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Notice of Construction for Proposed Backup Package Boiler

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ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
API	American Petroleum Institute
ASIL	Acceptable Source Impact Level
BACT	Best Available Control Technology
Btu	British Thermal Unit
Ecology	Washington State Department of Ecology
EPA	U.S. Environmental Protection Agency
gal	gallon
hr	hour
K	kilogram
km	kilometer
lb	pound
m	meter
mi	mile
MMBtu/hr	Million Btu per hour
PM	particulate matter
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gage
s	second
SO2	sulfur dioxide
TAP	toxic air pollutant
TPY	tons per year (TPY)
VOC	volatile organic compound
WAC	*Washington Administrative Code*

NOTICE OF CONSTRUCTION FOR PROPOSED BACKUP PACKAGE BOILER

1.0 INTRODUCTION

The Hanford Site steam plant consists of coal-fired boilers located at the 200 East and the 200 West Areas. These boilers have provided steam to heat and cool facilities in the 200 Areas since the early 1940's. As part of Project L-017, "Steam System Rehabilitation, Phase II", the 200 West Area coal-fired boilers will be permanently shut down. The shut down will only occur after a proposed package backup boiler (50,000 pounds per hour (lb/hr) steam, firing No. 2 oil) is installed at the 200 West Area. The proposed backup boiler will provide back-up services when the 200 East Area steam line, which provides steam to the 200 West Area, is down for maintenance or, when the demand for steam exceeds the supply available from the 200 East Plant.

This application is a request for approval to construct and operate the package backup boiler. This request is being made pursuant to *Washington Administrative Code* (WAC) Chapter 173-400, "General Regulations for Air Pollution Sources", and Chapter 173-460, "Controls for New Sources of Toxic Air Pollutants".

2.0 PROJECT DESCRIPTION

This section describes the proposed backup boiler that will be installed as part of the L-017, "Steam System Rehabilitation, Phase II".

2.1 LOCATION OF PROJECT

The proposed backup boiler will be located in the 200 West Area of the U.S. Department of Energy's Hanford Site, in south-central Washington north of Richland, Washington, as shown on Figure 2-1. Figure 2-2 shows the location of existing and proposed steam production units in the 200 Areas.

2.2 DESCRIPTION OF PACKAGE BOILER UNIT ASSUMPTIONS

Detailed design information is not currently available for the specific boiler that will be chosen for installation because bids for manufacturing and installation from boiler manufacturers have not yet been sought. Therefore, general information on a typical 50,000 lb/hr oil-fired boiler is used to estimate characteristics of the proposed package backup boiler described in this document.

Figure 2-1. Location of the 200 West Area at the Hanford Site.

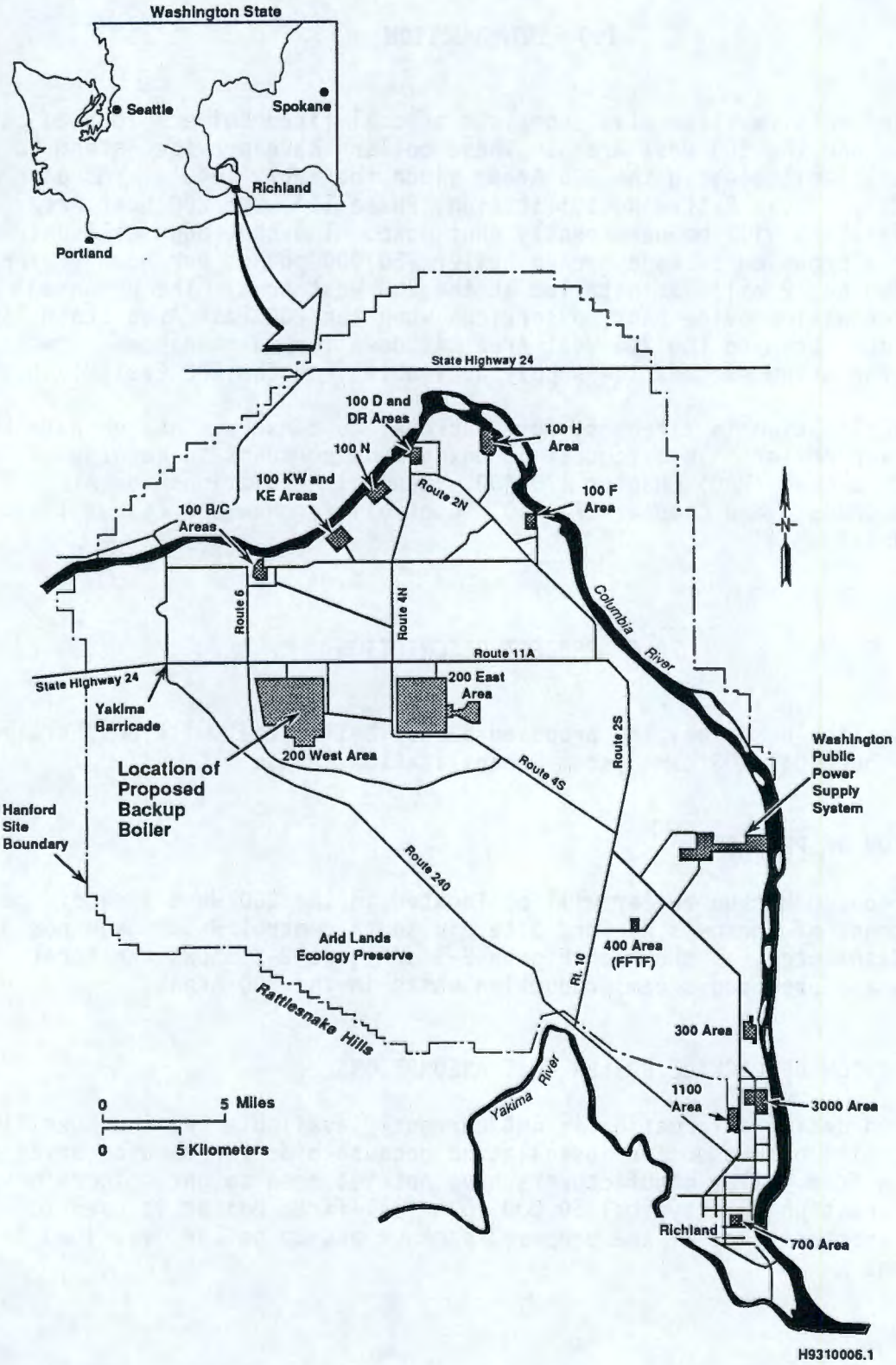
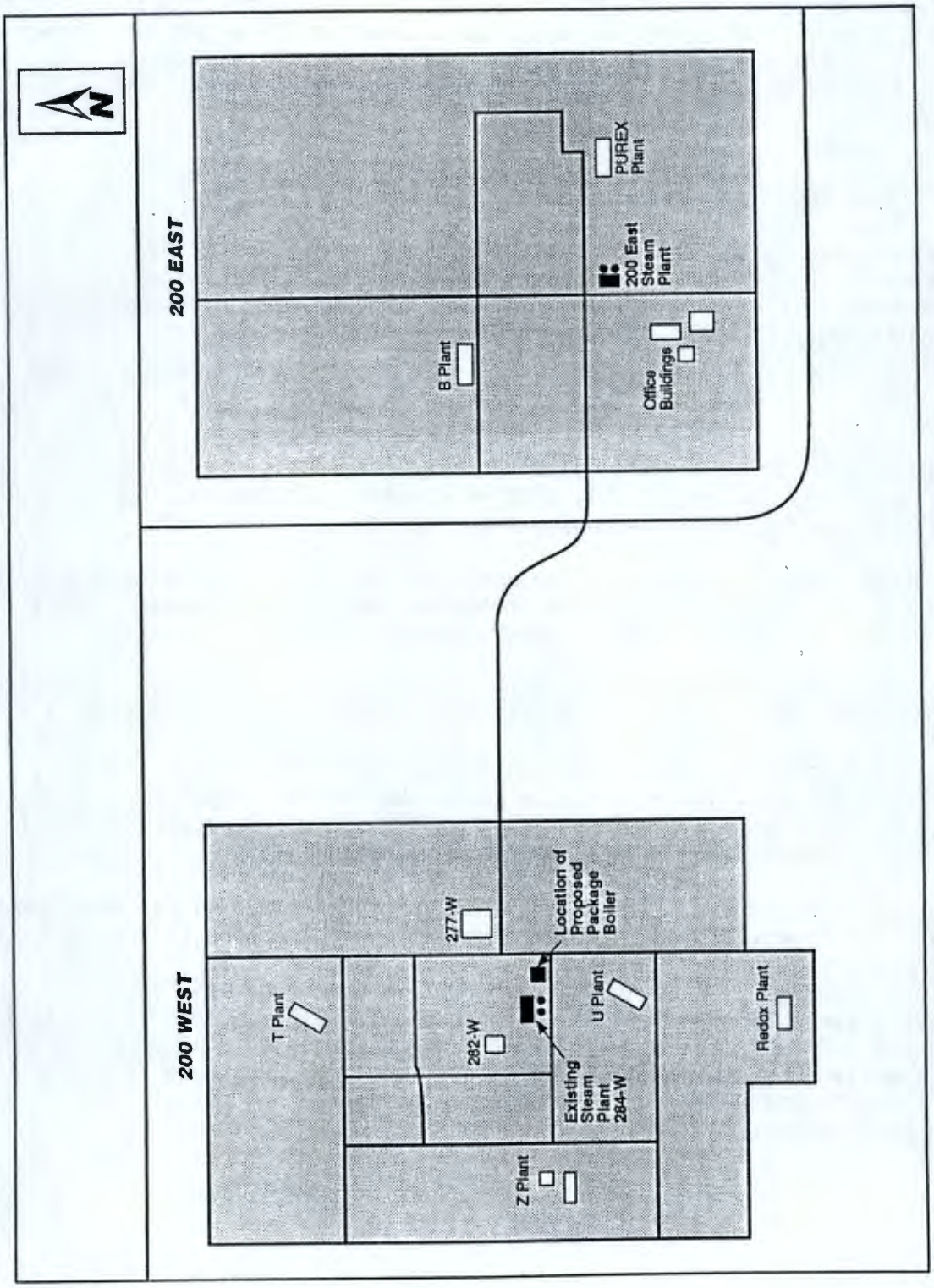


Figure 2-2. Location of Steam Plant Units in the 200 Areas. A



A typical package oil-fired boiler contains integral forced draft burners, burner controls, burner fuel trains, a fuel oil pump, boiler trim, and refractories. The boiler trim will include a water column, feedwater pump control, low water cutoff, a steam pressure gauge, and safety relief valves. It operates with a fuel consumption rate of about 3,000 lb/hr (at a higher heating value of about 19,500 British thermal units per pound [Btu/lb]). The proposed boiler will be specified to produce steam at 225 pounds per square inch gage (psig) and 456°F (superheated). Natural gas firing will not be requested because an adequate supply of natural gas is not available at the Hanford Site.

2.3 OPERATING MODE

The proposed backup boiler is assumed to be needed for 60 days per year. Based on past experience, about 15 days are required as backup for routine maintenance activities; 45 days are planned as backup when the steam demand exceeds the supply from the existing 200 East boilers.

3.0 CONTROL EQUIPMENT INFORMATION

A discussion of the best available control technology is included as Appendix C of this document. This section provides a summary of BACT and what control technologies will be used for the proposed backup boiler.

A low-NO_x combustion system that uses flue gas recirculation will be used with the proposed backup boiler even though no controls have been determined to be BACT for this application.

The use of low sulfur fuel has been determined to be BACT for SO_2 control in the proposed backup boiler. The proposed backup boiler utilizes No. 2 fuel oil as its heating source. This fuel oil has a low sulfur content, which will not exceed 0.5 percent sulfur. The use of low sulfur fuel results in only 8.5 tons per year (tpy) of SO_2 expected to be emitted to the atmosphere. Fuel oil purchased for the Hanford Site contains 0.2 percent sulfur, according to the specifications sheet from the fuel oil vendor (Appendix A).

