Application Received
January 31, 2022
cgmd

20.11.41 NMAC "AUTHORITY-TO-CONSTRUCT" PERMIT #0273-M3-1TR MODIFICATION APPLICATION FOR PRESBYTERIAN HEALTHCARE SERVICES' ENERGY CENTER

Albuquerque, New Mexico

PREPARED FOR
PRESBYTERIAN HEALTHCARE SERVICES

JANUARY 2022

Prepared by

Montrose Air Quality Services, LLC

MONTROSE
ENVIRONMENTAL

Introduction

This 20.11.41.2 permit application is for a significant modification of Presbyterian Healthcare Services (PHS) Permit #0273-M3-1TR to include installation of a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package (Unit 8) and installation of new burners for Boilers 1 and 2 (Permit Units 3 and 4). The CoGen will produce electricity and steam (heat) for the new hospital building under construction. PHS has retained Montrose Air Quality Services, LLC (Montrose) to assist with the 20.11.41 NMAC "Authority to Construct" significant permit modification application. The location for the new CoGen will be in the expanded energy center at 1002 Silver Ave SE. The UTM coordinates of the energy center is; 350,835 meters E, 3,883,175 meters N, Zone 13, NAD 83.

Presently, Air Quality Permit #0273-M3-1TR for the energy center includes four (4) steam boilers and three (3) emergency generators. In the existing permit, the boilers are allowed to operate 8,760 hours each which includes 48 hours burning diesel for Units 3, 4, and 6. For this permit modification, PHS will restrict the use of the boilers to only three boilers operating under maximum conditions at any one time for 8,760 hours per year. This requested permit change will add additional permit conditions to the present operation of the boilers, including recordkeeping and reporting requirements.

No startup/shutdown emission rates are expected to be greater than what is proposed for normal operations of the regulated equipment.

Operational Plan to Mitigate Emissions and Plan of Work Practices

Startup

CoGen - the engine is preheated before starting the warm up period to full loading, which is a very short period. The oxidation catalyst is the only pollution control equipment and it will be pre-heated and will be functioning almost immediately upon engine startup, so there is no startup emissions calculated. CAT does not publish emission numbers for startup and shutdown for the G3516H engine.

Boilers – The startup of the boilers takes a slow start and my last an hour to complete. During this time, the emission rates of all pollutants will not exceed the allowable emission rate. Most emission rates are based on fuel consumption, Btu input, or exhaust flowrate which will increase until maximum operation. No excess emissions beyond the allowable emissions will be generated during startup.

Shutdown

No excess emissions beyond the allowable emissions will be generated during shutdown. The oxidation catalyst will operate during shutdown of the CoGen.

Maintenance

All permitted equipment will be maintained to prevent excess emissions during startup or shutdown. This facility will not have excess emissions during any maintenance procedures. The Operations and Maintenance schedules are found in Section C and in files submitted with the application.

Malfunction

No predicted malfunctions are expected since each unit will have a rigorous maintenance schedule. Each unit is computer controlled where malfunctions will be identified and the unit shutdown. The malfunctioning equipment will cease until repairs are made. If excess emissions occur they will be reported per 20.11.49 NMAC– Excess Emissions.

If you have any questions regarding this permit application please call Paul Wade of Montrose at (505) 830-9680 x6 or Keith Long of PHS at (505) 563-6221.

The contents of this application packet include:

20.11.41 NMAC Permit Fee Review
20.11.41 NMAC Permit Application Checklist
20.11.41 NMAC Permit Application Forms
Attachment A: Figure A-1: PHS Energy Center Facility Layout
Attachment B: Emission Calculations
Attachment C: Emission Calculations Support Documents
Attachment D: Figure D-1: Aerial Map
Attachment E: Facility Description
Attachment F: Regulatory Applicability Determination
Attachment G: Dispersion Modeling Summary and Report
Attachment H: Public Notice Documents

City of Albuquerque

Environmental Health Department
Air Quality Program

Permit Application Review Fee Checklist Effective January 1 - December 31, 2021

Please completely fill out the information in each section. Incompleteness of this checklist may result in the Albuquerque Environmental Health Department not accepting the application review fees. If you should have any questions concerning this checklist, please call 768-1972.

I. COMPANY INFORMATION:

Company Name	Presbyterian Healthcare Services	
Company Address	1100 Central Ave. SE, Albuquerque, NM 87106	
Facility Name	Energy Center	
Facility Address	1002 Silver Ave. SE, Albuquerque, NM 87106	
Contact Person	Keith Long	
Contact Person Phone Number	hlong4@phs.org	
Are these application review fees for an existing permitted source located within the City of Albuquerque or Bernalillo County?	**Yes**	**No**
If yes, what is the permit number associated with this modification?	**Permit #0273-M3-1TR**	
Is this application review fee for a Qualified Small Business as defined in 20.11.2 NMAC? (See Definition of Qualified Small Business on Page 4)	**Yes**	**No**

II. STATIONARY SOURCE APPLICATION REVIEW FEES:

If the application is for a new stationary source facility, please check all that apply. If this application is for a modification to an existing permit please see Section III.

