fuel and thermal NO formations are suppressed, followed by an air-rich secondary zone where fuel combustion is completed. This is done by injecting air into the combustion zone in stages, rather than injecting all of it with the fuel through the burner. As a result, the primary flame zone becomes fuel-rich. SCA for PC-fired boilers includes two main techniques—OFA and BOOS.

OFA in PC-fired boilers typically involves the injection of secondary air into the furnace through OFA ports above the top burner level, coupled with a reduction in primary combustion airflow to the burners. OFA is applicable to both wall-fired and tangential-fired units. OFA is not applicable to cyclone boilers and other slagging furnaces because combustion staging significantly alters the heat release profile which changes the slagging rates and properties of the slag.⁹ Additional duct work, furnace wall penetration or replacement, and extra fan capacity may be required when retrofitting boilers with OFA. To retrofit an existing PC-fired boiler with OFA involves installing OFA ports in the wall of the furnace and extending the burner windbox.

Data for two PC-fired boilers operating with and without OFA were obtained during this study. Using OFA, a 25 percent reduction in NO_x was achieved at the first unit, a tangential-fired unit at the Kerr-McGee Chemical Corporation facility in Trona, California. This unit was retrofitted with a separated OFA system in conjunction with an LNB system. Separated OFA refers to the use of a separate OFA windbox mounted above but not an integral part of the main windbox, as opposed to "close coupled" OFA which is injected within the main windbox just above the top elevation of fuel. Controlled NO_x emissions from this unit ranged from 211 to

TABLE 5-3. COMBUSTION MODIFICATION NO_x CONTROLS FOR FULL-SCALE PC-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Type of industrial boiler tested	% NO _x reduction	Controlled NO _x levels ppm @ 3% O ₂ , lb/MMBtu	Comments
SCA	Fuel-rich firing burners with secondary air injection	Wall-fired	15	691 (0.93)	OFA.
		Wall-fired	27	250 (0.34)	BOOS, reduced load.
		Wall-fired	39	651 (0.88)	OFA, reduced load.
		Tangential	25	211-280 (0.29-0.38)	
LNB	Wall-fired boiler — LNB with distributed air for controlled mixing Tangential-fired boiler — uses air on wall concept for controlled mixing	Wall-fired	49	280 (0.38)	Wall-fired boilers used staged air burners.
		Wall-fired	65	220 (0.30)	
		Wall-fired	67	190-225 (0.26-0.34)	Tangential-fired boiler used low-NO _x concentric firing system (LNCFS).
		Wall-fired	49	370 (0.50)	
		Tangential	18	269 (0.36)	
Reburn with SCA (OFA)	Injection of coal, natural gas, or oil downstream of the burner area	Wall-fired w/coal reburn	N.A. ^a	170-250 (0.23-0.34)	SCA (OFA) used with reburn in all tests.
		Wall-fired w/coal reburn	N.A.	215-385 (0.29-0.52)	
		Tangential-fired w/oil reburn	30	167 (0.23)	
LNB+SCA	Combination of LNB and SCA control techniques	Wall-fired	42	180-360 (0.24-0.49)	Data for wall-fired units do not show benefit of adding SCA to LNB.
		Wall-fired	66	220-264 (0.30-0.36)	
		Wall-fired	N.A.	220-370 (0.30-0.50)	
		Wall-fired	60	275 (0.37)	
		Wall-fired	62	275 (0.37)	
		Wall-fired	65	275 (0.37)	
		Wall-fired	44	330 (0.45)	
		Tangential	55	148 (0.20)	

^aN.A. = Not available. No baseline (uncontrolled) NO_x data available.

Note: References, and greater detail including baseline emissions, for these data are included in Appendix B.

280 ppm^a (0.29 to 0.38 lb/MMBtu); this unit was also LNB-equipped. The second unit, a 325 MMBtu/hr wall-fired boiler, achieved 15 percent NO_x reduction using OFA. Controlled NO_x emissions from this unit were 690 ppm (0.93 lb/MMBtu). The NO_x reduction efficiencies of these two units are in agreement with OFA performance estimates for PC-fired utility boilers, which range between 15 and 30 percent NO_x reduction.^{9,10}

Two principal design requirements for the installation of OFA ports in an existing PC-fired boiler must be met in order for the technology to effectively reduce NO_x without adversely affecting operation and equipment integrity. First, there must be sufficient height between the top row of burners and the furnace exit, not only to physically accommodate the OFA ports but also to provide adequate residence time for the primary stage NO to reduce to N₂, and adequate residence time for the second stage gases to achieve carbon burnout before exiting the furnace. In order to maximize NO_x reduction, previous studies have shown that the optimum location for OFA injection is 0.8 seconds (residence time of primary gas before OFA injection) above the top burner row.¹¹ Additionally, these studies have shown that to achieve carbon burnout, a minimum of 0.5 seconds residence time is required above the OFA ports.

The second design consideration for OFA retrofit is that good mixing of OFA with the primary combustion products must be achieved in order to ensure complete combustion and maximize NO_x reduction. Some important parameters affecting the mixing of OFA and first stage gases are OFA injection velocity, OFA port size, number, shape, and location; and degree of staging.¹¹ Thus, OFA port design is critical in determining the effectiveness of OFA in reducing NO_x. Additionally, OFA port design must take into account the effects of port installation on the structural integrity of the boiler walls. Structural loads may be transferred from the firing walls to the side walls of the furnace, and OFA port shapes may be designed to minimize structural modifications. Given the magnitude of retrofitting PC-fired boilers with OFA and the moderate NO_x reduction efficiencies of 15 to 30 percent, OFA does not appear to be a primary retrofit technology for industrial sized PC-fired boilers. In general, the use of OFA is considered more feasible for new boilers than for retrofit applications.

The second major technique of staging combustion is BOOS, in which ideally all of the fuel flow is diverted from a selected number of burners to the remaining firing burners, keeping firing capacity constant. For maximum effectiveness, it is often the case that the top row of

^aAll ppm values in this study are referenced to 3 percent O₂.

burners be set on air only, mimicking the operation of OFA discussed above (Figure 5-3). For PC-fired boilers, this means shutting down the pulverizer (mill), as fuel flow cannot be shut off at the individual burners as can be done with oil- and gas-fired units. This sometimes presents a problem when pulverizers serve burners located on two separate levels. With PC-firing, BOOS is commonly considered more of an operating practice for pulverizer maintenance than for NO_x control, as pulverizers are routinely taken out of service because of maintenance requirements. The ability of boilers to operate units with one less pulverizer is generally very limited. For this reason, BOOS is not a popular control option for PC-fired units.

Data for two wall-fired units operating with one pulverizer out of service show NO_x reduction efficiencies of 27 and 39 percent. For one 230 MMBtu/hr boiler, NO_x was reduced from 340 ppm to 250 ppm (0.46 to 0.34 lb/MMBtu), while for a 260 MMBtu/hr unit, NO_x was reduced from 1,065 ppm to 651 ppm (1.44 to 0.88 lb/MMBtu).¹² However, in order to achieve the 39 percent reduction rate with the larger boiler, it was necessary for that particular boiler to be operated at 50 percent load reduction. Additionally, airflow could not be easily controlled to the individual burners so that burner swirl and coal air mixing were affected.¹² Operating at reduced load when using BOOS is often required for industrial sized units due to the limited number of burners and pulverizers.

In summary, data from three wall-fired boilers operating with SCA techniques of OFA and BOOS showed NO_x reduction ranges of 15 to 39 percent, while the single tangential-fired boiler with SCA showed 25 percent reduction (see Table 5-3). Although the two units operated with BOOS accounted for the higher NO_x reduction efficiencies of 27 and 39 percent, both had to be operated at significantly reduced load. Because industrial units have fewer burners and typically have more limited pulverizer-burner arrangements, BOOS is not considered a widely applicable control technique.

5.2.1.2 LNBS for PC-fired Boilers

LNBS, principally designed for utility boiler applications, have also been retrofitted to several large industrial boilers over the past decade. All major manufacturers of utility type boilers offer LNB for PC firing. Some of the larger manufacturers are ABB-Combustion Engineering, Babcock & Wilcox, Foster Wheeler, and Riley Stoker. In order to achieve low NO_x levels, LNBS basically incorporate into their design combustion techniques such as LEA, SCA, or recycling of combustion products. One of the most common types of LNB is the staged air burner.

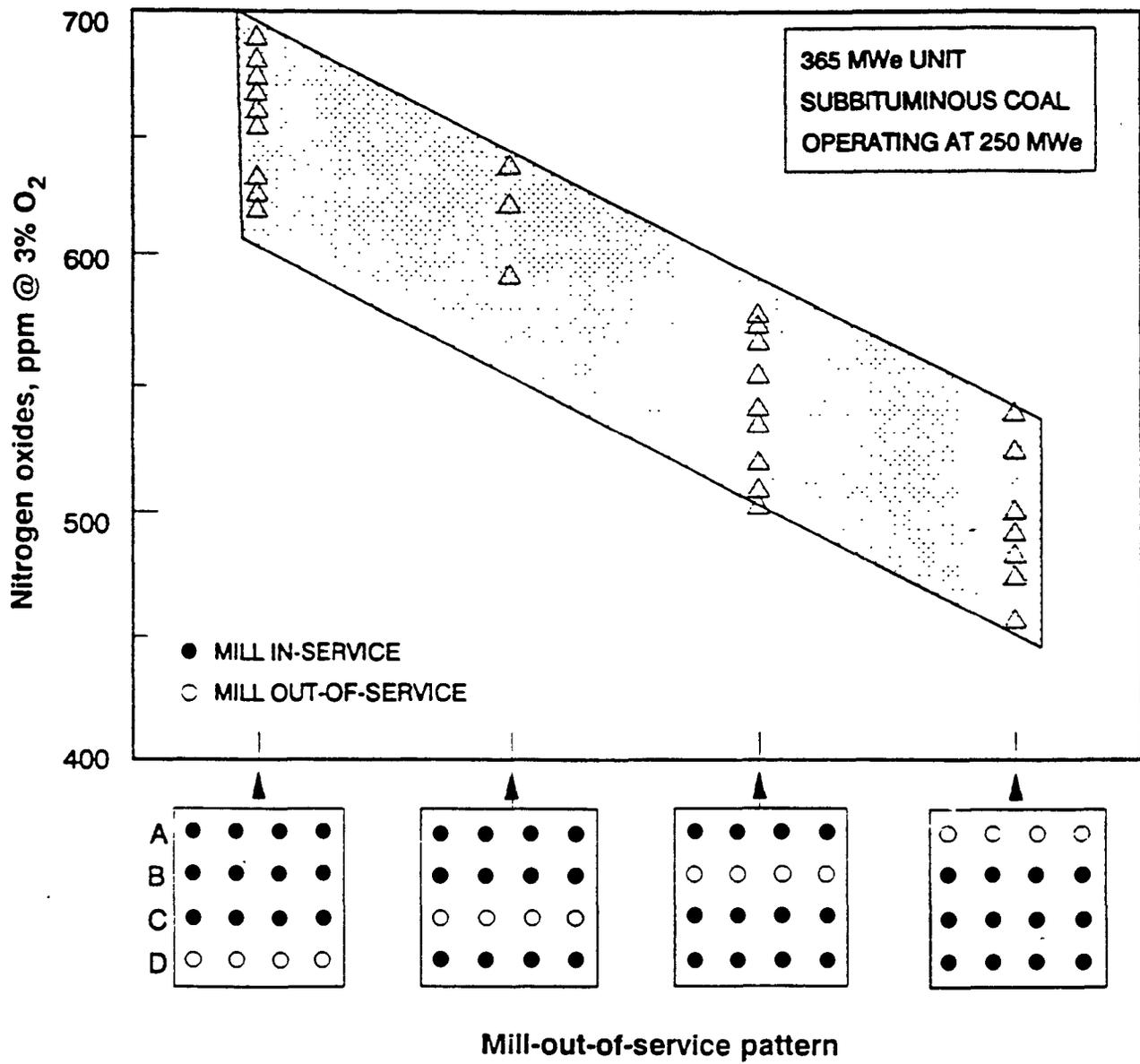


Figure 5-3. Effect of BOOS on emissions.

Air staging in this type of LNB is accomplished by dividing the combustion air into two or more streams within the burner, delaying the mixing of fuel and air. A portion of the air is used to create a fuel-rich primary combustion zone where the fuel is only partially combusted. Secondary combustion of this unburned fuel occurs downstream of the primary burnout zone, where the remainder of burner air is injected. Peak combustion temperatures are also lower with the staged air burner because flames are elongated and some heat from the primary combustion stage is transferred to the boiler tubes prior to the completion of combustion. As discussed in Section 5.1, NO_x formation is reduced due to the lowering of the peak flame temperature, the delayed air/fuel mixing, and the low oxygen primary zone, where volatile fuel bound nitrogen compounds reduce to form N_2 . Thus, both thermal and fuel NO_x are reduced.

One example of a staged air LNB is Foster Wheeler's Controlled Flow/Split Flame (CF/SF) LNB, which has been retrofitted to at least two industrial units. The CF/SF burner, shown in Figure 5-4, is an internally staged dual register burner. The outer register, where secondary air is injected, controls the overall flame shape while the inner register controls ignition at the burner throat and the air/fuel mixture in the primary substoichiometric region of the flame.¹³ The newer version of the CF/SF burner also incorporates a split flame nozzle that forms four distinct coal streams. The result is that volatiles are driven off and are burned under more reducing conditions than would occur without the split flame nozzle.⁹ CF/SF burners have been retrofitted to a 110,000 lb (steam)/hr (about 140 MMBtu/hr heat input) single wall-fired boiler at a Dupont chemical plant in Martinsville, Virginia. This unit, fired on bituminous coal, utilizes four CF/SF burners. Nearly 50 percent NO_x reduction was achieved, with average post-retrofit NO_x emissions of 280 ppm (0.38 lb/MMBtu). Post-retrofit CO emissions were 25 ppm. CF/SF burners were also retrofitted to a 125,000 lb/hr (about 150 MMBtu/hr heat input) four-burner, wall-fired steam boiler, where 65 percent NO_x reduction from baseline was achieved. Post-retrofit NO_x emissions at this site averaged 220 ppm (0.30 lb/MMBtu).¹⁰ Figure 5-5 shows the NO_x reduction performance of these two units—labeled as numbers 4 and 5 in the figure—as well as several utility sized boilers.

Babcock & Wilcox's DRB-XCL burner also utilizes dual registers to achieve internal staged combustion. The major elements of this burner are its use of a conical diffuser to disperse the fuel, which produces a fuel-rich ring near the walls of the nozzle and a fuel-lean core. Reducing species are formed by partial oxidation of coal volatiles from primary air and limited secondary air. The reducing zone created in the fuel-lean core prevents NO_x formation

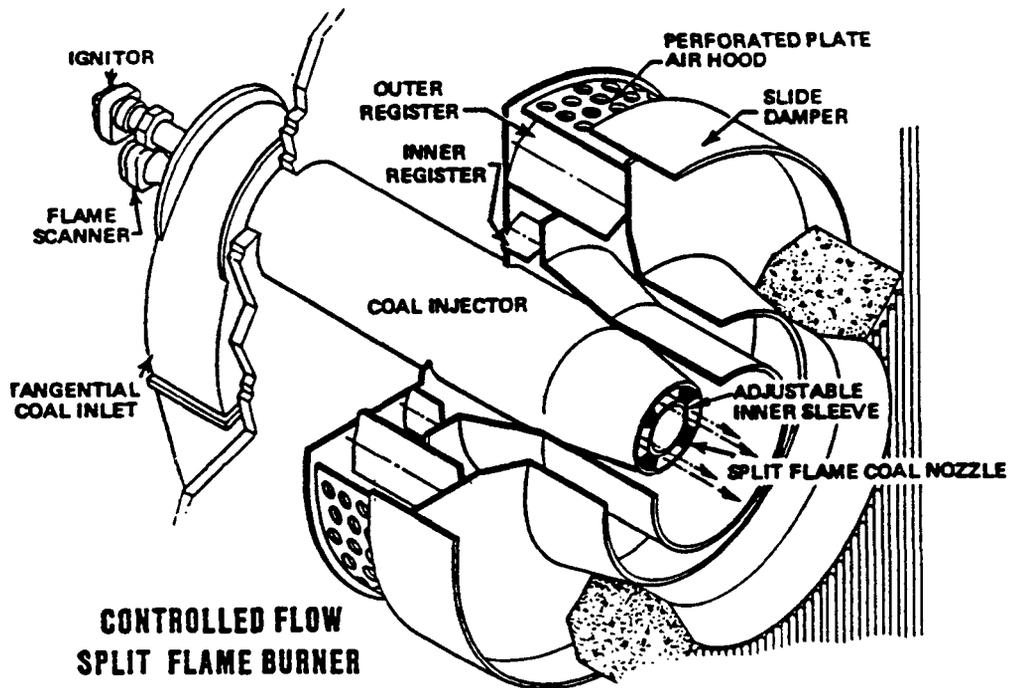


Figure 5-4. Foster Wheeler CF/SF LNB.⁹

- | | |
|-----------------------------|-----------------------------|
| (1) 800 MW Four Corners #4 | (4) 110,000 Lb/Hr. 4 Burner |
| (2) 626 MW Pleasants #2 | (5) 125,000 Lb/Hr. 4 Burner |
| ○ 275 MW Front Wall Fired | (6) CETF |
| (3) 360 MW Front Wall Fired | (7) 500 MW Opposed Fired |
| ● 525 MW Opposed Fired | |

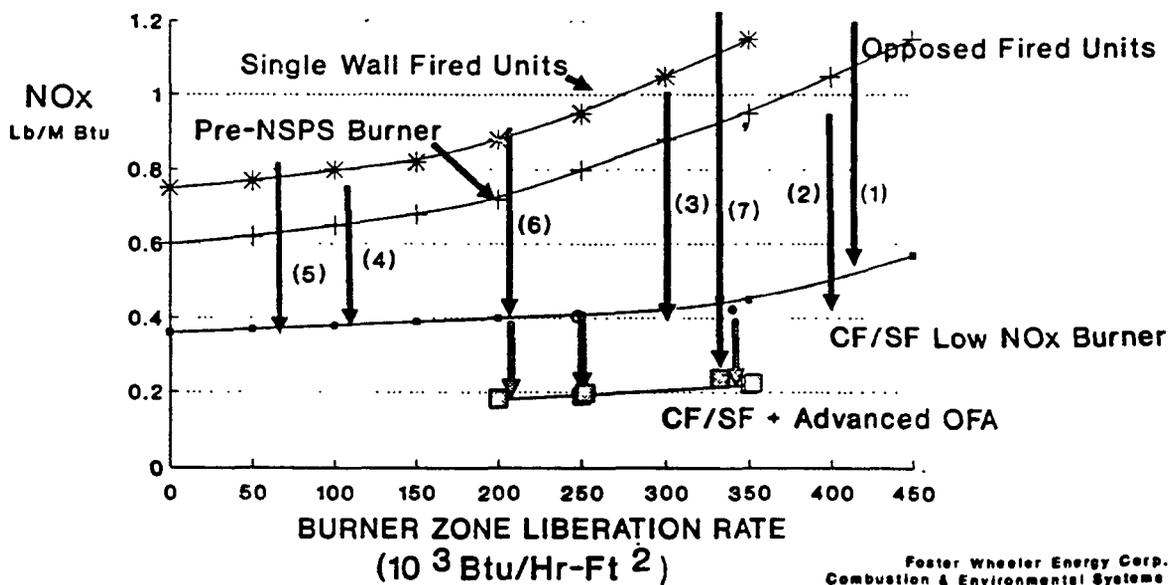


Figure 5-5. Performance of CF/SF LNB.¹⁰

during devolatilization, and the reducing species generated by oxidation decompose the formed NO_x as combustion continues.¹⁴ In a DRB-XCL burner retrofit program to a 220,000 lb/hr (about 275 MMBtu/hr heat input) wall-fired boiler at the Neil Simpson Power Station in Wyoming, average NO_x emissions were reduced approximately 67 percent, when operating at the same excess air level. Controlled NO_x emissions for this unit ranged between 190 and 255 ppm (0.26 and 0.34 lb/MMBtu).¹⁵

Riley Stoker also manufactures a LNB for PC wall-fired units, known as the Controlled Combustion venturi (CCV™) burner. Figure 5-6 depicts this burner, which uses a single register, unlike the dual register burners already discussed. The key element of this burner design is a patented venturi coal nozzle and low swirl coal spreader located in the center of the burner. The venturi nozzle concentrates fuel and air in the center of the coal nozzle, creating a fuel-rich zone. As in the CF/SF LNB, the coal/air mixture is divided into four distinct streams which then enter the furnace in a helical pattern. This produces very slow mixing of the coal with secondary air, which is injected through the single register. Devolatilization of the coal in the fuel-rich mixture occurs at the burner exit in a substoichiometric primary combustion zone, resulting in lower fuel NO_x formation. Thermal NO_x formation is suppressed by the reduction of peak flame temperature which results from the staged combustion.¹⁶

Riley's Tertiary Staged Venturi (TSV) burner is similar to the CCV burner but uses additional tertiary air and an advanced air staging (OFA) system for reducing NO_x emissions. This burner was developed for use on Riley's TURBO furnaces as well as downfired and arch fired boilers. These boilers are characterized by downward tilted burner firing, which lengthens the residence time of combustion products in the furnace. As such, the inherently long furnace retention time combined with gradual or distributed air/fuel mixing typically results in lower NO_x emissions than a conventional wall-fired unit operating at similar conditions with identical fuel.¹⁶ TURBO furnaces are commonly used to burn low volatile coals such as anthracite, which require longer residence time for complete combustion. Figure 5-7 shows a schematic of a TURBO furnace and the TSV LNB. Six TSV burners, in conjunction with OFA, were used in a 400,000 lb/hr (about 470 MMBtu/hr heat input) industrial TURBO furnace at a paper manufacturing facility in the Midwest. Firing bituminous coals, controlled NO_x emissions ranged between 220 and 370 ppm (0.30 and 0.50 lb/MMBtu).¹⁷

A different type of LNB has been developed for tangential-firing PC boilers, incorporated into the LNCFS system. The burner itself, manufactured by ABB Combustion

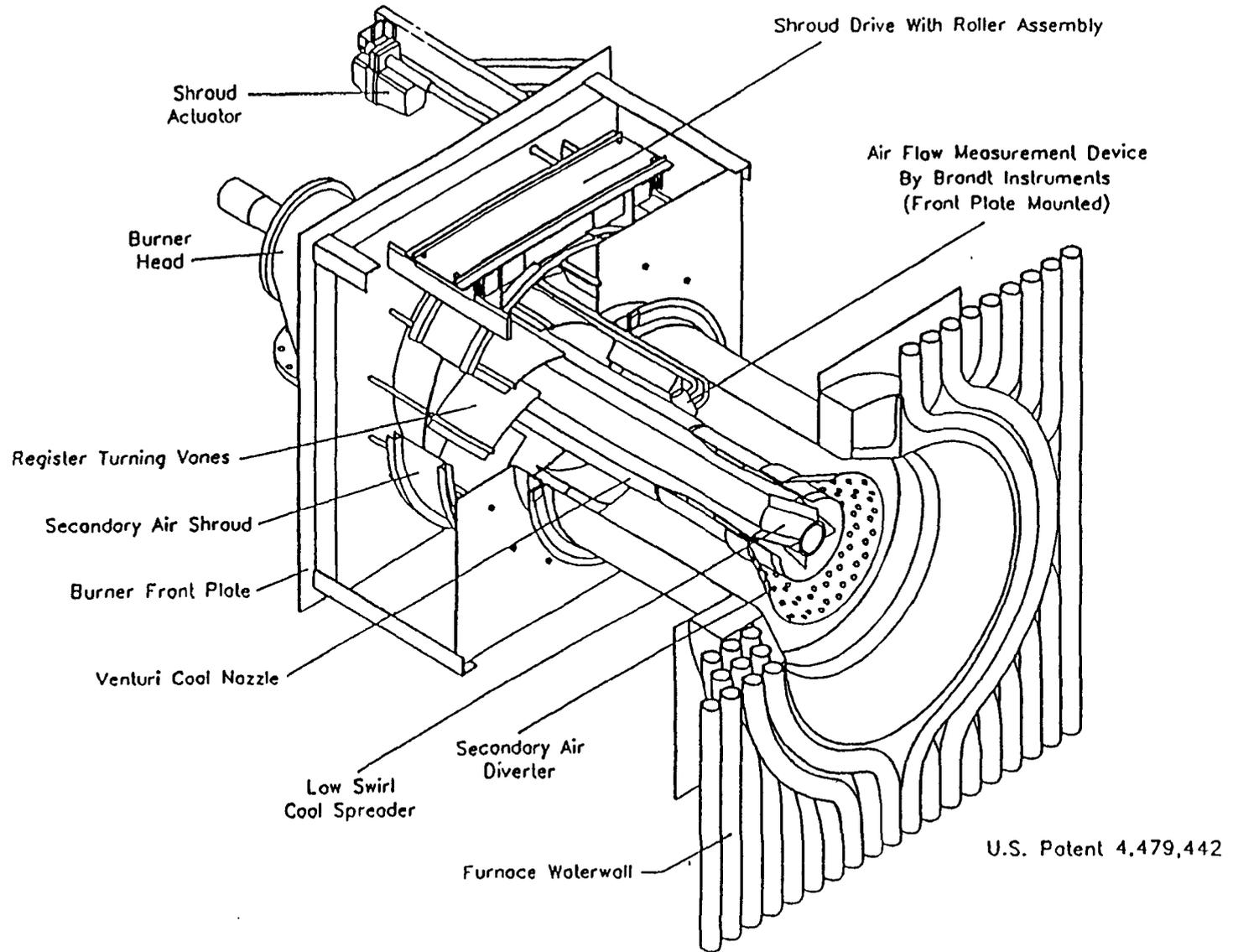
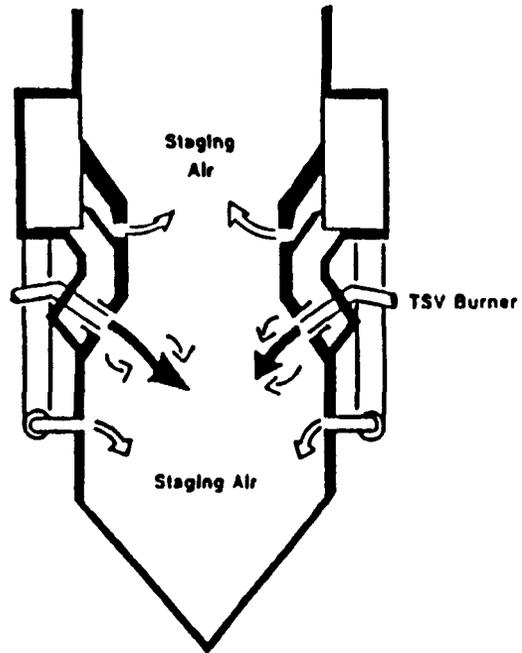
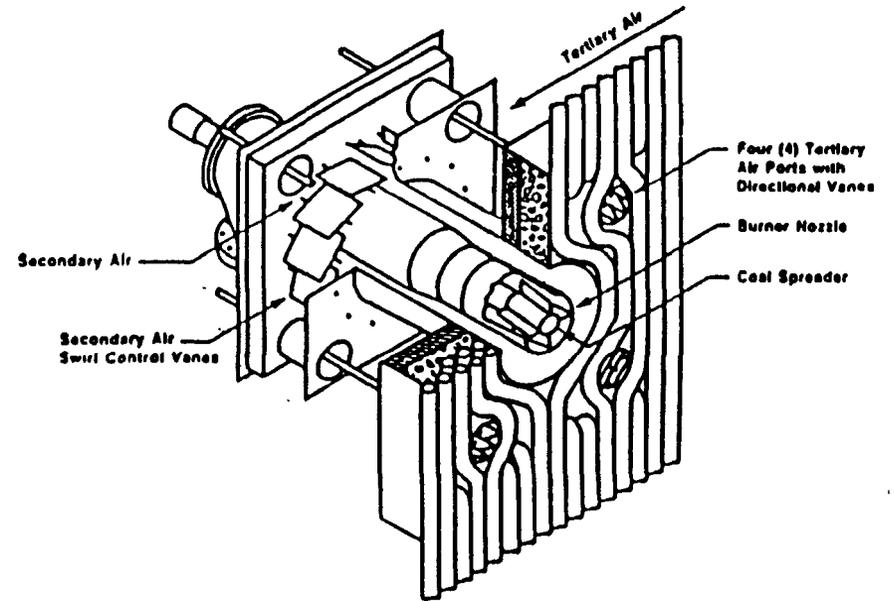


Figure 5-6. Riley low-NO_x CCV™ burner with secondary air diverter.¹⁶

S-19



Advanced TURBO Furnace Staging System



TSV Burner

Figure 5-7. Riley low- NO_x TSV burner with advanced air staging for turbo-furnace, down-fired and arch-fired installation.¹⁶

Engineering, is referred to as the Concentric Firing System (CFS). The CFS creates local staging by diverting a portion of secondary air horizontally away from the coal stream toward the furnace waterwall tubes. This delays the mixing of secondary air with the coal during the initial coal devolatilization stage of the combustion process, the stage when significant amounts of fuel nitrogen are typically released. Early ignition and devolatilization are achieved by using flame attachment coal nozzle tips. This early ignition and flame attachment feature provides greater control over volatile matter flame stoichiometry while enhancing flame stability and turndown.¹⁸ The boiler at Kerr-McGee Chemical, mentioned in the above discussion on OFA, has been retrofitted with the LNCFS. Operating with the CFS LNB only, 18 percent NO_x reduction was achieved, to 269 ppm (0.36 lb/MMBtu). When the full LNCFS was used (CFS+OFA), NO_x reduction improved to 55 percent, with NO_x at 148 ppm or 0.20 lb/MMBtu.¹⁸

The LNBs discussed were originally designed for use on utility boilers. However, as evidenced by the above industrial experiences, in most cases the burners are also applicable to larger industrial PC-fired boilers. In some cases, as with the Neil Simpson unit retrofitted with B&W DRB-XCL burners, modifications to the burner walls were necessary to accommodate the larger LNBs. Furnace wall openings of the Neil Simpson unit were enlarged by replacing two furnace wall tube panels, each containing two burner throats.¹⁵ In general, however, because there are already existing burner ports, LNB retrofits to PC-fired units do not require as much rework of the furnace walls as does installation of new OFA ports. However, significant modifications may be required for the windbox in order to improve air distribution with changes in the fuel ducting. Consideration must also be given to LNB flame characteristics such as shape and length to avoid flame impingement on the furnace walls. Because flames from staged combustion burners are often longer than from conventional burners, this may be a particularly important issue to small-volume furnaces.

NO_x emissions data for PC-fired units with LNB are summarized in Table 5-3. For four wall-fired units, NO_x reductions ranged between 49 and 67 percent, with controlled NO_x emissions of 190 to 370 ppm (0.26 to 0.50 lb/MMBtu). One tangential-fired unit experienced 18 percent reduction efficiency, with an NO_x level of 269 ppm (0.36 lb/MMBtu). Again, the minimum long-term NO_x level that can be reached with LNB retrofit depends on several factors, principally coal type, furnace dimension, boiler load, combustion air control, and boiler operating practice.

5.2.13 Reburn (Fuel Staging) with SCA, PC-fired Boilers

Reburning, also known as fuel staging, involves injecting a supplemental fuel into the main furnace above the primary combustion zone to produce a secondary combustion zone where a reducing atmosphere exists. The general idea is to provide a chemical path for the primary zone NO to convert to N₂ rather than NO₂. Hydrocarbon radicals formed during secondary combustion provide this chemical path; hence, some of the NO_x created in the primary combustion zone is reduced to molecular nitrogen. OFA is utilized in conjunction with reburning to complete combustion of supplemental fuel. Domestic experience in the ICI sector is nonexistent.

Reburning has been chiefly developed and applied to larger industrial boilers in Japan. Mitsubishi Heavy Industries (MHI) has developed the Mitsubishi Advanced Combustion Technology (MACT) process utilizing oil as the reburn fuel. Use of MACT in a 700,000 lb/hr (about 825 MMBtu/hr heat input) tangential-fired boiler at Taio Paper Company in Japan resulted in a 30-percent NO_x reduction to a level of 167 ppm (0.23 lb/MMBtu), during bituminous coal firing.¹⁹ MACT has been used in at least eight other wall or tangential coal-fired industrial boilers in Japan, with capacities ranging between 170 and 200 MMBtu/hr. In the United States, except for several utility demonstration projects and pilot scale test programs, reburning has not been applied to any commercial facility.²⁰ The results from one pilot-scale test are included in Appendix B—a test conducted at the 6 MMBtu/hr B&W Small Boiler Simulator facility.

This test analyzed the NO_x reduction efficiencies of reburning in a cyclone furnace with three types of fuel—bituminous coal, residual oil, and natural gas. With the main burners of the furnace firing bituminous coal, NO_x reduction efficiencies of 54 to 65 percent were achieved.²¹ Results showed that reburning with natural gas produced the best NO_x reduction and the lowest average NO_x emissions, between 235 and 420 ppm (0.32 and 0.57 lb/MMBtu). This was due to the low nitrogen content of natural gas. Use of natural gas as the reburning fuel also brings the added benefit of reducing SO₂ emissions. The use of coal as a reburn fuel resulted in the lowest NO_x removal efficiency. In general, the data suggest that the cleaner the reburn fuel, the more efficient the reburn process.

Prior to this pilot test, B&W had conducted a feasibility study of applying natural gas reburn technology to cyclone-fired boilers. Cyclone boilers are currently being used in both the utility and industrial sectors. Because cyclone boilers have a unique configuration that prevents

the application of standard low-NO_x burner technology—combustion occurs within a water-cooled horizontally-tilted cylinder attached to the outside of the furnace—this study sought to assess the feasibility of retrofitting existing cyclone furnaces with reburn controls. Reburning technology prior to the pilot scale test had never been applied to cyclone-equipped boilers. From an industrial boiler standpoint, the most important result of this study was the conclusion that in general, it is unfeasible to retrofit cyclone boilers below 80 MWe capacity with natural gas reburn controls, which essentially excludes all but the largest industrial cyclones.¹⁶ The reason for this is that cyclone units below this size range generally have insufficient furnace height to allow sufficient residence time for reburn and OFA to work effectively. For a 41 MWe boiler, it was determined that the furnace would have to be extended by over 50 percent, which is impractical.¹⁶ From this study, it appears that gas reburn is most applicable to larger existing cyclone boilers.

Thus, reburn technology is generally not applicable for retrofit to smaller cyclone boilers in the ICI sector because of insufficient furnace heights. For wall-fired and tangential-fired units, however, natural gas or coal reburn may emerge as a viable NO_x control technique for industrial PC-fired units as indicated by utility demonstrations.

5.2.1.4 LNB with SCA

The use of LNBs with SCA (OFA) in PC-fired boilers combines the effects of staged burner combustion and staged furnace combustion. ABB-CE, B&W, and Foster Wheeler offer OFA with LNB systems for retrofit. OFA is an integral part of ABB-CE's LNCFS NO_x reduction package for tangential-fired boilers, and in fact is responsible for the majority of NO_x reduction achieved.¹⁸ As mentioned earlier, in the Kerr-McGee boiler in California, 55 percent NO_x reduction was achieved with the LNCFS, combining OFA and the CFS LNB. Note that the NO_x reduction efficiencies for combined control techniques are not additive.

Emissions data for seven wall-fired units using LNB and SCA controls show NO_x reductions in the range of 42 to 66 percent (see Table 5-3). No baseline data were reported, however, for one of the seven units. This reduction range reflects LNB and SCA performance for six boilers. The 66 percent reduction efficiency was obtained on an industrial size 250 MMBtu/hr unit at Western Illinois Power Cooperative's (WIPCO) Pearl Station. Field tests showed that under normal operation, 50 percent reduction of NO_x was typically achieved while under carefully controlled conditions, the 66 percent NO_x reduction level was possible. Retrofit of four distributed mixing burners with tertiary air ports required replacement of the front wall,

modifications to the windbox, replacement of the burner management system, and provision of an alternative support structure for the hopper.²² Because of the extensive boiler modification required for this particular LNB+SCA system, it is generally intended for use in new boiler designs rather than in retrofit applications.

Controlled NO_x levels for these wall-fired units ranged between 180 and 370 ppm (0.24 and 0.50 lb/MMBtu). Generally, on utility boilers, NO_x reduction performance for this combination of controls can reach as high as 65 or 70 percent.²³ Thus, for large (greater than 250 MMBtu/hr) industrial boilers, this may be the maximum reduction achievable as well. However, insufficient data for PC-fired ICI boilers using LNB and SCA precludes reaching any definitive conclusions.

5.2.2 Combustion Modification NO_x Controls for Stoker Coal-fired ICI Boilers

The two most commonly used combustion modification NO_x controls for stoker coal-fired ICI boilers are SCA and FGR. A third combustion modification, RAP, has not been utilized as often. Gas cofiring with burners above the grate is under active evaluation. Table 5-4 summarizes the data compiled for stoker coal-fired ICI boilers with combustion modification NO_x controls. Available data are limited to 12 stoker units. The data show wide variability in NO_x control efficiency, ranging from -1 to 60 percent reduction. Controlled NO_x levels for spreader stokers with SCA ranged from 230 to 387 ppm (0.31 to 0.52 lb/MMBtu), while for spreaders with FGR+SCA, NO_x ranged from 140 to 350 ppm (0.19 to 0.47 lb/MMBtu). Data were available for only one spreader unit with RAP. This unit had a controlled NO_x level of 219 ppm (0.30 lb/MMBtu).

5.2.2.1 SCA

Stoker units naturally operate with a form of staged combustion due to their design. As the coal is fed onto the grate, volatile matter is driven from the fuel bed and burned above the bed level. The coal solids remaining are subsequently burned on a bed with lower combustion intensity. Because of this natural staging, NO_x emissions from stoker units are generally lower than those from PC-fired units of the same size.²⁴ As presented in Appendix A, uncontrolled NO_x emissions ranged from 341 to 659 ppm (0.46 to 30.89 lb/MMBtu) during nine tests of PC wall- and tangential-fired units ranging in size from 100 to 200 MMBtu/hr. For eight tests of similarly sized stoker units, uncontrolled NO_x levels ranged from 158 to 443 ppm (0.21 to 0.60 lb/MMBtu).

TABLE 5-4. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Type of Stoker boiler tested	% NO _x reduction	Controlled NO _x levels ppm @ 3% O ₂ , lb/MMBtu	Comments
SCA	Reduction of combustion air under the grate and increase of overfire air flow	Spreader	6	350 (0.47)	Danger of grate overheating, clinker formation, corrosion, high CO emissions.
		Spreader	10	353 (0.48)	
		Spreader	26	237 (0.32)	
		Spreader	31	263 (0.36)	
		Spreader	35	369 (0.50)	
		Spreader	N.A. ^a	230-387 (0.31-0.52)	
		Overfeed	-1	166 (0.22)	
		Overfeed	N.A.	172-202 (0.23-0.27)	
FGR+SCA	Recirculation and mixing of stack flue gas with the undergrate or overgrate combustion air	Spreader	0	300-345 (0.41-0.47)	FGR primarily leads to NO _x reduction by lowering achievable excess O ₂ .
		Spreader	13	350 (0.47)	
		Spreader	60	140 (0.19)	
RAP	Reduce temperature of preheated combustion air	Spreader	32	219 (0.30)	Limited applicability to larger units with air preheaters. Reduces boiler efficiency.
Gas cofiring	Achieves lower NO _x with reduced excess air	Spreader	25	170 (0.23)	Applicable to all types of stokers. Cofiring 5 to 40 percent gas possible.

^aN.A. = Not available. No baseline (uncontrolled) NO_x data available.

Note: All test data were obtained from short-term tests.

The availability of existing OFA ports offers the opportunity for increased air staging. Additional staging can be achieved by injecting more overfire air above the fuel bed while reducing the undergrate airflow. Using OFA, the boilers for which data were collected show a NO_x reduction range of zero to 35 percent, averaging 17 percent reduction. In two boilers, OFA did not affect NO_x. Controlled NO_x emissions ranged from 230 to 400 ppm (0.31 and 0.54 lb/MMBtu) for the spreader stokers tested and 166 to 202 ppm (0.22 to 0.27 lb/MMBtu) for the overfeed stokers. No data were collected for underfeed stoker type boilers in this study.

Many older stokers incorporate OFA ports as smoke control devices. Therefore, these OFA ports may not be optimally located for NO_x control purposes. For example, in one test, injection of OFA through oil burner ports high above the grate reduced NO_x by 25 percent. When OFA was injected through the actual OFA ports located closer to the grate, only 10 percent reduction was achieved.²⁵

Because the use of SCA in stoker boilers requires reduced undergrate air flow for staging, there are certain operational limitations involved. First, with the exception of a water-cooled vibrating grate, the only grate cooling mechanism used in stoker units is the flow of combustion air under the grate. During SCA operation, if undergrate air is lowered too much, the grate can overheat. There is also the possibility of creating local reducing zones with low oxygen which may form harmful corrosion products.²⁵ Still another problem that may arise from reduced undergrate air firing is the formation of clinkers. For coals with low ash fusion temperatures, significant clinker formation can be caused by the excessively high bed temperatures resulting from combustion with insufficient amounts of excess air.²⁶ Thus, a minimum amount of undergrate air must be used to provide adequate mixing and cooling. As such, there is a limit to the degree of OFA used in stoker boilers and consequently achievable NO_x reduction.

5.2.2.2 FGR with SCA

The requirements of mixing and cooling when using SCA can be met to a certain degree by recirculating a portion of the flue gas to the furnace and mixing it with the fresh combustion air. One effect of FGR in stoker units is that recirculated flue gas dilutes the oxygen concentration of the combustion air, allowing boiler operators to lower the overall excess air level which consequently reduces formation of NO_x. FGR is primarily considered a thermal NO_x control technique, reducing NO_x by lowering the peak furnace temperature. Because

temperatures in ICI stoker units are lower than in PC-fired units, thermal NO_x control has not been as high a priority for stoker coal-fired boilers.

Figure 5-8 depicts a schematic of a stoker boiler equipped with FGR. Flue gas is drawn from the entrance of the stack and mixed with the undergrate combustion air. This type of FGR system was used in a 100,000 lb/hr (125 MMBtu/hr heat input) spreader stoker fired on bituminous coal. Test results from this boiler illustrate the effect of FGR on allowable excess oxygen and consequently, its effects on NO_x. In this unit, minimum excess oxygen levels and boiler load were restricted by opacity. To prevent opacity from reaching unacceptable levels, pre-retrofit load was limited to 80 percent of capacity and the boiler was operated at minimum stack excess oxygen of 8 percent. Figure 5-9 illustrates the effect of adding FGR to the boiler on allowable excess oxygen. After retrofit, boiler operators could lower excess oxygen levels to as low as 3 percent, keeping opacity the same as pre-retrofit levels. Not only does this represent a significant increase in boiler efficiency, but because NO_x is dependent on the excess oxygen used, lower emission levels were achieved, as shown in Figure 5-10. Thus, at a constant load of 80 percent, using FGR allowed the excess oxygen level to be reduced from 8 percent to approximately 3.5 percent, resulting in a reduction of NO_x by as much as 60 percent. A controlled emission level of 140 ppm (0.19 lb/MMBtu) was measured.²⁷ Another spreader stoker unit also displayed similar characteristics when operated with FGR, experiencing 13 percent NO_x reduction. Less reduction was achieved in this unit because excess air was not reduced as much.²⁶ In a third spreader stoker, however, no NO_x reduction was achieved using FGR, since initial excess oxygen levels were already quite low at 4 percent. FGR did not allow the boiler operators to reduce oxygen concentration, thus resulting in no measurable change in NO_x emissions.²⁶

FGR was also applied to an overfeed stoker, but test results showed the use of FGR on this boiler to be unsatisfactory. Unlike spreader stokers which utilize the entire length of the grate for primary combustion, overfeed stoker units often have shorter active grate combustion zones depending on the location of the furnace wall arch over the grate, as shown in Figure 5-11. The particular boiler tested had a very short active combustion zone limited to the front half of the grate, due to the location of its furnace arch. The lowering of excess oxygen in the combustion air with FGR caused the active combustion zone to lengthen beyond the furnace arch, resulting in flame quenching and impingement on the arch. Also, FGR caused unstable combustion at the front portion of the active combustion zone.²⁶ In contrast with overfeed

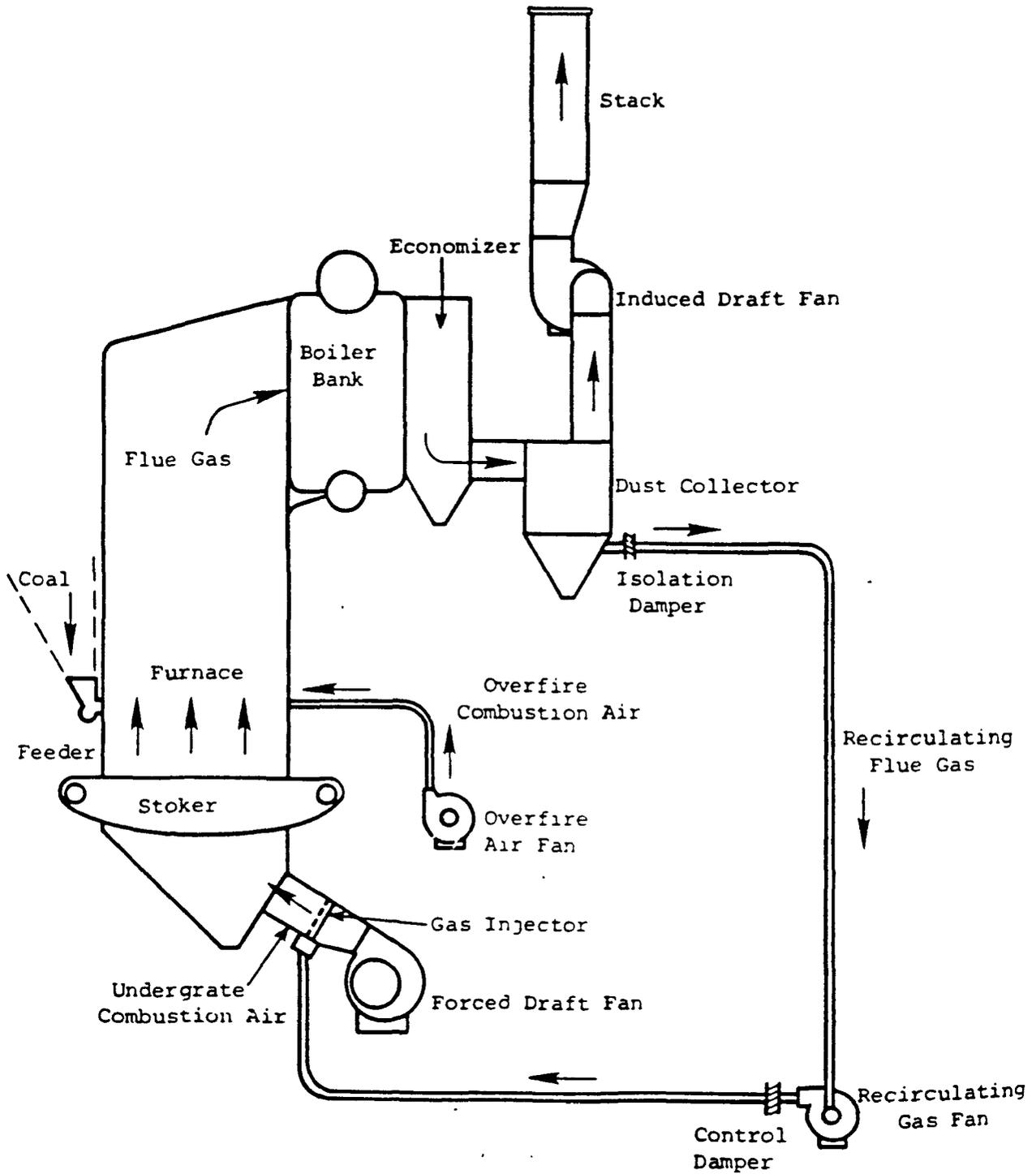


Figure 5-8. Schematic diagram of stoker with FGR.²⁷

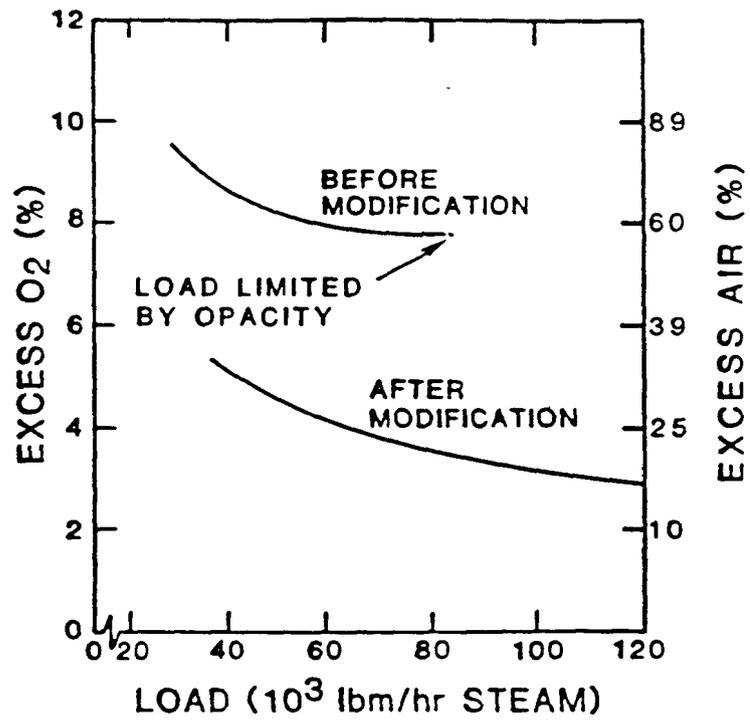


Figure 5-9. FGR effects on excess O₂.²⁷

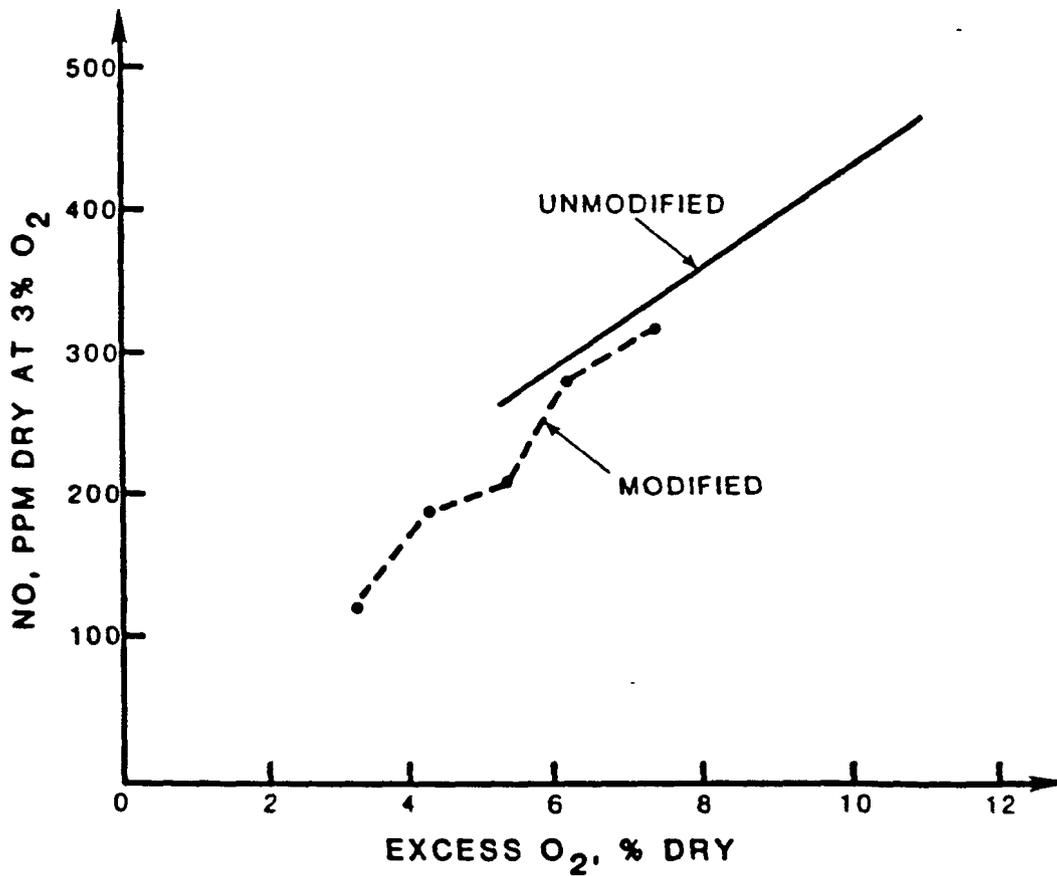


Figure 5-10. NO emission versus excess O₂, stoker boiler with FGR.²⁷

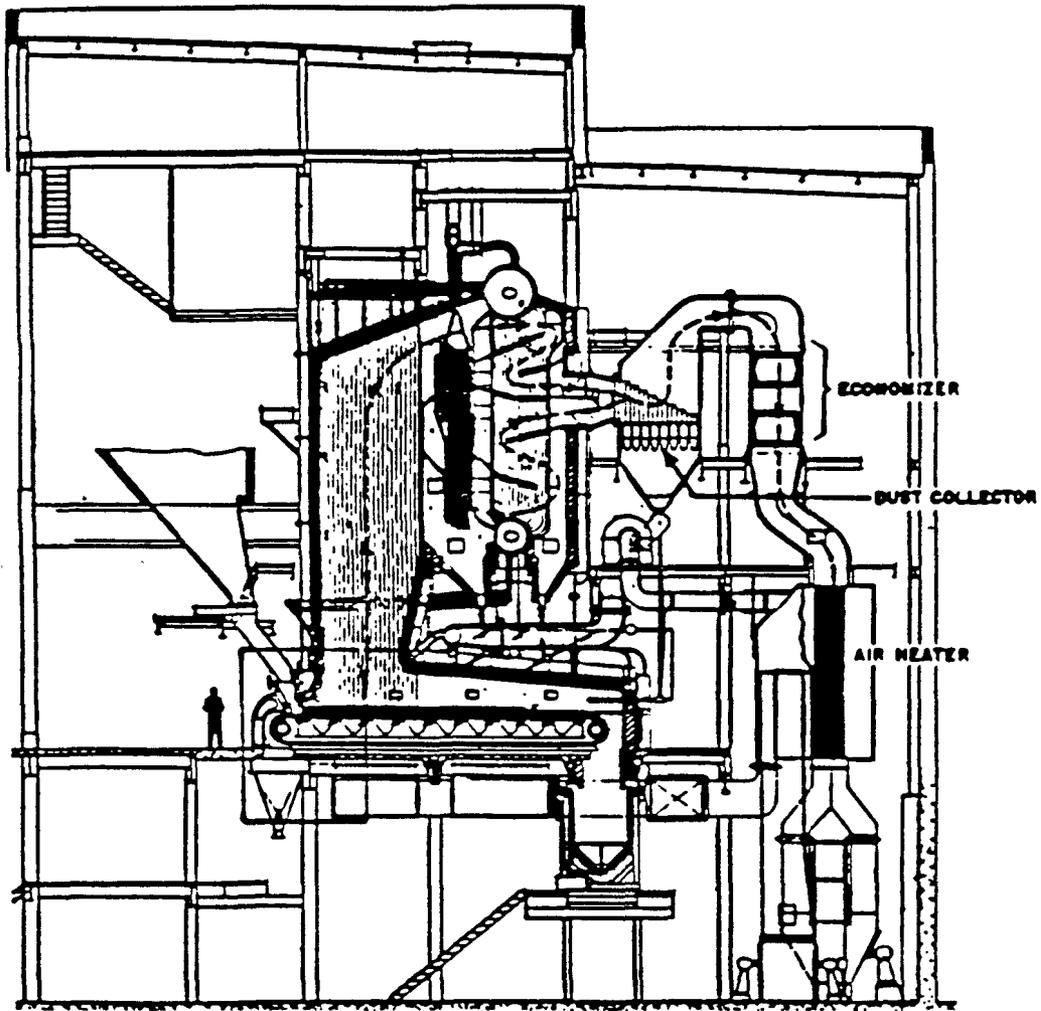


Figure 5-11. Overfeed stoker with short active combustion zone.²⁶

stokers, FGR's effect of lengthening the active combustion zone in spreader stokers is of little consequence because the length required for the coal to burn out is much shorter than the length of the fuel bed.²⁷

In summary, the use of FGR in stoker coal-fired ICI boilers has been demonstrated successfully in a limited number of boilers. NO_x reduction on two of the spreader stokers ranged from 13 to 60 percent. For the overfeed stoker unit, FGR caused unsatisfactory combustion conditions including flame quenching, flame impingement, and unstable combustion. The primary effect of FGR is to allow reduction of the excess oxygen level of the boiler, thereby reducing NO_x emissions and increasing boiler efficiency. FGR has also been shown to be beneficial in dealing with grate overheating.

5.2.2.3 RAP

RAP is limited to stokers equipped with combustion air preheaters. Usually only larger stokers with heat input capacities greater than 100 MM \dot{B} tu/hr tend to have air preheaters.²⁸ RAP is not commonly used in such boilers because significant losses in boiler efficiency occur when the flue gas bypasses the air preheaters. In bypassing the preheaters, recoverable heat from the flue gas is not utilized and the temperature of the flue gas leaving the stack is increased unless major equipment modifications are made to the heat transfer surfaces. Available emissions data for RAP is limited to one spreader stoker boiler. Reduction of preheated combustion air temperature reduced NO_x by 32 percent.²⁸ Because of its limited applicability and negative effects on boiler efficiency, RAP is not considered a primary NO_x control method for stoker coal-fired ICI boilers.

5.2.2.4 Natural Gas Cofiring

Gas cofiring for stokers has only recently been investigated for improving boiler operation and reducing emissions. The technique involves burning a fraction of the total fuel, typically 5 to 15 percent, as natural gas above the grate. The cofiring improves boiler efficiency through reduced excess air, lower LOI in ash, and reduced flue gas exit temperature. The reduced excess air lowers NO_x levels. Recent tests on a spreader stoker have shown that NO_x emissions can be reduced by 20 to 25 percent.²⁹ More tests are planned.

5.2.3 Combustion Modification NO_x Controls for Coal-fired Fluidized-bed Combustion (FBC) ICI Boilers

In FBC boilers, the fuel is burned at low combustion temperatures, 790 to 900°C (1,450 to 1,650°F). At these low temperatures, NO_x formation is limited to the conversion of fuel nitrogen (fuel NO_x). At these low combustion temperatures, studies have shown little correlation

between temperature and NO_x emission, thus combustion modification NO_x controls for FBC boilers focus on the control of fuel NO_x .^{30,31} The principal combustion modification controls used for NO_x reduction in FBC boilers are staged combustion, control of bed temperature, and FGR. Table 5-5 summarizes the performance and process requirements of these three techniques. Each of these control approaches is discussed in the following subsections. Process variables that impact NO_x formation are also discussed. As indicated earlier, most combustion modification research for FBC has been conducted on pilot scale facilities. Available data from full-scale units are limited; thus, the pilot-scale data offer the greatest insights into the control mechanisms and NO_x reduction potential of these controls.

5.2.3.1 SCA in Coal-fired FBC Boilers

SCA is widely accepted as the most effective combustion modification control for reducing NO_x from FBC boilers. Nearly all new commercial FBC units come equipped with overfire air ports along the freeboard section of the combustor to inject secondary and sometimes tertiary combustion air.³² The primary objective of using SCA in an FBC boiler is to reduce NO_x formation by operating the fluidized bed of a bubbling FBC (BFBC) boiler, or the lower portion of a circulating FBC (CFBC) boiler under substoichiometric conditions. Additionally, secondary air injection at high levels in the furnace help ensure good carbon, CO, and hydrocarbon burnout.³³

SCA is generally more effective for high to medium volatile coals than for low volatile fuels such as anthracite. High-volatile-content fuels, also described as high-reactivity fuels (reactivity being defined as the ratio of volatile matter to fixed carbon), contain larger amounts of fuel nitrogen in the volatile matter. When introduced to the combustor, these fuels undergo thermal decomposition and quickly release the organically bound nitrogen in the volatile matter, whereupon it combines to form NO in the presence of oxygen. By using SCA, which lowers the excess oxygen level in the dense portion of the fluidized bed, this conversion of volatile nitrogen to NO is suppressed. For lower volatile fuels, the amount of fuel nitrogen in the volatile fraction is also lower. For these fuels, conversion of char nitrogen to NO_x dominates the overall fuel NO_x , and nitrogen is released at a much slower rate which is a function of the char combustion rate. Thus, SCA has less of a NO_x reducing effect for these lower reactivity fuels.³³

NO_x reductions due to SCA in coal-fired FBC boilers have been reported on the order of 40 percent for full scale units in the ICI sector.³⁴ For example, Figure 5-12 shows the effects of SCA on NO_x and CO emissions for a 16 MWe BFBC boiler firing bituminous coal at

TABLE 5-5. NO_x CONTROL TECHNIQUES FOR FBC BOILERS³⁰

Control technique	Control mechanism	Application limits	Potential limitations
SCA	Staged combustion reduces oxygen for conversion of volatile nitrogen; promotes heterogeneous NO reduction with CO over char; causes increase in CaO char concentration in dense bed	Secondary/primary air ratio limited by fluidization requirements in FBC and reheat steam temperatures	Increase in CO emissions, carbon loss, and reduced sulfur capture primarily in FBC under severe staging ($SR_1 < 0.8$); excessive steam temperature
Control of dense bed temperature	Lower bed temperature reduces volatile nitrogen conversion and increases heterogeneous reduction between char and formed NO	Bed temperature is tied to fuel reactivity (ratio of volatiles/fixed carbon). Higher bed temperature or an increase in residence time is required for low reactivity coal. Optimum temperature is between 1,500 and 1,600°F for high sulfur capture.	Excessive temperature reduction increases CO and carbon loss (efficiency reduction), necessitating longer gas residence time for char combustion, especially with low reactivity coal
FGR	NO _x lowered principally by diluting the combustion air, thus reducing oxygen in the lower bed where NO _x is principally formed	Not a common control technology. FGR typically limited to 20 to 25 percent due to effects on fluidization velocity.	Excessive steam temperature, potential loss of fluidization with loss of FGR; FGR hardware reliability; reduced sulfur retention.

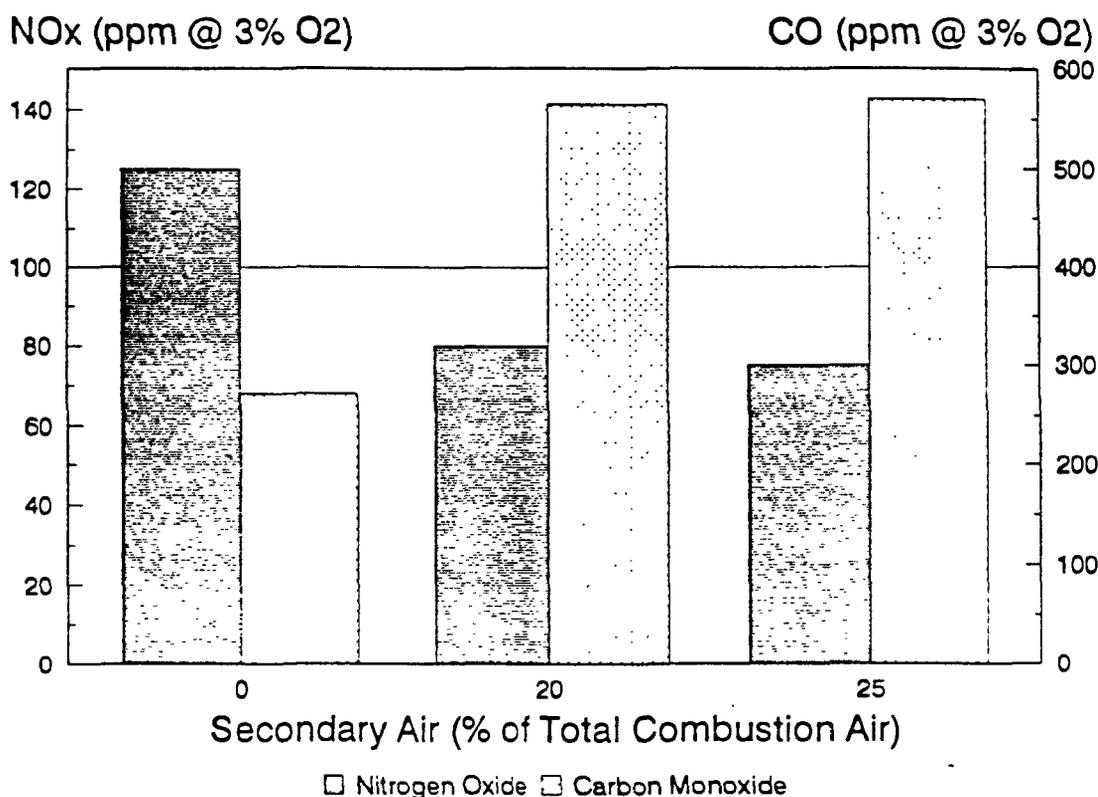


Figure 5-12. Effect of SCA on NO_x and CO emissions, Chalmers University.³⁴

Chalmers University in Sweden. Keeping the total excess air between 20 and 23 percent, NO_x was reduced 40 percent from 125 to 75 ppm (0.17 to 0.10 lb/MMBtu) when 20 percent of the total air supply was injected through OFA ports. When the proportion of air injected as secondary air was increased to 25 percent, NO_x reduction from baseline was only slightly more than 40 percent. Meanwhile, CO emissions more than doubled from a baseline level of 270 ppm to 565 ppm.³⁴ NO_x reduction efficiencies of as high as 60 to 70 percent have also been reported in several pilot-scale tests.³² For instance, at the TNO Research facility in Sweden, tests conducted on a 14 MMBtu/hr BFBC unit with SCA showed 67 percent NO_x reduction.³⁵ Pilot-scale tests, however, generally involve much higher amounts of staging—i.e., lower primary zone stoichiometries—than are practically achieved in full scale units, due to concerns over combustion efficiency, corrosion of watertubes, and refractory integrity.³²

Besides the amount of SCA used and fuel type, the location of the OFA ports can also have a significant impact on NO_x reduction. Several tests have shown that the greater the distance to the secondary air ports, the greater is the NO suppression.³⁶⁻³⁸ This is due to the

increased residence time between the primary and secondary air injection stages. However, there are practical limits on how high in the freeboard the OFA can be introduced without affecting combustion efficiency, corrosion, and steam temperature control. Additionally, because of the different rates of fuel nitrogen conversion for low- or high-reactivity coals mentioned earlier, in order to maximize NO_x reduction the optimal secondary air location must be specifically designed for each type of fuel used, as well as for fuel with different size distributions.

Reported NO_x emission levels for FBC units with SCA have been highly variable depending on the capacity, fuel type, OFA port location, and design type (i.e., CFBC or BFBC) of the boilers. For instance, controlled NO_x emissions from a 222 MMBtu/hr CFBC unit fired on bituminous coal ranged from 51 to 335 ppm (0.07 to 0.45 lb/MMBtu), while an identical unit fired on brown coal emitted 103 to 155 ppm (0.14 to 0.21 lb/MMBtu) of NO_x.³³ Another CFBC unit, rated at 140 MMBtu/hr and firing bituminous coal, emitted 280 ppm (0.38 lb/MMBtu) NO_x.³⁹ Data obtained for full-scale units showed controlled NO_x emissions ranging from 39 to 335 ppm for five CFBC boilers, and 75 to 100 ppm for two BFBC units. These data are tabulated in Table 5-6. Other sources have reported practical NO_x limits achieved with SCA to be between 80 and 130 ppm (0.11 and 0.18 lb/MMBtu) for CFBC and 100 to 200 ppm (0.14 to 0.27 lb/MMBtu) for BFBC boilers.³²

5.2.3.2 Bed Temperature Control

The temperature within FBC boilers is determined primarily by the combustion requirements of the coal and the temperature required to maximize sulfur capture. The optimum temperature range for sulfur capture is 800 and 850°C (1,470 to 1,560°F).⁴⁰ In this range, the sulfur capture can be as high as 98 percent depending on the Ca/S ratio, sorbent reactivity and size, residence time, and ash recirculation rate.

Low bed combustion temperature lowers the formation of thermal NO_x. The effects of bed temperature on NO_x formation for a pilot-scale BFBC was reported to be about 2 to 3 ppm NO_x reduction for every 10°C in temperature drop.⁴¹ Figure 5-13 shows this effect, as well as the bed temperature's effect on CO emissions, which increase as temperature is lowered. The effects of bed temperature on NO_x and CO are shown in Figure 5-14 for the full-scale 16 MWe BFBC test unit at Chalmers University, showing 54 percent NO_x reduction when bed temperature was lowered from 880 to 780°C (1,620 to 1,440°F). This equates to 13 ppm NO_x reduction per 10°C temperature drop, a greater effect than was experienced with the pilot-scale

TABLE 5-6. REPORTED CONTROLLED NO_x EMISSION LEVELS, FULL-SCALE, COAL-FIRED FBC BOILERS

Control technique	FBC boiler type	Controlled NO _x level, ppm @ 3% O ₂ , lb/MMBtu
SCA	Circulating	39-245 (0.05-0.33)
	Circulating	51-335 (0.07-0.45)
	Circulating	100 (0.14)
	Circulating	103-155 (0.14-0.21)
	Circulating	280 (0.38)
	Bubbling bed	75 (0.10)
	Dual bubbling bed	100 (0.14)
FGR+SCA	Circulating	90-116 (0.12-0.16)
	Circulating	100-115 (0.14-0.16)

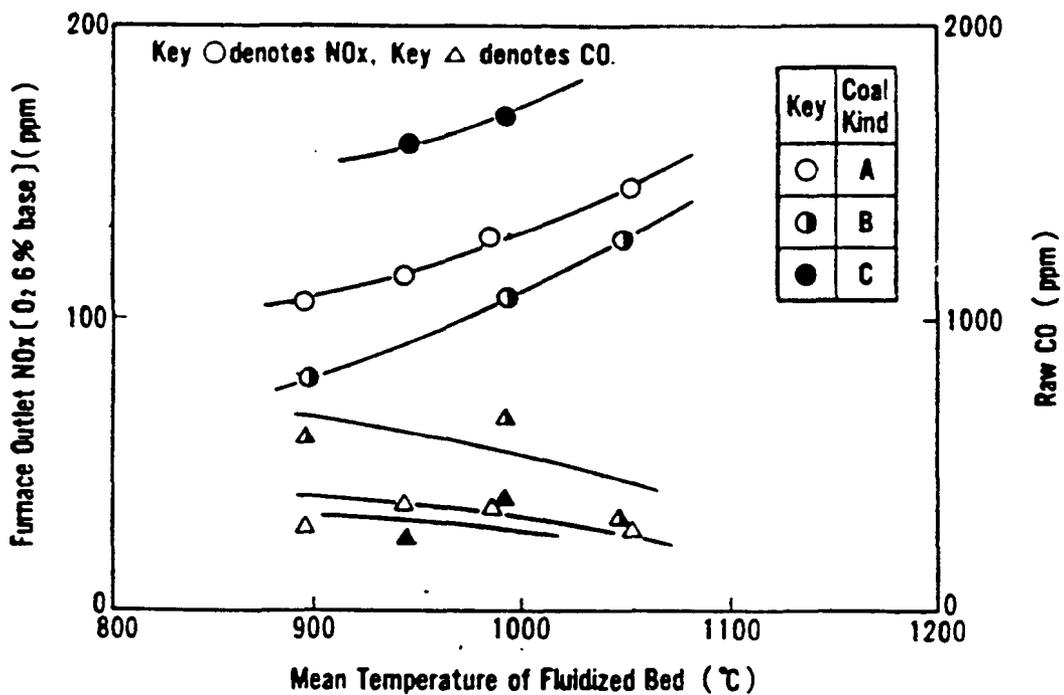


Figure 5-13. NO_x and CO versus bed temperature, pilot-scale BFBC.⁴¹

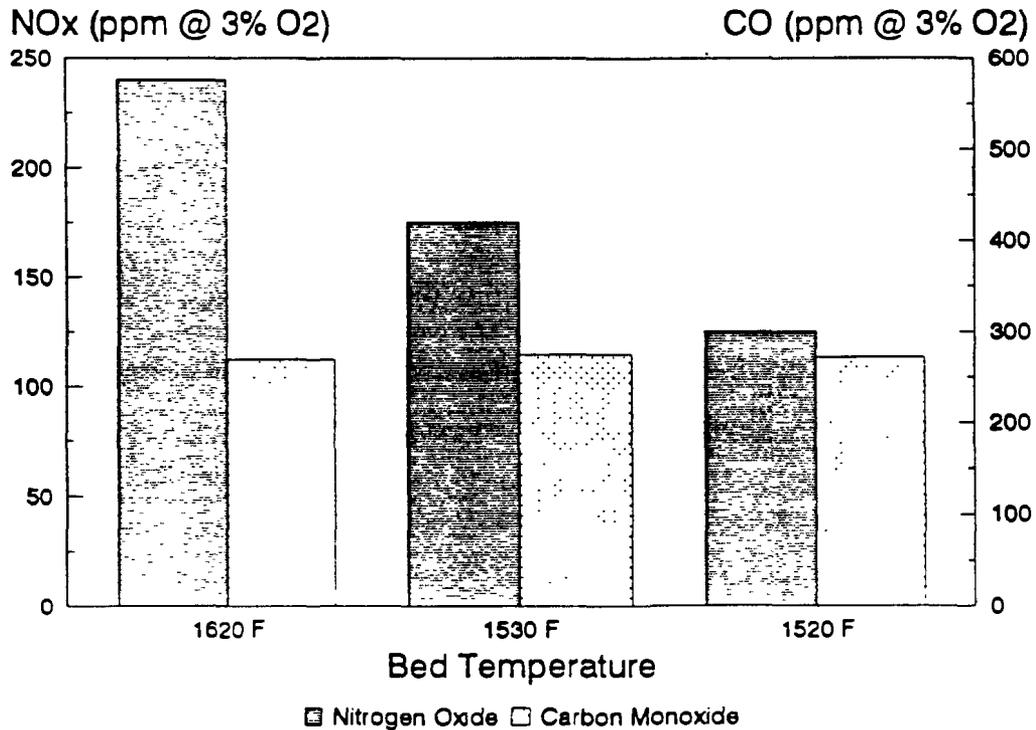


Figure 5-14. Effect of bed temperature on NO_x and CO, Chalmers University.³⁴

unit. The difference in temperature dependence is most likely due to differences in furnace geometry and the type of coal used. Unlike the pilot-scale results shown in Figure 5-13, CO emissions at Chalmers did not increase with lowered bed temperature, remaining fairly constant at 270 ppm.³⁴ For a CFBC pilot unit, the effect of bed temperature on NO_x reduction was 8 ppm reduction per 10°C.⁴² Similarly, tests conducted at the former 110 MWe CFBC Nuclear Power Station showed roughly 10 ppm NO_x reduction per 10°C temperature drop in the bed.⁴³

Although lowering bed temperature has shown measurable reductions in NO_x, the lowering of bed and freeboard gas temperatures is not considered a primary NO_x control method. Steam temperature control, sulfur capture, and combustion efficiency usually do not allow bed and freeboard temperatures much lower than 815°C (1,500°F).⁴⁰ Under staged combustion, lower bed and freeboard temperatures are not generally desired since temperature affects the rate of gas-solid catalytic reactions intended to reduce NO_x.

5.2.3.3 FGR in Coal-fired FBC Boilers

FGR through the air distribution plate in a FBC boiler is not a widely accepted NO_x control technology, or one that has received much research effort to date.⁴⁰ In general, FGR allows operation with reduced combustion oxygen levels in the dense portion of the bed, contributing to NO_x reduction. To some extent, FGR also reduces thermal NO_x by lowering the peak combustion temperature. When FGR is used in combination with SCA, the primary mechanism that results in NO_x reduction is the gas temperature drop in the lower portion of the bed combined with a localized reduction in the oxygen concentration. However, thermal NO_x reduction in FBC is not as high a priority as the control of fuel NO_x. FGR application in FBC has been limited for the most part to pilot scale research. However, test results reported for two full scale CFBC units with SCA and FGR show a marked NO_x reduction efficiency of nearly 70 percent for FGR rates in excess of 30 percent. Controlled NO_x emissions ranged from 90 to 116 ppm (0.12 to 0.16 lb/MMBtu).³³ These data are listed in Table 5-6 and in Appendix B.

Several disadvantages of applying FGR to CFBC units have been identified³³:

- Combustion efficiency and sulfur retention are generally lowered
- Larger combustor, backpassing boiler chamber, greater baghouse capacity, and fan size are required
- Greater power consumption is required for additional equipment
- Boiler capital and operating costs are increased

Because of these potential adverse side effects, FGR is generally not considered a viable NO_x control technology for FBC boilers.⁴⁰

5.2.3.4 Other Process Variables Affecting NO_x

The actual NO_x levels achieved by combustion modification or other controls will depend on several process variables which can influence NO_x emissions in FBC boilers. These variables can be grouped into three major categories: chemical and physical coal properties, chemical and physical properties of sorbent and bed material, and FBC operational variables.

Coal Properties

Two important coal properties are the reactivity and size. Lower reactivity coals emit lower levels of NO_x under both staged and unstaged conditions, due to the catalytic properties of char in reducing formed NO, and because of the rapid oxidation of volatile nitrogen to NO.⁴³ However, coals with low reactivity, and, hence, lower volatile content, are generally burned less efficiently in FBC boilers than high reactivity coals. Also, SCA is not as effective in reducing

NO_x when low reactivity coals are burned, as discussed in Section 5.2.3.1. Generally, an increase in coal size tends to reduce NO_x and improve thermal efficiency. NO_x is reduced due to the reduced surface area of the char which acts as a catalyst in NH_3 oxidation to NO in the presence of excess oxygen.⁴⁴ Thermal efficiency tends to improve as a result of the lower levels of elutriated coal leaving the bed.⁴⁴

NO_x emissions also depend on the nitrogen content of the volatile fraction of the coal being used, generally increasing as this nitrogen content increases. Under staged combustion, fuel nitrogen conversion is significantly reduced from typically 6 to 7 percent to as low as 1.5 to 2.5 percent, depending on the degree of staging. Thus, the effect of nitrogen content on NO_x emissions will tend to be less under staged conditions than for unstaged combustion.

The sulfur content of the coal does not in itself have any effect on NO_x emissions. Indirectly, however, the use of high-sulfur coals requires more limestone sorbent to suppress SO_2 emissions, which will likely increase NO_x unless the FBC boiler is operated with some degree of air staging. This is because under oxygen rich conditions, excessive calcined limestone (CaO) acts as a catalyst in the oxidation of NH_3 to NO, increasing the conversion rate of volatile nitrogen to NO.⁴⁴ With combustion staging, CO levels in the dense portion of the bed reduces formed NO over char and CaO surfaces.

Sorbent/Bed Material

NO_x emissions are also affected by the chemical and physical properties of the bed material and sorbent used for sulfur capture. An increase in Ca/S ratio for improved sulfur capture, for example, will increase NO_x , especially under unstaged combustion conditions, as discussed earlier. CFBC boilers utilize lower Ca/S levels than do BFBC units, and thus tend to emit less NO_x . With staged combustion, however, the effect of Ca/S ratio on NO formation is reduced due to the catalytic effect of CaO and CaS on NO_x reduction in the presence of high concentrations of CO.