The uncontrolled particulates and toxic air pollutants (TAPs) emission rates expected from the proposed backup boiler are low enough that the airborne concentrations at the Hanford Site boundary are much lower than federal and Washington State Ambient Air Quality Standards (AAQS) and Washington State's Acceptable Source Impact Level (ASIL) concentration limits, respectively. Because the air emissions from the proposed backup boiler will be sufficiently low, human health and safety should be protected from any potential health and other toxic effects. Therefore, no controls satisfy BACT for particulates and TAPs.

4.0 EMISSIONS ESTIMATION

4.1 EMISSIONS FROM PROPOSED BACKUP BOILER

Table 4-1 provides the expected steam production rate (lb/hr) and heat rate (MMBtu/hr) for the proposed backup boiler. Both the steam production rates and the heat rates were averaged over an annual period, based on the assumed maximum 60-days-per-year load factor.

Table 4-1. Production Rates for Proposed Backup Boiler.

Production Source	Total Steam Production Capacity (lb/hr)	Annualized Average Steam Production Rate (lb/hr)	Plant Average Heat Rate (Btu/lb steam)	Average Annual Heat Input (MMBtu/hr)
Package Oil Boiler	50,000	8,219	1,168	9.6

4.1.1 Air Pollutant Emission Factors

Emission factors used to estimate the criteria air pollutant emissions from the proposed backup boiler were taken from *Supplement C to Compilation of Air Pollutant Emission Factors, AP-42, Volume 1: Stationary Point and Area Sources* (EPA 1990). Emission factors used to calculate TAPs for the proposed backup boiler were derived from *Toxic Air Pollutant Emission Factors - A Compilation For Selected Air Toxic Compounds and Sources* (EPA 1988).

4.1.2 Emissions From Proposed Backup Boiler

The proposed backup boiler will fire No. 2 fuel oil. The No. 2 fuel oil distributed to the Hanford Site is purchased from MG Refining and Marketing, Inc., Forest Hill, Maryland. The specification data sheet (Appendix A) for the No. 2 fuel oil includes the following two important components: the percent sulfur content and the American Petroleum Institute (API) gravity value.

The percent sulfur value of 0.20 was used to calculate sulfur dioxide (SO_2) emissions using the AP-42 emission factor of 142 times the percent sulfur value (0.2). This results in an SO_2 emission factor of 28.4 lb/1,000 gallon (gal) of fuel used. Table 4-2 provides projected annual emissions from the proposed backup boiler.

The API gravity value of 30 on the specification sheet equates to a fuel density of 7.2 lb/gal (Perry and Chilton 1973). A fuel consumption rate of 3,000 lb/hr for a typical 50,000 lb/hr capacity boiler (Appendix B) divided by the fuel density gives a fuel rate of 417 gal/hr for use in the emission calculations of the criteria air pollutants (Table 4-2).

Emission rates for TAPs were predicted for the proposed backup boiler using figures for distillate (No. 2) fuel oil from the EPA guide for toxic

emission factors. These pollutants have emission factors listed in units of lb/MMBtu (Appendix B, Table B-1). To calculate an emission rate, the heat input value of the fuel in a typical 50,000 lb/hr size boiler was assumed to be 58.38 MMBtu/hr based on typical No. 2 fuel oil characteristics and a heat rate of 1,168 Btu/lb of steam.

Table 4-2. Projected Uncontrolled Emissions from Proposed Oil-Fired Package Backup Boiler.

CRITERIA AIR POLLUTANT	AP-42 Emission Factor (lb/1,000 gal)	Fuel Rate (gal/hr)	Emission Rate (lb/hr)	Operating Hours (hr/yr)	Annual Emission (TPY)
NO_x	20.0	417	8.3	1440	6.0
PM_{10}	2.0	417	0.8	1440	0.6
SO_2	28.4	417	11.8	1440	8.5
CO	5.0	417	2.1	1440	1.5
VOC	0.2	417	0.1	1440	0.1

TOXIC EMISSION	EPA Toxic Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Operating Hours (hr/yr)	Annual Emission (TPY)
Formaldehyde	4.05 E-04	58.38	2.36 E-02	1440	1.70 E-02
Lead*	2.80 E-05	58.38	1.63 E-03	1440	1.18 E-03
Manganese	2.60 E-05	58.38	1.52 E-03	1440	1.09 E-03
Mercury	3.00 E-06	58.38	1.75 E-04	1440	1.26 E-04
Nickel	1.70 E-04	58.38	9.92 E-03	1440	7.15 E-03
Arsenic	4.20 E-06	58.38	2.45 E-04	1440	1.77 E-04
Beryllium	2.50 E-06	58.38	1.46 E-04	1440	1.05 E-04
Cadmium	1.05 E-05	58.38	6.13 E-04	1440	4.41 E-04
Chromium	4.75 E-05	58.38	2.77 E-03	1440	2.00 E-03
Copper	2.80 E-04	58.38	1.63 E-02	1440	1.18 E-02

Note: Heat input obtained from vendor performance data for typical 50,000 lb/hr oil boiler. Fuel rate is based on 3,000 lb/hr fuel divided by the API density of 7.2 lb/gal and assumes 0.2-percent sulfur in the fuel oil.

* Lead is a criteria air pollutant and a hazardous air pollutant; the emission factor can be found in the "EPA Toxic Emission Factor Guideline" (EPA 1988).

5.0 AIR QUALITY IMPACT ANALYSIS

This section verifies that air emissions from the proposed backup boiler will comply with all federal and Washington State AAQS. Compliance with the AAQS is demonstrated through the use of the SCREEN-2 computer model. The analysis conforms to guidance provided by EPA (1992). Site layout is discussed along with the modeling methodology used to evaluate the dispersion of emissions from the proposed backup boiler. The predicted ambient air quality concentrations are compared to federal and Washington State allowable limits. The evaluation includes maximum predicted concentrations of both criteria air pollutants and TAPs.

5.1 HANFORD SITE LAYOUT

Rattlesnake Mountain on the westerly edge of the Hanford Site is the only significant rise in elevation (1,067 meters [m]) on the site, which is mostly flat. The average elevation of the Hanford Site is about 400 ft above sea level. The nearest off-site boundary is 13 km (8 mi) to the west of the projected location of the proposed backup boiler.

5.2 AIR QUALITY MODELING METHODOLOGY

The SCREEN-2 model was used to determine the maximum project-related ground-level air emission concentrations adjacent to the Hanford Site. The SCREEN-2 model is an updated version of EPA's original SCREEN model. The SCREEN-2 model was run assuming rural dispersion characteristics and was conducted with the following physical stack parameters:

Stack height:	21.3 m (70 ft)
Stack release diameter:	1.07 m (3.5 ft)
Exit velocity:	8.97 m/s (29.43 ft/s)
Exit temperature:	449.7 K (350°F)

The SCREEN-2 model requires stack data and building dimensions to account for downwash. The proposed backup boiler building will probably not affect the plume dispersion at the 21.3 m (70 ft) stack height. However, the proposed backup boiler will be located adjacent to the existing 200 West Boiler facility (284-W Building). The dimensions of this building were input to the SCREEN-2 model for downwash considerations. The SCREEN-2 input data and output report is given in Appendix D.

The objective of the dispersion analysis is to determine the maximum possible project-related airborne concentrations resulting from the proposed backup boiler emissions. The SCREEN-2 model automatically selects and uses a set of meteorological data appropriate to demonstrating the worst-case scenario impacts. Table 5-1 shows the meteorological conditions modeled by SCREEN-2.

Table 5-1. Matrix of SCREEN-2 Meteorological Conditions.

Stability Class	Wind Speed (m/s)
A	1, 2, 3
B	1, 2, 3, 4, 5
C	1, 2, 3, 4, 5, 8, 10
D	1, 2, 3, 4, 5, 8, 10, 20
E	1, 2, 3, 4, 5
F	1, 2, 3, 4

The SCREEN-2 model uses annual average ambient temperature for the plume rise calculation. An assumed annual average temperature of 70°F (21.1°C) was used for the model run. The mixing heights were calculated automatically and are a function of wind speed (mixing height equals wind speed multiplied by 320). If the plume height is calculated to be above the mixing height, 1 m above the predicted plume height is used for the mixing height.

SCREEN-2 predicts 1-hr concentrations for receptors located in low or intermediate terrain. No receptors at elevated terrain were needed for this model since it is flat terrain all the way to the nearest off-site receptor, which is 13 km (8 mi) away. Maximum 1-hr concentrations were converted to other regulatory averaging times for the purpose of evaluation.

The emission rate was assumed to be 1.0 g/sec in the SCREEN-2 model run for the proposed backup boiler. SCREEN-2 calculated a 1-hr dispersion factor to be 8.28 ($\mu g/m^3$)/(g/sec). The actual ambient concentrations are estimated by multiplying the model derived dispersion factor times the actual emission rate. Table 5-2 lists other multiplicative factors that were used as a post-processing step in this analysis.

Table 5-2. Multiplication Factors for Converting SCREEN-2 1-Hour Averages to Other Averaging Times.

Averaging Time	Multiplication Factor
3-hour	0.9
8-hour	0.7
24-hour	0.4
Annual	0.1

5.3 COMPARISON OF PROJECTED CONCENTRATIONS TO AMBIENT AIR QUALITY STANDARDS

Table 5-3 lists the calculated worst-case ambient concentrations and compares them with the allowable limits. A more detailed breakdown of the calculated worst-case conditions is presented in Table B-2 in Appendix B. The predicted worst-case concentrations are all well below their respective applicable limits. For the criteria air pollutants, the allowable limits listed in Table 5-3 are the federal and Washington State AAQS. For the TAPs, the allowable limits are ASILs.

Regional background concentrations of NO_x, SO_2, and CO were calculated using the emissions of the coal-fired boilers in the 200 West and 200 East Areas. SCREEN-2 dispersion modeling was performed for one stack in 200 West and one stack in 200 East. It was conservatively assumed that both the plume dispersions from the 200 West and East stacks will impact the same off-site receptor. Details regarding the background calculations and coal-fired plant dispersion modeling are included in Appendix D.

Regional background concentrations of particulate matter (PM_{10}) for both annual and 24-hour data are included. These data were taken from Washington State Department of Ecology's 1992 Annual Report (Ecology 1992) for 1991 measurements taken at the Sunnyside Intermediate School monitoring station. This station is the closest monitoring station to the off-site receptor that is most representative of the conditions of the modeled receptor location. The annual average particulate matter concentration is 42 $\mu g/m^3$. An average of the first and second highest 24-hour concentrations, 87.5 $\mu g/m3$, was used for the background 24-hour concentration. The projected added effects of the boiler do not exceed the annual or 24-hour limits.

For the TAPs that have a 24-hour standard ASIL, the predicted pounds per hour emission rates (see Table 2-2) at full load were used to determine the grams per second emissions. For the TAPs that have an annual standard ASIL, the predicted tons per year emission rates (see Table 4-2) considering 1,440 hr/yr of operation were used to determine the grams per second emissions. The ASILs and the small quantity emission rates for TAPs of concern are listed in Table 5.4.

Table 5-3. Comparison of Modeling Results with Allowable Limits.

Pollutant	Ambient Impact from Proposed Boiler	Regional Background Concentrations	Total Ambient Impact	Compliance Determination	
				Allowable Limit	% of Limit
NO_x (ppm)					
Annual	3.07 E-04	1.28	9.83 E-04	0.05	1.9
SO_2 (ppm)					
1-hour	4.69 E-03	43.9	2.14 E-02	0.4	
3-hour	4.22 E-03	39.5	1.92 E-02	0.5	5.3
24-hour	1.88 E-03	17.6	8.55 E-03	0.1	3.8
Annual	4.69 E-04	4.4	2.14 E-03	0.02	8.5
CO (ppm)					
1-hour	1.91 E-03	11.3	1.17 E-02	35	0.0
8-hour	1.34 E-03	7.9	8.22 E-03	9	0.1
PM_{10} (μg/cu. m)					
24-hour	3.31 E-01	87.5	87.8	150	58.5
Annual	8.28 E-02	42	42.1	50	84.2
Lead (μg/cu. m)					
Calendar Quarter	1.14E-03	N/A	1.14E-03	1.5	0.08
Toxic Air Pollutants					
Formaldehyde (μg/cu. m)					
Annual	4.06 E-04	N/A	4.06 E-04	0.08	0.5
Manganese (μg/cu. m)					
24-hour	6.29 E-04	N/A	6.29 E-04	16.7	0.004
Mercury (μg/cu. m)					
24-hour	7.29 E-05	N/A	7.29 E-05	0.03	0.2
Nickel (μg/cu. m)					
24-hour	4.14 E-03	N/A	4.14 E-03	3.3	0.1
Arsenic (μg/cu. m)					
Annual	4.22 E-06	N/A	4.22 E-06	0.00023	1.8
Beryllium (μg/cu. m)					
Annual	2.51 E-06	N/A	2.51 E-06	0.0006	0.4
Cadmium (μg/cu. m)					
Annual	1.05 E-05	N/A	1.05 E-05	0.00056	1.9
Chromium (μg/cu. m)					
24-hour	1.16 E-03	N/A	1.16 E-03	1.7	0.1
Copper (μg/cu. m)					
24-hour	6.82 E-03	N/A	6.82 E-03	3.3	0.2

Table 5-4. ASILs and Small Quantity Emission Rates for Selected Toxic Air Pollutants.

Toxic Air Pollutant	Class	Small Quantity Emission Rate (lbs/yr)	ASIL ($\mu g/m^3$)
Formaldehyde	A	20	0.077[1]
Manganese	B	1,750	16.7[2]
Mercury	B	175	0.03[2]
Nickel	A	500	3.3[1]
Arsenic	A	None	0.00023[1]
Beryllium	A	None	0.00042[1]
Cadmium	A	None	0.0005[1]
Chromium	B	175	1.7[2]
Copper	B	175	3.3[2]

[1]Annual average.
[2]24-hr average.
A = known and probable carcinogen
B = toxic air pollutant

6.0 COMPLIANCE WITH REQUIREMENTS

6.1 PREVENTION OF SIGNIFICANT DETERIORATION REVIEW

Although the 200 Areas Steam Plants are a major Prevention of Significant Deterioration (PSD) source, the proposed backup boiler is not subject to PSD review because it is not a major modification under PSD regulations. During New Source Review for the backup boiler, a PSD review is required if the proposed change is a major modification. A modification is considered "major" if the physical change at the facility or its operations will significantly increase net emissions of any pollutant subject to regulation under the Clean Air Act, 40 CFR 52.21(b)(2). These significance levels are specified in 40 CFR 52.21(b)(23). The proposed backup boiler will not emit any attainment area in excess of the significance levels, therefore PSD is not applicable.

A "net emissions increase" is determined by summing the increase in the actual emissions resulting from the proposed project and any other increases or decreases in actual emissions that are contemporaneous with the change. If this sum exceeds zero, then a net emissions increase exists [40 CFR 52.21(b)(3)(i)]. The "net emissions increase" is significant if these emissions exceed the rates in Table 6-1. The net emissions increases from the proposed backup boiler are also presented in Table 6-1. Because the proposed backup boiler will not emit any attainment area pollutant in excess of the significance levels, the project is not subject to PSD review.

Table 6-1. Comparison of Predicted Emissions Differences with PSD Significance Levels.[1]

Air Contaminant	Significance Level (TPY)	Predicted Emissions Increases (TPY)
Carbon Monoxide	100.0	1.5
Volatile Organic Compounds	40.0	0.1
Nitrogen Oxides	40.0	4.0[2]
PM_{10}	15.0	0.6
Sulfur Dioxide	40.0	8.5

[1]WAC 173-400-141; 40 C.F.R. § 5221(b)(23).
[2]Using low-NO_x combustion, NO_x emissions will be reduced from 6 TPY to 4 TPY.

6.2 AMBIENT AIR QUALITY STANDARDS FOR ATTAINMENT AREAS

The proposed backup boiler will be located within an area that is currently in attainment; therefore, the station is not subject to nonattainment area permitting requirements.

Based on worst-case SCREEN-2 modeling, including building downwash and regional background concentrations, the predicted ambient concentrations for all of the criteria pollutants are much lower than the ambient air quality standards.

6.3 TOXIC AIR POLLUTANTS

Based on worst-case SCREEN-2 modeling, the ambient concentrations of the toxic compounds listed in Table 5-3 are much lower than Ecology's ASILs. Therefore, it is concluded that the proposed expansion will cause no significant health risks based on ambient air impacts.

6.4 VISIBILITY IMPACTS

All Class I areas are more than 100 km (62 mi) away from the proposed site. Therefore, no modeling was performed and no visibility impacts to Class I areas are expected.

7.0 REFERENCES

40 CFR 52, "Approval and Promulgation of Implementation Plans," *Code of Federal Regulations*, as amended.

40 CFR 52.21, "Prevention of Significant Deterioration of Air Quality," *Code of Federal Regulations*, as amended.

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Ecology, 1992, *Air Quality Program Annual Report*, Olympia, Washington.

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APPENDIX A

FUEL SPECIFICATIONS

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MG REFINING AND MARKETING, INC.
10 Newport Drive
Forest Hill, Maryland 21050
Telephone: (410) 893-6200 893-6200

#2 Fuel Oil.

*Issue No. 13: Grade 76
Cancels Previous Issues of Grade 76

SPECIFICATIONS FOR FUNGIBLE FUEL OIL - 40 CETANE

Product Property	ASTM Test Method	Test Results Minimum	Maximum	Note
Gravity API	D287	30		
Flash Point, °F				
Pensky-Martin	D93	130		
Distillation, °F	D86			
90%		540	640	
End Point			690	
Color ASTM	D1500		2.5	
*Color Visual			Dyed	3
Viscosity, cSt @ 38°C (100°F)	D445	2.0	3.6	
Pour Point	D97			2
Cloud Point	D2500			2
Corrosion, 3 hrs. @ 50°C (122° F)	D130		1	
Total Sulfur, wt.%	D129, D1266, D1552, D2622, or D4294		0.20	
Cetane Number	D613	40		
or				
Cetane Index	D976 or D4737	40		
Ash, wt.%	D482		0.01	
Carbon Residue: Ramabottom on 10% Bottom	D524		0.35	
BS&W, vol.%	D1796 or equivalent		< 0.05	
Thermal stability, 90 minutes 300°F Pad rating, DuPont scale			7	
or				
Oxidation stability, mg/100 ml	D2274		2.5	
Haze rating @ 25°C (77°F)	D4176 Procedure 2		2	

NOTES:

1. Concentration and type of additives permitted only as approved by Colonial.
2. This schedule denotes the fluidity of the distillate at the time and place of use.

Pour Point, °C (°F) - September, October, November, December, January, February, March	Maximum	-18(0)
Pour Point, °C (°F) - April, May, June, July, August	Maximum	-12(+10)
Cloud Point, °C (°F) - September, October, November, December, January, February, March	Maximum	-9(+15)
Cloud Point, °C (°F) - April, May, June, July, August	Maximum	-7(+20)

3. This product must contain enough 1,4 - dialkylamino - anthraquinone blue dye to show visible evidence of dye. The maximum amount of active dye ingredient is 4 pounds per 1000 barrels.

Member of the Metallgesellschaft Group
Mailing Address: P.O. Box 1387, Bel Air, MD 21014-1387 • Toll Free: 1-800-824-4456 • Fax (410) 893-8211

*Denotes change

February 1993

PRELIMINARY PREDICTED PERFORMANCE DATA

Ultimate Analysis (% By Weight)	C	-	87.17
	H^2	-	12.50
	N^2	-	.02
For: Kaiser Aluminum	S	-	.30
Location: Mead, Washington	O^2	-	.01
	TOTAL	-	100.00
Fuel - No. 2 Oil	HHV BTU/Cu.Ft.	-	
	HHV BTU/Lb.	-	19,460

Load Rating - %		100
Steam Capacity - Lb/Hr		50,000
Fuel Type		No. 2 Oil
Fuel Burned - Lb/Hr.		2,951
Excess Air Lvg - %		10
Combustion Air Weight - Lb/Hr.		46,846
Flue Gas Weight - Lb/Hr.		49,798
Heat Release:		
	Furnace Volume-BTU/Hr/Cu/Ft (1065)	53,937
	Waterwall Surface-BTU/Hr/Sq.Ft. (615)	93,403
Pressure: (PSIG)	Steam Leaving NRV	150
	Unit Design	250
	Drop Thru Economizer	8
	SH Pressure Drop	---
Temperature: (Deg. F)	Steam Leaving NRV	Sat.
	Feed Water Ent. Econ.	227
	Feed Water Lvg. Econ.	292
	Air Entering F.D. Fan	80
	Air Leaving Airheater	---
	Gas Leaving Boiler	550
	Gas Leaving Economizer	300 >32
	Gas Leaving Airheater	---
Draft Loss: (In. H_2O)	Ducts	.2
	Airheater	---
	Combustion Equipment	3.1
	Furnace, SH and Boiler	6.2
	Economizer	.8
	Airheater	---
	Dust Collector	---
	Precipitator	---
	Breeching	.3
	Total	10.4
Efficiency: (%)	Dry Gas	4.30
	H_2 & H_2O in Fuel	6.60
	H_2O in Air	.10
	Unburned Combustibles	.00
	Radiation	.68
	Manufacturers Margin	1.00
	Total Heat Losses	12.68
	Efficiency of Unit	87.32

Tampella Power Corporation
Williamsport, Pennsylvania
Date: 9/12/91; Prepared By: EPT

Prop. No. 74-91-1
See Dwg. No. K00

APPENDIX B

CORRESPONDENCE AND CALCULATIONS

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LOW NO_x COMBUSTION SYSTEM AS BACT

Record of telephone September 1, 1993 conversation between G. Carter and D. Seacrest, Proposal Manager, Tempella Power, Keeler Boiler Division, Williamsport, Pennsylvania, September 1, 1993.

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EBASCO ENVIRONMENTAL

HANFORD ENVIRONMENTAL RESTORATION PROGRAMS

RECORD OF TELEPHONE CONVERSATION

DATE: 9/1/93

DATE OF CONTACT: 9/1/93

TO: Distribution WHC - FILE

FROM: Gary Carter

TASK: L-017 Package Boiler

SUBJECT: PPM for NO_x

DISCUSSION WITH:

Dick Seacrest - Tempella

Dick was asked if CO & VOC's increased when FGR is used. He said that both CO and VOC will not change for the package boiler when using FGR. For a standard boiler (no FGR) the NOx emmissions are 120 ppmv. He also said that the fuel bound Nitrogen prevails in NOx production for oil-firing of package boilers. N content typically ≈ 0.02%. He also stated that the cost of an FGR system would be about $30,000. The final NOx emissions using FGR will be 80 ppm.

Distribution

By: Gary A. Carter — Name

Project Engineer — Title

942 — Dept.

9206K

FUEL CONSUMPTION RATE

September 3, 1993 letter to G. Carter from F. Knod, Proposal Manager, Babcock and Wilson-ST Company, Little Rock, Arkansas.

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Babcock & Wilcox - ST Company
a McDermott company

8900 Fourche Dam Pike
Little Rock, AR 72206
Telephone: (501) 490-2424
Fax: (501) 490-1414
Telex: 535642

September 3, 1993

Mr. Gary Carter
Ebasco Environmental
10900 N.E. 8th Street
Bellevue, WA 98004

SUBJECT: FM Package Boiler for Westinghouse-Hanford
P55-0395

Dear Gary:

We appreciate your call requesting performance information on a 50,000 lb/hr. B & W watertube boiler. You have advised the boiler will operate at 150 psig producing saturated steam.

Per your instructions we have assumed No. 2 fuel oil will be the primary fuel with natural gas possible being added in the future. Also, we have assumed a feedwater temperature of 240°F, an exit temperature out of the economizer of 315°F (300°F on natural gas), an ambient temperature of 70°F, and an elevation of 500 FASL.

We are pleased to enclose our Predicted Performance Sheets Nos. P55-0395-1S0 and P55-0395-2S0 together with information from Coen Company (our burner supplier) providing expected emissions.

Finally, we have enclosed brochures outlining our FM Package Boilers and a typical General Arrangement Drawing No. P55-0395-1D0.

After you have reviewed this data, please do not hesitate to call if you have questions or desire additional information.

We would be pleased to provide a budget price or a firm price proposal for your consideration.