Operational Variables

Several operational variables have been reported to affect NO_x formation, including ash recirculation, coal distribution in the bed, and fluidization velocity. Of these, ash recirculation has the most effect. When CaO concentrations in the ash are low and char and CaSO_4 concentrations are high, a net reduction in NO_x is achieved with increased ash recycle. The CaSO_4 acts as a catalyst in oxidation of NH_3 and reduction in NO in the freeboard section of the furnace, according to localized temperature and concentration of NH_3 and O_2 .⁴⁵ This was

demonstrated in a 125 MMBtu/hr BFBC boiler in Japan, where the use of ash reinjection resulted in a 67 percent NO_x reduction, from 90 to 30 ppm (0.12 to 0.04 lb/MMBtu).⁴¹

Data on the effect of coal distribution in the bed are generally sparse and inconclusive. In small pilot-scale combustors, improved bed uniformity has been shown to increase NO_x. However, under staged conditions, it is likely that better distribution of the coal and increasing the bed depth will offer improved NO_x control and more efficient operation, although the reduction is anticipated to be small.⁴⁶

The effect of fluidization velocity on NO_x emissions from FBC boilers is generally small. At constant high excess air levels, an increase in fluidizing velocity has shown a small effect on NO_x. When overall excess air is kept low, the effect is relatively insignificant.⁴⁶

In summary, NO_x emissions from FBC boilers are influenced by several design and process parameters to such an extent that NO_x levels can vary significantly from one unit to the next. For a given type of FBC design, coal properties such as nitrogen content and reactivity; and FBC operating conditions such as bed temperature, ash recirculation, and coal distribution; are principal variables affecting NO_x. Additionally, the sulfur content of the coal together with the required amount of sulfur capture determine the amount of sorbent used, which in turn influences NO_x. Sorbent reactivity and size distribution also play important roles in NO_x emissions since they affect calcium utilization in the fuel bed. Of the combustion modification NO_x control techniques examined in this section, SCA is the most widely applicable and cost-effective method.

5.3 COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL- AND NATURAL-GAS-FIRED ICI BOILERS

Combustion modification NO_x controls for full-scale oil- and natural-gas-fired ICI boilers have been implemented primarily in California. Most of the retrofit activity has been in response to local air districts' rules restricting NO_x emissions from boilers and process heaters. For example, SCAQMD Rules 1146 and 1146.1 regulate NO_x emissions from boilers as small as 2 MMBtu/hr in capacity. Rule 1146 restricts NO_x emissions from ICI boilers with heat input capacities of 5 MMBtu/hr or more to 40 ppm (0.05 lb/MMBtu), unless the unit is greater than or equal to 40 MMBtu/hr capacity and has more than a 25 percent annual capacity factor, in which case NO_x emissions are limited to 30 ppm. Rule 1146.1 mandates a 30 ppm (0.04 lb/MMBtu) limit for ICI boilers of at least 2 MMBtu/hr capacity but less than 5 MMBtu/hr. Additionally, several districts restrict NO_x from boilers used in the petroleum refining industry. It should be noted that these limits are possible in Southern California only

because of the reliance on clean burning natural gas and light distillate oil. Applicable controls include WI/SI; FGR; LNB; SCA, including BOOS and OFA; and a combination of these.

The control of NO_x from fuel oil combustion relies on the suppression of both fuel and thermal NO_x , while with natural gas combustion, NO_x control focuses primarily on thermal NO_x only. In order to achieve this suppression, control methods involve combustion staging or reduction of peak flame temperature. Applicable combustion modification control techniques are SCA, including BOOS and OFA; use of LNBs; FGR; and combinations of these techniques. As explained earlier in this chapter, load reduction, reduced air preheat, and low excess air firing are not considered independent or viable control technologies. Fuel switching has traditionally not been viewed as a control technology. However, the switching from coal to oil or gas and from high-nitrogen residual oil to lighter oil fractions or gas have come under increased consideration in regional and seasonal NO_x compliance options. Fuel switching is discussed in this section along with more traditional combustion modification controls.

Tables 5-7 and 5-8 summarize the information available on the performance and applicability of these techniques for natural-gas-fired and oil-fired ICI boilers, respectively. For natural-gas-fired boilers, more data were available for watertube units equipped with LNB or combined LNB and FGR. Controlled NO_x levels for these units ranged from as low as 13 ppm (0.02 lb/MMBtu) to as high as 170 ppm (0.20 lb/MMBtu). The limited data available for gas-fired watertube units with SCA show controlled NO_x levels of 50 to 200 ppm (0.06 to 0.24 lb/MMBtu). Controlled NO_x emissions from gas-fired firetube units, most equipped with FGR, ranged from 15 to 68 ppm (0.02 to 0.08 lb/MMBtu).

The data presented in Table 5-8 also show wide variability in controlled NO_x levels. For example, units fired on distillate oil with LNB showed NO_x ranging from 60 to 260 ppm (0.08 to 0.33 lb/MMBtu). With combined LNB and FGR, NO_x ranged from 30 to 200 ppm (0.04 to 0.25 lb/MMBtu).

The following subsections, 5.3.1 through 5.3.7, describe each of these methods as they are applied to both oil and natural gas combustion. Although differences in fuel type are acknowledged and affect NO_x emission levels, in general the control equipment and techniques used for oil and natural gas firing are similar. In fact, a large percentage of industrial boilers are capable of burning gas and oil individually or in combination.⁴⁷ All data collected for this section are contained in Appendix B. Additionally, data provided by Coen Company and

TABLE 5-7. COMBUSTION MODIFICATION NO_x CONTROLS FOR FULL-SCALE NATURAL-GAS-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Number of industrial boilers tested	% NO _x reduction	Controlled NO _x levels ppm @ 3% O ₂ , lb/MMBtu	Comments
WI	Water injected into the flame in amounts equivalent to a fraction of the fuel.	Watertube—2 ^a	50-77	35-45 (0.04-0.056)	Thermal efficiency loss of 0.5 to 2.5%. Often implemented with OT, LNB, or BOOS. CO increase is expected. Experience limited to Southern California.
SCA	Fuel-rich firing burners with secondary air injection.	Watertube—5 ^b	17-46	50-200 (0.06-0.24)	Includes BOOS and OFA. BOOS applies to multi-burner units only.
		Watertube—7 ^c	N.A. ^d	67-170 (0.08-0.20)	
		Firetube—1 ^b	5	67 (0.08)	
LNB	LEA burners operate at lower oxygen concentrations. Staged combustion burners control mixing of primary combustion air and fuel. Also have radiant ceramic fiber burner which reduces peak furnace temperature.	Watertube—18 ^b	39-71 (for 5 boilers) ^e	25-140 (0.03-0.17)	LEA LNBs more applicable to single-burner systems. Staged air burners could result in flame impingement on furnace walls of smaller units.
		Watertube—177 ^c	N.A.	30-170 (0.04-0.20) ^f	
		Watertube—21 ^g	N.A.	<40 (<0.05)	
		Firetube—5 ^b	32 ^c	23-68 (0.03-0.08)	
		Firetube—2 ^g	N.A.	<40 (<0.05)	
Radiant LNB	Flameless premix ceramic radiant burner	Firetube—6	53-82	9-30 (0.01-0.036)	Special design LNB limited to firetube applications (<10 MMBtu/hr).
FGR	Recirculation and mixing of stack flue gas with burner combustion air.	Watertube—20 ^b	53-74 (for 2 boilers) ^e	18-67 (0.02-0.08)	Requires motor, fan, and connecting ducting. Reported NO _x data is for FGR rates of 10 to 30%.
		Watertube—13 ^c	N.A.	30-85 (0.04-0.10)	
		Firetube—57	55-76 (for 10 boilers) ^e	16-61 (0.02-0.08)	
LNB+FGR	Combination of LNB and FGR control techniques.	Watertube—22 ^b	55-84 (for 5 boilers) ^e	13-39 (0.02-0.05)	Combined methods are not additive in their effectiveness.
		Watertube—50 ^c	N.A.	25-170 (0.03-0.20)	
		Firetube—5 ^b	N.A.	20-37 (0.02-0.04)	
LNB+SCA	Combination of LNB and SCA control techniques.	Watertube—9 ^c	N.A.	85-170 (0.10-0.20)	Applicable principally to multi-burner boilers.

^aData primarily from Reference 48.

^bData primarily from test reports. See Appendix B.

^cData from LNB vendor (Coen Company). See Appendix C. NO_x levels are not necessarily actual. Often represent vendor-guaranteed levels.

^dN.A. = Not available. No baseline (uncontrolled) NO_x data available.

^eNo baseline (uncontrolled) NO_x data available for remainder of boilers.

^fRange for 95 percent of units listed in Appendix C.

^gData from LNB vendor (Tampella Power Corp.). See Appendix C.

Note: Watertube boilers include both single-burner packaged boilers and multi-burner field-erected boilers. For more detail on emission results from single-burner (PKG-WT) and multi-burner (FE-WT) units, see Section 5.6 and Appendix B.

TABLE 5-8. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL-FIRED INDUSTRIAL BOILERS

Control technique	Description of technique	Number of industrial boilers tested	% NO _x reduction	Controlled NO _x levels ppm @ 3% O ₂ , lb/MMBtu	Comments
LNB	Staged combustion burners control mixing of primary combustion air and fuel	Residual WT, FT-18 ^{a,b}	30-60	69-200 (0.09-0.25)	Staged air burners could result in flame impingement on furnace walls of smaller units.
		Residual WT-24 ^c	N.A. ^d	80-475 (0.10-0.60) ^e	
		Distillate WT-7 ^b	N.A.	60-119 (0.08-0.15)	
		Distillate WT-71 ^c Distillate FT-1 ^b	N.A. 15	65-260 (0.08-0.33) ^f 120 (0.15)	
FGR	Recirculation and mixing of stack flue gas with combustion air	Residual WT-2 ^b	4-30	91-197 (0.12-0.25)	Requires motor, fan, and connecting ducting. Reported data are for FGR rates of 10 to 30%.
		Residual WT-1 ^c	N.A.	275 (0.35)	
		Distillate WT-6 ^b	20-68	28-120 (0.04-0.15)	
		Distillate WT-2 ^c Distillate FT-11 ^b	N.A. N.A.	240 (0.30) 28-126 (0.04-0.16)	
SCA	Fuel-rich firing burners with secondary air injection	Residual WT-11 ^b	5-42	157-588 (0.20-0.74)	Includes BOOS and OFA. BOOS applicable for boilers with multiple burners only. Firetube test experimental.
		Residual WT-3 ^c	N.A.	160-240 (0.20-0.30)	
		Residual FT-1 ^b	49	90 (0.11)	
		Distillate WT-1 ^b Distillate WT-3 ^c	30 N.A.	77 (0.10) 70-95 (0.09-0.12)	
LNB + FGR	Combination of LNB and FGR control techniques	Residual WT-1 ^b	N.A.	180 (0.23)	Combined methods are not additive in their effectiveness.
		Residual WT-4 ^c	N.A.	80-435 (0.10-0.55)	
		Distillate WT-10 ^b	N.A.	20-103 (0.03-0.13)	
		Distillate WT-26 ^c	N.A.	30-200 (0.04-0.25)	
LNB + SCA	Combination of LNB and SCA control techniques	Residual WT-11 ^c	N.A.	160-315 (0.20-0.40)	Applicable principally to multi-burner boilers.
		Distillate WT-6 ^c	N.A.	160 (0.20)	

^aWT = watertube; FT = firetube. Watertube boilers include both single-burner packaged (PKG-WT) boilers and multi-burner field-erected (FE-WT) boilers.

^bData primarily from test reports. See Appendix B.

^cData from Coen Company. See Appendix C. NO_x levels are not necessarily actual. Often represent vendor-guaranteed levels.

^dN.A. = Not available. No baseline (uncontrolled) NO_x data available.

^eRange for 90 percent of units listed in Appendix C.

^fRange for 96 percent of units listed in Appendix C.

Tampella Power Corporation are contained in Appendix C. These data include emission levels based on vendor guarantees, and actual recorded emissions.

5.3.1 Water Injection/Steam Injection (WI/SI)

WI/SI are effective control techniques for reducing thermal NO_x in natural-gas-fired ICI boilers. When water or steam are injected in the flame, they reduce the peak flame temperature and the oxygen concentration. The quenching of the flame reduces the NO_x by as much as 75 percent, depending on the amount of water or steam injected. Less water than steam is needed to achieve the same quenching effect because of the heat of vaporization required to change water into steam.

WI has seen very limited application in Southern California, where NO_x emission regulations are the most stringent. Because of low initial cost, the technique is considered particularly effective for small single-burner packaged boilers operated infrequently.⁴⁸ In these applications, the oil gun positioned in the center of the natural gas ring burner is used to inject the water at high pressure. The amount of water injected normally varies between 25 and 75 percent of the natural gas feedrate, on a mass basis. Figure 5-15 illustrates the general trend of NO_x reduction with water injection rate. However, the technique has some important environmental and energy impacts. For example, CO emissions increase because of the quenching effect on combustion, and the thermal efficiency of the boiler decreases because the moisture content of the flue gas increases, contributing to greater thermal losses at the stack. Another concern related to the technique is its potential for unsafe combustion conditions that can result from poor feedrate control.

5.3.2 Low- NO_x Burners (LNBs) in Natural-gas- and Oil-fired ICI Boilers

LNBs for natural-gas- and oil-fired ICI units are becoming more widespread as the technology has been commercialized and improved, and as regulatory requirements become stricter. LNBs in the ICI sector have been applied primarily to packaged watertube ICI boilers, and to a lesser extent, to packaged firetube and field erected watertube boilers. Most of the available data are from gas-fired boilers located in California. Some of the principal types of LNB available are staged combustion burners, relying on either staged air or staged fuel, LNB with FGR, and ceramic fiber burners. Additionally, another type of burner known as the cyclonic combustion burner has recently been introduced. Major manufacturers of staged combustion burners for ICI sized boilers include Coen Company, Inc., Faber Burner (Tampella Power), Todd Combustion, Peabody, Riley Stoker, Industrial Combustion, and the John Zink Company. Alzeta

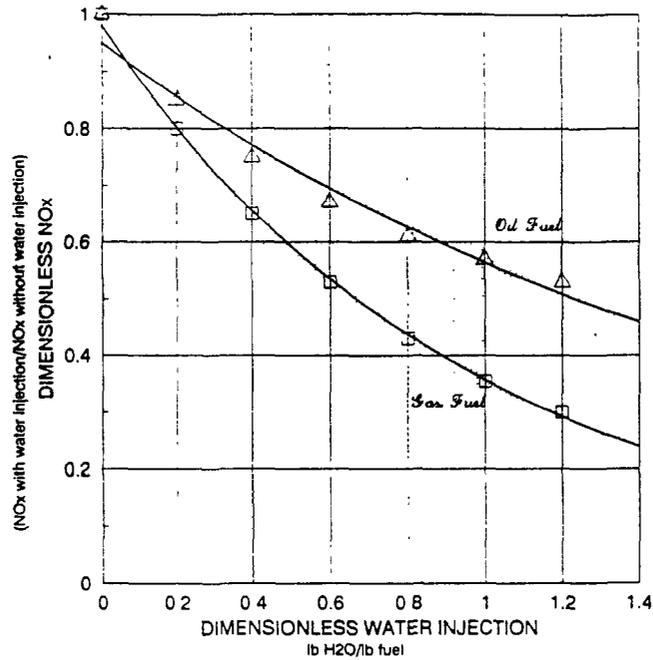


Figure 5-15. As the rate of water injection increases, NO_x decreases.⁴⁸

Corporation has developed the radiant ceramic burner, while York-Shipley has recently introduced the cyclonic burner, both of which are for use primarily in smaller packaged firetube boilers.

There are also burners known as LEA burners, which reduce NO_x formation by operating at low oxygen concentrations. An added benefit of LEA burners is improved thermal efficiency. When compared to conventional burners, however, these burners provide moderate reductions in NO_x, reportedly on the order of 10 to 25 percent reduction.⁴⁹ The primary benefits of LEA burners are their increased efficiency and fuel saving characteristics. Because of the greater difficulty in achieving equal air distribution in multiple burner systems, LEA burners are generally more applicable to single burner systems.

The data in Tables 5-7 and 5-8 indicate that ICI boiler LNB experience includes the reported NO_x levels and reduction efficiencies shown in Table 5-9, exclusive of LNB vendor data from Appendix C. There are many factors that affect the level of NO_x achieved with these burners. The nitrogen content of residual oil, the heat release rate, and the amount of combustion air preheat combined with level of FGR used for gas fuel are among the more

TABLE 5-9. REPORTED NO_x LEVELS AND REDUCTION EFFICIENCIES IN ICI BOILERS WITH LNBs

Fuel	Performance levels
Residual oil	30-60% 0.09-0.60 lb/MMBtu
Distillate oil	N.A. ^a 0.08-0.33 lb/MMBtu
Natural gas conventional burners	32-71% 0.03-0.20 lb/MMBtu
Natural gas radiant burners	53-82% 0.01-0.036 lb/MMBtu

^aN.A. = Not available.

critical factors contributing to the wide range in controlled NO_x levels. The following subsections highlight the principal design features of LNB types.

5.3.2.1 Staged Combustion Burners

Staged combustion burners, the most common type of LNB, achieve lower NO_x emissions by staging the injection of either air or fuel in the near burner region. Hence, staged combustion burners may be further classified as either staged air burners or staged fuel burners. Staged air burners have been applied to watertube boilers since 1979.⁵⁰ Figure 5-16 is a schematic of a typical staged air burner, in which primary, secondary, and tertiary (denoted as staged air in the figure) air are injected into the burner. As the figure notes, the division of combustion air reduces the oxygen concentration in the primary burner combustion zone, lowering the amount of NO formed and increasing the amount of NO reducing agents. Secondary and tertiary air complete the combustion downstream of the primary zone, lowering the peak temperature and reducing thermal NO_x formation. Besides the basic staged air burner shown, there are variations on staged air burners which incorporate internal recirculation of combustion products to aid in NO_x reduction.

Due to the staging effect of staged air burners, flame lengths tend to be longer than those of conventional burners.⁵¹ This is of particular concern for packaged units because there is the possibility that flame impingement will occur on the furnace walls, resulting in tube failure and corrosion. Additionally, staged air burners are often wider and longer than conventional burners, requiring significant modifications to existing waterwalls and windboxes. Burner size

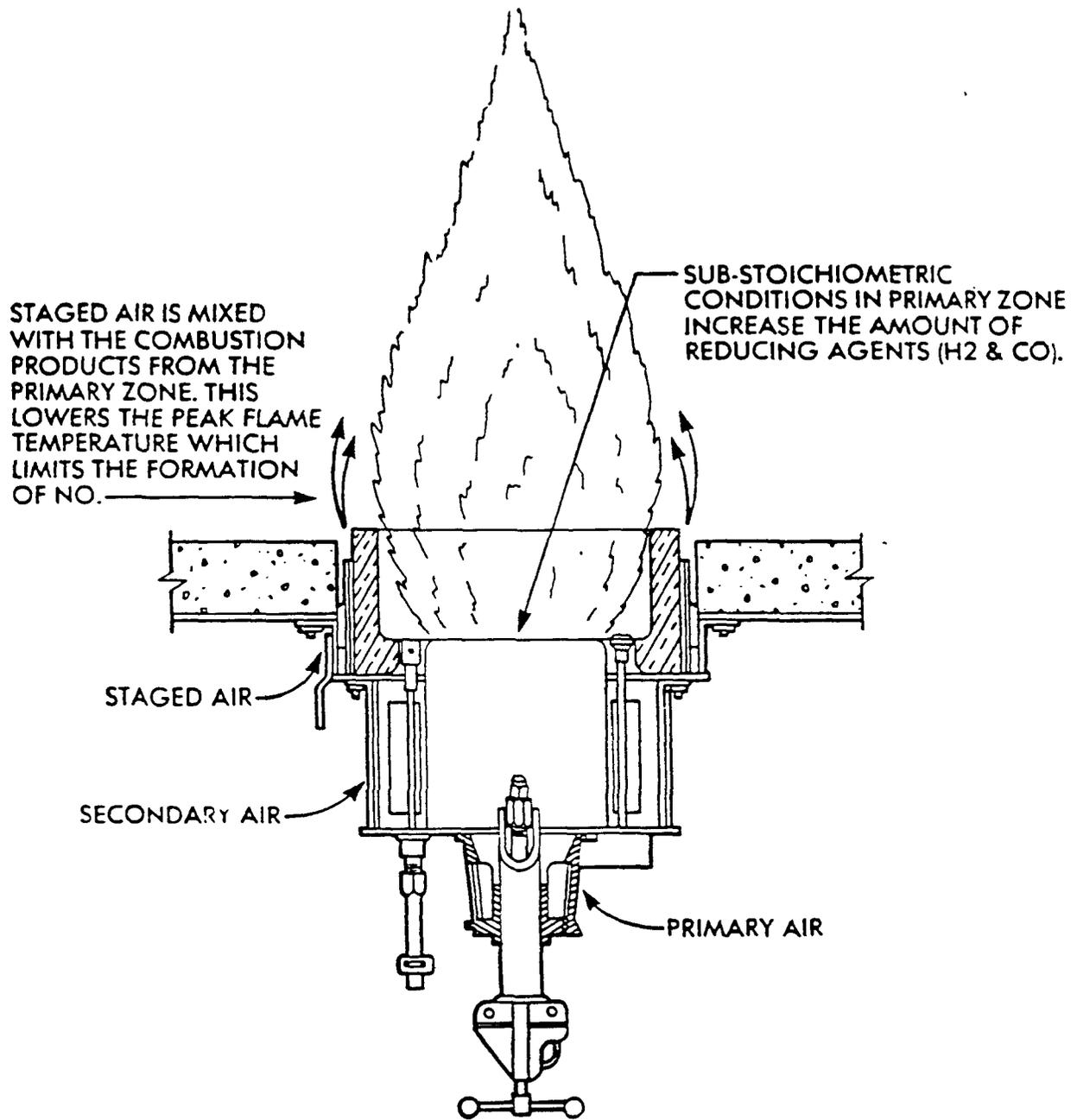


Figure 5-16. Staged air LNB.⁵³

may also be an important factor when assessing the feasibility of retrofitting boilers located in restricted spaces.

Staged fuel burners are a slightly more recent development in staged combustion LNBs. These burners were originally developed for use on process heaters in the refining and petrochemical industries, and hence have been applied primarily to process heaters rather than boilers. Figure 5-17 is a schematic of a staged fuel burner, manufactured by the John Zink Company. Here, combustion air is introduced without separation and instead the fuel is divided into primary and secondary streams. Despite the high oxygen concentration in the primary combustion zone, thermal NO_x formation is limited by low peak flame temperatures which result from the fuel-lean combustion. Quenching of the flame by the high excess air levels also occurs, further limiting the peak flame temperatures and providing active reducing agents for NO_x reduction.⁵² Inerts from the primary zone then reduce peak flame temperatures and localized oxygen concentration in the secondary combustion zone, thereby reducing NO_x formation. An advantage of staged fuel burners over staged air burners is that they tend to have shorter flame lengths, decreasing the likelihood of flame impingement.⁵⁴

Data collected on natural-gas- and oil-fired ICI boilers with staged air LNBs show a wide range in performance and emission levels. For natural gas firing, NO_x reductions of 39 to 71 percent were reported for three existing and one new watertube boiler. Controlled NO_x levels for these and 10 other gas-fired watertube boilers, five of which were existing units retrofitted with LNBs, ranged from 25 ppm (0.03 lb/MMBtu), for a 10 MMBtu/hr boiler in Taiwan, to 140 ppm (0.17 lb/MMBtu), for a 100 MMBtu/hr floor firing unit in Germany. This range is quite wide due to differences in boiler design, capacity, and burner type. An example of the levels of performance achievable with different burners is that when a different LNB was tested in the German boiler mentioned above, the controlled NO_x level was 112 ppm (0.13 lb/MMBtu) instead of 140 ppm (0.17 lb/MMBtu).⁵⁵

All but one of the above 14 units were packaged. The only field-erected unit, a 380 MMBtu/hr dual burner unit at Luz-Segs II in California, reported a controlled NO_x level of 80 ppm (0.10 lb/MMBtu) when retrofitted with an LNB.⁵⁶ Test results from one gas-fired firetube unit at Fort Knox retrofitted with a staged air burner showed a 32 percent reduction in NO_x , from 100 ppm down to 68 ppm (0.12 to 0.08 lb/MMBtu). No other data are available for firetube units with staged air LNB.

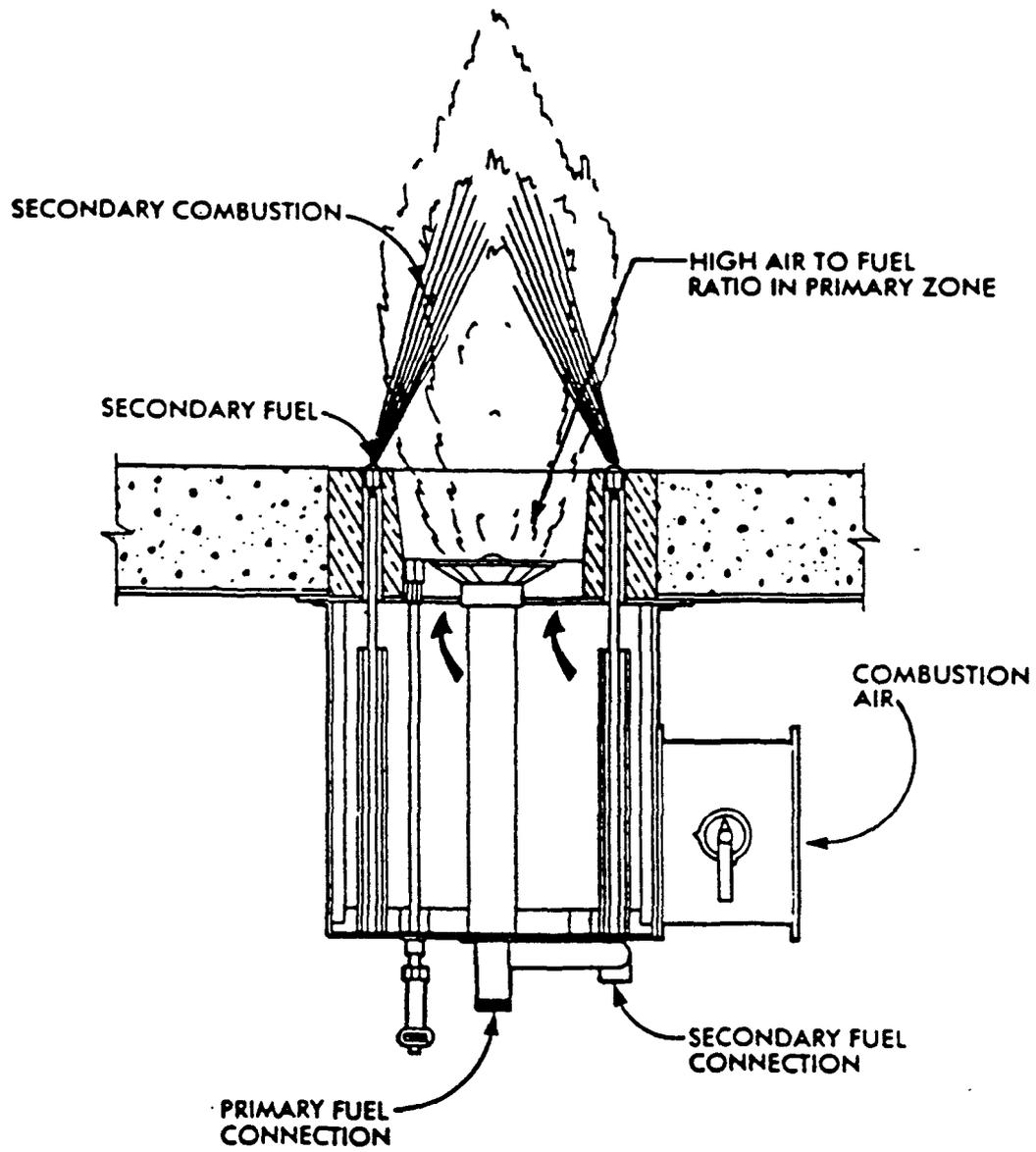


Figure 5-17. Staged fuel LNB.⁵²

Additional data supplied by Coen Company (see Appendix C) for 177 natural-gas-fired LNB installations showed guaranteed or actual NO_x levels typically between 30 and 170 ppm (0.04 to 0.20 lb/MMBtu) with LNB.⁵⁷ These data include emissions levels for boilers of various types and sizes, ranging from packaged to field erected units producing 25,000 to 520,000 lb/hr of steam (approximately 30 to 600 MMBtu/hr heat input). All units used Coen DAF LNBs. Appendix C also contains a list of 23 Tampella Power Corp. Faber LNB installations that reportedly emit 40 ppm NO_x (0.05 lb/MMBtu) or less when firing natural gas. All of these boilers are packaged units ranging from 9,000 to 100,000 lb/hr steam capacity.⁵⁸

For smaller industrial gas-/oil-fired boilers, Riley Stoker has also introduced the Axial Staged Return (ASR™) flow burner, the Axial Flame Staged (AFS™) burner, and the Swirl Tertiary Staged (STS™) burner. The ASR burner is based on patented Deutsche Babcock technology that uses axial staging of primary and secondary air streams and internal recirculation of self-aspirated hot furnace gases. The burner, illustrated in Figure 5-18, has a maximum design capacity of 275 MMBtu/hr, with controlled NO_x levels in the 20 to 30 ppm (0.025 to 0.035 lb/MMBtu) range when firing natural gas with 12 to 30 percent FGR assistance.⁵⁹ The AFS burner incorporates axial staging of primary and secondary air and staged fuel addition. The burner, illustrated in Figure 5-19, has a firing capacity in the 20 to 40 MMBtu/hr range.⁵⁹ With FGR addition, NO_x emissions in the 30 to 40 ppm (0.035 to 0.048 lb/MMBtu) range have been reported in full-scale retrofits.⁵⁹ The STS burner, illustrated in Figure 5-20, is designed for retrofit on multiple burner wall-fired boilers with 500°F air preheat. In one full-scale STS burner retrofit at a paper mill, reported NO_x emissions ranged from 90 to 110 ppm (about 0.1 to 0.13 lb/MMBtu) with high air preheat and heat release rate and without FGR.⁵⁹

In summary, LNB NO_x reduction efficiencies for natural-gas-fired boilers including one firetube boiler and five watertube units range from 32 to 71 percent, in agreement with previously reported performance levels for natural gas firing. LNB reduction efficiencies for 13 additional watertube units listed in Appendix B could not be computed because of a lack of baseline (uncontrolled) emissions data. Controlled NO_x emissions for the 18 watertube units ranged from 25 to 30 ppm (0.03 to 0.04 lb/MMBtu), for the smaller units (10 to 31 MMBtu/hr input), and from 58 to 140 ppm (0.07 to 0.17 lb/MMBtu), for the remaining boilers, which ranged in size from 45 to 380 MMBtu/hr input. Controlled NO_x emissions reported by two LNB manufacturers for nearly 200 units ranged between 30 and 170 ppm (0.04 to 0.20 lb/MMBtu). Some burner manufacturers have reported NO_x reduction efficiencies of anywhere from 50 to

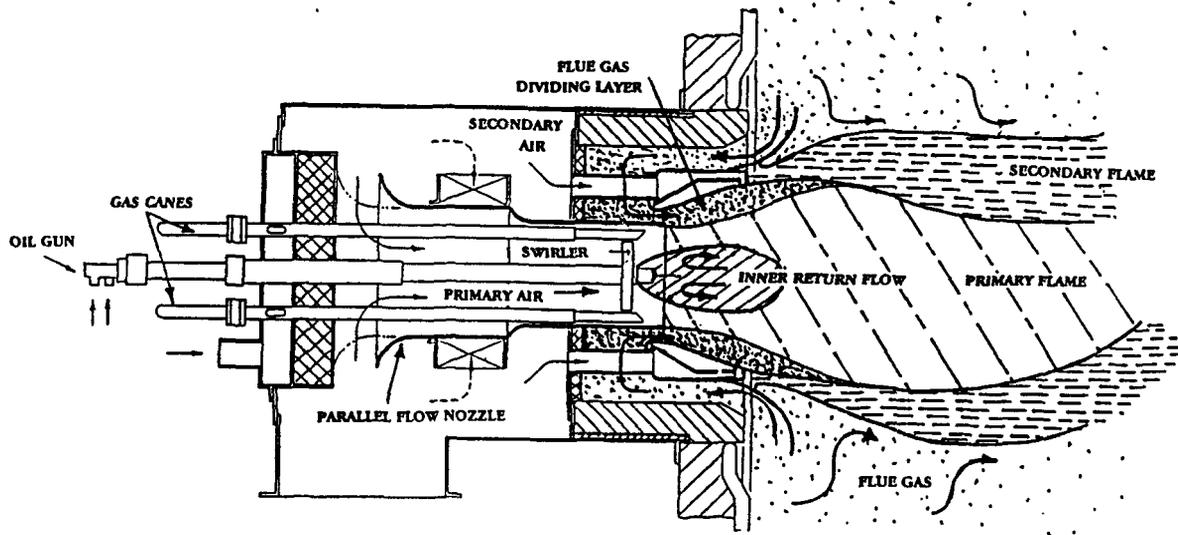


Figure 5-18. Low-NO_x ASR burner.⁵⁹

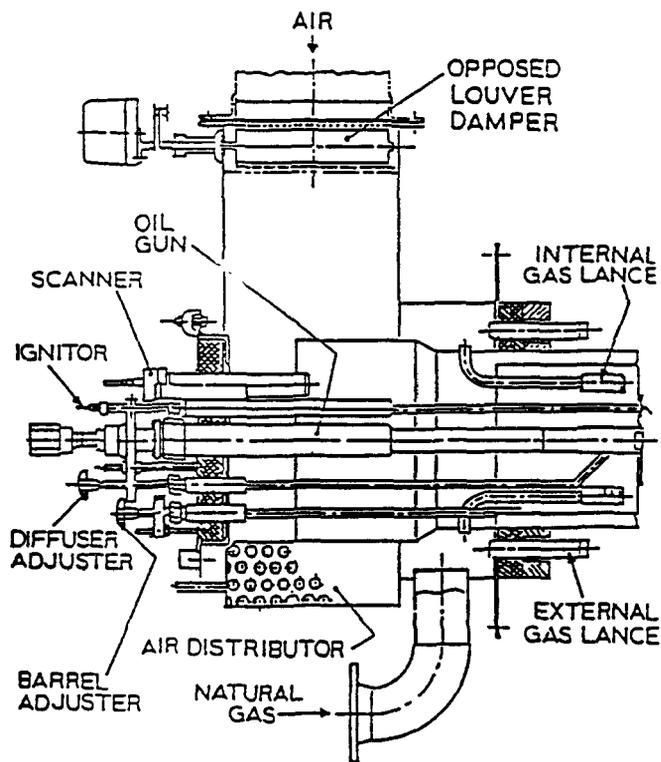


Figure 5-19. AFS air- and fuel-staged burner.⁵⁹

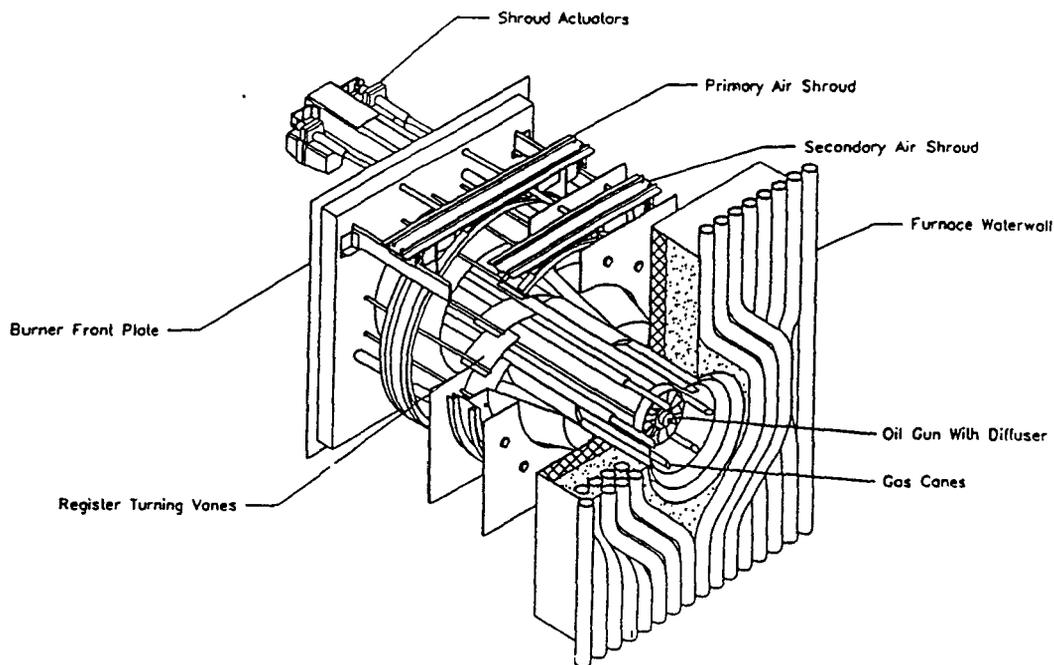


Figure 5-20. Riley Stoker STS burner.⁵⁹

90 percent. In fact, several manufacturers guarantee NO_x emissions below 40 ppm (0.05 lb/MMBtu) when firing natural gas in smaller industrial packaged boilers, primarily in response to the SCAQMD regulations in California. For example, Faber, a division of Tampella Power, guarantees less than 40 ppm NO_x on any burner system and will guarantee less than 30 ppm (0.04 lb/MMBtu) of NO_x on a case-by-case basis.⁶⁰ Similarly, Coen Company states that less than 30 ppm of NO_x will be emitted from its Micro- NO_x ® LNB.⁶¹ Performance levels of less than 20 ppm are achievable on a case-by-case basis.

For oil firing with staged air LNBS, data were collected for 84 boilers firing distillate oil and 46 boilers firing residual oil. The distillate-fuel-fired boilers with staged air LNBS showed controlled NO_x levels of 60 to 260 ppm (0.08 to 0.33 lb/MMBtu). The 25 domestic units fired on No. 6 residual oil (fuel nitrogen contents of 0.14 to 0.3 percent) had controlled emissions of 80 to 475 ppm (0.10 to 0.60 lb/MMBtu). Due to a lack of baseline uncontrolled emissions data for these domestic units, it was not possible to calculate NO_x reduction efficiencies for the boilers. Additionally, overall performance results of 17 firetube and watertube boilers in Japan firing residual oil have been reported. For these units, which ranged in size from 5 to 40 MMBtu/hr, test results showed NO_x reductions between 30 and 60 percent, with controlled emissions between 69 and 185 ppm (0.09 and 0.23 lb/MMBtu).⁶²

The retrofit of LNBs usually involves removing the original burner and bolting the LNB in. Most LNBs for ICI boilers are designed as self-contained units to allow easy bolt-on retrofit without boiler tube wall modifications. For applications where new fan or ducting equipment are desired, some manufacturers offer complete packaged burner units, in which the retrofit burner is combined with combustion controls, flame safeguard equipment, fuel piping, and a combustion air fan. These are sold together as factory assembled, self-contained packages.

5.3.2.2 Ceramic Fiber Burners

Alzeta Corporation has developed a ceramic fiber burner known as the Pyrocore® burner, applicable for use in gas-fired packaged boilers of up to 10 MMBtu/hr input. Although applicable to both watertube and firetube units, the Pyrocore burner has been demonstrated primarily in firetube boilers and process heaters. This burner, depicted in Figure 5-21, is a gas-fired infrared (IR) burner. An IR burner uses energy released from the fuel to elevate the temperature of the radiant surface of the burner, which in turn emits energy in the form of IR radiation. In the Pyrocore burner, fuel gas is premixed with combustion air before entering the burner. The mixture passes through a porous burner material and is ignited, establishing a thin combustion layer in contact with the surface. Because the surface material is cooled by the incoming air/fuel mixture and the material has a low thermal conductivity, radiant temperatures of 1,700 to 2,000°F occur only on the outer surface.⁶³ The low combustion temperature limits thermal NO_x formation.

Field tests of this burner retrofitted to a 3.3 MMBtu/hr firetube boiler at Hall Chemical in Ohio showed NO_x reduction of 78 percent, with controlled emission levels of 15 ppm (0.02 lb/MMBtu). Another field test conducted on an 8 MMBtu/hr boiler retrofitted with the Pyrocore burner showed 53 percent reduction in NO_x, to a controlled level of 24 ppm (0.03 lb/MMBtu), while a third test on a 2 MMBtu/hr unit resulted in a controlled emission level of 17 ppm. On the average, results from five field tests and one laboratory test showed that NO_x was reduced by 71 percent and CO by 94 percent.⁶⁴ To date, most burners supplied by Alzeta have been designed to achieve less than 30 ppm NO_x at full rated load, although the actual emissions for many are reported to be below 20 ppm. Currently, the single-burner applications of this burner are limited to small packaged boilers of less than 20 MMBtu/hr because of physical limits on the size of the radiant burner. Structural issues are the major concern with larger applications. Further research and tests are being conducted to extend the

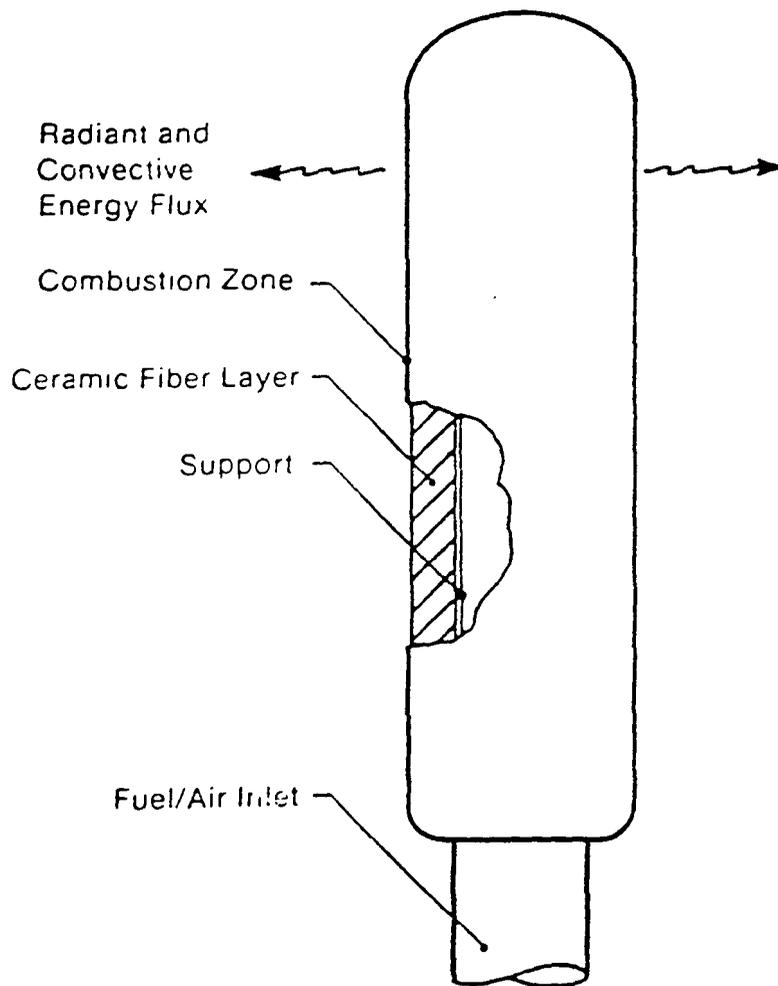


Figure 5-21. Pyrocore LNB schematic.⁶³

Pyrocore burner's applicability to larger firetube and watertube boilers, including the use of multiple burners.

Additional research is currently focusing on the use of lower surface firing rates, moderate temperature environments, and modest excess air to attain ultra-low NO_x levels of 9 ppm and below. Alzeta Corporation and Zurn Industries have recently commissioned an ultra-low-NO_x boiler, the Radiant Cell Boiler™, that utilizes the Alzeta flameless Pyrocore radiant burners and has a reported capability of 9 ppm of NO_x and less than 50 ppm of CO.⁶⁵

5.3.2.3 Other LNBs

An LNB type known as a cyclonic burner has recently been developed by York-Shipley for packaged firetube boilers. The burners are available up to 16.6 MMBtu/hr heat input. In cyclonic combustion, high tangential velocities are used in the burner to create a swirling flame pattern in the furnace. This causes intense internal mixing as well as recirculation of combustion gases, diluting the temperature of the near-stoichiometric flame and lowering thermal NO_x formation. The tangential flame causes close contact between combustion gases and the furnace wall, adding a convective component to the radiant heat transfer within the furnace. The increased heat transfer and low excess air operation of the cyclonic burner result in increased boiler efficiency.

To achieve ultra-low NO_x levels, a small quantity of low-pressure steam is injected into the burner, which further reduces the local flame temperature and NO_x formation. Testing revealed that NO_x emissions during natural gas firing could be reduced from 70 ppm to less than 20 ppm without affecting burner stability, low excess air operation, or turndown performance. However, the use of steam did result in a boiler heat efficiency loss of roughly 5 percent.⁶⁶ The cyclonic burner is available as a stand-alone retrofit burner with a bolt-on feature. However, no retrofit emissions data were obtained during this study.

5.3.3 Flue Gas Recirculation (FGR) in Natural-gas- and Oil-fired ICI Boilers

FGR involves recycling a portion of the combustion gases from the stack to the boiler windbox. These low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature and the residence time at peak flame temperature. These effects result in reduced thermal NO_x formation. However, there is little effect on fuel NO_x emissions. The amount of NO_x reduction achievable depends primarily on the fuel nitrogen content and amount of FGR used. Other thermal NO_x control concepts similar to FGR are such control techniques as WI and SI, in which

water, rather than recirculated flue gas, is used as an inert substance to lower the peak flame temperature. FGR is much more commonly used, however.

FGR is currently being used on a number of watertube and firetube boilers firing natural gas. Only limited NO_x reduction efficiency data are available, however, as baseline (uncontrolled) NO_x data for most units are unreported. Data for four natural-gas-fired watertube boilers equipped with FGR show a range in NO_x reduction of 53 to 74 percent, while for 10 gas-fired firetube units with FGR, NO_x reduction efficiency ranged from 64 to 76 percent. In all, controlled NO_x emission data were collected for a total of 33 gas-fired watertube and 57 gas-fired firetube units operating with FGR. Four of the watertube units and 26 of the firetube units were identified as retrofit applications. Controlled NO_x levels ranged from 20 to 85 ppm (0.02 to 0.10 lb/MMBtu) for the watertube units and 16 to 37 ppm (0.02 to 0.04 lb/MMBtu) for the firetube boilers. FGR rates were typically on the order of 20 percent during these tests. However, one firetube unit—which achieved 68 percent reduction—was run on 30 percent FGR during the emissions test. Boilers are usually not operated with more than 20 percent FGR due to flame stability considerations.⁶⁷

NO_x reduction efficiency data for oil-fired units with FGR are also very-limited. In one test program, a single boiler was fired on both residual oil and distillate oil, using FGR and keeping all other variables constant. NO_x was reduced by 68 percent for distillate oil firing, yet was only reduced by 11 percent when residual oil was used. These data illustrate that FGR is more effective when used with low nitrogen content fuels such as natural gas or distillate oil, since FGR is more effective in controlling thermal NO_x rather than fuel NO_x . The 68 percent reduction was obtained with a relatively high FGR rate of 28 percent. Another boiler firing distillate oil reported NO_x reduction of only 20 percent, using 10 percent FGR. Available data are too limited to estimate typical NO_x reduction efficiencies for oil-firing boilers with FGR. In general, however, thermal NO_x reductions from distillate-oil-fired boilers with FGR are somewhat less than from natural-gas-fired units.⁶⁸ This is due to the greater potential for flame instability and emissions of unburned combustibles from distillate-oil-fired units, which limits the practical rate of FGR that can be used. Controlled NO_x emissions for distillate oil firing with FGR were between 28 and 240 ppm (0.04 to 0.30 lb/MMBtu) for 19 boilers. For three units firing residual oil, controlled NO_x levels ranged from 125 to 275 ppm (0.16 to 0.35 lb/MMBtu).

When compared to the number of LNB or combined LNB and FGR installations listed in Tables 5-7 and 5-8, the number of watertube boilers equipped only with FGR is relatively

small. In general, for retrofit cases to existing packaged watertube ICI boilers, FGR is rarely applied without the installation of a new LNB as well. This is because the performance of many older burner systems tend to be adversely affected when an inert such as fuel gas is injected into the combustion zone.⁵⁷ Oxygen trim systems have been installed to allow use of an existing burner with FGR and LNB together. Thus, the most common combustion modification NO_x controls for packaged watertube boilers are either LNB or combined LNB and FGR. FGR systems have been applied more commonly to smaller firetube units. A typical FGR system is shown in Figure 5-22. In order to retrofit a boiler with FGR, the major additional equipment needed are a gas recirculation fan and ducting. Major companies that supply FGR equipment for packaged gas- and oil-fired boilers are Cleaver Brooks, Coen Company, Industrial Combustion, Keeler (Tampella Power), and Todd Combustion.

5.3.4 Fuel Induced Recirculation (FIR)

Fuel induced recirculation (FIR) is a control technology for natural-gas-fired boilers recently introduced by the John Zink and Holman Boiler Companies. FIR involves the recirculation of a portion of the boiler flue gas and mixing it with the gas fuel at some point upstream of the burner. Although FIR has not yet been widely applied, it has been demonstrated commercially in an industrial unit in California, achieving NO_x emission readings as low as 17 ppm with little adverse affect on CO emissions.⁶⁹

The primary difference between FIR and FGR is that in FIR the flue gas is mixed with the fuel stream, whereas in FGR the flue gas is recirculated into the combustion air. By diluting the fuel prior to combustion, which lowers the volatility of the fuel mixture, FIR reduces the concentration of hydrocarbon radicals that produce prompt NO .⁶ Additionally, FIR reduces thermal NO_x in the same manner as FGR, by acting as a thermal diluent. Thus, one of the main benefits of FIR technology is that it impacts both prompt NO and thermal NO_x formation in gas-fired boilers.

A second fundamental feature of FIR is that flue gas recirculation is induced using the natural gas dynamics of the burner flow streams, without additional equipment such as recirculation fans. According to the manufacturer, FIR tends to be self-adjusting at various firing rates, as natural gas introduction is dependent on the mass and pressure of the fuel.⁷⁰

5.3.5 Staged Combustion Air (SCA) in Natural-gas- and Oil-fired ICI Boilers

Staged combustion for oil- and natural-gas-fired boilers in the ICI sector consists of injecting a portion of the total combustion air downstream of the fuel-rich primary combustion

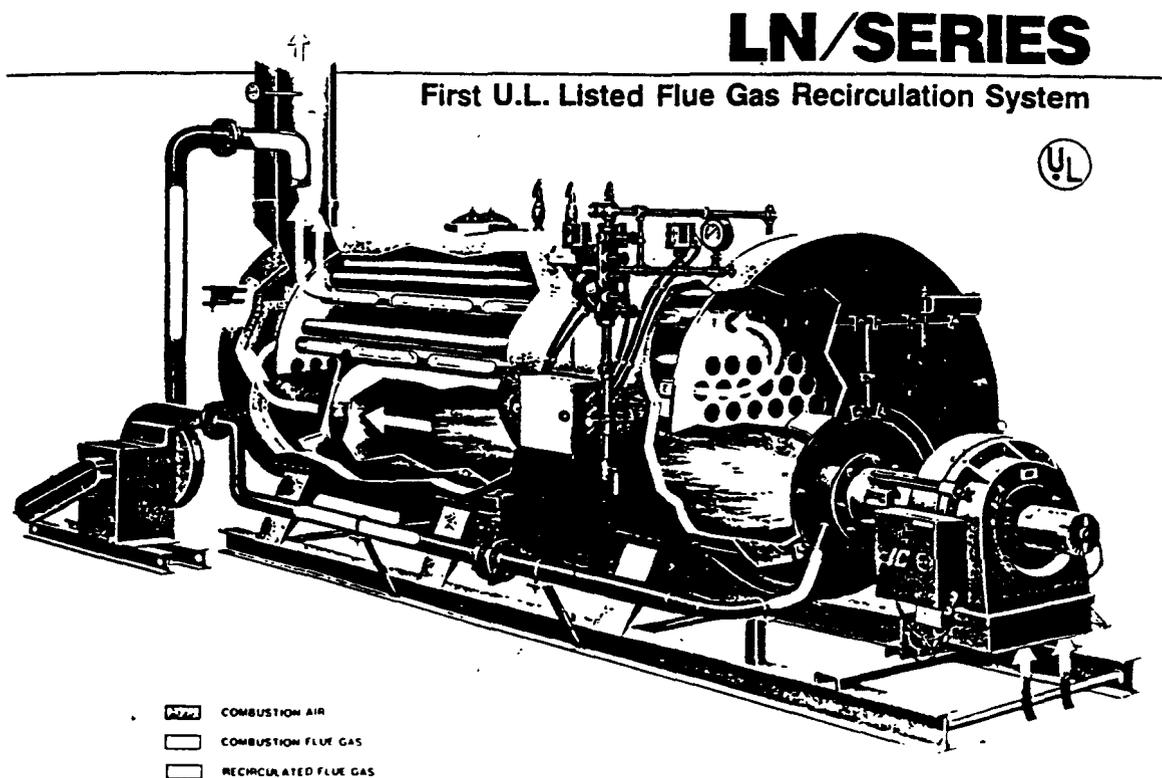


Figure 5-22. FGR system for gas- or oil-fired boiler.⁷¹

zone. Staged combustion can be accomplished using secondary OFA or side-fired air ports, or by using the BOOS technique. The applicability of OFA, side-fired air, or BOOS (collectively grouped under the term SCA) depends primarily on the type of furnace design involved — i.e., watertube or firetube — and the size of the boiler. Generally, SCA is not considered viable for retrofit to packaged boiler units due to installation difficulties. The following subsections summarize the performance, applicability, and availability of the various methods of implementing SCA on the major types of natural-gas- or oil-fired ICI boilers.

5.3.5.1 Firetube Boilers

SCA is not considered a primary NO_x control method for existing firetube boilers because of the major modifications required to retrofit staged air to these boilers.⁷² BOOS is not applicable because these units rarely have more than one burner. Side-fired air application is difficult as retrofit requires penetration of the firetube boiler water shell. Performance data are available only for one experimental application of side-fired air to a 12 MMBtu/hr firetube

boiler fired on residual oil and natural gas. In this test program, sponsored by the U.S. EPA, secondary air was injected at the rear of the furnace opposite the burner through eight pipes connected to a forced-draft fan. In this way the secondary air was independent of the primary burner air. Test results for residual oil firing showed that NO_x was reduced from 177 ppm to 90 ppm (0.22 to 0.11 lb/MMBtu), a 49 percent reduction in NO_x . During these residual oil combustion tests, the burner was operated at 76 percent of stoichiometric conditions, and the overall excess oxygen level was 4 percent.⁷³ However, boiler load was reduced to 50 percent due to combustion instabilities at high loads.

Tests conducted on the same boiler but firing natural gas at 71 percent load had almost no effect on NO_x , showing only 5 percent NO_x reduction, from 70 to 67 ppm (0.084 to 0.080 lb/MMBtu). NO_x reduction for gas-firing may not have been as high as the residual oil-firing case because of the slightly higher test load and because the burner oxygen level was higher, at 90 percent stoichiometry. Also, because natural gas combustion emits lower levels of NO_x than residual oil firing to begin with, it is generally more difficult to achieve as much percentage NO_x reduction with natural gas.

5.3.5.2 Packaged Watertube Boilers

Packaged watertube boilers generally use only one burner, so BOOS is not applicable as a means of achieving staged combustion. As was the case with firetube boilers, retrofit of SCA to smaller packaged watertube units is generally not considered a primary NO_x control option due to the difficulty of retrofitting SCA hardware. Hence, experience on these units has been limited. Data are available for two experimental retrofit applications of SCA in single-burner oil- and gas-fired packaged watertube units. The first application, in a 22 MMBtu/hr unit (Location 19), involved the injection of secondary air through four steel lances which were inserted through the windbox and the refractory firing face. At 83 percent load, NO_x emissions were reduced by 29 percent (controlled NO_x = 157 ppm or 0.20 lb/MMBtu) when residual oil was fired, by 30 percent (controlled NO_x = 77 ppm or 0.10 lb/MMBtu) when distillate oil was fired, and by 46 percent (controlled NO_x = 50 ppm or 0.07 lb/MMBtu) when natural gas was fired.⁷⁴

At the second site, identified as "Location 38," secondary air was injected into a 56 MMBtu/hr boiler through any of 10 SFA ports. This unit was equipped with combustion air preheating, which could vary the temperature from roughly 65 to 176°C (150 to 350°F). At operating conditions of 89 percent load, 2.3 percent excess oxygen, and 14 percent SCA flow,

NO_x was reduced by 42 percent from the baseline, when residual oil was fired. During natural gas firing, staged combustion resulted in a reduction of 32 percent from the baseline conditions at 2.4 percent excess oxygen and 14 percent SCA.⁷⁴ Results from these two applications showed that in order to maximize NO_x reduction using SCA in packaged watertube units, it is necessary to operate the burner at substoichiometric levels, and secondary air must be injected sufficiently downstream of the burner exit to allow for cooling of combustion gases. These types of SCA retrofits on full-scale packaged watertube boilers are generally not considered practical from installation and operational standpoints.

5.3.5.3 Field-erected Watertube Boilers

For field-erected watertube boilers equipped with more than one burner, staged combustion can be achieved by using OFA, BOOS, or biased burner firing. Biased burner firing consists of firing certain burners fuel-rich while other burners are fired fuel-lean. This may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that more fuel is sent to desired burners. Usually, the upper row of burners is fired fuel-lean, but this varies from boiler to boiler.

BOOS is more applicable as an NO_x control technique for natural-gas- and oil-fired boilers than it is for coal-fired units. As mentioned previously, with PC-fired ICI boilers the mill-burner arrangement usually determines which burners can be taken out of service. For this reason, BOOS is more often used as a maintenance operation than a direct NO_x control method. In contrast, with oil or natural gas firing, burners can be shut off individually or fuel flow adjusted to achieve optimum biased burner firing or BOOS operation.

For large wall-fired units, BOOS or biased firing are attractive first level retrofit NO_x control techniques because few equipment modifications are required. For natural gas firing, data compiled for three industrial boilers with BOOS showed NO_x reductions ranging from 17 to 44 percent, with an average of 29 percent reduction from uncontrolled NO_x levels. Controlled NO_x emissions from these units, ranging in size from 60 to 120 MMBtu/hr, were between 117 and 200 ppm (0.14 and 0.27 lb/MMBtu).⁷⁵ For residual oil firing, data from nine boilers using BOOS showed NO_x reduction efficiencies of 5 to 40 percent.

The wide range in control efficiencies is attributed to several factors, including the burner arrangement, the percentage of burners taken out of service, and the overall excess air. Some burner arrangements are more effective in reducing NO_x with BOOS. For example, a

square burner matrix is more effective than an arrangement in which all of the burners are located at the same level. Another controlling factor is stoichiometry of the active burners.

Although operation with BOOS can measurably reduce NO_x , the operating performance of the boiler can be somewhat degraded because of the need to increase excess air in order to control CO, hydrocarbon, and smoke emissions.⁷⁶ Adjustments to the airflow controls, such as burner registers, may be required to achieve the desired burner stoichiometry without increasing these emissions. Also, operation with BOOS usually requires that the unit be derated unless modification to the fuel delivery system is made.⁷⁷

Data on NO_x reductions from field-erected oil- or gas-fired ICI boilers using OFA are very limited. Controlled emissions from two units firing residual oil were from 160 to 180 ppm (0.20 to 0.23 lb/MMBtu).⁵⁷ Application of the technique to utility boilers in California has reportedly resulted in average NO_x reductions of 24 percent for oil and nearly 60 percent for gas.⁷⁸ Generally, OFA is applicable only to large furnaces with sufficient volume above the burners to allow complete combustion and steam temperature control. Because of required hardware modifications, OFA for large gas and oil wall-fired units is often not a preferred retrofit control as BOOS can offer similar reduction efficiency at less cost.⁷⁹

5.3.6 Combined Combustion Modification NO_x Controls for Natural-gas- and Oil-fired ICI Boilers

Many retrofits have utilized combinations of the above combustion modification methods. The most demonstrated combination is the use of LNB with FGR. As mentioned earlier, retrofit of combined LNB and FGR controls to existing packaged boilers is often more feasible than using FGR alone. Also, combined retrofit of FGR and LNB to ICI boilers is considered by some to be a way of meeting stringent NO_x control regulations without using flue gas treatment controls.⁸⁰ Data have been collected for 101 natural-gas-fired units, 44 distillate-oil-fired boilers, and 13 residual-oil-fired boilers (see Appendices B and C). All were watertube boilers, the majority located in California. Many of the California boilers were existing units retrofitted with LNB/FGR controls.

NO_x reduction efficiencies of 55 to 84 percent were reported for five units firing natural gas. No baseline uncontrolled NO_x data were available for the other boilers; thus, reduction efficiencies could not be calculated. Nearly all California units reported controlled NO_x emissions at or below 40 ppm (0.05 lb/MMBtu), while the non-California units reported NO_x levels between 40 and 170 ppm (0.05 to 0.20 lb/MMBtu). For the distillate-oil-firing units, baseline uncontrolled NO_x levels were not available; thus, NO_x reduction efficiencies could not

be determined. Controlled emissions ranged from 30 to 200 ppm (0.04 to 0.25 lb/MMBtu). For the residual-oil-firing units, controlled NO_x levels were between 80 and 435 ppm (0.10 to 0.55 lb/MMBtu).

While some experience has been obtained in combining SCA with LNB or FGR, these have involved new or experimental test units. In general, applications of SCA with LNB or FGR are limited to new units because of the costs involved in installing SCA in existing units, especially in packaged boilers. The use of SCA with an LNB in a new 140 MMBtu/hr natural-gas-fired watertube boiler resulted in controlled NO_x emissions of 64 ppm (0.08 lb/MMBtu), while in a new 150 MMBtu/hr residual-oil-fired boiler the controlled NO_x level was 175 ppm (0.22 lb/MMBtu).⁸¹ Coen Company reports controlled NO_x emissions from 85 to 170 ppm (0.10 to 0.20 lb/MMBtu) for nine boilers with LNB and SCA, firing natural gas or distillate oil. For 11 units firing residual oil, NO_x ranged from 160 to 315 ppm (0.20 to 0.40 lb/MMBtu).⁵⁷ In general, however, the retrofit of SCA is applicable mainly to large industrial boilers.

5.3.7 Fuel Switching

Because fuel-bound nitrogen plays such an important role in total NO_x emissions from fuel combustion in boilers, switching from high-nitrogen fuels, such as coal or residual oil, to lower nitrogen fuels, such as distillate oil or natural gas, is a strategy that can be as effective in reducing NO_x as any other combustion control. Low-nitrogen fuels, such as distillate oil and natural gas, can be used to displace a fraction of the coal or residual oil, or replace them entirely. In either case, significant NO_x reductions are possible. For example, the cofiring of natural gas with coal in utility boilers has reduced NO_x emissions by a minimum of 10 to 30 percent, depending on the boiler, coal, cofiring configuration, and amount of gas firing.⁸² The use of 33 percent natural gas in a gas cofiring configuration in the top row of burners of a PC-fired boiler (representing a more strategic way to maximize NO_x reduction efficiency with reburning techniques) can result in larger NO_x reductions reaching 35 to 60 percent from uncontrolled levels.⁸² Figure 5-23 illustrates NO_x reduction as a function of gas cofiring rate, expressed as a percentage of total heat input, measured during six full-scale utility boiler cofiring field tests. These results are applicable, in theory, to large PC-fired industrial boilers.

The replacement of high-nitrogen residual oil with a lower nitrogen fuel or natural gas is also very effective in reducing NO_x. To illustrate, the data shown in Table 5-10 were obtained from industrial boilers firing a residual oil first, and then switching to a distillate fuel.² NO_x reductions ranged from about 50 to 80 percent for reductions in fuel oil nitrogen of

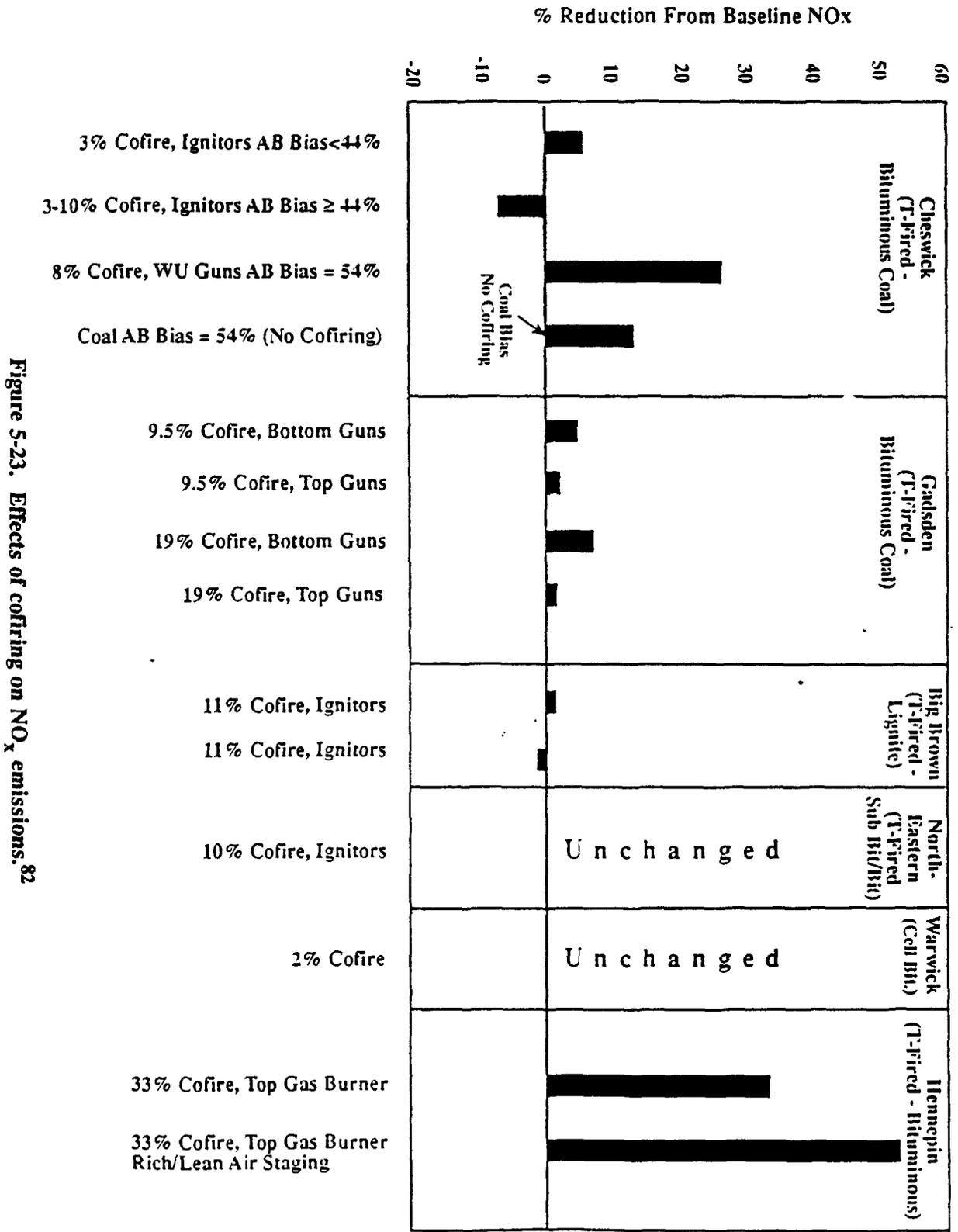


Figure 5-23. Effects of cofiring on NO_x emissions.⁸²

TABLE 5-10. EFFECTS OF SWITCHING FROM RESIDUAL OIL TO DISTILLATE FUEL ON INDUSTRIAL BOILERS

Fuel type	Fuel nitrogen, % weight	NO_x emissions @ 3% O₂
Residual oil	0.44	350
Distillate oil	0.006	65
Residual oil	0.27	298
Distillate oil	0.015	127
Residual oil	0.20	186
Distillate oil	0.014	84
Residual oil	0.20	220
Distillate oil	0.008	114

Source: Reference 2.

approximately 0.19 to 0.436 percent by weight. If all the recorded NO_x reduction is attributed to the drop in fuel nitrogen, about 55 to 65 ppm reduction in NO_x results from each 0.1 percentage point reduction in the nitrogen content of the oil. Table 5-11 lists estimates of NO_x reductions attainable from ICI boilers cofiring or switching to a cleaner fuel.

In addition to natural gas and low-nitrogen fuel oil, the Shell Oil Company is marketing a proprietary liquid fuel for industrial boilers. This proprietary fuel is similar to distillate oil in thermal energy and physical properties, but contrary to distillate oil it contains essentially no fuel-bound nitrogen (3 to 9 ppm). Therefore, its NO_x emissions are similar to those achievable with natural gas.⁸³ Short-term performance with this proprietary fuel show FGR-controlled emissions in the range of 18 to 35 ppm corrected to 3 percent O₂ (0.022 to 0.042 lb/MMBtu). It is used as a standby liquid fuel for many boilers in Southern California in cases where natural gas is curtailed.

5.3.8 Combustion Modification NO_x Controls for Thermally Enhanced Oil Recovery (TEOR) Steam Generators

NO_x controls for TEOR steam generators have also been implemented primarily in California, due to stringent NO_x emission regulations. For instance, in Kern County, California, over 2,000 oil field steam generators are in use, the majority fired on crude oil.^{84,85} Other fuels

TABLE 5-11. ESTIMATES OF NO_x REDUCTIONS WITH FUEL SWITCHING

Base fuel	Replacement fuel	Quantity used, %	Estimated NO_x reduction, %
PC	Natural gas	10-20	10-30
		10-20 (reburning zone)	30-60
		100	60-70
Residual oil with 0.6% N	Natural gas	100	50-80
	Distillate oil	100	50-80
	Residual oil with 0.3% N	100	30-40

Note: All emissions data were obtained from short-term tests.

used in these boilers include natural gas and refinery gas. Nearly all units in Kern County utilize some form of combustion modification NO_x control, including OT systems, LNB, or FGR.⁸⁴

5.3.8.1 OT Systems

OT systems or controllers limit the excess oxygen during combustion to reduce the formation of NO_x. It has been reported that these devices typically reduce the formation of NO_x from small steam generators (<35 MMBtu/hr input capacity) by 15 to 25 percent.⁸⁶ Controlled NO_x emissions from 71 tests conducted on small crude-oil-fired steam generators in Kern County ranged from 166 to 398 ppm (0.21 to 0.50 lb/MMBtu).⁸⁷ For larger units greater than 35 MMBtu/hr (most 62.5 MMBtu/hr), Kern County data from 326 tests showed controlled NO_x levels ranging between 174 and 340 ppm (0.22 and 0.43 lb/MMBtu). No uncontrolled data were reported for these units; thus, it was not possible to report actual NO_x reduction efficiencies. However, assuming a typical uncontrolled NO_x level of 300 ppm (0.38 lb/MMBtu), as reported in References 49 and 88 for large TEOR units in Kern County, average NO_x reduction on the order of 17 percent was achieved. It should be remembered that this is only an average value, based on average emission levels and average reported baseline levels. Actual NO_x reduction efficiencies may have been significantly higher or lower depending on the fuel characteristics, combustion conditions, and design type of each unit. The average levels are illustrative to a certain degree, however, as most TEOR steam generators are similar in design and all of the units tested fired Kern County crude.⁸⁴

5.3.8.2 LNBS with SCA and OT

LNB systems, which generally are used with O₂ controllers, have been applied primarily to large (35 to 62.5 MMBtu/hr) crude oil-fired steam generators. The most effective and widely used LNB systems also incorporate SCA, usually using sidefire air injection. In fact with TEOR steam generators it is common to describe a combined LNB+SCA system as either an LNB or an SCA system.^{86,87,89} Figure 5-24 depicts one type of LNB+SCA system, manufactured by the North American Company, the principal vendor of LNB systems for TEOR steamers. This burner system is being used on over 100 crude oil-fired generators in Kern County. Minor modifications are made to a standard burner and secondary air injection nozzles are inserted around the circumference of the furnace at various locations in the radiant heat transfer section. In a 62.5 MMBtu/hr steam generator, 28 secondary air injection ports are used, positioned 17 to 27 feet downstream of the burner. In most applications of this burner system, O₂ controllers are used to keep excess oxygen at the stack below 2 percent. NO_x emission levels of 100 to 160 ppm (0.13 to 0.20 lb/MMBtu) have been reported when crude oil is fired, representing 50 to 70 percent NO_x reduction when compared to unstaged conventional North American burners.⁸⁹

Another type of LNB system applicable for retrofit to TEOR steam generators is the single toroidal combustor, developed by Process Combustion Corporation (Figure 5-25). The single toroidal combustor is a two-stage burner in which approximately one-third of the fuel is combusted under highly reducing, turbulent conditions inside a precombustion chamber. The remaining two-thirds of the fuel is combusted in a secondary burnout zone at the entrance to the steam generator. The second stage is arranged so that the addition and mixing of 5 to 10 percent secondary excess air takes place in the high-velocity jet of flame emitted from the chamber throat inside the firebox.⁹⁰ The vigorous internal recirculation and mixing within the fuel-rich precombustion chamber aids in NO_x reduction, while combustion gases are entrained into the high-velocity flame of the secondary combustion zone, lowering the peak flame temperature. Results of 50 separate field tests using this burner showed average NO_x reductions of 60 percent, with average emissions of 125 ppm (0.16 lb/MMBtu) for 62.5 MMBtu/hr sized units and 150 ppm (0.19 lb/MMBtu) for 25 to 30 MMBtu/hr units. Controlled NO_x levels ranged from 90 to 225 ppm (0.11 to 0.28 lb/MMBtu).⁹¹

A third type of LNB for TEOR steam generators utilizes a split flame arrangement, whereby an inner fuel-rich diffusion flame is separated from an outer fuel-lean premix flame

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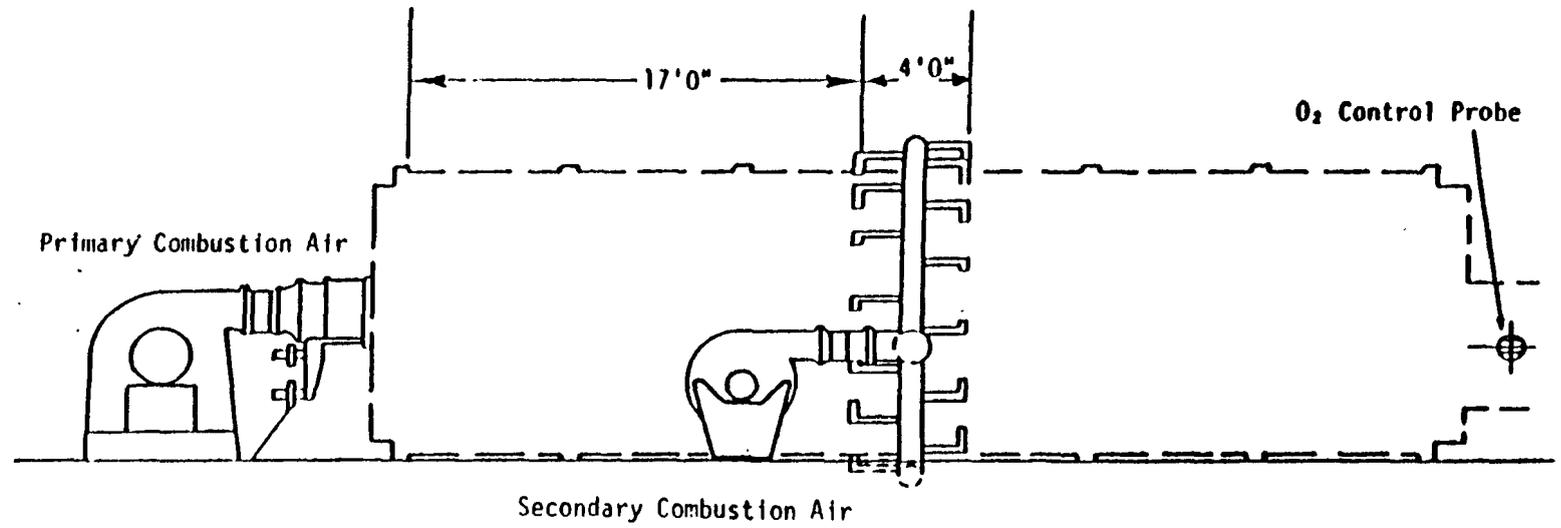


Figure 5-24. North American LNB on oil field steam generator.⁹²

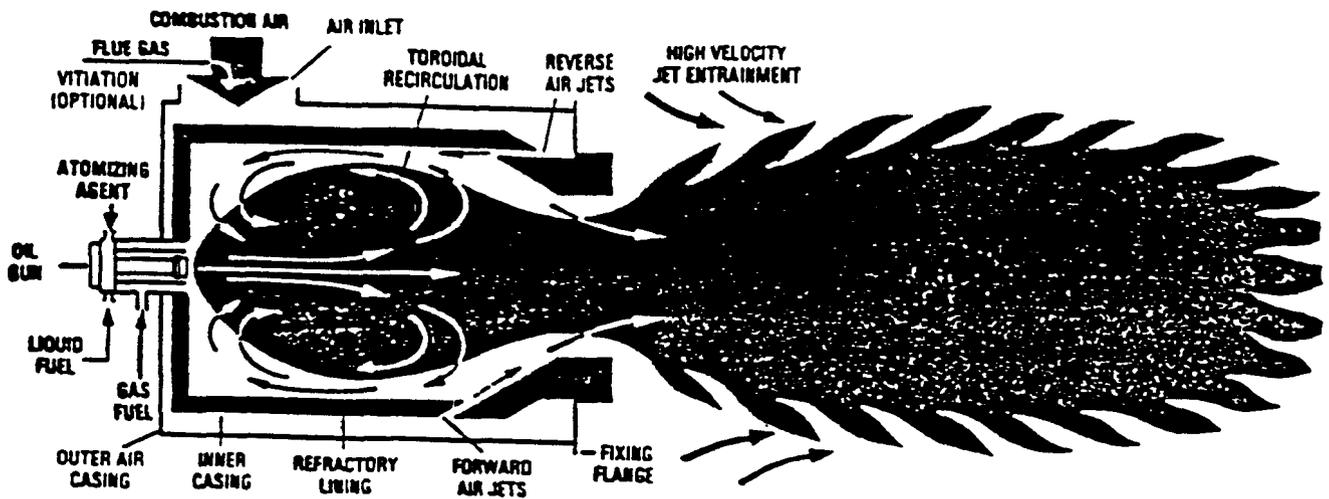


Figure 5-25. Process Combustion Corporation toroidal combustor.⁹⁰

by a blanket of recirculated flue gas. This burner, the MHI PM low- NO_x burner, illustrated schematically in Figure 5-26, was retrofitted to a 62.5 MMBtu/hr crude-oil-fired steam generator as part of an EPA-sponsored test program on a demonstration unit. No additional TEOR steamers have been retrofitted with this burner. Full-load NO_x emissions of 110 ppm (0.14 lb/MMBtu) were obtained with what were deemed "acceptable" smoke and CO emissions (<100 ppm CO). This compares to emissions of approximately 300 ppm (0.38 lb/MMBtu) measured from an identical generator equipped with a conventional burner.⁹³ Thus, NO_x was reduced by 63 percent.

Most LNB retrofit experiences have been with crude-oil-fired units larger than 35 MMBtu/hr. Results from 134 tests conducted on such units in Kern County show controlled NO_x levels of 87 to 232 ppm (0.11 to 0.29 lb/MMBtu). Because no baseline data were available, it was impossible to calculate NO_x reduction efficiencies for these tests. However, these controlled emissions may be compared to the generally accepted average baseline of 300 ppm for Kern County crude oil firing.^{84,88} For illustrative purposes, comparing average controlled emissions to this average baseline, 59 percent NO_x reduction was achieved with LNB systems. Again, however, it must be remembered that actual efficiencies may have varied significantly from unit to unit. Limited test data are available for natural gas fired units equipped with LNB. Data for two 62.5 MMBtu/hr gas-fired generators showed NO_x reductions of 8 and 28 percent.