Sincerely,

Fred Knod
Proposal Manager
Babcock & Wilcox - ST Company

FK/pa

cc: Tom Martinko - B & W
Ken Sabol/file

Attachments

PREDICTED PERFORMANCE SUMMARY SHEET

Model FM 10-66 Boiler
Date: September 2, 1993
P55-0395-1S0

Fuel		No. 2 Fuel Oil
Load	%	100
Steam flow	lb/hr	150,000
Outlet Pressure	Psig	150
Steam Outlet Temp.	°F	saturated
Feedwater Temp.	°F	240
Excess Air	%	15
Heat Input (Fuel)	(10^6) BTU/hr	57.32
Release Rate	(10^3) BTU/hr-sq.ft.	93.82
Furnace Liberation	(10^3) BTU/hr-cu.ft.	57.90
Flue Gas Recirc.	%	3
Gas Temp. Ent. Econ.	°F	556.78
Final Exit Gas Temp.	°F	315
Ambient Air Temp.	°F	70
Heat Losses		
Dry Gas	%	5.0
Water from Fuel	%	6.7
Moisture in air	%	.1
Radiation	%	.8
Margin	%	1.0
Total Losses	%	13.6
Efficiency (HHV)	%	86.4

Elevation: 500 FT.

Humidity: 0.013 lb moisture/lb dry air @ 29.90 in. Hg. barometric pressure

Fuel Analysis: No. 2 Fuel Oil (% WT)

Higher Heating Value : 19,300 Btu/lb.

S	0.3
H_2	12.5
C	87.0
N_2	0.02
O_2	0.18
Total:	100.00%

PREDICTED PERFORMANCE SUMMARY SHEET

Model FM 10-66 Boiler
Date: September 3, 1993
P55-0395-2S0

Fuel		Natural Gas
Load	%	100
Steam flow	lb/hr	150,000
Outlet Pressure	Psig	150
Steam Outlet Temp.	°F	saturated
Feedwater Temp.	°F	240
Excess Air	%	15
Heat Input (Fuel)	(10^6) BTU/hr	59.62
Release Rate	(10^3) BTU/hr-sq.ft.	97.58
Furnace Liberation	(10^3) BTU/hr-cu.ft.	60.22
Flue Gas Recirc.	%	3
Gas Temp. Ent. Econ.	°F	519.70
Final Exit Gas Temp.	°F	300
Ambient Air Temp.	°F	70
Heat Losses		
Dry Gas	%	4.3
Water from Fuel	%	10.7
Moisture in air	%	.1
Radiation	%	.8
Margin	%	1.0
Total Losses	%	16.9
Efficiency (HHV)	%	83.1

Elevation: 500 FT.

Humidity: 0.013 lb moisture/lb dry air @ 29.90 in. Hg. barometric pressure

Fuel Analysis: Natural Gas (% Vol)

Higher Heating Value : 1,000 Btu/cu.ft.

N_2	5.0
CH_4	90.0
C_2H_6	5.0

Total: 100.0 %

Telefax Transmittal

Please notify us ASAP if you do not receive a clear or complete copy. Call 916-668-2128. We are transmitting from a Nefax Bit III. Our Nefax telephone number is 916-668-2171.

Date: August 31, 1993
To: Babcock & Wilcox-ST
Attention: Mr. Fred Knod
Fax Number: 501-490-2123
Total Number of Pages: 2
From: Wayne A. Wieszczyk
Subject: Westinghouse Bellevue WA
Proposal No: 93-CS-539

Dear Fred,

In response to your fax, I have the following.

1) Coen will reduce the excess air to 15%.

Emission Guarantee for #2 oil with .02% fuel bound nitrogen:

NOx (Lbs/HR // Lbs/MMBTU.	8//0.139
VOC (Lbs/HR // Lbs/MMBTU)	0.23//0.004
Particulates (Lbs/HR // Lbs/MMBTU). . .	0.8//0.014
SOx (Lbs/HR // Lbs/MMBTU)	12.04//0.21

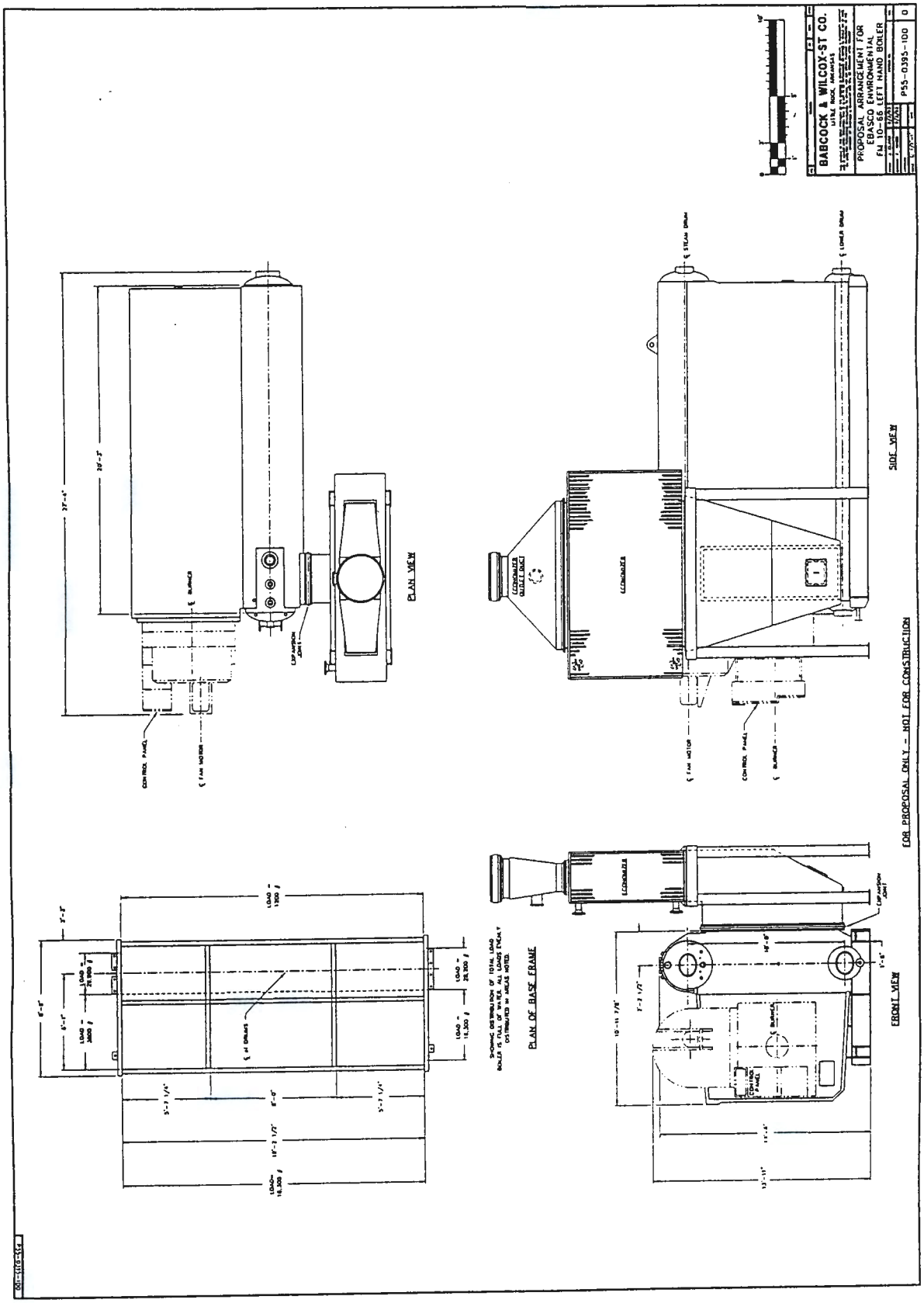
FGR Type	Induced
FGR %	3
FGR Flow (Lbs/HR)	1,573
Burner type	CPF/LN-21.5
Burner pressure drop ("W.C.).	5.89
Heat Input (MMBTU/HR)	57.32

Notes:
1) Guarantee is at loads stated above.
2) No additional particulates from the air.
3) Particulates on #2 oil are based on .01% Ash by weight, .2% Sulfur by weight, BS&W sediment of .01% and 0% conradson carbon. Note the sulfur contribution is based on 3% conversion and EP% test method 5, and 25% conversion of the BS&W.
4) Heating value of the oil is 19,300 BTU/LB.
5) VOC will be 10 PPM at the rear of the furnace and will be measured at the rear of the furnace. Any deviation from the rear of the furnace and the stack is the responsibility of the boiler manufacturer.

Regards,

Wayne A. Wieszczyk

CC. Mike Wilkinson-Thermal Economy Dave Sharpe-Western Combustion


BABCOCK & WILCOX-ST CO.
LITTLE ROCK, ARKANSAS
PROPOSAL ARRANGEMENT FOR
EBASCO ENVIRONMENTAL
FN 1-56 LEFT HAND BOILER
P55-0395-100
0
PLAN VIEW
SIDE VIEW
FRONT VIEW
PLAN OF BASE FRAME
ECONOMIZER
BURNER
CONTROL PANEL
FAN MOTOR
STEAM DRUM
LOWER DRUM
EXPANSION JOINT
FOR PROPOSAL ONLY - NOT FOR CONSTRUCTION

CALCULATIONS

EBASCO SERVICES INCORPORATED

BY GAC DATE 8/31/93 SHEET 1 OF 1

CHKD. BY _____ DATE _____ OFS NO. _____ DEPT. NO. 942

CLIENT WHC

PROJECT L-017

SUBJECT Heat Rate Calculation for Package Boiler

Heating value based on vendor performance data: 19,460 Btu/lb

Estimated fuel usage based on vendor performance data: 3,000 lb/hr

Heat rate estimate for use in Toxic Emissions Calculations (Table 2-3):

$$(19{,}460\ \text{Btu/lb})(3{,}000\ \text{lb/hr}) = \underline{58.38\ \text{MMBtu/hr}}$$

Average heat input:

$$50{,}000\ \text{lb/hr} \times 1440\ \text{hr/yr} = 7.2E{+}07\ \text{lb/yr} = 8{,}219\ \text{lb/hr}$$ - annual average

$$\frac{58.38\ \text{MMBtu/hr}}{50{,}000\ \text{lb/hr}} = 1.168\ \text{Btu/lb} \times 8219\ \text{lb/hr} = \underline{9.6\ \text{MMBtu/hr}}$$

Annualized average

Table B-1. Given Toxic Emission Factors [EPA 1988]

Stoker Coal-Fired Units		Distillate Oil-Fired Units	
Toxic	**Emission Factor**	**Toxic**	**Emission Factor**
Formaldehyde	1.17E-04	Formaldehyde	4.05E-04
Manganese	3.10E-05	Lead	2.80E-05
Mercury	1.60E-05	Manganese	2.60E-05
Nickel	2.11E-04	Mercury	3.00E-06
Arsenic	3.30E-05	Nickel	1.70E-04
Beryllium	5.90E-06	Arsenic	4.20E-06
Chromium	2.68E-04	Beryllium	2.50E-06
Copper	6.70E-05	Cadmium	1.05E-05
		Chromium	4.75E-05
		Copper	2.80E-04

Table B-2. Worst Case Ambient Concentrations

Proposed Package Boiler								
Dispersion Factor (ug/cu. m) at 1.0 g/s = 8.28				Conversion Factors			Compliance Determination	
No. of units 1								
Pollutant	Actual Emission Rates Per Unit (g/s)	Ambient Conc. From Package Boiler (ug/cu. m)	Regional Background Concentrations (ug/cu. m)	Time Factor	PPM Conversion	Total Ambient Impact	Allowable Limit	Percent of Limit
NOx (ppm)								
Annual	0.70	0.58	1.28	0.1	5.30E-04	9.83E-04	0.05	1.9
SO2 (ppm)								
1-hour	1.49	1.23E+01	43.90	1.0	3.80E-04	2.14E-02	0.40	5.3
3-hour	1.49	1.11E+01	39.51	0.9	3.80E-04	1.92E-02	0.50	3.8
24-hour	1.49	4.93E+00	17.56	0.4	3.80E-04	8.55E-03	0.10	8.5
Annual	1.49	1.23E+00	4.39	0.1	3.80E-04	2.14E-03	0.02	10.7
CO (ppm)								
1-hour	0.27	2.2	11.30	1.0	8.70E-04	1.17E-02	35	0.0
8-hour	0.27	1.5	7.91	0.7	8.70E-04	8.22E-03	9	0.1
PM-10 (μg/cu. m)								
24-hour	0.10	0.33	87.50	0.4		8.78E+01	150	58.6
Annual	0.10	0.08	42.00	0.1		4.21E+01	50	84.2
Lead (μg/cu. m) 3-month	1.37E-04	4.54E-04	N/A	0.4		4.54E-04	1.50	0.03
Formaldehyde (μg/cu. m)								
Annual	4.90E-04	4.06E-04	N/A	0.1		4.06E-04	0.08	0.5
Manganese (μg/cu. m)								
24-hour	1.90E-04	6.29E-04	N/A	0.4		6.29E-04	16.7	0.004
Mercury (μg/cu. m)								
24-hour	2.20E-05	7.29E-05	N/A	0.4		7.29E-05	0.03	0.2
Nickel (μg/cu. m)								
24-hour	1.25E-03	4.14E-03	N/A	0.4		4.14E-03	3.3	0.1
Arsenic (μg/cu. m)								
Annual	5.10E-06	4.22E-06	N/A	0.1		4.22E-06	0.00023	1.8
Beryllium (μg/cu. m)								
Annual	3.03E-06	2.51E-06	N/A	0.1		2.51E-06	0.0006	0.4
Cadmium (μg/cu. m)								
Annual	1.27E-05	1.05E-05	N/A	0.1		1.05E-05	0.00056	1.9
Chromium (μg/cu. m)								
24-hour	3.50E-04	1.16E-03	N/A	0.4		1.16E-03	1.7	0.1
Copper (μg/cu. m)								
24-hour	2.06E-03	6.82E-03	N/A	0.4		6.82E-03	3.3	0.2

APPENDIX C

BEST AVAILABLE CONTROL TECHNOLOGY
BEST AVAILABLE CONTROL TECHNOLOGY ASSESSMENT

C1.0 INTRODUCTION

As part of Project L-017, "200 Area Steam Plant Rehabilitation, Phase II", an oil-fired package backup boiler is proposed for addition to the steam plant operations. For the purpose of this assessment of Best Available Control Technology (BACT), it is assumed that the package boiler will emit NO_x, SO_2, CO, VOCs, PM_{10}, and toxic air pollutants. Good combustion practices are considered BACT for CO and VOCs for a No. 2 oil-fired package boiler (<100 MMBtu/hr), according to the South Coast Air Quality Management District's (SCAQMD) BACT Guideline. Good combustion practices are also accepted as BACT for particulate matter control due to typically small emissions of particulate from distillate oil-firing. The SCAQMD's BACT guideline was used because the state of Washington, Department of Ecology has not yet developed standards. Additionally, the SCAQMD has set the strictest guidelines found in the country due to the Los Angeles Basin being the only place in the country that routinely exceeds the federal nitrogen dioxide standard. To bring the Los Angeles Basin into compliance, the SCAQMD have developed BACT guidelines. NO_x and SO_2 emission regulations for new sources require a more detailed evaluation for a reduction achievable by BACT. Therefore, a top-down analysis using the EPA's 5-step process is provided to propose BACT for controlling NO_x and SO_2 emissions from the oil-fired package boiler.

The formation of nitrogen oxides in oil-fired boilers results from fuel-bound nitrogen reacting with oxygen in the combustion air. The combustion temperature is too low when burning No. 2 fuel oil for thermal oxidation of atmospheric nitrogen to occur (Appendix B). The rate of formation depends on residence time of the combustion products within the combustion zone, and the availability of oxygen in the flame zone. Section C4.0 discusses the available control alternatives for NO_x and includes a top-down analysis of those alternatives. There are two general schemes for NO_x reduction:

- Reduction during combustion by modification of the combustion process (combustion modification)
- Reduction after combustion by some means of flue gas treatment (tail gas control)

The oxidation of sulfur contained in the fuel forms SO_2. Organic sulfur will oxidize to produce gaseous SO_2 and, to a lesser extent, SO_3. Inorganic sulfur will not oxidize as readily and generally remains in the bottom ash. No. 2 fuel oil contains predominantly organic sulfur. The overall sulfur content in the No. 2 fuel oil used at Hanford is 0.2%. Control technologies used to control SO_2 emissions include the use of low sulfur fuel and flue gas treatment.

Section C5.0 includes a top-down analysis of available control alternatives for reduction of SO_2 emissions.

C2.0 METHODOLOGY

The five basic steps of EPA's top-down process along with a brief description of each step are presented below.

C2.1 Identify All Available Control Technologies

The first step in a top-down analysis is to identify all available control options for the emissions unit in question. Air pollution controls include available technologies, methods, systems, and techniques for control of the regulated pollutant, as well as alternate production processes that may reduce the generation of the pollutant. The control alternatives should include existing controls for the source category in question, and innovative technologies and controls applied to similar source categories. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives. LAER determinations usually represent the "top" alternative, if the LAER technology has been proven to be reliable and effective.

C2.2 Evaluation of Technical Feasibility

In the second step, the technical feasibility of the control options, identified in Step 1, is evaluated. There must be clear documentation, based on physical, chemical, and engineering principles, of all control options that are not technically feasible. These technically infeasible control options are then eliminated from further consideration in the BACT analysis.

C2.3 Ranking of Feasible Technologies

In Step 3, all remaining control alternatives not eliminated in Step 2 are ranked in order of control effectiveness (top-down) for the pollutant under review. A list is prepared for each pollutant and emission unit subject to the BACT analysis. The list represents the array of control technology alternatives and includes the following types of information:

- Range of control efficiencies (percentage of pollutant removed)
- Expected emission rate (TPY, pounds per hour)
- Expected removal efficiency
- Economic impacts (cost effectiveness)
- Environmental impacts (includes significant or unusual impacts on other media, water or solid waste)
- Energy impacts

A detailed analysis of costs and other impacts is not required if the applicant chooses the top control technology. The applicant must document that the control option is the top alternative and briefly explain the environmental impacts.

C2.4 Evaluation of Feasible Controls

In Step 4, after the available and technically feasible control technology options are identified, the energy, environmental, and economic impacts are considered to determine the final level of control.

In this analysis, the technology with the highest control efficiency is evaluated first. If this technology is found to have no adverse environmental, energy, or economic impacts, it is chosen as BACT and no further analysis is necessary. If the top technology is demonstrated to be inappropriate because of energy, environmental, or economic impacts, the rationale for this conclusion must be fully documented and added to the public record. Then, the next most effective control alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated due to source-specific environmental, energy, or economic impacts, which would demonstrate the alternative to be appropriate as BACT.

The capital costs, annual operation and maintenance costs, and the annualized cost for each technically feasible control option are estimated by using a combination of manufacturers' information, referenced costs from previous air quality permit applications, and published cost factors. The annualized cost is then divided by the tons per year of pollutant removed by the control device to derive the "cost effectiveness," with units of dollars per ton removed.

Capital costs are divided into two categories: direct costs and indirect costs. Direct capital costs include the purchase price for the equipment and the cost of installation. Indirect capital costs include engineering, licensing, and fees. Similarly, the annual costs are divided into direct costs and indirect costs. The direct operating costs include labor, expendable materials, and maintenance supplies. Indirect costs include overhead, taxes, and administration.

The economic life of the equipment is assumed to be 15 years. The annual interest rate is assumed to be 10 percent. Under the cost estimating procedures recommended by EPA, the increased costs from inflation are not considered.

C2.5 Select Best Available Control Technology

The most effective control option not eliminated in Step 4 is proposed as the BACT for the pollutant and emission unit under review.

C3.0 BEST AVAILABLE CONTROL TECHNOLOGY LOWEST ACHIEVABLE EMISSION RATE CLEARINGHOUSE REVIEW

A review of EPA's BACT/LAER Clearinghouse database was conducted, and one "process type" classification [Oil Fired Combustion Sources (Process Type 11.006)] was searched. Oil-fired boilers that were entered into the database after January 1, 1989 were reviewed and downloaded. Appendix E presents a printout of this list of permitted oil-fired facilities. Based on this information, low-NO_x combustion is the most common NO_x control; good combustion methods are used for control of all other pollutants.

C4.0 NITROGEN OXIDES CONTROL

C4.1 Identify Applicable Control Technologies

NO_x control technologies can generally be divided into two groups: combustion modifications and tail gas control processes. For oil-fired package boilers, the most common and widely used commercially available combustion modification technology is low-NO_x combustion utilizing flue gas recirculation. There are two developed and commercially available tail gas NO_x control processes. These include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNR).

C4.1.1 Low-NO_x Combustion. Flue gas recirculation (FGR) is the primary contributor to the low-NO_x combustion technology in oil-fired utility boilers. In this process, a portion of the exhaust gas is recycled back into the combustion zone where mixing recycled fuel gas and fuel is achievable. This mixing is accomplished by installation of extra gas ducts, a recirculation fan, and various shut-off and flow control valves. The recycled gas acts as a heat sink, absorbing a portion of the combustion energy and thereby lowering peak flame temperature. This technique can limit the amount of NO_x formed from fuel bound nitrogen in the fuel oil. Thermal NO_x, created by the oxidation of nitrogen contained in the air, is not formed because of the low combustion temperatures achieved with oil-fired boilers (Appendix B)

C4.1.1 Selective Catalytic Reduction. SCR applications on oil-fired boilers do not exist in the United States. No details about operational history exist for SCR for oil-fired boilers. Although Electrical Power Research Institute (EPRI) has conducted some research about SCR applications on large-scale industrial boilers, little data are available. In the SCR process, ammonia (NH_3) reacts with NO_x in the presence of a catalyst to produce N_2 and steam according to Equations 1 and 2 below. Honeycomb and plate-type catalysts are typically manufactured from a mixture of titanium oxide and vanadium pentoxide. Intimate mixing occurs between the NH_3 and flue gas NO_x (predominantly in the form of NO at the point of ammonia injection).

These catalytic reduction reactions are represented by the following equations:

$$4\ NO + 4\ NH_3\ [cat] + O_2 \rightarrow 4\ N_2 + 6H_2O \quad (1)$$

$$2\ NO_2 + 4\ NH_3\ [cat] + O_2 \xrightarrow[550\text{-}750°F]{} 3\ N_2 + 6H_2O \quad (2)$$

The optimum flue gas temperature range for this process is 550 to 750°F, which can be achieved downstream of the boiler exhaust. Because the boiler exhaust contains mostly NO, the first reaction above dominates and the stoichiometric NH_3 to NO_x molar ratio would be approximately 1:1.

C4.1.2 Selective Non-Catalytic Reduction. Like SCR, SNR applications on oil-fired utility boilers do not exist. SNR has been applied to large-scale coal-fired boiler facilities with successful results. However, no operational history exists on SNR applications to oil-fired boilers in this country. Similar to the SCR process, SNR uses ammonia or urea-based reagent to chemically react with the NO_x in the exhaust gas stream forming diatomic nitrogen and steam. This technology is applicable for high-temperature exhaust at temperatures greater than those typical of units to be considered for the proposed package boiler. The primary chemical reactions for the SNR process are:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6H_2O \quad (3)$$

$$2\ NO_2 + 4\ NH_3 + O_2 \xrightarrow[1{,}500\text{-}1{,}750°F]{} 3\ N_2 + 6H_2O \quad (4)$$

Because no catalyst is used for SNR, the temperature required for the reaction ranges between 1,500 to 1,750°F for ammonia, and 1,900°F for urea-based reagents. Typical combustion temperatures in oil-fired package boilers range between 1,000 to 1,200°F with flue gas temperatures even lower. The NO_x conversion efficiency decreases at temperatures below these ranges, and the unreacted ammonia reagent slip increases.

C4.2 Evaluation of Technical Feasibility for NO_x Controls

This section discusses the technical feasibility of the three NO_x control options described in Section C4.1. Table C4-1 presents a summary of the technical advantages and disadvantages of each technology.

C4.2.1 Low-NO_x Combustion. This technology has been fully developed by most utility boiler manufacturers. Low-NO_x combustion using flue gas recirculation can achieve NO_x emissions of 80 parts per million by volume (ppmv) (reduced from approximately 120 ppmv for basic, non-recirculating designs). Flue gas recirculation does not use complex mechanical features, except for a special duct system with various control valves. This technology has been an integral part of recent utility boiler designs and is technically feasible and available for application on the proposed L-017 package boiler.