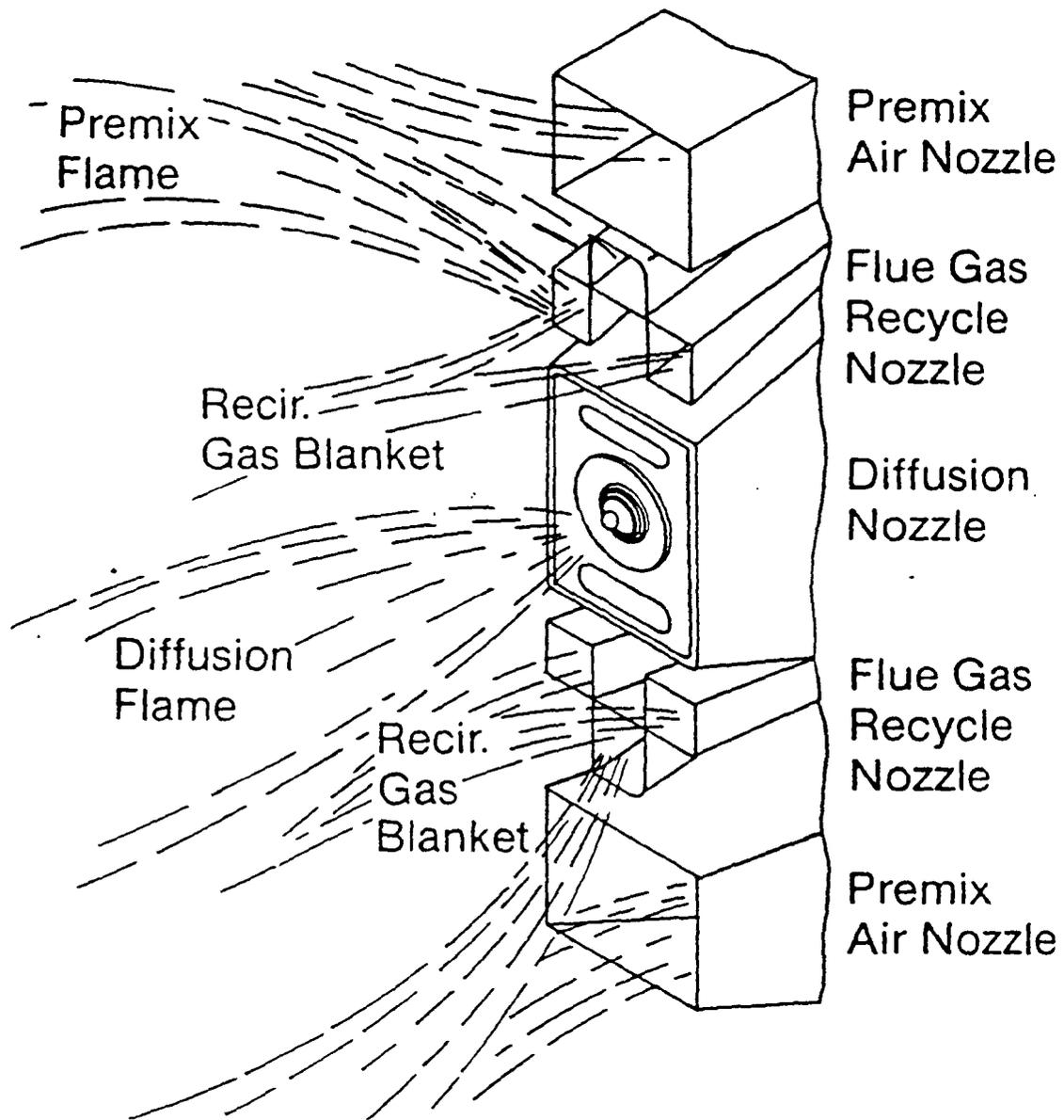


Figure 5-26. The MHI PM burner nozzle.⁹³

Because of the limited data, however, no conclusions can be drawn about typical reduction efficiencies for LNB gas firing.

LNB systems have also been applied on a very limited basis to steam generators smaller than 35 MMBtu/hr. Reported NO_x emission reductions range from 30 to 60 percent for these units.⁸⁶ The limited application of LNB to small generators is due to the longer and wider flame produced by the LNB and the geometry of small steam generators. Because the radiant section in small generators is shorter in length and diameter than the radiant section in large generators, flame impingement is more of a problem.⁸⁶ Thus, LNB retrofits are primarily applicable to TEOR steam generators larger than 35 MMBtu/hr.

5.3.8.3 FGR and OT

FGR systems have been applied to TEOR steam generators on a more limited basis than LNB systems. Results from Kern County tests of 36 crude-oil-fired steam generators with FGR and O₂ trim showed controlled NO_x levels similar to those obtained with LNB systems, ranging from 79 to 264 ppm (0.10 to 0.33 lb/MMBtu).⁸⁷ Thus, for crude oil firing, FGR controls appear as effective as LNB systems in reducing NO_x. For natural gas firing, tests of three large units using FGR in combination with LNB measured controlled emission levels of 25 to 35 ppm (0.03 to 0.04 lb/MMBtu). NO_x reduction for two of these units ranged from 50 to 68 percent. For these particular units, these reductions in NO_x represent significant improvement over NO_x reduction efficiencies obtained using LNB alone.^{56,88} Data are too limited, however, to characterize the performance of FGR controls used with natural-gas-fired TEOR steam generators.

5.3.9 Gas Fuel Flow Modifiers

In addition to the combustion techniques discussed thus far, a device known as a gas turbulator has been demonstrated to reduce NO_x formation in natural-gas-fired packaged boilers. Originally designed to produce savings in fuel consumption, the turbulator is a small stainless steel venturi incorporating strategically placed fins. The turbulator is inserted in the gas pipe directly upstream of the burner, creating highly turbulent fuel flow. This turbulence facilitates the bonding of hydrocarbon particles with the oxygen molecules of the combustion air, resulting in increased combustion efficiency.⁹⁴ Fuel savings typically range between 2 and 10 percent, but have been as high as 35 percent.⁹⁵

From an NO_x standpoint, the more efficient turbulent mixing of the fuel and air results in lower excess air requirements for efficient combustion, producing lower levels of NO_x.^{94,95}

The only turbulator-related NO_x emissions data available to date are for a 33.5 MMBtu/hr natural-gas-fired firetube boiler at Duncan Boiler Service, Inc., in Kenner, Louisiana. At this site, the use of a turbulator raised full-load boiler efficiency by 3 percent, and the improved air/fuel mixing reduced the required excess oxygen by 27 percent. Consequently, NO_x emissions were reduced from 58 to 35 ppm at 3-percent oxygen, a 40-percent decrease.⁹⁶

5.4 COMBUSTION MODIFICATIONS FOR NONFOSSIL-FUEL-FIRED ICI BOILERS

Application of combustion modification NO_x controls to nonfossil-fuel-fired ICI boilers is very limited. Many waste-fuel-fired boilers are not easily modified to reduce NO_x without compromising combustion efficiency and byproduct emissions. Furthermore, nonfossil fuels include a variety of waste fuels with varying combustion characteristics and pollutant profiles. Consequently, adaptation of conventional combustion controls can be difficult and very site-specific. Currently, more attention has focused on the application of flue gas treatment controls to nonfossil-fuel-fired ICI boilers, especially in California, where flue gas treatment controls have been applied to at least 17 units fired on wood or MSW. These applications are discussed in Section 5.3.

Combustion modification retrofit experience has been limited to the use of SCA. In one wood-/natural-gas-fired overfeed stoker unit, equipped with four gas burners as well as a traveling grate for wood firing, staged combustion was achieved by removing one of the four gas burners from service. Although 20 percent NO_x reduction was achieved, it should be noted that combustion modification was applied to the gas burners without any change to the wood-firing stoker system. This control approach would not be possible on boilers without supplemental gas firing. Difficulties were experienced with fluctuating bark flows, resulting in unsteady combustion conditions.⁷⁴

Applications of combustion modifications to new nonfossil-fuel-fired units involve MSW-fired boilers equipped with FGR and natural gas reburn controls. Gas reburn for MSW boilers is being developed by Riley Stoker and Takuma Company, for NO_x control purposes and to suppress the formation of air toxic organics and combustible emissions.⁹⁷ In a 45 MMBtu/hr overfeed stoker MSW facility in Minnesota, NO_x emissions were reduced by 40 percent using FGR. When natural gas reburn was used in combination with FGR, NO_x was reduced by 60 percent, to a controlled level below 50 ppm. CO emissions were also decreased by 50 percent, to levels below 25 ppm. Natural gas reburn represented 12 to 15 percent of the total heat input, and FGR rates during these tests were roughly 8 percent.⁹⁷ Test results from a pilot-scale

MSW-fired stoker boiler equipped with FGR and natural gas reburn showed 49 percent NO_x reduction efficiency, utilizing 17 percent FGR.^{98,99} Because of the limited documented experiences regarding the retrofit of combustion modifications to existing nonfossil-fuel-fired boilers, no meaningful conclusions can be reached as far as NO_x control effectiveness or feasibility.

5.5 FLUE GAS TREATMENT NO_x CONTROLS FOR ICI BOILERS

NO_x control with flue gas treatment involves the reduction of NO_x in the flue gas by injecting a chemical reducing agent into the post-combustion region of a combustion unit. The reducing agents, primarily ammonia and urea, convert the NO in the flue gas to molecular nitrogen at high temperatures, between 870 and 1,100°C (1,600 and 2,000°F), without a catalyst. When a catalyst is used, this conversion takes place at a lower temperature range, roughly 300 and 425°C (575 to 800°F). Flue gas treatment methods without a catalyst are SNCR, while those with a catalyst are termed SCR. These methods are discussed in the following subsections.

Retrofitting these technologies to boilers typically involves installation of reagent injection nozzles, reagent storage and control equipment, and, in the case of SCR, catalytic reactors. Because flue gas treatment NO_x reduction efficiency depends in large part on flue gas temperature, injection nozzle placement is limited to those locations where acceptable process temperatures are present. Generally, in packaged ICI boilers, available locations for reagent injection and catalyst placement are further limited by space considerations. These units may also operate with wide ranges in boiler steam load that cause flue gas temperature shifts outside the optimum temperature window. Injection of reagents outside the optimum reaction temperature window results in lowered NO_x reduction efficiency and emissions of unreacted ammonia. SNCR and SCR controls have been applied primarily to larger boilers or new packaged boilers because these applications offer better control of temperature window and steady load demands.

5.5.1 Selective Noncatalytic Reduction (SNCR)

Two primary types of SNCR control technologies are currently available for retrofit to ICI boilers. The first is based on the use of ammonia (NH₃) as the reducing agent, while the second, more recently introduced, is based on the use of urea (NH₂CONH₂). Several urea-based systems have been patented and are commercially offered by several domestic vendors. The following subsections briefly describe the experience to date using these controls on ICI boilers. Available data for SNCR application to industrial boilers are contained in Appendix B and

summarized in Table 5-12. Generally, similar NO_x reduction efficiencies were obtained whether ammonia or urea was used. For ammonia injection, NO_x reduction ranged from 50 to 80 percent, depending on fuel type. For urea-based systems, most reported NO_x reduction efficiencies also fell within this range, although some were as low as 25 percent and as high as 88 percent. Experience with SNCR on smaller capacity boilers is minimal. Low-load operation and frequent load changes on such boilers pose additional complexities on the retrofit of SNCR for these boilers.

5.5.1.1 Ammonia-based SNCR

Exxon Research and Engineering Company developed and patented an ammonia-based SNCR process known as Thermal De NO_x ®. The Thermal De NO_x process is based on a gas phase homogeneous reaction between NO_x and ammonia which produces molecular nitrogen and water at high temperature. In this process, aqueous or anhydrous ammonia is vaporized and injected into the flue gas through wall-mounted nozzles at a location selected for optimum reaction temperature and residence time. The optimum reaction temperature range for this process is 870 to 1,100°C (1,600 to 2,000°F), although this can be lowered to 700°C (1,300°F) with additional injection of gaseous hydrogen.¹⁰⁰ At temperatures above 1,100°C (2,000°F), ammonia injection becomes counterproductive, resulting in additional NO formation. Below 870°C (1,600°F), the reaction rate drops and undesired amounts of ammonia are carried out in the flue gas. Unreacted ammonia is commonly referred to as ammonia slip, breakthrough, or carryover.¹⁰¹ The amount of ammonia slip also depends in part on the amount of ammonia injected. Although the chemical reaction requires one mole of NH_3 for each mole of NO, the NH_3/NO_x ratio used is usually greater than 1 to avoid an undesired reaction which results in formation of NO.¹⁰⁰ NH_3/NO_x ratios of 4 to 1 have been reported in fluidized bed applications.¹⁰² Ratios used are usually greater than 1 due to competing reactions at the temperatures involved.

The Thermal De NO_x process has been applied to a number of boilers firing both fossil and nonfossil fuels. In the U.S., most Thermal De NO_x applications have been on new units, many located in California. At least two retrofit applications on wood-fired industrial boilers have also been reported, one to a 375 MMBtu/hr wood-fired stoker unit and one to a 210 MMBtu/hr boiler, also a wood-fired stoker.¹⁰⁰ Both retrofits resulted in 50 percent NO_x reduction, with controlled emissions of 45 and 50 ppm (0.06 and 0.07 lb/MMBtu).

TABLE 5-12. SNCR NO_x CONTROL FOR ICI BOILERS

Reagent	Description of technique	Fuel type	Number of industrial boilers tested	% NO _x reduction	Controlled NO _x levels		Comments
					ppm @ 3% O ₂	lb/MMBtu	
Ammonia	Injection of ammonia into flue gas to chemically reduce NO _x	Natural gas/oil	11 FE-WT ^a	50-72	25-160	0.03-0.20	Temperature window between 870 and 1,100°C (1,600 and 2,000°F). Most data are for Thermal DeNO _x [®] .
			5 PKG-WT ^b	30-65	N.A. ^c	N.A.	
		Coal	4 FBC	76-80	30-65	0.04-0.087	
			4 stoker	50-66	110-132	0.15-0.18	
			1 PC ^d	57	135	0.18	
Wood	10 stoker	50-80	25-160	0.035-0.23			
	8 FBC	44-80	24-140	0.035-0.20			
MSW	13 stoker	45-79	48-195	0.068-0.28			
Urea	Injection of urea into flue gas to chemically reduce NO _x	Natural gas/oil	7 FE-WT	50-60	41-104	0.049-0.13	Most data are for NO _x OUT [®] .
			Coal	4 FBC	57-88	21-106	
		4 PC		30-83	110-300	0.15-0.41	
		9 stoker		40-74	105-210	0.14-0.28	
		Wood	14 stoker	25-78	60-118	0.084-0.17	
			2 PKG-WT	50	178-187	0.24-0.26	
			2 FBC	60-70	45-50	0.063-0.070	
1 cell	52	96	0.14				
MSW	13 stoker	41-75	44-210	0.062-0.30			

^aFE-WT = field-erected watertube.

^bPKG-WT = packaged watertube.

^cN.A. = Not available in reference source used.

^dBoiler burning coke in Japan.

Overall, experience with ammonia-based SNCR on both new and existing units has shown the following results, listed in Table 5-12. NO_x reduction ranged from 50 to 80 percent for 10 wood-firing stokers and between 44 and 80 percent for eight wood-firing FBC units. For 13 MSW-fired units, NO_x reduction ranged from 45 to 79 percent, while for four coal-fired FBC units, 76 to 80 percent reductions were achieved. Several natural-gas-fired furnaces experienced 30 to 72 percent NO_x reduction. In addition to these applications, it has been reported that ammonia-based SNCR has been used on over 100 TEOR steam generators burning crude oil in Kern County, achieving reductions of approximately 70 percent.¹⁰³ Thus, for all applications, ammonia-based De NO_x reduced NO_x by roughly 30 to 80 percent. The upper range of NO_x reduction efficiency range is more characteristic of boilers operating at steady load such as cogeneration FBC units.

Achievable NO_x reductions for an individual boiler depend on the flue gas temperature, the residence time at that temperature, the initial NO_x concentration, the NH_3/NO_x ratio, the excess oxygen level, and the degree of ammonia/flue gas mixing. Also, stratification of both temperature and NO_x in the flue gas can affect the performance of the SNCR control.¹⁰⁴ The optimum placement of SNCR injectors requires a detailed mapping of the temperature profile in the convective passes of the boiler, because of the narrow temperature window. According to Exxon, the Thermal De NO_x process has no measurable effect on CO , CO_2 , or SO_x emissions.¹⁰⁰

The feasibility of retrofitting an existing boiler with SNCR often hinges on the ability to accommodate injection nozzles at a location where flue gas temperatures and residence time are optimum for the reaction to take place. In field-erected boilers, the ammonia is usually injected into either a superheater tube bank or between a superheater tube bank and the steam generator tube bank,¹⁰³ while, for a typical wood-fired stoker boiler, injectors are usually located before the first superheater coil. In a coal or wood-fired CFBC boiler, ammonia injectors are usually located after the cyclone to avoid high solids and NH_3 recirculation.¹⁰⁰ Smaller units, especially packaged watertube and firetube boilers, have limited space and access for the injection nozzles.

5.5.1.2 Urea-based SNCR

Originally developed by the Electric Power Research Institute (EPRI), a newer SNCR technology for flue gas treatment NO_x control utilizes urea as a reagent rather than ammonia. One urea-based SNCR process, known by the trade name of NOxOUT[®], is offered by Nalco

Fuel Tech, Inc., and its licensees (Foster Wheeler, Wheelabrator Air Pollution Control, Research Cottrell, Todd Combustion, RJM Corporation, and several others internationally). Other vendors, such as Applied Utility Systems and Noell, Inc., have also developed and installed urea-based SNCR processes. In the NO_xOUT process, an aqueous solution containing urea and chemical enhancers is injected into the furnace or boiler at one or more locations, depending on the boiler type and size. The urea reacts with NO_x in the flue gas to produce nitrogen, carbon dioxide, and water. The main advantage of urea injection over ammonia injection is that urea is a nontoxic liquid that can be safely stored and handled.

Like ammonia injection, NO_xOUT is effective only within a certain temperature range. Without the use of chemical enhancers, urea injection effectively reduces NO_x at temperatures between 900 and 1,150°C (1,650 and 2,100°F). Residence time at temperature of interest is important. By using proprietary enhancers and adjusting concentrations, greater NO_x reduction efficiency can be achieved over a wider temperature window. If the urea is released at too high a temperature, the chemical species can actually be oxidized to form NO_x. Below this temperature, urea reacts with NO_x to form undesired amounts of ammonia. Table 5-12 lists NO_x reduction efficiencies of 25 to 88 percent, reported for different types of boilers burning coal, oil, MSW, and wood which have been retrofitted with urea injection. As with Thermal DeNO_x, actual reduction performance is highly dependent on temperature, amount of reagent used, and level of reagent/NO_x mixing.¹⁰⁵ Most of the commercial experience includes MSW-, wood-, and coal-fired stokers, and gas-fired boilers and incinerators. These applications have been on new and existing units. Successful demonstrations are documented on oil- and coal-fired boilers in the utility industry. NO_x reductions of as low as 10 percent to as high as 76 percent have been recorded for utility boilers. An average NO_x reduction performance of 45 percent is estimated for PC-fired boilers.¹⁰⁶ Due to residence time and temperature constraints, small packaged watertube and firetube boilers with fluctuating steam loads are difficult applications, and require case-by-case determinations for cost and performance levels.

5.5.2 Selective Catalytic Reduction (SCR)

The SCR process takes advantage of the selectivity of ammonia to reduce NO_x to nitrogen and water at lower temperature in the presence of a catalytic surface. Two catalyst formulations are denoted "base metal," this category including oxides of titanium, molybdenum, tungsten, and vanadium, and zeolites, which are alumina-silicate-based. These formulations may include other components that impart structural stability. Catalysts come in various shapes and

sizes, according to the particular application. Gaseous ammonia is injected with a carrier gas, typically steam or compressed air, into the flue gas upstream of the catalyst. The ammonia/flue gas mixture enters the catalyst, where it is distributed through the catalytic bed. The flue gas then leaves the catalytic reactor and continues to the exit stack or air preheater. SCR technology is capable of achieving similar NO_x reductions as Thermal De NO_x SNCR using a much smaller amount of ammonia, due to the positive effects of the lower reaction temperature and the selective catalyst.¹⁰¹ Because of this, ammonia slip tends to be less with SCR than with SNCR.

SCR operates most efficiently at temperatures between 300 and 425°C (575 and 800°F) and when the flue gas is relatively free of particulate matter, which tends to contaminate or "poison" the catalytic surfaces.^{101,107} Recent catalyst formulations can resist poisoning and abrasion in flue gas environments with high ash loading and trace metals, while maintaining NO_x reduction performance. Typically, the catalytic reactor is located ahead of the air heater, to take advantage of the temperature regime. Sometimes, however, the reactor may be placed just ahead of the stack and downstream of particulate collection devices, avoiding catalyst contamination. In most cases, however, such placement requires reheating of the flue gas to meet temperature requirements, impacting the cost of the system. To avoid reheat requirements, some manufacturers are currently developing or have already developed special low-temperature catalysts which can be used at temperatures as low as 200°C (400°F).¹⁰⁷

SCR has seen very limited application on domestic ICI boilers. Table 5-13 shows a selected list of SCR applications on industrial boilers in California. A more complete list of SCR installations on ICI boilers is included in Appendix B. Most of the industrial applications of this control technology have been in Japan, where much of the original SCR technology development took place. Within the industrial sector, SCR has been applied primarily to gas- or oil-fired units, as well as a few PC-fired units or coal-fired BFBCs. SCR has not yet been demonstrated in CFBC units or stoker coal-fired boilers. However, it was recently announced that SCR will be incorporated into the design of a 220 MWe stoker coal-fired power plant in Virginia, as well as a 125 MWe CFBC in Sweden.^{108,109} Major suppliers of SCR catalysts include MHI, Babcock Hitachi, Cormetech, Engelhard, Johnson Matthey, and Norton.

Table 5-14 summarizes performance data for SCR applications to boilers in the ICI sector. Data from Japanese oil-fired industrial boilers retrofitted with SCR show NO_x reductions ranging from 85 to 90 percent. These units had controlled NO_x levels between 17 and 25 ppm (0.02 and 0.03 lb/MMBtu), operating with flue gas treatment temperatures of 300 to 370°C (575

TABLE 5-13. SELECTED SCR INSTALLATIONS, CALIFORNIA ICI BOILERS

Boiler ID	Boiler type	Capacity, MMBtu/hr	Fuel used	Controlled NO _x emissions	
				ppm @ 3% O ₂	lb/MMBtu
Darling-Delaware	PKG-WT ^a	110	Natural gas/ propane	9	0.011
Fletcher Oil and Refining	Unknown	49	Distillate oil	20	0.025
Lockheed	PKG-WT	N.A. ^b	Natural gas/ distillate oil	9	0.011
Kalkan Foods, Inc.	PKG-WT	78.6	Natural gas/ methanol	9	0.011
Ultramar Refinery	PKG-WT	N.A.	Refinery gas	11	0.011
Southern California Edison	Unknown	107 MWe	Natural gas	20	0.024

^aPKG-WT = Packaged watertube boiler.

^bN.A. = Not available.

TABLE 5-14. SCR NO_x CONTROLS FOR ICI BOILERS

Description of technique	Fuel type	Number of industrial boilers tested	% NO _x reduction	Controlled levels		Comments
				ppm @ 3% O ₂	lb/MMBtu	
Injection of ammonia into flue gas to chemically reduce NO _x	Oil	7	85-90	17-25	0.022-0.032	Temperature window between 300 and 425°C (575 and 800°F).
	Natural Gas	3	53-80	9-46	0.011-0.055	
	Coal	2	53-63	72-110	0.097-0.15	
	Ref. gas	4	83-94	9-11	0.011-0.013	
	MSW	1	53	36	0.051	
	Wood waste	2	80	154	0.22	

to 700°F).¹⁰⁹ Specific information was not available on the types of oil fired in these boilers or on boiler operating conditions; therefore, these reported NO_x levels should not be used to extrapolate controlled NO_x levels for all oil-fired boilers.

Similar reduction efficiencies of 83 and 94 percent were obtained on units firing refinery gas.¹¹⁰ One of these units was located in Japan, the others at a California refinery. Results from tests conducted on three natural-gas- and two coal-fired boilers with SCR showed more moderate reduction efficiencies of 53 to 80 percent. Likewise, a single MSW-fired unit experienced 53 percent NO_x reduction with SCR.¹⁰¹ In summary, NO_x reduction efficiencies with SCR have been reported in the range between 53 and 90 percent. Available data are too limited, however, to allow any correlations between fuel type, boiler type, and SCR effectiveness to be made.

The retrofit of SCR to an existing boiler requires far more extensive modifications than does SNCR, as the SCR reactor must be placed in the existing flue gas path where the temperature is sufficiently high for efficient NO_x control. This is in addition to the required installation of reagent injectors and storage and control equipment. The difficulty in retrofitting SCR to existing boilers was reflected in the compliance plans put forth by petroleum refiners in California's South Coast Air Basin, in response to the SCAQMD Rule 1109. Rather than retrofit existing boilers with SCR, many refiners instead opted to replace their old boilers with new units already incorporating SCR.¹¹¹ Because catalysts lose their effectiveness over time due to contamination or clogging of catalyst pores, they must be replaced periodically. On large boilers, it has been reported that catalyst replacement may be necessary every 1 to 5 years, depending on the application and the level of contaminants in the fuel.¹¹²

5.6 SUMMARY OF NO_x REDUCTION PERFORMANCE

Table 5-15 summarizes the reduction efficiencies and controlled NO_x levels for each boiler, fuel, and control combination investigated in this report. Arithmetic average performances are listed, but care must be used in interpreting them. Because these are averages, the data do not represent the NO_x control performance attainable in all cases. Actual performance will be influenced by several factors, including fuel type, degree of control applied, and the boiler's design and operating condition. Because coal and residual oil can vary in nitrogen content and other properties, the actual NO_x level achieved with these fuels will be very much a function of these fuel properties. Certainly, the degree of FGR and air staging applied,

TABLE 5-15. SUMMARY OF NO_x REDUCTION PERFORMANCE

Boiler and fuel	NO _x control	Range in performance		Average performance ^a	
		Reduction efficiency, %	Controlled NO _x , lb/MMBtu	Reduction efficiency, %	Controlled NO _x , lb/MMBtu
PC-fired boilers: all firing types with wall or corner burners	SCA	15-39	0.33-0.93	27	0.62
	LNB	18-67	0.26-0.50	55	0.35
	Reburn + OFA	30-65	0.23-0.52	52	0.34
	LNB + SCA	42-66	0.24-0.49	60	0.38
	SNCR	30-83	0.15-0.40	45 ^b	0.39
Coal-fired stokers	SCA	-1-35	0.22-0.52	18	0.38
	FGR + SCA	0-60	0.19-0.47	24	0.54
	SNCR	40-74	0.14-0.28	58	0.22
Coal-fired FBC	SCA	40-67	0.05-0.45	58	0.18
	FGR + SCA	N.A. ^c	0.12-0.16	N.A.	0.14
	SNCR	57-88	0.03-0.14	74	0.08
	SCR	53-63	0.10-0.15	60	0.12
Gas-fired firetube	LNB	32-78	0.02-0.08	50	0.03
	Radiant LNB	53-82	0.011-0.036	71	0.02
	FGR	55-76	0.02-0.08	65	0.07
	LNB + FGR	N.A.	0.02-0.04	N.A.	0.03
Gas-fired SBWT ^{d,e}	WI	50-77	0.04-0.056	64	0.05
	FGR	53-74	0.02-0.08	64	0.05
	LNB	46-71	0.03-0.11	58	0.08
	LNB : FGR	55-84	0.018-0.09	76	0.06
	SCR	80-91	0.011-0.06	85	0.024

(continued)

^aArithmetic averages of reported control efficiency NO_x levels with specified controls. Values do not necessarily reflect emission targets that can be achieved in all cases.

^bAverage NO_x reduction is based on utility boiler PC experience.

^cN.A. = Not available.

^dSBWT = Single-burner watertube. Also referred to as packaged watertube (PKG-WT).

^eData for gas- and oil-fired watertube boilers are limited to performance reported in Appendix B, exclusive of equipment vendor data reported in Appendix C.

TABLE 5-15. (continued)

Boiler and fuel	NO _x control	Range in performance		Average performance ^a	
		Reduction efficiency, %	Controlled NO _x , lb/MMBtu	Reduction efficiency, %	Controlled NO _x , lb/MMBtu
Gas-fired MBWT ^{e,f}	SCA (BOOS)	17-46	0.06-0.24	31	0.15
	LNB ^g	39-52	0.10-0.17	46	0.12
	SNCR	50-72	0.03-0.19	58	0.10
	SCR ^h	N.A. ^c	0.024	N.A.	0.024
	LNB + SCA	N.A.	0.10-0.20	N.A.	0.15
Distillate firetube	LNB ^g	15	0.15	15	0.15
	FGR	N.A.	0.04-0.16	N.A.	0.12
Distillate SBWT ^{d,e}	LNB	N.A.	0.08-0.33	N.A.	0.10
	FGR	20-68	0.04-0.15	44	0.08
	LNB + FGR	N.A.	0.03-0.13	N.A.	0.07
	SCR ^h	N.A.	0.011	N.A.	0.011
Residual oil firetube	LNB ⁱ	30-60 ^j	0.09-0.25	40	0.17
Residual oil SBWT ^{d,e}	LNB	30-60	0.09-0.23	40	0.19
	FGR	4-30	0.12-0.25	15	0.17
	LNB + FGR ^h	N.A.	0.23	N.A.	0.23
Residual oil MBWT ^{e,f}	SCA	5-40	0.22-0.74	20	0.34
	LNB ⁱ	30-60	0.09-0.23	40	0.19
	LNB + SCA ^h	N.A.	0.22	N.A.	0.22
	SCR ⁱ	58-90	0.025-0.15	85	0.045
Wood-fired stoker	SNCR	25-80	0.04-0.23	58	0.13
Wood-fired FBC	SNCR	44-80	0.035-0.20	64	0.09
MSW-fired stoker	SNCR	41-79	0.06-0.31	60	0.18

^aArithmetic averages of reported control efficiency NO_x levels with specified controls. Values do not necessarily reflect emission targets that can be achieved in all cases.

^cN.A. = Not available.

^dSBWT = Single-burner watertube. Also referred to as packaged watertube (PKG-WT).

^eData for gas- and oil-fired watertube boilers are limited to performance reported in Appendix B, exclusive of equipment vendor data reported in Appendix C.

^fMBWT = Multi-burner watertube. Also referred to as field-erected watertube (FE-WT).

^gMost LNB applications include FGR.

^hOnly one data point available.

ⁱExperience relies primarily on Japanese industrial installations.

^jNo data available. NO_x levels assumed to be on the same order as those reported for single-burner packaged watertubes.

or the amount of ammonia or urea reagent used, will influence the percent reduction efficiency and the NO_x level achieved.

NO_x from pulverized coal combustion in industrial boilers with LNB controls was shown to be controlled to levels ranging from 0.26 to 0.50 lb/MMBtu. These data include results for both tangential- and wall-fired boilers. The average, 0.35 lb/MMBtu, is lower than reported average control levels for utility boilers.¹¹³ Therefore, this average efficiency should be used cautiously, considering the limited data available to this study. Other data show SNCR to be quite effective in reducing NO_x from coal- and waste-fuel-fired FBC and stoker boilers. Average levels for these sources controlled with either ammonia or urea range from 0.08 to 0.22 lb/MMBtu. For gas- and distillate-oil-fired ICI boilers, FGR and LNB controls operating alone or in combination can attain NO_x levels averaging 0.02 to 0.15 lb/MMBtu. Data on residual oil are somewhat more sparse. NO_x control levels from residual-oil-fired boilers are largely influenced by the nitrogen content of the fuel. Combustion controls for these boilers show average controlled levels ranging from 0.17 to 0.34 lb/MMBtu.

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6. COSTS OF RETROFIT NO_x CONTROLS

This chapter evaluates the economic impacts of controlling NO_x from existing ICI boilers. Costing methodologies and assumptions are discussed in Section 6.1. Section 6.2 presents the costs calculated for various NO_x controls retrofitted to ICI boilers. Section 6.3 discussed the capital and total annual costs of NO_x controls. Section 6.4 presents the cost effectiveness of NO_x controls. Supporting documentation, including costing spreadsheets, are included as appendices. Appendix D contains cost effectiveness data for the boilers and control systems analyzed, scaled from annual cost data of Appendices E, F, and G. The latter appendices contain detailed cost analysis spreadsheets developed from actual data provided by vendors, boiler owners, and regulatory agencies.

Whenever possible, cost data from actual retrofit projects were used to develop the cost effectiveness figures presented in Section 6.4. When key cost figures from actual projects were unavailable or not accounted for, however, the cost algorithms and assumptions described in Section 6.1 were used to supplement the available cost data.

6.1 COSTING METHODOLOGY

The costing methodology used in this study is based primarily on the U.S. EPA's OAQPS Control Cost Manual,¹ although certain cost components have been modified specifically for this study, based on conventional costing practice and actual cost data. Costs of retrofit NO_x controls for ICI boilers can be divided into two major cost categories — capital investment costs and annual operations and maintenance (O&M) costs. Capital costs are the total investment necessary to purchase, construct, and make operational a control system. O&M costs are the total annual costs necessary to operate and maintain the control system, above what was required to operate the pre-retrofit boiler without NO_x control. Each of these cost categories can be further subdivided into individual cost components. Section 6.1.1 discusses capital cost components, Section 6.1.2 discusses elements of O&M costs, and Section 6.1.3 describes the methodology for evaluating a control technology's overall cost effectiveness based on these capital and O&M costs.

6.1.1 Capital Costs of Retrofit NO_x Controls

Capital costs of NO_x controls include both direct and indirect cost components. Direct capital costs are expenses required to purchase equipment for the control system, referred to as purchased equipment costs, as well as those expenses required for installing the equipment in the existing boiler, known as direct installation costs. Indirect capital costs are costs entailed in the development of the overall control system, but not attributable to a specific equipment item. These costs are also referred to as indirect installation costs. In addition to direct and indirect components of capital investment costs, contingency costs are also added to account for unpredictable expenses. Figure 6-1 illustrates these principal elements of total capital investment and lists common sub-elements which comprise them. The major capital cost elements are described in detail below.

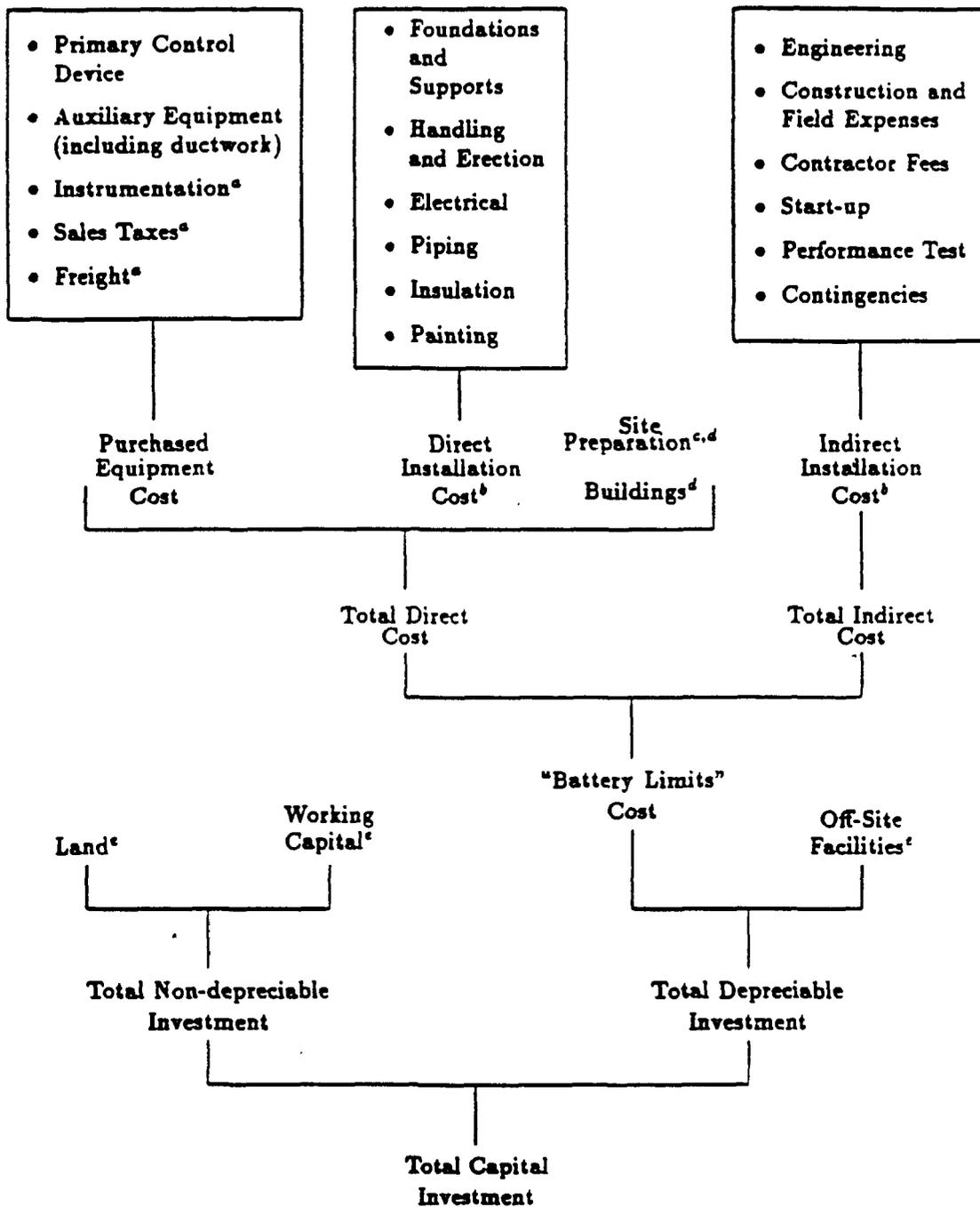
All costs in this chapter and the appendices are presented in 1992 dollars. When available cost data were referenced to other years, the Chemical Engineering Plant Cost Index was used to convert costs to 1992 dollars.²⁻⁴

6.1.1.1 Purchased Equipment Costs

Purchased equipment costs include the costs of primary control equipment, such as low-NO_x burners, FGR fans, or catalytic converters; auxiliary control equipment; instrumentation; and applicable sales taxes and shipping charges. When data were provided, the cost of CEM equipment was also included in the purchased equipment cost. For this study, instrumentation, tax, and freight charges were estimated as being 18 percent of the total primary and auxiliary equipment costs.¹

6.1.1.2 Direct Installation Costs

The second major component of direct capital costs, direct installation costs include both labor and materials costs for foundations, supporting structures, piping, insulation, painting, handling and erection, and electrical work. Direct installation costs vary considerably from site to site and depend on such factors as availability of space, the amount of boiler modification that must be done to accommodate the control system, and existing facilities. Although direct installation costs may vary widely, they were estimated as 30 percent of purchased equipment cost in this study, unless an actual cost figure was provided. This is towards the low end of reported ranges for direct installation cost.^{1,5} When direct installation cost data for new boiler applications were provided by vendors, the figures were doubled to account for additional retrofit



- ^a Typically factored from the sum of the primary control device and auxiliary equipment costs.
- ^b Typically factored from the purchased equipment cost.
- ^c Usually required only at "grass roots" installations.
- ^d Unlike the other direct and indirect costs, costs for these items usually are not factored from the purchased equipment cost. Rather, they are sized and costed separately.
- ^e Normally not required with add-on control systems.

Figure 6-1. Elements of total capital investment cost.¹

expenses.^{1,6} Costs of research and development and the cost of lost production during installation and startup were not included in direct installation cost.

6.1.1.3 Indirect Installation Costs

Indirect installation costs consist of engineering costs, construction and field expenses, construction fees, and expenses associated with startup, performance tests, and permitting. When actual cost data were unavailable, these costs were estimated to be approximately 33 percent of the purchased equipment cost.¹ For SCR retrofits, indirect installation was estimated as 66 percent of purchased equipment cost to account for additional engineering and construction requirements.

6.1.1.4 Contingencies

Contingency costs were added to capital cost estimates to account for additional expenses due to such things as price changes, small design changes, errors in estimation, strikes, or adverse weather conditions. These are unpredictable costs likely to occur.⁵ In the cost spreadsheets of Appendices E, F, and G, contingency costs were estimated primarily as 20 percent of the total direct and indirect capital cost.^{7,8} Cost estimates obtained from selected control vendors already included contingencies. To avoid double accounting, no additional contingency costs were added.

6.1.1.5 Other Capital Costs

Other costs which may be included as capital costs are expenditures for site preparation, buildings, land, and working capital. Site preparation costs are sometimes accounted for in direct installation costs, and in most cases are unreported. Additional buildings are usually not required for retrofit NO_x control systems for ICI boilers, except in cases where existing facilities are absolutely unable to accommodate additional equipment installation. For the purposes of this study, site preparation and building costs were listed in the cost spreadsheets, but were only used if sources provided costs for these items.

Working capital is a fund set aside to cover the initial O&M costs of labor, fuel, chemicals, and other materials for a given time, usually on the order of 90 days.⁷ This fund is primarily used in cost analyses for large systems which require significant amounts of utilities, O&M labor, and materials.¹ Because most of the control systems considered in this study do not require large amounts of utilities, O&M labor and materials, working capital costs were not included in this study. Costs of additional land were also not included since most retrofit control systems do not require much space. These omissions are consistent with U.S. EPA OAQPS costing methodologies.¹

6.1.2 Annual Operations and Maintenance (O&M) Costs

Annual O&M costs of NO_x control systems are classified as either direct or indirect annual costs. For this study, O&M costs were considered to be costs resulting from the use of the NO_x control equipment only, and are separate from the annual O&M costs of the existing boiler. Figure 6-2 displays common elements of annual O&M costs. Included as direct annual O&M costs are expenses for labor and maintenance materials, utilities such as electricity or steam, fuel or chemicals which may be required for the control system, and waste disposal which may be required with SCR system catalysts. With FGR NO_x control systems, boiler fuel consumption may actually decrease due to increased boiler efficiency, resulting in an overall fuel savings. Two sources estimated fuel savings of 1 to 2 percent when FGR was retrofitted.^{9,10} In the cost calculations of Appendices E, F, and G, fuel savings of 1 percent were included for all FGR systems.

Prices for fuels and electricity in the U.S. were obtained from Energy User News.¹¹ The cost of electricity was estimated as \$0.05/kWh, while the cost per MMBtu for natural gas, distillate oil, and residual oil were estimated as \$3.63, \$4.83, and \$2.35, respectively. The price of bulk anhydrous ammonia used for ammonia injection systems was estimated at \$250 per ton, while the price of bulk urea was estimated at \$220 per ton.¹²

Indirect annual O&M costs include overhead, administrative charges, property taxes, and insurance. Following the cost methodology developed by OAQPS, overhead charges were estimated as 60 percent of the annual labor and maintenance materials costs, while administrative, property tax, and insurance costs were estimated as 4 percent of the total capital investment cost described in Section 6.1.1.¹

Table 6-1 summarizes the assumptions made for estimating capital and O&M costs for retrofit NO_x control systems. When developing a NO_x control cost spreadsheet based on data from a particular reference source, these estimates were used whenever data were not provided by the source.

6.1.3 Total Annualized Cost and Cost Effectiveness

Total capital investment and total annual O&M costs may be combined to give a total annualized cost. Total capital investment is converted into uniform annual capital recovery costs which represent the payments necessary to repay the capital investment over a given time period at a given interest rate. This is done by multiplying the total capital investment cost by a capital recovery factor. For this analysis, a 10-percent interest rate and an amortization period of 10

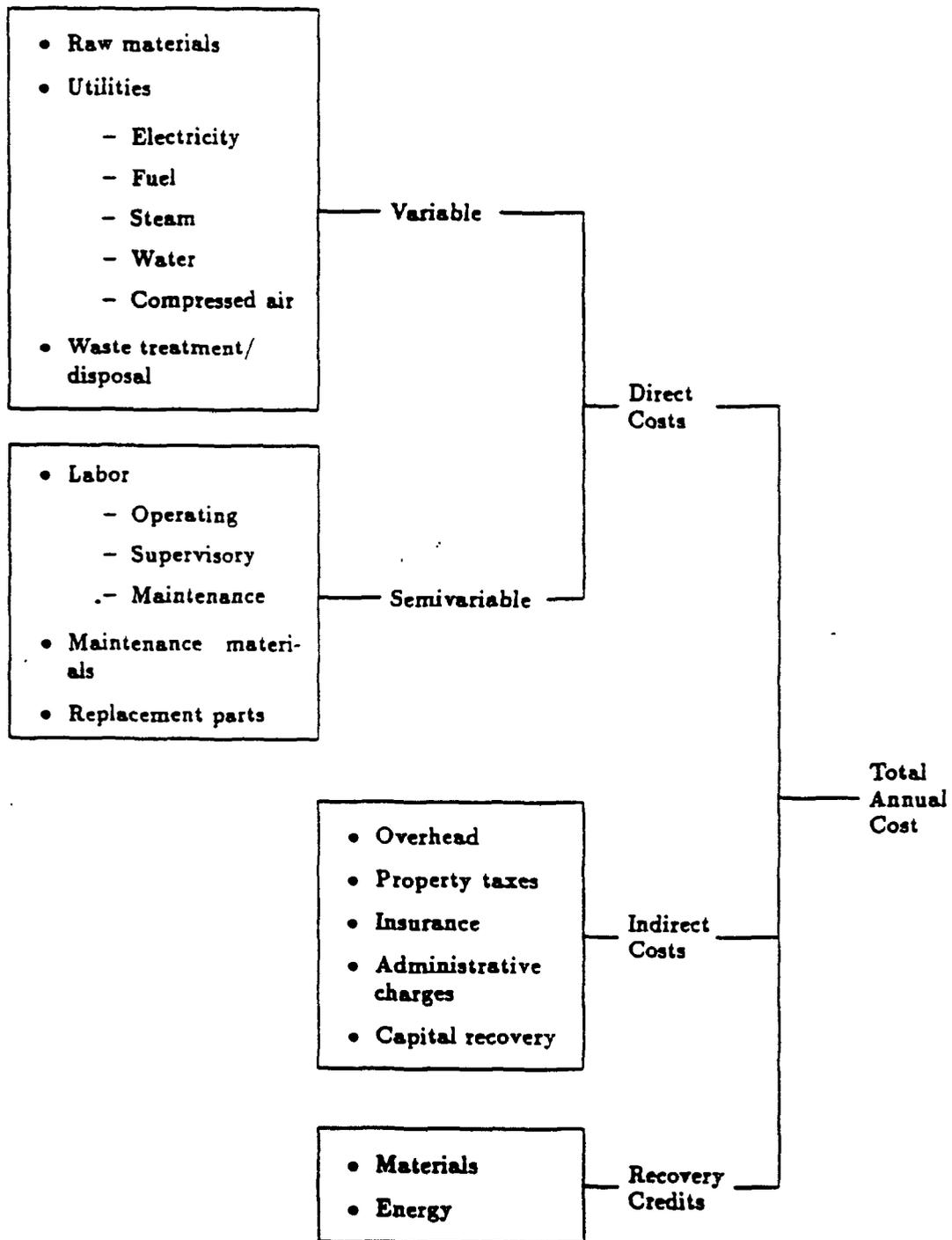


Figure 6-2. Elements of total annual O&M cost.¹

TABLE 6-1. ASSUMPTIONS FOR ESTIMATING CAPITAL AND ANNUAL O&M COSTS

Cost element	Cost assumption
Direct capital costs	
NO _x control equipment	Given
Instrumentation	10% of equipment cost
Sales taxes	3% of equipment cost
<u>Freight</u>	5% of equipment cost
Total = Purchased Equipment Cost (PEC)	
Direct installation cost	30% of PEC
Site preparation	0 unless given
Buildings	0 unless given
Indirect capital costs	
Engineering	10% of PEC ^a
Construction and field expenses	10% of PEC ^a
Construction fee	10% of PEC ^a
Startup	2% of PEC ^a
Performance test	1% of PEC ^a
Contingency	20% of direct and indirect capital costs
O&M costs	
FGR fuel savings	1% of boiler fuel cost
Overhead	60% of labor and maintenance material cost
Administrative	2% of total capital cost
Property tax	1% of total capital cost
Insurance	1% of total capital cost

^aIncreased by a factor of 2 for SCR installations.

years was assumed for the NO_x control systems, which results in a capital recovery factor of 0.1627.¹³ The interest rate of 10 percent was selected as a typical constant dollar rate of return on investment to provide a basis for calculation of annualized capital investment cost. Although 10 years was chosen as the capital amortization period, other periods could have been selected if desired, as long as the same amortization period is used when comparing costs of different control systems. When the annualized capital cost is added to the total annual O&M costs discussed in Section 6.1.2, the resulting figure is the total annualized cost of the NO_x control system.

In order to compare the cost effectiveness of different controls on a given boiler, the total annualized cost of each control system was divided by the amount of NO_x removed by the

system over 1 year. The amount of NO_x removed from a boiler is a function of the achievable NO_x reduction of the control system and of the annual capacity of that unit. An annual capacity factor represents the ratio of the amount of heat input a unit uses in a year to the amount it could have used if it was operated at full rated capacity 24 hours a day, 365 days per year. For the purposes of this study, it was assumed that all boilers, when operated, ran at full rated capacity, as opposed to being run at half load, for example. However, the annual capacity factors of all boilers were assumed to be less than 1.

The actual amount of boiler operating time over a year typically depends on the boiler size and application. For example, smaller capacity boilers used in commercial or institutional sectors are often operated intermittently, providing power for daily needs of office buildings, schools, etc. as needed. On the other hand, larger units located in large manufacturing facilities may operate almost continuously during the workweek. To illustrate the effect of capacity factor on NO_x control cost effectiveness, cost effectiveness was calculated for each boiler test case at capacity factors of 0.33, 0.5, 0.66, and 0.8. While data for the complete range of capacity factors are presented in the appendices, the summary tables in this chapter show cost effectiveness calculated for the mid-range capacity factors of 0.5 and 0.66 only.

To estimate the amount of NO_x removed by a control system per year, pre-retrofit and post-retrofit NO_x emission levels must be known, in addition to the boiler capacity factor and heat input capacity rating. Assumed baseline NO_x levels were selected for each fuel and boiler type based on data contained in Appendices A and B and summarized in Table 4-7 of Chapter 4. Table 6-2 lists the average baseline NO_x levels assumed for the purposes of calculating cost effectiveness. For natural-gas-fired watertube boilers, five boiler size categories were considered in the retrofit cost analyses. Average baseline NO_x emissions increase with boiler size because of the higher heat release rate and greater thermal NO_x formation. NO_x reduction efficiencies for each type of control were selected based on data contained in Chapter 5 and Appendix B, and are listed in Table 6-3. These NO_x reduction efficiencies are assumed levels only; actual NO_x reduction performance of particular control systems may vary depending on boiler, fuel, and operating characteristics, as discussed in Chapter 5.

Total annualized costs are divided by the amount of NO_x emission reduction per year to obtain the cost effectiveness in terms of dollars per ton of NO_x reduced. As stated earlier, all costs in this analysis are expressed in terms of 1992 dollars.

TABLE 6-2. BASELINE (UNCONTROLLED) NO_x EMISSIONS USED FOR COST CASES

Fuel	Boiler type	Baseline NO _x , lb/MMBtu ^a
Natural gas	Firetube	0.12
	Watertube	
	10 to <75 MMBtu/hr	0.16
	75 to 150 MMBtu/hr	0.18
	>150 to <350 MMBtu/hr	0.24
	350 to <750 MMBtu/hr	0.30
	≥750 MMBtu/hr	0.40
Distillate oil	All	0.20
Residual oil	All	0.38
Pulverized coal	Wall-fired	0.70
Coal	Spreader stoker	0.53
Coal	FBC	0.32
Wood	Stoker	0.25
Wood	FBC	0.25
Wood/natural gas	Stoker	0.20
Paper	Packaged watertube	0.50
MSW	Stoker	0.40

^aTo convert to ppm at 3 percent O₂, multiply by the following factors: natural gas, 835; distillate oil, 790; residual oil, 790; coal, 740; wood, 710; paper, 710; MSW, 705 (approximate).

TABLE 6-3. NO_x REDUCTION EFFICIENCIES USED FOR COST CASES

NO _x control technology	Applicable boiler equipment	NO _x reduction efficiency, % ^a
BT/OT	PKG-WT and FT	15
BT/OT and WI	PKG-WT and FT	65
BOOS with OT	FE-WT	50
BOOS/WI with OT	FE-WT	75
LNB	PC: wall-fired	50
	Nat. gas/oil: PKG-WT, FE-WT ^b	50
FGR	Nat. gas/oil: PKG-FT ^c	40
LNB and FGR	Nat. gas/oil: PKG-WT	60
SNCR	PC: wall-fired	45
	Coal: FBC	75
	Coal: Stoker	58
	Nonfossil: stoker, PKG-WT, FBC	55
SCR	PC: wall-fired	80
	Nat. gas/oil: PKG-WT	85

^aSee Chapter 5 and Appendix B.

^bPKG-WT = packaged watertube; FE-WT = field-erected watertube.

^cPKG-FT = packaged firetube.

6.2 NO_x CONTROL COST CASES AND SCALING METHODOLOGY

NO_x control cost cases were selected based on the prevalence of control system applications to specific types and sizes of boilers and on the availability of cost data. Table 6-4 lists the cost cases analyzed and data sources from which various cost figures, principally capital and annual costs, were obtained. Cost data were compiled primarily from published reports and communications with selected boiler operators and control system manufacturers. Cost data for PC-fired boilers were limited to LNB, SNCR, and SCR control technologies. Capital and O&M costs for LNB and SCR were provided by the Council of Industrial Boiler Owners (CIBO)¹⁴, and recent costs were developed for small utility PC-fired boilers.¹⁵ Cost estimates for SNCR with urea and ammonia reagents were provided by vendors of these technologies. Experience with NO_x controls for ICI PC-fired boilers is generally very sparse; therefore, these cost estimates should be used with caution. Data on NO_x controls for FBC boilers were limited to SNCR, since combustion staging is usually integrated into the original FBC boiler design and operation. For firetube boilers, data were also limited primarily to FGR only. Cost estimates of WI+OT for firetube boilers were based on the data reported for packaged watertube boilers.

Raw data from the referenced sources listed were used to calculate the annual cost effectiveness figures presented in Appendices E, F, and G. Cost effectiveness estimates for each of the NO_x control cost cases were then obtained from these values, using the logarithmic scaling law known as the "six-tenths power rule," to account for differences in boiler capacity size.⁵ Cost effectiveness was calculated for each cost case, using each applicable source of raw cost data. For example, the cost effectiveness of LNB used in 10 to 250 MMBtu/hr (2.9 to 73 MWt) natural-gas-fired packaged watertube units was calculated using annual costs derived from References 6 and 14, each of which provided data on more than one LNB retrofit project. Each individual retrofit project was used to calculate a cost effectiveness value. Results obtained for each cost case from each source are contained in Appendix D. The ranges in cost effectiveness obtained from all sources are summarized in the following subsections. In all, cost data for 42 different boiler/NO_x control configurations were used to develop these ranges, varying in boiler type, size, fuel, and NO_x control technology.

Most of the data obtained were for natural-gas-fired units, in part because of boiler retrofit activity in California's South Coast Air Basin, where natural gas is the primary fuel used. Cost effectiveness figures for distillate- and residual-oil-fired units were estimated using the annual costs for natural-gas-fired units. Appropriate baseline NO_x levels for fuel oil firing were

TABLE 6-4. NO_x CONTROL COST EFFECTIVENESS CASES

Fuel type	Boiler type	Boiler capacity, MMBtu/hr	NO_x control technology	Cost data reference
PC	Wall-fired	250-750	LNB	14
		250-750	SNCR-ammonia	16
		250-750	SNCR-urea	17
		250-750	SCR	15
Coal	FBC	250-750	SNCR-urea	18
	Spreader stoker	250-750	SNCR-urea	17
Natural gas/distillate oil/residual oil	Packaged watertube	10-250	OT	19
	Packaged watertube	10-250	OT+ WI	19
	Packaged firetube	3-34	OT	19
	Packaged firetube	3-34	OT+ WI	19
	Packaged firetube	3-34	FGR	20
	Packaged watertube	10-250	LNB	6,14
	Packaged watertube	10-250	LNB+FGR	6,14,21
	Packaged watertube	10-250	SCR	9,22
	Field-erected wall-fired	250-750	LNB	14
Nonfossil fuel	Stoker	50-500	SNCR-urea	16
	Packaged watertube	10-250	SNCR-urea	16
	FBC	250-750	SNCR-ammonia	23

used to calculate annual NO_x reduction. For FGR, fuel oil prices were used to estimate the annual fuel savings.

6.3 CAPITAL AND TOTAL ANNUAL COSTS OF NO_x CONTROLS

Table 6-5 summarizes the capital and total annualized costs of retrofit controls on selected "model" size boilers. The table also lists the anticipated NO_x control levels applicable to each control technology and model boiler. This information corresponds to data presented in Chapter 5. The total annualized cost includes the payments for the initial investment and the recurring direct and indirect O&M costs. The references indicate the sources of the capital cost data, and, in some cases, the O&M cost data, used in the analysis. As indicated earlier, when the reference cost data were for a different year or size of boiler, the capital costs were first updated to 1992 base year and then adjusted for boiler size using the "six-tenths" power law. That is:

TABLE 6-5. CAPITAL AND TOTAL ANNUAL COSTS OF RETROFIT NO_x CONTROLS FOR ICI BOILERS, 1992 DOLLARS

Boiler type, size, and fuel	NO _x control	Controlled NO _x , lb/MMBtu ^a	Capital cost, \$/MMBtu/hr	Total annual cost, \$/yr/MMBtu/hr ^b	Reference
400 MMBtu/hr PC-fired wall-fired watertube	LNB	0.35	5,300	1,220	14
	SNCR	0.28	1,600-2,100	950-1,200	16,17
	SCR	0.14	20,000	5,800	15
400 MMBtu/hr FBC	SNCR	0.08	1,600	680	18
400 MMBtu/hr stoker	SNCR	0.22	1,100	1,200	17
10.5 MMBtu/hr oil/gas firetube	OT+WI	0.04 (Gas)	2,400	690	19
	OT+FGR	0.07 (Gas) 0.12 (No. 2 oil)	5,400	1,100	20
50 MMBtu/hr oil/gas packaged watertube	OT+WI	0.06 (Gas)	530	210	19
	LNB	0.08 (Gas) 0.10 (No. 2 oil) 0.19 (No. 6 oil)	650-2,300	340-420	6,14
	LNB+FGR	0.06 (Gas) 0.07 (No. 2 oil) 0.15 (No. 6 oil)	2,100-4,700	430-890	6,14,21
	SCR	0.02 (Gas) 0.03 (No. 2 oil) 0.06 (No. 6 oil)	2,400-6,900	1,500-1,900	9,22
300 MMBtu/hr oil/gas field-erected watertube	OT+SCA (BOOS)	0.15 (Gas)	190	96	19
	LNB	0.12 (Gas) 0.10 (No. 2 oil) 0.19 (No. 6 oil)	5,100-8,300	990-1,500	14
150 MMBtu/hr wood- fired stoker	SNCR	0.11	2,100-2,500	500-800	16
400 MMBtu/hr wood- fired FBC	SNCR	0.11	970	590	23
500 MMBtu/hr MSW stoker	SNCR	0.18	2,100-3,300	940-1,100	15

^aArithmetic average of reported NO_x control performance. Not indicative of levels achievable in all cases.

^bCalculated based on 0.66 capacity factor or 5,460 operating hours per year at the boiler capacity.

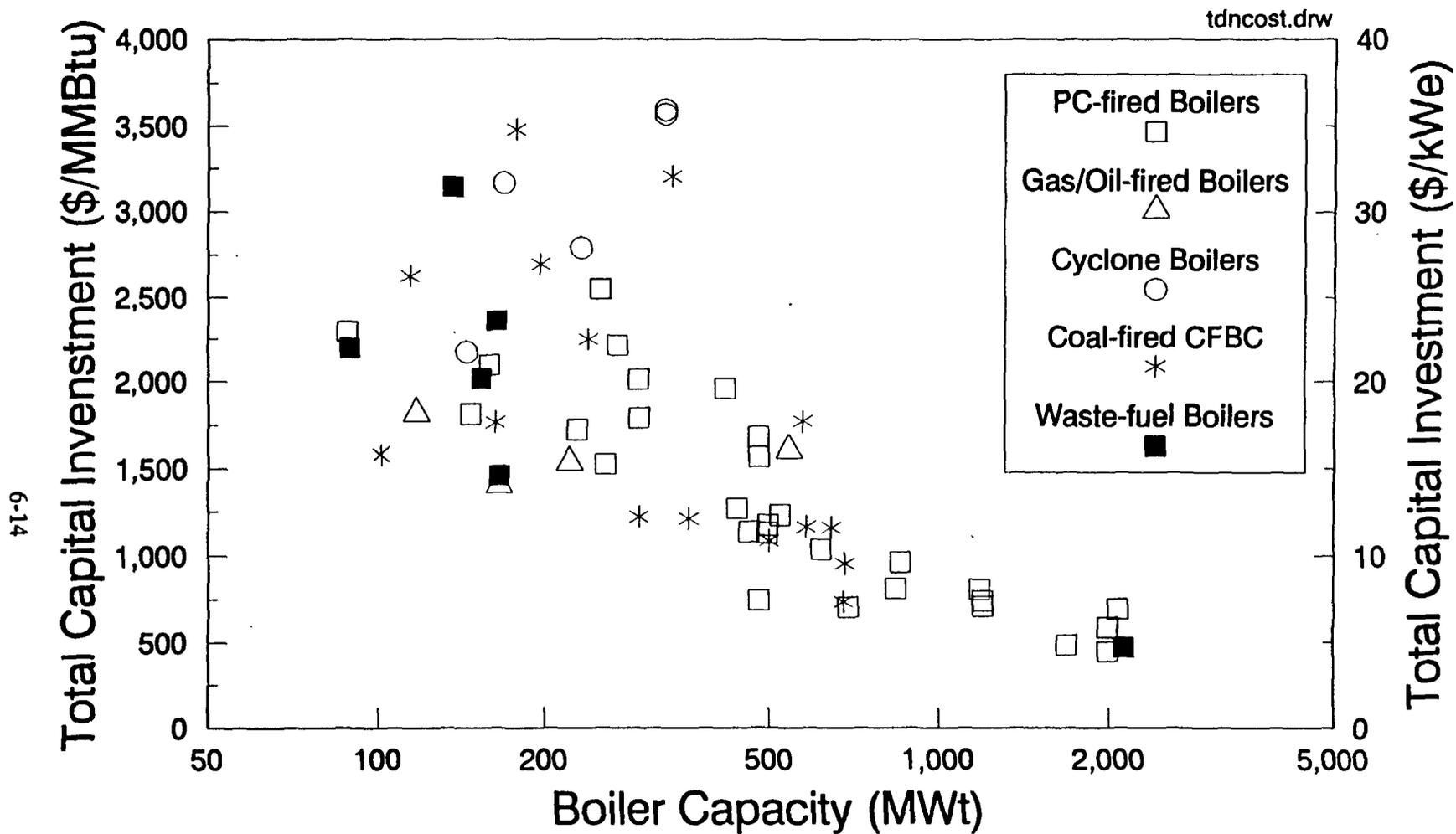
Note: All estimates are rounded to two significant figures.

$$Capital\ cost_2 = \left[\frac{(MMBtu/hr)_2}{(MMBtu/hr)_1} \right]^{0.6} Capital\ cost_1 \quad (6-1)$$

The ranges in both capital and operating costs indicate that the references provided more than one cost case from which data could be extrapolated to the model boilers.

The reported capital cost of retrofit NO_x controls has been found to vary by two orders of magnitude, from the low cost of BOOS (\$190/MMBtu) and WI (\$530/MMBtu), on small- to medium-sized gas-fired boilers, to the high estimate for SCR retrofit (\$20,000/MMBtu/hr), on PC-fired boilers. As shown, even the cost of SCR shows some large variations. Estimates from vendors and installers of the technology indicated that SCR can cost as little as \$2,400 to \$6,900/MMBtu for a relatively small gas-fired industrial boiler of 50 MMBtu/hr capacity (about 24 MWt), compared to an estimate of \$20,000/MMBtu based on estimates from a comparable-sized utility boiler.¹⁵ However, because of the lack of experience with SCR on coal-fired industrial boilers, it is difficult to draw any definitive conclusions with respect to the actual retrofit cost of SCR on these boiler types. Recent experience with utility boilers indicates that the cost of SCR has lowered due to technology improvements and market competition. These benefits are likely to transfer into the industrial boiler sector.

Where applicable, the capital cost of SNCR has been found to be in the same range as the capital costs of such combustion controls as LNB and FGR. Both SNCR-urea and SNCR-ammonia estimates were based on costs provided by vendors, and escalated to account for boiler size differences. For example, for a PC-fired 800 MMBtu/hr (234 MWt) boiler, the capital cost for SNCR-ammonia was estimated by Exxon to be about \$900/MMBtu/hr.¹⁶ For an 812 MMBtu/hr (238 MWt) tangential boiler, the capital cost for SNCR-urea was estimated by Nalco Fuel Tech to be about \$600/MMBtu/hr.¹⁷, while a smaller, 400 MMBtu/hr boiler will require an investment of \$830,000.¹⁷ Figure 6-3 plots the actual or estimated capital cost for the Thermal DeNO_x process for several boiler types. These costs were prepared by Exxon Research and Engineering (ER&E) for new and retrofit installations on large, >250 MMBtu/hr (73 MWt), industrial and utility boilers burning a variety of fuels, including waste fuels.^{24,25} These data show the exponential increase in capital cost with decreasing boiler size (boiler capacity is plotted on a logarithmic scale).



Source: Reference 22

Cost in \$/kWe assumes heat rate=10,000 Btu/kWhr

Costs are based on 1989 and 1992 ER&E estimates

Figure 6-3. Total capital cost reported by Exxon for SNCR-ammonia on a variety of industrial boilers.

6.4 COST EFFECTIVENESS OF NO_x CONTROLS

This section presents the cost effectiveness of various NO_x controls retrofitted to a range of ICI boilers, using the costing methodology and assumptions discussed earlier. Section 6.4.1 describes the boiler NO_x control cases analyzed, and Sections 6.4.2 through 6.4.6 discuss the cost analyses results.

6.4.1 NO_x Control Cost Effectiveness: Coal-fired ICI Boilers

Table 6-6 summarizes the results obtained for coal-fired ICI boilers retrofitted with various NO_x controls. The cost effectiveness values presented here and in all subsequent tables and figures in this chapter were calculated using capacity factors of 0.50 to 0.66. These capacity factors were chosen as mid-range capacity levels for this analysis, although it is likely that small ICI boilers such as packaged firetube units will have capacity factors less than 0.50.⁷ In all cost cases, costs per ton of NO_x control were higher as the capacity factor decreased, due to the reduced amount of NO_x removed. Thus, costs for boilers with capacity factors such as 0.33 will be higher than those presented in this section. See Appendix D for calculated cost effectiveness values for capacity factors of 0.33 and 0.80.

Figure 6-4 graphically shows the relationship of cost effectiveness and boiler capacity for NO_x controls retrofitted to PC wall-fired boilers. The cost estimates depicted are based on data from a detailed cost study for a 766 MMBtu/hr (224 MWt) PC wall-fired unit.¹⁴ Cost estimates for other boiler sizes were extrapolated using the 0.6 power law for capital cost and a proportional dependence for O&M cost. The data show reduced costs per ton of NO_x removed as boiler capacity increases, due to greater amounts of NO_x removed and economies of scale. SNCR controls were the most cost effective per ton of NO_x removed, with costs ranging from a low of \$950 per ton of NO_x removed, for a 750 MMBtu/hr (220 MWt) unit, to a high of \$1,340 per ton, for a smaller, 250 MMBtu/hr (73 MWt) unit. The difference in cost effectiveness between SNCR with urea and SNCR with ammonia is well within the margin of error for this cost analysis.

LNB controls required greater expenditures for equivalent NO_x removal, ranging from \$980 to \$1,760 per ton of NO_x removed. LNB costs were developed based on estimates provided by CIBO.¹⁴ SCR has the highest costs per ton of NO_x removal, ranging from \$4,610 to \$7,810 per ton of NO_x. These estimates were also developed from EPA cost estimates for a 100 MWe utility boiler.¹⁵ Recent trends in SCR applications have shown significant decreases in capital investment for this technology. However, due to the lack of experience in SCR application on

TABLE 6-6. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, COAL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}
PC wall-fired	250	LNB	0.35	1,340-1,760
	400	LNB	0.35	1,170-1,530
	500	LNB	0.35	1,090-1,430
	750	LNB	0.35	980-1,280
	250	SNCR-ammonia	0.39	1,360-1,450
	400	SNCR-ammonia	0.39	1,310-1,400
	500	SNCR-ammonia	0.39	1,300-1,370
	750	SNCR-ammonia	0.39	1,270-1,330
	250	SNCR-urea	0.39	1,120-1,340
	400	SNCR-urea	0.39	1,040-1,240
	500	SNCR-urea	0.39	1,010-1,190
	750	SNCR-urea	0.39	960-1,130
	250	SCR	0.14	3,800-4,800
	400	SCR	0.14	3,400-4,200
	500	SCR	0.14	3,200-4,000
	750	SCR	0.14	3,000-3,700
CFBC	250	SNCR-urea	0.08	960-1,130
	400	SNCR-urea	0.08	890-1,030
	500	SNCR-urea	0.08	860-980
	750	SNCR-urea	0.08	810-920
Spreader stoker	250	SNCR-urea	0.22	1,360-1,440
	400	SNCR-urea	0.22	1,320-1,380
	500	SNCR-urea	0.22	1,300-1,360
	750	SNCR-urea	0.22	1,280-1,320

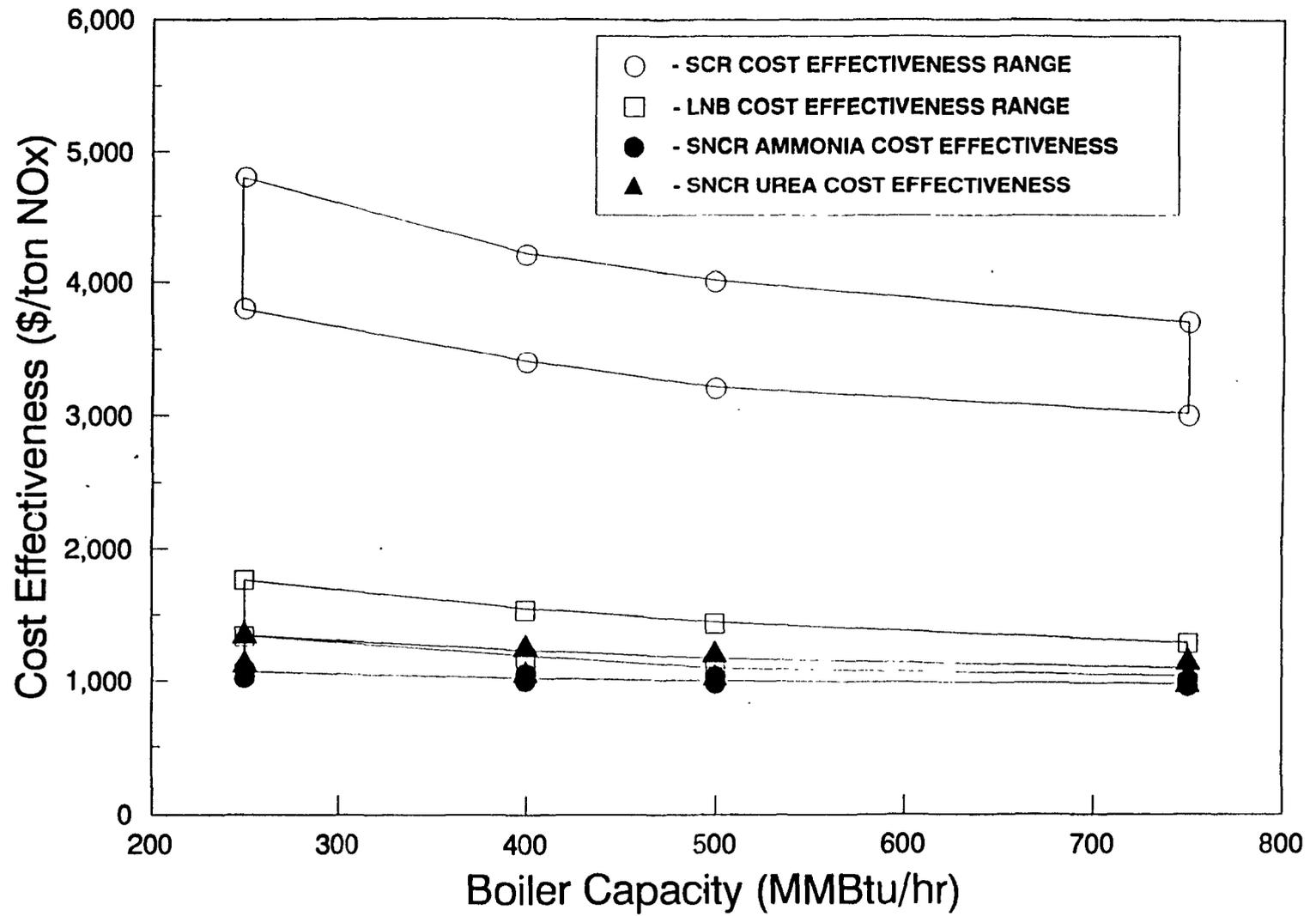
^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

PC-fired boilers, the actual cost of this control option is speculative at this stage. Overall, on a per-ton of NO_x removed basis of comparison, SNCR controls were the most cost effective for PC wall-fired boilers.

It should be noted that the controlled NO_x levels achieved using LNB were higher than those achieved using SNCR or SCR. This lower reduction efficiency, coupled with higher capital costs, results in higher cost effectiveness for LNB technology. For SCR controls, the most

6-17



Boiler capacity factor = 0.50 to 0.66

Figure 6-4. Cost effectiveness versus boiler capacity, PC wall-fired boilers.

expensive cost elements were purchased equipment cost and annual chemical or catalyst replacement costs. SCR catalyst replacement was based on a 4-year catalyst life. Both capital and O&M SCR costs are in line with EPA estimates for small PC-fired utility boilers. In general, costs per ton of NO_x control for tangential-fired PC boilers may be expected to be slightly higher than those estimated for the PC wall-fired units, since baseline NO_x levels are generally lower for tangential firing, and, hence, the amount of NO_x removed will be slightly lower.

6.4.2 NO_x Control Cost Effectiveness: Natural-gas-fired ICI Boilers

Cost effectiveness estimates were made for packaged watertube, packaged firetube, and field-erected wall-fired units firing natural gas, and are summarized in Table 6-7. Cost data for 26 different boilers were used to derive these estimates. Section 6.4.2.1 describes the results obtained for packaged watertube units equipped with WI+OT, LNB, LNB+FGR, and SCR. Section 6.4.2.2 presents cost effectiveness estimates for packaged firetube units retrofitted with WI+OT, and FGR controls, and Section 6.4.2.3 discusses field erected wall-fired units retrofitted with LNB. These estimates do not include the cost of purchasing and maintaining a fully instrumented CEM system to monitor compliance with an emission limit. The impact of CEMs on these costs is discussed in Section 6.4.6.

TABLE 6-7. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, NATURAL-GAS-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}
Packaged watertube (single-burner)	10	WI+OT	0.06	960-1,160
	25	WI+OT	0.06	800-940
	50	WI+OT	0.06	710-820
	100	WI+OT	0.06	570-650
	150	WI+OT	0.06	540-610
	250	WI+OT	0.08	380-430
	10	LNB	0.08	990-4,300
	25	LNB	0.08	720-3,070
	50	LNB	0.08	570-2,390
	100	LNB	0.09	410-1,670
	150	LNB	0.09	360-1,450
	250	LNB	0.12	240-920

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

(continued)

TABLE 6-7. (continued)

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}	
Packaged watertube (single-burner) (continued)	10	LNB+FGR	0.06	2,630-7,630	
	25	LNB+FGR	0.06	1,930-5,510	
	50	LNB+FGR	0.06	1,540-4,350	
	100	LNB+FGR	0.07	1,110-3,090	
	150	LNB+FGR	0.07	990-2,730	
	250	LNB+FGR	0.10	650-1,760	
	10	SCR	0.02	7,400-10,090	
	25	SCR	0.02	5,730-8,010	
	50	SCR	0.02	4,830-6,880	
	100	SCR	0.03	3,040-5,350	
	150	SCR	0.03	2,690-4,990	
	250	SCR	0.04	1,810-3,460	
	Packaged firetube	2.9	WI+OT	0.04	4,190-5,240
		5.2	WI+OT	0.04	3,600-4,450
		10.5	WI+OT	0.04	3,050-3,720
20.9		WI+OT	0.04	2,640-3,180	
33.5		WI+OT	0.04	2,410-2,890	
2.9		FGR+OT	0.07	26,570-35,410	
5.2		FGR+OT	0.07	15,160-20,380	
10.5		FGR+OT	0.07	7,970-10,830	
20.9		FGR+OT	0.07	4,520-6,100	
33.5		FGR+OT	0.07	3,000-4,080	
Field-erected wall-fired (multiple-burner)	100	BOOS+OT	0.09	440-510	
	250	BOOS+OT	0.12	280-330	
	400	BOOS+OT	0.15	210-240	
	500	BOOS+OT	0.15	210-240	
	750	BOOS+OT	0.20	150-170	
	100	BOOS+WI+OT	0.05	750-820	
	250	BOOS+WI+OT	0.06	530-570	
	400	BOOS+WI+OT	0.08	410-440	
	500	BOOS+WI+OT	0.08	400-430	
	750	BOOS+WI+OT	0.10	300-310	
	250	LNB	0.12	3,030-6,210	
	400	LNB	0.15	2,070-4,210	
	500	LNB	0.15	1,920-3,900	
	750	LNB	0.20	1,690-3,400	

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

6.4.2.1 Natural-gas-fired Packaged Watertube Boilers

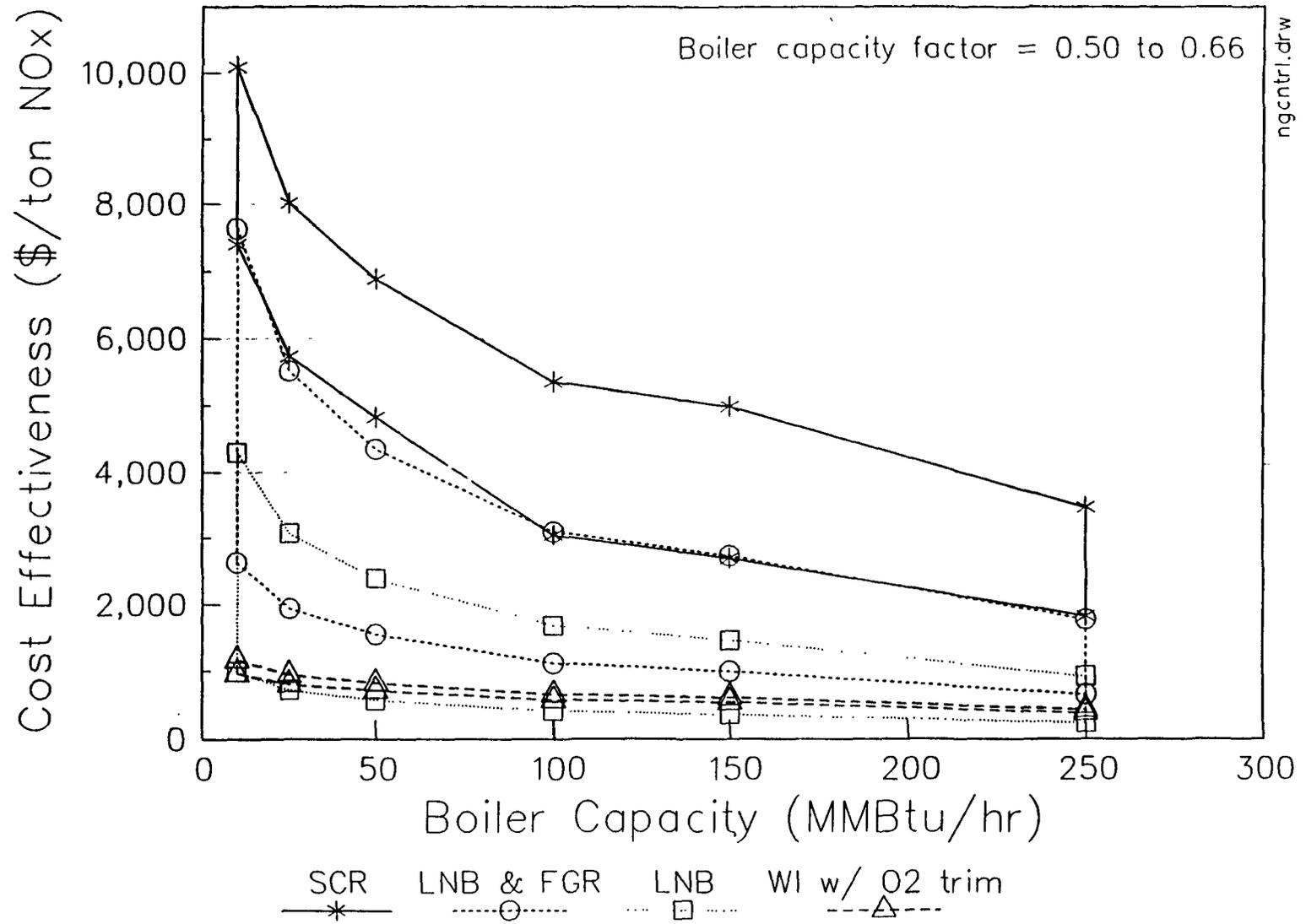
NO_x control cost data for natural-gas-fired packaged (single-burner) watertube boilers are more available than for other boiler and fuel types, primarily due to retrofit activity in California. Cost data from four boilers were used to estimate costs of WI and LNB retrofit, while data from six units were used to estimate combined LNB and FGR retrofit costs. SCR retrofit cost estimates were based on data supplied by a major manufacturer of SCR systems, with experience installing SCR systems on packaged boilers rated as small as 66,000 lb steam/hr (8.3 kg/s).