C4.2.2 Selective Catalytic Reduction. Because of the lack of research data and operational history, this technology is considered technically infeasible for application on the proposed utility boiler.

C4.2.3 Selective Non-Catalytic Reduction. Because of the high temperature requirements and the lack of operational history in the oil-fired boiler industry, this technology is also considered technically infeasible for application on the proposed package boiler.

Table C4-1. Summary of NO_x Control Technologies.

Control Technology	Technical Advantages	Technical Disadvantages	Technically Feasible
Low NO_x Combustion with FGR	• Inexpensive • Simple Design • Units come packaged with FGR installed • Successful operational history	• Requires more instrumentational controls	Yes
SCR	• Very low NO_x emissions can be achieved	• No operational history • Very little research conducted for oil-boiler applications • Not practical for small-scale applications • Potential high NH_3 emissions • Very expensive	No
SNR	• No catalyst needed • Less costly than SCR	• No operational history • Very little research conducted for oil-boiler applications • Potential high NH_3 emissions • Package boiler does not meet optimum temperature window	No

C4.3 Ranking of Feasible NO_x Control Technologies

Of the three technologies evaluated, only low-NO_x combustion using flue gas recirculation was determined technically feasible for application on the proposed package boiler.

C4.4 Evaluation of Feasible NO_x Controls

This section provides a detailed evaluation of the only feasible NO_x control technology—low NO_x combustion, using flue gas recirculation. This technology will be evaluated for energy, environmental, and economic impacts. If any of these impacts are determined to be too extreme, the technology will be eliminated from BACT consideration, and no controls would be considered BACT.

C4.4.1 Environmental Impacts. Flue gas recirculation technology will not adversely affect the environment. No waste streams are produced when using this technology. No major increases in VOC or CO are expected. Good combustion practices will be utilized to achieve low CO and VOC emissions (Appendix B).

C4.4.2 Energy Impacts. It was estimated that a total performance loss imposed by flue gas recirculation would be 0.5 percent. This amount is equivalent to 420 MMBtu/yr, and does not impose an adverse impact.

C4.4.3 Economic Impacts. The costs (Table C4-2) for low-NO_x combustion using flue gas recirculation were estimated based on a vendor estimate of the price difference between purchasing a package boiler with flue gas recirculation technology applied and a basic package boiler (Appendix B).

Table 4-2. Costs for Low-NO_x Combustion.

Item	Cost
PURCHASED EQUIPMENT	
FGR System (Factory Installed)	$30,000
TOTAL CAPITAL COSTS	$30,000
DIRECT ANNUAL COSTS	
Operating Labor (120 hours x $30/hour)	$ 3,600
Supervisory Labor (15% of operating labor)	540
Maintenance and Materials (10% of capital costs)	3,000
Performance Loss (420 MMBtu/year x $2/MMBtu)	840
Subtotal - Direct Annual Costs	$ 7,980
INDIRECT ANNUAL COSTS	
Overhead on Directs (0.6 x Labor and Materials)	4,284
Subtotal - Indirect Annual Costs	$ 4,284
CAPITAL RECOVERY	
i = 10%; n = 15 years (0.131[1/] x 30,000)	$ 3,930
TOTAL ANNUALIZED COST	
i = 10%; n = 15 years	$ 16,194
COST EFFECTIVENESS ($ PER TON BASED ON 2 TPY)	$ 8,100

Basis: Capital cost estimate from Tempella Power Corp.
NO_x removal from 120 ppm to 80 ppm - 2 TPY.
No additional installation costs.
[1/] Perry and Chilton 1973.

It is assumed that the flue gas recirculation technology will reduce the NO_x emissions from 120 ppmv (Appendix B) to 80 ppmv, or about 33 percent. With a total proposed operating time of 1,440 hours per year, a total NO_x annual reduction of 2 tons per year will occur. Operating labor costs were based on 2 hours per day and $30 per hour. The performance loss was applied to a heat rate reduction at $2 per MMBtu lost.

Based on an assumed 15-year service life and 10% interest, the cost effectiveness for low-NO_x combustion using flue gas recirculation is about $8,100 per ton of NO_x removed. This cost effectiveness is high, mainly because of the low annual emissions of the proposed package boiler.

C4.5 Summary of Low-NO_x Combustion Impacts

The cost effectiveness value ($8,100 per ton) for low-$NO_x$ combustion using flue gas recirculation has been determined to be high, therefore no controls

is considered BACT for the proposed package boiler. However, the low-NO_x combustion using flue gas recirculation will be used, because the high cost per ton of NO_x is attributed to the costs being amortized over a limited number of annual operating hours. The package boiler units can easily be installed with the flue gas recirculation technology at minimal additional capital cost.

C4.6 Summary of BACT for NO_x Emissions

Although no controls is considered BACT for NO_x emissions from the proposed package boiler, low-NO_x combustion will be utilized. This will result in NO_x emissions of 4 tons per year. The air quality impact analysis in Section 5.0 shows that this emission will not exceed air quality standards at the nearest boundary.

C5.0 SULFUR DIOXIDE CONTROL

C5.1 Identify Applicable Control Technologies

The oxidation of sulfur contained in the fuel forms SO_2. Organic sulfur will oxidize to produce gaseous SO_2 and, to a lesser extent, SO_3. Inorganic sulfur will not oxidize as readily and generally remains in bottom ash.

In recent years, the power industry has achieved widespread technological advances concerning SO_2 control with various flue gas desulfurization (FGD) processes. These processes include wet lime/limestone scrubbing, dry injection towers using lime/limestone for SO_2 absorption, and dry sorbent duct or furnace injection. The large-scale FGD processes, wet scrubbing and dry injection towers, are not applicable to package oil-fired boilers. These large-scale FGD processes are intended and designed for large coal-fired industrial boilers with very large SO_2 emissions. They are also designed for continuous operation, which is not the case for the proposed package boiler. Dry sorbent furnace injection can be applied to smaller scale combustion sources, such as a package utility boiler, and therefore is evaluated below.

The most common SO_2 control technology for small scale operations is the use of low sulfur fuels. Since SO_2 emissions are directly proportional to the amount of sulfur contained in the fuel, limits on the percentage of sulfur contained in the fuel is a feasible SO_2 control. No. 2 fuel oil contains predominantly organic sulfur. The overall sulfur content in the No. 2 fuel oil used at the Hanford site is 0.2%, according to the fuel oil specifications sheet from the fuel oil vendor.

C5.1.1 Furnace Sorbent Injection. There is no widespread history of this technology being applied to oil-fired units in the United States. However, it has been demonstrated and applied commercially in Europe to coal-fired units ranging from 15 to 750 megawatts (MW). With this technology, the sorbent, typically slaked lime or sodium bicarbonate, is injected into the furnace directly and reacted directly with the SO_2 (Offen et al. 1987). This technology requires the ability to achieve rapid, uniform mixing of the sorbent with the combustion products through the proper design of the injection system. Sorbent injection produces more particulate matter in the exhaust because of the high quantity of byproducts created in the reaction

with SO_2. This technology is typically used when a particulate control device is employed downstream.

C5.1.2 Use of Low Sulfur Fuel. This is the most common control for oil-fired utility boilers. The New Source Performance Standards (CFR 60) for oil-fired utility boilers requires less than 0.5% sulfur content in the oil. The proposed new package boiler will use No. 2 fuel oil that contains 0.2% sulfur.

C5.2 Evaluation of Technical Feasibility for SO_2 Controls

This section discusses the technical feasibility of the two SO_2 control options described in Section C5.1. Table C5-1 presents a summary of the technical advantages and disadvantages of each technology.

C5.2.1 Furnace Sorbent Injection. This technology has not been researched or demonstrated for oil-fired combustion units. It does, however, carry an operational history based on European demonstrations with coal-fired units. Impacts from this technology include fouling of convective heat transfer surfaces due to the added sorbent and humidification of the flue gas ducts. Because of the lack of operational history on oil-fired applications, the probable requirement for a particulate control device such as a baghouse or an electrostatic precipitator (ESP), and the fact that this technology is most effective on very high concentrations of SO_2, furnace sorbent injection is considered technically infeasible for application on the proposed package boiler.

Table C5-1. Summary of SO_2 Control Technologies.

Control Technology	Technical Advantages	Technical Disadvantages	Technically Feasible
Furnace Sorbent Injection	• Few or no moving parts • Inexpensive	• Very little operational history • Sorbent will foul heat transfer surfaces • Exhaust duct can humidify • Produces large amount of particulate requiring ESP or baghouse • Mostly effective for very large SO_2 concentrations > 500 ppmv	No
Low Sulfur Fuel	• No capital costs incurred • No mechanical parts	None	Yes

C5.2.2 Use of Low Sulfur Fuel. This application is a very common SO_2 control and is considered technically feasible for use in the proposed package boiler.

C5.3 Ranking of Feasible SO_2 Control Technologies

Of the two technologies evaluated, only low sulfur fuel was determined to be technically feasible for application on the proposed package boiler. Without using mechanical SO_2 controls and using low sulfur fuel, the package boiler will emit approximately 11.8 pounds of SO_2 per hour (8.5 TPY). These emissions estimates are based on AP-42 factors for distillate oil.

C5.4 Evaluation of Feasible SO_2 Controls

The only feasible SO_2 control technology for use in the proposed package boiler is the use of low sulfur fuel oil. This application is a limit on the characterization of the fuel oil, and contains no mechanical features that would pose any environmental, energy, or economic impacts. Therefore, the use of low sulfur fuel is considered to be BACT for use in the proposed package boiler.

C5.5 Summary of Best Available Control Technology for SO_2 Emissions

Low sulfur fuel has been selected as BACT for this application. The sulfur content in the fuel oil will not exceed 0.5%. The fuel oil specifications sheet from the fuel oil vendor indicates that the No. 2 fuel oil purchased for Hanford Site operations contains 0.2% sulfur (see Appendix C). The air quality impact analysis in Section 5.0 shows that the estimated SO_2 emissions will not exceed air quality standards at the nearest boundary.

APPENDIX D

SCREEN-2 MODEL DETAILS

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EBASCO

BY GAC DATE 9/2/93 SHEET 1 OF 1

CHKD. BY _____ DATE _____ OFS NO. _____ DEPT. NO. 942

CLIENT WHC

PROJECT 1-017

SUBJECT SCREEN MODEL Input Data

Assume: 1 lb. air / lb of steam (vendor info.)