As tabulated in Table 6-7 and shown in Figure 6-5, cost effectiveness estimates for packaged watertube units fired by natural gas were highest for SCR NO_x control and lowest for LNB and WI+OT, with LNB+FGR falling in between. WI+OT is considered cost-competitive with LNB because of its low initial capital investment. In spite of the thermal efficiency loss of 0.5 to 1.0 percent associated with WI, this technique can be cost effective especially for small boilers with a low capacity factor.

As was the case with coal-fired units, costs per ton of NO_x reduction decreased with increased boiler capacity, due to the increased amount of NO_x removed from the larger units and general economies of scale. For packaged watertube units, the effect of boiler capacity on cost effectiveness becomes significant below about 50 MMBtu/hr (15 MWt) capacity. For units smaller than this capacity, costs of NO_x control increase rapidly as capacity decreases, especially when SCR is used. The costs per ton of NO_x control for a 250 MMBtu/hr (73 MWt) single-burner packaged boiler with LNB are much lower than those estimated for a multiple-burner field-erected unit of similar size. Some of the discrepancy between the figures can be attributed to the different data sources; however, the principal reason lies in the number of burners to be retrofitted. A field-erected unit with four or more burners, for example, will tend to require capital equipment and installation costs several times higher than a single-burner unit.

On average, LNB+FGR control costs per ton of NO_x removed were twice as high as for LNB and WI+OT, while SCR control costs per ton of NO_x removed were 3 times higher. Cost effectiveness of WI+OT ranged from \$380 to \$1,160 per ton of NO_x removed. Cost effectiveness for LNB controls ranged from \$240 to \$4,300 per ton of NO_x removed, across the capacity range of 10 to 250 MMBtu/hr (2.9 to 73 MWt). LNB+FGR cost effectiveness ranged from about \$650 to \$7,630/ton, while SCR had the highest range in cost per ton of NO_x

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Figure 6-5. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers.

removed, approximately \$1,810 to \$10,090/ton. The high-end costs of these ranges were for the smallest, 10 MMBtu/hr (2.9 MWt) units at a 0.50 capacity factor. Because it is likely that many units this small are operated at even lower capacity factors, actual costs of NO_x control may be much higher than these estimates. For these lower capacity factor boilers, controls with a high initial capital investment, such as SCR, LNB, and LNB+FGR, are particularly penalized when compared on a cost-effectiveness basis.

Figure 6-5 illustrates the overall trend of cost effectiveness with boiler capacity. The enclosed areas reflect the ranges in cost and are representative of the uncertainty in these estimates. Cost-effectiveness ranges for LNB and for LNB+FGR overlap, due to the wide range of cost effectiveness values obtained. These cost-effectiveness data illustrate the potential variability in the costs of retrofitting boilers with NO_x controls, which are highly dependent on site-specific installation and operating factors. Figure 6-6 illustrates the variability of the cost effectiveness of SCR controls, assuming various catalyst lifetimes. As catalyst life increases, cost effectiveness slowly decreases.

6.4.2.2 Natural-gas-fired Firetube Boilers

Cost data were obtained for retrofitting WI+OT and FGR+OT controls to packaged firetube units ranging in size from approximately 3 to 34 MMBtu/hr (0.9 to 10 MWt) capacity. The data for FGR+OT controls were obtained from a distributor of industrial boilers and NO_x control systems, and are based on experiences with nearly 20 units operating with FGR.²⁰ Costs for WI+OT are based on recently reported NO_x retrofit experiences in Southern California.¹⁹

FGR+OT is one of the most common retrofit NO_x control strategies for natural-gas-fired firetube units, besides LNB or combined LNB and FGR. Costs per ton of NO_x removed for these units firing natural gas were relatively high, ranging from \$3,000 to \$35,410, with the highest costs being for units 5 MMBtu/hr (1.5 MWt) and smaller. The most significant cost components for these cost cases were equipment and installation costs. The costs of NO_x control for a 10 MMBtu/hr (2.9 MWt) firetube unit retrofitted with FGR+OT are relatively similar to the high-end costs estimated for a 10 MMBtu/hr (2.9 MWt) watertube unit retrofitted with LNB and FGR, as discussed above. Although no cost estimates were made for firetube units retrofitted with LNB or LNB+FGR controls, it is likely that cost effectiveness for these control cases will be comparable to those estimated for packaged watertube units of similar capacity.

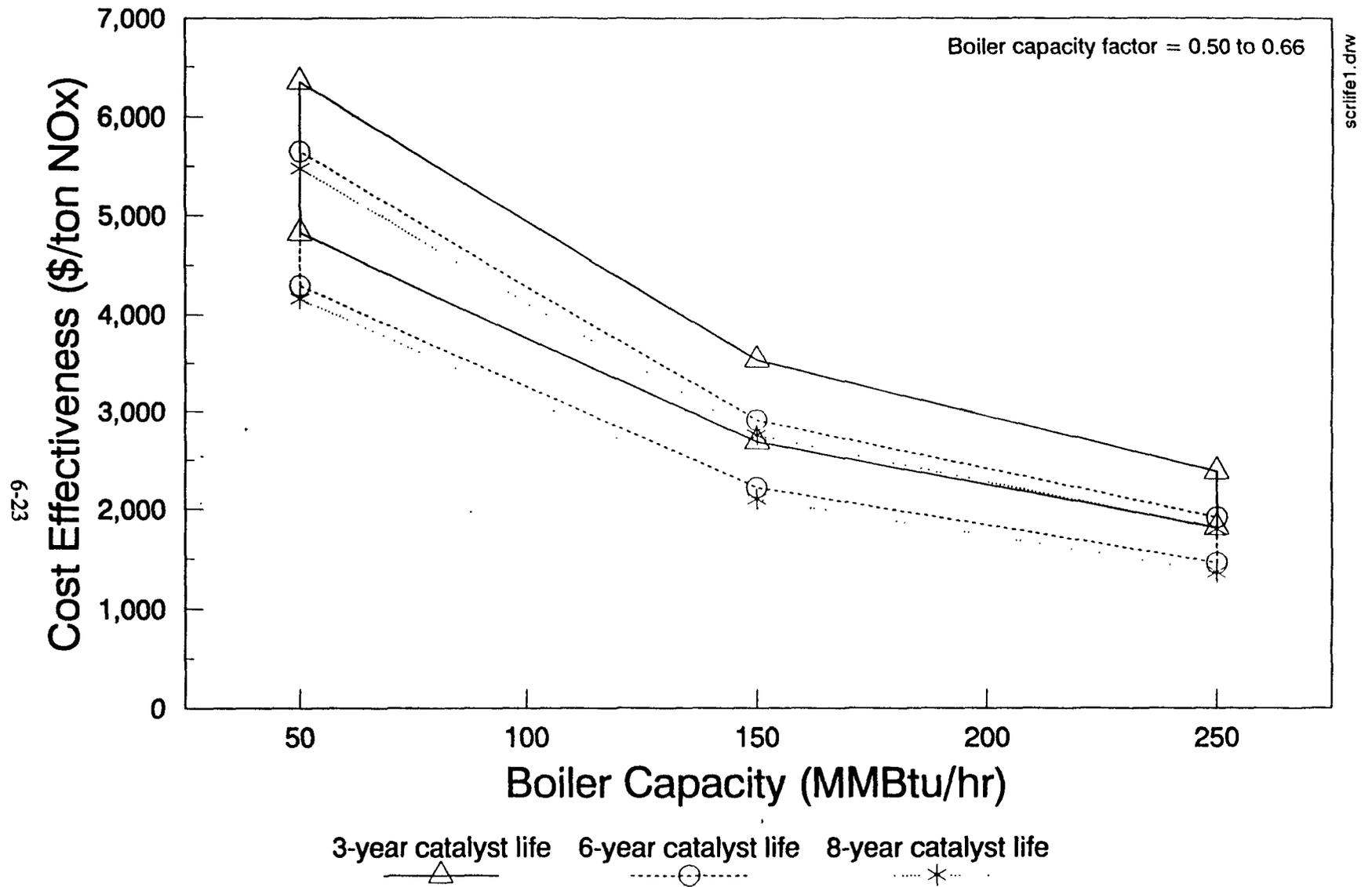


Figure 6-6. Cost effectiveness versus boiler capacity, natural-gas-fired packaged watertube boilers using SCR controls.

The estimated costs for WI+OT for these firetube boilers are based on a retrofit investment of \$35,000, irrespective of boiler size, and an efficiency penalty of 1.0 percent. It is difficult to predict the actual thermal efficiency impact in a retrofit situation. The actual impact will depend on current unit operating practices; given a poor operating condition with high excess air combustion, the retrofit of this control may, in some cases, result in an improvement. However, it was considered prudent to associate an efficiency loss with the use of WI in spite of potential gains with an OT control. As shown in Table 6-7, the estimated cost for this control strategy is similar to that for LNB retrofit, but still slightly higher than comparable controls for watertube units. This is due to lower baseline NO_x levels for firetube boilers compared with watertube units (see Table 6-2).

6.4.2.3 Natural-gas-fired Field-erected Wall-fired Boilers

The implementation of BOOS or biased firing and WI on large multi-burner gas-fired boilers will depend on the number of burners available and the load requirements of the boiler. Units with several burners with small heat input ratings per burner offer the greater opportunity for implementation of these effective control techniques. Where possible, the retrofit of BOOS and BOOS+WI+OT is likely to be the more cost effective options in spite of thermal efficiencies, here assumed to range between 0.25 and 1.0 percent. The lower the capacity factor of these boilers, the more cost-competitive these controls may prove to be. Estimates in this study range between about \$150 and \$510 per ton for BOOS+OT, and between \$300 and \$820 per ton for BOOS+WI+OT.

Cost estimates per ton of NO_x removed for natural-gas-fired field-erected units with LNB, listed in Table 6-7, range from \$1,690 to \$6,210 per ton of NO_x removed for boilers ranging in size from 250 to 750 MMBtu/hr (73 to 220 MWt). The costs per ton of NO_x control for a multiple-burner field-erected 250 MMBtu/hr (73 MWt) unit are much higher than the costs estimated for a single-burner packaged unit due to greater capital equipment and installation costs as discussed in Section 6.4.2.1. Although the listed cost effectiveness ranges are for a capacity factor as low as 0.50, most field-erected units have factors closer to 0.66.⁷ The high end of the cost effectiveness ranges listed in Table 6-7 represent a 0.50 capacity factor. If considering a 0.66 capacity factor only, the high-end cost effectiveness estimates are roughly 25 percent lower. The estimates presented are based on capital cost data supplied for two boilers retrofitted with LNB.¹⁴

6.4.3 NO_x Control Cost Effectiveness: Fuel-oil-fired ICI Boilers

As discussed earlier, NO_x control cost effectiveness estimates for fuel-oil-firing units were made based on cost data for natural-gas-fired boilers, using appropriate baseline NO_x emission levels and fuel oil prices. Tables 6-8 and 6-9 summarize these estimates, and Figures 6-7 and 6-8 graphically show the results for packaged watertube boilers. NO_x controls that use water injection were not considered for oil-fired units because of lack of experience and greater operational and environmental impacts that are likely with these fuels compared with natural gas. Comparative cost results for the different NO_x control technologies are similar to those obtained for natural-gas-fired units, as expected, with SCR showing the highest costs per ton of NO_x removed and LNB showing the lowest. Like the cost estimates for natural gas firing, LNB+FGR control costs were, on average, twice as high as the costs of LNB controls, while SCR controls were 3 times as high.

Overall costs of NO_x control per ton removed are lower for fuel oil firing than for natural gas firing due to higher baseline NO_x emission levels, and, hence, greater amounts of NO_x removal per MMBtu heat input. As discussed for natural gas-fired boilers, the cost effectiveness discrepancy between a 250 MMBtu/hr (73 MWt) packaged boiler and a 250 MMBtu/hr (73 MWt) field-erected unit equipped with LNB is primarily due to the greater capital equipment and installation costs associated with retrofitting multiple burners rather than a single burner. Multiple-burner field-erected boilers are likely to benefit from selected BOOS. Where applicable, this technique can result in considerable NO_x reduction at much lower cost than LNB retrofit.

6.4.4 NO_x Control Cost Effectiveness: Nonfossil-fuel-fired ICI Boilers

Limited cost data were available for nonfossil-fuel-fired boilers retrofitted with NO_x controls. For this reason, cost estimates could only be made for the application of SNCR controls to several types of nonfossil-fuel-fired boilers. Data were obtained directly from leading SNCR system manufacturers, and reflect cost experiences for nine different installations. NO_x control performance and cost are considered the same regardless of the reagent used. Typical applications use either ammonia or urea in aqueous solution. Table 6-10 summarizes the cost effectiveness ranges for these boilers. Cost effectiveness estimates made for wood-fired stokers with urea injection are comparable to those calculated for wood-fired FBC boilers with ammonia injection, ranging between \$890 and \$2,130 per ton of NO_x removed for boilers 250 to 500 MMBtu/hr (73 to 146 MWt). The range in cost effectiveness for MSW-fired stokers of the

TABLE 6-8. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, DISTILLATE-OIL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}
Packaged watertube (single burner)	10	LNB	0.10	790-3,440
	25	LNB	0.10	580-2,450
	50	LNB	0.10	460-1,910
	100	LNB	0.10	370-1,500
	150	LNB	0.10	330-1,310
	250	LNB	0.10	280-1,110
	10	LNB+FGR	0.08	1,900-5,900
	25	LNB+FGR	0.08	1,340-4,210
	50	LNB+FGR	0.08	1,030-3,280
	100	LNB+FGR	0.08	800-2,580
	150	LNB+FGR	0.08	690-2,250
	250	LNB+FGR	0.08	580-1,910
	10	SCR	0.03	5,920-8,070
	25	SCR	0.03	4,590-6,410
	50	SCR	0.03	3,860-5,500
	100	SCR	0.03	2,740-4,820
	150	SCR	0.03	2,420-4,490
	250	SCR	0.03	2,170-4,150
Packaged firetube	2.9	FGR+OT	0.12	15,640-20,940
	5.2	FGR+OT	0.12	8,800-11,930
	10.5	FGR+OT	0.12	4,490-6,200
	20.9	FGR+OT	0.12	2,410-3,360
	33.5	FGR+OT	0.12	1,500-2,150
Field-erected wall-fired (multiple burner)	250	LNB	0.10	3,630-7,450
	400	LNB	0.10	3,100-6,320
	500	LNB	0.10	2,880-5,850
	750	LNB	0.10	2,530-5,100

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

TABLE 6-9. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, RESIDUAL-OIL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a, b}	
Packaged watertube (single burner)	10	LNB	0.19	420-1,810	
	25	LNB	0.19	300-1,290	
	50	LNB	0.19	240-1,010	
	100	LNB	0.19	190-790	
	150	LNB	0.19	170-690	
	250	LNB	0.19	150-580	
	10	LNB+FGR	0.23	1,220-3,320	
	25	LNB+FGR	0.23	920-2,430	
	50	LNB+FGR	0.23	760-1,950	
	100	LNB+FGR	0.23	640-1,580	
	150	LNB+FGR	0.23	580-1,400	
	250	LNB+FGR	0.23	520-1,220	
	10	SCR	0.06	3,110-4,240	
	25	SCR	0.06	2,420-3,370	
	50	SCR	0.06	2,030-2,900	
	100	SCR	0.06	1,440-2,530	
	150	SCR	0.06	1,270-2,360	
	250	SCR	0.06	1,140-2,190	
	Packaged firetube	2.9	FGR+OT	0.23	8,560-11,350
		5.2	FGR+OT	0.23	4,960-6,600
		10.5	FGR+OT	0.23	2,690-3,590
20.9		FGR+OT	0.23	1,600-2,100	
33.5		FGR+OT	0.23	1,120-1,460	
Field-erected wall-fired (multiple burner)	250	LNB	0.19	1,910-3,920	
	400	LNB	0.19	1,630-3,330	
	500	LNB	0.19	1,520-3,080	
	750	LNB	0.19	1,330-2,680	

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

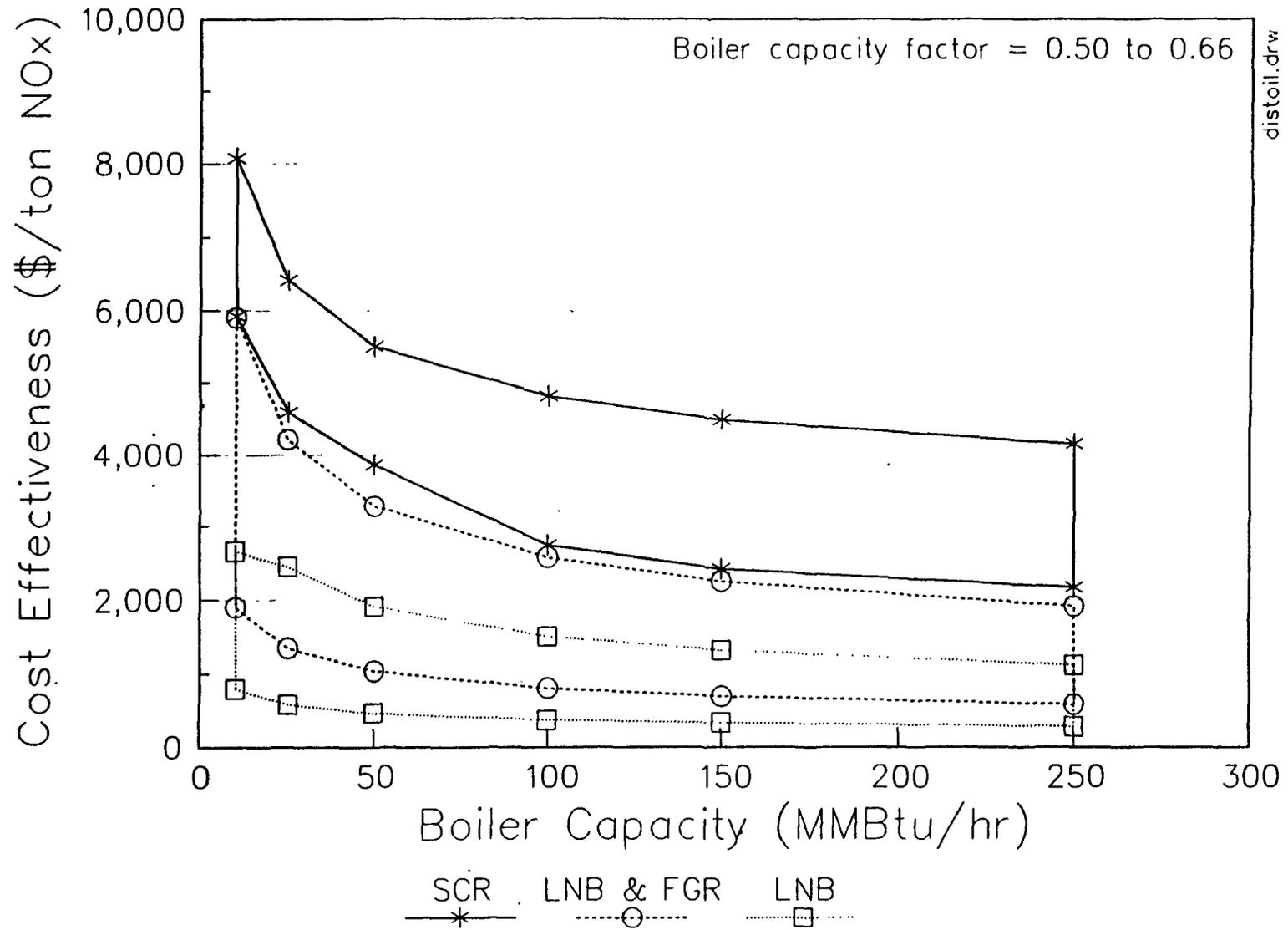
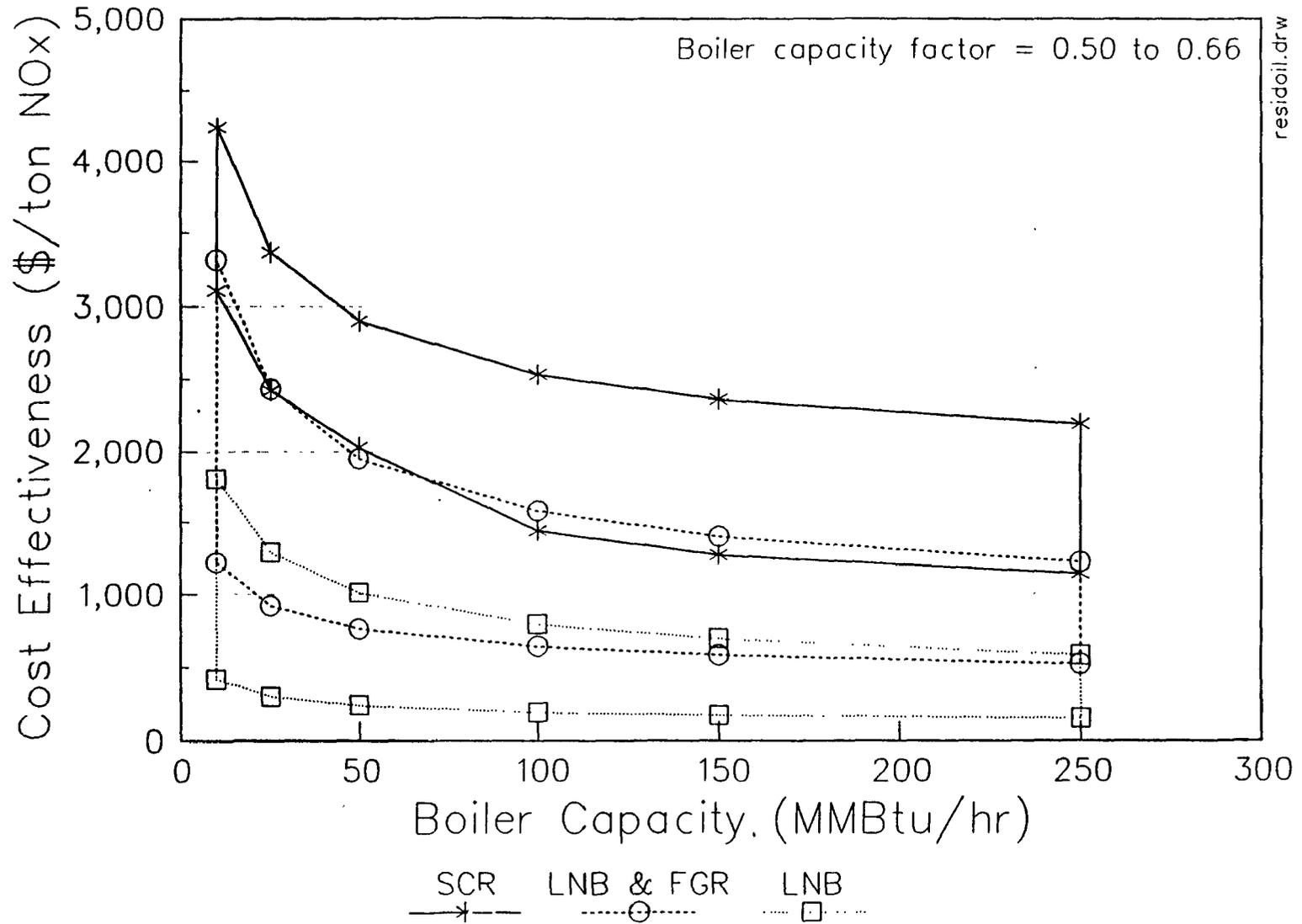


Figure 6-7. Cost effectiveness versus boiler capacity, distillate-oil-fired boilers.

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Figure 6-8. Cost effectiveness versus boiler capacity, residual-oil-fired boilers.

TABLE 6-10. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, NONFOSSIL-FUEL-FIRED ICI BOILERS

Boiler type	Fuel type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}
Stoker	Wood	50	SNCR-urea	0.11	1,810-3,130
		150	SNCR-urea	0.11	1,270-2,380
		250	SNCR-urea	0.11	1,080-2,130
		350	SNCR-urea	0.11	980-2,000
		500	SNCR-urea	0.11	890-1,870
	MSW	50	SNCR-urea	0.18	3,390-3,800
		150	SNCR-urea	0.18	1,890-2,790
		250	SNCR-urea	0.18	1,690-2,450
		350	SNCR-urea	0.18	1,580-2,270
		500	SNCR-urea	0.18	1,470-2,090
Packaged watertube	Paper	10	SNCR-urea	0.23	2,220-3,520
		25	SNCR-urea	0.23	1,780-2,710
		50	SNCR-urea	0.23	1,550-2,270
		100	SNCR-urea	0.23	1,370-1,930
		150	SNCR-urea	0.23	1,280-1,770
		250	SNCR-urea	0.23	1,190-1,610
BFBC	Wood	250	SNCR-ammonia	0.11	1,560-1,750
		350	SNCR-ammonia	0.11	1,480-1,650
		400	SNCR-ammonia	0.11	1,450-1,600
		500	SNCR-ammonia	0.11	1,390-1,530
		750	SNCR-ammonia	0.11	1,110-1,310

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

same capacity retrofit with urea injection is \$1,470 and \$2,450 per ton of NO_x removed. For wood- or MSW-fired boilers smaller than 250 MMBtu/hr (73 MWt) but at least 50 MMBtu/hr (15 MWt), SNCR control costs ranged from approximately \$1,270 to \$3,800 per ton of NO_x removed. Cost estimates for similarly sized paper-fired units were lower, ranging from \$1,280 to roughly \$2,270 per ton of NO_x removed.

6.4.5 NO_x Control Cost Effectiveness: Oil-fired Thermally Enhanced Oil Recovery (TEOR) Steam Generators

No cost analyses were performed for NO_x controls for TEOR steam generators. However, it has been estimated that for a 25 MMBtu/hr (7.3 MWt) crude-oil-fired TEOR unit, annual costs would be \$52,000 for LNB retrofit, \$88,000 for SNCR, and \$400,000 for SCR.²⁶

Based on these estimates, and assuming a baseline NO_x emission level of 0.38 lb/MMBtu (see Chapter 4) and the NO_x reduction efficiencies listed in Table 6-3, cost effectiveness is \$3,790 per ton of NO_x removed for LNB at 0.66 capacity factor, \$8,000/ton for SNCR, and \$19,400/ton for SCR.

6.4.6 Cost Effect of Continuous Emissions Monitoring (CEM) System

Addition of a CEM system to an NO_x control retrofit package can increase the costs of NO_x control. For example, Table 6-11 shows the cost effect of adding a CEM system to a natural-gas-fired packaged watertube boiler, equipped with LNB or with LNB and FGR. The cost estimates are based on data from one source, for a 265 MMBtu/hr (77.7 MWt) unit, that showed a total CEM system capital cost of roughly \$200,000, including installation.¹⁴ Average cost increased by roughly 65 percent when a CEM system was included. While it is not possible to draw conclusions from one source about the extent to which CEM systems will increase costs, the data nevertheless show that CEM cost impact is considerable. For small-capacity boilers, in particular, the additional cost of CEM may be disproportionately large when compared to the overall cost of the boiler itself. At least one California air district requires CEM systems only for boilers that are 40 MMBtu/hr (12 MWt) or greater in capacity.²⁷

TABLE 6-11. NO_x CONTROL COST EFFECTIVENESS WITHOUT/WITH CEM SYSTEM, NATURAL-GAS-FIRED ICI BOILERS^a

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness without CEM, \$/ton NO _x removed ^{b,c}	Cost effectiveness with CEM, \$/ton NO _x removed ^{b,c}
Packaged watertube	10	LNB	0.08	3,260-4,300	5,410-7,140
	25	LNB	0.08	2,320-3,070	3,850-5,080
	50	LNB	0.08	1,810-2,390	3,000-3,960
	100	LNB	0.09	1,260-1,670	2,090-2,760
	150	LNB	0.09	1,100-1,450	1,830-2,410
	250	LNB	0.12	700-920	1,160-1,530
	10	LNB + FGR	0.06	3,700-5,000	5,480-7,360
	25	LNB + FGR	0.06	2,530-3,460	3,800-5,140
	50	LNB + FGR	0.06	1,900-2,620	2,890-3,930
	100	LNB + FGR	0.07	1,260-1,760	1,950-2,680
	150	LNB + FGR	0.07	1,050-1,500	1,660-2,290
	250	LNB + FGR	0.10	630-910	1,020-1,420

^aBased on data contained in Reference 19, for a 265 MMBtu/hr (7.7 MWt) natural-gas-fired unit.

^bCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^c1992 dollars.

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7. ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the NO_x emissions control techniques described in Chapter 5. These control techniques are specific to certain boiler and fuel equipment, as shown in Table 7-1. For example, LNB is not applicable to stoker and FBC boilers. WI and FGR are rarely considered when burning coal in any type of industrial combustion equipment. Similarly, among ICI boilers reburning with natural gas has only limited application potential to boilers burning municipal solid waste or stoker coal. Flue gas treatment controls have limited application experience, especially for SCR, on small boilers and boilers burning fuels other than natural gas. SNCR, instead, is generally limited to application on larger boilers with the greatest performance success recorded on FBC boilers.

This chapter is organized in four major sections. Section 7.1 presents the air pollution impacts, Section 7.2 the solid waste disposal impacts, Section 7.3 the water pollution impacts, and Section 7.4 the energy impacts.

7.1 AIR POLLUTION

7.1.1 NO_x Reductions

Control techniques presented in this document can result in significant NO_x reductions for selected ICI boilers. The actual NO_x reduction that can be achieved at each site will depend on many factors including the extent of the equipment upgrade, the degree of control applied, and the boilers current configuration such as furnace size, number of burners and burner matrix. For example, the amount of flue gas recirculated has a strong influence on the percent NO_x reduction. Also, the amount that can be safely recirculated will depend on the optimization of the burner design in order to maintain safe flame conditions, and low emissions of other pollutants such as CO. In another example, the amount of SCR catalyst that can be retrofit may depend on site accessibility. Many ICI boilers are often located inside buildings making access for large retrofit difficult at best.

Table 7-2 lists the anticipated NO_x reductions that can be achieved on a yearly basis with the retrofit of candidate control techniques. These estimates are based on "model size"

TABLE 7-1. EXPERIENCE WITH NO_x CONTROL TECHNIQUES ON ICI BOILERS

NO _x control technique	Coal-fired			Oil-/natural-gas-fired			Nonfossil-fuel-fired		MSW-fired
	Field-erected PC-fired	Stoker	FBC	Field-erected watertube	Packaged watertube	Packaged firetube	Stoker	FBC	Mass burn
BT/OT					X	X			
WI/SI					X	X			
SCA	X	X ^a	X	X	X ^b		X ^a	X	X ^a
LNB	X			X	X	X			
FGR				X	X	X			X ^b
NGR	X ^b								X ^b
SNCR	X ^b	X	X	X	X ^b		X	X	X
SCR	X ^b		X ^b	X ^b					

7-2

BT/OT = Burner tuning/oxygen trim

WI/SI = Water injection/steam injection

SCA = Staged combustion air, includes burners out of service (BOOS), biased firing, or overfire air (OFA)

LNB = Low-NO_x burners

FGR = Flue gas recirculation

NGR = Natural gas reburning

SNCR = Selective noncatalytic reduction

SCR = Selective catalytic reduction

MSW = Municipal solid waste

^aSCA is designed primarily for control of smoke and combustible fuel rather than NO_x. Optimization of existing SCA (OFA) ports can lead to some NO_x reduction.

^bLimited experience.

TABLE 7-2. NO_x EMISSIONS REDUCTION FROM MODEL BOILERS

Boiler type and size, MMBtu/hr	Baseline NO _x			NO _x control technique	Control NO _x level, lb/MMBtu	NO _x reduction			
	lb/MMBtu	Tons/yr (0.50 CF ^a)				%	Tons/yr (0.33 CF)	Tons/yr (0.50 CF)	Tons/yr (0.66 CF)
PC	400	0.70	610	BT/OT	0.62	15	46	70	93
				LNB	0.35	50	200	310	400
				NGR	0.28	60	240	370	490
				SNCR	0.39	45	180	270	360
				SCR	0.14	85	320	490	650
Stoker coal	250	0.53	290	SCA	0.42	20	40	60	79
				SNCR	0.29	45	86	130	170
FBC coal	400	0.32	280	SCA	0.19	40	75	110	150
				SNCR	0.13	75	110	170	220
FE-WT gas	300	0.26	150	BT/OT	0.20	15	13	20	26
				SCA	0.15	35	35	53	69
				LNB	0.12	55	60	92	120
				LNB+FGR	0.10	60	69	110	140
				SNCR	0.10	60	69	110	140
				SCR	0.04	85	95	140	190
FE-WT No. 2 oil	300	0.21	140	BT/OT	0.18	15	13	20	26
				SCA	0.13	40	35	53	69
				LNB	0.10	50	48	72	95
				LNB+FGR	0.08	60	56	85	110
				SNCR	0.10	50	48	72	95
				SCR	0.03	80	78	120	160
FE-WT No. 6 oil	300	0.38	250	BT/OT	0.32	15	26	34	52
				SCA	0.29	25	39	59	78
				LNB	0.19	50	82	120	160
				FGR	0.34	10	17	26	35
				LNB+FGR	0.15	60	100	150	200
				SCR	0.08	80	130	200	260
PK-WT gas	50	0.14	15	BT/OT	0.12	15	1.4	2.2	2.8
				WI/SI	0.06	55	5.8	8.8	12
				LNB	0.08	45	4.3	6.6	8.7
				LNB+FGR	0.06	57	5.8	8.8	12
				SNCR	0.07	50	5.1	7.7	10
				SCR	0.02	85	8.7	13	17
PK-WT No. 2 oil	50	0.13	14	BT/OT	0.11	15	1.4	2.2	2.8
				LNB	0.10	25	2.2	3.3	4.3
				FGR	0.07	45	4.3	6.6	8.6
PK-WT No. 6 oil	50	0.36	39	BT/OT	0.31	15	3.6	5.5	7.2
				LNB	0.19	45	12	19	25
				LNB+FGR	0.15	60	15	23	30
				SCR	0.06	85	22	33	43
FT gas	15	0.10	3.3	BT/OT	0.09	15	0.22	0.33	0.44
				WI/SI	0.04	65	1.3	2.0	2.6
				LNB	0.08	20	0.43	0.66	0.87
				FGR	0.07	30	0.65	1.0	1.3
				LNB+FGR	0.03	70	1.5	2.3	3
FT No. 2 oil	15	0.17	5.6	BT/OT	0.15	15	0.43	0.66	0.86
				LNB	0.09	50	1.7	2.6	3.5
				FGR	0.12	30	1.1	1.6	2.2
FT No. 6 oil	15	0.31	10	BT/OT	0.26	15	1.1	1.6	2.2
				LNB	0.17	45	3.0	4.6	6.1
Stoker nonfossil	150	0.24	79	SNCR	0.11	55	28	43	56
FBC nonfossil	200	0.25	110	SNCR	0.11	55	40	61	80
Mass MSW	500	0.40	440	NGR	0.16	60	170	260	350
				SNCR	0.18	55	160	240	320

^aCF = capacity factor.

boilers, baseline emissions presented in Chapter 4, and NO_x reduction potentials presented in Chapter 5. Thus, a 400 MMBtu/hr (73 MWt) circulating FBC boiler burning coal with a baseline level of 0.32 lb/MMBtu could successfully employ SNCR to reduce emission levels to approximately 0.10 lb/MMBtu, corresponding to 210 tons/yr NO_x reduction at a capacity factor of 0.50.

7.1.2 CO Emissions

The CO emissions from ICI boilers are normally near zero, with the exception of a few boilers that have poor combustion air control or burner problems.¹ In an extensive study of industrial boilers' emissions, oil-fired units were found to have the lowest baseline CO emissions than either coal- or gas-fired units. This was attributed to higher excess air levels typically used to avoid visible smoke emissions when oil is burned.¹ CO emissions are generally caused by poor fuel-air mixing, flame quenching, and low residence time at elevated temperatures. Additionally, in some ICI furnace designs, CO emissions can also occur because of furnace gas leaks between furnace tubes.

The modification of combustion conditions aimed at reducing NO_x formation can result in increases in emissions of CO and hydrocarbons. This is because controls that reduce peak flame temperature and delay the mixing of fuel and air for NO_x reduction can cause some incomplete combustion of the fuel. However, the actual impact of NO_x control retrofits often depends on the operating conditions of the ICI boiler and the extent of improvements made to the combustion control system. In some cases, combustion NO_x control can also result in lower emissions of CO and other unburned fuel emissions.

Tables 7-3 through 7-5 list changes in emissions of CO measured following the retrofit of selected controls. These data can also be found in Appendix A of this document. As shown in Table 7-3, LNB, SCA and NGR controls achieved NO_x reductions in the range of 10 to 67 percent, with lowest reductions reported for the spreader stoker. Emissions of CO increased in nearly all cases, except for the retrofit of NGR on the cyclone boiler and one minor application of OFA for 10 percent reduction in NO_x in the spreader stoker. The implementation of staged air will typically result in increased CO emissions.

Data on the effect of NO_x controls on CO emissions from natural gas-fired ICI boilers were limited to the retrofit of FGR, LNB and FGR+LNB controls. Bulk dilution of combustion mixtures with FGR is limited by flame instability and reduced flammability. Slightly higher

**TABLE 7-3. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT —
COAL-FIRED BOILERS**

Boiler type	NO _x control	NO _x reduction, %	CO emissions impact		Reference
			Baseline/low NO _x , ppm	Average change, %	
WT	LNB	67	20-27/13-420	+800	2
	LNB+SCA	66	35/60-166	+215	3
Cyclone	NGR	65	30/30	0	4
Spreader stoker	SCA (OFA)	31	231-252/429	+80	5
		10	313/300	-4	6
		26	0/49	NA ^a	1
FBC	SCA	67	387-500/550-1,100	+86	7

^aNA = Not applicable.

TABLE 7-4. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT — GAS-FIRED BOILERS

Boiler type	NO _x control	NO _x reduction, %	CO emissions impact		Reference
			Baseline/ low NO _x , ppm	Average change, %	
PKG-FT	FGR	59	16/13	-18	8
	FGR	73	205/77	-62	9
	FGR	71	205/192	-6.3	9
	FGR	64	205/103	-50	9
	FGR	74	205/84	-59	9
	FGR	67	23/3	-87	8
	FGR	73	105/7	-93	8
	FGR	76	205/67	-67	9
	FGR	69	205/49	-76	9
	FGR	73	51/12	-76	10
	LNB	82	9/9	0	11
	LNB	53	51/24	-53	12
	LNB	32	39/8	-80	13
	LNB	78	856/30	-97	11
	LNB	NA ^a	342/30	-91	11
	LNB	NA	205/0	-100	11
	LNB	NA	9/9	0	12
	PKG-WT	FGR	74	205/62	-70
FGR		62	20/20	0	14
FGR		78	10/55	+450	14
FGR		53	205/205	0	9
FGR		73	14/22	+57	10
FGR		56	132/77	-42	10
LNB+FGR		55	60-125/2	-98	15

^aNA = Not applicable.

TABLE 7-5. CO EMISSION CHANGES WITH NO_x CONTROL RETROFIT — OIL-FIRED BOILERS

Oil/boiler type	NO _x control	NO _x reduction, %	CO emissions impact		Reference
			Baseline/low NO _x , ppm	Average change, %	
Distillate/WT	FGR	68	4/46	+1,000	16
	FGR	20	20/24	+20	14
Distillate/FT	LNB	15	6/13	+120	13
Residual/WT	FGR	4	20/20	0	14
	FGR	30	10/145	+1,400	14
	SCA (BOOS)	8	0/100	NA ^a	1
	SCA (BOOS)	40	0/20	NA	1

^aNA = Not applicable.

excess air levels at high rates of FGR (typically 15 to 20 percent) coupled with improved burner settings often can result in decreased CO emissions in addition to lower NO_x.

The data in Table 7-4 suggest that baseline CO emission levels from these units ranged from 9 to 856 ppm, and that the application of these controls, along with an increase in excess air, resulted in a reduction of CO in most cases. The average CO reduction for these retrofits was nearly 70 percent. One of the boilers with an initial low CO level, 10 ppm, showed an increase in CO to 55 ppm when FGR was implemented. In another application, the CO level in the low-NO_x configuration increased to only 22 ppm. Excess air is an important operational parameter that determines the level of CO emissions following the retrofit of NO_x controls. As suggested above, most of the reductions in CO levels from these gas-fired boilers resulted from increases in excess air. Low-NO_x firing with LNB typically causes an increase in CO at equivalent excess air levels. Also, there is the possibility of CO emissions occurring due to gas leaks between tubes from furnace to convective section.

Figure 7-1 illustrates the dependence of CO emissions on excess air. The rapid increase in CO is indicative of reduced fuel and air mixing that often accompanies low-NO_x combustion controls such as LNB and SCA. Each boiler type has its own characteristic "knee" in CO versus

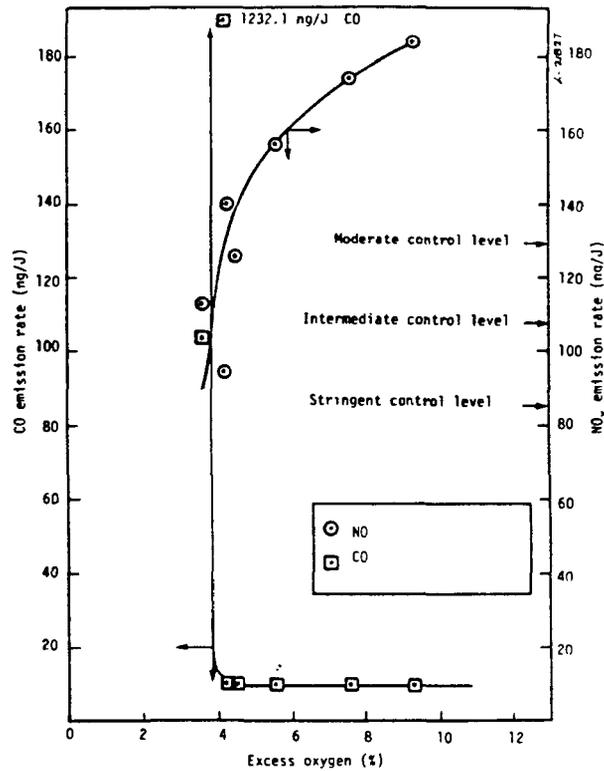


Figure 7-1. Changes in CO and NO_x emissions with reduced excess oxygen for a residual-oil-fired watertube industrial boiler.¹⁷

excess oxygen, depending on several factors such as fuel type and burner maintenance. California's SCAQMD permits CO levels up to 400 ppm from ICI boilers when NO_x emissions are reduced to strict levels.¹⁸ Also, the ABMA recommends an equivalent permitted level for CO for ICI boilers retrofitted with combustion controls.¹⁹

As shown in Table 7-5, the limited data base on fuel oil-fired ICI boilers indicates that baseline CO emission levels for these selected boilers were below 20 ppm. When NO_x controls such as LNB, FGR, and BOOS were applied, the CO emission levels increased in nearly all cases. The increase in CO, however, did not result in emission levels greater than 200 ppm, considered a safe limit for boiler operation.

7.1.3 Other Air Pollution Emissions

Other air pollution emissions that are a concern when NO_x controls are applied to ICI boilers are: ammonia (NH₃) and nitrous oxide (N₂O), unburned hydrocarbon (HC), particulate matter (PM), and air toxic emissions. Ammonia and N₂O emissions are associated with the use

of the SNCR process, primarily, and with SCR to a lesser extent. With either urea or ammonia hydroxide, unreacted ammonia emissions escape the SNCR temperature window resulting in direct emissions to the atmosphere. When sulfur-bearing fuels are burned, these emissions also pose an operational concern because of cold end corrosion and reduced heat transfer due to ammonium sulfate deposits. N_2O emissions are often a byproduct of the SNCR reaction, and, because of this, some N_2O emissions are likely with the process. In fact, the emissions have been reported with all reagents, particularly with urea reagents.²⁰ Some urea-based SNCR processes offer proprietary additives to minimize N_2O and NH_3 emissions.

SNCR vendors have paid particular attention to minimizing the breakthrough of unreacted ammonia considering the potentially negative impacts on the operation of the boiler. This is typically accomplished by careful selection of the injection location, method of injection to maximize mixing and residence time, and by careful control of reagent use with boiler load and operating conditions. Table 7-6 lists NH_3 slip levels reported for several retrofit installations. Boilers best suited for retrofit of SNCR are FBC, bubbling and circulating designs. Stokers and mass burning equipment have also been targets for application of SNCR because combustion modifications have traditionally been limited and ineffective. In spite of large NO_x reductions achieved in the units with the retrofit of SNCR, typically in the range of 50 to 70 percent, NH_3 slip levels have been reported mostly in the range of less than 30 ppm, and often less than 20 ppm. Monitoring of NH_3 emissions is often difficult because direct on line measurement methods are only now being introduced into the market place and are often very expensive, therefore not a part of the monitoring system at these facilities.

Pilot-scale and field tests have clearly shown that a portion of the NO_x reduced by the SNCR process is merely transformed into N_2O emissions. Figure 7-2 illustrates the amount of N_2O produced in relation to the amount of NO_x reduction with three types of SNCR chemicals: cyanuric acid, urea, and ammonia. These test results obtained in a pilot-scale facility, show that nearly 30 percent of the NO_x reduced can actually be transformed to N_2O with urea, less when using ammonia. Cyanuric acid is not a preferred chemical because of its obvious disadvantage in N_2O formation compared with the other two more popular SNCR chemicals. In addition, cyanuric acid is 6 to 8 times more expensive than urea.

Increases in HC, PM and air toxic emissions are primarily of concern with the application of combustion modification controls. Information on HC and air toxic emissions is sparse at best. However, the limited data suggest that HC emissions do not change when NO_x

**TABLE 7-6. AMMONIA EMISSIONS WITH UREA-BASED
SNCR RETROFIT^a**

Fuel/boiler type	NO_x reduction, %	Ammonia emission level, ppm	Reference
Coal/CFBC	57	<18	21
	70	<10	21
	30	<5	21
Wood/stoker	50	<40	21
	60	<27	21
	25	<21	21
	47	<10	21
	35	<21	21
	50	<40	21
	52	<30	21
	69	<25	21
MSW/mass	48	<10	21
	60	<10	21
	75	22	22
	70	17	21
	41	<5	21
	60	<7	21
	60	12	22
	60	<15	21
	50	<21	21
	58	22	22
	Paper/PKG-WT	50	<10
Fiber/PKG-WT	50	<10	21

^aTest data are included in Appendix A.

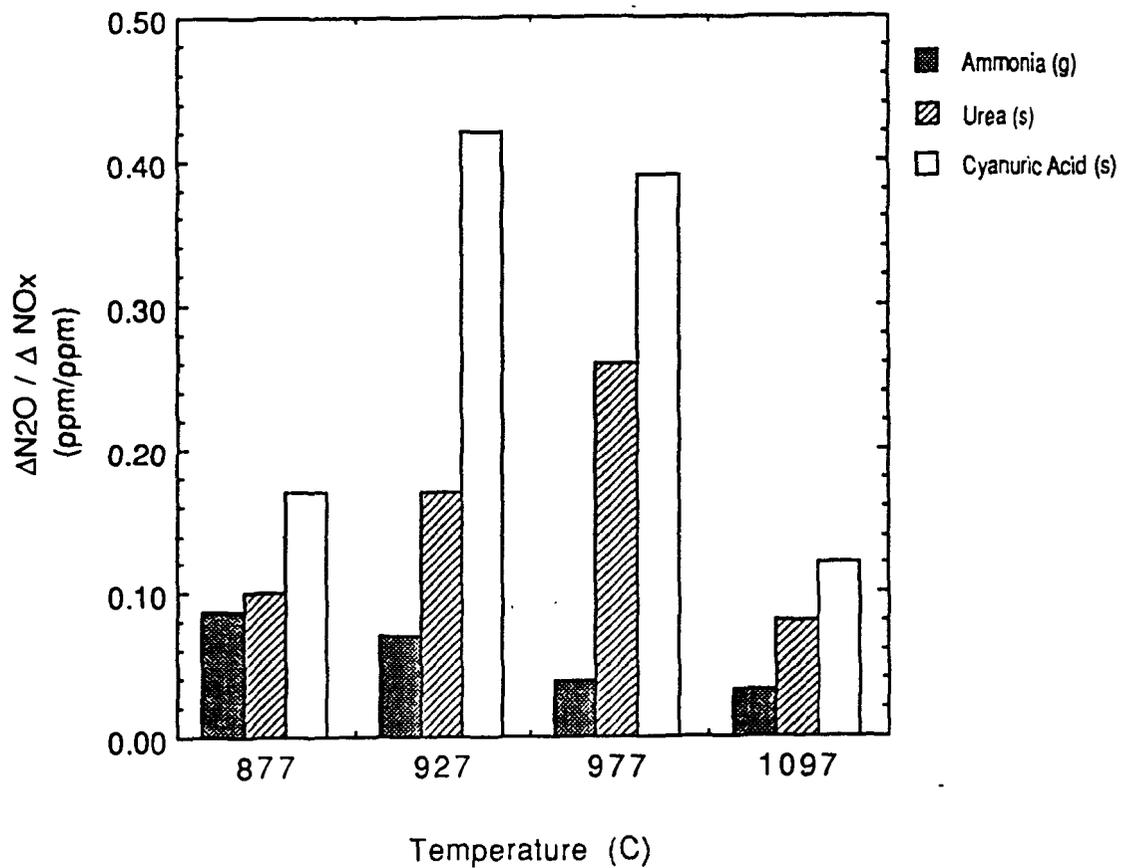


Figure 7-2. Pilot-scale test results, conversion of NO_x to N_2O ($\text{NO}_i = 300$ ppm, $\text{N}/\text{NO} = 2.0$).²⁰

controls are implemented. HC emissions are the result of poor combustion conditions such as inefficient fuel-air mixing, low temperatures, and short residence time. These emissions are most often preceded by large increases in CO, soot, and unburned carbon content. Thus, by limiting CO, smoke and unburned carbon in the flyash, HC emissions are also suppressed, and changes with retrofit of NO_x controls become imperceptible.

A comprehensive test program in the mid-1970s reported on the effect of combustion modification controls for industrial boilers. The results of this program revealed the following trends with respect to filterable $\text{PM}^{2.5}$:

- LEA reduced PM emissions on the order of 30 percent
- SCA, including BOOS, increased PM by 20 to 95 percent

- Burner adjustments and tuning had no effect on PM. However, the lower CO emission levels generally achieved with these adjustments would tend to lower PM as well.
- FGR resulted in an increase in PM from oil-fired packaged boilers by 15 percent over baseline levels

Information on the effects of LNB on PM is unavailable. However, newer burner designs have improved combustion air control and distribution. These features tend to compensate for the potential increase in PM from oil- and coal-burning equipment due to delayed mixing and lower peak temperatures that are needed to suppress NO_x formation.

7.2 SOLID WASTE DISPOSAL

NO_x reduction techniques that have a potential impact on the disposal of solid waste are combustion controls for PC-fired boilers and flue gas treatment systems for all applicable boilers. Combustion controls for PC-fired boilers are principally LNB and LNB+OFA. These controls can result in an increase in the carbon content of flyash that can preclude its use in cement manufacturing. Although primarily a practice of coal-fired power plants, the use of flyash for cement manufacturing reduces the ash disposal requirements. The impact of increased carbon content in the flyash from ICI boilers can result in an ash disposal requirement where one did not exist before. The environmental and economic impact of this requirement cannot be easily quantified.

An increase in flyash disposal can also occur with the use of flue gas treatment NO_x controls such as SNCR and SCR on coal-fired boilers. Both of these control options use ammonia-based reagents to reduce NO to N₂ and water. Excessive use of reagent can result in ammonia slip emissions, as discussed in Section 7.1.3. This excessive ammonia condenses on the flyash and, when present in quantities exceeding the odor threshold, would preclude its use as a cement additive. The likelihood or extent of this potential problem is not known because there is little experience in this country with the use of either SNCR or SCR for coal-fired boilers, especially PC-fired industrial boilers.

Finally, one potential solid waste impact is the result of catalyst replacement when the SCR process is used. With continuous use, the catalyst material will become less active. That is, the efficiency of the catalyst in reducing NO_x will gradually deteriorate. When this happens, the catalyst material must be replaced. This is often accomplished by replacing layers of individual modules starting with the most exposed layer (at the inlet), until all the catalyst

material is finally replaced. Performance guarantees for SCR catalysts are often set at 3 years, or 24,000 hours, for natural-gas-fired applications, and 2 years, or 16,000 hours, for oil and coal applications. However, some catalysts have shown longer life, 8 to 10 years, when applied on clean-burning fuel.²⁴

The disposal of spent catalyst can present a potential environmental impact because some of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under RCRA and its amendments. For example, vanadia and titania catalysts are considered hazardous material. However, recent industry trends have shown that these material are readily regenerable. In fact, many catalyst vendors recycle this material thus avoiding any disposal problem for the user. Some of the catalysts, especially those that use rare earth material such as zeolites, are not hazardous and their disposal does not present an adverse environmental impact.

7.3 WATER USAGE AND WASTEWATER DISPOSAL

The only increase in water use is associated with the use of WI or SI and potentially with the use of flue gas treatment NO_x controls, especially SNCR. The use associated with WI or SI injection is an obvious one. The amount of water used does often not exceed 50 percent of the total fuel input on a weight basis. This is because excessive use of flame quenching with water can result in high emissions of CO and high thermal efficiency loss. Therefore, a 50 MMBtu/hr (15 MWt) boiler would use approximately 600,000 gal (2.2 million L) of water per year when operating with a 50 percent capacity factor.

An increase in water use and wastewater disposal requirement could result from the use of SNCR techniques, either urea or ammonia based. This is because ammonia slip when combined with SO₃ in the flue gas will form corrosive salts that deposit on heat transfer surfaces such as air heaters. These deposits must be removed to minimize pressure drop and material corrosion. Air heater acid washing could become more frequent. This practice would result in greater generation of wastewater requiring treatment and disposal. However, urea-based SNCR can actually use wastewater as reagent dilution water prior to injection, thus minimizing the amount of wastewater generated. Increased air heater washing has not been reported in the more than 80 combustion sources equipped with SNCR in the United States.

7.4 ENERGY CONSUMPTION

This section discusses the energy consumption associated with NO_x control techniques for ICI boilers. Energy consumption can come in various forms: a boiler fuel consumption

penalty caused by reduced thermal or combustion efficiency; an increase in electrical power to operate fans and pumps; an increase in fuel consumption due to reheat of flue gas; an increase in energy for treatment and disposal of solid or liquid wastes generated by the control technology. Some controls offer the potential for a reduction in energy consumption. Trimming the excess oxygen necessary to assure complete combustion is the most noted of these energy savings techniques. Others include the installation of economizers and air preheaters to recover waste heat in some older and smaller boilers. However, contrary to oxygen trim, these other techniques do not offer a potential for NO_x reduction as well.

7.4.1 Oxygen Trim (OT)

ICI boilers are operated at various excess air levels, ranging from about 10 to over 100 percent of the theoretical amount of air needed to complete combustion. Some amount of excess air is required regardless of fuel burned and method of burning because fuel and air do not perfectly mix and the residence time in the combustion chamber is not infinite. This additional air provides a safe method to increase flame turbulence and assure near complete combustion of fuel. The type of fuel burned and the method of burning determines the minimum amount of excess air required for safe and near complete combustion. For example, the following minimum excess O₂ levels are considered typical for these fuels²⁵:

- Natural gas, 0.5 to 3.0 percent
- Oil fuels, 2.0 to 4.0 percent
- Pulverized coal, 3.0 to 6.0 percent
- Coal stoker, 4.0 to 8.0 percent

Generally, excessive combustion air are found in poorly maintained, unattended boilers. This added air provides some measure of safety for burning all the fuel, especially when the operation of boilers is poorly supervised. In many such instances, burner tuning and combustion control adjustments and equipment improvements can be readily made that reduce the amount of excess air resulting in a thermal efficiency improvement and reduced NO_x emissions without compromising the safety of the operation of the unit. Qualified boiler and burner engineers and consultants can upgrade key components of the combustion air control system, including the installation of monitors for O₂ and CO levels in the stack.

Figure 7-3 illustrates the efficiency improvement that can be obtained by reducing excess combustion air in ICI boilers. For example, a 10-percent reduction in excess air (say, from O₂ of 3.5 to 2.0 percent) would result in an efficiency improvement of approximately 0.6 percent

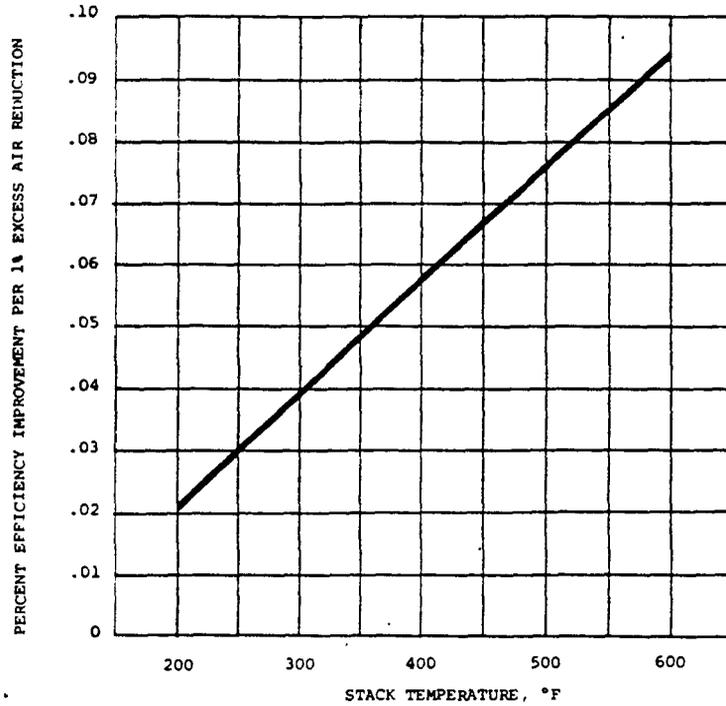


Figure 7-3. Curve showing percent efficiency improvement per every 1 percent reduction in excess air. Valid for estimating efficiency improvements on typical natural gas, No. 2 through No. 6 oils, and coal fuels.²⁵

when the stack temperature is at 200°C (400°F). For a natural-gas-fired boiler with a capacity of 150 MMBtu/hr and a capacity factor of 0.5, this improvement will result in fuel savings of about 3.7 million ft³ of natural gas per year or about \$13,600/yr savings. Algebraically, the relationship between boiler efficiency and excess air can be expressed as follows²⁶:

$$\Delta E = \frac{(T - 70)}{63.1} \times \frac{\%EA}{89.5} \quad (7-1)$$

Where:

T = stack temperature in °F

% EA = the change in percent excess air

The reduction in excess air, however, can result in some increase in unburned fuel primarily in the form of CO emissions, when gas or fuel oil is burned, and in unburned carbon in the flyash, when coal is burned. Increased emissions of CO have a detrimental effect on the

efficiency, as illustrated in Figure 7-4. For example, the example boiler describe above operating at 2.0 percent oxygen might have an increase in CO to about 350 ppm, measured on a dry basis in the flue gas. This amount of CO would reduce the efficiency gain of 0.6 percent described above by about 0.1 percent. Besides this efficiency loss, the air quality impact of increased CO must be considered. The objective of boiler/burner tuning, however, is to reduce excess air without increasing CO emissions or unburned carbon, as discussed in Chapter 5. Algebraically, the relationship between boiler efficiency and CO can be expressed as follows²⁶:

$$\Delta E = \frac{CO}{3,682} \times \left[1 + \frac{\%EA}{89.5} \right] \quad (7-2)$$

Where:

T = stack temperature in °F

% EA = the change in percent excess air

7.4.2 Water Injection/Steam Injection (WI/SI)

The injection of water or steam in the burner zone to reduce peak flame temperature and NO_x will have a detrimental impact on the efficiency of the boiler. Figure 7-5 illustrates the relationship between the amount of water or steam injected and the reduction in the thermal efficiency of the boiler. The data were developed using standard American Society of Mechanical Engineers (ASME) boiler efficiency calculation procedures.²⁷ The amount of water injected is typically in the range of 20 to 50 percent of the fuel input on a weight basis. Higher injection levels can cause large increases in CO and HC emissions. The corresponding loss in thermal efficiency when using water is in the range of about 1 to 2.5 percent. The efficiency loss when using an equivalent amount of steam is lower. However, the NO_x reduction efficiency is also lower.

7.4.3 Staged Combustion Air (SCA)

The operation of an ICI boiler with staged combustion air, whether BOOS or OFA, will likely not require additional energy. Taking selected burners out of service will not influence the air distribution. Also any increase in fan power associated with the operation of OFA ports will likely be compensated, for the most part, with reduction of air flow at the original burners.

7.4.4 Low-NO_x Burners (LNBs)

Minor or no increases in energy consumption are anticipated with the retrofit of LNB technology. This is because newer LNB designs operate at lower excess air levels, thus requiring lower fan power. Some increases in windbox pressures are likely with some retrofits because of

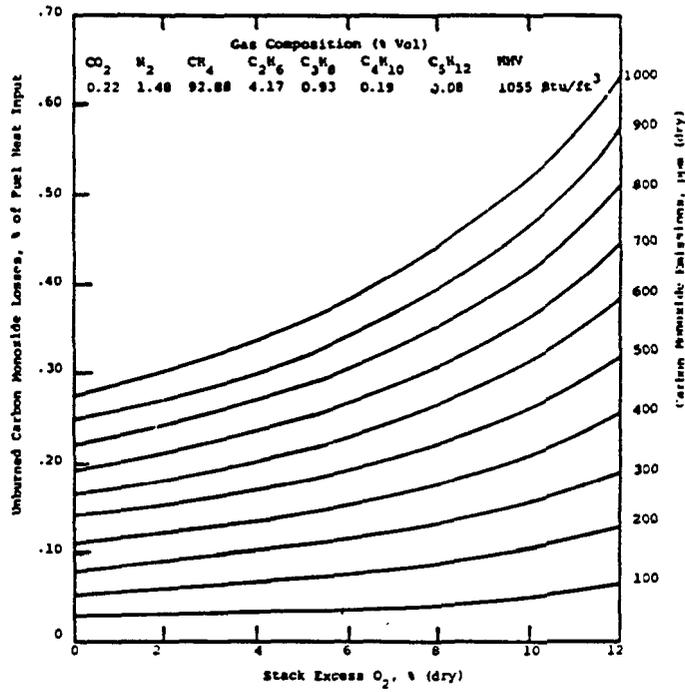


Figure 7-4. Unburned carbon monoxide loss as a function of excess O₂ and carbon monoxide emissions for natural gas fuel.²⁸

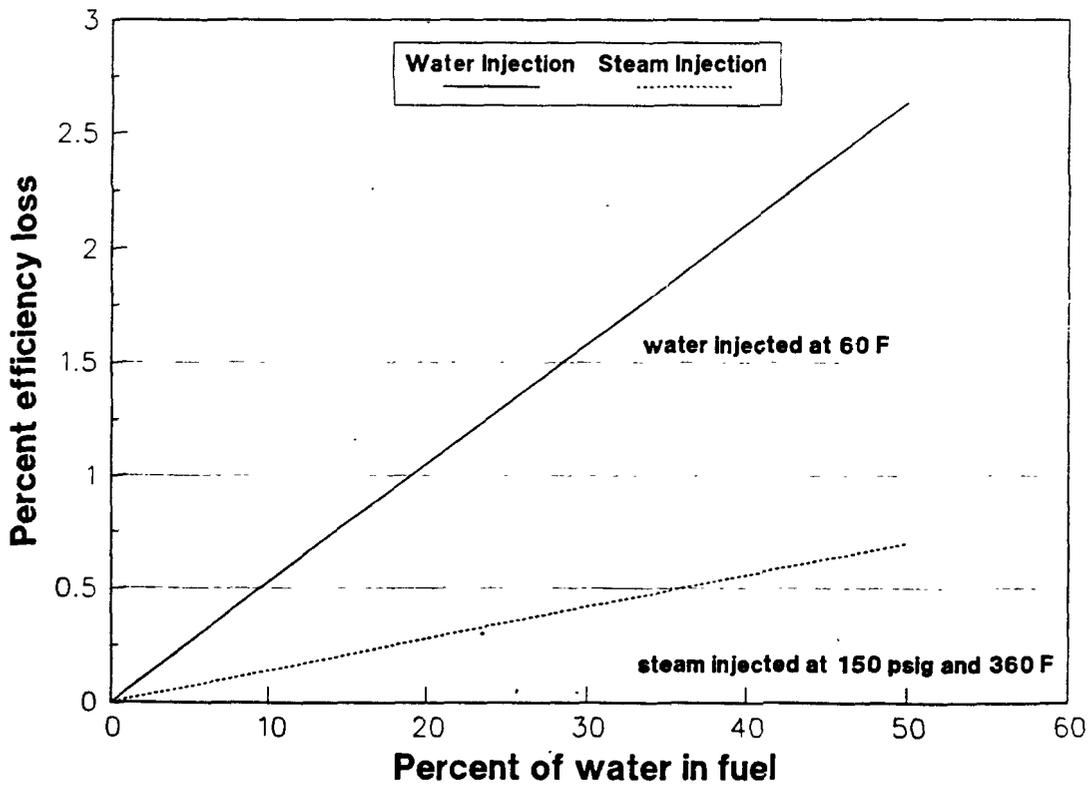


Figure 7-5. Energy penalty associated with the use of WI or SI for NO_x control in ICI boilers.

higher gas velocities and more register control. This increase in pressure drop will tend to increase fan power somewhat, or compensate for the reduction in energy consumption at lower combustion air levels.

7.4.5 Flue Gas Recirculation (FGR)

The retrofit of FGR requires the installation of a fan to recirculate a portion of the hot flue gas back to the burner(s). The operation of the fan will result in an increase in energy consumption. Figure 7-6 illustrates the calculated power requirements with the use of FGR. The relationship between power consumption and FGR rate is based on the following equation:

$$\frac{kWh}{yr} = (0.5) (8,760 \text{ hr/yr}) (0.0013558 \text{ kW/ft-lb}) (FGR \text{ ft}^3/\text{s}) (\Delta P \text{ lb/ft}^2) \quad (7-3)$$

Where:

0.5 = The capacity factor

ΔP = Assumed to be 10 inches of water to account for efficiency loss

Some additional energy penalty will also be incurred with an increase in pressure drop in the windbox. However, any additional penalty is minor compare to the energy consumption for the FGR fan.

7.4.6 Selective Noncatalytic Reduction (SNCR)

Energy consumption in the SNCR process is related to pretreatment and injection of ammonia-based reagents and their carrier gas or liquids. Liquid ammonia or urea are injected in liquid form at high pressures to ensure efficient droplet atomization and dispersion. In some Thermal DeNO_x installations, anhydrous ammonia is stored in liquid form under pressure. The liquid ammonia must be vaporized with some heat, mixed with carrier gas (air or steam) and then injected for adequate mixing. The amount of electricity used depends on whether the process uses air or steam for carrier gas. If steam is used, less electricity is needed but power consumption must take into consideration the amount of steam used.

Data supplied by Exxon suggest that the amount of electricity needed for the Thermal DeNO_x Process is on the order of 1.0 to 1.5 kW for each MWt of boiler capacity (or 0.29 to 0.44 kW/MMBtu/hr) when using compressed air as the carrier medium.²⁹ The actual amount of electricity will depend on the baseline NO_x emission level, the NH₃/NO ratio used, and the NO_x reduction target. Therefore, a 250 MMBtu/hr (73 MWt) boiler operating with a capacity factor of 0.5 will use approximately:

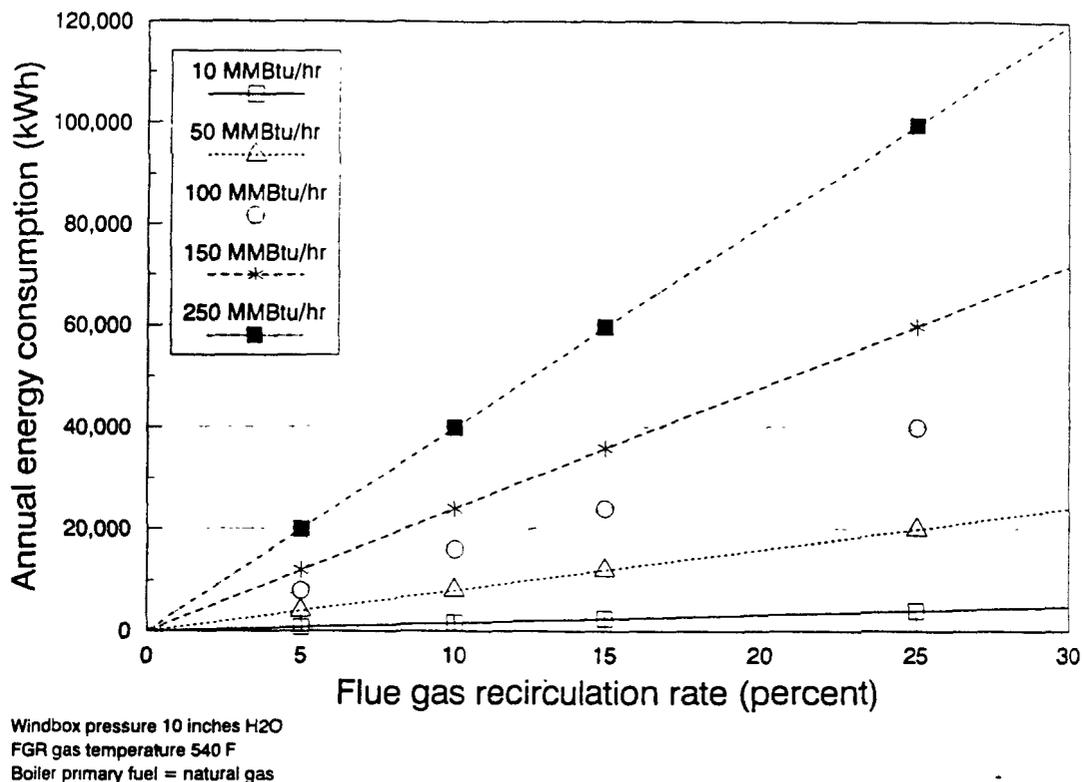


Figure 7-6. Estimated energy consumption in FGR use.

$$0.29 \text{ kW/MMBtu/hr} \times 250 \text{ MMBtu/hr} \times 0.5 \times 8,760 \text{ hr/yr} = 319,740 \text{ kWh} \quad (7-4)$$

which corresponds to about \$16,000/yr electricity cost. For steam-assisted ammonia injection, electricity use reduces to about 0.2 to 0.3 kW/MWt or 0.05 to 0.08 kW/MMBtu/hr boiler capacity. The amount of steam used is on the order of 25 to 75 lb/hr/MWt. In general, ammonia is most economically injected using compressed air rather than steam. Data supplied by Nalco Fuel Tech suggest that the urea-based SNCR process uses much lower levels of electricity than either ammonia-based SNCR or SCR. Typical auxiliary power requirements for an ICI boiler using urea-based SNCR ranges from 20 to 60 kW.³⁰

7.4.7 Selective Catalytic Reduction (SCR)

Energy consumption for the use of SCR systems consists of three principal areas: (1) the energy needed to store, pretreat and inject the chemical reagent ammonia or ammonia hydroxide; (2) the increased fan power to overcome the added pressure drop of the catalyst reactor in the flue gas; and (3) the thermal efficiency loss associated with maintaining the

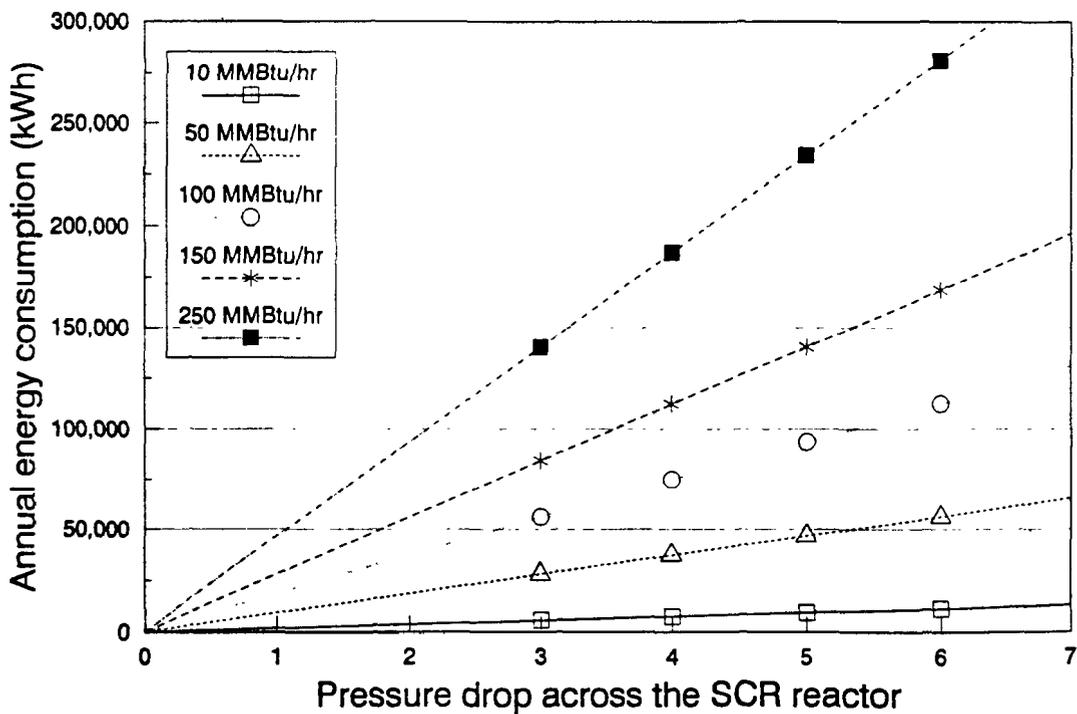
catalyst reactor temperature within the specifications for optimum performance at variable boiler load. The energy to store, pretreat, and inject the reagent is equivalent to that of an SNCR system. Estimates of increased pressure drop across the catalyst vary with the various catalyst vendors and applications, primarily fuel. Typically, the pressure drop across a catalyst is on the order of 3 to 6 inches of water. Figure 7-7 illustrates the energy consumption associated with the additional pressure drop. The relationship between energy consumption and pressure drop across the catalyst is based on the following equation:

$$\frac{kWh}{yr} = (\Delta P \text{ in } H_2O) \left(0.0361 \frac{lb}{in^2} \text{ in } H_2O \right) \left(144 \frac{in^2}{ft^2} \right) \left(Q \frac{ft^3}{s} \right) \frac{0.5}{0.85} \times 8.760 \quad (7-5)$$

Where:

ΔP = Pressure drop across catalyst, in inches of water

Q = Flue gas flowrate in actual ft^3/s



Flue gas temperature = 540 F
 Fan efficiency 85 percent
 Primary fuel = natural gas

Figure 7-7. Estimated increase in energy consumption with SCR pressure drop.

Finally, the third potentially large source of energy consumption is the result of increased flue gas temperature at the stack at low boiler loads. This increase in stack temperature is associated with the bypass of heat exchange areas or increased fuel consumption to maintain the catalyst at optimum reaction temperature. Figure 7-8 illustrates the loss in boiler thermal efficiency as stack temperature increases. For example, at 20 percent excess air level the thermal efficiency loss is approximately 1.2 percent for an increase in flue gas temperature of 50°F. From an efficiency effect standpoint, each 10°F increase in stack temperature is equivalent to a 583-ppm increase in CO emissions. Whether a facility will incur in this energy penalty will depend on the retrofit configuration, the boiler's load cycle, and the operating temperature window of the catalyst.

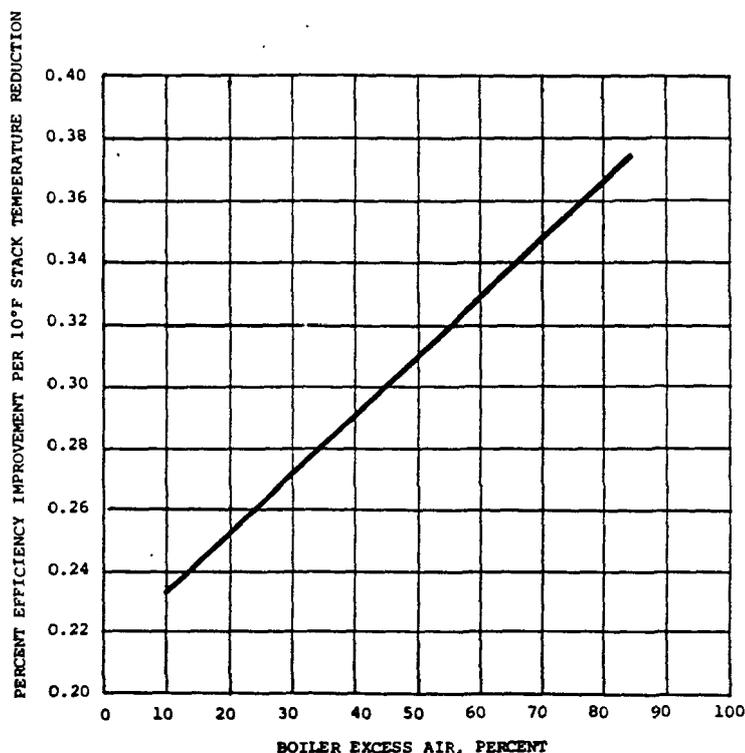


Figure 7-8. Curve showing percent efficiency improvement per every 10°F drop in stack temperature. Valid for estimating efficiency improvements on typical natural gas, No. 2 through No. 6 oils, and coal fuels.²⁵

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APPENDIX A. ICI BOILER BASELINE EMISSION DATA

This appendix lists baseline NO_x, CO, and unburned THC data for more than 200 ICI boilers. The data were obtained primarily from published technical papers and EPA documents summarizing data from numerous test programs. Boiler data are listed by fuel type, with the exception of FBC boilers which are listed separately. More detailed data may be obtained by referring directly to the individual references.

UNCONTROLLED EMISSIONS DATA
 COAL-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	FIRING METHOD	RATED INPUT CAPACITY (MMBtu/hr)	OPERATING INPUT LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
					NOx (ppm@3%O2)	NOx (lb/MMBtu)	CO (ppm@3%O2)	CO (lb/MMBtu)	UHC (ppm@3%O2)	UHC (lb/MMBtu)	
200	WT	PC WALL	111	99	640	0.865	40	0.033	29.8	0.014	1
FREMONT 6	WT	PC WALL	160	108	591	0.799	11	0.009	40.4	0.019	2
FREMONT 6	WT	PC WALL	160	112	438	0.592	10	0.008			2
FREMONT 6	WT	PC WALL	160	113	341	0.461	61	0.050			2
FREMONT 6	WT	PC WALL	160	140	488	0.659	14	0.012			2
FREMONT 6	WT	PC WALL	160	115	390	0.527	12	0.010			2
FREMONT 6	WT	PC WALL	160	134	659	0.891	20	0.016			2
224	WT	PC WALL	194	126			0	0.000	4.3	0.002	1
225	WT	PC WALL	194	126			0	0.000	2.1	0.001	1
ALMA 3	WT	PC WALL	230	200	597	0.807	17	0.014	28.0	0.013	2
223	WT	PC WALL	260	158			0	0.000	2.1	0.001	1
9	WT	PC WALL	624	499	601	0.812			6.4	0.003	1
15	WT	PC WALL	624	499	371	0.502	0	0.000			1
343	WT	PC TANG	117	110	482	0.651			10.6	0.005	3
321	WT	PC TANG	184	145	427	0.577	170	0.140	12.8	0.006	3
6	WT	PC TANG	281	225	392	0.530	0	0.000	19.1	0.009	1
341	WT	PC TANG	303	243			70	0.058	8.5	0.004	1
13	WT	PC TANG	401	325	501	0.677	0	0.000	10.6	0.005	1
10	WT	CYCLONE	640	512	830	1.121	0	0.000			1
344		S	20	20					31.9	0.015	3
345		S	20	20					8.5	0.004	3
320		S	24	24					31.9	0.015	3
24		S	444	311	306	0.414	435	0.358			1
20	WT	SS	14	9			164	0.135			1
325		SS	30	21	446	0.602			27.7	0.013	3
4	WT	SS	63	50	482	0.651	36	0.030	14.9	0.007	1
FAIRMONT	WT	SS	80	57	317	0.428	41	0.036			2
FAIRMONT	WT	SS	80	59	312	0.422	56	0.046			2
FAIRMONT	WT	SS	80	60	260	0.351	77	0.063			2
FAIRMONT	WT	SS	80	61	311	0.420	57	0.047			2
5	WT	SS	89	75	482	0.651	130	0.107	14.9	0.007	1
SITE F	WT	SS	98	74	346	0.468	146	0.12			4
SITE F	WT	SS	98	74	336	0.454	139	0.114			4
SITE G	WT	SS	99	98	400	0.54			38.3	0.018	4
SITE G	WT	SS	99	98	423	0.572					4
MADISON	WT	SS	100	60	443	0.599	177	0.146			2
MADISON	WT	SS	100	90	438	0.592	455	0.374			2
226		SS	154	62			0	0.000	0.0	0.000	1
WILMAR	WT	SS	160	124	415	0.561	289	0.238			2
WILMAR	WT	SS	160	125	395	0.534	509	0.419			2
WILMAR	WT	SS	160	126	366	0.495	642	0.528			2
WILMAR	WT	SS	160	128	315	0.426	2200	1.811			2
3	WT	SS	166	135	384	0.519	36	0.030	29.8	0.014	1
340		SS	181	145			173	0.142	8.5	0.004	1
221		SS	186	170			0	0.000	10.6	0.005	1
SITE E	WT	SS	232	142	477	0.645	81	0.067			5
14	WT	SS	254	168	337	0.456	0	0.000			1
8	WT	SS	395	277	566	0.765					1

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A-3

UNCONTROLLED EMISSIONS DATA
 COAL-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	FIRING METHOD	RATED INPUT CAPACITY (MMBtu/hr)	OPERATING INPUT LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
					NOx (ppm@3%O2)	NOx (lb/MMBtu)	CO (ppm@3%O2)	CO (lb/MMBtu)	UHC (ppm@3%O2)	UHC (lb/MMBtu)	
342		OFS	18	18	325	0.440	1	0.001	46.8	0.022	3
STOUT 2	WT	OFS	45	33	160	0.216					2
STOUT 2	WT	OFS	45	36	176	0.238	94	0.077			2
STOUT 2	WT	OFS	45	30	156	0.211	2000	1.646			2
STOUT 2	WT	OFS	45	30	158	0.214	2000	1.646			2
STOUT 2	WT	OFS	45	30	143	0.193	2000	1.646			2
STOUT 2	WT	OFS	45	40	221	0.299					2
STOUT 2	WT	OFS	45	44	185	0.250	1120	0.922			2
STOUT 2	WT	OFS	45	30	187	0.253	23	0.019			2
SITE H	WT	OFS	60	60	308	0.416	239	0.197	51.1	0.024	6
SITE K	WT	OFS	63	64	240	0.324	139	0.114			4
EAU CLAIRE	WT	OFS	70	43	233	0.315	134	0.110			2
EAU CLAIRE	WT	OFS	70	45	255	0.345	41	0.034			2
EAU CLAIRE	WT	OFS	70	49	211	0.285	102	0.084			2
SITE J	WT	OFS	77	77	261	0.353					4
SITE I	WT	OFS	95	97	169	0.229					4
SITE I.	WT	OFS	95	99	296	0.4					4
25		OFS	102	81	158	0.214	36	0.030			1
220		UFS	3	1					21.3	0.010	3
12	FT	UFS	12	10	358	0.484	1136	0.935			1
11	FT	UFS	12	10	282	0.381	341	0.281			1
1	WT	UFS	75	60	275	0.372	0	0.000			1
2	WT	UFS	78	60	232	0.314	0	0.000			1

WT: WATERTUBE
 FT: FIRETUBE
 PC: PULVERIZED COAL
 WALL: WALL FIRED
 TANG: TANGENTIAL FIRED
 OFS: OVERFEED STOKER
 SS: SPREADER STOKER
 UFS: UNDERFEED STOKER
 S: STOKER

A-4

UNCONTROLLED EMISSIONS DATA
RESIDUAL OIL-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	BOILER CAPACITY (MMBtu/hr)	OPERATING LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
				NOx (lb/MMBtu)	NOx (ppm@3%O2)	CO (lb/MMBtu)	CO (ppm@3%O2)	UHC (lb/MMBtu)	UHC (ppm@3%O2)	
25	FT	3.9	3.0	0.372	294	0.016	21			1
25	FT	3.9	3.0	0.307	243	0.019	25			1
25	FT	3.9	3.6	0.377	298	0.021	27			1
25	FT	3.9	3.6	0.356	281	0.023	30			1
10	FT	7.3	7.0	0.381	301	0.017	22	0.003	7	1
10	FT	7.3	7.0	0.354	280	0.000	0			1
23-1	FT	9.0	8.6	0.389	307	0.016	21			7
11	FT	10.1	11.0	0.235	186	0.000	0			1
24-TV	FT	13.0	13.5	0.239	189	0.000	0			7
13	FT	15.4	13.0	0.233	184	0.000	0	0.002	5	1
12	FT	18.5	18.0	0.228	180	0.000	0			1
12	FT	18.5	18.0	0.207	164	0.010	13			1
346	FT	22.6	18			0.007	9	0.014	32	3
26-1	FT	23.0	21.6	0.213	168	0.010	13			7
14	WT	12.9	10.0	0.793	626	0.028	36	0.031	70	1
1	WT	21.8	17.5	0.449	355	0.000	0	0.014	32	1
1	WT	21.8	17.5	0.428	338	0.000	0			1
22	WT	21.9	17.5	0.212	167	0.000	0	0.000	0	1
22	WT	21.9	17.5	0.221	175	0.000	0			1
LOC 19	WT	22.0	17.6	0.278	220	0.003	4			7
19-2	WT	22.0	17.8	0.217	171	0.015	19			7
19-1	WT	22.0	18.3	0.459	363	0.000	0			7
19-1	WT	22.0	18.3	0.436	344	0.000	0			7
23	WT	23.7	19.0	0.286	226	0.003	4	0.003	7	1
23	WT	23.7	18.9	0.280	221	0.003	4	0.005	11	1
23	WT	23.7	20.7	0.274	216	0.016	21	0.000	0	1
23	WT	23.7	19.5	0.314	248	0.028	36	0.003	7	1
337	WT	24.8	16.1			0.114	148	0.016	36	3
2	WT	30.5	19.2	0.256	202	0.000	0			1
ECCC	WT	31.0	24.2	0.200	158	0.008	10			7
20	WT	49.8	39.8	0.254	201	0.000	0	0.007	16	1
37-2	WT	50.0	40.5	0.251	198	0.000	0			7
153	WT	52.4	43	0.451	356	0.014	18	0.015	34	1
152	WT	53.1	43	0.437	345	0.012	16	0.013	30	1
LOC 38	WT	56.0	47.6	0.386	305	0.017	22			7
38-2	WT	56.0	45.4	0.419	331	0.000	0			7
21	WT	56.3	45.0	0.426	337	0.000	0			1
6	WT	78.4	65.0	0.240	190	0.000	0			1
24	WT	79.1	66.4			0.017	22			1
16-2	WT	81.0	67.2	0.256	202	0.000	0			7
2-4	WT	81.0	64.8	0.641	506	0.000	0			7
15	WT	85.7	66.0	0.598	472					1
124	WT	86.2	57.8					0.023	52	3
28-1	WT	88.0	36.1	0.263	208	0.000	0			7
163	WT	92.8	45	0.254	201	0.014	18	0.001	2	1
160	WT	93.4	62.6	0.340	269	0.016	21	0.001	2	1
138	WT	93.7	86.2					0.002	5	3
20-4	WT	100.0	64.0	0.398	314	0.000	0			7

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A-5

UNCONTROLLED EMISSIONS DATA
RESIDUAL OIL-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	BOILER CAPACITY (MMBtu/hr)	OPERATING LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
				NOx (lb/MMBtu)	NOx (ppm@3%O2)	CO (lb/MMBtu)	CO (ppm@3%O2)	UHC (lb/MMBtu)	UHC (ppm@3%O2)	
5	WT	114.0	90.0	0.316	250	0.000	0			1
17	WT	118.2	100.5	0.598	472					1
3	WT	123.6	85.3	0.421	333	0.066	86			1
4	WT	125.0	80.0	0.391	309	0.000	0			1
202	WT	136.5		0.374	295	0.012	16	0.007	16	1
7	WT	138.5	105.2	0.321	254	0.000	0			1
19	WT	155.1	121.0	0.344	272	0.000	0	0.004	9	1
120	WT	159.0	127					0.002	5	3
16	WT	164.9	131.9	0.430	340					1
8	WT	208.4	168.8	0.307	243	0.000	0			1
18	WT	216.4	158.0	0.384	303	0.000	0	0.016	36	1
9	WT	658.8	527.0	0.342	270			0.003	7	1

WT: WATERTUBE
FT: FIRETUBE

UNCONTROLLED EMISSIONS DATA
DISTILLATE OIL-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	BOILER CAPACITY (MMBtu/hr)	OPERATING LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
				NOx (lb/MMBtu)	NOx (ppm@3%O2)	CO (lb/MMBtu)	CO (ppm@3%O2)	UHC (lb/MMBtu)	UHC (ppm@3%O2)	
14	FT	3.7	2.5	0.149	118	0.007	9			1
14	FT	3.7	2.5	0.114	90	0.007	9			1
14	FT	3.7	2.0	0.119	94	0.014	18			1
8	FT	7.3	7.0	0.163	129	0.000	0			1
4	FT	10.7	11.0	0.165	130	0.000	0			1
3-2	FT	13.0	6.5	0.221	175	0.000	0			4
2	FT	14.4	10.0	0.216	171					1
11	FT	15.3	13.0	0.107	85	0.000	0			1
5	FT	20.6	18.0	0.149	118	0.000	0			1
5	FT	20.6	18.0	0.151	119	0.000	0			1
6	FT	25.0	20.0	0.247	195	0.000	0	0.012	27	1
4-4	FT	25.0	11.8	0.224	177					4
12	WT	21.5	17.8	0.157	124	0.003	4	0.001	2	1
3	WT	21.9	17.5	0.102	81	0.000	0	0.000	0	1
3	WT	21.9	17.5	0.126	100	0.000	0	0.001	2	1
3	WT	21.9	17.5	0.084	66	0.038	49			1
19-1	WT	22.0	17.6	0.134	106	0.000	0			4
19-1	WT	22.0	14.5	0.107	85	0.000	0			4
LOC 19	WT	22.0	18.3	0.154	122	0.003	4			4
19-1	WT	22.0	17.6	0.098	77	0.000	0			4
13	WT	22.5	18.0	0.150	119	0.010	13	0.003	7	1
7	WT	33.7	29.0	0.111	88					1
1-2	WT	36.0	18.0	0.136	107					4
1-3	WT	38.0	30.0	0.158	125	0.000	0			4
10	WT	47.1	33.0	0.158	125	0.000	0			1
140	WT	48.6	38.9					0.001	2	3
173	WT	48.9	45.5			1.177	1528	0.001	2	1
139	WT	53.3	42.7					0.003	7	3
174	WT	127.3	89.1			0.837	1086	0.001	2	1
170	WT	136.9	98.6			0.507	658	0.009	20	1
1	WT	137.4	109.9	0.228	180	0.000	0			1
172	WT	183.2	109.9			0.623	809	0.001	2	1
9	WT	219.4	160.2	0.233	184	0.000	0	0.004	9	1
JAMES RIVER	WT	240.0		0.180	142					8
339	CI	5.9	4.7			0.158	205	0.022	50	3

WT: WATERTUBE
FT: FIRETUBE
CI: CAST IRON

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UNCONTROLLED EMISSIONS DATA
NATURAL GAS-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	BOILER CAPACITY (MMBtu/hr)	OPERATING LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
				NO _x (lb/MMBtu)	NO _x (ppm@3%O ₂)	CO (lb/MMBtu)	CO (ppm@3%O ₂)	UHC (lb/MMBtu)	UHC (ppm@3%O ₂)	
SITE 6	FT	8	3	0.11	88	0.02	27			4
13	FT	8	7	0.09	76	0.15	207	0.024	58	1
OHIO UNIV	FT	8		0.10	84	0.15	205			9
151	FT	10	6			0.78	1075	0.090	216	1
18	FT	10	8	0.09	72	0.00	0	0.014	34	1
5-248-1	FT	10	8	0.08	63	0.00	0			4
12	FT	12	11	0.11	94	0.12	159			1
10	FT	13	10	0.07	56	0.00	0	0.006	14	1
3-2	FT	13	7	0.12	102	0.01	14			4
DISNEY STUOIO	FT	13		0.10	84	0.15	205			9
15	FT	14	13	0.07	60	0.00	0	0.010	24	1
14	FT	14	10	0.11	94	0.13	176	0.117	281	1
158	FT	17	5			0.37	508	0.005	12	1
LOCKHEED, CA	FT	17		0.10	84	0.15	205			9
16	FT	19	18	0.07	60	0.01	14	0.011	26	1
ST. JOSEPH MED	FT	21		0.10	84	0.15	205			9
26-1	FT	23	22	0.07	59	0.01	15			4
4-4	FT	25	18	0.13	110					4
SHARP HOSP, CA	FT	25		0.10	84	0.15	205			9
11	FT	29	20	0.13	109	0.00	0	0.026	62	1
150	FT	29	18			0.03	45	0.004	10	1
ROYALTY CARPET	FT	29		0.10	84	0.15	205			9
17	FT	32	20	0.10	84	0.11	144			1
CLEAVER BROOKS	FT	33		0.10	80	0.04	51			11
CLEAVER BROOKS	WT	5		0.09	73	0.01	14			11
ACS, CA	WT	6		0.10	84	0.15	205			9
333	WT	22	14	0.06	50			0.023	55	3
30	WT	22	18	0.07	58	0.01	10	0.002	5	1
19-2	WT	22	20	0.08	63	0.01	10			4
31	WT	24	20	0.15	126	0.02	23	0.000	0	1
31	WT	24	14	0.16	137	0.01	19	0.002	5	1
31	WT	24	15	0.17	144	0.00	4	0.002	5	1
5-716-3	WT	31	20	0.10	81	0.00	0			4
1	WT	31	25	0.09	73	0.13	173	0.013	31	1
3	WT	35	29	0.12	99	0.11	147	0.018	43	1
24	WT	35	29	0.09	73	0.35	486			1
1-1	WT	36	29	0.10	84	0.00	5			4
1-2	WT	36	21	0.10	84	0.01	10			4
1-3	WT	38	30	0.12	98	0.00	0			4
2	WT	38	29	0.09	72	0.12	166			1
328	WT	42	32	0.12	99	0.01	10	0.002	5	1
32	WT	45	40			0.10	139			1
19	WT	45	33	0.11	91	0.00	0			1
352	WT	50	43	0.10	85	0.02	29	0.001	2	3
29	WT	51	45	0.26	218	0.00	0	0.004	10	1
38-2	WT	56	50	0.27	224	0.00	0			4
MARTIN MARIETTA	WT	62		0.10	84	0.15	205			9
CLEAVER BROOKS	WT	64		0.10	84	0.10	132			11
334	WT	72	58			1.45	1988	0.008	19	1
335	WT	73	58	0.11	95	0.38	527	0.003	7	1
4	WT	74	60	0.14	118	0.76	1044	0.012	29	1

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UNCONTROLLED EMISSIONS DATA
NATURAL GAS-FIRED ICI BOILERS

BOILER ID	BOILER TYPE	BOILER CAPACITY (MMBtu/hr)	OPERATING LOAD (MMBtu/hr)	EMISSIONS						REFERENCE
				NOx (lb/MMBtu)	NOx (ppm@3%O2)	CO (lb/MMBtu)	CO (ppm@3%O2)	UHC (lb/MMBtu)	UHC (ppm@3%O2)	
5	WT	75	60	0.13	105	0.00	0			1
10-4	WT	75	61	0.13	106	0.00	0			4
9-BC-1	WT	75	59	0.31	256	0.00	0			4
6	WT	78	60	0.29	245	0.01	10			1
20	WT	80	66	0.12	99	0.07	99			1
159	WT	85	60	0.24	200			0.002	5	1
161	WT	85	60	0.19	157			0.005	12	1
162	WT	85	60	0.03	23	0.01	19	0.001	2	1
122	WT	87	67					0.000	0	3
28-1	WT	88	80	0.26	215	0.00	0			4
123	WT	100	71					0.000	0	3
25	WT	134	106	0.13	110	0.00	0			1
23	WT	143	116	0.11	95	0.00	0			1
121	WT	158	133					0.000	0	3
26	WT	187	158	0.18	153	0.00	0	0.051	122	1
7	WT	188	169	0.45	379	0.04	55			1
8	WT	203	169	0.35	291	0.00	0	0.014	34	1
157	WT	222	117			0.02	32	0.002	5	1
JAMES RIVER	WT	240		0.06	50					8
SO CAL ED	WT	240		0.04	33					8
27	WT	247	180	0.27	227	0.00	0			1
#1	WT	265	260	0.24	200					10
21	WT	281	237	0.26	215			0.003	7	1
28	WT	321	264	0.22	187	0.23	320	0.016	38	1
9	WT	349	317	0.24	202	0.00	0	0.001	2	1
22	WT	401	343	0.39	324	0.00	0	0.002	5	1

WT: WATERTUBE
FT: FIRETUBE

A-9

UNCONTROLLED EMISSIONS DATA
WOOD-FIRED ICI BOILERS

BOILER ID	BOILER HEAT INPUT (MMBtu/hr)	BOILER OUTPUT CAPACITY (MMBtu/hr)	FUEL TYPE	EMISSIONS				REFERENCE
				NOx (lb/MMBtu)	NOx (ppm@3%O2)	CO (lb/MMBtu)	CO (ppm@3%O2)	
A	6.8	5.1	SHAV	0.01		8		12
B	8.2	8.5	SHAV, SAW	0.01		9		12
C	7.4	6.8	SHAV, SAW	0.01		9		12
D	10.4	8.5	WW	0.09		62		12
E	20.8	9.9	WW	0.02		11		12
F	5.8	5.1	SHAV, SAW	0.00		3		12
G	1.7	5.1	SAW	0.00		3		12
H	94.0	39.5	WW	0.15		104		12
I	141.0	57.3	SAW	0.13		90		12
J	19.1	22.5	SAW	0.01		8		12
K	23.5	19.4	WW	0.03		23		12
SIERRA PACIFIC	130		WW	0.29		200		13
L	134.0	112.6	80%WOOD/20%DIST	0.12		84		12
LFC	190		WW	0.24		170		13
YANKEE ENERGY	190		WW	0.17		120		13
KENETECH ENERGY	225		WW	0.30		210		13
RYEGATE POWER	300		WW	0.30		210		13
BLACK & VEATCH	440		WW	0.21		150		13
HONEY LAKE PWR	480		WW	0.20		140		13
ALT ENERGY	500		WW	0.18		128		13
ALT ENERGY	500		WW	0.18		128		13
ALT ENERGY	500		WW	0.18		128		13
M	NA	229.0	85%BARK/15%NG	0.29		206		12
N	NA	112.6	20%BARK/80%COAL	0.39		277		12

NA: NO DATA AVAILABLE
SHAV: WOOD SHAVINGS
SAW: SAWDUST
WW: WOOD WASTE

DIST: DISTILLATE OIL
NG: NATURAL GAS

UNCONTROLLED EMISSIONS,
BUBBLING BED FBC BOILERS

FBC ID	MAXIMUM CAPACITY (MMBtu/hr)	PRIMARY FUEL TYPE	NOx (lb/MMBtu)	NOx (ppm @3%O2)	CO (lb/MMBtu)	CO (ppm @3%O2)	REFERENCE
B&W Pilot		coal RDF	0.81 0.44	600 315	0.49 4.68	600 5523	14
Canadian Forces Base, P. Edward Is., Canada	50	coal	0.62	460	0.37	453	4
Colmac, CA	330	biomass	0.10	70	0.15	173	15
CCRL Pilot, Canada	3.4	rice hulls	0.20	140	3.10	3655	7
Dong Chang Paper, Korea	55	coal	0.17	125			16
HBCM Le Bec, France	6.8	coal	0.11	80	0.49	600	17
Mesquite Lk, CA	160	cow manure	0.42	294	0.38	437	18
Mitsui Toatsu, Japan	75	coal	0.46	340			16
Saarbruecken, Germany	289	coal	0.12	90	0.17	204	19
Sakito Salt, Japan	145	coal	0.23	170			16
SOHIO Refinery, OH	97	coal	0.56	415			4
Sumitomo Power, Japan	245	coal	0.27	200			16
Sumitomo Metal, Japan	150	coal	0.30	220			16
TNO	14	coal	0.28	210	0.30	365	20
TVA Pilot, KY	134	coal	0.17	125	0.41	495	21

RDF: REFUSE DERIVED FUEL

UNCONTROLLED EMISSIONS,
CIRCULATING FBC BOILERS

FBC ID	MAXIMUM CAPACITY (MMBtu/hr)	PRIMARY FUEL TYPE	NOx (lb/MMBtu)	NOx (ppm @3%O2)	CO (lb/MMBtu)	CO (ppm @3%O2)	REFERENCE
ADM, Cedar Rapids, IA	500	coal	0.30	222	0.02	26	22
A.E. Staley	394	coal	0.60	444	0.17	207	23
Ansaldo/Studovik	8.5	coal	0.20	150	0.17	210	24
Archbald Cogen	210	culm	0.25	180			23
BF Goodrich	130	coal	0.34 0.22	252 164	0.03 0.03	38 31	25
Energieversorgung, Germany	250	coal	0.16	118			16,26
Ft. Howard Co.	362	coal	0.16	118	0.08	100	27
Foster Wheeler	400	culm	0.20	140			28
GM-Ft. Wayne, IN	157	coal	0.40	296	0.20	243	23
Idemitsu, Japan	693	coal	0.18	133			23
Ione Cogen., CA	155	coal	0.14	101	0.03	33	29
Kerry Coop, Ireland	122	coal/peat/ww	0.09	65	0.06	75	23
Kuk Dong Oil, Korea	280	petroleum coke	0.34	250			16,26
Kuraray, Japan	162	coal	0.20	148			23
Lauoff Grain, IL	250	coal	0.20	150	0.08	100	30
Montana One	476	coal waste	0.28	200	0.00	2	31
Paper mill, U.S.	340	coal	0.49	362	0.25	300	32
Pyropower Corp.		coal petroleum coke	0.27 0.12	200 90	0.25 0.21	300 250	33
Scott Paper	683	culm	0.60	430			34
Sun Kyong Fibers, Korea	300	coal	0.27	200			16,26
Thyssen Industrie, Germany	84	coal	0.18	135	0.23	276	35
Ultra Systems, CA	280	wood	0.21	150			13
U. of Iowa	179	coal	0.40	296	0.17	207	23
U. of Missouri	210	coal	0.50	370	0.17	207	23
Wheelabrator Energy	430	coal	0.50	370	0.10	122	22

ww: WOOD WASTE

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APPENDIX B. CONTROLLED NO_x EMISSION DATA

This appendix lists controlled emissions data for boilers used in the ICI sector. Where appropriate, data for small utility boilers and representative pilot-scale units are also included. The data were compiled primarily from technical reports, EPA documents, compliance records, and manufacturers' literature, as listed in the references at the end of this appendix. Additional low-NO_x performance data specific to low-NO_x burners (LNB) marketed by Coen Company, of California, and Tampella Power Corporation, Faber Burner Division, of Pennsylvania, are in Appendix C. Boiler emissions data are listed by fuel type and whether the NO_x control method used was a combustion modification or a flue gas treatment method.

NOx EMISSIONS DATA - PULVERIZED COAL FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	AVERAGE LOAD (%)	STACK O2	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	REF. NO.
							UNCONTROLLED (%)	NOx (ppm@3%O2)*	CO (ppm@3%O2)		
UNITS WITH LOW NOx BURNERS (LNB)											
DUPONT CHEMICAL	BITUM	WT/SW	140	LNB	R			550/280	NA/25	49	1
FOSTER WHEELER CETF (CF/SF LNB) PILOT	BITUM	WT/SW	80	LNB	R			700/260		63	2
FOSTER WHEELER CETF (IFS LNB) PILOT	BITUM	WT/SW	80	LNB	R			770/200		74	3
KERR-MCGEE CHEM CORP, CA	BITUM	WT/TANG		LNB	R	100	NA/3.6	290-365/269	NA/12	18	4
NEIL SIMPSON UNIT 5, WY	SUBBITUM	WT/SW	275	LNB	R		2.3-3.4/ 2.3-3.5	630-725/ 190-255	20-27/ 13-420	67	5
PUBLIC SVC INDIANA WABASH #5	BITUM	WT/WALL	1,000	LNB	R			730/370		49	6
UNNAMED	BITUM	WT/SW	150	LNB	R			630/220		65	1
UNITS WITH STAGED COMBUSTION AIR (SCA)											
ALMA #3	BITUM	WT/SW	230	SCA (BOOS)		57		340/250		27	7
KERR-MCGEE CHEM CORP, CA	BITUM	WT/TANG		SCA (OFA)	R	100		290-365/ 211-280	NA/30-98	25	4
SITE #31-7	BITUM	WT/SW	260	SCA (BOOS)		25		1065/651		39	7
UNNAMED SITE 3	BITUM	WT	325	SCA (OFA)		70		815/691**		15	8
UNITS WITH COMBINED LNB AND SCA											
ALBRIGHT #1, ALLEGHANY POWER, PA	BITUM	WT/WALL	875	LNB & SCA (OFA)				695/275		60	6
BHK	BITUM	WT	200	LNB & SCA	R			330-600/ 180-360		42	9
GALLAGHER #2, PUBLIC SVC, INDIANA	BITUM	WT/WALL	1,250	LNB & SCA (OFA)				720/275		62	6
HOWARD DOWN #10 VINELAND, NJ	BITUM	WT/WALL	365	LNB & SCA (OFA)				785/275		65	6

B-3

NOx EMISSIONS DATA - PULVERIZED COAL FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	AVERAGE LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	REF. NO.
								NOx (ppm@3%O2)*	CO (ppm@3%O2)		
FOSTER WHEELER CETF (CF/SF LNB) PILOT	BITUM	WT/SW	80	LNB & SCA	R			700/110		84	2
KERR-MCGEE CHEM CORP, CA	BITUM	WT/TANG		LNB & SCA	R	100	NA/3.6	290-365/148	NA/34	55	4
UNNAMED PAPER CO	BITUM	WT/OW	470	LNB & SCA	R			NA/220-370	NA/5-30		10
WABASH #2 PUBLIC SVC INDIANA	BITUM	WT/WALL	875	LNB & SCA (OFA)				590/330		44	6
WIPCO PEARL STATION, IL	BITUM	WT/SW	250	LNB & SCA	R	100		690-725/220-264	35/60-166	66	11

UNITS WITH REBURN

EPRI/GRI/BBW PILOT TEST	BITUM	CYCLONE	6	N. GAS REBURN	100	3/3	925/235-420	30/30	65	12
				OIL REBURN	100	3/3	925/250-537		57	
				COAL REBURN	100	3/3	925/300-555		54	
PLANT "A", JAPAN	BITUM	WT/SW	190	COAL REBURN	100		NA/215-385			13
PLANT "B", JAPAN	BITUM	WT/OW	375	COAL REBURN	100		NA/170-250			13
TAIO PAPER, JAPAN	BITUM	WT/TANG	825	OIL REBURN	100		240/167		30	14

WT: watertube; SW: single wall-fired; OW: opposed wall-fired; TANG: tangential fired

NA: no data available

* To convert NOx to lb/MMBtu divide by 740.

** Long term test data. All others are short term

B4

NOx EMISSIONS DATA - COAL FIRED STOKER BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	AVERAGE LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
								NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
UNITS WITH STAGED COMBUSTION AIR (SCA)												
SITE "A"	LOW S COAL	SS	375	SCA (OFA)	79	6/5.9		394/353	313/300	97/NA	10	15
SITE "C"	BITUM	SS	250	SCA (OFA)	92	NA/8.6-8.9		NA/230-387	NA/S3-103			16
SITE "D"	BITUM	OFS	102	SCA (OFA)	89	NA/7.4-7.8		NA/172-202	NA/73-2345			17
SITE "F"	BITUM	SS	98	SCA (OFA)	99	8.2/5.5		348-413/263	231-252/429	9/5	31	18
SITE 14	COAL	SS	200	SCA (OFA)	75	NA/11		568/369			35	7
SITE 30	COAL	SS	125	SCA (OFA)	66	6.2/6.1		320/237	0/49		26	19
SITE 35	COAL	OFS	215	SCA (OFA)	47	9.5/9.0		164/166	25/15	25/35	-1	19
WILMAR 3	COAL	SS	160	SCA (OFA)	66	NA/9.0		372/350			6	20
UNITS WITH COMBINED FLUE GAS RECIRCULATION (FGR) AND SCA												
UNNAMED	BITUM	SS	125	FGR & SCA	80	8/3.5	NA	350/140			60	21
SITE 1	BITUM	SS	134	FGR & SCA	95	8/5	NA	400/350			13	22
SITE 2	BITUM	SS	270	FGR & SCA	75	4/4	NA	280-340/			0	22
SS: spreader stoker; OFS: overfeed stoker FGR: flue gas recirculation; SCA: staged combustion air; OFA: overfire air; RAP: reduced air preheat NA: no data available * To convert NOx to lb/MMBtu divide by 740. Note: all are short term test data												
UNITS WITH NATURAL GAS COFIRE												
VANDERBILT UNIVERSITY	COAL	SS	90	GAS COFIRE	100	5.6/3.5		290-250/200			20-25	92

B-5

NOx EMISSIONS DATA - COAL FIRED FBC BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	AVERAGE LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
								NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
AHLSTROM CORP, FINLAND	BITUM	CFBC	222	SCA (OFA)				NA/51-335				23
AHLSTROM CORP	BROWN COAL	CFBC	222	SCA (OFA)				NA/103-155				23
BF GOODRICH	BITUM	CFBC	140	SCA (OFA)				NA/280	NA/33	NA/2		24
CHALMERS UNIV, SWEDEN	BITUM	BFBC	16 MWe	SCA (OFA)		23/22**		125/75			40	25
CONOCO, TX	COAL/COKE	CFBC	50	SCA (OFA)				NA/100				26
IOWA BEEF	BITUM/SUB	DBFBC	88	SCA (OFA)				NA/100	NA/100	NA/22		27
KERAVA ENERGY, FINLAND	COAL	CFBC	102	SCA (OFA)				NA/39-245				23
TNO AFBB RESEARCH FACILITY, SWEDEN	BITUM	BFBC	14	SCA (OFA)				270-337/67-135	387-500/550-1100		67	28
UNNAMED	COAL	CFBC	222	SCA & FGR				NA/90-116				23
UNNAMED	COAL	CFBC	102	SCA & FGR				NA/100-115				23
YOSHIWARA #1, JAPAN	COAL, PAPER	BFBC	125	ASH REINJECT	100			90/30			67	29

CFBC: circulating fluidized bed combustor (FBC); BFBC: bubbling bed FBC; DBFBC: dual bed FBC
 SCA: staged combustion air; OFA: overfire air; FGR: flue gas recirculation
 NA: no data available
 * To convert NOx to lb/MMBtu divide by 740.
 ** Total excess air
 Note: all are short term test data

B-6

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)		UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF NO.
							UNCONTROLLED (%)	FGR (%)	NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
WITH FLUE GAS RECIRCULATION (FGR)													
ADVANCED CARDIO-VASCULAR SYSTEMS, CA	NG	WT/PKG	6	FGR	R			NA	84/22	205/62		74	30
ALLIED SIGNAL, CA	NG	FT/PKG	12.5	FGR		100		NA	NA/29	NA/30			31
ALLIED SIGNAL, CA	NG	FT/PKG	6.3	FGR		100		NA	NA/25	NA/32			31
ANAHEIM MILLS, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/27	NA/6			31
ARATEX, CA	NG	FT/PKG	21	FGR	N	100		NA	NA/21	NA/0.5			31
BAXTER HIGHLAND, CA	NG	FT/PKG	17	FGR	N	100		NA	NA/28	NA/51			31
BAXTER HIGHLAND, CA	NG	FT/PKG	10.5	FGR	N	100		NA	NA/20				31
BEV HILLS HILTON	NG	FT/PKG	8.5	FGR	R	73	NA/4	20	NA/21	NA/5			32
				FGR	R	100	NA/4	20	NA/28	NA/10			
CA DEPT OF CORRECTIONS	NG	FT/PKG	25	FGR	N	95	NA/3.7	NA	NA/25	NA/26			33
CA MILK PROD	NG	WT/PKG	60	FGR	N			NA	NA/33				34
CAL COMPACK, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/29	NA/21			31
CLAYTON INDUSTRIES TEST	NG	WT		FGR			3.6/3.6	10-20	70-100/25-35			65	35
CLEAVER BROOKS TEST	NG	FT/PKG	8.5	FGR		100		5	60/50			17	36
				FGR		100		10	60/38			37	
				FGR		100		15	60/27			55	
				FGR		100		20	60/20			67	
CLEAVER BROOKS TEST	NG	FT/PKG	15	FGR		100		5	88/79			10	37
				FGR		100		10	88/61			31	
				FGR		100		15	88/40			55	
				FGR		100		20	88/28			68	
CLOUGHERTY PACKING, CA	NG	WT/PKG	18	FGR	R	100		NA	NA/28	NA/52			33
CLOUGHERTY PACKING, CA	NG	WT/PKG	36	FGR	R	100		NA	NA/30	NA/48			33
COMMUNITY LINEN, CA	NG	FT/PKG	15	FGR	R	100		NA	NA/29	NA/33			31
COMMUNITY LINEN, CA	NG	FT/PKG	8.4	FGR	R	100		NA	NA/23	NA/0			31
DISNEY STUDIOS, CA	NG	FT/PKG	12.6	FGR	R			NA	84/23	205/77		73	30

B-7

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK D2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
ECCC	NG	FT/PKG	12	FGR		50	4/4	30	79/25			68	7
ECCC	NG	WT/PKG	31	FGR		39 30	3 1/2 6 3.5/1.2	22 26	47/18 58/13	20/20 10/55		62 78	38
FOLSOM PRISON	NG	WT/PKG	48	FGR	N			NA	NA/42				34
FOUR SEASONS HOTEL, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/16	NA/41			31
FRIENDLY HILLS MED CENTER, CA	NG	FT/PKG	21	FGR	R	100		NA	NA/35	NA/194			31
FRITO LAY, CA	NG	WT/PKG	78	FGR	N			NA	NA/42				34
FRITO LAY, CA	NG	FT/PKG	12.6	FGR	R	100		NA	NA/24	NA/33			31
FRITO LAY, CA	NG	FT/PKG	12.6	FGR	R	100		NA	NA/27	NA/32			31
GAF BUILDING MATERIALS, CA	NG	WT/PKG	16.7	FGR		100		NA	NA/23	NA/124			31
GREEN FOODS CORP, CA	NG	FT/PKG	10	FGR	N	100	NA/11.7	12.7	NA/27	NA/27	NA/0.9		33
HILL PET FOODS, CA	NG	FT/PKG	4.2	FGR	N	100		NA	NA/27	NA/13			31
HUGHES AIRCRAFT 1 CA	NG	FT/PKG	8	FGR	R	100		NA	NA/30				33
HUGHES AIRCRAFT 2 CA	NG	FT/PKG	8	FGR	R	100		NA	NA/30				33
HUGHES AIRCRAFT, CA	NG	FT/PKG	8.4	FGR	R	100		NA	NA/30	NA/34			31
INTEGRATED PROTEIN	NG	WT/PKG	37	FGR	N			NA	NA/33				34
KAISER HOSP, CA	NG	FT/PKG	8	FGR	N	100	4/4.7	12.5	80/33	16/13		59	89
KAISER HOSPITAL, CA	NG	FT/PKG	14.6	FGR	R	100		NA	NA/30	NA/46			31
KIRKHILL RUBBER, CA	NG	FT/PKG	16.8	FGR	N	95		NA	NA/22	NA/9			31
KNOTT'S BERRY FARM, CA	NG	FT/PKG	14	FGR	R	100		NA	NA/27	NA/0			31
LIBERTY VEG OIL, CA	NG	FT/PKG	9.4	FGR		100		NA	NA/27	NA/26			31
L.A. DYE & PRINT, CA	NG	FT/PKG	14.6	FGR		100		NA	NA/19				31
L.A. HILTON	NG	FT/PKG	6	FGR	N			NA	NA/33				34
L.A. PAPER BOX, CA	NG	WT/PKG		FGR	R	100		NA	NA/27	NA/11			31
LOCKHEED, CA	NG	FT/PKG	16.7	FGR	N			NA	84/24	205/192		71	30

B-8

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
MARTIN MARIETTA, CA	NG	WT/PKG	62	FGR	N			NA	84/39	205/205		53	30
MATCHMASTERS, CA	NG	FT/PKG	21	FGR		100		NA	NA/21	NA/32			31
MCCLELLAN AFB	NG	WT/PKG	58	FGR	N			NA	NA/42				34
NORTHROP CORP	NG	WT/PKG	22	FGR	N			NA	NA/42				34
NUWAY LINEN, CA	NG	FT/PKG	18.8	FGR		100		NA	NA/28	NA/21			31
OHIO UNIVERSITY	NG	FT/PKG	8.4	FGR	N			NA	84/30	205/103		64	30
PACIFIC COAST DYING & FINISHING, CA	NG	FT/PKG	25	FGR	N	100		NA	NA/23	NA/12			33
PACIFIC DYE, CA	NG	FT/PKG	16.7	FGR	R	100		NA	NA/21	NA/37			31
REINHOLD IND., CA	NG	FT/PKG	14.6	FGR	R	100		NA	NA/28	NA/76			31
ROCKWELL INTNL, CA	NG	FT/PKG	9	FGR	N	100	NA/9.4	NA	NA/24	NA/140			33
ROCKWELL INTNL, CA	NG	FT/PKG	14.6	FGR	R	100		NA	NA/25	NA/8			31
ROYALTY CARPET, CA	NG	FT/PKG	29	FGR	N			NA	84/22	205/84		74	30
ST. FRANCIS HOSP, CA	NG	FT/PKG	14.6	FGR		100	3.7/3.7	20	87/29	23/3		67	89
ST. FRANCIS HOSP, CA	NG	FT/PKG	21	FGR		100	3.9/3.9	20	70/19	105/7		73	89
ST. JOHN'S REGIONAL MEDICAL CENTER, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/37	NA/42			31
ST. JOSEPH MEDICAL CENTER, CA	NG	FT/PKG	21	FGR	N			NA	84/20	205/67		76	30
ST. JUDE MEDICAL CENTER, CA	NG	WT/PKG	10.5	FGR		100		NA	NA/24	NA/33			31
SANTEE DAIRIES, CA	NG	FT/PKG	17.4	FGR	R	100		NA	NA/25	NA/44			31
SCHOOL FOR DEAF, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/25	NA/75			31
SHARP HOSPITAL, CA	NG	FT/PKG	25	FGR	R			NA	84/26	205/49		69	30
SHERATON UNIVERSAL HOTEL, CA	NG	FT/PKG	12.5	FGR	R	100		NA	NA/27	NA/2			33
STANISLAUS FOODS	NG	WT/PKG	162	FGR	N			NA	NA/50				34
TRI VALLEY GROWER, CA	NG	WT/PKG	175	FGR	N			NA	NA/50				34
UNIVERSAL HILTON, CA	NG	FT/PKG	10.5	FGR		100		NA	NA/37	NA/38			31

B-9

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
UNNAMED #1	NG	WT/PKG	5	FGR		100		NA	73/20	14/22		73	39
UNNAMED #2	NG	WT/PKG	64	FGR		100		NA	84/37	132/77		56	39
UNNAMED #3	NG	FT/PKG	12.6	FGR		100		NA	NA/24	NA/25			39
UNNAMED #4	NG	FT/PKG	25	FGR		100		NA	NA/24	NA/49			39
UNNAMED #5	NG	FT/PKG	33.5	FGR		100		NA	80/22	51/12		73	39
UNNAMED #6	NG	WT/PKG	23	FGR	N			NA	NA/67				34
VENTURA COASTAL, CA	NG	FT/PKG	30	FGR	N	100	NA/3.9	NA	NA/32	NA/103			33
VERDUGO HILLS HOSPITAL, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/33	NA/2			31
VITA-PAKT, CA	NG	FT/PKG	10.5	FGR	R	100		NA	NA/29	NA/27			31
VITA-PAKT, CA	NG	FT/PKG	6.3	FGR	R	100		NA	NA/32	NA/31			31
WILSON SPORTING GOODS, CA	NG	FT/PKG	3	FGR	N	100	NA/3.3	NA	NA/22	NA/8	NA/22		33
20TH CENT FOX, CA	NG	FT/PKG	4.2	FGR		100		NA	NA/26	NA/40			31

WITH LOW NOx BURNER (LNB)

ALZETA TEST	NG	FT/PKG	0.84	RADIANT LNB			16/10**		49/9	9/9	0/17	82	40
ARMSTRONG IND., CA	NG	WT/PKG	12	LNB	R	100			NA/30	NA/0			41
B&W XCL-FM TEST	NG	WT/PKG	50	LNB		100			NA/60-70	<50			42
CA FATS & OILS	NG	WT/PKG	63	LNB	N				NA/75				34
CA VEG COMPANY	NG	FT/PKG	9.5	LNB	N	100	NA/4.5		NA/23	NA/1			33
COMMUNITY MEM HOSPITAL, CA	NG	FT/PKG	8	RADIANT LNB	R		17/12**		51/24	28/9		53	43
ERL, TAIWAN	NG	WT/PKG	10	LNB		100	NA/10-18**		NA/25-33				44
FT. KNOX	NG	FT/PKG	8.5	LNB	R	95	2/1.3		100/68	39/8		32	45
HALL CHEMICAL	NG	FT/PKG	3.3	RADIANT LNB	R		7/13**		68/15	856/30		78	40
HARVARD COGEN	NG	WT/PKG	225	LNB					NA/92				6

B-10

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
								FGR (%)	NOx (ppm@3%O2)*	CO (ppm@3%O2)		
IBM #3	NG	WT/PKG	45	LNB	R	93	NA/2.1	NA/84	NA/0		46	
IBM #6	NG	WT/PKG	45	LNB	R	100		120/65			46	47
LUZ-SEGS II, CA	NG	WT/FE	380	LNB	R			NA/80				48
METRO STATE HOSPITAL, CA	NG	WT/PKG		LNB		20-80	NA/2-3	NA/40				49
NABISCO FOODS, CA	NG	FT/PKG	12.5	LNB	R	100	NA/3.0	NA/29	NA/3	NA/1.6		33
NABISCO FOODS, CA	NG	FT/PKG	10.6	LNB	R	100	NA/3.0	NA/30	NA/1	NA/2.2		33
O.L.S ENERGY, CA	NG	WT/PKG	31	LNB	N	100	NA/3.5-4.9	NA/31-36	NA/64-117	NA/2.9-29		33
O.L.S ENERGY, CA	NG	WT/PKG	31	LNB	N	100	NA/4.0	NA/30	NA/204	NA/22		33
PETER PAUL CADBURY	NG	FT/PKG	2	RADIANT LNB	R		20/7**	NA/17	342/30			40
PROCTOR & GAMBLE, WI	NG	WT/FE	365	LNB	N		NA/3.5	NA/142	NA/166			90****
ROCKWELL INTNL, CA	NG	FF/PKG	5	LNB	N	100	NA/7.9	NA/28	NA/15	NA/2.8		33
SUNKIST, CA	NG	WT/PKG	51	LNB	R			135/58			57	34
SAN JOAQUIN, CA	NG	WT/PKG	75	LNB	R			NA/58				34
UNNAMED #7	NG	WT/PKG	75	LNB		86	NA/4.3	NA/58	NA/744			38
UNNAMED #8	NG	WT/PKG	100	LNB	R	38		221/65 ***			71	8
VANDEBURG AFB	NG	FT/PKG	1.34	RADIANT LNB	N		55/10**		205/0			40
VA HOSPITAL, CA	NG	WT/PKG	55	LNB	R	100	NA/3.6	NA/108	NA/39			50
YORK SHIPLEY TEST	NG	FT/PKG	2	RADIANT LNB			15/10**		9/9			43
DEUTSCHE-BABCOCK	NG	WT/FE	100	LNB #1				230/140			39	56
DEUTSCHE-BABCOCK	NG	WT/FE	100	LNB #2				230/112			52	56

COMBINED LNB & FGR

AMERICAN COGEN, CA	NG	WT/PKG	136	LNB & FGR	R			12	NA/29			51
BBW XCL-FM TEST	NG	WT/PKG	50	LNB & FGR		100		17	NA/30			42
BOISE CASCADE, AL	NG	WT/PKG	205	LNB & FGR	N		NA/3.1	18	NA/33	NA/50		90****
CONTADINA FOODS, CA	NG	WT/PKG	150	LNB & FGR	N		NA/3.5	19	NA/32	NA/3		90****

B.11

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
ERL, TAIWAN	NG	WT/PKG	10	LNB & FGR LNB & FGR		100 100	NA/4-8 NA/5-9	5 10	NA/15-19 NA/13-17				44
GANGI BROS, CA	NG	WT/PKG	75	LNB & FGR	N		NA/2.0	27	NA/20	NA/40			90****
GANGI BROS, CA	NG	WT/PKG	150	LNB & FGR	N		NA/3.5	17	NA/24	NA/40			90****
GEN ELECTRIC, IN	NG	WT/PKG	200	LNB & FGR	N		NA/3.5	7	NA/75	NA/30			90****
HANFORD COGEN, CA	NG	WT/PKG	70	LNB & FGR	N		NA/2.8	20	NA/24	NA/6			90****
HENKEL CORP, CA	NG	WT/PKG	40	LNB & FGR	N		NA/3.3	17	NA/22	NA/15			90****
HUNTINGTON HOSP, CA	NG	WT/PKG	30	LNB & FGR	N		NA/2.8	NA	NA/35	NA/21			90****
IBM #3	NG	WT/PKG	45	LNB & FGR	R	80-95	NA/2.1	11.6-13	NA/30-36	NA/0-76			46
IBM #6	NG	WT/PKG	45	LNB & FGR	R	100		12.9-14	120/22-27		79		47
KWIKSET CORP, CA	NG	FT/PKG	17.6	LNP & FGR	N	100		NA	NA/29				33
MILLER BREWERY	NG	WT/PKG	60	LNB & FGR	R	100		NA	50-60/25	60-125/2	55		52
MISSION LINEN, CA	NG	FT/PKG	10	LNB & FGR	N	100	NA/6.6	NA	NA/20	NA/89			33
ORANGE COUNTY #1	NG	WT/PKG	55	LNB & FGR	R	100		19.5	150/24	NA/50	84		53
ORANGE COUNTY #2	NG	WT/PKG	55	LNB & FGR	R	100		18	150/33	NA/5	78		53
ORANGE COUNTY #3	NG	WT/PKG	100	LNB & FGR	R	88		18	150/27	NA/97	82		53
QUALITY ASSURED PACKING, CA	NG	WT/PKG	40	LNB & FGR	R			4	NA/35				51
RAGU FOODS, CA	NG	WT/PKG	190	LNB & FGR	R			12	NA/35				51
RICHARD SHAW FOODS, CA	NG	FT/PKG	8.7	LNB & FGR	N	100	NA/4.1	NA	NA/28	NA/125	NA/22		33
SWEDLOW INC., CA	NG	FT/PKG	13.2	LNB & FGR		100		NA	NA/22	NA/11			33
UNNAMED, CIBO CASE D	NG	WT/PKG	90	LNB & FGR	R			NA	NA/28				54
US NAVY NCBC, CA	NG	FT/PKG	27.7	LNB & FGR	N	100		NA	NA/37	NA/135			33
VA HOSPITAL, CA	NG	WT/PKG	55	LNB & FGR	R	100	NA/3.5	13.3-13	NA/39	NA/33			50

B-12

NOx EMISSIONS DATA - NATURAL GAS FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBtu/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
STAGED COMBUSTION AIR (SCA)													
ECCC	NG	FT/PKG	12	SCA		71	1.9/2.9			70/67		5	7
KVB SITE 19	NG	WT/PKG	22	SCA	R	83	3.2/2.5			92/50		46	55
KVB SITE 38	NG	WT/PKG	56	SCA	R	89	2.5/2.4			170/116		32	55
#9-BC-1	NG	WT	60	SCA (BOOS)		77	3/3			240/200		17	7
#28-1	NG	WT	70	SCA (BOOS)		41	5.5/5.5			210/117		44	7
#32-1	NG	WT	120	SCA (BOOS)		50	4.4/4.4			205/150		27	7
DEUTSCHE-BABCOCK	NG	WT/FE	100	SCA (OFA)						230/119		37	56

OTHER COMBUSTION MOD COMBINATIONS

KVB SITE 19	NG	WT/PKG	22	SCA & FGR	R	83	3.2/2.5	20		92/22		76	55
DEUTSCHE-BABCOCK	NG	WT/FE	100	LNB #1 & SCA						230/100		56	56
DEUTSCHE-BABCOCK	NG	WT/FE	100	LNB #2 & SCA						230/82		64	56
GALLO, CA	NG	WT	140	LNB & SCA	N					NA/64	NA/100		48
TEMPLE INLAND FOREST PRODUCTS	NG	WT/FE	220	LNB, FGR & SCA LNB, FGR & SCA				NA		NA/117			6

WT: watertube; FT: firetube; PKG: packaged; FE: field erected
 NA: no data available
 * To convert NOx to lb/MMBtu divide by 835.
 ** total excess combustion air
 *** Long term test data. All others are short term
 ****Also tabulated in Coen Co. Installation List, Appendix C.

B-13

NOx EMISSIONS DATA - OIL FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS AVERAGE			REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)	
DISTILLATE-FIRED UNITS WITH FGR												
ALLIED SIGNAL, CA	DISTILLATE	FT/PKG	12.5	FGR		100	NA	NA/30	NA/74			31
ALLIED SIGNAL, CA	DISTILLATE	FT/PKG	6.3	FGR		100	NA	NA/33	NA/39			31
CA MILK PROD.	DISTILLATE	WT/PKG	60	FGR	N		NA	NA/119				34
FRIENDLY HILLS MEDICAL CENTER, CA	DISTILLATE	FT/PKG	21	FGR	R	100	NA	NA/28	NA/60			31
GAF BUILDING MATLS	DISTILLATE	WT/PKG	16.7	FGR		100	NA	NA/28	NA/186			31
HUGHES AIRCRAFT, CA	DISTILLATE	FT/PKG	8.4	FGR	R	100	NA	NA/34	NA/107			31
KAISER HOSPITAL	DISTILLATE	FT/PKG	14.6	FGR	R	100	NA	NA/36	NA/68			31
KAISER HOSPITAL	DISTILLATE	FT/PKG	8	FGR	N		NA	NA/126				34
KVB SITE 19	DISTILLATE	WT/PKG	22	FGR		83	3.2/3.1	28	110/35	4/46	68	55
LIBERTY VEG OIL, CA	DISTILLATE	FT/PKG	9.4	FGR		100	NA	NA/36	NA/49			31
L.A. DYE AND PRINT	DISTILLATE	FT/PKG	14.6	FGR		100	NA	NA/30				31
L.A. PAPER BOX	DISTILLATE	WT/PKG		FGR	R	100	NA	NA/37	NA/30			31
ST. JUDE MED CTR, CA	DISTILLATE	WT/PKG	10.5	FGR		100	NA	NA/37	NA/51			31
SCHOOL FOR DEAF, CA	DISTILLATE	FT/PKG	10.5	FGR	R	100	NA	NA/41	NA/69			31
UNIVERSAL HILTON, CA	DISTILLATE	FT/PKG	10.5	FGR		100	NA	NA/38	NA/149			31
VERDUGO HILLS HOSPITAL, CA	DISTILLATE	FT/PKG	10.5	FGR	R	100	NA	NA/34	NA/13			31
UNNAMED #5	DISTILLATE	WT/PKG	56	FGR		100	3.5/3.4	10	150/120	20/24	20	38

DISTILLATE-FIRED UNITS WITH LNB

B&W XCL-FM TEST	DISTILLATE	WT/PKG	50	LNB		100			NA/60-65			42
CA FATS & OILS	DISTILLATE	WT/PKG	63	LNB	N				NA/119			34
FT KNOX	DISTILLATE	FT/PKG	8.5	LNB	R	100	3.9/3.7		142/120	6/13	15	45
IBM #3	DISTILLATE	WT/PKG	45	LNB	R				NA/99			46
IBM #6	DISTILLATE	WT/PKG	45	LNB	R				NA/85-102			47

B-14

NOx EMISSIONS DATA - OIL FIRED IC1 BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS AVERAGE				REF. NO.
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)	NOx REDUCTION (%)	
SAN JOAQUIN COUNTY	DISTILLATE	WT/PKG	75	LNB	R				NA/87				34
UNNAMED #3	DISTILLATE	WT/PKG	75	LNB		84	NA/1.9		NA/87	NA/91			38
VA HOSPITAL, CA	DISTILLATE	WT/PKG	55	LNB	R	100	NA/3.6		NA/100	NA/35			50
DISTILLATE-FIRED UNITS WITH LNB & FGR													
B&W XCL-FM TEST	DISTILLATE	WT/PKG	50	LNB & FGR		100		17	NA/45				42
HENKEL CORP, CA	DISTILLATE	WT/PKG	40	LNB & FGR	N		NA/4.3	17	NA/20	NA/30			90***
HUNTINGTON HOSP, CA	DISTILLATE	WT/PKG	30	LNB & FGR	N		NA/2.6	NA	NA/35	NA/37			90***
IBM #3	DISTILLATE	WT/PKG	45	LNB & FGR	R			14-21	NA/72-76				46
IBM #6	DISTILLATE	WT/PKG	45	LNB & FGR	R			25-40	NA/43-50				47
NORTHROP CORP	DISTILLATE	WT/PKG	22	LNB & FGR	N			NA	NA/103				34
ORANGE COUNTY #1	DISTILLATE	WT/PKG	55	LNB & FGR	R	83		20.6	NA/31	NA/6.4			53
ORANGE COUNTY #2	DISTILLATE	WT/PKG	55	LNB & FGR	R	100		18	NA/35	NA/8			53
ORANGE COUNTY #3	DISTILLATE	WT/PKG	100	LNB & FGR	R	63		18	NA/36	NA/175			53
VA HOSPITAL, CA	DISTILLATE	WT/PKG	55	LNB & FGR	R	100	NA/3.5	13-15.6	NA/76-78	NA/31-33			50
DISTILLATE-FIRED UNITS WITH SCA													
KVB SITE 19	DISTILLATE	WT/PKG	22	SCA (OFA) FGR & SCA		83	3.2/3.1		110/77			30	55
						83	3.2/3.1	NA	110/34			69	
RESIDUAL-FIRED UNITS WITH FGR													
ECCC	RESIDUAL	WT/PKG	31	FGR		67	4.4/4.5	7	130/125	20/20		4	38
				FGR		67	4.4/2.0	19	130/91	10/145		30	
KVB SITE 19	RESIDUAL	WT/PKG	22	FGR		83	3.2/3.1	NA	221/197			11	55

B-15

NOx EMISSIONS DATA - OIL FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROLS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE	NEW (N) OR RETROFIT (R)	LOAD (%)	STACK O2 UNCONTROLLED/CONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS AVERAGE			REF. NO
									NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)	
RESIDUAL-FIRED UNITS WITH LNB												
B&W XCL-FM TEST	RESIDUAL	WT/PKG	50	LNB		100			NA/200			42
KOBE STEEL (17 UNITS)	RESIDUAL	FT, WT	5-40	LNB	R				138-286/69-185		40 (30-60)	57

RESIDUAL-FIRED UNITS WITH SCA

ECCC	RESIDUAL	FT/PKG	12	SCA (OFA)		50	NA/4.4		177/90		49	7	
KVB SITE 19	RESIDUAL	WT/PKG	22	SCA (OFA)		83	3.2/3.1		221/157		29	55	
KVB SITE 38	RESIDUAL	WT/PKG	56	SCA (OFA)		89	2.9/2.3		270/157		42	55	
UNNAMED SITE 2	RESIDUAL	WT	110	SCA (BOOS)		67			235/181 **		23	8	
#2-2	RESIDUAL	WT	59	SCA (BOOS)		80			668/588		12	7	
#2-4	RESIDUAL	WT	65	SCA (BOOS)		78			505/455		10	7	
#7-3	RESIDUAL	WT	85	SCA (BOOS)		58			350/270		24	7	
#18-2	RESIDUAL	WT	90	SCA (BOOS)		67	7.4/8.2		254/180		29	7	
#18-3	RESIDUAL	WT	105	SCA (BOOS)		72			245/234		5	7	
#18-4	RESIDUAL	WT	160	SCA (BOOS)		74			244/173		29	7	
#28-1	RESIDUAL	WT	70	SCA (BOOS)		41			205/188	0/100	8	19	
#29-5	RESIDUAL	WT	150	SCA (BOOS)		47			294/177	0/20	35/35	40	19

RESIDUAL-FIRED UNITS WITH COMBINED COMBUSTION MODS

B&W XCL-FM TEST	RESIDUAL	WT/PKG	50	LNB & FGR		100		17	NA/180			42
KVB SITE 19	RESIDUAL	WT/PKG	22	FGR & SCA		83	3.2/3.1	NA	221/104		53	55
NY HOSPITAL, NY	RESIDUAL	WT/PKG	150	LNB & SCA	R				NA/175			51

WT: watertube; FT: firetube; PKG: packaged
 LNB: low NOx burner; FGR: flue gas recirculation, SCA: staged combustion air
 NA: no data available
 * To convert NOx to lb/MMBtu divide by 790.
 ** Long term test data. All others are short term
 *** Also tabulated in Coen Co. Installation List, Appendix C.

B-16

NOx EMISSION DATA - GAS/OIL FIRED TEOR STEAM GENERATORS

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
						NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
EPA TEST	CRUDE OIL	TEOR	62.5	LNB (R)		300/110			63	58
GETTY OIL UNIT HSG172	CRUDE OIL	TEOR	62.5	SCA (R)		300/155		NA/12-24	48	59
				SNCR (R)		300/86			71	
				SCA & SNCR (R)		300/60			80	
STANDARD OIL UNIT 50-1	CRUDE OIL	TEOR	62.5	LNB		368/359		4 2/5 2	2	60, 61
GRACE PETROLEUM	N. GAS	TEOR	25	FGR (R)	NA	35-40/20-25			40	62
MOBIL OIL	N. GAS	TEOR	62.5	LNB (R)		100/70-75	NA/0.3	NA/3	28	48
				LNB & FGR (R)	10-12	100/30-35	NA/0.3	NA/3	68	
MOBIL OIL	N. GAS/ REF. GAS	TEOR	62.5	LNB (R)		NA/42	NA/0.3	NA/1		63
				LNB & FGR (R)	3	NA/35	NA/0.3	NA/1		
				LNB & FGR (R)	8	NA/25	NA/0.3	NA/1		
UNNAMED	N. GAS	TEOR	62.5	LNB		60/55			8	64
				LNB & FGR	NA	60/30			50	

TEOR: thermally enhanced oil recovery
 SCA: staged combustion air; SNCR: selective non-catalytic reduction; LNB: low NOx burner; FGR: flue gas recirculation
 NA: no data available
 * To convert NOx to lb/MMBtu, divide by 835 for natural gas fuel, 790 for oil fuel.
 Note: all are short term test data.

B-17

KERN COUNTY, CA APCD DATA (REF. NO. 65) - CRUDE OIL FIRED TEOR STEAM GENERATORS

NOx CONTROL TYPE	UNITS < 35 MMBTU/HR INPUT:			UNITS 35 - 62.5 MMBTU/HR INPUT:		
	NUMBER OF TESTS	MEAN NOx EMISSIONS (ppm@3%O2)*	MEAN CO EMISSIONS (ppm@3%O2)	NUMBER OF TESTS	MEAN NOx EMISSIONS (ppm@3%O2)*	MEAN CO EMISSIONS (ppm@3%O2)
O2 TRIM	71	280		326	250	
	39		60	245		23
FGR, O2 TRIM	4	188		32	125	
	1		23	26		44
LNB (SCA), O2 TRIM	0			134	122	
	0			113		25
SNCR, O2 TRIM	0			38	105	
	0			37		37

FGR: flue gas recirculation; LNB: low NOx burner; SCA: staged combustion air
 SNCR: selective non-catalytic reduction
 * To convert NOx to lb/MMBtu divide by 790.

NOx EMISSIONS DATA - NONFOSSIL FUEL FIRED ICI BOILERS WITH COMBUSTION MODIFICATION NOx CONTROL

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	AVERAGE LOAD (%)	STACK O2 UNCONTROLLED (%)	FGR (%)	UNCONTROLLED/CONTROLLED EMISSIONS			AVERAGE NOx REDUCTION (%)	REF. NO.
								NOx (ppm@3%O2)*	CO (ppm@3%O2)	UHC (ppm@3%O2)		
KVB SITE 10/1	WOOD/N. GAS	OFS	250	SCA-BOOS (R)***				229/183			20	55
MSW FACILITY, OLMSTEAD COUNTY, MN	MSW	WT/OFS	45	FGR ONLY		76/54**	9.5	234/140	92/94		40	66
				FGR WITH N. GAS REBURN	100	76/41**	10	234/96	92/42		59	
RILEY/TAKUMA MASS BURN PILOT	MSW	OFS	3	FGR WITH N GAS REBURN	80	70/31**	17	284/146	54/52	0/2	49	67, 68

OFS: overfeed stoker; WT: watertube; WF: wall fired
 SCA: staged combustion air; FGR: flue gas recirculation
 MSW: municipal solid waste
 * To convert NOx to lb/MMBtu divide by 710 for wood fuel, 705 for MSW
 ** Total excess combustion air
 *** Combustion modifications to auxiliary gas burners only.
 Note: all are short term test data.

NOx EMISSIONS DATA - ICI BOILERS WITH FLUE GAS TREATMENT NOx CONTROLS: SNCR

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	AMMONIA SLIP (ppm@3%O2)	REF. NO.
					NOx (ppm@3%O2)*	CO (ppm@3%O2)			
OIL/GAS-FIRED UNITS:									
ESSO A.G. #5, GERMANY	NG	WALL	87 MWe	SNCR AMMONIA (R)	394/160		60		69
EXXON, CA	NG	VERT CYL FURNACE	200	LNB & SNCR AMMONIA (N)	90/25		72		70
INDUSTRIAL UNIT, JAPAN	OIL		90	SNCR UREA (R)	120-140/60-70		50		71

COAL-FIRED UNITS:

WEPCO VALLEY #4	COAL	WT/WALL	800	SNCR UREA	984/300		69		77
UNNAMED	BITUM	WT/SW	50 (MWe)	SNCR UREA	650/110		83		76
N. AMERICAN CHEM CORP TRONA, CA	BITUM	TANG	2x75 MWe	SNCR UREA	200/140		30***	<5	74
FORMOSA PLASTICS	COAL	WT/WALL	331	SNCR UREA	200/80		60		91
ULTRASYSTEMS, VA	COAL	STKR	2x383	SNCR AMMONIA (N)	296/110		50-65	<20	89
ULTRASYSTEMS, VA	COAL	STKR	2x380	SNCR AMMONIA (N)	300/132		54-66	<20	89
COGENTRIX, VA	COAL	STKR	8x28MWe	SNCR UREA	350/200		40	<1	91
TEKNISKAVERKEN	COAL	STKR	275	SNCR UREA	300-350/100-125		65	<15	91
UNNAMED	COAL	CFBC	1.4	SNCR UREA	90-135/39		65		76
MICHIGAN ST UNIV	COAL	CFBC	460	SNCR UREA	247/106		57***	<18	74
CORN PRODUCTS, CA	BITUM	CFBC	580	SNCR AMMONIA (N)	300/65		78		72
UNNAMED	BITUM	CFBC	12 (MWe)	SNCR UREA	175/21		88		76
JASMIN, CA	COAL	CFBC	500	SNCR AMMONIA (N)	150/30		80		73
PDSO	BITUM	CFBC	500	SNCR AMMONIA (N)	150/30		80		73
RIO BRAVO, CA	COAL	CFBC	394	SNCR AMMONIA (N)	220/53		76		75
UNNAMED	BITUM	CFBC	2.6	SNCR UREA	150/50		67		76

B-19

NOx EMISSIONS DATA - ICI BOILERS WITH FLUE GAS TREATMENT NOx CONTROLS: SNCR

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	AMMONIA SLIP (ppm@3XO2)	REF. NO.
					NOx (ppm@3XO2)*	CO (ppm@3XO2)			
WOOD/BIOMASS-FIRED UNITS:									
ALTERNATIVE ENERGY, MI	WOOD	STKR	500	SNCR UREA	128/64		50***	<40	74
BLACK & VEATCH, MI	WOOD WASTE	STKR	440	SNCR UREA	150/60		60***	<27	74
BOISE CASCADE, MN	BARK/N. GAS	STKR	395	SNCR UREA	85-125/80		25***	<20	74
BRAWLEY	WOOD	STKR	315	SNCR AMMONIA (N)	400/160		60		73
BURNEY	WOOD	STKR	300	SNCR AMMONIA (N)	116/56		52		73
CHINESE STATION, CA	WOOD	BFBC	250	SNCR AMMONIA (N)	250/140 250/50-90	<--NH3/NO=2.1 <--NH3/NO=4.0	44 72		78
CHINESE STATION, CA	WOOD	STKR	390	SNCR AMMONIA (N)	125/25		80		73
FRESNO, CA	WOOD	CFBC	440	SNCR AMMONIA (N)	120/29		76		73
GARDEN STATE PAPER	PAPER	PKG WT	72	SNCR UREA	355/178		50***	<10	74
GARDEN STATE PAPER	FIBER WASTE	PKG WT	172	SNCR UREA	374/187		50***	<10	74
KENETECH ENERGY, MA	WOOD	STKR	225	SNCR UREA	210/111		47***	<10	74
LFC, MI	WOOD	STKR	190	SNCR UREA	170/110		35***	<20	74
LONG BEACH, CA	WOOD	STKR	270	SNCR AMMONIA (N)	325/130		60		73
MALAGA COGEN, CA	WOOD WASTE	CFBC	380	SNCR AMMONIA	126/43	10/10	66		75
MENDOTA, CA	WOOD	CFBC	435	SNCR AMMONIA (N)	120/24		80		73
RYEGATE POWER, VT	WOOD	STKR	300	SNCR UREA	210/105		50***	<40	74
S.D. WARREN, ME	OIL/BIOMASS	STKR	900	SNCR UREA	235/118		50***	<20	74
SACRAMENTO, CA	WOOD	STKR	220	SNCR AMMONIA (N)	220/90		59		73
SHASTA, CA	WOOD	STKR	375	SNCR AMMONIA (R)	90/45		50		73
SIERRA PACIFIC, CA	WOOD WASTE	CELL	2x 130	SNCR UREA	200/96		52***	<20	74
SUSANVILLE, CA	WOOD	STKR	480	SNCR UREA	140/67		52***	<30	74
SUSANVILLE, CA	WOOD	STKR	625	SNCR AMMONIA (N)	130/55		58		73
TERRA BELLA, CA	WOOD	STKR	210	SNCR AMMONIA (R)	100/50		50		73
TRACY, CA	WOOD	STKR	350	SNCR AMMONIA (N)	310/78		75		73
ULTRA SYSTEMS, CA	WOOD	CFBC	280	SNCR UREA	150/45		70***	<10	74

NOx EMISSIONS DATA - ICI BOILERS WITH FLUE GAS TREATMENT NOx CONTROLS: SNCR

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	AMMONIA SLIP (ppm@3%O2)	REF. NO.
					NOx (ppm@3%O2)*	CO (ppm@3%O2)			
UNNAMED	WOOD	CFBC	3.4	SNCR UREA	125/50		60		76
WOODLAND	WOOD	CFBC	415	SNCR AMMONIA (N)	120/29		76		73

MSW-FIRED UNITS:

BASEL, SWITZERLAND	MSW	MB	125	STAGED SNCR UREA (R)	290/58-142	9-18 ABOVE BASELINE	66		79
BERLIN (7 UNITS), GERMANY	MSW	STKR		SNCR UREA	160/50		69***	<25	74
BREMERHAVEN, GERMANY	MSW	MB		SNCR AMMONIA (R)	225/48		79		80
COMMERCE, CA	MSW	MB/OFS	190	SNCR AMMONIA (N)	225/116	NA/20	48		81
EMMENSPIITZ, SWITZERLAND	MSW	STKR	121	SNCR UREA	200/64		68***	<10	74
FOSTER WHEELER, SC	MSW	STKR	138	SNCR UREA	110/44		60***	<10	74
FRANKFURT, GERMANY	MSW	MB/OFS	115	SNCR UREA (R)	362/90	9 ABOVE BASE	75	22****	82
FRANKFURT (4 UNITS), GERMANY	MSW	STKR	660	SNCR UREA	170/51		70***	17	74
HAM (4 UNITS), GERMANY	MSW	STKR	528	SNCR UREA	170/100		41***	<5	74
HERTEN (2 UNITS), GERMANY	MSW	STKR	242	SNCR UREA	185/74		60***	<7	74
LONG BEACH, CA	MSW	MB		SNCR AMMONIA, FGR (N)	NA/120				80
MILLBURY, MA	MSW	MB/OFS	325	SNCR UREA (R)	310/125	12 ABOVE BASE	60	12	82
NEW HANOVER COUNTY, NC	MSW	MB	108	SNCR UREA	300/120		60***	<15	74
SEMASS, MA	MSW	STKR	375	SNCR UREA	220/110		50***	<20	74
STANISLAUS, CA #1	MSW			SNCR AMMONIA (N)	380/120		68		80
STANISLAUS, CA #2	MSW			SNCR AMMONIA (N)	390/145		63		80
SWITZERLAND	MSW	OFS	80	SNCR UREA (R)	500/210	9 ABOVE BASE	58	22****	82
UNNAMED	MSW	OFS	15 (MWe)	SNCR UREA	200/64		68		76

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NOx EMISSIONS DATA - ICI BOILERS WITH FLUE GAS TREATMENT NOx CONTROLS: SNCR

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	AMMONIA SLIP (ppm@3%O2)	REF. NO.
					NOx (ppm@3%O2)*	CO (ppm@3%O2)			

WT: watertube; PKG: packaged; SW: single wall-fired; CFBC: circulating FBC; BFBC: bubbling FBC; STKR: stoker; MB: mass burn; OFS: overfeed stoker
 SNCR: selective non-catalytic reduction (ammonia based unless noted as urea); LNB: low NOx burner; SCA: staged combustion air; FGR: flue gas recirculation
 NA: no data available
 * To convert NOx to lb/MMBtu divide by the following: coal-740, gas-835; oil-740; wood-710; MSW-705.
 ** Total excess combustion air
 *** According to vendor, reduction to meet unit's permitted emission level, not necessarily lowest achievable
 **** Chemical enhancers used to reduce ammonia slip to levels indicated
 Note: All are short term test data.

NOx EMISSIONS DATA - ICI BOILERS WITH FLUE GAS TREATMENT NOx CONTROLS: SCR

BOILER ID	FUEL TYPE	BOILER TYPE	HEAT INPUT CAPACITY (MMBTU/HR)	CONTROL TYPE NEW (N) OR RETROFIT (R)	UNCONTROLLED/CONTROLLED		AVERAGE NOx REDUCTION (%)	REF. NO.
					NOx (ppm@3%O2)*	CO (ppm@3%O2)		
CHEMICAL CO**	OIL		750	SCR (R)	250/25		90	83
CHEMICAL CO**	OIL		240	SCR (R)	167/17		90	83
PETROLEUM CO**	OIL		125	SCR (R)	160/24		85	83
PETROLEUM CO**	OIL		240	SCR (R)	188/18.8		90	83
PETROLEUM CO**	OIL		240	SCR (R)	188/18.8		90	83
PETROLEUM CO**	OIL		300	SCR (R)	188/18.8		90	83
AICHI REFINERY, JAPAN	PULV COAL		270	SCR (N)	265/110		58	84
WAKAMATSU DEMO PLANT, JAPAN	COAL "A"	BFBC	300	SCR	206/96		53	85
	COAL "B"				210/80		62	
	COAL "C"				194/72		63	
	COAL "D"				167/73		56	
TOSCO REFINERY, CA	NG	VERT CYL FURNACE	160	SCR (N)	85/40		53	70
WESTINGHOUSE, CA	NG	WT/PKG	330	SCA, FGR, O2	NA/40	NA/67		86
				SCA, FGR, O2 W/SCR (N)	NA/10		87	
WILLAMETTE IND., CA	NG	WT	75	SCR (N)	228/46		80	83
CHEMICAL CO**	REF. GAS		75	SCR (R)	70/10		86	83
CHEVRON EL SEGUNDO	REF. GAS		310	SCR (N)	100/9		91	88
IWATSUKI, JAPAN	MSW			SCR (N)	77/36		53	80

BFBC: bubbling fluidized bed combustor; WT: watertube; PKG: packaged
 SCR: selective catalytic reduction; SCA: staged combustion air; FGR: flue gas recirculation; O2: O2 trim
 NA: no data available

* To convert NOx to lb/MMBtu divide by the following factors: coal-740; gas-835; oil-790.

** Not located in the U.S.

Note : all are short term test data.

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**APPENDIX C. LOW-NO_x INSTALLATION LISTS,
COEN COMPANY AND TAMPELLA POWER CORP.**

(Note: NO_x levels reported in the Coen list are not necessarily those achieved with the Coen low-NO_x burner, but often represent NO_x guarantees. Actual levels may be lower.)