Flue gas weight = 50,000 lb/hr

$T = 350°F$

$P = 14.7 \frac{lb}{in^2} = 1 ATM = 2117 \, lb/ft^2$

Flue gas volume flow: $V = \frac{1}{P} \frac{m}{MW} \cdot R \cdot T$

$$V(ft^3) = \frac{1}{P} \cdot \frac{50{,}000 \, lb/hr}{29 \, lb/lb\,mol} \cdot 1545 \frac{lb/ft^2 \cdot ft^3}{lb\,mol \cdot °R} \cdot 810 \, °R$$

$$= \frac{1}{2117 \, lb/ft^2} \cdot 2.16E+09 \, lb\,ft/hr$$

$$= 1{,}019{,}300 \, ft^3/hr$$

$$= 16{,}988 \, ft^3/min$$

Stack height = 70 ft = 21.3 m

Stack diameter = 3.5 ft = 1.07 m

Stack Area = $\pi \frac{(1.07m)^2}{4} = 0.894 \, m^2 = 9.62 \, ft^2$

Exit velocity = 29.43 ft/sec = 8.97 m/s

Exit Temp. = 350° F = 176.7 °C = 449.7 K

Ambient Air Temp = 70°F = 21° C = 294 K

Building Height = 70 ft = 21.3 m

" Length = 216 ft = 65.8 m

" Width = 71 ft = 21.6 m

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*** SCREEN2 MODEL RUN ***
*** VERSION DATED 92245 ***

L-017 Package Boiler

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	1.00000
STACK HEIGHT (M)	=	21.3000
STK INSIDE DIAM (M)	=	1.0700
STK EXIT VELOCITY (M/S)	=	8.9700
STK GAS EXIT TEMP (K)	=	449.7000
AMBIENT AIR TEMP (K)	=	294.0000
RECEPTOR HEIGHT (M)	=	1.5000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	21.3000
MIN HORIZ BLDG DIM (M)	=	21.6000
MAX HORIZ BLDG DIM (M)	=	65.8000

BUOY. FLUX = 8.717 M**4/S**3; MOM. FLUX = 15.056 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	.0000	0	.0	.0	.0	.00	.00	.00	NA
100.	396.7	6	2.5	3.8	10000.0	23.58	4.07	14.84	SS
200.	202.2	6	3.0	4.5	10000.0	25.94	7.73	21.17	SS
300.	138.0	6	2.0	3.0	10000.0	32.68	11.23	21.57	SS
400.	109.0	6	2.0	3.0	10000.0	32.68	14.64	22.08	SS
500.	91.36	6	2.0	3.0	10000.0	32.68	17.97	22.65	SS
600.	79.24	6	2.0	3.0	10000.0	32.68	21.24	23.21	SS
700.	70.31	6	2.0	3.0	10000.0	32.68	24.46	23.76	SS
800.	63.41	6	2.0	3.0	10000.0	32.68	27.63	24.30	SS
900.	58.69	6	1.5	2.3	10000.0	36.44	30.78	23.60	SS
1000.	54.92	6	1.5	2.3	10000.0	36.44	33.88	24.14	SS
1100.	51.70	6	1.5	2.3	10000.0	36.44	36.96	24.68	SS
1200.	48.90	6	1.5	2.3	10000.0	36.44	40.01	25.20	SS
1300.	46.43	6	1.5	2.3	10000.0	36.44	43.04	25.71	SS
1400.	44.21	6	1.5	2.3	10000.0	36.44	46.05	26.22	SS
1500.	42.22	6	1.5	2.3	10000.0	36.44	49.03	26.72	SS
1600.	39.42	6	1.5	2.3	10000.0	36.44	51.99	26.42	SS
1700.	37.91	6	1.5	2.3	10000.0	36.44	54.94	26.91	SS
1800.	36.44	6	1.5	2.3	10000.0	36.44	57.87	27.34	SS
1900.	35.08	6	1.5	2.3	10000.0	36.44	60.78	27.74	SS
2000.	33.82	6	1.5	2.3	10000.0	36.44	63.68	28.15	SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:

64.	542.3	6	2.5	3.8	10000.0	22.30	2.73	12.83	SS

```
DWASH=   MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

**********************************
*** SCREEN DISCRETE DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST      CONC                U10M    USTK   MIX HT    PLUME    SIGMA    SIGMA
   (M)    (UG/M**3)    STAB    (M/S)   (M/S)    (M)     HT (M)    Y (M)    Z (M)   DWASH
-------   ----------   ----    -----   -----   ------   ------   ------   ------   -----
 13000.    8.282         6      1.0     1.5   10000.0    43.46   342.12    52.84     SS

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** CAVITY CALCULATION - 1 ***        *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)       =    355.8        CONC (UG/M**3)       =    279.8
  CRIT WS @10M (M/S)   =     2.30        CRIT WS @10M (M/S)   =     8.90
  CRIT WS @ HS (M/S)   =     2.67        CRIT WS @ HS (M/S)   =    10.36
  DILUTION WS (M/S)    =     1.34        DILUTION WS (M/S)    =     5.18
  CAVITY HT (M)        =    30.42        CAVITY HT (M)        =    21.91
  CAVITY LENGTH (M)    =    75.10        CAVITY LENGTH (M)    =    30.16
  ALONGWIND DIM (M)    =    21.60        ALONGWIND DIM (M)    =    65.80

     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************

 CALCULATION          MAX CONC     DIST TO    TERRAIN
  PROCEDURE          (UG/M**3)     MAX (M)     HT (M)
--------------      -----------   -------    -------
SIMPLE TERRAIN        542.3          64.         0.

BUILDING CAVITY-1     355.8          75.        --   (DIST = CAVITY LENGTH)
BUILDING CAVITY-2     279.8          30.        --   (DIST = CAVITY LENGTH)


****************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****************************************************
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EBASCO

BY GAC DATE 9/13/93 SHEET 1 OF 1

CHKD. BY _____ DATE _____ OFS NO. _____ DEPT. NO. 942

CLIENT WHC

PROJECT L-017

SUBJECT SCREEN Model Run for coal-fired boilers

Assume: 10 lbs air per 1 lb coal

$$\left(\frac{1200 \text{ Btu}}{\text{lb steam}}\right)\left(\frac{1 \text{ lb coal}}{10{,}000 \text{ Btu}}\right) = 0.12 \ \frac{\text{lb coal}}{\text{lb steam}}$$

Average of 88,400 lb/hr steam

$$\therefore \left(0.12 \ \frac{\text{lb coal}}{\text{lb steam}}\right)(88{,}400) = 10{,}608 \text{ lb coal/hr}$$

$$\left(\frac{10 \text{ lb air}}{1 \text{ lb coal}}\right)\left(10{,}608 \ \frac{\text{lb coal}}{\text{hr}}\right) = 106{,}080 \text{ lb/hr}$$

$$V(ft^3) = \frac{1}{P} \cdot \frac{106{,}080 \text{ lb/hr}}{29 \text{ lb/lbmol}} \cdot 1545 \ \frac{\text{lb/ft}^2 \cdot \text{ft}^3}{\text{lb-mol} \cdot {}^\circ R} \cdot 810\,{}^\circ R$$

$$= \frac{1}{2117 \text{ lb/ft}^2} \cdot 4.578 \text{ E+09 lb-ft/hr}$$

$$= 2{,}162{,}360 \text{ ft}^3/\text{hr}$$

$$= 36{,}040 \text{ ft}^3/\text{min}$$ (divided by 2 stacks - 200W and 200E)

↳ 18,020 ft³/min @ each stack (200-W, 200-E)

Stack Parameters, each stack (200 W and 200 E):

Stack height: 115 ft = 34 m

Stack dia: 8 ft = 2.44 m stack area = $\pi \frac{(2.44\text{m})^2}{4}$ = 4.67 m² = 50.27 ft²

Exit velocity: 5.97 ft/sec = 1.82 m/sec

Exit temp.: 350°F = 176.7 °C = 449.7 °K

Ambient Air Temp: 70°F = 21°C = 294 °K

Building height: 21.3 m

" width: 21.6 m

" length: 65.8 m

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```
***  SCREEN2 MODEL RUN  ***
*** VERSION DATED 92245 ***

Coal Boilers Background Contribution

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      1.00000
   STACK HEIGHT (M)         =      34.0000
   STK INSIDE DIAM (M)      =       2.4400
   STK EXIT VELOCITY (M/S)=         1.8200
   STK GAS EXIT TEMP (K)    =     449.7000
   AMBIENT AIR TEMP (K)     =     294.0000
   RECEPTOR HEIGHT (M)      =       1.5000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      21.3000
   MIN HORIZ BLDG DIM (M) =        21.6000
   MAX HORIZ BLDG DIM (M) =        65.8000

BUOY. FLUX =    9.197 M**4/S**3;  MOM. FLUX =    3.223 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN DISCRETE DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
13000.	3.614	6	1.0	2.0	10000.0	72.55	342.32	54.99	HS
21000.	2.546	6	1.0	2.0	10000.0	72.55	523.11	63.53	HS

```
DWASH=   MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** CAVITY CALCULATION - 1 ***        *** CAVITY CALCULATION - 2 ***
 CONC (UG/M**3)       =    233.5        CONC (UG/M**3)       =    .0000
 CRIT WS @10M (M/S)   =     3.19        CRIT WS @10M (M/S)   =    99.99
 CRIT WS @ HS (M/S)   =     4.07        CRIT WS @ HS (M/S)   =    99.99
 DILUTION WS (M/S)    =     2.04        DILUTION WS (M/S)    =    99.99
 CAVITY HT (M)        =    30.42        CAVITY HT (M)        =    21.91
 CAVITY LENGTH (M)    =    75.10        CAVITY LENGTH (M)    =    30.16
 ALONGWIND DIM (M)    =    21.60        ALONGWIND DIM (M)    =    65.80

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************
```

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)	
SIMPLE TERRAIN	3.614	13000.	0.	
BUILDING CAVITY-1	233.5	75.	--	(DIST = CAVITY LENGTH)
BUILDING CAVITY-2	.0000	30.	--	(DIST = CAVITY LENGTH)

****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

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BY _____ DATE _____ SHEET ____ OF ____

CHKD. BY _____ DATE _____ OFS NO. _____ DEPT. NO. _____

CLIENT _____

PROJECT _____

SUBJECT _____

1991 200 W & 200 E Actual Emissions

	200 W		200 East	
	TPY	g/s	TPY	g/s
NO_x	75	2.2	66	1.9
SO_2	260	7.5	230	6.6
CO	63	1.8	66	1.9

200 W emission factor = 3.614 $(\mu g/m^3)/(g/s)$

NO_x = (2.2 g/s)(3.614) = 7.95 $\mu g/m^3$
SO_2 = (7.5 g/s)(3.614) = 27.1 $\mu g/m^3$
CO = (1.8 g/s)(3.614) = 6.5 $\mu g/m^3$

200 E emission factor = 2.546 $(\mu g/m^3)/(g/s)$

NO_x = (1.9 g/s)(2.546) = 4.8 $\mu g/m^3$
SO_2 = (6.6 g/s)(2.546) = 16.8 $\mu g/m^3$
CO = (1.9 g/s)(2.546) = 4.8 $\mu g/m^3$

Total Impact at offsite receptor

NO_x = 7.95 + 4.8 = 12.75 $\mu g/m^3$

SO_2 = 27.1 + 16.8 = 43.9 $\mu g/m^3$

CO = 6.5 + 4.8 = 11.3 $\mu g/m^3$

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APPENDIX E

BACT/LAER CLEARINGHOUSE

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS (FREEFORM) PAGE 1

BLIS ID : AL-0036
SUFFIX :
*COMPANY : GENERAL ELECTRIC
ADDRESS :
CITY : BURKVILLE
STATE : AL
COUNTY :
ZIP CODE :
EPA REGION : 4
NEW/MODIFIED : N
SOURCE SIZE : 0
SOURCE UNIT :
AGENCY CODE : AL001
AGENCY NAME : ALABAMA DEPT OF ENVIRONMENTAL MGMT
CONTACT : KENNETH BARRETT
PHONE : (205)-271-7861
*PERMIT # : 297-0008-X014,X015
START UP EST : 09/01/89
START UP ACT : / /
FINAL PERMIT ISSUED EST : / /
*FINAL PERMIT ISSUED ACT : 10/14/88
ENTRY DATE : 06/01/89
LAST UPDATE : 06/01/89
NOTES :
NO AIR PREHEAT IS USED IN ADDITION TO LOW NOX BURNERS.

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS (FREEFORM) PAGE 2

---

* PROCESS : BOILER, FUEL OIL
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 99.48
THROUGHPUT UNIT : MMBTU/H
BOILER SIZE : 99.48
COMPLIANCE VERIFIED : N
STACK TESTING : N

INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

---

* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT : LOW NOX BURNERS
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 14.9
PRIMARY EMISSIONS UNIT : LB/H
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 50
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0.15
ATLERNATE EMISSION UNIT : LB/MMBTU
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

BLIS ID : CA-0279
SUFFIX :
*COMPANY : DELANO GROWERS GRAPE PRODUCTS
ADDRESS :
CITY :
STATE : CA
COUNTY :
ZIP CODE :
EPA REGION : 9
NEW/MODIFIED : M
SOURCE SIZE : 0
SOURCE UNIT :
AGENCY CODE : CA012
AGENCY NAME : KERN COUNTY APCD (DESERT PORTION), CA
CONTACT : TOM PAXSON
PHONE : (805)-861-3682
*PERMIT # : 3046004A
ENTRY DATE : 06/01/89
LAST UPDATE : 06/01/89
NOTES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

---

* PROCESS : BOILER, OIL FIRED
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 32
THROUGHPUT UNIT : MMBTU/H
BOILER SIZE : 32
COMPLIANCE VERIFIED : N
STACK TESTING : N
INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT : LOW NOX BURNER, AUTO O2 TRIM
* PROCESS MODIFICATION : RECIRCULATED FLUE GAS

MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 10.6
PRIMARY EMISSIONS UNIT : LB/H
* BASIS : OTHER
* PERCENT EFFICIENCY : 20
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

BLIS ID : CT-0009
SUFFIX :
*COMPANY : U.S.NAVY BASE, NORTHERN DIVISION
ADDRESS : SUBMARINE BASE
CITY : GROTON
STATE : CT
COUNTY :
ZIP CODE :
EPA REGION : 1
NEW/MODIFIED : M
SOURCE SIZE : 0
SOURCE UNIT :
AGENCY CODE : CT001
AGENCY NAME : CONNECTICUT BUREAU OF AIR MANAGEMENT
CONTACT : JOSEPH ULEVICUS
PHONE : (203)-566-8230
*PERMIT # : 070-0074
*FINAL PERMIT ISSUED ACT : 02/07/90
ENTRY DATE : 04/30/90
LAST UPDATE : 04/30/90
NOTES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

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* PROCESS : BOILER, WATER TUBE, OIL FIRED
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 98
THROUGHPUT UNIT : MMBTU/H
BOILER SIZE : 98
COMPLIANCE VERIFIED : N
STACK TESTING : N
INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

* POLLUTANT : PM
* CAS NUMBER :
* CONTROL EQUIPMENT :