<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOx LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOx REDUCTION</u>
D-2023-1	Bergan Mercy Med. Omaha, NE	NBC NS-C-53	(1) 40,000 PPH	Natural Gas No. 2 oil No. 6 oil	40 PPM 56 PPM 271 PPM	1	DAF-22 W/FGR
D-2019-1 D-2019-2 D-2019-3	Rancho Los Amigos Downey, CA	Nebraska NS-B-38-ECON	(3) 24,000 PPH	Natural Gas Low Nit. Oil	25 PPM 40 PPM	1	SDAF-17 W/FGR
D-2009-1	Stillwater Util. Stillwater, OK	Erie	(1) 150,000 PPH	Natural Gas No. 2 oil	0.1 LBS/MMBTU	4	DAF-28 W/FGR
D-2008-1	Wright Patterson AFB Dayton, OH	IBW D-Type	(2) 80,000 PPH	Natural Gas No. 1 oil	.10 LBS/MMBTU .12 LBS/MMBTU	1	DAF-28 W/FGR
D-2007-1	Neenah Paper Neenah, WI	Nebraska NS-G-80-ECON	(1) 120,000 PPH	Natural Gas No. 2 oil	.16 LBS/MMBTU .20 LBS/MMBTU	1	DAF-34
D-2005-1	Smurfit Venezuela	B&W FM117-97	(1) 150,000 PPH	Natural Gas No. 6 oil	.20 LBS/MMBTU .52 LBS/MMBTU	1	DAF-36
D-2003-1	Merck & Co. West Point, PA	B&W FM120-97	(1) 140,000 PPH	Natural Gas No. 2 oil	.05 LBS/MMBTU .52 LBS/MMBTU	1	DAF-39
D-1999-1 D-1999-2 D-1999-3	James River Berlin, NH	C.E. VU	(8) 100,000 PPH	No. 6 oil	.28 LBS/MMBTU	1	DAF-30 W/FGR
D-1998-1	Champion Int'l Cantonment, FL	CE 34VP18/60	(1) 350,000 PPH (1) 385,000 PPH	Natural Gas	.048 LBS/MMBTU	2	DAF-45 W/FGR
D-1996-1	Sithe Energies Scriba, NY	C.E. 38A14/48	(1) 200,000 PPH (1) 210,000 PPH	Natural Gas No. 2 oil	.20 LBS/MMBTU	2	DAF-42 W/FGR
D-1987-1 D-1987-2	Nationwide Fremont, CA	B&W FM 227-97	(2) 150,000 PPH	Natural Gas No. 2 oil No. 6 oil	30 PPM	1	DAF-36 W/FGR
D-1982-1	Marion Merrell Cincinnati, OH	Nebraska N2S-4A-67	(1) 60,000 PPH	Natural Gas No. 2 oil	.012 LBS/MMBTU .17 LBS/MMBTU	1	DAF-28
D-1967-1	Contadina Foods Hanford, CA	Nebraska NS-F-84-ECON	(2) 100,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-32 W/FGR
D-1966-1	CITGO Lake Charles, LA	Zurn Keystone	(2) 250,000 PPH	Refinery Gas	.06 LBS/MMBTU	1	DAF-36 W/FGR
D-1960-2	Cargill Lake Charles, LA	B&W FM 120-97	(1) 165,000 PPH	Natural Gas	.10 LBS/MMBTU	1	DAF-39 W/FGR
D-1960-1	Cargill Eddyville, IA	B&W FM 120-97	(1) 150,000 PPH	Natural Gas	.07 LBS/MMBTU	1	DAF-36 W/FGR
D-1954-1	Heublin Wines Madera, CA	Nebraska NS-F-81-ECON	(2) 100,000 PPH	Natural Gas Propane/Air	30 PPM	1	DAF-32 W/FGR
D-1945-1 D-1945-2	Chevron USA Perth Amboy, NJ	Nebraska NS-E-67	(1) 82,300 PPH (1) 68,500 PPH	Natural Gas Refinery Gas	.05 LBS/MMBTU .05 LBS/MMBTU	1	DAF-30 W/FGR
D-1942-1	So. Peru Copper Ilo, Peru	CE 39VP22/54"	(2) 400,000 PPH	No. 6 oil	.50 LBS/MMBTU	1	DAF-45
D-1937-1	Wabash Wheeling, IL	Nebraska N2S-B/S-116SH	(1) 250,000 PPH	No. 2 oil No. 6 oil	.20 LBS/MMBTU .40 LBS/MMBTU	1	DAF-48 W/FGR

<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOX LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOX REDUCTION</u>
D-1930-1	Miami University Oxford, OH	Nebraska N2S-7-93-ECON	(1) 100,000 PPH	Natural Gas No. 2 oil	.1 LBS/MMBTU	1	DAF-34 W/FGR
D-1923-1	Henkel Corp. Los Angeles, CA	B&W FM10-79B	(1) 60,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-28 W/FGR
D-1919-1	Appleton Paper Combined Locks, WI	CE 40A16/48	(1) 200,000 PPH	Natural Gas No. 2 oil	.05 LBS/MMBTU .10 LBS/MMBTU	1	DAF-45 W/FGR
D-1915-1	Central Soya Bellevue, OH	Boiler Eng DS35-112R	(1) 112,000 PPH	Natural Gas Waste oil	.18 LBS/MMBTU	1	DAF-30
D-1891-1	City of Virginia Virginia, MN	Zurn Keystone	(1) 200,000 PPH	Natural Gas	.10 LBS/MMBTU	1	DAF-45 W/FGR
D-1889-1	Indeck	Zurn	(1) 100,000 PPH	No. 2 oil	.12 LBS/MMBTU	1	DAF-32
D-1889-2	Wheeling, IL	16M		Natural Gas	.055 LBS/MMBTU		W/FGR
D-1886-1	Indeck Wheeling, IL	Zurn Keystone 250S	(1) 250,000 PPH	Natural Gas No. 2 oil No. 6 oil	.15 LBS/MMBTU	1	DAF-45 W/FGR
D-1867-1	Chief Ethanol Fuels Hastings, NE	Foster Wheeler AG-5175B	(1) 200,000 PPH	Natural Gas No. 2 oil	.20 LBS/MMBTU	1	DAF-42
D-1854-1	Occidental Chem. Pasadena, TX	Nebraska N2S-8/S-103SH	(1) 150,000 PPH	Natural Gas	.05 LBS/MMBTU	1	DAF-39 W/FGR
D-1851-1	Meyerhaeuser Co. Eugene, OR	Zurn Keystone	(1) 250,000 PPH	Natural Gas No. 6 oil	.146 LBS/MMBTU .35 LBS/MMBTU	1	DAF-45 W/FGR
D-1830-1	General Motors Ft Wayne, IN	Riley MH	(1) 200,000 PPH	Natural Gas No. 2 oil	.098 LBS/MMBTU .13 LBS/MMBTU	1	DAF-42 W/FGR
D-1823-1	Passaic Valley Sewer Newark, NJ	B&W FM 10-70	(4) 50,000 PPH	Natural Gas	.05 LBS/MMBTU	1	DAF-26 W/FGR
D-1815-2	Kansas City Power Kansas City, KS	ABCO D-Type	(1) 184,000 PPH	No. 2 oil	.20 LBS/MMBTU	1	DAF-42 W/FGR
D-1815-1	Kansas City Power Kansas City, KS	ABCO D-Type	(2) 208,000 PPH	No. 2 oil	.20 LBS/MMBTU	1	DAF-42 W/FGR
D-1812-1	Ultra Systems Weldon, NC	Volcano D-Type	(1) 20,000 PPH	No. 2 oil	.10 LBS/MMBTU	1	DAF-18 W/FGR
D-1803-1	Texaco Inc. Montebello, CA	B&W FM-D-9-34	(1) 16,000 PPH	Natural Gas Syn Gas	30 PPM	1	DAF-16.5 W/FGR
D-1796-1	ALCOA Lafayette, IN	Nebraska NS-E-63	(1) 70,000 PPH	Natural Gas	.13 LBS/MMBTU	1	DAF-28 W/FGR
D-1778-1	Nationwide Boiler Fremont, CA	B&W FM 117-B8C	(2) 120,000 PPH	Natural Gas No. 2 oil No. 6 oil	30 PPM	1	DAF-34 W/FGR
D-1777-1	Hercules Aerospace Maggna, UT	Nebraska NS-C-48-ECON	(1) 35,000 PPH	Natural Gas No. 2 oil	.048 LBS/MMBTU .075 LBS/MMBTU	1	DAF-22 W/FGR
D-1773-1	Ross Labs Columbus, OH	Nebraska NS-f-65-ECON	(1) 80,000 PPH	Natural Gas No. 2 oil	.10 LBS/MMBTU .165 LBS/MMBTU	1	DAF-28
D-1762-1	Toray Industries No. Kingstown, RI	Nebraska NS-C-46-ECON	(1) 33,000 PPH	Natural Gas No. 2 oil	.08 LBS/MMBTU .11 LBS/MMBTU	1	DAF-20

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J-1757-2	Boise Cascade Rumford, ME	Zurn 2-Drum	(1) 200,000 PPH	No. 6 oil	.34 LBS/MMBTU	3	DAF-30 W/FGR
J-1755-1	Morton Salt	Zurn	(1) 70,000 PPH	Natural Gas	.10 LBS/MMBTU	1	DAF-30
J-1755-2	Hutchinson, KS	Keystone		No. 2 oil No. 6 oil	.20 LBS/MMBTU .34 LBS/MMBTU		
J-1754-5	Kalamazoo Psy.	Wickes 2-Drum	(1) 125,000 PPH	Natural Gas	.14 LBS/MMBTU	1	DAF-26
J-1754-4	Kalamazoo Psy.	Erie City 2-Drum	(1) 125,000 PPH	Natural Gas	.14 LBS/MMBTU	1	DAF-26
J-1754-3	Kalamazoo Psy.	Wicks 3-Drum	(1) 50,000 PPH	Natural Gas	.14 LBS/MMBTU	1	DAF-26
J-1754-2	Kalamazoo Psy.	Wicks 3-Drum	(1) 50,000 PPH	Natural Gas	.14 LBS/MMBTU	1	DAF-26
J-1754-1	Kalamazoo Psy.	Wicks 3-Drum	(1) 50,000 PPH	Natural Gas	.14 LBS/MMBTU	1	DAF-26
J-1746-1	Barrick Goldstrike Carlin, NV	Foster Wheeler AG-5110B	(1) 100,000 PPH	Propane Gas	.134 LBS/MMBTU	1	DAF-34 W/FGR
J-1740-1	U.S. Paper Menasha, WI	B&W FM120-97	(1) 165,000 PPH	Natural Gas Prop.-Air/Gas	.12 LBS/MMBTU .20 LBS/MMBTU	1	DAF-39 W/FGR
J-739-1	U.S. Borax Willamington, CA	Nebraska NS-B-35-ECON	(1) 21,500 PPH	Natural Gas	30 PPH	1	DAF-18 W/FGR
J-1729-1	Douglas Energy Placentia, CA	Zurn	(1) 69,000 PPH	Landfill Gas Natural Gas	18 PPH 30 PPH	1	DAF-30 W/FGR
J-1726-1	Miles Research West Haven, CT	B&W FM10-79	(1) 60,000 PPH	Natural Gas No. 2 oil No. 6 oil	.046 LBS/MMBTU .078 LBS/MMBTU .38 LBS/MMBTU	1	DAF-28 W/FGR
J-1721-1	Grain Processing Eddyville, IA	ABB C.E. 12F40A16	(2) 300,000 PPH	Natural Gas	0.187 LBS/MMBTU	2	DAF-36
J-1719-2	ARCO Alaska	Econotherm 1077B	(1) 65 MMBTU	Spec. Gas	.08 LBS/MMBTU	1	DAF-24
J-1719-1	ARCO Alaska	Econotherm 1077B	(1) 80 MMBTU	Spec. Gas	.08 LBS/MMBTU	1	DAF-26
J-1715-1	Indeck	Zurn 14H	(1) 65,000 PPH	Natural Gas	30 PPH	1	DAF-30 W/FGR
J-1712-1	CF Industries Donaldsonville, LA	ABCO D-Type	(1) 75,000	Natural Gas	.090 LBS/MMBTU	1	DAF-30 W/FGR
J-1708-1	Central Heating Plt Washington, DC	Vogt	(2) 90,000	Natural Gas	.07 LBS/MMBTU	2	DAF-30
J-1704-1	Minnesota Corn Proc. Marshall, MN	NBC NS-F-86	(1) 120,000	Natural Gas No. 6 oil	0.1 LBS/MMBTU .4 LBS/MMBTU	1	DAF-34 W/FGR
J-1703-1	Letter Day Saints Hos Salt Lake City, Utah	NBC NS-C-59	(2) 38,000 PPH	Natural Gas No. 2 oil	.10 LBS/MMBTU .20 LBS/MMBTU	1	DAF-22

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D-1702-1	United Distillers Louisville, KY	NBC NS-F-77	(1) 100,000 PPH	Natural Gas No. 2 oil No. 6 oil	.15 LBS/MMBTU .20 LBS/MMBTU .37 LBS/MMBTU	1	DAF-32
D-1701-1	Ford Motor Co. Sterling Heights, MI	Wicks ROP	(1) 120,000 PPH	Natural Gas No. 2 oil	.14 LBS/MMBTU .14 LBS/MMBTU	1	DAF-28 W/FGR
D-1694-1	Ross Labs Chicago, IL	NBC NS-F-65	(1) 80,000 PPH	Natural Gas No. 2 oil	.10 LBS/MMBTU .165 LBS/MMBTU	1	DAF-28
D-1680-1	3M Company Middleway, WV	Nebraska NS-C-54	(2) 40,000 PPH	Natural Gas No. 2 oil	77 PPM 92 PPM	1	DAF-22 W/FGR
D-1675-1	General Mills Cedar Rapids, IA	Nebraska NS-C-53	(1) 40,000 PPH	Natural Gas No. 2 oil		1	DAF-22
D-1675-1	Chambers Works Carneys Point, NJ	Volcano VM-700	(1) 72,000 PPH	No. 2 oil	.17LBS/MMBTU	1	DAF-30 W/FGR
D-1674-1	Monitor Sugar Eay City, MI	Nebraska NS-G-96-ECON	(2) 150,000 PPH	Natural Gas No. 2 oil	0.10 LBS/MMBTU .155 LBS/MMBTU	1	DAF-36 W/FGR
D-1670-1	General Mills So. Chicago, IL	Nebraska NS-E-57	(1) 60,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.10 LBS/MMBTU 0.155 LBS/MMBTU 0.41 LBS/MMBTU	1	DAF-26 W/FGR
D-1663-1	Shintech Freeport, TX	Nebraska NS-E-57-ECON	(2) 60,000 PPH	Natural Gas No. 2 oil	0.06 LBS/MMBTU .13 LBS/MMBTU	1	DAF-26 W/FGR
D-1661-3	Univ of Calif. Irvine, CA	Trane MCF2-38	(1) 30,300 PPH	Natural Gas Propane-Air	40 PPM	1	DAF-20 W/FGR
D-1661-2	Univ of Calif. Irvine, CA	Nebraska NS-C-51	(1) 28,100 PPH	Natural Gas Propane-Air	40 PPM	1	DAF-20
D-1661-1	Univ of Calif. Irvine, CA	B&W FM-9-57	(2) 26,500 PPH	Natural Gas Propane-Air	40 PPM	1	DAF-18 W/FGR
D-1660-1	Ohio State Univ. Athens, Ohio	Keeler	(1) 70,000 PPH	Natural Gas		1	DAF-28
D-1659-1	Gangl Brothers Riverbank, CA	Nebraska N2S-7-95-ECON	(1) 150,000 PPH	Natural Gas Propane-Air	.072 LBS/MMBTU	1	DAF-39 W/FGR
D-1632-2	Wayside Honor Rancho Saugus, CA	Keeler DS-10-13	(1) 50,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-26 W/FGR
D-1632-1	Wayside Honor Rancho Saugus, CA	Keeler DS-10-13	(1) 50,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-26 W/FGR
D-1631-1	LA County Mens Jail Los Angeles, CA	Murray MCF1-59	(1) 30,600 PPH	Natural Gas No. 2 oil	40 PPM	1	DAF-20 W/FGR
D-1630-2	LA County Mens Jail Los Angeles, CA	Murray C-18	(1) 27,500 PPH	Natural Gas No. 2 oil	40 PPM	1	DAF-20 W/FGR
D-1630-1	LA County Mens Jail Los Angeles, CA	Murray C-18	(1) 27,500 PPH	Natural Gas No. 2 oil	40 PPM	1	DAF-20 W/FGR
D-1623-1	Marathon Petroleum Garyville, LA	Zurn Special Keystone	(1) 250,000 PPH	Natural Gas Refinery Gas	.123 LBS/MMBTU	2	DAF-36 W/FGR
19-1	Dupont Corpus Christi, TX	Erie City Keystone 20H	(1) 130,000 PPH	Natural Gas	0.06 LBS/MMBTU	1	DAF-36 W/FGR

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D-1615-1	BASF Greenville, OH	B&W FH 10-66	(1) 50,000 PPH	Natural Gas/ No. 2 oil or Waste Gas/ No. 6 oil	0.10 LBS/MMBTU 0.10 LBS/MMBTU	1	DAF-24 W/FGR
D-1614-1	Univ. of North Dakota Grand Forks, ND	Nebraska NS-E-57	(2) 60,000 PPH	Natural Gas No. 2 oil	0.12 LBS/MMBTU 0.16 LBS/MMBTU	1	DAF-26
D-1613-1	Indeck Wheeling, IL	Zurn N2S-7-95	(1) 150,000 PPH	Natural Gas No. 2 oil	0.1 LBS/MMBTU	1	DAF-36 W/FGR
D-1612-1	Indeck Wheeling, IL	Zurn Keystone 23H	(1) 140,000 PPH	Natural Gas Hydrogen	0.10 LBS/MMBTU	1	DAF-36 W/FGR
D-1611-1	Indeck Wheeling, IL	Zurn Keystone 22H	(1) 150,000 PPH	Natural Gas No. 2 oil	0.1 LBS/MMBTU	1	DAF-36 W/FGR
D-1610-1	Indeck Wheeling, IL	Zurn Keystone 16H	(1) 95,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.1 LBS/MMBTU 0.16 LBS/MMBTU	1	DAF-32 W/FGR
D-1509-1	Indeck Wheeling, IL	Zurn Keystone 16H	(1) 95,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.1 LBS/MMBTU 0.16 LBS/MMBTU	1	DAF-32 W/FGR
D-1608-1	Indeck Wheeling, IL	Zurn Keystone 16H	(1) 95,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.1 LBS/MMBTU 0.16 LBS/MMBTU	1	DAF-32 W/FGR
D-1607-1	Indeck Wheeling, IL	Zurn Keystone 16	(1) 95,000 PPH	Natural Gas No. 2 oil	0.1 LBS/MMBTU 0.147 LB/MMBTU	1	DAF-32 W/FGR
D-1598-1	Cambell Soup Co. Naxton, NC	Keeler DS10-22	(1) 100,000 PPH	Natural Gas No. 6 oil	0.30 LBS/MMBTU 0.10 LBS/MMBTU	1	DAF-32
D-1586-1	Lockheed Palmdale, CA	Nebraska NS-E-65-ECON	(1) 75,000 PPH	Natural Gas No. 2 oil	.048 LBS/MMBTU .076 LBS/MMBTU	1	DAF-32 W/FGR
D-1585-1	Marine Corp. Logistics Base Barstow, CA	IBW TJW-C-25	(3) 25,000 PPH	Natural Gas No. 2 oil	40 PPM 200 PPM	1	DAF-20 W/FGR
D-1584-1	Contadina Foods Woodland, CA	Nebraska NS2-7-95-ECON	(1) 150,000 PPH	Natural Gas Propane-Air Butane-Air	40 PPM 55 PPM	1	DAF-39 W/FGR
D-157E-1	Patton State Hospital San Bernardino, CA	Nebraska NSC 42	(1) 30,000 PPH	Natural Gas	39.4 PPM	1	DAF-20 W/FGR
D-1577-1	Boise Cascade International Falls, MN	C.E. 12F48A16	(2) 250,000 PPH	Natural Gas	0.05 LBS/MMBTU	2	DAF-36 W/FGR
D-1571-1	GWF Hanford Cogen Hanford, CA	Nebraska NS-E-65-ECON	(1) 68,000 PPH	Natural Gas	30 PPM	1	DAF-38 W/FGR
D-1563-1	Indeck Power Wheeling, IL	Zurn 24H	(1) 250,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.10 LBS/MMBTU 0.28 LBS/MMBTU 0.40 LBS/MMBTU	1	DAF-45 W/FGR
D-1562-1	Indeck Power Wheeling, IL	Zurn 24H	(1) 250,000 PPH	Natural Gas No. 2 oil No. 6 oil	0.10 LBS/MMBTU 0.28 LBS/MMBTU 0.40 LBS/MMBTU	1	DAF-45 W/FGR

<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOx LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOx REDUCTION</u>
D-1559-1	3M St. Paul, MN	Nebraska N2S-B/S-93-ECON	(1) 180,000 PPH	Natural Gas No. 2 oil (.017% FEN)	0.05 LBS/MMBTU 0.11 LBS/MMBTU	1	DAF-42 W/FGR SCROLL
D-1545-1	BYU Provo, UT	Volcano TJU-C-150	(2) 150,000 MKB	Natural Gas No. 2 oil (0.02% FEN)	0.11 LBS/MMBTU 0.20 LBS/MMBTU	1	DAF-39
D-1545-2	BYU Provo, UT	Volcano TJU-C-50	(1) 50,000 MKB	Natural Gas No. 2 oil (0.02% FEN)	0.09 LBS/MMBTU 0.16 LBS/MMBTU	1	DAF-24
D-1544-1	Newark Bay Cogen Newark, NJ	B&W	(1) 140,000 PPH	Natural Gas No. 2 oil	45 PPH	1	DAF-39 W/FGR
D-1540-1	Spreckles Sugar Manteca, CA	UIW MH	(1) 120,000 PPH	Natural Gas No. 2 oil No. 6 oil	.0829 LBS/MMBTU 0.30 LBS/MMBTU 0.75 LBS/MMBTU	1	DAF-42 W/FGR
D-1540-2	Spreckles Sugar Manteca, CA	CE 25VP12	(1) 100,000 PPH	Natural Gas No. 2 oil No. 6 oil	.082 LBS/MMBTU 0.30 LBS/MMBTU 0.75 LBS/MMBTU	1	DAF-39 W/FGR
D-1539-1	A&P Tea Company Columbus, OH	Wicks RB	(1) 65,000 PPH	Natural Gas Landfield Gas	.11 LBS/MMBTU	1	DAF-26
D-1538-1	Union Co. Court House Elizabeth, NJ	B&W FM9-43	(1) 30,000 PPH	Natural Gas No. 6 oil		1	DAF-18
D-1538-2	Union Co. Court House Elizabeth, NJ	B&W FM9-39	(1) 26,000 PPH	Natural Gas No. 6 oil		1	DAF-18
D-1527-1	E.I. Dupont Sabine, TX	CE VU60	(1) 360,000 PPH	Natural Gas	0.23 LBS/MMBTU	4	DAF-32
D-1525-1	UCLA Westwood, CA	Zurn Keystone	(1) 160,000 PPH	Natural Gas No. 2 oil (.00001% FEN)	0.055 LBS/MMBTU 0.084 LBS/MMBTU	1	DAF-45 W/FGR
D-1522-1	Washington Univ. St. Louis, MO	Zurn Keystone	(1) 70,000 PPH	Natural Gas No. 2 oil	0.15 LBS/MMBTU 0.2 LBS/MMBTU	1	DAF-28
D-1520-1	Okeelanta Sugar South Bay, FL	B&W FM128-97	(1) 150,000 PPH/ 100,000 PPH	No. 2 Oil (0.1% FEN)	0.21 LBS/MMBTU	1	DAF-42 W/FGR
D-1508-1	Savannah Electric Power Co. Savannah, GA	ABB Combustion 40AF16/42	(2) 200,000 PPH	Natural Gas	0.07 LBS/MMBTU	1	DAF-45 W/FGR
D-1498-1	Cedar Sinai Medical Ctr Los Angeles, CA	MIW MCF 4-49	(3) 50,000 PPH	Natural Gas No. 2 Oil (0.001% FEN)	40 PPH 400 PPH	1	DAF-26 W/FGR
D-1496-1	Lunday-Thagard Co. South Gate, CA	B&W FM1061B	(1) 48,000 PPH	Natural Gas No. 2 Oil Propane/Air (0.003% FEN)	39.9 PPH 30 PPH 33 PPH	1	DAF-22 W/FGR
D-1478-1	Henkel Corporation Los Angeles, CA	B&W FM 1061A	(1) 40,000 PPH	Natural Gas No. 2 Oil (0.001% FEN)	30 PPH 400 PPH	1	DAF-24 W/FGR

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J-1469-1	Santa Monica Hospital Santa Monica, CA	Murray MCF-2-42	(2) 30,000 PPH	Natural Gas No. 2 Oil (0.001% FBN)	40 PPM 40 PPM	1	DAF-22 W/FGR
J-1463-1	Campbell Soup Company Maxton, NC	Union Boiler "A" MH	(1) 100,000 PPH	Natural Gas No. 6 Oil		1	DAF-32
J-1452-1	Shell Western M. Teerebone, LA	Holman MH	(1) 85,000 PPH	Natural Gas	83.5 PPM	1	DAF-34 W/FGR
J-1437-1	BP Oil Lima, OH	CE 12F40A16/54	(1) 225,000 PPH	Refinery Gas Future Oil	.1 LBS/MMBTU	2	DAF-36 W/FGR
J-1436-1	Metrohealth Med Center Cleveland, OH	Nebraska NS-E-51-ECON	(1) 50,000 PPH	Natural Gas No. 2 Oil	0.1 LBS/MMBTU 0.2 LBS/MMBTU	1	DAF-24
J-1434-1	Huntington Mem. Hosp. Pasadena, CA	Bros W3-35	(3) 28,000 PPH	Natural Gas No. 2 Oil (0.001% FBN)	40 PPM	1	DAF-20 W/FGR
J-1425-1	Univ. of Cincinnati Cincinnati, OH	NBC N2S-7-107 ECON	(2) 150,000 PPH	Natural Gas No. 2 Oil	0.20 LBS/MMBTU (.02% FBN)	1	DAF-36
J-1420-1	Wabash Power Equip. Rental Unit	CE 35-A-14	(4) 150,000 PPH (3)	Natural Gas No. 2 Oil (0% FBN)	0.19 LBS/MMBTU 0.20 LBS/MMBTU	1	DAF-42
J-1399-1				No. 6 Oil	0.39 LBS/MMBTU		
J-1398-1				(.25% FBN)			
J-1403-1	Wabash Power Equip. Rental Unit	NBC N2S-7-89	(2) 150,000 PPH	Natural Gas No. 2 Oil (0% FBN)	0.19 LBS/MMBTU 0.20 LBS/MMBTU	1	DAF-42
J-1402-1				No. 6 Oil (.25% FBN)	0.39 LBS/MMBTU		
J-1384-1	Old Dominion Electric Clover, VA	CE 34A13	(1) 140,000 PPH	No. 2 Oil	0.23 LB/MMBTU	1	DAF-42
J-1376-1	McDonnell Douglas Long Beach, CA	IBW LFU-20	(2) 32,000 PPH	Natural Gas	0.048 LB/MMBTU	1	DAF-22 W/FGR
J-1373-1	Hoechst Celanese Carlsale, CA	NBC NS-E-57	(1) 60,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU 0.35 LB/MMBTU (0.28 WT % FBN)	1	DAF-26
J-1372-1	Global Octane Deer Park, TX	Abco D Type	(1) 25,000 PPH	Natural Gas	0.08 LB/MMBTU	1	DAF-20 W/FGR
J-1365-1	Holman Boiler Works Rental Unit	Zurn Keystone	(1) 200,000 PPH	Natural Gas No. 2 Oil (0% FBN)	0.19 LBS/MMBTU 0.20 LBS/MMBTU	1	DAF-45 W/FGR
J-1364-1				No. 6 Oil (.25% FBN)	0.39 LBS/MMBTU		
J-1366-1	Holman Boiler Works Rental Unit	CE 33A14	(5) 155,000 PPH	Natural Gas No. 2 Oil (0% FBN)	0.19 LBS/MMBTU 0.20 LBS/MMBTU	1	DAF-39 W/FGR
J-1363-1				No. 6 Oil	0.39 LBS/MMBTU		
J-1362-1				(.25% FBN)			
J-1361-1							
J-1354-1	Cannara Steam Company Terminal Island, CA	UIW Type H	(2) 100,000 PPH	Natural Gas No. 6 Oil	0.048 LB/MMBTU (Up to 80,000 PPH)	4	DAF-20

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D-1351-1	Procter & Gamble Oxnard, CA	B&W FMD-103-88	(1) 80,000 PPH	Natural Gas No. 2 Oil	0.05 LB/MMBTU	1	DAF-32 W/FGR
D-135C-1	Monsanto Company Long Beach, CA	B&W FM9-52	(1) 25,000 PPH	Natural Gas No. 2 Oil	0.048 LB/MMBTU	1	DAF-28 W/FGR
D-1344-1	St. Mary's Hospital Rochester, MN	NBC NS-F-86	(3) 80,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU (0.01% FBN)	1	DAF-32 W/FGR
D-1343-1 D-1343-2	Mobile Refinery Saraland, AL	Cleaver Brooks DL-52	(2) 40,000 PPH	Refinery Gas	0.15 LB/MMBTU	1	DAF-24
D-1338-1	Anitec Cogeneration Binghamton, NY	Abco D Type	(1) 104,000 PPH	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.14 LB/MMBTU (0.048% FBN)	1	DAF-34 W/FGR
D-1336-1	Dixie Chemicals Pasadena, TX	NBC NS-E-57	(1) 60,000 PPH	Natural Gas	0.06 LB/MMBTU	1	DAF-26 W/FGR
D-1333-1	General Electric Waterford, NY	Zurn Keystone	(1) 250,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LB/MMBTU 0.15 LB/MMBTU 0.30 LB/MMBTU	1	DAF-45 W/FGR
D-1332-2	Orange County Santa Ana, CA	Keeler DS-10-10	(1) 38,000 PPH	Natural Gas No. 2 Oil (0.001% FBN)	0.04 LB/MMBTU 0.05 LB/MMBTU	1	DAF-22 W/FGR
332-1	Orange County Santa Ana, CA	NBC NS-G-70	(1) 70,000 PPH	Natural Gas No. 2 Oil	0.04 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-30 W/FGR
D-1331-1	E. I. DuPont Newark, DE	NBC NTC-61	(1) 40,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-24
D-1325-1	Cape Industries Wilmington, NC	B&W FM 220	(1) 205,000 PPH	Natural Gas No. 6 Oil	0.20 LB/MMBTU	2	DAF-32
D-1320-1	Witco Chemical Oildale, CA	Zurn 15H	(1) 80,000 PPH	Natural Gas Propane/Air	0.10 LB/MMBTU 0.28 LB/MMBTU	1	DAF-30
D-1316-1	Rohm & Haas Louisville, KY	C. E. 35A14	(2) 180,000 PPH	Natural Gas #2 Oil Waste Oil	0.20 LB/MMBTU 0.20 LB/MMBTU	1	DAF-42 W/FGR
D-1310-1	Luz Engineering Boron, CA	G.C. Broach Heater	(12) 53.00 HMBTUH	Natural Gas	0.03 LB/MMBTU	1	DAF-30 W/FGR
D-1305-1	Geneva Steel Orem, UT	Zurn 21H	(2) 100,000 PPH	Natural Gas No. 6 Oil Coke Oven Gas	0.1 LB/MMBTU 0.43 LB/MMBTU 0.50 LB/MMBTU	1	DAF-32
D-1303-1	Mohawk Rubber Salem, VA	ABCO D Type	(1) 65,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.30 LB/MMBTU	1	DAF-26
D-1295-1 D-1294-1 D-1293-1	Indeck Power Rental	ZURN 24 H	(3) 250,000 PPH	Natural Gas	0.15 LB/MMBTU	1	DAF-45
D-1288-1	Ford Motor Company Livonia, MI	NBC NS-C-43	(1) 30,000 PPH	Natural Gas	0.08 LB/MMBTU	1	DAF-20
1286-1 286-2	Rancho Los Amigos H.C. Downey, CA	Murray M-64E275	(2) 30,000 PPH	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-22 W/FGR

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D-1284-1	University of Iowa Iowa City, IA	Riley MHV	(2) 150,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (.02% FBN)	1	DAF-42
D-1265-2	Ashland Oil Catlettsburg, KY	B&W FM-117-88	(1) 100,000 PPH	Refinery Gas	0.14 LB/MMBTU	1	DAF-34
D-1265-1	Ashland Oil Catlettsburg, KY	B&W FM-26	(1) 200,000 PPH	Refinery Gas	0.14 LB/MMBTU	4	DAF-26
D-1255-1	Ashland Oil St. Paul, MN	Petrochem 5-37-B1 Heater	(1) 54 MMBTU	Refinery Gas	0.14 LB/MMBTU	1	DAF-22
D-1254-1	Ashland Oil Catlettsburg, KY	Petrochem 2-121-B3	(1) 110 MMBTU	Refinery Gas	0.14 LB/MMBTU	1	DAF-28
D-1253-1	Ashland Oil St. Paul, MN	Petrochem 5-37-B2	(1) 31 MMBTU	Refinery Gas	0.14 LB/MMBTU	1	DAF-16.5
D-1252-1	Ashland Oil Catlettsburg, KY	Petrochem 2-121-B2 Heater	(2) 54 MMBTU	Refinery Gas	0.14 LB/MMBTU	1	DAF-22
D-1251-1	Amoco Performance Augusta, GA	NBC NS-E-57ECON	(1) 60,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU	1	DAF-24
D-1227-1 D-1226-1 D-1225-1	Wabash Mobile Unit	NBC NOS-2A-58	(3) 60,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU	1	DAF-26
D-1211-1 D-1211-2	Morgantown Energy Morgantown, WV	Zurn 20H	(2) 101,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-32
D-1210-1	Sterling Power Oneida, NY	Zurn 17H	(1) 98,500 PPH	Natural Gas No. 2 Oil	0.09 LB/MMBTU 0.20 LB/MMBTU	1	DAF-32 W/FGR
D-1200-1	Tennessee Eastman Kingsport, TN	CE 35A14	(1) 150,000 PPH	Natural Gas Methanol	0.10 LB/MMBTU 0.23 LB/MMBTU	1	DAF-39
D-1197-1	Franklin Heating Rochester, MN	Riley	(1) 93,000 PPH	Natural Gas No. 2 Oil	0.13 LB/MMBTU 0.33 LB/MMBTU	1	DAF-36
D-1194-1	N.E. Missouri State University Kirksville, MO	NBC NS-C-53ECON	(2) 40,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.30 LB/MMBTU	1	DAF-20
D-1183-1 D-1183-2	Tennessee Eastman Kingsport, TN	CE 35A14	(2) 150,000 PPH	Natural Gas Methanol	0.10 LB/MMBTU 0.23 LB/MMBTU	1	DAF-39
D-1179-1	Ultra Systems Hopewell, VA	NBC NS-E-56	(1) 65,000 PPH	Natural Gas No. 2 Oil	0.07 LB/MMBTU 0.10 LB/MMBTU (.02% FBN)	1	DAF-26 W/FGR
D-1178-1	Ultra Systems Buena Vista, VA	NBC NS-E-50	(1) 55,000 PPH	Natural Gas No. 2 Oil (.02% FBN)	.065 LB/MMBTU 0.10 LB/MMBTU	1	DAF-24 W/FGR
D-1173-1 D-1172-1 D-1171-1 D-1170-1 D-1169-1 68-1	Indeck Power (Mobile Unit)	Zurn 13MS	(6) 70,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN)	1	DAF-28

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D-1143-1 D-1142-1 D-1141-1 D-1140-1	Indeck Power (Mobile Unit)	NBC NOS-2-52(S)	(4) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN)	1	DAF-28
D-1139-1	Nabisco Foods Oxnard, CA	B&W FM 10-79	(1) 60,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.05 LB/MMBTU	1	DAF-26 W/FGR
D-1131-1	I/N Kote New Carlise, IN	NBC NS-E-57	(1) 58,400 PPH	Natural Gas	0.046 LB/MMBTU	1	DAF-28 W/FGR
D-1121-1	Univ. of Minnesota St. Paul MN	NBC NS-F-77	(1) 79,000 PPH	Natural Gas No. 2 Oil	0.075 LB/MMBTU 0.14 LB/MMBTU (0.01%)	1	DAF-28
D-1113-1	San Francisco Int'l Airport San Francisco, CA	IBW TJU-C-50	(1) 50 MMBTUH	Natural Gas No. 2 Oil	0.05 LB/MMBTU	1	DAF-24 W/FGR
D-1112-1	Ultra Systems Alta Vista, VA	NBC NS-G-88	(1) 122,000 PPH	Natural Gas No. 2 Oil	0.065 LB/MMBTU 0.20 LB/MMBTU	1	DAF-34 W/FGR
D-1111-1	Ultra Systems Southampton, VA	NBC NS-E-59	(1) 72,000 PPH	Tall Oil No. 2 Oil	0.65 LB/MMBTU 0.10 LB/MMBTU (0.4% FBN)	1	DAF-30 W/FGR
D-1109-1	Ashland Oil Catlettsburg, KY	NBC NS-G-85-ECON	(1) 150,000 PPH	Refinery Gas	0.14 LB/MMBTU	1	DAF-36
D-1107-1	Ross Laboratories Columbus, OH	NBC NS-F-85-ECON	(1) 80,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.165 LB/MMBTU (0.01% FBN)	1	DAF-28
D-1100-1	Fulton Cogen Fulton, NY	Zurn 13M	(2) 62,000 PPH	Natural Gas No. 2 Oil	0.168 LB/MMBTU 0.183 LB/MMBTU	1	DAF-26 W/FGR
D-1099-1	Rockwell Int'l Rocketdyne Division Canoga Park, CA	Keeler DS-20	(1) 20,000 PPH	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-16.5 W/FGR
D-1090-1	NL Chemicals Lake Charles, LA	ABCO D Type	() 75,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-30
D-1085-4	Bunker Hill Los Angeles, CA	IBW HTWG	(1) 30 MMBTUH	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-20 W/FGR
D-1085-3	McDonnell Douglas Huntington Beach, CA	MIW D Type	(1) 25,000 PPH	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-22 W/FGR
D-1085-2	Century City Los Angeles, CA	MIW D Type	(1) 112,000 PPH	Natural Gas No. 2 Oil	0.04 LB/MMBTU 0.04 LB/MMBTU (0.001% FBN)	1	DAF-36 W/FGR
D-1085-1	Bunker Hill Los Angeles, CA	IBW HTWG	(1) 30 MMBTU/HR	Natural Gas No. 2 Oil	0.05 LB/MMBTU 0.05 LB/MMBTU (0.001% FBN)	1	DAF-18 W/FGR
83-1	Boeing Company Auburn, WA	Union Riley A Type	(1) 140,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-36

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D-1072-1 D-1072-2 D-1072-3	Metropolitan Airport Minneapolis, MN	BROS P2-60	(3) 40,000 PPH	Natural Gas No. 6 Oil	0.08 LB/MMBTU 0.60 LB/MMBTU	1	DAF-22
D-1069-1	Chevron St. James, LA	CE 25A15	(3) 150,000 PPH	Natural Gas Waste Oil	0.06 LB/MMBTU 0.10 LB/MMBTU	1	DAF-39 W/FGR
D-1064-1	NASA Johnson Center Houston, Texas	NBC NS-E-68	(1) 80,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-28
D-1059-1	Monitor Sugar Bay City, MI	NBC NS-F-88	(1) 120,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (.028x FBN)	1	DAF-34
D-1057-1	General Tire & Rubber Mayfield, KY	Murray MCF6X-94	(1) 125,000 PPH	Natural Gas No. 2 Oil (0.01x FBN)	0.10 LB/MMBTU 0.24 LB/MMBTU	1	DAF-36
D-1055-1	Ciba Geigy Corp. McIntosh, AL	NBC NS-E-63 ECON	(1) 70,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.17 LB/MMBTU (.01x FBN)	1	DAF-28
D-1054-1	Indeck Power (Rental Unit)	Zurn 17H	(1) 90,000 PPH	Natural Gas	40 PPH	1	DAF-30
D-1019-1 D-1019-2	Shell Offshore Inc. Mon Louis, AL	NBC NS-C-53	(2) 40,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-22
08-1	Chrysler Corporation No. Jefferson, MI	IBW TJU-C-75	(3) 87,500 PPH	Natural Gas No. 2 Oil	40 PPH	1	DAF-28 W/FGR
D-1007-1	Wellesley College Wellesley, MA	NBC NS-C-56	(1) 45,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU	1	DAF-24 W/NOx Ports
D-1006-1	Norenc Corporation Minneapolis, MN	NBC NOS-1A-53S	(1) 36,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-20
D-1005-1	Norenc Corporation Minneapolis, MN	MIW MCF-5-85	(1) 115,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-34
D-1000-1	J.M. Huber Etowah, TN	NBC NS-F-69	(1) 88,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU	1	DAF-28
D-0998-1 D-0997-1 D-0996-1 D-0995-1 D-0994-1 D-0993-1	Indeck Power (Mobile Units)	Zurn 23H	(6) 150,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU	1	DAF-36
D-0991-1	Occidental Chemical Corpus Christi, TX	Zurn	(1) 190,000 PPH	Natural Gas Hydrogen & NG	0.12 LB/MMBTU 0.12 LB/MMBTU	1	DAF-45 W/FGR
D-0987-1	Certainteed Corp. Riverside, CA	Wicks A Type	(1) 35,000 PPH	Natural Gas Methanol	0.05 MMBTU 40 PPH @ 30 MMBTU	1	DAF-22 W/FGR
D-0985-1	General Electric Mt. Vernon, IN	Riley Stoker RH	(1) 150,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU 0.39 LB/MMBTU (.15x FBN)	1	DAF-39
D-0984-2	Glendale Adventist Medical Center Glendale, CA	BEW FMG-39	(1) 23,500 PPH	Natural Gas No. 2 Oil	0.05 MMBTU	1	DAF-18 W/FGR

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D-0980-1	Quality Assured Packing Stockton, CA	NBC NSE-65	(1) 75,000 PPH	Natural Gas	40 PPM	1	DAF-28
D-0979-1	Kal Kan Columbus, OH	CB DL-68E	(1) 50,000 PPH	Natural Gas	0.065 LB/MMBTU	1	DAF-24
D-0978-1	Takeda Chemical Wilmington, NC	CB D-34	(1) 13,500 PPH	#2 Oil #6 Oil	85 Tons/Year (.35% FBN)	1	DAF-15 W/NOx Ports
D-0970-1 D-0969-1 D-0968-1	Shintech Freeport, TX	NBC NS-E-57	(3) 60,000 PPH	Natural Gas	0.09 LB/MMBTU	1	DAF-26
D-0963-1	Great Lakes Steel Zug Island, MI	Zurn 23M	(1) 135,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-36
D-0962-1	Great Lakes Steel Zug Island, MI	Zurn 21M	(1) 115,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-34
D-0960-1 D-0959-1 D-0958-1 D-0957-1 D-0956-1 D-0955-1	Indeck Power (Rental Units)	Zurn Keystone	(6) 150,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-36
D-0950-1	Consolidated Paper Biron, WI	B&W Stirling	(3) 60,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-28
D-0948-3 D-0948-4	E.R. Squibb Lawrenceville, NJ	B&W FM 103-70	(2) 70,000 PPH	Kerosene Natural Gas	0.11 LB/MMBTU 0.068 LB/MMBTU	1	DAF-28
D-0941-1	Bridgestone Tire La Vergne, TN	B&W FM-10-57	(1) 65,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU	1	DAF-26
D-0940-1	SCH Chemicals Ashtabula, OH	NBC NS-F-77	(1) 100,000 PPH	Natural Gas No. 2 Oil	0.03 LB/MMBTU 0.25 LB/MMBTU (.03% FBN)	1	DAF-34 W/FGR
D-0931-1	Pacific Coast Pro. Lodi, CA	B&W FM106-88	(1) 120,000 PPH	Natural Gas No. 6 Oil	0.05 LB/MMBTU 0.29 LB/MMBTU (.15% FBN)	1	DAF-36 W/FGR
D-0926-1	Gaylord Container Bogalusa, LA	B&W FM 130-97	(1) 165,000 PPH	Natural Gas	0.12 LB/MMBTU	1	DAF-39
D-0924-1	IBM Manassas, VA	IBW TJM-C-62.5	(1) 62.5 MMBTU	Natural Gas	BACT	1	DAF-26
D-0918-1	Riley Stoker Stock Unit	Riley MMW	(1) 200,000 MMBTU	Natural Gas No. 2 Oil	0.20 LB/MMBTU	1	DAF-42
D-0916-1	Simpson Paper Tacoma, WA	Riley 2 Drum; Field Erected	(2) 300 MMBTU Gas 290 MMBTU Oil	No. 6 Oil	0.10 LB/MMBTU	2	DAF-39
D-0902-1 D-0901-1	Wabash Power Equip. Rental Unit	CE 35A14	(2) 150,000 PPH	Natural Gas No. 2 Oil (0% FBN) No. 6 Oil (.25% FBN)	0.19 LBS/MMBTU 0.20 LBS/MMBTU 0.39 LBS/MMBTU	1	DAF-42

<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOx LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOx REDUCTION</u>
D-0900-1	Desert Hospital Palm Springs, CA	Trane/Murray D-Type	(1) 30,000 PPH	Natural Gas Oil	40 PPM	1	DAF-20 W/FGR
D-0892-1	E.R. Squibb & Sons New Brunswick, NJ	NBC NS F 13-ECON	(2) 95,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LB/MMBTU 0.30 LB/MMBTU (.1% FBN)	1	DAF-30
D-0886-1	Minnesota Power Corp.	CE 12F40A16	(2) 250,000 PPH	Natural Gas	0.05 LB/MMBTU	2	DAF-36
D-0874-1	Louisiana State Univ. Baton Rouge, LA	NBC NS-F-77-ECON	(1) 100,000 PPH	Natural Gas	0.12 LB/MMBTU	1	DAF-32
D-0867-1	Gangi Bros. Riverbank, CA	NBC NSE-65	(2) 75,000 PPH	Natural Gas	30 PPM	1	DAF-28 W/FGR
D-0866-1 D-0865-1	Holman Boiler Works Rental Unit	CE 35A14	(2) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN) 0.40 LB/MMBTU (0.25% FBN)	1	DAF-39
D-0862-1	Frito Lay Modesto, CA	NBC NSB-41	(1) 25,000 PPH	Natural Gas	40 PPM	1	DAF-18
D-0857-1	Hekoosa Paper Ashdown, AR	CE #3 Bark/Gas Power Boiler	(1) 520,000 PPH	Natural Gas	0.10 LB/MMBTU	4	DAF-36
D-0849-1	Spreckels Sugar Mendota, CA	CE VU60	(1) 250,000 PPH	Gas No. 2 Oil No. 6 Oil	0.085 LB/MMBTU 0.25 LB/MMBTU 0.55 LB/MMBTU	4	DAF-30 W/FGR
D-0846-1 D-0841-1	Wabash Power Rental Unit	NBC N2S-7-89	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN) 0.4 LBS/MMBTU (0.2% FBN)	1	DAF-42
D-0840-1 D-0839-1 D-0838-1 D-0837-1	Indeck Power Rental Unit	NBC NOS-1A-53S	(4) 40,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN) 0.40 LBS/MMBTU (0.20% FBN)	1	DAF-22
D-0836-1 D-0832-1 D-0831-1	Indeck Power Rental Unit	Zurn Keystone	(3) 150,000 PPH Derated	Natural Gas No. 6 Oil	0.05 LB/MMBTU	1	DAF-36 W/FGR
D-0829-1	Columbia Nitrogen Augusta, GA	Zurn Keystone 23M	(1) 150,000 PPH	Natural Gas No. 6 Oil		1	DAF-36
D-0825-1	Holman Boiler Rental Unit	NBC N2S-7-95	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.30 LB/MMBTU (0.2% FBN)	1	DAF-39 Front Wall Nox Ports
D-0820-1	Soltex Polymers Deer Park, TX	NBC NS-F-77	(1) 100,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	DAF-32

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOX LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
D-0804-1	Cambria Cogen. Fac. Ebensburg, PA	NBC NSE-65	(1) 78,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-28
D-0799-1	San Diego Gas & Elect. San Diego, CA	B&W FN10-70B	(2) 50,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU	1	DAF-24
D-0791-1	Arco Alaska, Inc. Prudhoe Bay, AK	Breach Heater	(1) 35,000 MMBTU	Gas	0.08 LB/MMBTU	1	DAF-22
D-0785-1	A.E. Staley Decatur, IL	Riley RX	(1) 125,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	DAF-32
D-0779-1	3M Company Hutchinson, MN	NBC NS-E-68	(1) 80,000 PPH	Natural Gas No. 6 Oil	0.20 LB/MMBTU 0.40 LB/MMBTU (.3X FBN)	1	DAF-30
D-0768-2	Ogden Martin Systems Lawrence, MA	B&W F22 SPLAH15	(1) 100,000 PPH	Natural Gas No. 6 Oil	BACT	1	DAF-36
D-0768-1	Ogden Martin Systems Lawrence, MA	CE 30VP-12	(1) 115,000 PPH	Natural Gas No. 6 Oil	BACT	1	DAF-36
D-0766-1 D-0765-1 D-0764-1	Holman Boiler	CE 35A14	(3) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN) 0.30 LBS/MMBTU (0.2% FBN)	1	DAF-39
D-0752-1 D-0751-1	Indeck Power	Zurn 24M	(2) 250,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LBS/MMBTU 0.28 LBS/MMBTU (0.01% FBN) 0.40 LBS/MMBTU (0.14% FBN)	1	DAF-45S
D-0748-1	E.I. Dupont New Johnsonville, TN	B&W FN120-97	(1) 150,000 PPH	Natural Gas No. 2 Oil	0.08 LB/MMBTU 0.20 LB/MMBTU (.01% FBN)	1	DAF-39
D-0747-1	O'Brien Energy Systems Parlin, NJ	ABCO Special	(1) 177,000 PPH	Natural Gas No. 2 Oil	0.20 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN)	1	DAF-39
D-0745-1	Amoco Chemical Clute, TX	OPF Cabin Heater	(1) 30.4MM BTU/HR	Natural Gas	0.08 LB/MMBTU	1	DAF-18
D-0721-1	Indeck Power	Zurn 23M	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN) 0.40 LB/MMBTU (0.30% FBN)	1	DAF-36
D-0715-1	Boise Cascade Corp. Int. Falls, MN	Zurn Keystone	(2) 180,000 PPH	Natural Gas	0.05 LBS/MMBTU	1	DAF-42 W/FGR
D-0700-1	Union Texas Petroleum	Vogt BT-113-105	(1) 100,000 PPH	Natural Gas Off Gas Mixture	0.08 LBS/MMBTU 0.12 LB/MMBTU 0.10 LBS/MMBTU	1	DAF-34
D-0700-2	Union Texas Petroleum	CE 27VP14	(1) 150,000 PPH	Natural Gas Off Gas Mixture	0.08 LBS/MMBTU 0.12 LB/MMBTU 0.10 LBS/MMBTU	1	DAF-39

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOX LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
D-0698-1	Boeing - Plant II Seattle, WA	CB 9LD94E	(2) 80,000 PPH	Natural Gas No. 6 Oil	0.10 LBS/MMBTU 0.30 LBS/MMBTU (0.15% FBN)	1	DAF-30
D-0688-1	Kal Kan Vernon, CA	B&W FM101-88	(1) 75,000 PPH	Natural Gas Propane Gas	0.05 LBS/MMBTU 0.07 LBS/MMBTU	1	DAF-26 W/FGR
D-0687-1	Vicksburg Chemical Vicksburg, MS	FW AG5150B	(1) 150,000 PPH	Natural Gas	0.20 LBS/MMBTU	1	DAF-42
D-0681-1	Indeck Power	Nebraska NOS-2-67	(1) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN)	1	DAF-28
D-0679-1	Whiteman AFB Knob Mower, MO	NBC NS-E-58	(1) 60,000 PPH	No. 2 Oil Natural Gas	0.12 LBS/MMBTU (0.01% FBN) 0.14 LBS/MMBTU	1	DAF-26
D-0674-1 D-0673-1 D-0672-1 D-0671-1	Indeck Power	Nebraska NOS-2-67	(4) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN)	1	DAF-28
D-0668-1	Union Texas Petroleum Geismar, LA	Zurn Keystone	(1) 200,000 PPH	Natural Gas Off Gas	0.10 LBS/MMBTU 0.10 LBS/MMBTU	1	DAF-45
D-0661-1	Willamette Industries Bennettsville, SC	CE 12F33A/B	(1) 223,500 PPH	Natural Gas	0.20 LBS/MMBTU	2	DAF-34
D-0658-1	Salinas Supply Corp. Salinas, CA	NBC NS-E-68-SH	(1) 65,000 PPH	Natural Gas	0.065 LBS/MMBTU	1	DAF-28
D-0657-1	Folgers Coffee Co. Sherman, TX	CE 25-A-12	(1) 75,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	DAF-28
D-0639-1 D-0638-1	Wabash	CE 35A14	(2) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.19 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN) 0.40 LBS/MMBTU (0.25% FBN)	1	DAF-42
D-0637-1 D-0636-1 D-0635-1	Indeck Power	Nebraska NOS-2-52(S)	(3) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN)	1	DAF-28
D-0634-1	Darling Delaware Vernon, Calif.	Nebraska N25-6-69	(1) 80,000 PPH	Natural Gas	40 PPH	1	DAF-30
D-0631-1	Shell Sarnia Ontario, Canada	CE 35A14	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN) 0.40 LBS/MMBTU (0.25% FBN)	1	DAF-42
D-0630-1	Indeck Power	Nebraska NOS-2-52(S)	(1) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.20 LBS/MMBTU (0.01% FBN)	1	DAF-28
D-0627-1	Chevron St. James, LA	CE 12F35A16/42*	(1) 250,000 PPH	Natural Gas Process Gas	0.099 LBS/MMBTU	2	DAF-36 W/FGR
D-0626-1	Monsanto Envir. Chem Bradenton, FL	B&W FM117-88	(1) 120,000 PPH	Natural Gas No. 2 Oil	0.05 LBS/MMBTU 0.10 LBS/MMBTU (.05% FBN)	1	DAF-39

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D-0620-1	E.I. Dupont Delisle, MS	B&W FM 120-97	(1) 180,000 PPH	Natural Gas No. 2 Oil	0.086 LB/MMBTU 0.20 LB/MMBTU (.005% FBN)	1	DAF-42
D-0615-1	Arizona Chemical Co. Panama City, FL	CE 35A14	(1) 125,000 PPH	Natural Gas Pitch Tarcores		1	DAF-36
D-0603-1	Dow Chemical Midland, MI	NBC NS-E-58	(2) 60,000 PPH	Natural Gas	0.07 LB/MMBTU	1	DAF-24
D-0599-1	Peru Municipal Util. Peru, IL	Zurn FIELD ERECTED	(1) 105,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU	2	DAF-26
D-0595-1	Royal Tallow San Francisco, CA	NBC NS-E-52	(1) 50,000 PPH	Natural Gas No. 2 Oil	40 PPM	1	DAF-26 W/FGR
D-0591-1	Ashland Petroleum St. Paul, MN	Vertical Heater	(1) 120 MMBTU	H2 Waste Light/heav. Oil	Various	1	DAF-32
D-0589-1	City of Huntsville Huntsville, AL	NBC NSF-B4SH	(2) 100,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.10 LB/MMBTU (0.01% FBN)	1	DAF-36 W/FGR
D-0589-2	City of Huntsville Huntsville, AL	NBC NS-F-B4SH	(2) 100,000 PPH	Natural Gas Landfill Gas No. 2 Oil	0.10 LB/MMBTU 0.10 LB/MMBTU 0.10 LB/MMBTU (0.01% FBN)	1	DAF-36 W/FGR
D-0588-1	Hopevell Cogeneration	B&W	(2) 180,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-42
D-0588-2	Hopevell, VA	Special FM		No. 2 Oil	0.10 LB/MMBTU (0.02% FBN)		W/FGR
D-0585-1	New England Submarine Base Groton, CT	IBW VSG 36.5	(1) 84,150 PPH	No. 5 Oil	0.20 LB/MMBTU (0.3% FBN)	2	DAF-22 W/Front Wall NOx Ports
D-0581-1	S.D. Warren Hinkley, ME	B&W FM 10-79	(1) 60,000 PPH	No. 2 Oil	0.148 LB/MMBTU (.04% FBN)	1	DAF-24
D-0577-1	Consolidated Paper Stevens Point, WI	CE 33A13/48"	(1) 140,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-36
D-0573-1	McClellan AFB Sacramento, CA	NBC NS-B-44	(3) 25,000 PPH	Natural Gas No. 2 Oil No. 5 Oil	40 PPM 115 PPM (0.10% FBN)	1	DAF-18 W/FGR
D-0571-1	Harter Packing Yuba City, CA	NBC NSE 68	(1) 80,000 PPH	Natural Gas No. 6 Oil	40 PPM	1	DAF-30 W/FGR
D-0569-1	McDonnell Douglas Ontario, Canada	NBC N2S-7-89	(1) 150,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN)	1	DAF-42
D-0566-1	Quantum Ethylene Deerpark, TX	CE 34VP14/48"	(2) 160,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-45
D-0564-1	U.S. Army	Keeler	(2) 200,000 PPH	No. 6 Oil	0.30 LB/MMBTU (0.35% FBN)	4	DAF-25 W/ Floor NOx Ports
D-0564-2	Military Academy West Point, NY						
62-1	Occidental Chemical Lake Charles, LA	Zurn	(1) 245 MMBTU	Natural Gas Tail gas	0.10 LB/MMBTU 0.10 LB/MMBTU	1	DAF-45 W/FGR

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0-0560-1	Stauffer Chemical Dominguez, CA	Zurn	(1) 40 PPH	Natural Gas	70 PPM	1	DAF-24
0-0557-1	Ragu Foods Stockton, CA	NBC N2S-7-89-ECON	(1) 150,000 PPH	Natural Gas	40 PPM	1	DAF-36 W/FGR
0-0550-1	Cannery Steam Company Terminal Island, CA	Union Iron Works	(1) 100 K PPH	Natural Gas No. 6 Oil	40 PPM	4	DAF-20 W/ FGR
0-0530-1	Standard Rendering Houston, TX	NBC NS-D-54	(1) 50,000 PPH	Natural Gas No. 2 Oil	0.12 LB/MMBTU 0.16 LB/MMBTU (0.01% FBN)	1	DAF-25
0-0521-1	General Electric Mt. Vernon, IN	NBC N2S-S-114	(1) 200,000 PPH	Natural Gas	0.20 LB/MMBTU	1	DAF-42
0-0513-1	L.A. County Landfill SPADRA Project	Zurn Keystone	(1) 110 MMBTU	Landfill Gas	24 PPM	1	DAF-36 W/FGR
0-0478-1 0-0478-2	Simpson Paper Pasadena, TX	Zurn 23M	(2) 150,000 PPH	Natural Gas	0.10 LB/MMBTU	1	DAF-36
0-0475-1	James River Paper Milford, NJ	NBC N2S-7-97SH	(1) 120,000 PPH	Natural Gas No. 2 Oil	33.3 PPM 31.9 PPM (0.04% FBN)	1	DAF-36
0-0437-1	Arco Crane, TX	Hicks 90-3K-8	(2) 100,000 PPH	Natural Gas	0.20 LB/MMBTU	1	DAF-36
0-423-1	Luz-SEGS II Daggett, CA	CE/Mitsubishi	(1) 190 MMBTU Per Burner	Natural Gas Waste Oil (0.03% FBN)	80 PPM	2	DAF-39
0-0397-1	San Joaquin Milk Prod. Turlock, CA	NBC NSC-61 ECON	(2) 50,000 PPH	Natural Gas No. 2 Oil No. 5 Oil	70 PPM 84 PPM (0.045% FBN)	1	DAF-24
0-0389-1	Mobil Oil Corp. McKittrick, CA	Struthers Thermaflood Htr.	(1) 62.5 MMBTU	Natural Gas		1	DAF-24 W/FGR
0-0384-1	Indiana University Bloomington, IN	UIW Field Erected	(1) 75,000 PPH	Natural Gas No. 2 Oil	0.10 LB/MMBTU 0.10 LB/MMBTU (.05% FBN)	2	DAF-28
0-0376-1 0-0375-1 0-0374-1	Columbia University New York, NY	B&W FM103-88	(3) 88,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU 0.30 LB/MMBTU (0.3% FBN)	1	DAF-26 W/Front Wall NOx Ports
0-0367-2	Inland Steel New Carlisle, IN	ERI/NBC Waste Heat Blr.	(1) 124.3 MMBTU	Natural Gas	0.05 LB/MMBTU	1	DAF-32
0-0367-1	Inland Steel New Carlisle, IN	NBC NSE-57	(1) 58,400 PPH	Natural Gas	40 PPM	1	DAF-28
0-0358-2	Harrison Radiator Dayton, OH	C.E. "A" Type 33-7KT-10	(1) 200,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.30 LB/MMBTU (0.05% FBN)	1	DAF-39
0-0358-1	Harrison Radiator Dayton, OH	C.E. "A" Type 96-4KT-5	(2) 120,000 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.30 LB/MMBTU (0.05% FBN)	1	DAF-36
0-46-1	General Electric Burkville, AL	Nebraska N2S-109	(1) 200,000 PPH	Natural Gas	0.20 LB/MMBTU	1	DAF-42

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D-0345-1	General Electric Burkville, AL	Nebraska NS-E-68	(1) 85,500 PPH	Natural Gas No. 2 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU (0.01% FBN)	1	DAF-30
D-0342-1	Westinghouse Electric Sunnyvale, CA	Zurn Field Erected Boiler	(1) 300,000 PPH	Natural Gas	40 PPH	2	DAF-39 W/FGR
D-0332-1	E & J Gallo Winery Modesto, CA	Nebraska NSF-84	(1) 115,000 PPH	Natural Gas No. 6 Oil	0.10 LB/MMBTU 0.20 LB/MMBTU (0.2% FBN)	1	DAF-30 W/Front Wall NOx Ports
D-0324-4	Sun Oil Company Yabucoa, Puerto Rico	Zurn 20M	(1) 115,000 PPH	Refinery Gas Pitch	- 0.43 LB/MMBTU (1.08% FBN)	1	DAF-34 W/Front Wall NOx Ports
D-0324-3	Sun Oil Company Yabucoa, Puerto Rico	B&W FM 117-97	(1) 150,000 PPH	Refinery Gas Pitch	- 0.43 LB/MMBTU (1.08% FBN)	1	DAF-36 W/Front Wall NOx Ports
D-0324-2	Sun Oil Company Yabucoa, Puerto Rico	B&W FM 106-79	(1) 100,000 PPH	Refinery Gas Pitch	- 0.43 LB/MMBTU (1.08% FBN)	1	DAF-30 W/Front Wall NOx Ports
D-0324-1	Sun Oil Company Yabucoa, Puerto Rico	Nebraska NSF-82	(1) 100,000 PPH	Refinery Gas Pitch	- 0.43 LB/MMBTU (1.08% FBN)	1	DAF-30 W/Front Wall NOx Ports
194-1	SOHIO Oil Company Toledo, OH	B&W CO Boiler	(1) 450,000 PPH 180°F Air	Refinery Gas Refinery Gas/ No. 6 Oil	0.10 LB/MMBTU 0.157 LB/MMBTU (0.35% FBN)	6	DAF-30
D-0286-2	Mobil Oil Co. Torrance, CA	ECIW	(1) 200,000 PPH 565°F Air	Natural/ Refinery Gas	0.095 LB/MMBTU	4	DAF-28
D-0286-1	Mobil Oil Co. Torrance, CA	B&W PFI-3161	(1) 220,000 PPH 460°F Air	Natural/ Refinery Gas	0.12 LB/MMBTU	3	DAF-26
D-0284-1	Holman Boiler Works Dallas, TX (Rental)	Zurn 19M	(1) 100,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.30 LB/MMBTU (0.2% FBN)	1	DAF-32 W/Front Wall NOx Ports
D-0283-1	Holman Boiler Works (Rental)	UIW "A"	(1) 100,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.30 LB/MMBTU (0.2% FBN)	1	DAF-36 W/Front Wall NOx Ports
D-0282-1	Holman Boiler Works (Rental)	Nebraska N2S-7-113SH	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.30 LB/MMBTU (0.2% FBN)	1	DAF-39 W/Front Wall NOx Ports
D-0281-1 D-0280-1	Holman Boiler Works (Rental)	Nebraska N2S-7-95	(2) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.30 LB/MMBTU (0.2% FBN)	1	DAF-39 W/Front Wall NOx Ports
D-0274-1	Ponderay Newsprint Usk, WA	Nebraska N2S-7-112	(1) 180,000 PPH	Propane	0.20 LBS/MMBTU	1	DAF-36

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<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOX LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOX REDUCTION</u>
D-0268-1	Quality Assured Packing Stockton, CA	B&W FM 10-52A	(1) 30,000 PPH	Natural Gas No. 2 Oil	40 PPH 70 PPH (0.01% FBN)	1	DAF-20
D-0267-2	Hoffman La Roche Belvidere, NJ	B&W FM 117-976	(1) 142,000 PPH 600°F Air	Natural Gas Oil	0.68 LB/MMBTU 0.90 LB/MMBTU (0.3% FBN)	1	DAF-36
D-0267-1	Hoffman La Roche Belvidere, NJ	CE A Type	(1) 70,000 PPH 350°F Air	Natural Gas No. 6 Oil	0.28 LB/MMBTU 0.52 LB/MMBTU (0.3% FBN)	1	DAF-28
D-0243-2	Newsprint South Grenada, MS	B&W FM-117-88	(1) 135,000 PPH	Natural Gas	0.20 LB/MMBTU	1	DAF-36
D-0243-1	Newsprint South Grenada, MS	Keele MMBTU Steam Generator	(1) 200,000 PPH	Natural Gas	0.20 LBS/MMBTU at 135,000 PPH	2	DAF-36
D-0226-1	Takeda Chemical Co. Wilmington, NC	Nebraska NS-B-25	(1) 13,500 PPH	No. 6 Oil	85 Tons/Year based upon average load of 85 MMBTU/HR, both boilers operating continuously	1	DAF-15
D-0225-1	Takeda Chemical Co. Wilmington, NC	Nebraska NS-F-67	(1) 90,000 PPH	No. 6 Oil	85 Tons/Year based upon average load of 85 MMBTU/HR, both boilers operating continuously	1	DAF-26 W/Front Wall NOx Ports
D-0207-1	Holman Boiler Works Dallas, TX	Zurn 23-M	(1) 150,000 PPH	Natural Gas #2/#6 Oil	0.20 LB/MMBTU 0.40 LB/MMBTU (0.25% FBN)	1	DAF-42
D-0161-1	Georgia Pacific Port Hudson, LA	C.E. 35A14	(1) 150,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	DAF-39 W/FGR
D-0123-1	Amer. 1 Co-Gen Project King City, CA	Nebraska NSF-87	(2) 136.5 MMBTU 132.2 MMBTU	Natural Gas No. 2 Oil	40 PPH 69 PPH	1	DAF-34 W/FGR
D-0121-1	Cambell Soup Company Maxton, NC	Nebraska	(1) 150,000 PPH	Natural Gas No. 2 Oil No. 6 Oil	0.20 LB/MMBTU 0.20 LB/MMBTU 0.40 LB/MMBTU	1	DAF-34 W/Stone Wall NOx Ports
D-0064-1	Reynolds Metals Gregory, TX	FW	(1) 360,000 PPH	T.E.G.	0.06 LBS/MMBTU (50 PPH)	6	DAF-31
D-0036-1	Union Oil Company Wilmington, CA	Zurn	(1) 150,000 PPH	Refinery Gas	0.10 LBS/MMBTU	1	FGR
D-9995-1	Detroit Edison Detroit, MI	B&W FM 120-97L	(1) 150,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	DAF-42
D-9961-2	Pantex Power Plant Amarillo, TX	B&W FM 9-39	(2) 25,000 PPH	Gas and No. 2 Oil	0.12 LBS/MMBTU	1	DAF-18
D-9961-1	Pantex Power Plant Amarillo, TX	B&W FM 10-66	(2) 50,000 PPH	Gas and No. 2 Oil	0.12 LBS/MMBTU	1	DAF-24

<u>JOB NO.</u>	<u>INSTALLATION</u>	<u>TYPE OF BOILER</u>	<u>(NO. OF UNITS) CAPACITY</u>	<u>FUEL TYPE</u>	<u>GUARANTEED AND/OR ACTUAL NOx LEVELS</u>	<u>NO. OF BURNERS/ BOILER</u>	<u>COEN METHOD OF NOx REDUCTION</u>
D-9958-1	New York Hospital New York, NY	B&W FM 117-97B	(1) 125,000 PPH	No. 6 Oil	0.40 LBS/MMBTU (0.5% FBN)	1	DAF-30 W/Side Wall NOx Ports
D-9915-1 D-9915-2	Camarillo Hospital Camarillo, CA	B&W FM10-52	(2) 25,000 PPH	Natural Gas No. 2 Oil	40 PPM 115 PPM (0.06% FBN)	1	DAF-18
D-9912-1 D-9912-2	Chino Cogeneration Chino, CA	B&W FM10-52	(2) 25,000 PPH	Natural Gas No. 2 Oil	40 PPM 115 PPM (0.06% FBN)	1	DAF-18
D-9911-1	V.A. Hospital Kansas City, MO	C.E. 6 (VU10)16A	(2) 19,500 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.30 LBS/MMBTU	1	FGR
D-9879-1	Union Oil Company Of California Wilmington, CA	C.E. 35A15	(1) 200,000 PPH	Refinery Gas No. 6 Oil	0.12 LBS/MMBTU 0.35 LBS/MMBTU (0.25% FBN)	1	FGR
D-9851-1	V.A. Medical Center Cincinnati, OH	Titusville 3 Drum	(3) 24,000 PPH	Natural Gas No. 2 Oil	0.10 LBS/MMBTU 0.3 LBS/MMBTU	1	FGR
D-9834-1	Minnesota Power and Light Company Duluth, MN	Zurn Field Erected	(1) 120 MMBTU	Gas	0.20 LBS/MMBTU	4	DAF-34
D-9821-1	Chevron U.S.A. El Segundo, CA	C.E. 12F40A16	(1) 381.2 MMBTU	Natural Gas Refinery Gas	0.10 LBS/MMBTU	2	FGR
.798-1	Tinker Air Force Base Oklahoma City, OK	Nebraska N2T-7-93	(1) 114,000 PPH	Gas and No. 2 Oil	0.10 LBS/MMBTU	1	FGR
D-9792-1	Coyote Canyon LFG Project Orange County, CA	Zurn	(1) 255.86 MMBTU	Landfill Gas	48 PPM (Vol. Dry Ref. 3% O2)	2	FGR
D-9728-1	Shell Western Sheradon, TX	Zurn 23M Keystone	(1) 150,000 PPH	Natural Gas	0.10 LBS/MMBTU	1	FGR
D-9716-1	Newport Naval Newport, RI	Nebraska NS-F-87-SH(S)	(1) 90,000 PPH	Gas and No. 5 Oil	0.10 LBS/MMBTU 0.30 LBS/MMBTU (0.23% FBN)	1	FGR
D-9706-1	Gilroy Foods Gilroy, CA	Nebraska NSE-68	(2) 86,890 PPH	Natural Gas No. 2 Oil	40 PPM (Vol. Dry Ref. 3% O2)	1	FGR
D-9697-1	L.A. County Sanitation District Carson, CA	B&W FM-10-57	(1) 44,000 PPH	Gas (Oil Backup)	45 PPM (Vol. Dry Ref. 3% O2)	1	FGR
D-9645-3	U.C. Berkeley Berkeley, CA	Union Iron Works	65 MMBTU/ (1) Per Burner	Gas and Oil	BACT	2	DAF-26
D-9645-2 D-9645-1	U.C. Berkeley Berkeley, CA	Zurn	(1) 43.3 MMBTU/ Per Burner	Gas and Oil	BACT	3	DAF-22
D-9591-2	Shepard Oil Jennings, LA	Nebraska Boiler N25789	(1) 150,000 PPH	No. 6 Oil No. 2 Oil	0.10 LBS/MMBTU No Requirements	1	DAF-36 W/FGR
D-9570-1	Commonwealth Edison Chicago, IL	Nebraska Boiler NS-F-82	(1) 110,000 PPH	Natural Gas	79 PPM (Vol. Dry Ref. 3% O2)	1	FGR
61-1	Boise Cascade Deridder, LA	Babcock & Wilcox FM-120-97	(2) 165,000 PPH	Natural Gas	83 PPM (Vol. Dry Ref. 3% O2)	1	FGR

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOx LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOx REDUCTION
D-9425-1	Los Angeles Sanitation District	Zurn Keystone Type 'O'	(2) 264,000 PPH (330 MMBTU)	Land Fill Gas (420BTU/FT ³)	60 PPM (Vol. Dry Reference 3% O ₂)	2 3% O ₂ ---Up	FGR To 220 MKBTU
D-9351-1	Occidental Petroleum Lake Charles, LA	C.E. 33-A-16	(2) 180,000 PPH (268 MMBTU)	Natural Gas	75 PPM (Vol. Dry (Ref. 3% O ₂))	2	FGR
D-9293-1	Integrated Protein Corona, CA	Nebraska NS-C-42	(2) 30,000 PPH (36 MMBTU)	Natural Gas No. 2 Oil	30 PPM (Vol. Dry Ref. 3% O ₂)	1	FGR
D-9279-1	Palmdale A.F.B. Palmdale, CA	ISW TJW (HTHW)	(2) 23 MMBTU (Input)	Natural Gas No. 2 Oil	65 PPM (Vol. Dry Ref. 3% O ₂)	1	FGR
D-9252-1	Frito Lay Bakersfield, CA	Eabcock & Wilcox FM-10-79	(1) 62,000 PPH (78 MMBTU)	Natural Gas Future #2 Oil	40 PPM (Vol. Dry Ref. 3% O ₂)	1	FGR
D-9203-1	ISM San Jose, CA	Cleaver Brooks D-60	(1) 36,000 PPH (45 MMBTU)	Natural Gas No. 2 Oil	40 PPM (Vol. Dry Ref. 3% O ₂)	1	FGR
D-9140-1	Stanislaus Foods Modesto, CA	Nebraska NS-G-101	(1) 100,000 PPH (127 MMBTU)	Natural Gas No. 6 Oil	65 PPM (Vol. Dry Ref. 3% O ₂)-Gas Only	1	FGR
D-9002-1	Union Oil Santa Maria, CA	Nebraska NS-F-91	(1) 100,000 PPH (127 MMBTU)	Natural Gas No. 2 Oil	0.12 LBS/MMBTU 0.12 LBS/MMBTU	1	Side Wall NOx Ports
D-8943	Pfizer Groton, CT	Eabcock & Wilcox FM-140-97	(1) 195,000 PPH (250 MMBTU)	No. 6 Oil	0.30 LBS/MMBTU	2	Side Wall NOx Ports
D-8879	Lectromelt Longview, TX	Nebraska NS-C-49	(1) 30,000 PPH (39 MMBTU)	Natural Gas No. 2 Oil	0.12 LB/MMBTU 0.12 LBS/MMBTU	1	Side Wall NOx Ports
D-8811	City of Hope Durante, CA	Nebraska NS-E-75SH	(1) 55,000 PPH (70 MMBTU)	Natural Gas No. 2 Oil	0.09 LBS/MMBTU 0.09 LBS/MMBTU	1	Front Wall NOx Ports
D-8795	Murphy Oil Meroux, LA	Nebraska NS-E-84	(1) 80,000 PPH (100 MMBTU)	Refinery Gas Natural Gas	0.15 LBS/MMBTU 0.15 LBS/MMBTU	1	Side Wall NOx Ports
D-8523	Mobil Oil Joliet, IL	C.E. VU-60 Watertube	(1) 400,000 PPH (576 MMBTU)	Refinery Gas No. 6 Oil	0.20 LBS/MMBTU 0.20 LBS/MMBTU	4	Side Wall NOx Ports
D-8439	Arco North Slope, AK	G.C. Broach (Glycol Heater)	(2) 73.7 MMBTU	Natural Gas	0.08 LBS/MMBTU	1	Front Wall NOx Ports
D-8365	Willamette Industries Port Hueneme, CA	Nebraska NS-E-955H	(1) 68,200 PPH (99 MMBTU)	Natural Gas No. 2 Oil	75 PPM (Vol. Dry Ref. 3% O ₂)	1	Front Wall NOx Ports
D-8327	Ind. Valley Energy Co. Bakersfield, CA	Eabcock & Wilcox FM-9-37B	(1) 20,000 PPH (26 MMBTU)	Refinery Gas Natural Gas	70 PPM (Vol. Dry Ref. 3% O ₂)	1	Front Wall NOx Ports
D-8233	Shell Oil Woodriver, IL	Riley Stoker Field Erected Watertube	(1) 250,000 PPH (384 MMBTU)	Refinery Gas No. 6 Oil Ref. P-1000	0.14 LBS/MMBTU 0.23 LBS/MMBTU 0.28 LBS/MMBTU	4	Side Wall NOx Ports
D-7829	University of Wyoming Laramie, WY	ISW Cross Drum Watertube	(3) Natural Gas (77 MMBTU)	Oil	0.20 LBS/MMBTU 0.30 LBS/MMBTU	2	Front Wall NOx Ports
D-6348	Texas A and M College Station, TX	Vogt CL-VS-P Watertube	(1) 300,000 PPH (425 MMBTU)	Refinery Gas No. 2 Oil	0.20 LBS/MMBTU 0.30 LBS/MMBTU	4	Biased Firing
D-4935	Phillips Petroleum Kansas City, KS	Vogt CL-VS-P Watertube	(1) 300,000 PPH (425 MMBTU)	Refinery Gas Ref. P-1000	0.20 LBS/MMBTU 0.30 LBS/MMBTU	4	Biased Firing
EXPORT	Electricite De France Paris, France (Gennevillier Station)	Eabcock & Wilcox Watertube	(1) 528,000 PPH	No. 6 Oil		12	FGR

TOTAL AMOUNT OF JOBS: 444

FABER BURNER — LOW-NO_x BURNER PROJECTS

40 ppm OR LESS — FIRING NATURAL GAS

	<u>Quantity</u>	<u>Boiler capacity</u>	<u>Boiler manufacturer</u>
Tampella Power Williamsport, PA	1	17,500 pph	TP — Package
International Business Machines San Jose, CA	1	36,000 pph	TP — Package
Formosa Plastics Co. Point Comfort, TX	2 3	35,000 pph 55,000 pph	TP — Package
Miller Brewing Co. Irwindale, CA	4	50,000 pph	TP — Package
Veterans Administration Medical Center Sheridan, WY	1	12,500 pph	TP — CP
Veterans Administration Medical Center Los Angeles, CA	1	45,000 pph	B&W — Package
Veterans Administration Medical Center Des Moines, IA	1 2	20,000 pph 15,000 pph	B&W — Package
General Motors Proving Grounds Milford, MI	2	50,000 pph	(1) B&W — Package (1) TP — Package
Armstrong World Industries South Gate, CA	1	9,000 pph	TP — CP
Nationwide Boiler Co. Fremont, CA	2	75,000 pph	Nebraska — Package
Canadian Forces Base Halifax, Nova Scotia	1	60,000 pph (No. 6 oil)	TP — Package
Hershey Chocolate Hershey, PA	3	40,000 pph	TP — Package
Kimberly Clark Fullerton, CA	1	40,000 pph	B&W — Package
Farmer John Vernon, CA	3	23,000 pph 12,000 pph	(1) CE — Marine (2) B&W — Package
3M Corporation Camarillo, CA	2	30,000 pph 22,000 pph	Nebraska — Package Trane — Package
Georgia Pacific Buena Park, CA	1	30,000 pph	TP — Package
Medical Center Co. Cleveland, OH	1	100,000 pph	Nebraska — Package
Sunkist Growers Ontario, CA	1	40,000 pph	B&W — Package
Luzerne County Wilkes-Barre, PA	3	17,500 pph	TP — Package

APPENDIX D. SCALED COST EFFECTIVENESS VALUES

The following tables present cost effectiveness figures for the cost cases analyzed in Chapter 6 and listed in Table 6-4. These costs are based on the annual costs calculated in Appendices E, F, and G for 46 different boiler, fuel, and NO_x control combinations. To estimate cost effectiveness for the boiler capacities listed in this appendix, which in most cases differ from the actual capacities of the 42 boilers cases, the logarithmic relationship known as the "six-tenths" power rule was used (Reference 5 of Chapter 6). Cost estimates for distillate- and residual oil-firing were based on the annual costs of natural gas-fired boilers calculated in Appendix E, using appropriate baseline NO_x emission values and fuel prices.

This appendix contains the following tables:

<u>Cost Case</u>	<u>Page</u>
Natural-gas-fired:	
Packaged watertube, 45 MMBtu/hr, with WI and O ₂ trim	D-3
Packaged firetube, 10.5 MMBtu/hr, with WI and O ₂ trim	D-3
Packaged watertube, 51, 75, and 265 MMBtu/hr, with LNB	D-4
Packaged watertube, 265 MMBtu/hr, with LNB and CEM	D-5
Packaged watertube, 17.7 and 41.3 MMBtu/hr, with LNB and FGR	D-5
Packaged watertube, 45, 55, and 265 MMBtu/hr, with LNB and FGR	D-6
Packaged watertube, 81.3, 91, and 265 MMBtu/hr, with LNB, FGR, and CEM	D-7
Packaged firetube, 2.9-33.5 MMBtu/hr, with FGR and O ₂ trim	D-8
Packaged watertube, 50-250 and 100 MMBtu/hr, with SCR	D-9
Field-erected wall-fired, 75 MMBtu/hr, with BOOS and O ₂ trim	D-10
Field-erected wall-fired, 75 MMBtu/hr, with BOOS, WI, and O ₂ trim	D-10
Field-erected wall-fired, 590 and 1,300 MMBtu/hr, with LNB	D-11
Distillate-oil-fired:	
Packaged watertube, 51, 75, and 265 MMBtu/hr, with LNB	D-12
Packaged watertube, 265 MMBtu/hr, with LNB and CEM	D-13
Packaged watertube, 17.7 and 41.3 MMBtu/hr, with LNB and FGR	D-13
Packaged watertube, 45, 55, and 265 MMBtu/hr, with LNB and FGR	D-14
Packaged watertube, 81.3, 91, and 265 MMBtu/hr, with LNB, FGR, and CEM	D-15
Packaged watertube, 50-250 and 100 MMBtu/hr, with SCR	D-16
Packaged firetube, 2.9-33.5 MMBtu/hr, with FGR and O ₂ trim	D-17
Field-erected wall-fired, 590 and 1,300 MMBtu/hr, with LNB	D-17

<u>Cost Case</u>	<u>Page</u>
Residual-oil-fired:	
Packaged watertube, 51, 75, and 265 MMBtu/hr, with LNB	D-18
Packaged watertube, 265 MMBtu/hr, with LNB and CEM	D-19
Packaged watertube, 17.7 and 41.3 MMBtu/hr, with LNB and FGR	D-19
Packaged watertube, 45, 55, and 265 MMBtu/hr, with LNB and FGR	D-20
Packaged watertube, 81.3, 91, and 265 MMBtu/hr, with LNB, FGR, and CEM	D-21
Packaged watertube, 50-250 and 100 MMBtu/hr, with SCR	D-22
Packaged firetube, 2.9-33.5 MMBtu/hr, with FGR and O ₂ trim	D-23
Field-erected wall-fired, 590 and 1,300 MMBtu/hr, with LNB	D-23
Coal-fired:	
Field-erected wall-fired, 766 MMBtu/hr, with LNB	D-24
Circulating FBC, 460 MMBtu/hr, with urea-based SNCR	D-24
Tangentially-fired, with SCR	D-25
Field-erected wall-fired, 800 MMBtu/hr, with ammonia-based SNCR	D-25
Wall-fired, 400 MMBtu/hr, with SNCR	D-26
Spreader stoker, 303 MMBtu/hr, with urea-based SNCR	D-26
Wood-fired:	
Stoker, 190, 225, and 300 MMBtu/hr, with urea-based SNCR	D-27
Stoker, 395 and 500 MMBtu/hr, with urea-based SNCR	D-28
Bubbling FBC, 250 MMBtu/hr, with ammonia-based SNCR	D-28
Paper-fired:	
Packaged watertube, 72 and 172 MMBtu/hr, with urea-based SNCR	D-29
MSW-fired:	
Stoker, 108, 121, and 325 MMBtu/hr, with urea-based SNCR	D-30

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube(single burner)		
NOx CONTROL: WATER INJECTION WITH OXYGEN TRIM				
REFERENCE COST BASE:		COLANNINO, 1993; 45 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$855	\$963	\$1,161	\$1,581
25	\$718	\$797	\$941	\$1,247
50	\$642	\$705	\$820	\$1,064
100	\$520	\$565	\$648	\$823
150	\$496	\$536	\$610	\$765
250	\$354	\$380	\$427	\$529

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged firetube		
NOx CONTROL: WATER INJECTION WITH OXYGEN TRIM				
REFERENCE COST BASE:		COLANNINO, 1993; 10.5MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
2.9	\$3,620	\$4,192	\$5,238	\$7,461
5.2	\$3,130	\$3,598	\$4,454	\$6,274
10.5	\$2,674	\$3,045	\$3,724	\$5,168
20.9	\$2,335	\$2,635	\$3,183	\$4,348
33.5	\$2,152	\$2,413	\$2,889	\$3,903

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB		REFERENCE COST BASE: California ARB, 1987; 51 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$816	\$989	\$1,306	\$1,978
25	\$594	\$720	\$950	\$1,440
50	\$473	\$573	\$756	\$1,146
100	\$338	\$410	\$541	\$820
150	\$300	\$364	\$480	\$727
250	\$195	\$236	\$312	\$472

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB		REFERENCE COST BASE: California ARB, 1987; 75 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,126	\$2,577	\$3,402	\$5,154
25	\$1,538	\$1,865	\$2,461	\$3,729
50	\$1,217	\$1,475	\$1,947	\$2,950
100	\$865	\$1,048	\$1,384	\$2,097
150	\$763	\$925	\$1,221	\$1,851
250	\$493	\$597	\$788	\$1,194

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB		REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,690	\$3,261	\$4,304	\$6,522
25	\$1,916	\$2,322	\$3,066	\$4,645
50	\$1,493	\$1,809	\$2,388	\$3,618
100	\$1,041	\$1,262	\$1,666	\$2,525
150	\$908	\$1,100	\$1,452	\$2,201
250	\$576	\$698	\$921	\$1,395

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,462	\$5,408	\$7,139	\$10,816
25	\$3,178	\$3,852	\$5,084	\$7,703
50	\$2,475	\$3,000	\$3,961	\$6,001
100	\$1,727	\$2,094	\$2,764	\$4,187
150	\$1,506	\$1,825	\$2,409	\$3,650
250	\$955	\$1,157	\$1,527	\$2,314

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: CIBO, 1992; 17.7 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,101	\$2,625	\$3,582	\$5,617
25	\$1,523	\$1,925	\$2,658	\$4,217
50	\$1,208	\$1,542	\$2,153	\$3,451
100	\$861	\$1,112	\$1,573	\$2,552
150	\$761	\$992	\$1,413	\$2,310
250	\$492	\$649	\$934	\$1,542

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: Impell Corp., 1989; 41.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,624	\$5,686	\$7,627	\$11,752
25	\$3,302	\$4,083	\$5,511	\$8,546
50	\$2,575	\$3,206	\$4,354	\$6,792
100	\$1,805	\$2,259	\$3,090	\$4,856
150	\$1,576	\$1,982	\$2,725	\$4,302
250	\$1,002	\$1,269	\$1,756	\$2,791

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: California ARB, 1987; 45 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,895	\$3,586	\$4,852	\$7,541
25	\$2,041	\$2,552	\$3,486	\$5,471
50	\$1,574	\$1,986	\$2,739	\$4,339
100	\$1,085	\$1,384	\$1,931	\$3,095
150	\$937	\$1,205	\$1,696	\$2,737
250	\$587	\$763	\$1,086	\$1,772

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: California ARB, 1987; 55 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,560	\$5,605	\$7,516	\$11,577
25	\$3,238	\$4,003	\$5,402	\$8,374
50	\$2,516	\$3,127	\$4,246	\$6,622
100	\$1,749	\$2,190	\$2,995	\$4,706
150	\$1,521	\$1,913	\$2,630	\$4,153
250	\$961	\$1,217	\$1,685	\$2,680

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,985	\$3,696	\$4,996	\$7,759
25	\$2,024	\$2,531	\$3,459	\$5,431
50	\$1,499	\$1,895	\$2,619	\$4,157
100	\$978	\$1,255	\$1,761	\$2,837
150	\$812	\$1,054	\$1,496	\$2,435
250	\$479	\$632	\$913	\$1,510

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: Impell Corp., 1989; 81.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$5,455	\$6,692	\$8,953	\$13,758
25	\$3,852	\$4,748	\$6,387	\$9,870
50	\$2,975	\$3,685	\$4,984	\$7,743
100	\$2,053	\$2,559	\$3,484	\$5,451
150	\$1,776	\$2,223	\$3,041	\$4,779
250	\$1,114	\$1,403	\$1,932	\$3,056

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 91 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$11,804	\$14,386	\$19,107	\$29,139
25	\$8,515	\$10,400	\$13,845	\$21,167
50	\$6,717	\$8,219	\$10,967	\$16,807
100	\$4,759	\$5,837	\$7,810	\$12,002
150	\$4,191	\$5,140	\$6,902	\$10,625
250	\$2,696	\$3,320	\$4,461	\$6,886

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,459	\$5,483	\$7,355	\$11,334
25	\$3,074	\$3,804	\$5,140	\$7,977
50	\$2,317	\$2,886	\$3,928	\$6,140
100	\$1,549	\$1,947	\$2,675	\$4,221
150	\$1,310	\$1,657	\$2,292	\$3,641
250	\$794	\$1,015	\$1,418	\$2,275

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged firetube		
NOx CONTROL: FGR with oxygen trim				
REFERENCE COST BASE:		Hugh Dean, 1988; 2.9-33.5 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
2.9	\$21,741	\$26,572	\$35,406	\$54,179
5.2	\$12,304	\$15,159	\$20,380	\$31,475
10.5	\$6,410	\$7,974	\$10,834	\$16,912
20.9	\$3,651	\$4,518	\$6,103	\$9,471
33.5	\$2,404	\$2,998	\$4,083	\$6,390

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Peerless, 1992; 50-250 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$6,112	\$7,396	\$9,744	\$14,734
25	\$4,741	\$5,734	\$7,551	\$11,410
50	\$3,991	\$4,825	\$6,351	\$9,592
100	\$2,516	\$3,040	\$3,999	\$6,037
150	\$2,223	\$2,686	\$3,531	\$5,329
200	\$1,563	\$1,888	\$2,483	\$3,746
250	\$1,498	\$1,810	\$2,380	\$3,590

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Damon, 1987; 100 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$6,303	\$7,640	\$10,085	\$15,280
25	\$5,007	\$6,070	\$8,012	\$12,139
50	\$4,299	\$5,210	\$6,878	\$10,421
100	\$3,344	\$4,053	\$5,350	\$8,105
150	\$3,120	\$3,782	\$4,992	\$7,563
250	\$2,164	\$2,623	\$3,462	\$5,245

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: field erected wall fired		
NOx CONTROL: BOOS WITH OXYGEN TRIM				
REFERENCE COST BASE: COLANNINO, 1993; 75 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
100	\$394	\$435	\$510	\$670
250	\$260	\$284	\$327	\$418
400	\$197	\$214	\$244	\$308
500	\$193	\$209	\$237	\$297
750	\$139	\$150	\$169	\$210

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: natural gas		BOILER: field erected wall fired		
NOx CONTROL: BOOS AND WATER INJECTION WITH OXYGEN TRIM				
REFERENCE COST BASE: COLANNINO, 1993; 75 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
100	\$714	\$753	\$823	\$972
250	\$503	\$525	\$565	\$650
400	\$392	\$408	\$436	\$495
500	\$388	\$403	\$429	\$485
750	\$286	\$296	\$314	\$352

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: natural gas		BOILER: field erected wall fired		
NO _x CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 590 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$2,498	\$3,028	\$3,996	\$6,055
400	\$1,707	\$2,069	\$2,730	\$4,137
500	\$1,586	\$1,923	\$2,538	\$3,845
750	\$1,393	\$1,689	\$2,229	\$3,377

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: natural gas		BOILER: field erected wall fired		
NO _x CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 1300 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$3,880	\$4,703	\$6,208	\$9,406
400	\$2,632	\$3,190	\$4,211	\$6,381
500	\$2,437	\$2,954	\$3,899	\$5,908
750	\$2,125	\$2,575	\$3,399	\$5,151

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		California ARB, 1987; 51 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$653	\$791	\$1,044	\$1,582
25	\$475	\$576	\$760	\$1,152
50	\$378	\$458	\$605	\$917
100	\$304	\$369	\$457	\$738
150	\$270	\$327	\$432	\$655
250	\$234	\$283	\$374	\$567

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		California ARB, 1987; 75 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,701	\$2,062	\$2,721	\$4,123
25	\$1,231	\$1,492	\$1,969	\$2,983
50	\$973	\$1,180	\$1,557	\$2,360
100	\$778	\$944	\$1,245	\$1,887
150	\$687	\$833	\$1,099	\$1,666
250	\$591	\$717	\$946	\$1,433

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 265 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,152	\$2,609	\$3,443	\$5,217
25	\$1,533	\$1,858	\$2,452	\$3,716
50	\$1,194	\$1,447	\$1,910	\$2,895
100	\$937	\$1,136	\$1,500	\$2,272
150	\$817	\$990	\$1,307	\$1,981
250	\$691	\$837	\$1,105	\$1,674

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NO _x CONTROL: LNB with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$3,569	\$4,326	\$5,711	\$8,653
25	\$2,542	\$3,081	\$4,067	\$6,163
50	\$1,980	\$2,400	\$3,168	\$4,801
100	\$1,554	\$1,884	\$2,487	\$3,768
150	\$1,355	\$1,642	\$2,168	\$3,285
250	\$1,146	\$1,389	\$1,833	\$2,777

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE: CIBO, 1992; 17.7 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,481	\$1,900	\$2,666	\$4,294
25	\$1,019	\$1,340	\$1,927	\$3,174
50	\$766	\$1,033	\$1,522	\$2,561
100	\$574	\$801	\$1,216	\$2,097
150	\$485	\$692	\$1,072	\$1,879
250	\$391	\$578	\$921	\$1,651

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil				
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE: Impell Corp, 1989; 41.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$3,500	\$4,349	\$5,902	\$9,202
25	\$2,442	\$3,066	\$4,209	\$6,637
50	\$1,863	\$2,365	\$3,283	\$5,234
100	\$1,424	\$1,833	\$2,581	\$4,170
150	\$1,219	\$1,584	\$2,252	\$3,672
250	\$1,003	\$1,323	\$1,907	\$3,149

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		California ARB, 1987; 45 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,116	\$2,669	\$3,681	\$5,833
25	\$1,433	\$1,841	\$2,589	\$4,177
50	\$1,059	\$1,389	\$1,991	\$3,272
100	\$776	\$1,046	\$1,538	\$2,585
150	\$643	\$885	\$1,326	\$2,264
250	\$504	\$716	\$1,103	\$1,926

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		California ARB, 1987; 55 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$3,448	\$4,284	\$5,813	\$9,062
25	\$2,391	\$3,003	\$4,122	\$6,499
50	\$1,813	\$2,302	\$3,197	\$5,098
100	\$1,374	\$1,771	\$2,496	\$4,036
150	\$1,169	\$1,522	\$2,157	\$3,538
250	\$954	\$1,261	\$1,822	\$3,016

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		CIBO, 1992; 265 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,188	\$2,757	\$3,797	\$6,007
25	\$1,419	\$1,825	\$2,567	\$4,144
50	\$999	\$1,316	\$1,895	\$3,126
100	\$680	\$930	\$1,385	\$2,353
150	\$531	\$749	\$1,146	\$1,991
250	\$374	\$559	\$896	\$1,612

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: Impell Corp., 1989; 81.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,164	\$5,154	\$6,962	\$10,806
25	\$2,881	\$3,598	\$4,910	\$7,696
50	\$2,180	\$2,748	\$3,787	\$5,995
100	\$1,648	\$2,103	\$2,936	\$4,706
150	\$1,399	\$1,801	\$2,537	\$4,101
250	\$1,137	\$1,484	\$2,119	\$3,467

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 91 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$9,243	\$11,309	\$15,086	\$23,111
25	\$6,612	\$8,120	\$10,876	\$16,734
50	\$5,173	\$6,376	\$8,574	\$13,245
100	\$4,083	\$5,054	\$6,829	\$10,602
150	\$3,572	\$4,434	\$6,011	\$9,363
250	\$3,036	\$3,784	\$5,153	\$8,063

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$3,367	\$4,187	\$5,684	\$8,867
25	\$2,259	\$2,844	\$3,912	\$6,181
50	\$1,653	\$2,109	\$2,942	\$4,712
100	\$1,194	\$1,552	\$2,207	\$3,599
150	\$979	\$1,291	\$1,863	\$3,077
250	\$753	\$1,018	\$1,501	\$2,530

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Peerless, 1992; 50-250 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$4,890	\$5,917	\$7,795	\$11,787
25	\$3,793	\$4,588	\$6,041	\$9,128
50	\$3,193	\$3,860	\$5,081	\$7,674
100	\$2,265	\$2,736	\$3,599	\$5,433
150	\$2,001	\$2,417	\$3,178	\$4,796
200	\$1,876	\$2,266	\$2,979	\$4,495
250	\$1,798	\$2,172	\$2,855	\$4,308

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Damon, 1987; 100 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$5,043	\$6,112	\$8,068	\$12,224
25	\$4,006	\$4,856	\$6,409	\$9,711
50	\$3,439	\$4,168	\$5,502	\$8,337
100	\$3,009	\$3,647	\$4,815	\$7,295
150	\$2,808	\$3,403	\$4,492	\$6,807
250	\$2,596	\$3,147	\$4,154	\$6,294

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: packaged firetube		
NOx CONTROL: FGR with oxygen trim				
REFERENCE COST BASE:		Hugh Dean, 1988; 2.9-33.5 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
2.9	\$12,744	\$15,643	\$20,944	\$32,207
5.2	\$7,083	\$8,796	\$11,928	\$18,585
10.5	\$3,546	\$4,485	\$6,201	\$9,847
20.9	\$1,891	\$2,411	\$3,362	\$5,383
33.5	\$1,143	\$1,499	\$2,150	\$3,534

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: field erected wall fired		
NOx CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 590 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$2,997	\$3,633	\$4,796	\$7,266
400	\$2,560	\$3,103	\$4,096	\$6,206
500	\$2,379	\$2,884	\$3,807	\$5,768
750	\$2,090	\$2,533	\$3,343	\$5,066

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: distillate oil		BOILER: field erected wall fired		
NOx CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 1300 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$4,656	\$5,644	\$7,450	\$11,287
400	\$3,948	\$4,785	\$6,317	\$9,571
500	\$3,656	\$4,431	\$5,849	\$8,862
750	\$3,187	\$3,863	\$5,099	\$7,726

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		California ARB, 1987; 51 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$344	\$416	\$550	\$833
25	\$250	\$303	\$400	\$606
50	\$199	\$241	\$318	\$482
100	\$160	\$194	\$256	\$388
150	\$142	\$172	\$227	\$344
250	\$123	\$149	\$197	\$298

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		California ARB, 1987; 75 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$895	\$1,085	\$1,432	\$2,170
25	\$648	\$785	\$1,036	\$1,570
50	\$512	\$621	\$820	\$1,242
100	\$410	\$497	\$656	\$993
150	\$362	\$438	\$579	\$877
250	\$311	\$377	\$498	\$754

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 265 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,133	\$1,373	\$1,812	\$2,746
25	\$807	\$978	\$1,291	\$1,956
50	\$628	\$762	\$1,005	\$1,523
100	\$493	\$598	\$789	\$1,196
150	\$430	\$521	\$688	\$1,042
250	\$364	\$441	\$582	\$881

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,879	\$2,277	\$3,006	\$4,554
25	\$1,338	\$1,622	\$2,141	\$3,244
50	\$1,042	\$1,263	\$1,668	\$2,527
100	\$818	\$992	\$1,309	\$1,983
150	\$713	\$864	\$1,141	\$1,729
250	\$603	\$731	\$965	\$1,462

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: CIBO, 1992; 17.7 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$997	\$1,217	\$1,621	\$2,477
25	\$754	\$923	\$1,231	\$1,888
50	\$621	\$761	\$1,019	\$1,565
100	\$520	\$639	\$857	\$1,321
150	\$473	\$582	\$782	\$1,206
250	\$423	\$522	\$702	\$1,086

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR				
REFERENCE COST BASE: Impell Corp., 1989; 41.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,059	\$2,506	\$3,324	\$5,060
25	\$1,503	\$1,831	\$2,433	\$3,710
50	\$1,198	\$1,462	\$1,945	\$2,972
100	\$967	\$1,182	\$1,576	\$2,412
150	\$859	\$1,051	\$1,403	\$2,150
250	\$745	\$914	\$1,221	\$1,875

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		California ARB, 1987; 45 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,331	\$1,622	\$2,155	\$3,287
25	\$972	\$1,187	\$1,580	\$2,416
50	\$775	\$948	\$1,266	\$1,939
100	\$626	\$768	\$1,027	\$1,578
150	\$556	\$683	\$915	\$1,409
250	\$483	\$594	\$798	\$1,231

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		California ARB, 1987; 55 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,032	\$2,472	\$3,277	\$4,987
25	\$1,476	\$1,798	\$2,387	\$3,638
50	\$1,172	\$1,429	\$1,900	\$2,901
100	\$941	\$1,150	\$1,531	\$2,342
150	\$833	\$1,019	\$1,358	\$2,080
250	\$719	\$881	\$1,177	\$1,805

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NO _x CONTROL: LNB and FGR				
REFERENCE COST BASE:		CIBO, 1992; 265 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,369	\$1,668	\$2,216	\$3,379
25	\$965	\$1,178	\$1,569	\$2,399
50	\$743	\$910	\$1,215	\$1,863
100	\$576	\$707	\$947	\$1,456
150	\$497	\$612	\$821	\$1,266
250	\$415	\$512	\$689	\$1,066

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: Impell Corp., 1989; 81.3 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,409	\$2,930	\$3,882	\$5,905
25	\$1,734	\$2,111	\$2,802	\$4,268
50	\$1,365	\$1,664	\$2,211	\$3,373
100	\$1,085	\$1,324	\$1,763	\$2,694
150	\$954	\$1,166	\$1,553	\$2,376
250	\$816	\$999	\$1,333	\$2,042

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 91 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$5,082	\$6,169	\$8,157	\$12,381
25	\$3,698	\$4,491	\$5,942	\$9,025
50	\$2,940	\$3,573	\$4,730	\$7,189
100	\$2,366	\$2,877	\$3,812	\$5,797
150	\$2,097	\$2,551	\$3,381	\$5,145
250	\$1,815	\$2,209	\$2,930	\$4,461

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: LNB and FGR with CEM system				
REFERENCE COST BASE: CIBO, 1992; 265 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,990	\$2,421	\$3,209	\$4,885
25	\$1,407	\$1,714	\$2,276	\$3,471
50	\$1,088	\$1,328	\$1,766	\$2,698
100	\$846	\$1,035	\$1,379	\$2,112
150	\$733	\$897	\$1,198	\$1,837
250	\$614	\$753	\$1,008	\$1,549

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Peerless, 1992; 50-250 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,574	\$3,114	\$4,103	\$6,204
25	\$1,996	\$2,415	\$3,179	\$4,804
50	\$1,681	\$2,032	\$2,674	\$4,039
100	\$1,192	\$1,440	\$1,894	\$2,860
150	\$1,053	\$1,272	\$1,673	\$2,524
200	\$987	\$1,193	\$1,568	\$2,366
250	\$946	\$1,143	\$1,503	\$2,267

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: residual oil		BOILER: packaged watertube		
NOx CONTROL: SCR				
REFERENCE COST BASE:		Damon, 1987; 100 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,654	\$3,217	\$4,246	\$6,434
25	\$2,108	\$2,556	\$3,373	\$5,111
50	\$1,810	\$2,194	\$2,896	\$4,388
100	\$1,584	\$1,920	\$2,534	\$3,839
150	\$1,478	\$1,791	\$2,364	\$3,583
250	\$1,367	\$1,656	\$2,186	\$3,313

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: packaged firetube		
NO _x CONTROL: FGR with oxygen trim				
REFERENCE COST BASE:		Hugh Dean, 1988; 2.9-33.5 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
2.9	\$7,034	\$8,560	\$11,349	\$17,277
5.2	\$4,054	\$4,956	\$6,604	\$10,108
10.5	\$2,193	\$2,687	\$3,590	\$5,509
20.9	\$1,321	\$1,595	\$2,096	\$3,159
33.5	\$928	\$1,115	\$1,458	\$2,186

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: field erected wall fired		
NO _x CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 590 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$1,578	\$1,912	\$2,524	\$3,824
400	\$1,347	\$1,633	\$2,156	\$3,266
500	\$1,252	\$1,518	\$2,004	\$3,036
750	\$1,100	\$1,333	\$1,760	\$2,666

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: residual oil		BOILER: field erected wall fired		
NO _x CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 1300 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$2,451	\$2,970	\$3,921	\$5,941
400	\$2,078	\$2,519	\$3,325	\$5,037
500	\$1,924	\$2,332	\$3,079	\$4,664
750	\$1,677	\$2,033	\$2,684	\$4,066

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: coal		BOILER: field erected wall fired		
NOx CONTROL: LNB				
REFERENCE COST BASE:		CIBO, 1992; 766 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$1,112	\$1,340	\$1,758	\$2,645
400	\$968	\$1,165	\$1,527	\$2,295
500	\$908	\$1,093	\$1,432	\$2,151
750	\$813	\$977	\$1,279	\$1,919

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: coal		BOILER: circulating FBC		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 460 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
250	\$875	\$964	\$1,125	\$1,468
400	\$813	\$888	\$1,025	\$1,316
500	\$787	\$856	\$984	\$1,254
750	\$745	\$806	\$917	\$1,153

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: Pulverized coal		BOILER: Tangentially-fired		
NOx CONTROL: SCR				
REFERENCE COST BASE: Utility Boiler ACT (EPA-453/R-94-023)				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.50	0.33
250	\$3,304	\$3,923	\$4,772	\$6,789
400	\$2,968	\$3,415	\$4,233	\$5,972
500	\$2,828	\$3,246	\$4,011	\$5,635
750	\$2,605	\$2,976	\$3,654	\$5,094

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: Coal		BOILER: Field Erected Wall Fired		
NOx CONTROL: SNCR - ammonia				
REFERENCE COST BASE: EXXON, 1990; 800 MMBtu/hr boiler				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.50	0.33
250	\$1,306	\$1,358	\$1,453	\$1,655
400	\$1,270	\$1,314	\$1,395	\$1,567
500	\$1,255	\$1,296	\$1,371	\$1,531
750	\$1,231	\$1,267	\$1,332	\$1,472

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: Pulverized coal		BOILER: wall-fired		
NOx CONTROL: SNCR				
REFERENCE COST BASE: Nalco Fuel Tech, 1994; 400 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.50	0.33
250	\$1,100	\$1,121	\$1,337	\$1,662
400	\$1,036	\$1,044	\$1,235	\$1,508
500	\$1,010	\$1,012	\$1,193	\$1,444
750	\$968	\$961	\$1,126	\$1,342

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: Coal		BOILER: Spreader Stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE: Nalco Fuel Tech; 1992; 303 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.50	0.33
250	\$1,318	\$1,359	\$1,435	\$1,595
400	\$1,285	\$1,319	\$1,382	\$1,514
500	\$1,271	\$1,302	\$1,360	\$1,481
750	\$1,249	\$1,276	\$1,324	\$1,427

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE: Nalco Fuel Tech, 1992; 190 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,144	\$2,445	\$2,996	\$4,166
150	\$1,687	\$1,891	\$2,264	\$3,057
250	\$1,533	\$1,705	\$2,019	\$2,686
350	\$1,448	\$1,602	\$1,883	\$2,480
500	\$1,370	\$1,507	\$1,757	\$2,289

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE: Nalco Fuel Tech, 1992; 225 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,266	\$2,571	\$3,128	\$4,312
150	\$1,800	\$2,006	\$2,383	\$3,183
250	\$1,644	\$1,817	\$2,133	\$2,805
350	\$1,558	\$1,712	\$1,995	\$2,595
500	\$1,478	\$1,615	\$1,867	\$2,401

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE: Nalco Fuel Tech, 1992; 300 MMBtu/hr				
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,119	\$2,435	\$3,014	\$4,243
150	\$1,630	\$1,843	\$2,233	\$3,060
250	\$1,467	\$1,645	\$1,971	\$2,663
350	\$1,376	\$1,535	\$1,826	\$2,443
500	\$1,292	\$1,434	\$1,692	\$2,240

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 395 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$1,519	\$1,806	\$2,330	\$3,444
150	\$1,073	\$1,265	\$1,616	\$2,363
250	\$923	\$1,084	\$1,377	\$2,000
350	\$840	\$983	\$1,244	\$1,799
500	\$764	\$890	\$1,122	\$1,614

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 500 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$1,661	\$1,912	\$2,370	\$3,343
150	\$1,269	\$1,436	\$1,742	\$2,392
250	\$1,138	\$1,277	\$1,532	\$2,074
350	\$1,065	\$1,189	\$1,415	\$1,897
500	\$997	\$1,107	\$1,308	\$1,734

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: wood		BOILER: bubbling FBC		
NOx CONTROL: SNCR - ammonia based				
REFERENCE COST BASE:		Hurst, 1988; 250 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$1,459	\$1,563	\$1,754	\$2,158
150	\$1,392	\$1,481	\$1,646	\$1,994
250	\$1,364	\$1,448	\$1,601	\$1,927
350	\$1,319	\$1,394	\$1,530	\$1,818
500	\$997	\$1,107	\$1,308	\$1,734

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: paper		BOILER: packaged watertube		
NO _x CONTROL: SNCR - urea based		REFERENCE COST BASE: Nalco Fuel Tech, 1992; 72 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$1,949	\$2,216	\$2,705	\$3,744
25	\$1,591	\$1,782	\$2,132	\$2,876
50	\$1,395	\$1,545	\$1,819	\$2,401
100	\$1,247	\$1,365	\$1,582	\$2,042
150	\$1,177	\$1,281	\$1,470	\$1,873
250	\$1,104	\$1,192	\$1,354	\$1,696

SCALED COST EFFECTIVENESS, \$/TON NO _x REMOVED				
FUEL: paper		BOILER: packaged watertube		
NO _x CONTROL: SNCR - urea based		REFERENCE COST BASE: Nalco Fuel Tech, 1992; 172 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
10	\$2,474	\$2,844	\$3,520	\$4,958
25	\$1,967	\$2,230	\$2,710	\$3,730
50	\$1,690	\$1,894	\$2,266	\$3,059
100	\$1,480	\$1,639	\$1,930	\$2,549
150	\$1,382	\$1,520	\$1,773	\$2,311
250	\$1,278	\$1,395	\$1,608	\$2,061

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: MSW		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 108 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,123	\$2,394	\$2,889	\$3,942
150	\$1,721	\$1,907	\$2,246	\$2,968
250	\$1,587	\$1,744	\$2,031	\$2,642
350	\$1,512	\$1,653	\$1,912	\$2,461
500	\$1,443	\$1,570	\$1,801	\$2,293

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: MSW		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 121 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,603	\$3,025	\$3,796	\$5,434
150	\$1,975	\$2,263	\$2,790	\$3,910
250	\$1,764	\$2,008	\$2,453	\$3,400
350	\$1,647	\$1,866	\$2,266	\$3,117
500	\$1,539	\$1,735	\$2,093	\$2,855

SCALED COST EFFECTIVENESS, \$/TON NOx REMOVED				
FUEL: MSW		BOILER: stoker		
NOx CONTROL: SNCR - urea based				
REFERENCE COST BASE:		Nalco Fuel Tech, 1992; 325 MMBtu/hr		
BOILER CAPACITY MMBtu/hr	CAPACITY FACTOR			
	0.8	0.66	0.5	0.33
50	\$2,167	\$2,486	\$3,070	\$4,312
150	\$1,672	\$1,887	\$2,280	\$3,114
250	\$1,507	\$1,686	\$2,015	\$2,713
350	\$1,415	\$1,575	\$1,868	\$2,490
500	\$1,330	\$1,472	\$1,732	\$2,284

**APPENDIX E. ANNUAL COSTS OF RETROFIT NO_x CONTROLS:
NATURAL-GAS-FIRED ICI BOILERS**

This appendix contains cost spreadsheets for natural-gas-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10-percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

<u>Boiler and NO_x Control</u>	<u>Page</u>
Packaged watertube, 45 MMBtu/hr, with WI and O ₂ trim	E-3
Packaged firetube, 10.5 MMBtu/hr, with WI and O ₂ trim	E-5
Field-erected watertube, 75 MMBtu/hr, with BOOS and O ₂ trim	E-7
Field-erected watertube, 75 MMBtu/hr, with BOOS, WI, and O ₂ trim	E-9
Packaged watertube, 51, 75, and 265 MMBtu/hr, with LNB	E-11
Field-erected watertube, 590 and 1,300 MMBtu/hr, with LNB	E-17
Packaged watertube, 265 MMBtu/hr, with LNB and CEM	E-21
Packaged watertube, 17.7, 41.3, 45, 55, and 265 MMBtu/hr, with LNB and FGR	E-23
Packaged watertube, 81.3, 91, and 265 MMBtu/hr, with LNB, FGR, and CEM	E-33
Packaged firetube, 2.9, 5.23, 10.46, 20.9, and 33.5 MMBtu/hr, with FGR and O ₂ trim	E-39
Packaged watertube, 50, 100, 150, 200, and 250 MMBtu/hr, with SCR	E-49
Field-erected watertube, 250 MMBtu/hr, with SCR	E-59
Packaged watertube, 50 and 150 MMBtu/hr, with SCR (variable catalyst life)	E-61
Field-erected watertube, 250 MMBtu/hr, with SCR (variable catalyst life)	E-69

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	45	COLANNINO, 1993	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	WATER INJECTION WITH OXYGEN TRIM				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$0	\$0	\$0	\$0
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$0	\$0	\$0	\$0
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$0	\$0	\$0	\$0
C. CONTINGENCY	CONT				
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$24,786	\$24,786	\$24,786	\$24,786
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 45		COLANNINO, 1993		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: WATER INJECTION WITH OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% NET EFFICIENCY LOSS, N.GAS @ \$3.63/MMBTU		\$5,675	\$4,682	\$3,547	\$2,341
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$5,675	\$4,682	\$3,547	\$2,341
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$496	\$496	\$496	\$496
3.	PROPERTY TAX (0.01*TCIC)		\$248	\$248	\$248	\$248
4.	INSURANCE (0.01*TCIC)		\$248	\$248	\$248	\$248
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$991	\$991	\$991	\$991
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$6,666	\$5,673	\$4,538	\$3,332
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$24,786	\$24,786	\$24,786	\$24,786
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$4,034	\$4,034	\$4,034	\$4,034
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$6,666	\$5,673	\$4,538	\$3,332
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$10,700	\$9,707	\$8,572	\$7,366
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.16	0.16	0.16	0.16
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.056	0.056	0.056	0.056
3.	NO _x REMOVAL EFFICIENCY (%)		65	65	65	65
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	45	45	45	45
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			16.4	13.5	10.2	6.8
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$652	\$717	\$836	\$1,089

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED FIRETUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	10.5	COLANNINO, 1993	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	WATER INJECTION WITH OXYGEN TRIM				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
	PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP			
	CEM SYSTEM				
	INSTRUMENTATION				
	SALES TAX				
	FREIGHT				
	*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$0	\$0	\$0
2. DIRECT INSTALLATION COST (DIC)					
	*** TOTAL DIRECT INSTALLATION COST ***	DIC			
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
	*** TOTAL DIRECT CAPITAL COST ***	DCC	\$0	\$0	\$0
	(PEC+DIC+SP+BLDG)				
B. INDIRECT CAPITAL COST (ICC)					
	1. ENGINEERING				
	2. CONSTRUCTION AND FIELD EXPENSES				
	3. CONSTRUCTION FEE				
	4. STARTUP				
	5. PERFORMANCE TEST				
	*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$0	\$0	\$0
C. CONTINGENCY		CONT			
	*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$24,786	\$24,786	\$24,786
	(DCC+ICC+CONT)				

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 10.5		COLANNINO, 1993		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: WATER INJECTION WITH OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% NET EFFICIENCY LOSS, N.GAS @ \$3.63/MMBTU		\$2,648	\$2,185	\$1,655	\$1,092
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$2,648	\$2,185	\$1,655	\$1,092
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$496	\$496	\$496	\$496
3.	PROPERTY TAX (0.01*TCIC)		\$248	\$248	\$248	\$248
4.	INSURANCE (0.01*TCIC)		\$248	\$248	\$248	\$248
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$991	\$991	\$991	\$991
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***		O&M	\$3,640	\$3,176	\$2,646	\$2,084
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (inc. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
	INTEREST RATE		0.1	0.1	0.1	0.1
	CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$24,786	\$24,786	\$24,786	\$24,786
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$4,034	\$4,034	\$4,034	\$4,034
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$3,640	\$3,176	\$2,646	\$2,084
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$7,673	\$7,210	\$6,680	\$6,117
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.12	0.12	0.12	0.12
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.042	0.042	0.042	0.042
3.	NOx REMOVAL EFFICIENCY (%)		65	65	65	65
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	10.5	10.5	10.5	10.5
*** NOx REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			2.9	2.4	1.8	1.2
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$2,674	\$3,045	\$3,724	\$5,168

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 75		COLANNINO, 1993		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: BOOS WITH OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)					
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		\$0	\$0	\$0	\$0
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***					
3. SITE PREP, SP (as required)					
4. BUILDINGS, BLDG (as required)					
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		\$0	\$0	\$0	\$0
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***		\$0	\$0	\$0	\$0
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		\$24,786	\$24,786	\$24,786	\$24,786

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 75		COLANNINO, 1993		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: BOOS WITH OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER: 1% NET EFFICIENCY LOSS, N.GAS @ \$3.63/MMBTU			\$4,729	\$3,901	\$2,956	\$1,951
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$4,729	\$3,901	\$2,956	\$1,951
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)			\$0	\$0	\$0	\$0
2. ADMINISTRATIVE (0.02*TCIC)			\$496	\$496	\$496	\$496
3. PROPERTY TAX (0.01*TCIC)			\$248	\$248	\$248	\$248
4. INSURANCE (0.01*TCIC)			\$248	\$248	\$248	\$248
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$991	\$991	\$991	\$991
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$5,720	\$4,893	\$3,947	\$2,942
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$24,786	\$24,786	\$24,786	\$24,786
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$4,034	\$4,034	\$4,034	\$4,034
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$5,720	\$4,893	\$3,947	\$2,942
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$9,754	\$8,927	\$7,981	\$6,976
B. NOx REMOVAL PER YEAR						
1. BASELINE NOx LEVEL (lb/MMBtu)		(NOx)1	0.18	0.18	0.18	0.18
2. CONTROLLED NOx LEVEL (lb/MMBtu)		(NOx)2	0.09	0.09	0.09	0.09
3. NOx REMOVAL EFFICIENCY (%)			50	50	50	50
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	75	75	75	75
*** NOx REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			23.7	19.5	14.8	9.8
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS). ***			\$412	\$457	\$540	\$715

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 75		COLANNINO, 1993		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: BOOS & WATER INJEC WITH OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)					
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		\$0	\$0	\$0	\$0
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***					
3. SITE PREP, SP (as required)					
4. BUILDINGS, BLDG (as required)					
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		\$0	\$0	\$0	\$0
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***		\$0	\$0	\$0	\$0
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		\$34,700	\$34,700	\$34,700	\$34,700

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 75		COLANNINO, 1993		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: BOOS & WATER INJEC WITH OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% NET EFFICIENCY LOSS, N.GAS @ \$3.63/MMBTU		\$18,915	\$15,605	\$11,822	\$7,803
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$18,915	\$15,605	\$11,822	\$7,803
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$694	\$694	\$694	\$694
3.	PROPERTY TAX (0.01*TCIC)		\$347	\$347	\$347	\$347
4.	INSURANCE (0.01*TCIC)		\$347	\$347	\$347	\$347
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$1,388	\$1,388	\$1,388	\$1,388
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$20,303	\$16,993	\$13,210	\$9,191
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$34,700	\$34,700	\$34,700	\$34,700
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$5,647	\$5,647	\$5,647	\$5,647
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$20,303	\$16,993	\$13,210	\$9,191
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$25,951	\$22,640	\$18,857	\$14,838
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.18	0.18	0.18	0.18
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.045	0.045	0.045	0.045
3.	NO _x REMOVAL EFFICIENCY (%)		75	75	75	75
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	75	75	75	75
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			35.5	29.3	22.2	14.6
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$731	\$774	\$850	\$1,014

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	51	CAL ARB, 1987	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LOW NO _x BURNER				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$19,828	\$19,828	\$19,828	\$19,828
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$19,828	\$19,828	\$19,828	\$19,828
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$13,285	\$13,285	\$13,285	\$13,285
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$33,113	\$33,113	\$33,113	\$33,113
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$0	\$0	\$0	\$0
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$33,113	\$33,113	\$33,113	\$33,113

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 51		CAL ARB, 1987		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LOW NO _x BURNER						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$662	\$662	\$662	\$662
3.	PROPERTY TAX (0.01*TCIC)		\$331	\$331	\$331	\$331
4.	INSURANCE (0.01*TCIC)		\$331	\$331	\$331	\$331
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$1,325	\$1,325	\$1,325	\$1,325
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$1,325	\$1,325	\$1,325	\$1,325
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$33,113	\$33,113	\$33,113	\$33,113
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$5,389	\$5,389	\$5,389	\$5,389
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$1,325	\$1,325	\$1,325	\$1,325
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$6,714	\$6,714	\$6,714	\$6,714
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.16	0.16	0.16	0.16
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.08	0.08	0.08	0.08
3.	NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	51	51	51	51
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			14.3	11.8	8.9	5.9
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$470	\$569	\$751	\$1,138

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	75	CAL ARB, 1987	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LOW NO _x BURNER				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$65,235	\$65,235	\$65,235	\$65,235
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$65,235	\$65,235	\$65,235	\$65,235
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$15,466	\$15,466	\$15,466	\$15,466
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$80,702	\$80,702	\$80,702	\$80,702
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$29,842	\$29,842	\$29,842	\$29,842
C. CONTINGENCY					
CONNT	CONNT				
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$110,543	\$110,543	\$110,543	\$110,543
(DCC+ICC+CONNT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 75	CAL ARB, 1987	1992 DOLLARS			
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LOW NO _x BURNER					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	OAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (50% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2. ADMINISTRATIVE (0.02*TCIC)		\$2,211	\$2,211	\$2,211	\$2,211
3. PROPERTY TAX (0.01*TCIC)		\$1,105	\$1,105	\$1,105	\$1,105
4. INSURANCE (0.01*TCIC)		\$1,105	\$1,105	\$1,105	\$1,105
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$4,422	\$4,422	\$4,422	\$4,422
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$4,422	\$4,422	\$4,422	\$4,422
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$110,543	\$110,543	\$110,543	\$110,543
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$17,990	\$17,990	\$17,990	\$17,990
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$4,422	\$4,422	\$4,422	\$4,422
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$22,412	\$22,412	\$22,412	\$22,412
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.18	0.18	0.18	0.18
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.09	0.09	0.09	0.09
3. NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	75	75	75	75
*** NO_x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		23.7	19.5	14.8	9.8
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***		\$948	\$1,149	\$1,516	\$2,297

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS

BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 265		CIBO, 1992	1992 DOLLARS			
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LOW NOx BURNER						
TOTAL CAPITAL INVESTMENT COST (TCIC)						
		BOILER CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT CAPITAL COST (DCC)						
1. PURCHASED EQUIPMENT COST (PEC)						
PRIMARY AND AUXILIARY EQUIPMENT (EQP)						EQP
CEM SYSTEM						
INSTRUMENTATION						
SALES TAX						
FREIGHT						320000
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$158,723	\$158,723	\$158,723	\$158,723
2. DIRECT INSTALLATION COST (DIC)						
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$47,617	\$47,617	\$47,617	\$47,617
(30 percent of purchased equipment)						
3. SITE PREP, SP (as required)		SP				
4. BUILDINGS, BLDG (as required)		BLDG				
*** TOTAL DIRECT CAPITAL COST ***		DCC	\$206,340	\$206,340	\$206,340	\$206,340
(PEC+DIC+SP+BLDG)						
B. INDIRECT CAPITAL COST (ICC)						
1. ENGINEERING (0.10PEC)			\$15,872	\$15,872	\$15,872	\$15,872
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)			\$15,872	\$15,872	\$15,872	\$15,872
3. CONSTRUCTION FEE (0.10PEC)			\$15,872	\$15,872	\$15,872	\$15,872
4. STARTUP (0.02PEC)			\$3,174	\$3,174	\$3,174	\$3,174
5. PERFORMANCE TEST (0.01PEC)			\$1,587	\$1,587	\$1,587	\$1,587
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$52,379	\$52,379	\$52,379	\$52,379
C. CONTINGENCY (20 percent of direct and indirect)		CONT	\$51,744	\$51,744	\$51,744	\$51,744
*** TOTAL CAPITAL INVESTMENT COST ***		TCIC	\$310,463	\$310,463	\$310,463	\$310,463
(DCC+ICC+CDNT)						

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 265		CIBO, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LOW NO _x BURNER						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$6,209	\$6,209	\$6,209	\$6,209
3.	PROPERTY TAX (0.01*TCIC)		\$3,105	\$3,105	\$3,105	\$3,105
4.	INSURANCE (0.01*TCIC)		\$3,105	\$3,105	\$3,105	\$3,105
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$12,419	\$12,419	\$12,419	\$12,419
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$12,419	\$12,419	\$12,419	\$12,419
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$310,463	\$310,463	\$310,463	\$310,463
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$50,526	\$50,526	\$50,526	\$50,526
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$12,419	\$12,419	\$12,419	\$12,419
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$62,945	\$62,945	\$62,945	\$62,945
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.12	0.12	0.12	0.12
3.	NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	265	265	265	265
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			111.4	91.9	69.6	46.0
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$565	\$685	\$904	\$1,369

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	590	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LOW NO _x BURNER				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$1,175,725	\$1,175,725	\$1,175,725	\$1,175,725
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$352,717	\$352,717	\$352,717	\$352,717
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$1,528,442	\$1,528,442	\$1,528,442	\$1,528,442
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$117,572	\$117,572	\$117,572	\$117,572
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$117,572	\$117,572	\$117,572	\$117,572
3. CONSTRUCTION FEE (0.10PEC)		\$117,572	\$117,572	\$117,572	\$117,572
4. STARTUP (0.02PEC)		\$23,514	\$23,514	\$23,514	\$23,514
5. PERFORMANCE TEST (0.01PEC)		\$11,757	\$11,757	\$11,757	\$11,757
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$387,989	\$387,989	\$387,989	\$387,989
C. CONTINGENCY (20 PERCENT OF DIRECT AND INDIRECT)					
	CONT	\$383,286	\$383,286	\$383,286	\$383,286
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$2,299,718	\$2,299,718	\$2,299,718	\$2,299,718
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 590	C180, 1992	1992 DOLLARS			
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LOW NO _x BURNER					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kw-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2. ADMINISTRATIVE (0.02*TCIC)		\$45,994	\$45,994	\$45,994	\$45,994
3. PROPERTY TAX (0.01*TCIC)		\$22,997	\$22,997	\$22,997	\$22,997
4. INSURANCE (0.01*TCIC)		\$22,997	\$22,997	\$22,997	\$22,997
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$91,989	\$91,989	\$91,989	\$91,989
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$91,989	\$91,989	\$91,989	\$91,989
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.16274539	0.16274539	0.16274539	0.16274539
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$2,299,718	\$2,299,718	\$2,299,718	\$2,299,718
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$374,269	\$374,269	\$374,269	\$374,269
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$91,989	\$91,989	\$91,989	\$91,989
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$466,257	\$466,257	\$466,257	\$466,257
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.3	0.3	0.3	0.3
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.15	0.15	0.15	0.15
3. NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	590	590	590	590
*** NO_x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		310.1	255.8	193.8	127.9
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***		\$1,504	\$1,822	\$2,406	\$3,645

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 1300		CIBO, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LOW NOx BURNER					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$3,056,885	\$3,056,885	\$3,056,885	\$3,056,885
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$917,065	\$917,065	\$917,065	\$917,065
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$3,973,950	\$3,973,950	\$3,973,950	\$3,973,950
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$305,688	\$305,688	\$305,688	\$305,688
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$305,688	\$305,688	\$305,688	\$305,688
3. CONSTRUCTION FEE (0.10PEC)		\$305,688	\$305,688	\$305,688	\$305,688
4. STARTUP (0.02PEC)		\$61,138	\$61,138	\$61,138	\$61,138
5. PERFORMANCE TEST (0.01PEC)		\$30,569	\$30,569	\$30,569	\$30,569
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$1,008,772	\$1,008,772	\$1,008,772	\$1,008,772
C. CONTINGENCY (20 percent of direct and indirect)					
	CONT	\$996,544	\$996,544	\$996,544	\$996,544
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$5,979,267	\$5,979,267	\$5,979,267	\$5,979,267
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: FIELD ERRECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 1300		CIBO, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LOW NO _x BURNER						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kw-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)			\$0	\$0	\$0	\$0
2. ADMINISTRATIVE (0.02*TCIC)			\$119,585	\$119,585	\$119,585	\$119,585
3. PROPERTY TAX (0.01*TCIC)			\$59,793	\$59,793	\$59,793	\$59,793
4. INSURANCE (0.01*TCIC)			\$59,793	\$59,793	\$59,793	\$59,793
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$239,171	\$239,171	\$239,171	\$239,171
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$239,171	\$239,171	\$239,171	\$239,171
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$5,979,267	\$5,979,267	\$5,979,267	\$5,979,267
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$973,098	\$973,098	\$973,098	\$973,098
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$239,171	\$239,171	\$239,171	\$239,171
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$1,212,269	\$1,212,269	\$1,212,269	\$1,212,269
B. NO_x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.4	0.4	0.4	0.4
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.2	0.2	0.2	0.2
3. NO _x REMOVAL EFFICIENCY (%)			50	50	50	50
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	1300	1300	1300	1300
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			911.0	751.6	569.4	375.8
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$1,331	\$1,613	\$2,129	\$3,226

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	265	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LOW NOx BURNER WITH CEM SYSTEM				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$263,245	\$263,245	\$263,245	\$263,245
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$78,973	\$78,973	\$78,973	\$78,973
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$342,218	\$342,218	\$342,218	\$342,218
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$26,324	\$26,324	\$26,324	\$26,324
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$26,324	\$26,324	\$26,324	\$26,324
3. CONSTRUCTION FEE (0.10PEC)		\$26,324	\$26,324	\$26,324	\$26,324
4. STARTUP (0.02PEC)		\$5,265	\$5,265	\$5,265	\$5,265
5. PERFORMANCE TEST (0.01PEC)		\$2,632	\$2,632	\$2,632	\$2,632
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$86,871	\$86,871	\$86,871	\$86,871
C. CONTINGENCY (20 percent of direct and indirect)					
	CONT	\$85,818	\$85,818	\$85,818	\$85,818
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$514,907	\$514,907	\$514,907	\$514,907
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 265	CIBO, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LOW NO _x BURNER WITH CEM SYSTEM					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$0	\$0	\$0	\$0
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2. ADMINISTRATIVE (0.02*TCIC)		\$10,298	\$10,298	\$10,298	\$10,298
3. PROPERTY TAX (0.01*TCIC)		\$5,149	\$5,149	\$5,149	\$5,149
4. INSURANCE (0.01*TCIC)		\$5,149	\$5,149	\$5,149	\$5,149
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$20,596	\$20,596	\$20,596	\$20,596
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$20,596	\$20,596	\$20,596	\$20,596
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$514,907	\$514,907	\$514,907	\$514,907
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$83,799	\$83,799	\$83,799	\$83,799
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$20,596	\$20,596	\$20,596	\$20,596
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$104,395	\$104,395	\$104,395	\$104,395
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.24	0.24	0.24	0.24
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.12	0.12	0.12	0.12
3. NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	265	265	265	265
*** NO_x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		111.4	91.9	69.6	46.0
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***		\$937	\$1,136	\$1,499	\$2,271

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	17.7	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LNB AND FGR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$28,017	\$28,017	\$28,017	\$28,017
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$8,405	\$8,405	\$8,405	\$8,405
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$36,421	\$36,421	\$36,421	\$36,421
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$2,802	\$2,802	\$2,802	\$2,802
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$2,802	\$2,802	\$2,802	\$2,802
3. CONSTRUCTION FEE (0.10PEC)		\$2,802	\$2,802	\$2,802	\$2,802
4. STARTUP (0.02PEC)		\$560	\$560	\$560	\$560
5. PERFORMANCE TEST (0.01PEC)		\$280	\$280	\$280	\$280
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$9,245	\$9,245	\$9,245	\$9,245
C. CONTINGENCY (20 percent of direct and indirect)					
	CONT	\$9,133	\$9,133	\$9,133	\$9,133
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$54,800	\$54,800	\$54,800	\$54,800
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 17.7	CIBO, 1992	1992 DOLLARS			
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LNB AND FGR					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4. REPLACEMENT MATERIALS		\$500	\$500	\$500	\$500
5. ELECTRICITY @ \$0.05/kW-hr		\$2,313	\$1,909	\$1,446	\$954
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$4,503)	(\$3,715)	(\$2,814)	(\$1,857)
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$1,189)	(\$806)	(\$368)	\$97
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$300	\$300	\$300	\$300
2. ADMINISTRATIVE (0.02*TCIC)		\$1,096	\$1,096	\$1,096	\$1,096
3. PROPERTY TAX (0.01*TCIC)		\$548	\$548	\$548	\$548
4. INSURANCE (0.01*TCIC)		\$548	\$548	\$548	\$548
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$2,492	\$2,492	\$2,492	\$2,492
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$1,303	\$1,686	\$2,124	\$2,589
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$54,800	\$54,800	\$54,800	\$54,800
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$8,919	\$8,919	\$8,919	\$8,919
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$1,303	\$1,686	\$2,124	\$2,589
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$10,221	\$10,604	\$11,042	\$11,507
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.16	0.16	0.16	0.16
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.06	0.06	0.06	0.06
3. NO _x REMOVAL EFFICIENCY (%)		60	60	60	60
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	17.7	17.7	17.7	17.7
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		6.0	4.9	3.7	2.5
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,717	\$2,159	\$2,967	\$4,685

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 41.3		IMPELL CORP., 1989		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LNB AND FGR						
TOTAL CAPITAL INVESTMENT COST (TCIC)						
		BOILER CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT CAPITAL COST (DCC)						
1. PURCHASED EQUIPMENT COST (PEC)						
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP				
CEM SYSTEM						
INSTRUMENTATION						
SALES TAX						
FREIGHT						
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$95,751	\$95,751	\$95,751	\$95,751
2. DIRECT INSTALLATION COST (DIC)						
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$50,394	\$50,394	\$50,394	\$50,394
3. SITE PREP. SP (as required)		SP				
4. BUILDINGS, BLDG (as required)		BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$146,145	\$146,145	\$146,145	\$146,145
B. INDIRECT CAPITAL COST (ICC)						
1. ENGINEERING						
2. CONSTRUCTION AND FIELD EXPENSES						
3. CONSTRUCTION FEE						
4. STARTUP						
5. PERFORMANCE TEST						
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$26,203	\$26,203	\$26,203	\$26,203
C. CONTINGENCY		CONT				
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$208,634	\$208,634	\$208,634	\$208,634

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 41.3		IMPELL CORP., 1989		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LNB AND FGR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (OAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4.	REPLACEMENT MATERIALS		\$500	\$500	\$500	\$500
5.	ELECTRICITY @ \$0.05/kW-hr		\$5,228	\$4,313	\$3,267	\$2,157
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$10,506)	(\$8,668)	(\$6,566)	(\$4,334)
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	(\$4,278)	(\$3,355)	(\$2,299)	(\$1,177)
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$300	\$300	\$300	\$300
2.	ADMINISTRATIVE (0.02*TCIC)		\$4,173	\$4,173	\$4,173	\$4,173
3.	PROPERTY TAX (0.01*TCIC)		\$2,086	\$2,086	\$2,086	\$2,086
4.	INSURANCE (0.01*TCIC)		\$2,086	\$2,086	\$2,086	\$2,086
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$8,645	\$8,645	\$8,645	\$8,645
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$4,367	\$5,291	\$6,346	\$7,468
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$208,634	\$208,634	\$208,634	\$208,634
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$33,954	\$33,954	\$33,954	\$33,954
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$4,367	\$5,291	\$6,346	\$7,468
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$38,321	\$39,245	\$40,301	\$41,422
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.16	0.16	0.16	0.16
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.06	0.06	0.06	0.06
3.	NO _x REMOVAL EFFICIENCY (%)		60	60	60	60
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	41.3	41.3	41.3	41.3
*** NO_x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			13.9	11.5	8.7	5.7
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***			\$2,758	\$3,424	\$4,641	\$7,228

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	45	CAL ARB, 1987	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LNB AND FGR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$48,381	\$48,381	\$48,381	\$48,381
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$57,403	\$57,403	\$57,403	\$57,403
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$105,785	\$105,785	\$105,785	\$105,785
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$35,989	\$35,989	\$35,989	\$35,989
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$141,773	\$141,773	\$141,773	\$141,773
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 45	CAL ARB, 1987		1992 DOLLARS		
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LNB AND FGR					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR		\$500	\$500	\$500	\$500
3. MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kw-hr		\$5,881	\$4,852	\$3,676	\$2,426
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$11,448)	(\$9,444)	(\$7,155)	(\$4,722)
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$4,566)	(\$3,592)	(\$2,479)	(\$1,296)
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$600	\$600	\$600	\$600
2. ADMINISTRATIVE (0.02*TCIC)		\$2,835	\$2,835	\$2,835	\$2,835
3. PROPERTY TAX (0.01*TCIC)		\$1,418	\$1,418	\$1,418	\$1,418
4. INSURANCE (0.01*TCIC)		\$1,418	\$1,418	\$1,418	\$1,418
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$6,271	\$6,271	\$6,271	\$6,271
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$1,705	\$2,679	\$3,792	\$4,975
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$141,773	\$141,773	\$141,773	\$141,773
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$23,073	\$23,073	\$23,073	\$23,073
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$1,705	\$2,679	\$3,792	\$4,975
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$24,778	\$25,752	\$26,865	\$28,048
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.16	0.16	0.16	0.16
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.06	0.06	0.06	0.06
3. NOx REMOVAL EFFICIENCY (%)		60	60	60	60
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	45	45	45	45
*** NOx REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		15.1	12.5	9.5	6.2
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$1,637	\$2,062	\$2,840	\$4,492

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 55		CAL ARB. 1987		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LNB AND FGR					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$84,370	\$84,370	\$84,370
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$122,639	\$122,639	\$122,639
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$207,008	\$207,008	\$207,008
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$40,500	\$40,500	\$40,500
C. CONTINGENCY		CONT			
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$247,508	\$247,508	\$247,508

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 55	CAL ARB, 1987		1992 DOLLARS		
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LNB AND FGR					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR		\$500	\$500	\$500	\$500
3. MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr		\$7,188	\$5,930	\$4,493	\$2,965
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$13,991)	(\$11,543)	(\$8,745)	(\$5,771)
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$5,803)	(\$4,612)	(\$3,252)	(\$1,806)
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$600	\$600	\$600	\$600
2. ADMINISTRATIVE (0.02*TCIC)		\$4,950	\$4,950	\$4,950	\$4,950
3. PROPERTY TAX (0.01*TCIC)		\$2,475	\$2,475	\$2,475	\$2,475
4. INSURANCE (0.01*TCIC)		\$2,475	\$2,475	\$2,475	\$2,475
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$10,500	\$10,500	\$10,500	\$10,500
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$4,697	\$5,888	\$7,248	\$8,694
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$247,508	\$247,508	\$247,508	\$247,508
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$40,281	\$40,281	\$40,281	\$40,281
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$4,697	\$5,888	\$7,248	\$8,694
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$44,978	\$46,169	\$47,529	\$48,975
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.16	0.16	0.16	0.16
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.06	0.06	0.06	0.06
3. NOx REMOVAL EFFICIENCY (%)		60	60	60	60
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	55	55	55	55
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		18.5	15.3	11.6	7.6
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$2,431	\$3,025	\$4,110	\$6,417

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 265		CIBO, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: LNB AND FGR					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$236,321	\$236,321	\$236,321
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$70,896	\$70,896	\$70,896
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST ***		DCC	\$307,217	\$307,217	\$307,217
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)			\$23,632	\$23,632	\$23,632
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)			\$23,632	\$23,632	\$23,632
3. CONSTRUCTION FEE (0.10PEC)			\$23,632	\$23,632	\$23,632
4. STARTUP (0.02PEC)			\$4,726	\$4,726	\$4,726
5. PERFORMANCE TEST (0.01PEC)			\$2,363	\$2,363	\$2,363
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$77,986	\$77,986	\$77,986
C. CONTINGENCY (20 percent of direct and indirect)		CONT	\$77,041	\$77,041	\$77,041
*** TOTAL CAPITAL INVESTMENT COST ***		TCIC	\$462,244	\$462,244	\$462,244
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr):	265	CIBO, 1992		1992 DOLLARS	
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LNB AND FGR				
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4. REPLACEMENT MATERIALS		\$500	\$500	\$500	\$500
5. ELECTRICITY @ \$0.05/kW-hr		\$34,635	\$28,574	\$21,647	\$14,287
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$67,413)	(\$55,616)	(\$42,133)	(\$27,808)
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$31,778)	(\$26,042)	(\$19,486)	(\$12,521)
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$300	\$300	\$300	\$300
2. ADMINISTRATIVE (0.02*TCIC)		\$9,245	\$9,245	\$9,245	\$9,245
3. PROPERTY TAX (0.01*TCIC)		\$4,622	\$4,622	\$4,622	\$4,622
4. INSURANCE (0.01*TCIC)		\$4,622	\$4,622	\$4,622	\$4,622
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$18,790	\$18,790	\$18,790	\$18,790
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	(\$12,988)	(\$7,252)	(\$697)	\$6,269
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$462,244	\$462,244	\$462,244	\$462,244
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$75,228	\$75,228	\$75,228	\$75,228
2. ANNUAL O&M COSTS (O&M, above)	O&M	(\$12,988)	(\$7,252)	(\$697)	\$6,269
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$62,240	\$67,976	\$74,531	\$81,497
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.24	0.24	0.24	0.24
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.10	0.10	0.10	0.10
3. NO _x REMOVAL EFFICIENCY (%)		60	60	60	60
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	265	265	265	265
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		133.7	110.3	83.6	55.2
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$465	\$616	\$892	\$1,478

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 81.3		IMPELL CORP., 1989		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LNB AND FGR WITH CEM SYSTEM						
TOTAL CAPITAL INVESTMENT COST (TCIC)						
		BOILER CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT CAPITAL COST (DCC)						
1. PURCHASED EQUIPMENT COST (PEC)						
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP				
CEM SYSTEM						
INSTRUMENTATION						
SALES TAX						
FREIGHT						
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$215,634	\$215,634	\$215,634	\$215,634
2. DIRECT INSTALLATION COST (DIC)						
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$68,507	\$68,507	\$68,507	\$68,507
3. SITE PREP, SP (as required)		SP				
4. BUILDINGS, BLDG (as required)		BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$284,141	\$284,141	\$284,141	\$284,141
B. INDIRECT CAPITAL COST (ICC)						
1. ENGINEERING						
2. CONSTRUCTION AND FIELD EXPENSES						
3. CONSTRUCTION FEE						
4. STARTUP						
5. PERFORMANCE TEST						
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$33,213	\$33,213	\$33,213	\$33,213
C. CONTINGENCY		CONT				
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$379,813	\$379,813	\$379,813	\$379,813

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 81.3		IMPELL CORP., 1989		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LNB AND FGR WITH CEM SYSTEM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4.	REPLACEMENT MATERIALS		\$500	\$500	\$500	\$500
5.	ELECTRICITY @ \$0.05/kW-hr		\$10,456	\$8,626	\$6,535	\$4,313
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu D=4.83 R=2.35		(\$20,682)	(\$17,063)	(\$12,926)	(\$8,531)
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$9,226)	(\$7,436)	(\$5,391)	(\$3,218)
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$300	\$300	\$300	\$300
2.	ADMINISTRATIVE (0.02*TCIC)		\$7,596	\$7,596	\$7,596	\$7,596
3.	PROPERTY TAX (0.01*TCIC)		\$3,798	\$3,798	\$3,798	\$3,798
4.	INSURANCE (0.01*TCIC)		\$3,798	\$3,798	\$3,798	\$3,798
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$15,493	\$15,493	\$15,493	\$15,493
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$6,267	\$8,056	\$10,101	\$12,274
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$379,813	\$379,813	\$379,813	\$379,813
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$61,813	\$61,813	\$61,813	\$61,813
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$6,267	\$8,056	\$10,101	\$12,274
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$68,079	\$69,869	\$71,914	\$74,087
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.18	0.18	0.18	0.18
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.07	0.07	0.07	0.07
3.	NO _x REMOVAL EFFICIENCY (%)		60	60	60	60
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	81.3	81.3	81.3	81.3
***	NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		30.8	25.4	19.2	12.7
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$2,213	\$2,753	\$3,740	\$5,838

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	91	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LOW NO _x BURNER AND FGR WITH CEM SYSTEM				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$426,040	\$426,040	\$426,040	\$426,040
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$127,812	\$127,812	\$127,812	\$127,812
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$553,851	\$553,851	\$553,851	\$553,851
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$42,604	\$42,604	\$42,604	\$42,604
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$42,604	\$42,604	\$42,604	\$42,604
3. CONSTRUCTION FEE (0.10PEC)		\$42,604	\$42,604	\$42,604	\$42,604
4. STARTUP (0.02PEC)		\$8,521	\$8,521	\$8,521	\$8,521
5. PERFORMANCE TEST (0.01PEC)		\$4,260	\$4,260	\$4,260	\$4,260
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$140,593	\$140,593	\$140,593	\$140,593
C. CONTINGENCY (20 percent of direct and indirect)					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$833,333	\$833,333	\$833,333	\$833,333
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 91		CIBO, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LOW NO _x BURNER AND FGR WITH CEM SYSTEM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR			\$7,000	\$7,000	\$7,000	\$7,000
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kw-hr			\$11,894	\$9,812	\$7,434	\$4,906
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu r & d			(\$23,150)	(\$19,098)	(\$14,468)	(\$9,549)
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	(\$4,256)	(\$2,286)	(\$35)	\$2,357
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)			\$4,200	\$4,200	\$4,200	\$4,200
2. ADMINISTRATIVE (0.02*TCIC)			\$16,667	\$16,667	\$16,667	\$16,667
3. PROPERTY TAX (0.01*TCIC)			\$8,333	\$8,333	\$8,333	\$8,333
4. INSURANCE (0.01*TCIC)			\$8,333	\$8,333	\$8,333	\$8,333
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$37,533	\$37,533	\$37,533	\$37,533
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$33,277	\$35,247	\$37,498	\$39,890
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$833,333	\$833,333	\$833,333	\$833,333
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$135,621	\$135,621	\$135,621	\$135,621
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$33,277	\$35,247	\$37,498	\$39,890
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$168,899	\$170,868	\$173,120	\$175,511
B. NO_x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.18	0.18	0.18	0.18
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.07	0.07	0.07	0.07
3. NO _x REMOVAL EFFICIENCY (%)			60	60	60	60
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	91	91	91	91
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			34.4	28.4	21.5	14.2
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$4,905	\$6,014	\$8,043	\$12,355

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	265	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	LNB AND FGR WITH CEM SYSTEM				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$340,725	\$340,725	\$340,725	\$340,725
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$102,218	\$102,218	\$102,218	\$102,218
(30 percent of purchased equipment)					
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$442,943	\$442,943	\$442,943	\$442,943
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.10PEC)		\$34,073	\$34,073	\$34,073	\$34,073
2. CONSTRUCTION AND FIELD EXPENSES (0.10PEC)		\$34,073	\$34,073	\$34,073	\$34,073
3. CONSTRUCTION FEE (0.10PEC)		\$34,073	\$34,073	\$34,073	\$34,073
4. STARTUP (0.02PEC)		\$6,815	\$6,815	\$6,815	\$6,815
5. PERFORMANCE TEST (0.01PEC)		\$3,407	\$3,407	\$3,407	\$3,407
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$112,439	\$112,439	\$112,439	\$112,439
C. CONTINGENCY (20 percent of direct and indirect)					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$666,459	\$666,459	\$666,459	\$666,459
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 265		CIBD, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: LNB AND FGR WITH CEM SYSTEM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4.	REPLACEMENT MATERIALS		\$500	\$500	\$500	\$500
5.	ELECTRICITY @ \$0.05/kw-hr		\$34,635	\$28,574	\$21,647	\$14,287
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$67,413)	(\$55,616)	(\$42,133)	(\$27,808)
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	(\$31,778)	(\$26,042)	(\$19,486)	(\$12,521)
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$300	\$300	\$300	\$300
2.	ADMINISTRATIVE (0.02*TCIC)		\$13,329	\$13,329	\$13,329	\$13,329
3.	PROPERTY TAX (0.01*TCIC)		\$6,665	\$6,665	\$6,665	\$6,665
4.	INSURANCE (0.01*TCIC)		\$6,665	\$6,665	\$6,665	\$6,665
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$26,958	\$26,958	\$26,958	\$26,958
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	(\$4,820)	\$916	\$7,472	\$14,437
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$666,459	\$666,459	\$666,459	\$666,459
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$108,463	\$108,463	\$108,463	\$108,463
2. ANNUAL O&M COSTS (O&M, above)		O&M	(\$4,820)	\$916	\$7,472	\$14,437
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$103,643	\$109,379	\$115,935	\$122,900
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.10	0.10	0.10	0.10
3.	NOx REMOVAL EFFICIENCY (%)		60	60	60	60
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	265	265	265	265
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			133.7	110.3	83.6	55.2
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$775	\$992	\$1,387	\$2,228

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 2.9		HUGH DEAN, 1988		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: FGR AND OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$23,546	\$23,546	\$23,546	\$23,546
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$1,531	\$1,531	\$1,531	\$1,531
FREIGHT		\$843	\$843	\$843	\$843
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$25,920	\$25,920	\$25,920	\$25,920
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$8,764	\$8,764	\$8,764	\$8,764
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLOG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLOG)	DCC	\$34,684	\$34,684	\$34,684	\$34,684
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$4,873	\$4,873	\$4,873	\$4,873
C. CONTINGENCY (20 percent of direct and indirect)		CONT			
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$47,468	\$47,468	\$47,468	\$47,468

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 2.9		HUGH DEAN, 1988		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: FGR AND OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR	\$500	\$500	\$500	\$500	
3.	MAINTENANCE MATERIALS	\$500	\$500	\$500	\$500	
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr	\$235	\$194	\$147	\$97	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu	(\$745)	(\$615)	(\$466)	(\$307)	
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$490	\$579	\$681	\$790
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$600	\$600	\$600	\$600	
2.	ADMINISTRATIVE (0.02*TCIC)	\$949	\$949	\$949	\$949	
3.	PROPERTY TAX (0.01*TCIC)	\$475	\$475	\$475	\$475	
4.	INSURANCE (0.01*TCIC)	\$475	\$475	\$475	\$475	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$2,499	\$2,499	\$2,499	\$2,499
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$2,989	\$3,078	\$3,180	\$3,288
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$47,468	\$47,468	\$47,468	\$47,468	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$7,725	\$7,725	\$7,725	\$7,725
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$2,989	\$3,078	\$3,180	\$3,288
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$10,714	\$10,803	\$10,905	\$11,013
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.12	0.12	0.12	0.12
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.07	0.07	0.07	0.07
3.	NOx REMOVAL EFFICIENCY (%)		40	40	40	40
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	2.9	2.9	2.9	2.9
***	NOx REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		0.5	0.4	0.3	0.2
***	COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$21,741	\$26,572	\$35,406	\$54,179

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 5.23		HUGH DEAN, 1988		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: FGR AND OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$24,984	\$24,984	\$24,984	\$24,984
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$1,624	\$1,624	\$1,624	\$1,624
FREIGHT		\$892	\$892	\$892	\$892
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$27,500	\$27,500	\$27,500	\$27,500
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$9,290	\$9,290	\$9,290	\$9,290
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$36,790	\$36,790	\$36,790	\$36,790
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$5,300	\$5,300	\$5,300	\$5,300
C. CONTINGENCY (20 percent of direct and indirect)		CONT			
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$50,508	\$50,508	\$50,508	\$50,508
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 5.23		HUGH DEAN, 1988		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: FGR AND OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR		\$500	\$500	\$500	\$500
3.	MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr		\$314	\$259	\$196	\$129
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$1,330)	(\$1,098)	(\$832)	(\$549)
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	(\$17)	\$161	\$365	\$581
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$600	\$600	\$600	\$600
2.	ADMINISTRATIVE (0.02*TCIC)		\$1,010	\$1,010	\$1,010	\$1,010
3.	PROPERTY TAX (0.01*TCIC)		\$505	\$505	\$505	\$505
4.	INSURANCE (0.01*TCIC)		\$505	\$505	\$505	\$505
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$2,620	\$2,620	\$2,620	\$2,620
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$2,604	\$2,781	\$2,985	\$3,201
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$50,508	\$50,508	\$50,508	\$50,508
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$8,220	\$8,220	\$8,220	\$8,220
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$2,604	\$2,781	\$2,985	\$3,201
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$10,823	\$11,001	\$11,205	\$11,421
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.12	0.12	0.12	0.12
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.07	0.07	0.07	0.07
3.	NOx REMOVAL EFFICIENCY (%)		40	40	40	40
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	5.23	5.23	5.23	5.23
*** NOx REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			0.9	0.7	0.5	0.4
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$12,304	\$15,159	\$20,380	\$31,475

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 10.46		HUGH DEAN, 1988		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: FGR AND OXYGEN TRIM						
TOTAL CAPITAL INVESTMENT COST (TCIC)						
		BOILER CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT CAPITAL COST (DCC)						
1. PURCHASED EQUIPMENT COST (PEC)						
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP	\$29,346	\$29,346	\$29,346	\$29,346
CEM SYSTEM						
INSTRUMENTATION						
SALES TAX			\$1,907	\$1,907	\$1,907	\$1,907
FREIGHT			\$942	\$942	\$942	\$942
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$32,195	\$32,195	\$32,195	\$32,195
2. DIRECT INSTALLATION COST (DIC)						
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$9,290	\$9,290	\$9,290	\$9,290
3. SITE PREP, SP (as required)		SP				
4. BUILDINGS, BLDG (as required)		BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$41,485	\$41,485	\$41,485	\$41,485
B. INDIRECT CAPITAL COST (ICC)						
1. ENGINEERING						
2. CONSTRUCTION AND FIELD EXPENSES						
3. CONSTRUCTION FEE						
4. STARTUP						
5. PERFORMANCE TEST						
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$5,255	\$5,255	\$5,255	\$5,255
C. CONTINGENCY (20 percent of direct and indirect)		CONT	\$9,348	\$9,348	\$9,348	\$9,348
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$56,087	\$56,087	\$56,087	\$56,087

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 10.46		HUGH DEAN, 1988		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: FGR AND OXYGEN TRIM						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR		\$500	\$500	\$500	\$500
2.	MAINTENANCE LABOR		\$500	\$500	\$500	\$500
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr		\$967	\$798	\$604	\$399
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$2,661)	(\$2,195)	(\$1,663)	(\$1,098)
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$694)	(\$397)	(\$59)	\$301
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$600	\$600	\$600	\$600
2.	ADMINISTRATIVE (0.02*TCIC)		\$1,122	\$1,122	\$1,122	\$1,122
3.	PROPERTY TAX (0.01*TCIC)		\$561	\$561	\$561	\$561
4.	INSURANCE (0.01*TCIC)		\$561	\$561	\$561	\$561
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$2,843	\$2,843	\$2,843	\$2,843
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$2,150	\$2,446	\$2,785	\$3,145
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)		10	10	10	10
	EXPECTED LIFETIME OF EQUIPMENT, YEARS		0.1	0.1	0.1	0.1
	INTEREST RATE		0.1627	0.1627	0.1627	0.1627
	CAPITAL RECOVERY FACTOR		\$56,087	\$56,087	\$56,087	\$56,087
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)					
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$9,128	\$9,128	\$9,128	\$9,128
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$2,150	\$2,446	\$2,785	\$3,145
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$11,278	\$11,574	\$11,913	\$12,273
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.12	0.12	0.12	0.12
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.07	0.07	0.07	0.07
3.	NO _x REMOVAL EFFICIENCY (%)		40	40	40	40
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	10.46	10.46	10.46	10.46
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		1.8	1.5	1.1	0.7
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$6,410	\$7,974	\$10,834	\$16,912

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 20.9		HUGH DEAN, 1988		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: FGR AND OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$34,204	\$34,204	\$34,204	\$34,204
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$2,224	\$2,224	\$2,224	\$2,224
FREIGHT		\$1,041	\$1,041	\$1,041	\$1,041
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$37,469	\$37,469	\$37,469	\$37,469
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$9,815	\$9,815	\$9,815	\$9,815
3. SITE PREP, SP (as required)					
	SP				
4. BUILDINGS, BLDG (as required)					
	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$47,284	\$47,284	\$47,284	\$47,284
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$5,255	\$5,255	\$5,255	\$5,255
C. CONTINGENCY (20 percent of direct and indirect)					
	CONT	\$10,508	\$10,508	\$10,508	\$10,508
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$63,046	\$63,046	\$63,046	\$63,046

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE:	PACKAGED FIRETUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr):	20.9	HUGH DEAN, 1988	1992 DOLLARS			
FUEL TYPE:	NATURAL GAS					
CONTROL METHOD:	FGR AND OXYGEN TRIM					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR	\$500	\$500	\$500	\$500	
3.	MAINTENANCE MATERIALS	\$500	\$500	\$500	\$500	
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr	\$3,790	\$3,127	\$2,369	\$1,563	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu	(\$5,323)	(\$4,392)	(\$3,327)	(\$2,196)	
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$533)	(\$265)	\$42	\$368
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$600	\$600	\$600	\$600	
2.	ADMINISTRATIVE (0.02*TCIC)	\$1,261	\$1,261	\$1,261	\$1,261	
3.	PROPERTY TAX (0.01*TCIC)	\$630	\$630	\$630	\$630	
4.	INSURANCE (0.01*TCIC)	\$630	\$630	\$630	\$630	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$3,122	\$3,122	\$3,122	\$3,122
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$2,589	\$2,857	\$3,164	\$3,490
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$63,046	\$63,046	\$63,046	\$63,046	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$10,260	\$10,260	\$10,260	\$10,260
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$2,589	\$2,857	\$3,164	\$3,490
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$12,849	\$13,118	\$13,424	\$13,750
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.12	0.12	0.12	0.12
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.07	0.07	0.07	0.07
3.	NO _x REMOVAL EFFICIENCY (%)		40	40	40	40
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	20.9	20.9	20.9	20.9
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		3.5	2.9	2.2	1.5
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$3,651	\$4,518	\$6,103	\$9,471

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED FIRETUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 33.5		HUGH DEAN, 1988		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: FGR AND OXYGEN TRIM					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$37,971	\$37,971	\$37,971	\$37,971
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$2,469	\$2,469	\$2,469	\$2,469
FREIGHT		\$1,091	\$1,091	\$1,091	\$1,091
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$41,531	\$41,531	\$41,531	\$41,531
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$11,401	\$11,401	\$11,401	\$11,401
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$52,932	\$52,932	\$52,932	\$52,932
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$5,255	\$5,255	\$5,255	\$5,255
C. CONTINGENCY (20 percent of direct and indirect)		CONT			
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$69,824	\$69,824	\$69,824	\$69,824

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED FIRETUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 33.5	HUGH DEAN, 1988		1992 DOLLARS		
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: FGR AND OXYGEN TRIM					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR		\$500	\$500	\$500	\$500
3. MAINTENANCE MATERIALS		\$500	\$500	\$500	\$500
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/KW-hr		\$6,300	\$5,197	\$3,937	\$2,599
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER: 1% FUEL SAVINGS, N. GAS @ \$3.63/MMBtu		(\$8,517)	(\$7,027)	(\$5,323)	(\$3,513)
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	(\$1,217)	(\$829)	(\$386)	\$85
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$600	\$600	\$600	\$600
2. ADMINISTRATIVE (0.02*TCIC)		\$1,396	\$1,396	\$1,396	\$1,396
3. PROPERTY TAX (0.01*TCIC)		\$698	\$698	\$698	\$698
4. INSURANCE (0.01*TCIC)		\$698	\$698	\$698	\$698
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$3,393	\$3,393	\$3,393	\$3,393
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$2,176	\$2,564	\$3,007	\$3,478
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$69,824	\$69,824	\$69,824	\$69,824
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$11,363	\$11,363	\$11,363	\$11,363
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$2,176	\$2,564	\$3,007	\$3,478
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$13,539	\$13,927	\$14,371	\$14,842
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.12	0.12	0.12	0.12
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.07	0.07	0.07	0.07
3. NO _x REMOVAL EFFICIENCY (%)		40	40	40	40
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	33.5	33.5	33.5	33.5
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		5.6	4.6	3.5	2.3
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$2,404	\$2,998	\$4,083	\$6,390