```
*   PROCESS MODIFICATION                : COMBUSTION METHODS
    MANUFACTURER                        :
    MODEL                               :
    NUMBER OF OPTIONS CONSIDERED        :        0
    RANK OF OPTION SELECTED             :        0
    PRIMARY EMISSIONS                   :        0.05
    PRIMARY EMISSIONS UNIT              : LB/MMBTU
*   BASIS                               : BACT-PSD
*   PERCENT EFFICIENCY                  :        0
    CALCULATED EFFICIENCY               :        0
    ALTERNATE EMISSION                  :        0
    ATLERNATE EMISSION UNIT             :
    STANDARD EMISSION                   :        0.05
    STANDARD EMISSION UNIT              : LB/MMBTU
    BASE EMISSION                       :        0
    BASE EMISSION UNIT                  :
*   EMISSION TYPE                       :
    CAP COST OF CONTROL EQUIPMENT       :        0
    O/M COST OF CONTROL EQUIPMENT       :        0
    ANNUALIZED COST                     :        0
    COST EFFECTIVENESS                  :        0
    COST VERIFIED BY AGENCY             : N
    DOLLAR YEAR USED IN COST ESTIMATES :

*   POLLUTANT                           : SOX
*   CAS NUMBER                          :
*   CONTROL EQUIPMENT                   :
*   PROCESS MODIFICATION                : 0.5% S OIL
    MANUFACTURER                        :
    MODEL                               :
    NUMBER OF OPTIONS CONSIDERED        :        0
    RANK OF OPTION SELECTED             :        0
    PRIMARY EMISSIONS                   :        0.53
    PRIMARY EMISSIONS UNIT              : LB/MMBTU
*   BASIS                               : BACT-PSD
*   PERCENT EFFICIENCY                  :        50
    CALCULATED EFFICIENCY               :        0
```

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

—

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.53
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT : LOW NOX BURNERS
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.2
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 33
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.2
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

*	POLLUTANT	: VOC
*	CAS NUMBER	:
*	CONTROL EQUIPMENT	:
*	PROCESS MODIFICATION	: COMBUSTION METHODS
	MANUFACTURER	:
	MODEL	:
	NUMBER OF OPTIONS CONSIDERED	: 0
	RANK OF OPTION SELECTED	: 0
	PRIMARY EMISSIONS	: 0.0017
	PRIMARY EMISSIONS UNIT	: LB/MMBTU
*	BASIS	: BACT-PSD
*	PERCENT EFFICIENCY	: 0
	CALCULATED EFFICIENCY	: 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.0017
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : CO
* CAS NUMBER : 630-08-0
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : COMBUSTION METHODS
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.03
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.03
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : PB
* CAS NUMBER : 7439-92-1
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : COMBUSTION METHODS
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 2.48
PRIMARY EMISSIONS UNIT : E-5 LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

BLIS ID : CT-0011
SUFFIX :
*COMPANY : MANSFIELD TRAINING SCHOOL
ADDRESS : ROUTE 32 & 44
CITY : MANSFIELD DEPOT
STATE : CT
COUNTY :
ZIP CODE :
EPA REGION : 1
NEW/MODIFIED : N
SOURCE SIZE : 0
SOURCE UNIT :
AGENCY CODE : CT001
AGENCY NAME : CONNECTICUT BUREAU OF AIR MANAGEMENT
CONTACT : JOLENE CRANE
PHONE : (203)-566-8230
*PERMIT # : 098-0003 THRU 6
START UP EST : 05/28/84
START UP ACT : / /
FINAL PERMIT ISSUED EST : / /
*FINAL PERMIT ISSUED ACT : 09/14/89
ENTRY DATE : 04/30/90
LAST UPDATE : 04/30/90
NOTES :
MAX FUEL USAGE AS FOLLOWS - 4.8 MMBTU/H UNIT, 33.2 GAL/H, 45000 GAL/YR #4 F
UEL OIL AT 1%S - 2.9 MMBTU/H UNITS, 20 GAL/H, 48000 GAL/YR #4 FUEL OIL AT 1
%S - 2.2 MMBUT/H UNIT, 16.5 GAL/H, 15000 GAL/YR #4 FUEL OIL AT 1% S.

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* PROCESS : BOILER, SPACE HEATING, OIL FIRED
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 4.8
THROUGHPUT UNIT : MMBTU/H

BOILER SIZE : 4.8
COMPLIANCE VERIFIED : N
STACK TESTING : N
INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

* POLLUTANT : PM
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.048
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.048
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : SO2
* CAS NUMBER : 7446-09-5
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 1.097
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD

* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 1.097
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.379
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.379
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N

DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : VOC
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.003
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.003
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : CO
* CAS NUMBER : 630-08-0
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.034
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0

CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.034
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : PB
* CAS NUMBER : 7439-92-1
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 2.9
PRIMARY EMISSIONS UNIT : E-5 LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : H2SO4
* CAS NUMBER : 7664-93-9
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.017
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.017
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* PROCESS : BOILER, SPACE HEATING, OIL FIRED, #1
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 2.9
THROUGHPUT UNIT : MMBTU/H
BOILER SIZE : 2.9
COMPLIANCE VERIFIED : N
STACK TESTING : N
INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

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* POLLUTANT : PM
* CAS NUMBER :

```
*       CONTROL EQUIPMENT                  :
*       PROCESS MODIFICATION               : FUEL LIMITATION
        MANUFACTURER                       :
        MODEL                              :
        NUMBER OF OPTIONS CONSIDERED       :        0
        RANK OF OPTION SELECTED            :        0
        PRIMARY EMISSIONS                  :        0.048
        PRIMARY EMISSIONS UNIT             : LB/MMBTU
*       BASIS                              : BACT-PSD
*       PERCENT EFFICIENCY                 :        0
        CALCULATED EFFICIENCY              :        0
        ALTERNATE EMISSION                 :        0
        ATLERNATE EMISSION UNIT            :
        STANDARD EMISSION                  :        0.048
        STANDARD EMISSION UNIT             : LB/MMBTU
        BASE EMISSION                      :        0
        BASE EMISSION UNIT                 :
*       EMISSION TYPE                      :
        CAP COST OF CONTROL EQUIPMENT      :        0
        O/M COST OF CONTROL EQUIPMENT      :        0
        ANNUALIZED COST                    :        0
        COST EFFECTIVENESS                 :        0
        COST VERIFIED BY AGENCY            : N
        DOLLAR YEAR USED IN COST ESTIMATES :

*       POLLUTANT                          : SO2
*       CAS NUMBER                         : 7446-09-5
*       CONTROL EQUIPMENT                  :
*       PROCESS MODIFICATION               : FUEL LIMITATION
        MANUFACTURER                       :
        MODEL                              :
        NUMBER OF OPTIONS CONSIDERED       :        0
        RANK OF OPTION SELECTED            :        0
        PRIMARY EMISSIONS                  :        1.097
        PRIMARY EMISSIONS UNIT             : LB/MMBTU
*       BASIS                              : BACT-PSD
*       PERCENT EFFICIENCY                 :        0
        CALCULATED EFFICIENCY              :        0
        ALTERNATE EMISSION                 :        0
        ATLERNATE EMISSION UNIT            :
        STANDARD EMISSION                  :        1.097
        STANDARD EMISSION UNIT             : LB/MMBTU
        BASE EMISSION                      :        0
        BASE EMISSION UNIT                 :
*       EMISSION TYPE                      :
        CAP COST OF CONTROL EQUIPMENT      :        0
```

O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

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* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.379
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.379
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : VOC
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.003

PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.003
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

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* POLLUTANT : CO
* CAS NUMBER : 630-08-0
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.034
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.034
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N

DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : PB
* CAS NUMBER : 7439-92-1
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 2.9
PRIMARY EMISSIONS UNIT : E-5 LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

---

* POLLUTANT : H2SO4
* CAS NUMBER : 7664-93-9
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : FUEL LIMITATION
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.017
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.017
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

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BLIS ID : CT-0081
SUFFIX :
*COMPANY : NEW ENGLAND FURNITURE
ADDRESS : 1 HILL ST
CITY : JEWETT CITY
STATE : CT
COUNTY :
ZIP CODE :
EPA REGION : 1
NEW/MODIFIED : N
SOURCE SIZE : 0
SOURCE UNIT :
AGENCY CODE : CT001
AGENCY NAME : CONNECTICUT BUREAU OF AIR MANAGEMENT
CONTACT : SUSAN AMARELLO
PHONE : (203)-566-8230
*PERMIT # : 069-0003
START UP EST : 04/15/86
START UP ACT : / /
FINAL PERMIT ISSUED EST : / /
*FINAL PERMIT ISSUED ACT : 03/15/88
ENTRY DATE : 04/30/90
LAST UPDATE : 04/30/90
NOTES :
0.5% SULFUR CONTENT OIL & 100000. GAL/YR LIMIT.

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

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* PROCESS : BOILER
* PROCESS TYPE : 11.006
* SCC CODE :
THROUGHPUT : 15.2
THROUGHPUT UNIT : MMBTU/H
BOILER SIZE : 15.2
COMPLIANCE VERIFIED : N
STACK TESTING : N
INSPECTIONS : N
CALCULATIONS : N
OTHER TESTING : N
OTHER TESTING METHOD :

* POLLUTANT : PM
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.047
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.047
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : SOX
* CAS NUMBER :

* CONTROL EQUIPMENT :
* PROCESS MODIFICATION : SEE NOTES
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.523
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.523
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : NOX
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.367
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.367

STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : VOC
* CAS NUMBER :
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.009
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

REPORT DATE: 09/07/93 CONTROL TECHNOLOGY DETERMINATIONS

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.009
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : CO
* CAS NUMBER : 630-08-0
* CONTROL EQUIPMENT :

* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 0.033
PRIMARY EMISSIONS UNIT : LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0
ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0.033
STANDARD EMISSION UNIT : LB/MMBTU
BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

* POLLUTANT : PB
* CAS NUMBER : 7439-92-1
* CONTROL EQUIPMENT :
* PROCESS MODIFICATION :
MANUFACTURER :
MODEL :
NUMBER OF OPTIONS CONSIDERED : 0
RANK OF OPTION SELECTED : 0
PRIMARY EMISSIONS : 4
PRIMARY EMISSIONS UNIT : E-6 LB/MMBTU
* BASIS : BACT-PSD
* PERCENT EFFICIENCY : 0
CALCULATED EFFICIENCY : 0

ALTERNATE EMISSION : 0
ATLERNATE EMISSION UNIT :
STANDARD EMISSION : 0
STANDARD EMISSION UNIT :

BASE EMISSION : 0
BASE EMISSION UNIT :
* EMISSION TYPE :
CAP COST OF CONTROL EQUIPMENT : 0
O/M COST OF CONTROL EQUIPMENT : 0
ANNUALIZED COST : 0
COST EFFECTIVENESS : 0
COST VERIFIED BY AGENCY : N
DOLLAR YEAR USED IN COST ESTIMATES :

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