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	50	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$121,300	\$121,300	\$121,300	\$121,300
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$85,000	\$85,000	\$85,000	\$85,000
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLOG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$206,300	\$206,300	\$206,300	\$206,300
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
3. CONSTRUCTION FEE (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
4. STARTUP (0.04PEC)		\$4,852	\$4,852	\$4,852	\$4,852
5. PERFORMANCE TEST (0.02PEC)		\$2,426	\$2,426	\$2,426	\$2,426
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$80,058	\$80,058	\$80,058	\$80,058
C. CONTINGENCY (0.20*(DCC+ICC))					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$343,630	\$343,630	\$343,630	\$343,630
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 50		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR (semi-annual inspection)						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS (catalyst replacement every 3 yrs)						
5. ELECTRICITY @ \$0.05/kw-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL (catalyst)						
9. CHEMICALS (ammonia @ \$250/ton, 1 lb/hr)						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$24,232	\$23,987	\$23,708	\$23,410
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)						
2. ADMINISTRATIVE (0.02*TCIC)						
3. PROPERTY TAX (0.01*TCIC)						
4. INSURANCE (0.01*TCIC)						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$14,945	\$14,945	\$14,945	\$14,945
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***		O&M	\$39,177	\$38,933	\$38,653	\$38,356
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS						
INTEREST RATE						
CAPITAL RECOVERY FACTOR						
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)						
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$55,924	\$55,924	\$55,924	\$55,924
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$39,177	\$38,933	\$38,653	\$38,356
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$95,101	\$94,857	\$94,577	\$94,280
B. NO_x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)						
2. CONTROLLED NO _x LEVEL (lb/MMBtu)						
3. NO _x REMOVAL EFFICIENCY (%)						
4. CAPACITY FACTOR						
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)						
*** NO _x REMOVED PER YEAR (TONS/YR) ***			23.8	19.7	14.9	9.8
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000						
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$3,991	\$4,825	\$6,351	\$9,592

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	100	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$152,600	\$152,600	\$152,600	\$152,600
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$107,000	\$107,000	\$107,000	\$107,000
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$259,600	\$259,600	\$259,600	\$259,600
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$30,520	\$30,520	\$30,520	\$30,520
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$30,520	\$30,520	\$30,520	\$30,520
3. CONSTRUCTION FEE (0.20PEC)		\$30,520	\$30,520	\$30,520	\$30,520
4. STARTUP (0.04PEC)		\$6,104	\$6,104	\$6,104	\$6,104
5. PERFORMANCE TEST (0.02PEC)		\$3,052	\$3,052	\$3,052	\$3,052
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$100,716	\$100,716	\$100,716	\$100,716
C. CONTINGENCY (0.20*(DCC+ICC))					
	CONT	\$72,063	\$72,063	\$72,063	\$72,063
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$432,379	\$432,379	\$432,379	\$432,379

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 100		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000	
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS (catalyst replacement every 3 yrs)		\$33,333	\$33,333	\$33,333	\$33,333	
5. ELECTRICITY @ \$0.05/kW-hr		\$523	\$431	\$327	\$216	
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL (catalyst)		\$8,333	\$8,333	\$8,333	\$8,333	
9. CHEMICALS (ammonia @ \$250/ton, 2.1 lb/hr)		\$1,840	\$1,518	\$1,150	\$759	
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$46,029	\$45,616	\$45,143	\$44,641
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200	
2. ADMINISTRATIVE (0.02*TCIC)		\$8,648	\$8,648	\$8,648	\$8,648	
3. PROPERTY TAX (0.01*TCIC)		\$4,324	\$4,324	\$4,324	\$4,324	
4. INSURANCE (0.01*TCIC)		\$4,324	\$4,324	\$4,324	\$4,324	
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$18,495	\$18,495	\$18,495	\$18,495
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$64,524	\$64,111	\$63,638	\$63,136
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10	
INTEREST RATE		0.1	0.1	0.1	0.1	
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627	
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$432,379	\$432,379	\$432,379	\$432,379	
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$70,368	\$70,368	\$70,368	\$70,368
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$64,524	\$64,111	\$63,638	\$63,136
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$134,892	\$134,479	\$134,006	\$133,504
B. NO _x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.18	0.18	0.18	0.18
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.03	0.03	0.03	0.03
3. NO _x REMOVAL EFFICIENCY (%)			85	85	85	85
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	100	100	100	100
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			53.6	44.2	33.5	22.1
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$2,516	\$3,040	\$3,999	\$6,037

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	100	DAMON, 1987	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC				
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
CONT	CONT				
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$492,271	\$492,271	\$492,271	\$492,271
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 100		OAMON, 1987		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 2 yrs)		\$54,675	\$54,675	\$54,675	\$54,675
5.	ELECTRICITY @ \$0.05/kw-hr		\$6,700	\$6,700	\$6,700	\$6,700
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)		\$13,669	\$13,669	\$13,669	\$13,669
9.	CHEMICALS (ammonia @ \$250/ton)		\$4,400	\$4,400	\$4,400	\$4,400
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$79,444	\$79,444	\$79,444	\$79,444
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$0	\$0	\$0	\$0
2.	ADMINISTRATIVE (0.02*TCIC)		\$9,845	\$9,845	\$9,845	\$9,845
3.	PROPERTY TAX (0.01*TCIC)		\$4,923	\$4,923	\$4,923	\$4,923
4.	INSURANCE (0.01*TCIC)		\$4,923	\$4,923	\$4,923	\$4,923
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$19,691	\$19,691	\$19,691	\$19,691
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$99,135	\$99,135	\$99,135	\$99,135
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
	INTEREST RATE		0.1	0.1	0.1	0.1
	CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$492,271	\$492,271	\$492,271	\$492,271
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$80,115	\$80,115	\$80,115	\$80,115
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$99,135	\$99,135	\$99,135	\$99,135
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$179,249	\$179,249	\$179,249	\$179,249
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.18	0.18	0.18	0.18
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.03	0.03	0.03	0.03
3.	NOx REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	100	100	100	100
***	NOx REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		53.6	44.2	33.5	22.1
***	COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$3,344	\$4,053	\$5,350	\$8,105

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	150	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$190,997	\$190,997	\$190,997	\$190,997
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$133,643	\$133,643	\$133,643	\$133,643
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$324,640	\$324,640	\$324,640	\$324,640
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$38,199	\$38,199	\$38,199	\$38,199
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$38,199	\$38,199	\$38,199	\$38,199
3. CONSTRUCTION FEE (0.20PEC)		\$38,199	\$38,199	\$38,199	\$38,199
4. STARTUP (0.04PEC)		\$7,640	\$7,640	\$7,640	\$7,640
5. PERFORMANCE TEST (0.02PEC)		\$3,820	\$3,820	\$3,820	\$3,820
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$126,058	\$126,058	\$126,058	\$126,058
C. CONTINGENCY (0.20*(DCC+ICC))					
*** TOTAL CAPITAL INVESTMENT COST ***	CONT	\$90,140	\$90,140	\$90,140	\$90,140
(DCC+ICC+CONT)					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$540,838	\$540,838	\$540,838	\$540,838
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 150		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR (semi-annual inspection)			\$2,000	\$2,000	\$2,000	\$2,000
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS (catalyst replacement every 3 yrs)			\$50,000	\$50,000	\$50,000	\$50,000
5. ELECTRICITY @ \$0.05/kw-hr			\$523	\$431	\$327	\$216
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL (catalyst)			\$12,500	\$12,500	\$12,500	\$12,500
9. CHEMICALS (ammonia @ \$250/ton, 3.3 lb/hr)			\$2,891	\$2,385	\$1,807	\$1,192
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$67,914	\$67,316	\$66,633	\$65,908
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)			\$1,200	\$1,200	\$1,200	\$1,200
2. ADMINISTRATIVE (0.02*TCIC)			\$10,817	\$10,817	\$10,817	\$10,817
3. PROPERTY TAX (0.01*TCIC)			\$5,408	\$5,408	\$5,408	\$5,408
4. INSURANCE (0.01*TCIC)			\$5,408	\$5,408	\$5,408	\$5,408
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$22,834	\$22,834	\$22,834	\$22,834
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$90,747	\$90,150	\$89,467	\$88,742
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$540,838	\$540,838	\$540,838	\$540,838
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$88,019	\$88,019	\$88,019	\$88,019
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$90,747	\$90,150	\$89,467	\$88,742
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$178,766	\$178,169	\$177,486	\$176,761
B. NO_x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.18	0.18	0.18	0.18
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.03	0.03	0.03	0.03
3. NO _x REMOVAL EFFICIENCY (%)			85	85	85	85
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	150	150	150	150
*** NO _x REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			80.4	66.3	50.3	33.2
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$2,223	\$2,686	\$3,531	\$5,329

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 200		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$230,900	\$230,900	\$230,900
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$161,600	\$161,600	\$161,600
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$392,500	\$392,500	\$392,500
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)			\$46,180	\$46,180	\$46,180
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)			\$46,180	\$46,180	\$46,180
3. CONSTRUCTION FEE (0.20PEC)			\$46,180	\$46,180	\$46,180
4. STARTUP (0.04PEC)			\$9,236	\$9,236	\$9,236
5. PERFORMANCE TEST (0.02PEC)			\$4,618	\$4,618	\$4,618
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$152,394	\$152,394	\$152,394
C. CONTINGENCY (0.20*(DCC+ICC))		CONT	\$108,979	\$108,979	\$108,979
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$653,873	\$653,873	\$653,873

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 200		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR (semi-annual inspection)	\$2,000	\$2,000	\$2,000	\$2,000	
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 3 yrs)	\$66,667	\$66,667	\$66,667	\$66,667	
5.	ELECTRICITY @ \$0.05/kW-hr	\$523	\$431	\$327	\$216	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)	\$16,667	\$16,667	\$16,667	\$16,667	
9.	CHEMICALS (ammonia @ \$250/ton, 4.4 lb/hr)	\$3,854	\$3,180	\$2,409	\$1,590	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	OAC	\$89,711	\$88,945	\$88,069	\$87,139
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$1,200	\$1,200	\$1,200	\$1,200	
2.	ADMINISTRATIVE (0.02*TCIC)	\$13,077	\$13,077	\$13,077	\$13,077	
3.	PROPERTY TAX (0.01*TCIC)	\$6,539	\$6,539	\$6,539	\$6,539	
4.	INSURANCE (0.01*TCIC)	\$6,539	\$6,539	\$6,539	\$6,539	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$27,355	\$27,355	\$27,355	\$27,355
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (OAC+IAC)	O&M	\$117,065	\$116,299	\$115,424	\$114,494
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$653,873	\$653,873	\$653,873	\$653,873	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$106,415	\$106,415	\$106,415	\$106,415
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$117,065	\$116,299	\$115,424	\$114,494
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$223,480	\$222,714	\$221,839	\$220,909
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.04	0.04	0.04	0.04
3.	NOx REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	200	200	200	200
***	NOx REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		143.0	117.9	89.4	59.0
***	COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$1,563	\$1,888	\$2,483	\$3,746

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 250		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$270,100	\$270,100	\$270,100
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$189,000	\$189,000	\$189,000
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST ***		DCC	\$459,100	\$459,100	\$459,100
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)			\$54,020	\$54,020	\$54,020
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)			\$54,020	\$54,020	\$54,020
3. CONSTRUCTION FEE (0.20PEC)			\$54,020	\$54,020	\$54,020
4. STARTUP (0.04PEC)			\$10,804	\$10,804	\$10,804
5. PERFORMANCE TEST (0.02PEC)			\$5,402	\$5,402	\$5,402
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$178,266	\$178,266	\$178,266
C. CONTINGENCY (0.20*(DCC+ICC))		CONT	\$127,473	\$127,473	\$127,473
*** TOTAL CAPITAL INVESTMENT COST ***		TCIC	\$764,839	\$764,839	\$764,839
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr):	250	PEERLESS, 1992	1992 DOLLARS			
FUEL TYPE:	NATURAL GAS					
CONTROL METHOD:	SCR					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR (semi-annual inspection)	\$2,000	\$2,000	\$2,000	\$2,000	
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 3 yrs)	\$83,333	\$83,333	\$83,333	\$83,333	
5.	ELECTRICITY @ \$0.05/kW-hr	\$523	\$431	\$327	\$216	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)	\$20,833	\$20,833	\$20,833	\$20,833	
9.	CHEMICALS (ammonia @ \$250/ton, 5.5 lb/hr)	\$4,818	\$3,975	\$3,011	\$1,987	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$111,507	\$110,573	\$109,505	\$108,370
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$1,200	\$1,200	\$1,200	\$1,200	
2.	ADMINISTRATIVE (0.02*TCIC)	\$15,297	\$15,297	\$15,297	\$15,297	
3.	PROPERTY TAX (0.01*TCIC)	\$7,648	\$7,648	\$7,648	\$7,648	
4.	INSURANCE (0.01*TCIC)	\$7,648	\$7,648	\$7,648	\$7,648	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$31,794	\$31,794	\$31,794	\$31,794
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$143,301	\$142,366	\$141,298	\$140,163
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$764,839	\$764,839	\$764,839	\$764,839	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$124,474	\$124,474	\$124,474	\$124,474
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$143,301	\$142,366	\$141,298	\$140,163
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$267,775	\$266,840	\$265,772	\$264,637
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.04	0.04	0.04	0.04
3.	NO _x REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	250	250	250	250
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		178.7	147.4	111.7	73.7
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,498	\$1,810	\$2,380	\$3,590

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 50		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$121,300	\$121,300	\$121,300	\$121,300
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$85,000	\$85,000	\$85,000	\$85,000
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$206,300	\$206,300	\$206,300	\$206,300
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
3. CONSTRUCTION FEE (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
4. STARTUP (0.04PEC)		\$4,852	\$4,852	\$4,852	\$4,852
5. PERFORMANCE TEST (0.02PEC)		\$2,426	\$2,426	\$2,426	\$2,426
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$80,058	\$80,058	\$80,058	\$80,058
C. CONTINGENCY (0.20*(DCC+ICC))	CONT	\$57,272	\$57,272	\$57,272	\$57,272
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$343,630	\$343,630	\$343,630	\$343,630

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 50	PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS (catalyst replacement every 6 yrs)		\$8,333	\$8,333	\$8,333	\$8,333
5. ELECTRICITY @ \$0.05/kW-hr		\$523	\$431	\$327	\$216
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL (catalyst)		\$2,083	\$2,083	\$2,083	\$2,083
9. CHEMICALS (ammonia @ \$250/ton, 1 lb/hr)		\$876	\$723	\$548	\$361
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$13,815	\$13,571	\$13,291	\$12,994
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200
2. ADMINISTRATIVE (0.02*TCIC)		\$6,873	\$6,873	\$6,873	\$6,873
3. PROPERTY TAX (0.01*TCIC)		\$3,436	\$3,436	\$3,436	\$3,436
4. INSURANCE (0.01*TCIC)		\$3,436	\$3,436	\$3,436	\$3,436
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$14,945	\$14,945	\$14,945	\$14,945
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$28,761	\$28,516	\$28,236	\$27,939
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$343,630	\$343,630	\$343,630	\$343,630
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$55,924	\$55,924	\$55,924	\$55,924
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$28,761	\$28,516	\$28,236	\$27,939
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$84,685	\$84,440	\$84,160	\$83,863
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.16	0.16	0.16	0.16
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.02	0.02	0.02	0.02
3. NOx REMOVAL EFFICIENCY (%)		85	85	85	85
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	50	50	50	50
*** NOx REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		23.8	19.7	14.9	9.8
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$3,554	\$4,296	\$5,651	\$8,532

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 50		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$121,300	\$121,300	\$121,300	\$121,300
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$85,000	\$85,000	\$85,000	\$85,000
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$206,300	\$206,300	\$206,300	\$206,300
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
3. CONSTRUCTION FEE (0.20PEC)		\$24,260	\$24,260	\$24,260	\$24,260
4. STARTUP (0.04PEC)		\$4,852	\$4,852	\$4,852	\$4,852
5. PERFORMANCE TEST (0.02PEC)		\$2,426	\$2,426	\$2,426	\$2,426
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$80,058	\$80,058	\$80,058	\$80,058
C. CONTINGENCY (0.20*(DCC+ICC))	CONT	\$57,272	\$57,272	\$57,272	\$57,272
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$343,630	\$343,630	\$343,630	\$343,630

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	50	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR - VARIABLE CATALYST LIFE				
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS (catalyst replacement every 8 yrs)		\$6,250	\$6,250	\$6,250	\$6,250
5. ELECTRICITY @ \$0.05/kw-hr		\$523	\$431	\$327	\$216
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL (catalyst)		\$1,563	\$1,563	\$1,563	\$1,563
9. CHEMICALS (ammonia @ \$250/ton, 1 lb/hr)		\$876	\$723	\$548	\$361
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$11,211	\$10,967	\$10,687	\$10,390
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200
2. ADMINISTRATIVE (0.02*TCIC)		\$6,873	\$6,873	\$6,873	\$6,873
3. PROPERTY TAX (0.01*TCIC)		\$3,436	\$3,436	\$3,436	\$3,436
4. INSURANCE (0.01*TCIC)		\$3,436	\$3,436	\$3,436	\$3,436
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$14,945	\$14,945	\$14,945	\$14,945
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$26,156	\$25,912	\$25,632	\$25,335
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$343,630	\$343,630	\$343,630	\$343,630
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$55,924	\$55,924	\$55,924	\$55,924
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$26,156	\$25,912	\$25,632	\$25,335
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$82,081	\$81,836	\$81,556	\$81,259
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.16	0.16	0.16	0.16
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.02	0.02	0.02	0.02
3. NO _x REMOVAL EFFICIENCY (%)		85	85	85	85
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	50	50	50	50
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		23.8	19.7	14.9	9.8
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$3,445	\$4,163	\$5,477	\$8,267

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 150		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE ANALYSIS						
TOTAL CAPITAL INVESTMENT COST (TCIC)						
		BOILER CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT CAPITAL COST (DCC)						
1. PURCHASED EQUIPMENT COST (PEC)						
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP				
CEM SYSTEM						
INSTRUMENTATION						
SALES TAX						
FREIGHT						
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$190,997	\$190,997	\$190,997	\$190,997
2. DIRECT INSTALLATION COST (DIC)						
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$133,643	\$133,643	\$133,643	\$133,643
3. SITE PREP, SP (as required)		SP				
4. BUILDINGS, BLDG (as required)		BLDG				
*** TOTAL DIRECT CAPITAL COST ***		DCC	\$324,640	\$324,640	\$324,640	\$324,640
(PEC+DIC+SP+BLDG)						
B. INDIRECT CAPITAL COST (ICC)						
1. ENGINEERING (0.20PEC)			\$38,199	\$38,199	\$38,199	\$38,199
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)			\$38,199	\$38,199	\$38,199	\$38,199
3. CONSTRUCTION FEE (0.20PEC)			\$38,199	\$38,199	\$38,199	\$38,199
4. STARTUP (0.04PEC)			\$7,640	\$7,640	\$7,640	\$7,640
5. PERFORMANCE TEST (0.02PEC)			\$3,820	\$3,820	\$3,820	\$3,820
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$126,058	\$126,058	\$126,058	\$126,058
C. CONTINGENCY (0.20*(DCC+ICC))		CONT				
			\$90,140	\$90,140	\$90,140	\$90,140
*** TOTAL CAPITAL INVESTMENT COST ***		TCIC	\$540,838	\$540,838	\$540,838	\$540,838
(DCC+ICC+CONT)						

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	150	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR - VARIABLE CATALYST LIFE ANALYSIS				
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS (catalyst replacement every 6 yrs)		\$25,000	\$25,000	\$25,000	\$25,000
5. ELECTRICITY @ \$0.05/kw-hr		\$523	\$431	\$327	\$216
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL (catalyst)		\$6,250	\$6,250	\$6,250	\$6,250
9. CHEMICALS (ammonia @ \$250/ton, 3.3 lb/hr)		\$2,891	\$2,385	\$1,807	\$1,192
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$36,664	\$36,066	\$35,383	\$34,658
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200
2. ADMINISTRATIVE (0.02*TCIC)		\$10,817	\$10,817	\$10,817	\$10,817
3. PROPERTY TAX (0.01*TCIC)		\$5,408	\$5,408	\$5,408	\$5,408
4. INSURANCE (0.01*TCIC)		\$5,408	\$5,408	\$5,408	\$5,408
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$22,834	\$22,834	\$22,834	\$22,834
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$59,497	\$58,900	\$58,217	\$57,492
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$540,838	\$540,838	\$540,838	\$540,838
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$88,019	\$88,019	\$88,019	\$88,019
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$59,497	\$58,900	\$58,217	\$57,492
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$147,516	\$146,919	\$146,236	\$145,511
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.18	0.18	0.18	0.18
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.03	0.03	0.03	0.03
3. NOx REMOVAL EFFICIENCY (%)		85	85	85	85
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	150	150	150	150
*** NOx REMOVED PER YEAR (TDNS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		80.4	66.3	50.3	33.2
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$1,834	\$2,215	\$2,910	\$4,387

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 150		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE ANALYSIS					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$190,997	\$190,997	\$190,997
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	\$133,643	\$133,643	\$133,643
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$324,640	\$324,640	\$324,640
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)			\$38,199	\$38,199	\$38,199
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)			\$38,199	\$38,199	\$38,199
3. CONSTRUCTION FEE (0.20PEC)			\$38,199	\$38,199	\$38,199
4. STARTUP (0.04PEC)			\$7,640	\$7,640	\$7,640
5. PERFORMANCE TEST (0.02PEC)			\$3,820	\$3,820	\$3,820
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$126,058	\$126,058	\$126,058
C. CONTINGENCY (0.20*(DCC+ICC))		CONT	\$90,140	\$90,140	\$90,140
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$540,838	\$540,838	\$540,838

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 150		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE ANALYSIS						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 8 yrs)		\$18,750	\$18,750	\$18,750	\$18,750
5.	ELECTRICITY @ \$0.05/kw-hr		\$523	\$431	\$327	\$216
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)		\$4,688	\$4,688	\$4,688	\$4,688
9.	CHEMICALS (ammonia @ \$250/ton, 3.3 lb/hr)		\$2,891	\$2,385	\$1,807	\$1,192
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$28,851	\$28,254	\$27,571	\$26,846
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200
2.	ADMINISTRATIVE (0.02*TCIC)		\$10,817	\$10,817	\$10,817	\$10,817
3.	PROPERTY TAX (0.01*TCIC)		\$5,408	\$5,408	\$5,408	\$5,408
4.	INSURANCE (0.01*TCIC)		\$5,408	\$5,408	\$5,408	\$5,408
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$22,834	\$22,834	\$22,834	\$22,834
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$51,685	\$51,087	\$50,405	\$49,679
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
	INTEREST RATE		0.1	0.1	0.1	0.1
	CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$540,838	\$540,838	\$540,838	\$540,838
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$88,019	\$88,019	\$88,019	\$88,019
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$51,685	\$51,087	\$50,405	\$49,679
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$139,704	\$139,106	\$138,423	\$137,698
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.18	0.18	0.18	0.18
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.03	0.03	0.03	0.03
3.	NO _x REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	150	150	150	150
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		80.4	66.3	50.3	33.2
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,737	\$2,097	\$2,754	\$4,151

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 250		PEERLESS, 1992		1992 DOLLARS	
FUEL TYPE: NATURAL GAS					
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
	PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP			
	CEM SYSTEM				
	INSTRUMENTATION				
	SALES TAX				
	FREIGHT				
	*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$270,100	\$270,100	\$270,100
2. DIRECT INSTALLATION COST (DIC)					
	*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$189,000	\$189,000	\$189,000
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
	*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$459,100	\$459,100	\$459,100
B. INDIRECT CAPITAL COST (ICC)					
	1. ENGINEERING (0.20PEC)		\$54,020	\$54,020	\$54,020
	2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$54,020	\$54,020	\$54,020
	3. CONSTRUCTION FEE (0.20PEC)		\$54,020	\$54,020	\$54,020
	4. STARTUP (0.04PEC)		\$10,804	\$10,804	\$10,804
	5. PERFORMANCE TEST (0.02PEC)		\$5,402	\$5,402	\$5,402
	*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$178,266	\$178,266	\$178,266
C. CONTINGENCY (0.20*(DCC+ICC))		CONT	\$127,473	\$127,473	\$127,473
	*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$764,839	\$764,839	\$764,839

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr):	250	PEERLESS, 1992	1992 DOLLARS			
FUEL TYPE:	NATURAL GAS					
CONTROL METHOD:	SCR - VARIABLE CATALYST LIFE					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR (semi-annual inspection)	\$2,000	\$2,000	\$2,000	\$2,000	
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 6 yrs)	\$41,667	\$41,667	\$41,667	\$41,667	
5.	ELECTRICITY @ \$0.05/kw-hr	\$523	\$431	\$327	\$216	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)	\$10,417	\$10,417	\$10,417	\$10,417	
9.	CHEMICALS (ammonia @ \$250/ton, 5.5 lb/hr)	\$4,818	\$3,975	\$3,011	\$1,987	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$59,424	\$58,489	\$57,421	\$56,286
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$1,200	\$1,200	\$1,200	\$1,200	
2.	ADMINISTRATIVE (0.02*TCIC)	\$15,297	\$15,297	\$15,297	\$15,297	
3.	PROPERTY TAX (0.01*TCIC)	\$7,648	\$7,648	\$7,648	\$7,648	
4.	INSURANCE (0.01*TCIC)	\$7,648	\$7,648	\$7,648	\$7,648	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$31,794	\$31,794	\$31,794	\$31,794
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$91,218	\$90,283	\$89,215	\$88,080
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$764,839	\$764,839	\$764,839	\$764,839	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$124,474	\$124,474	\$124,474	\$124,474
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$91,218	\$90,283	\$89,215	\$88,080
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$215,692	\$214,757	\$213,689	\$212,554
B. NO _x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.04	0.04	0.04	0.04
3.	NO _x REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	250	250	250	250
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		178.7	147.4	111.7	73.7
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,207	\$1,457	\$1,913	\$2,883

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	250	PEERLESS, 1992	1992 DOLLARS		
FUEL TYPE:	NATURAL GAS				
CONTROL METHOD:	SCR - VARIABLE CATALYST LIFE				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$270,100	\$270,100	\$270,100	\$270,100
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$189,000	\$189,000	\$189,000	\$189,000
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$459,100	\$459,100	\$459,100	\$459,100
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING (0.20PEC)		\$54,020	\$54,020	\$54,020	\$54,020
2. CONSTRUCTION AND FIELD EXPENSES (0.20PEC)		\$54,020	\$54,020	\$54,020	\$54,020
3. CONSTRUCTION FEE (0.20PEC)		\$54,020	\$54,020	\$54,020	\$54,020
4. STARTUP (0.04PEC)		\$10,804	\$10,804	\$10,804	\$10,804
5. PERFORMANCE TEST (0.02PEC)		\$5,402	\$5,402	\$5,402	\$5,402
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$178,266	\$178,266	\$178,266	\$178,266
C. CONTINGENCY (0.20*(DCC+ICC))					
	CONT	\$127,473	\$127,473	\$127,473	\$127,473
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$764,839	\$764,839	\$764,839	\$764,839
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: FIELD ERRECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 250		PEERLESS, 1992		1992 DOLLARS		
FUEL TYPE: NATURAL GAS						
CONTROL METHOD: SCR - VARIABLE CATALYST LIFE						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR (semi-annual inspection)		\$2,000	\$2,000	\$2,000	\$2,000
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement every 8 yrs)		\$31,250	\$31,250	\$31,250	\$31,250
5.	ELECTRICITY @ \$0.05/kw-hr		\$523	\$431	\$327	\$216
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)		\$7,813	\$7,813	\$7,813	\$7,813
9.	CHEMICALS (ammonia @ \$250/ton, 5.5 lb/hr)		\$4,818	\$3,975	\$3,011	\$1,987
10.	OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$46,403	\$45,469	\$44,400	\$43,266
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)		\$1,200	\$1,200	\$1,200	\$1,200
2.	ADMINISTRATIVE (0.02*TCIC)		\$15,297	\$15,297	\$15,297	\$15,297
3.	PROPERTY TAX (0.01*TCIC)		\$7,648	\$7,648	\$7,648	\$7,648
4.	INSURANCE (0.01*TCIC)		\$7,648	\$7,648	\$7,648	\$7,648
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$31,794	\$31,794	\$31,794	\$31,794
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$78,197	\$77,262	\$76,194	\$75,059
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$764,839	\$764,839	\$764,839	\$764,839
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$124,474	\$124,474	\$124,474	\$124,474
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$78,197	\$77,262	\$76,194	\$75,059
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$202,671	\$201,736	\$200,668	\$199,533
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.24	0.24	0.24	0.24
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.04	0.04	0.04	0.04
3.	NOx REMOVAL EFFICIENCY (%)		85	85	85	85
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	250	250	250	250
*** NOx REMOVED PER YEAR (TONS/YR) ***						
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			178.7	147.4	111.7	73.7
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$1,134	\$1,368	\$1,797	\$2,707

**APPENDIX F. ANNUAL COSTS OF RETROFIT NO_x CONTROLS:
COAL-FIRED ICI BOILERS**

This appendix contains cost spreadsheets for coal-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10 percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

<u>Boiler and NO_x Control</u>	<u>Page</u>
Field-erected watertube, 766 MMBtu/hr, with LNB	F-3
FBC boiler, 460 MMBtu/hr, with urea-based SNCR	F-5
Field-erected watertube, 760 MMBtu/hr, with SCR	F-7
Boiler, 800 MMBtu/hr, with ammonia-based SNCR	F-9
Tangential-fired, 1,255 MMBtu/hr, with ammonia-based SNCR	F-11
PC boiler, 2,361, 2,870, and 6,800 MMBtu/hr, with ammonia-based SNCR	F-13
Coal-fired, 8,055 MMBtu/hr, with ammonia-based SNCR	F-19
Wall-fired, 400 MMBtu/hr, with urea-based SNCR	F-21
Spreader stoker, 303 MMBtu/hr, with urea-based SNCR	F-23

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	766	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	COAL				
CONTROL METHOD:	LOW NO _x BURNER				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$1,195,653	\$1,195,653	\$1,195,653	\$1,195,653
CEM SYSTEM					
INSTRUMENTATION		\$59,783	\$59,783	\$59,783	\$59,783
SALES TAX					
FREIGHT		\$62,772	\$62,772	\$62,772	\$62,772
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$1,318,207	\$1,318,207	\$1,318,207	\$1,318,207
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$655,616	\$655,616	\$655,616	\$655,616
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$1,973,823	\$1,973,823	\$1,973,823	\$1,973,823
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$278,986	\$278,986	\$278,986	\$278,986
2. CONSTRUCTION AND FIELD EXPENSES		\$165,399	\$165,399	\$165,399	\$165,399
3. CONSTRUCTION FEE		\$49,819	\$49,819	\$49,819	\$49,819
4. STARTUP		\$79,710	\$79,710	\$79,710	\$79,710
5. PERFORMANCE TEST		\$39,855	\$39,855	\$39,855	\$39,855
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$613,768	\$613,768	\$613,768	\$613,768
C. CONTINGENCY (20 percent of direct and indirect)	CONT	\$517,518	\$517,518	\$517,518	\$517,518
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$3,105,110	\$3,105,110	\$3,105,110	\$3,105,110
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	766	CIBO, 1992	1992 DOLLARS		
FUEL TYPE:	COAL				
CONTROL METHOD:	LOW NO _x BURNER				
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR		\$21,105	\$21,105	\$21,105	\$21,105
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS		\$24,120	\$24,120	\$24,120	\$24,120
4. REPLACEMENT MATERIALS		\$50,250	\$50,250	\$50,250	\$50,250
5. ELECTRICITY @ \$0.05/kW-hr		\$33,440	\$27,588	\$20,900	\$13,794
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$128,915	\$123,063	\$116,375	\$109,269
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD		\$25,125	\$25,125	\$25,125	\$25,125
2. ADMINISTRATIVE		\$49,848	\$49,848	\$49,848	\$49,848
3. PROPERTY TAX		\$24,924	\$24,924	\$24,924	\$24,924
4. INSURANCE		\$24,924	\$24,924	\$24,924	\$24,924
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$124,821	\$124,821	\$124,821	\$124,821
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$253,736	\$247,884	\$241,196	\$234,090
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$3,105,110	\$3,105,110	\$3,105,110	\$3,105,110
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$505,342	\$505,342	\$505,342	\$505,342
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$253,736	\$247,884	\$241,196	\$234,090
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$759,078	\$753,226	\$746,538	\$739,432
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.7	0.7	0.7	0.7
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.35	0.35	0.35	0.35
3. NO _x REMOVAL EFFICIENCY (%)		50	50	50	50
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	766	766	766	766
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		939.4	775.0	587.1	387.5
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$808	\$972	\$1,271	\$1,908

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	CIRCULATING FLUIDIZED BED	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	460	MALCO FUEL TECH, 1992	1992 DOLLARS		
FUEL TYPE:	COAL				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	OIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC				
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
CONT	CONT				
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$680,930	\$680,930	\$680,930	\$680,930
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: CIRCULATING FLUIDIZED BED		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 460		MALCO FUEL TECH, 1992		1992 DOLLARS		
FUEL TYPE: COAL						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***		DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE					
3.	PROPERTY TAX					
4.	INSURANCE					
5.	OTHER					
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$197,186	\$166,116	\$130,608	\$92,880
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$680,930	\$680,930	\$680,930	\$680,930
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$110,818	\$110,818	\$110,818	\$110,818
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$197,186	\$166,116	\$130,608	\$92,880
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$308,004	\$276,934	\$241,426	\$203,698
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.32	0.32	0.32	0.32
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.08	0.08	0.08	0.08
3.	NO _x REMOVAL EFFICIENCY (%)		75	75	75	75
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	460	460	460	460
*** NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			386.8	319.1	241.8	159.6
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$796	\$868	\$999	\$1,277

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: FIELD ERECTED WATERTUBE		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 766		UTILITY BOILERS ACT, 1994		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SCR					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
AMMONIA STORAGE AND HANDLING	EQP	\$309,347	\$309,347	\$309,347	\$309,347
SCR REACTOR (no catalyst)		\$1,003,377	\$1,003,377	\$1,003,377	\$1,003,377
FLUE GAS HANDLING		\$1,698,741	\$1,698,741	\$1,698,741	\$1,698,741
AIR HEATER MODIFICATIONS		\$382,683	\$382,683	\$382,683	\$382,683
CATALYST (\$400/CFT)		\$3,129,471	\$3,129,471	\$3,129,471	\$3,129,471
FANS		\$50,669	\$50,669	\$50,669	\$50,669
MISCELLANEOUS		\$93,337	\$93,337	\$93,337	\$93,337
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$6,667,626	\$6,667,626	\$6,667,626	\$6,667,626
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	INCLUDED	INCLUDED	INCLUDED	INCLUDED
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$6,667,626	\$6,667,626	\$6,667,626	\$6,667,626
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$634,387	\$634,387	\$634,387	\$634,387
2. CONSTRUCTION AND FIELD EXPENSES		\$1,509,031	\$1,509,031	\$1,509,031	\$1,509,031
3. CONSTRUCTION FEE		\$754,665	\$754,665	\$754,665	\$754,665
4. STARTUP		\$67,788	\$67,788	\$67,788	\$67,788
5. PERFORMANCE TEST		\$33,894	\$33,894	\$33,894	\$33,894
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$2,999,765	\$2,999,765	\$2,999,765	\$2,999,765
C. CONTINGENCY (20 percent of direct and indirect)		CONT			
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$11,600,869	\$11,600,869	\$11,600,869	\$11,600,869

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS		
BOILER TYPE:	FIELD ERECTED WATERTUBE	CHAP. 6 REFERENCES
BOILER CAPACITY (MMBtu/hr):	766	UTILITY BOILERS ACT, 1994
FUEL TYPE:	COAL	COST BASE
CONTROL METHOD:	SCR	1992 DOLLARS

ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR				
		0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR	\$96,480	\$96,480	\$96,480	\$96,480	
2.	MAINTENANCE LABOR	\$55,275	\$55,275	\$55,275	\$55,275	
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS (catalyst replacement)	\$948,324	\$782,368	\$592,703	\$391,184	
5.	ELECTRICITY @ \$0.05/kW-hr	\$251,515	\$207,500	\$157,197	\$103,750	
6.	STEAM	\$9,600	\$7,920	\$6,000	\$3,960	
7.	FUEL					
8.	WASTE DISPOSAL (catalyst)	\$30,455	\$25,125	\$19,034	\$12,563	
9.	CHEMICALS	\$49,600	\$40,920	\$31,000	\$20,460	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$1,441,249	\$1,215,588	\$957,689	\$683,671
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE	\$91,455	\$91,455	\$91,455	\$91,455	
3.	PROPERTY TAX	\$139,690	\$139,690	\$139,690	\$139,690	
4.	INSURANCE	\$169,845	\$169,845	\$169,845	\$169,845	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$570,835	\$570,835	\$570,835	\$570,835
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$2,012,084	\$1,786,423	\$1,528,524	\$1,254,506

COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10	
INTEREST RATE		0.1	0.1	0.1	0.1	
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627	
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$11,600,869	\$11,600,869	\$11,600,869	\$11,600,869	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$1,887,988	\$1,887,988	\$1,887,988	\$1,887,988
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$2,012,084	\$1,786,423	\$1,528,524	\$1,254,506
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$3,900,072	\$3,674,411	\$3,416,512	\$3,142,494
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.7	0.7	0.7	0.7
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.14	0.14	0.14	0.14
3.	NOx REMOVAL EFFICIENCY (%)		80	80	80	80
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	766	766	766	766
***	NOx REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			1503	1240	939	620
***	COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$2,595	\$2,963	\$3,637	\$5,068

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	BOILER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	800	Exxon, 1990	1992 DOLLARS		
FUEL TYPE:	COAL				
CONTROL METHOD:	SNCR - AMMONIA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$265,776	\$265,776	\$265,776	\$265,776
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$7,973	\$7,973	\$7,973	\$7,973
FREIGHT		\$13,289	\$13,289	\$13,289	\$13,289
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$287,038	\$287,038	\$287,038	\$287,038
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$89,910	\$89,910	\$89,910	\$89,910
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$376,948	\$376,948	\$376,948	\$376,948
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$66,222	\$66,222	\$66,222	\$66,222
2. CONSTRUCTION AND FIELD EXPENSES		\$36,999	\$36,999	\$36,999	\$36,999
3. CONSTRUCTION FEE		\$32,071	\$32,071	\$32,071	\$32,071
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$134,179	\$134,179	\$134,179	\$134,179
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$269,471	\$269,471	\$269,471	\$269,471
C. CONTINGENCY (15 percent of direct and indirect)					
	CONT	\$76,836	\$76,836	\$76,836	\$76,836
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$723,255	\$723,255	\$723,255	\$723,255
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	BOILER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	800	Exxon, 1990	1992 DOLLARS		
FUEL TYPE:	COAL				
CONTROL METHOD:	SNCR - AMMONIA				
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kw-hr		\$612,850	\$505,601	\$383,031	\$252,800
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. AMMONIA (@ \$250/TON)		\$324,120	\$267,399	\$202,575	\$133,700
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$936,970	\$773,000	\$585,606	\$386,500
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF LABOR & MAINTENANCE MATL)					
2. ADMINISTRATIVE (2% OF TCIC)		\$14,465	\$14,465	\$14,465	\$14,465
3. PROPERTY TAX (1% OF TCIC)		\$7,233	\$7,233	\$7,233	\$7,233
4. INSURANCE (1% OF TCIC)		\$7,233	\$7,233	\$7,233	\$7,233
5. OTHER					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$28,930	\$28,930	\$28,930	\$28,930
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$965,900	\$801,930	\$614,536	\$415,430
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAP. TAL INVESTMENT COSTS (TCIC, above)		\$723,255	\$723,255	\$723,255	\$723,255
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$117,706	\$117,706	\$117,706	\$117,706
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$965,900	\$801,930	\$614,536	\$415,430
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$1,083,606	\$919,637	\$732,243	\$533,137
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.7	0.7	0.7	0.7
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.39	0.39	0.39	0.39
3. NOx REMOVAL EFFICIENCY (%)		45	45	45	45
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	800	800	800	800
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		883	728	552	364
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$1,227	\$1,262	\$1,327	\$1,464

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: TANGENTIAL FIRED UTILITY BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 1255		Exxon, 1991		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$414,985	\$414,985	\$414,985	\$414,985
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$12,450	\$12,450	\$12,450	\$12,450
FREIGHT		\$20,749	\$20,749	\$20,749	\$20,749
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$448,184	\$448,184	\$448,184	\$448,184
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$196,519	\$196,519	\$196,519	\$196,519
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$644,703	\$644,703	\$644,703	\$644,703
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$88,195	\$88,195	\$88,195	\$88,195
2. CONSTRUCTION AND FIELD EXPENSES		\$80,868	\$80,868	\$80,868	\$80,868
3. CONSTRUCTION FEE		\$124,202	\$124,202	\$124,202	\$124,202
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$169,037	\$169,037	\$169,037	\$169,037
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$462,302	\$462,302	\$462,302	\$462,302
C. CONTINGENCY (15 percent of direct and indirect)	CONT	\$140,695	\$140,695	\$140,695	\$140,695
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$1,247,701	\$1,247,701	\$1,247,701	\$1,247,701

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: TANGENTIAL FIRED UTILITY BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 1255		Exxon, 1991		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr		\$220,051	\$181,542	\$137,532	\$90,771
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. AMMONIA (@ \$250/TON)		\$711,750	\$587,194	\$444,844	\$293,597
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$931,801	\$768,736	\$582,376	\$384,368
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF LABOR & MAINTENANCE MATL)					
2. ADMINISTRATIVE (2% OF TCIC)		\$24,954	\$24,954	\$24,954	\$24,954
3. PROPERTY TAX (1% OF TCIC)		\$12,477	\$12,477	\$12,477	\$12,477
4. INSURANCE (1% OF TCIC)		\$12,477	\$12,477	\$12,477	\$12,477
5. OTHER					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$49,908	\$49,908	\$49,908	\$49,908
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$981,709	\$818,644	\$632,284	\$434,276
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$1,247,701	\$1,247,701	\$1,247,701	\$1,247,701
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$203,058	\$203,058	\$203,058	\$203,058
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$981,709	\$818,644	\$632,284	\$434,276
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$1,184,767	\$1,021,702	\$835,341	\$637,334
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.7	0.7	0.7	0.7
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.39	0.39	0.39	0.39
3. NOx REMOVAL EFFICIENCY (%)		45	45	45	45
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	1255	1255	1255	1255
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		1385	1143	866	571
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$855	\$894	\$965	\$1,115

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PC BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 2361		Exxon, 1992		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$463,810	\$463,810	\$463,810	\$463,810
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$13,914	\$13,914	\$13,914	\$13,914
FREIGHT		\$23,191	\$23,191	\$23,191	\$23,191
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$500,915	\$500,915	\$500,915	\$500,915
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$114,420	\$114,420	\$114,420	\$114,420
3. SITE PREP, SP (as required)					
	SP				
4. BUILDINGS, BLDG (as required)					
	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$615,335	\$615,335	\$615,335	\$615,335
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$328,950	\$328,950	\$328,950	\$328,950
2. CONSTRUCTION AND FIELD EXPENSES		\$35,017	\$35,017	\$35,017	\$35,017
3. CONSTRUCTION FEE		\$47,600	\$47,600	\$47,600	\$47,600
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$506,100	\$506,100	\$506,100	\$506,100
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$917,667	\$917,667	\$917,667	\$917,667
C. CONTINGENCY (15 percent of direct and indirect)					
	CONT	\$154,035	\$154,035	\$154,035	\$154,035
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$1,687,037	\$1,687,037	\$1,687,037	\$1,687,037
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: PC BOILER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 2361		Exxon, 1992		1992 DOLLARS		
FUEL TYPE: COAL						
CONTROL METHOD: SNCR - AMMONIA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr	\$283,824	\$234,155	\$177,390	\$117,077	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	AMMONIA (@ \$250/TON)	\$952,650	\$785,936	\$595,406	\$392,968	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$1,236,474	\$1,020,091	\$772,796	\$510,046
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF LABOR & MAINTENANCE MATL)					
2.	ADMINISTRATIVE (2% OF TCIC)	\$33,741	\$33,741	\$33,741	\$33,741	
3.	PROPERTY TAX (1% OF TCIC)	\$16,870	\$16,870	\$16,870	\$16,870	
4.	INSURANCE (1% OF TCIC)	\$16,870	\$16,870	\$16,870	\$16,870	
5.	OTHER					
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$67,481	\$67,481	\$67,481	\$67,481
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$1,303,955	\$1,087,573	\$840,278	\$577,527
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$1,687,037	\$1,687,037	\$1,687,037	\$1,687,037	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$274,558	\$274,558	\$274,558	\$274,558
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$1,303,955	\$1,087,573	\$840,278	\$577,527
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$1,578,513	\$1,362,130	\$1,114,835	\$852,085
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.7	0.7	0.7	0.7
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.39	0.39	0.39	0.39
3.	NO _x REMOVAL EFFICIENCY (%)		45	45	45	45
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	2361	2361	2361	2361
***	NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		2606	2150	1629	1075
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$606	\$634	\$684	\$793

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 2870		Exxon, 1989		1992 DOLLARS	
FUEL TYPE: PULVERIZED COAL					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$566,549	\$566,549	\$566,549	\$566,549
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$16,996	\$16,996	\$16,996	\$16,996
FREIGHT		\$28,327	\$28,327	\$28,327	\$28,327
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$611,873	\$611,873	\$611,873	\$611,873
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$184,494	\$184,494	\$184,494	\$184,494
3. SITE PREP. SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$796,367	\$796,367	\$796,367	\$796,367
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$326,368	\$326,368	\$326,368	\$326,368
2. CONSTRUCTION AND FIELD EXPENSES		\$65,034	\$65,034	\$65,034	\$65,034
3. CONSTRUCTION FEE		\$116,607	\$116,607	\$116,607	\$116,607
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$901,397	\$901,397	\$901,397	\$901,397
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$1,409,406	\$1,409,406	\$1,409,406	\$1,409,406
C. CONTINGENCY (15 percent of direct and indirect)		CONT			
		\$195,656	\$195,656	\$195,656	\$195,656
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$2,401,430	\$2,401,430	\$2,401,430	\$2,401,430

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: BOILER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 2870		Exxon, 1989		1992 DOLLARS		
FUEL TYPE: PULVERIZED COAL						
CONTROL METHOD: SNCR - AMMONIA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. AMMONIA (@ \$250/TON)						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC	\$1,377,335	\$1,136,301	\$860,834	\$568,151
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF LABOR & MAINTENANCE MATL)						
2. ADMINISTRATIVE (2% OF TCIC)						
3. PROPERTY TAX (1% OF TCIC)						
4. INSURANCE (1% OF TCIC)						
5. OTHER						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$96,057	\$96,057	\$96,057	\$96,057
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***		O&M	\$1,473,392	\$1,232,358	\$956,891	\$664,208
		(DAC+IAC)				
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS						
INTEREST RATE						
CAPITAL RECOVERY FACTOR						
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)						
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$390,822	\$390,822	\$390,822	\$390,822
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$1,473,392	\$1,232,358	\$956,891	\$664,208
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$1,864,214	\$1,623,180	\$1,347,713	\$1,055,029
B. NO_x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)						
2. CONTROLLED NO _x LEVEL (lb/MMBtu)						
3. NO _x REMOVAL EFFICIENCY (%)						
4. CAPACITY FACTOR						
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)						
*** NO _x REMOVED PER YEAR (TONS/YR) ***			3168	2613	1980	1307
		[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000				
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$588	\$621	\$681	\$807

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PC BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 6800		Exxon, 1992		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$1,006,700	\$1,006,700	\$1,006,700	\$1,006,700
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$30,201	\$30,201	\$30,201	\$30,201
FREIGHT		\$50,335	\$50,335	\$50,335	\$50,335
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$1,087,236	\$1,087,236	\$1,087,236	\$1,087,236
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$214,610	\$214,610	\$214,610	\$214,610
3. SITE PREP, SP (as required)					
	SP				
4. BUILDINGS, BLDG (as required)					
	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$1,301,846	\$1,301,846	\$1,301,846	\$1,301,846
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$392,500	\$392,500	\$392,500	\$392,500
2. CONSTRUCTION AND FIELD EXPENSES		\$90,780	\$90,780	\$90,780	\$90,780
3. CONSTRUCTION FEE		\$89,280	\$89,280	\$89,280	\$89,280
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$950,000	\$950,000	\$950,000	\$950,000
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$1,522,560	\$1,522,560	\$1,522,560	\$1,522,560
C. CONTINGENCY (15 percent of direct and indirect)					
	CONT	\$281,161	\$281,161	\$281,161	\$281,161
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$3,105,567	\$3,105,567	\$3,105,567	\$3,105,567
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: PC BOILER	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 6800	E Exxon, 1992	1992 DOLLARS			
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr		\$833,952	\$688,010	\$521,220	\$344,005
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. AMMONIA (@ \$250/TON)		\$2,923,650	\$2,412,011	\$1,827,281	\$1,206,006
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC	\$3,757,602	\$3,100,022	\$2,348,501	\$1,550,011
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD (60% OF LABOR & MAINTENANCE MATL)					
2. ADMINISTRATIVE (2% OF TCIC)		\$62,111	\$62,111	\$62,111	\$62,111
3. PROPERTY TAX (1% OF TCIC)		\$31,056	\$31,056	\$31,056	\$31,056
4. INSURANCE (1% OF TCIC)		\$31,056	\$31,056	\$31,056	\$31,056
5. OTHER					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$124,223	\$124,223	\$124,223	\$124,223
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$3,881,825	\$3,224,244	\$2,472,724	\$1,674,234
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$3,105,567	\$3,105,567	\$3,105,567	\$3,105,567
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$505,417	\$505,417	\$505,417	\$505,417
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$3,881,825	\$3,224,244	\$2,472,724	\$1,674,234
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$4,387,241	\$3,729,661	\$2,978,141	\$2,179,650
B. NOx REMOVAL PER YEAR					
1. BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.7	0.7	0.7	0.7
2. CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.39	0.39	0.39	0.39
3. NOx REMOVAL EFFICIENCY (%)		45	45	45	45
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	6800	6800	6800	6800
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		7506	6192	4691	3096
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$585	\$602	\$635	\$704

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: BOILER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 8055		Exxon, 1990		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$1,078,918	\$1,078,918	\$1,078,918	\$1,078,918
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX		\$32,368	\$32,368	\$32,368	\$32,368
FREIGHT		\$53,946	\$53,946	\$53,946	\$53,946
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$1,165,231	\$1,165,231	\$1,165,231	\$1,165,231
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$1,085,967	\$1,085,967	\$1,085,967	\$1,085,967
3. SITE PREP, SP (as required)					
	SP				
4. BUILDINGS, BLDG (as required)					
	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC	\$2,251,198	\$2,251,198	\$2,251,198	\$2,251,198
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING		\$397,369	\$397,369	\$397,369	\$397,369
2. CONSTRUCTION AND FIELD EXPENSES		\$121,081	\$121,081	\$121,081	\$121,081
3. CONSTRUCTION FEE		\$119,459	\$119,459	\$119,459	\$119,459
4. ONE-TIME ROYALTY FEE (NO CONTINGENCY ON THIS)		\$1,680,539	\$1,680,539	\$1,680,539	\$1,680,539
5. OTHERS					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	\$2,318,449	\$2,318,449	\$2,318,449	\$2,318,449
C. CONTINGENCY (15 percent of direct and indirect)					
	CONT	\$433,366	\$433,366	\$433,366	\$433,366
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$5,003,013	\$5,003,013	\$5,003,013	\$5,003,013
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: BOILER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 8055		Exxon, 1990		1992 DOLLARS		
FUEL TYPE: COAL						
CONTROL METHOD: SNCR - AMMONIA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. AMMONIA (@ \$250/TON)						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		OAC	\$3,653,446	\$3,014,093	\$2,283,404	\$1,507,046
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD (60% OF LABOR & MAINTENANCE MATL)						
2. ADMINISTRATIVE (2% OF TCIC)						
3. PROPERTY TAX (1% OF TCIC)						
4. INSURANCE (1% OF TCIC)						
5. OTHER						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC	\$200,121	\$200,121	\$200,121	\$200,121
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$3,853,566	\$3,214,213	\$2,483,524	\$1,707,167
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$5,003,013	\$5,003,013	\$5,003,013	\$5,003,013
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$814,217	\$814,217	\$814,217	\$814,217
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$3,853,566	\$3,214,213	\$2,483,524	\$1,707,167
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$4,667,784	\$4,028,431	\$3,297,741	\$2,521,384
B. NOx REMOVAL PER YEAR						
1. BASELINE NOx LEVEL (lb/MMBtu)		(NOx)1	0.7	0.7	0.7	0.7
2. CONTROLLED NOx LEVEL (lb/MMBtu)		(NOx)2	0.39	0.39	0.39	0.39
3. NOx REMOVAL EFFICIENCY (%)			45	45	45	45
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	8055	8055	8055	8055
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			8891	7335	5557	3667
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$525	\$549	\$593	\$688

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: WALL-FIRED		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 400		NALCO FUEL TECH, 1994		1992 DOLLARS	
FUEL TYPE: PULVERIZED COAL					
CONTROL METHOD: SNCR - UREA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP	\$580,000	\$580,000	\$580,000	\$580,000
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC	\$580,000	\$580,000	\$580,000	\$580,000
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC	\$177,000	\$177,000	\$177,000	\$177,000
3. SITE PREP, SP (as required)					
	SP				
4. BUILDINGS, BLDG (as required)					
	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC	\$757,000	\$757,000	\$757,000	\$757,000
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC	Included	Included	Included	Included
C. CONTINGENCY (10 PERCENT - not considered by NALCO)					
	CONT	\$75,700	\$75,700	\$75,700	\$75,700
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$832,700	\$832,700	\$832,700	\$832,700

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: WALL-FIRED		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 400		NALCO FUEL TECH, 1994		1992 DOLLARS		
FUEL TYPE: PULVERIZED COAL						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS		\$10,600	\$10,600	\$10,600	\$10,600
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr		\$8,376	\$6,911	\$5,235	\$3,455
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS		\$303,059	\$227,294	\$189,412	\$125,012
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$322,035	\$244,805	\$205,247	\$139,067
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE					
3.	PROPERTY TAX					
4.	INSURANCE					
5.	OTHER					
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	Included	Included	Included	Included
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$322,035	\$244,805	\$205,247	\$139,067
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
	INTEREST RATE		0.1	0.1	0.1	0.1
	CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$832,700	\$832,700	\$832,700	\$832,700
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$135,518	\$135,518	\$135,518	\$135,518
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$322,035	\$244,805	\$205,247	\$139,067
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$457,553	\$380,323	\$340,765	\$274,585
B. NOx REMOVAL PER YEAR						
1.	BASELINE NOx LEVEL (lb/MMBtu)	(NOx)1	0.7	0.7	0.7	0.7
2.	CONTROLLED NOx LEVEL (lb/MMBtu)	(NOx)2	0.39	0.39	0.39	0.39
3.	NOx REMOVAL EFFICIENCY (%)		45	45	45	45
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	400	400	400	400
***	NOx REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000		441.5	364.2	275.9	182.1
***	COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***		\$1,036	\$1,044	\$1,235	\$1,508

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: SPREADER STOKER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 303		NALCO FUEL TECH, 1992		1992 DOLLARS	
FUEL TYPE: COAL					
CONTROL METHOD: SNCR - UREA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP) EQP					
CEM SYSTEM					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
*** TOTAL PURCHASED EQUIPMENT COST *** PEC					
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST *** DIC					
3. SITE PREP, SP (as required) SP					
4. BUILDINGS, BLDG (as required) BLDG					
*** TOTAL DIRECT CAPITAL COST *** DCC (PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST *** ICC					
C. CONTINGENCY CONT					
*** TOTAL CAPITAL INVESTMENT COST *** TCIC (DCC+ICC+CONT)		\$360,360	\$360,360	\$360,360	\$360,360

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: SPREADER STOKER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 303		NALCO FUEL TECH, 1992		1992 DOLLARS		
FUEL TYPE: COAL						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***					
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE					
3.	PROPERTY TAX					
4.	INSURANCE					
5.	OTHER					
***	TOTAL INDIRECT ANNUAL COSTS ***					
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	\$366,912	\$302,702	\$229,320	\$151,351	
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$360,360	\$360,360	\$360,360	\$360,360	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	\$58,647	\$58,647	\$58,647	\$58,647	
2.	ANNUAL O&M COSTS (O&M, above)	\$366,912	\$302,702	\$229,320	\$151,351	
***	TOTAL ANNUALIZED COST ***	\$425,559	\$361,349	\$287,967	\$209,998	
B. NO _x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.53	0.53	0.53	0.53
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.22	0.22	0.22	0.22
3.	NO _x REMOVAL EFFICIENCY (%)		58	58	58	58
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	303	303	303	303
***	NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		326.4	269.3	204.0	134.6
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,304	\$1,342	\$1,412	\$1,560

**APPENDIX G. ANNUAL COSTS OF RETROFIT NO_x CONTROLS:
NONFOSSIL-FUEL-FIRED ICI BOILERS**

This appendix contains cost spreadsheets for nonfossil-fuel-fired boilers retrofitted with various NO_x controls. The spreadsheets are based on data from actual boiler retrofit experiences or studies. Capital annualization for all analyses are based on a 10-year amortization period and a 10-percent interest rate. All costs presented are in 1992 dollars. For further information on the methodology and assumptions made in these cost analyses, see Chapter 6.

This appendix contains cost spreadsheets for the following boilers:

<u>Boiler and NO_x Control</u>	<u>Page</u>
Wood-Fired:	
Stoker, 190, 225, 300, 395, and 500 MMBtu/hr, with urea-based SNCR	G-3
FBC boiler, 250 MMBtu/hr, with ammonia-based SNCR	G-13
Paper-Fired:	
Packaged watertube, 72 and 172 MMBtu/hr, with urea-based SNCR	G-15
MSW-Fired:	
Stoker, 108, 121, and 325 MMBtu/hr, with urea-based SNCR	G-19

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	190	NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE:	WOOD				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC				
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY	CONT				
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$424,113	\$424,113	\$424,113	\$424,113

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: STOKER		CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr): 190		NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE: WOOD					
CONTROL METHOD: SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD					
2. ADMINISTRATIVE					
3. PRDPERTY TAX					
4. INSURANCE					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$78,532	\$66,930	\$53,671	\$39,583
(DAC+IAC)					
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$424,113	\$424,113	\$424,113	\$424,113
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$69,023	\$69,023	\$69,023	\$69,023
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$78,532	\$66,930	\$53,671	\$39,583
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$147,555	\$135,953	\$122,693	\$108,605
B. NO _x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.25	0.25	0.25	0.25
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.11	0.11	0.11	0.11
3. NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	190	190	190	190
*** NO _x REMOVED PER YEAR (TONS/YR) ***					
[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		91.5	75.5	57.2	37.8
*** CDST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,612	\$1,800	\$2,144	\$2,876

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	225	NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE:	WOOD				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC				
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY	CONT				
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$477,853	\$477,853	\$477,853	\$477,853

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: STOKER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 225		NALCO FUEL TECH 1992		1992 DOLLARS		
FUEL TYPE: WOOD						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD						
2. ADMINISTRATIVE						
3. PROPERTY TAX						
4. INSURANCE						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$103,699	\$87,964	\$69,981	\$50,875
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$477,853	\$477,853	\$477,853	\$477,853
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$77,768	\$77,768	\$77,768	\$77,768
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$103,699	\$87,964	\$69,981	\$50,875
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$181,467	\$165,732	\$147,750	\$128,643
B. NO _x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.25	0.25	0.25	0.25
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.11	0.11	0.11	0.11
3. NO _x REMOVAL EFFICIENCY (%)			55	55	55	55
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	225	225	225	225
*** NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			108.4	89.4	67.8	44.7
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$1.674	\$1.853	\$2.181	\$2.877

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	300	NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE:	WOOD				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
	PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP			
	INSTRUMENTATION				
	SALES TAX				
	FREIGHT				
	CEM SYSTEM				
	*** TOTAL PURCHASED EQUIPMENT COST ***	PEC			
2. DIRECT INSTALLATION COST (DIC)					
	*** TOTAL DIRECT INSTALLATION COST ***	DIC			
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
	*** TOTAL DIRECT CAPITAL COST ***	DCC			
	(PEC+DIC+SP+BLDG)				
B. INDIRECT CAPITAL COST (ICC)					
	1. ENGINEERING				
	2. CONSTRUCTION AND FIELD EXPENSES				
	3. CONSTRUCTION FEE				
	4. STARTUP				
	5. PERFORMANCE TEST				
	*** TOTAL INDIRECT CAPITAL COST ***	ICC			
C. CONTINGENCY		CONT			
	*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$595,417	\$595,417	\$595,417
	(DCC+ICC+CONT)				

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr):	300	NALCO FUEL TECH 1992	1992 DOLLARS			
FUEL TYPE:	WOOD					
CONTROL METHOD:	SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE					
3.	PROPERTY TAX					
4.	INSURANCE					
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC				
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$107,809	\$91,949	\$73,822	\$54,563
	(DAC+IAC)					
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$595,417	\$595,417	\$595,417	\$595,417	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$96,901	\$96,901	\$96,901	\$96,901
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$107,809	\$91,949	\$73,822	\$54,563
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$204,710	\$188,850	\$170,724	\$151,464
B. NO _x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.25	0.25	0.25	0.25
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.11	0.11	0.11	0.11
3.	NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	300	300	300	300
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		144.5	119.2	90.3	59.6
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,416	\$1,584	\$1,890	\$2,540

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	395	NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE:	WOOD				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC				
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$641,834	\$641,834	\$641,834	\$641,834

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: STOKER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 395		NALCO FUEL TECH 1992		1992 DOLLARS		
FUEL TYPE: WOOD						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD						
2. ADMINISTRATIVE						
3. PROPERTY TAX						
4. INSURANCE						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$50,263	\$44,707	\$38,358	\$31,612
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$641,834	\$641,834	\$641,834	\$641,834
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$104,456	\$104,456	\$104,456	\$104,456
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$50,263	\$44,707	\$38,358	\$31,612
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$154,719	\$149,163	\$142,814	\$136,068
B. NOx REMOVAL PER YEAR						
1. BASELINE NOx LEVEL (lb/MMBtu)		(NOx)1	0.25	0.25	0.25	0.25
2. CONTROLLED NOx LEVEL (lb/MMBtu)		(NOx)2	0.11	0.11	0.11	0.11
3. NOx REMOVAL EFFICIENCY (%)			55	55	55	55
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	395	395	395	395
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NOx)1-(NOx)2]/2000			190.3	157.0	118.9	78.5
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$813	\$950	\$1,201	\$1,733

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: STOKER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 500		MALCO FUEL TECH 1992		1992 DOLLARS	
FUEL TYPE: WOOD					
CONTRDL METHOD: SNCR - UREA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***					
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***					
3. SITE PREP, SP (as required)					
4. BUILDINGS, BLDG (as required)					
*** TOTAL DIRECT CAPITAL COST ***					
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***					
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST ***					
(DCC+ICC+CONT)		\$650,123	\$650,123	\$650,123	\$650,123

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: STOKER	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 500	NALCO FUEL TECH 1992	1992 DOLLARS			
FUEL TYPE: WOOD					
CONTROL METHOD: SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD					
2. ADMINISTRATIVE					
3. PROPERTY TAX					
4. INSURANCE					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (OAC+IAC)	O&M	\$134,437	\$114,193	\$91,057	\$66,474
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$650,123	\$650,123	\$650,123	\$650,123
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$105,805	\$105,805	\$105,805	\$105,805
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$134,437	\$114,193	\$91,057	\$66,474
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$240,242	\$219,998	\$196,861	\$172,279
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.25	0.25	0.25	0.25
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.11	0.11	0.11	0.11
3. NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	500	500	500	500
*** NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		240.9	198.7	150.6	99.4
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$997	\$1,107	\$1,308	\$1,734

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: FLUIDIZED BED COMBUSTOR (BUBBLING BED)		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 250		HURST, 1988		1992 DOLLARS	
FUEL TYPE: WOOD					
CONTROL METHOD: SNCR - AMMONIA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)		EQP			
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***		PEC	\$203,291	\$203,291	\$203,291
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***		DIC	included	above	included
3. SITE PREP, SP (as required)		SP			
4. BUILDINGS, BLDG (as required)		BLDG			
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)		DCC	\$203,291	\$203,291	\$203,291
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***		ICC	\$88,137	\$88,137	\$88,137
C. CONTINGENCY		CONT			
			included	above	included
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)		TCIC	\$291,428	\$291,428	\$291,428

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: FLUIDIZED BED COMBUSTOR (BUBBLING BED)		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 250		HURST, 1988		1992 DOLLARS		
FUEL TYPE: WOOD						
CONTROL METHOD: SNCR - AMMONIA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kW-hr	\$7,080	\$5,841	\$4,425	\$2,921	
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS (AMMONIA @ \$250/TON)	\$109,600	\$90,420	\$68,500	\$45,210	
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC	\$116,680	\$96,261	\$72,925	\$48,131
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD (60% OF SUM OF ALL LABOR AND MAINTENANCE MATERIALS)	\$0	\$0	\$0	\$0	
2.	ADMINISTRATIVE (0.02*TCIC)	\$5,829	\$5,829	\$5,829	\$5,829	
3.	PROPERTY TAX (0.01*TCIC)	\$2,914	\$2,914	\$2,914	\$2,914	
4.	INSURANCE (0.01*TCIC)	\$2,914	\$2,914	\$2,914	\$2,914	
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC	\$11,657	\$11,657	\$11,657	\$11,657
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS ***	O&M	\$128,337	\$107,918	\$84,582	\$59,788
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.162745	0.162745	0.162745	0.162745	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$291,428	\$291,428	\$291,428	\$291,428	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$47,429	\$47,429	\$47,429	\$47,429
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$128,337	\$107,918	\$84,582	\$59,788
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$175,766	\$155,347	\$132,011	\$107,216
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.25	0.25	0.25	0.25
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.11	0.11	0.11	0.11
3.	NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	250	250	250	250
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		120.5	99.4	75.3	49.7
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,459	\$1,563	\$1,754	\$2,158

COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE:	PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE		
BOILER CAPACITY (MMBtu/hr):	72	NALCO FUEL TECH 1992	1992 DOLLARS		
FUEL TYPE:	PAPER				
CONTROL METHOD:	SNCR - UREA				
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC				
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$225,789	\$225,789	\$225,789	\$225,789
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NOx CONTROLS						
BOILER TYPE: PACKAGED WATERTUBE		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 72		NALCO FUEL TECH 1992		1992 DOLLARS		
FUEL TYPE: PAPER						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD						
2. ADMINISTRATIVE						
3. PROPERTY TAX						
4. INSURANCE						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$54,265	\$45,909	\$36,359	\$26,211
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR ²			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$225,789	\$225,789	\$225,789	\$225,789
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$36,746	\$36,746	\$36,746	\$36,746
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$54,265	\$45,909	\$36,359	\$26,211
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$91,012	\$82,655	\$73,105	\$62,957
B. NOx REMOVAL PER YEAR						
1. BASELINE NOx LEVEL (lb/MMBtu)		(NOx)1	0.5	0.5	0.5	0.5
2. CONTROLLED NOx LEVEL (lb/MMBtu)		(NOx)2	0.23	0.23	0.23	0.23
3. NOx REMOVAL EFFICIENCY (%)			55	55	55	55
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	72	72	72	72
*** NOx REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*((NOx)1-(NOx)2)/2000			69.4	57.2	43.4	28.6
*** COST EFFECTIVENESS (\$/TON NOx REMOVED, 1992 DOLLARS) ***			\$1,312	\$1,444	\$1,686	\$2,200

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS

BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES	COST BASE
BOILER CAPACITY (MMBtu/hr): 172	NALCO FUEL TECH 1992	1992 DOLLARS
FUEL TYPE: PAPER FIBER WASTE		
CONTROL METHOD: SNCR - UREA		

TOTAL CAPITAL INVESTMENT COST (TCIC)

		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC				
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
CONT	CONT				
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$538,776	\$538,776	\$538,776	\$538,776

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: PACKAGED WATERTUBE	CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 172	NALCO FUEL TECH 1992		1992 DOLLARS		
FUEL TYPE: PAPER FIBER WASTE					
CONTROL METHOD: SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)					
1. DVERHEAD					
2. ADMINISTRATIVE					
3. PROPERTY TAX					
4. INSURANCE					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$136,352	\$115,211	\$91,049	\$65,377
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$538,776	\$538,776	\$538,776	\$538,776
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$87,683	\$87,683	\$87,683	\$87,683
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$136,352	\$115,211	\$91,049	\$65,377
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$224,036	\$202,894	\$178,732	\$153,060
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.5	0.5	0.5	0.5
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.23	0.23	0.23	0.23
3. NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	172	172	172	172
*** NO_x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		165.7	136.7	103.6	68.4
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***		\$1,352	\$1,484	\$1,725	\$2,239

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS					
BOILER TYPE: STOKER		CHAP. 6 REFERENCES		COST BASE	
BOILER CAPACITY (MMBtu/hr): 108		NALCO FUEL TECH 1992		1992 DOLLARS	
FUEL TYPE: MUNICIPAL SOLID WASTE					
CONTROL METHOD: SNCR - UREA					
TOTAL CAPITAL INVESTMENT COST (TCIC)					
		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)					
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***					
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***					
3. SITE PREP, SP (as required)					
4. BUILDINGS, BLDG (as required)					
*** TOTAL DIRECT CAPITAL COST ***					
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***					
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST ***					
(DCC+ICC+CONT)		\$424,666	\$424,666	\$424,666	\$424,666

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS					
BOILER TYPE: STOKER	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr): 108	MALCO FUEL TECH 1992	1992 DOLLARS			
FUEL TYPE: MUNICIPAL SOLID WASTE					
CONTROL METHOD: SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)					
	CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)					
1. OPERATING LABOR					
2. MAINTENANCE LABOR					
3. MAINTENANCE MATERIALS					
4. REPLACEMENT MATERIALS					
5. ELECTRICITY @ \$0.05/kW-hr					
6. STEAM					
7. FUEL					
8. WASTE DISPOSAL					
9. CHEMICALS					
10. OTHER					
*** TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)					
1. OVERHEAD					
2. ADMINISTRATIVE					
3. PROPERTY TAX					
4. INSURANCE					
*** TOTAL INDIRECT ANNUAL COSTS ***	IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (OAC+IAC)	O&M	\$82,718	\$70,386	\$56,293	\$41,319
COST EFFECTIVENESS					
A. TOTAL ANNUALIZED COST (incl. capital and O&M)					
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
EXPECTED LIFETIME OF EQUIPMENT, YEARS		10	10	10	10
INTEREST RATE		0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR		0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)		\$424,666	\$424,666	\$424,666	\$424,666
*** ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$69,112	\$69,112	\$69,112	\$69,112
2. ANNUAL O&M COSTS (O&M, above)	O&M	\$82,718	\$70,386	\$56,293	\$41,319
*** TOTAL ANNUALIZED COST ***	ACIC+O&M	\$151,830	\$139,498	\$125,405	\$110,431
B. NO_x REMOVAL PER YEAR					
1. BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.4	0.4	0.4	0.4
2. CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.18	0.18	0.18	0.18
3. NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4. CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	108	108	108	108
*** NO_x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		83.3	68.7	52.0	34.3
*** COST EFFECTIVENESS (\$/TON NO_x REMOVED, 1992 DOLLARS) ***		\$1,824	\$2,031	\$2,410	\$3,216

COST EFFECTIVENESS OF RETROFIT NOx CONTROLS

BOILER TYPE: STOKER	CHAP. 6 REFERENCES	COST BASE
BOILER CAPACITY (MMBtu/hr): 121	NALCO FUEL TECH 1992	1992 DOLLARS
FUEL TYPE: MUNICIPAL SOLID WASTE		
CONTROL METHOD: SNCR - UREA		

TOTAL CAPITAL INVESTMENT COST (TCIC)

		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEN SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST ***	DCC				
(PEC+DIC+SP+BLDG)					
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST ***	TCIC	\$711,461	\$711,461	\$711,461	\$711,461
(DCC+ICC+CONT)					

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE: STOKER		CHAP. 6 REFERENCES		COST BASE		
BOILER CAPACITY (MMBtu/hr): 121		NALCO FUEL TECH 1992		1992 DOLLARS		
FUEL TYPE: MUNICIPAL SOLID WASTE						
CONTROL METHOD: SNCR - UREA						
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
		CAPACITY FACTOR	0.8	0.66	0.5	0.33
A. DIRECT ANNUAL COSTS (DAC)						
1. OPERATING LABOR						
2. MAINTENANCE LABOR						
3. MAINTENANCE MATERIALS						
4. REPLACEMENT MATERIALS						
5. ELECTRICITY @ \$0.05/kW-hr						
6. STEAM						
7. FUEL						
8. WASTE DISPOSAL						
9. CHEMICALS						
10. OTHER						
*** TOTAL DIRECT ANNUAL COSTS ***		DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1. OVERHEAD						
2. ADMINISTRATIVE						
3. PROPERTY TAX						
4. INSURANCE						
*** TOTAL INDIRECT ANNUAL COSTS ***		IAC				
*** TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)		O&M	\$77,928	\$67,883	\$56,402	\$44,204
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1. ANNUALIZED CAPITAL INVESTMENT COST (ACIC)						
EXPECTED LIFETIME OF EQUIPMENT, YEARS			10	10	10	10
INTEREST RATE			0.1	0.1	0.1	0.1
CAPITAL RECOVERY FACTOR			0.1627	0.1627	0.1627	0.1627
TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)			\$711,461	\$711,461	\$711,461	\$711,461
*** ANNUALIZED CAPITAL INVESTMENT COST ***		ACIC	\$115,787	\$115,787	\$115,787	\$115,787
2. ANNUAL O&M COSTS (O&M, above)		O&M	\$77,928	\$67,883	\$56,402	\$44,204
*** TOTAL ANNUALIZED COST ***		ACIC+O&M	\$193,715	\$183,670	\$172,189	\$159,991
B. NO _x REMOVAL PER YEAR						
1. BASELINE NO _x LEVEL (lb/MMBtu)		(NO _x)1	0.4	0.4	0.4	0.4
2. CONTROLLED NO _x LEVEL (lb/MMBtu)		(NO _x)2	0.18	0.18	0.18	0.18
3. NO _x REMOVAL EFFICIENCY (%)			55	55	55	55
4. CAPACITY FACTOR		CF	0.8	0.66	0.5	0.33
5. BOILER HEAT INPUT CAPACITY (MMBtu/hr)		CAP	121	121	121	121
*** NO _x REMOVED PER YEAR (TONS/YR) *** [CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000			93.3	77.0	58.3	38.5
*** COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***			\$2,077	\$2,387	\$2,954	\$4,158

COST EFFECTIVENESS OF RETROFIT NO_x CONTROLS

BOILER TYPE: STOKER	CHAP. 6 REFERENCES	COST BASE
BOILER CAPACITY (MMBtu/hr): 325	NALCO FUEL TECH 1992	1992 DOLLARS
FUEL TYPE: MUNICIPAL SOLID WASTE		
CONTROL METHOD: SNCR - UREA		

TOTAL CAPITAL INVESTMENT COST (TCIC)

		BOILER CAPACITY FACTOR			
		0.8	0.66	0.5	0.33
A. DIRECT CAPITAL COST (DCC)					
1. PURCHASED EQUIPMENT COST (PEC)					
PRIMARY AND AUXILIARY EQUIPMENT (EQP)	EQP				
INSTRUMENTATION					
SALES TAX					
FREIGHT					
CEM SYSTEM					
*** TOTAL PURCHASED EQUIPMENT COST ***	PEC				
2. DIRECT INSTALLATION COST (DIC)					
*** TOTAL DIRECT INSTALLATION COST ***	DIC				
3. SITE PREP, SP (as required)	SP				
4. BUILDINGS, BLDG (as required)	BLDG				
*** TOTAL DIRECT CAPITAL COST *** (PEC+DIC+SP+BLDG)	DCC				
B. INDIRECT CAPITAL COST (ICC)					
1. ENGINEERING					
2. CONSTRUCTION AND FIELD EXPENSES					
3. CONSTRUCTION FEE					
4. STARTUP					
5. PERFORMANCE TEST					
*** TOTAL INDIRECT CAPITAL COST ***	ICC				
C. CONTINGENCY					
*** TOTAL CAPITAL INVESTMENT COST *** (DCC+ICC+CONT)	TCIC	\$1,011,932	\$1,011,932	\$1,011,932	\$1,011,932

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COST EFFECTIVENESS OF RETROFIT NO _x CONTROLS						
BOILER TYPE:	STOKER	CHAP. 6 REFERENCES	COST BASE			
BOILER CAPACITY (MMBtu/hr):	325	NALCO FUEL TECH 1992	1992 DOLLARS			
FUEL TYPE:	MUNICIPAL SOLID WASTE					
CONTROL METHOD:	SNCR - UREA					
ANNUAL OPERATING AND MAINTENANCE COSTS (O&M)						
	CAPACITY FACTOR	0.8	0.66	0.5	0.33	
A. DIRECT ANNUAL COSTS (DAC)						
1.	OPERATING LABOR					
2.	MAINTENANCE LABOR					
3.	MAINTENANCE MATERIALS					
4.	REPLACEMENT MATERIALS					
5.	ELECTRICITY @ \$0.05/kw-hr					
6.	STEAM					
7.	FUEL					
8.	WASTE DISPOSAL					
9.	CHEMICALS					
10.	OTHER					
***	TOTAL DIRECT ANNUAL COSTS ***	DAC				
B. INDIRECT ANNUAL COSTS (IAC)						
1.	OVERHEAD					
2.	ADMINISTRATIVE					
3.	PROPERTY TAX					
4.	INSURANCE					
***	TOTAL INDIRECT ANNUAL COSTS ***	IAC				
***	TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS *** (DAC+IAC)	O&M	\$194,596	\$165,651	\$132,570	\$97,422
COST EFFECTIVENESS						
A. TOTAL ANNUALIZED COST (incl. capital and O&M)						
1.	ANNUALIZED CAPITAL INVESTMENT COST (ACIC)					
	EXPECTED LIFETIME OF EQUIPMENT, YEARS	10	10	10	10	
	INTEREST RATE	0.1	0.1	0.1	0.1	
	CAPITAL RECOVERY FACTOR	0.1627	0.1627	0.1627	0.1627	
	TOTAL CAPITAL INVESTMENT COSTS (TCIC, above)	\$1,011,932	\$1,011,932	\$1,011,932	\$1,011,932	
***	ANNUALIZED CAPITAL INVESTMENT COST ***	ACIC	\$164,687	\$164,687	\$164,687	\$164,687
2.	ANNUAL O&M COSTS (O&M, above)	O&M	\$194,596	\$165,651	\$132,570	\$97,422
***	TOTAL ANNUALIZED COST ***	ACIC+O&M	\$359,284	\$330,338	\$297,258	\$262,110
B. NO_x REMOVAL PER YEAR						
1.	BASELINE NO _x LEVEL (lb/MMBtu)	(NO _x)1	0.4	0.4	0.4	0.4
2.	CONTROLLED NO _x LEVEL (lb/MMBtu)	(NO _x)2	0.18	0.18	0.18	0.18
3.	NO _x REMOVAL EFFICIENCY (%)		55	55	55	55
4.	CAPACITY FACTOR	CF	0.8	0.66	0.5	0.33
5.	BOILER HEAT INPUT CAPACITY (MMBtu/hr)	CAP	325	325	325	325
***	NO _x REMOVED PER YEAR (TONS/YR) ***					
	[CAP*CF*(24 hr/day)*(365 days/yr)]*[(NO _x)1-(NO _x)2]/2000		250.5	206.7	156.6	103.3
***	COST EFFECTIVENESS (\$/TON NO _x REMOVED, 1992 DOLLARS) ***		\$1,434	\$1,598	\$1,898	\$2,536

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16. ABSTRACT This document describes available control techniques for reducing NOx emissions from ICI Boilers. Discussions of NOx formation and uncontrolled emission levels are included. NOx control techniques include staged combustion, low NOx burners, natural gas reburn, Flue gas recirculation, wet injection, selective noncatalytic reduction, and selective catalytic reduction. Achievable NOx emission levels, costs and cost effectiveness and environmental impacts for these controls are presented.		
17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Nonutility boilers Nitrogen Oxide Emissions NOx Control Techniques Costs of Emission Controls Low NOx Burners Natural Gas Reburn Selective Noncatalytic Reduction Selective Catalytic Reduction		
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