Check All That Apply	Stationary Sources	Review Fee	Program Element
Air Quality Notifications			
	AQN New Application	$581.00	2801
	AQN Technical Amendment	$318.00	2802
	AQN Transfer of a Prior Authorization	$318.00	2803
X	*Not Applicable*	*See Sections Below*	
Stationary Source Review Fees (Not Based on Proposed Allowable Emission Rate)			
	Source Registration required by 20.11.40 NMAC	$ 592.00	2401
	A Stationary Source that requires a permit pursuant to 20.11.41 NMAC or other board regulations and are not subject to the below proposed allowable emission rates	$ 1,185.00	2301
X	*Not Applicable*	*See Sections Below*	
Stationary Source Review Fees (Based on the Proposed Allowable Emission Rate for the single highest fee pollutant)			
	Proposed Allowable Emission Rate Equal to or greater than 1 tpy and less than 5 tpy	$ 889.00	2302
	Proposed Allowable Emission Rate Equal to or greater than 5 tpy and less than 25 tpy	$1,777.00	2303
	Proposed Allowable Emission Rate Equal to or greater than 25 tpy and less than 50 tpy	$3,554.00	2304
	Proposed Allowable Emission Rate Equal to or greater than 50 tpy and less than 75 tpy	$5,331.00	2305
	Proposed Allowable Emission Rate Equal to or greater than 75 tpy and less than 100 tpy	$7,108.00	2306
	Proposed Allowable Emission Rate Equal to or greater than 100 tpy	$8,885.00	2307
X	*Not Applicable*	*See Section Above*	

Federal Program Review Fees (In addition to the Stationary Source Application Review Fees above)			
	40 CFR 60 - "New Source Performance Standards" (NSPS)	$1,185.00	2308
	40 CFR 61 - "Emission Standards for Hazardous Air Pollutants (NESHAPs)	$1,185.00	2309
	40 CFR 63 - (NESHAPs) Promulgated Standards	$1,185.00	2310
	40 CFR 63 - (NESHAPs) Case-by-Case MACT Review	$11,847.00	2311
	20.11.61 NMAC, Prevention of Significant Deterioration (PSD) Permit	$5,924.00	2312
	20.11.60 NMAC, Non-Attainment Area Permit	$5,924.00	2313
X	*Not Applicable*	*Not Applicable*	

III. MODIFICATION TO EXISTING PERMIT APPLICATION REVIEW FEES:

If the permit application is for a modification to an existing permit, please check all that apply. If this application is for a new stationary source facility, please see Section II.

Check All That Apply	Modifications	Review Fee	Program Element
Modification Application Review Fees (Not Based on Proposed Allowable Emission Rate)			
	Proposed modification to an existing stationary source that requires a permit pursuant to 20.11.41 NMAC or other board regulations and are not subject to the below proposed allowable emission rates	$ 1,185.00	2321
X	*Not Applicable*	*See Sections Below*	
Modification Application Review Fees (Based on the Proposed Allowable Emission Rate for the single highest fee pollutant)			
	Proposed Allowable Emission Rate Equal to or greater than 1 tpy and less than 5 tpy	$889.00	2322
	Proposed Allowable Emission Rate Equal to or greater than 5 tpy and less than 25 tpy	$1,777.00	2323
	Proposed Allowable Emission Rate Equal to or greater than 25 tpy and less than 50 tpy	$3,554.00	2324
X	Proposed Allowable Emission Rate Equal to or greater than 50 tpy and less than 75 tpy	$5,331.00	2325
	Proposed Allowable Emission Rate Equal to or greater than 75 tpy and less than 100 tpy	$7,108.00	2326
	Proposed Allowable Emission Rate Equal to or greater than 100 tpy	$8,885.00	2327
	Not Applicable	*See Section Above*	
Major Modifications Review Fees (In addition to the Modification Application Review Fees above)			
	20.11.60 NMAC, Permitting in Non-Attainment Areas	$5,924.00	2333
	20.11.61 NMAC, Prevention of Significant Deterioration	$5,924.00	2334
X	*Not Applicable*	*Not Applicable*	
Federal Program Review Fees (This section applies only if a Federal Program Review is triggered by the proposed modification) (These fees are in addition to the Modification and Major Modification Application Review Fees above)			
X	40 CFR 60 - "New Source Performance Standards" (NSPS)	$1,185.00	2328
	40 CFR 61 - "Emission Standards for Hazardous Air Pollutants (NESHAPs)	$1,185.00	2329
	40 CFR 63 - (NESHAPs) Promulgated Standards	$1,185.00	2330
	40 CFR 63 - (NESHAPs) Case-by-Case MACT Review	$11,847.00	2331
	20.11.61 NMAC, Prevention of Significant Deterioration (PSD) Permit	$5,924.00	2332
	20.11.60 NMAC, Non-Attainment Area Permit	$5,924.00	2333
	Not Applicable	*Not Applicable*	

IV. ADMINISTRATIVE AND TECHNICAL REVISION APPLICATION REVIEW FEES:

If the permit application is for an administrative or technical revision of an existing permit issued pursuant to 20.11.41 NMAC, please check one that applies.

Check One	Revision Type	Review Fee	Program Element
	Administrative Revisions	$ 250.00	2340
	Technical Revisions	$ 500.00	2341
X	*Not Applicable*	*See Sections II, III or V*	

V. PORTABLE STATIONARY SOURCE RELOCATION FEES:

If the permit application is for a portable stationary source relocation of an existing permit, please check one that applies.

Check One	Portable Stationary Source Relocation Type	Review Fee	Program Element
	No New Air Dispersion Modeling Required	$ 500.00	2501
	New Air Dispersion Modeling Required	$ 750.00	2502
X	*Not Applicable*	*See Sections II, III or V*	

VI. Please submit a check or money order in the amount shown for the total application review fee.

Section Totals	Review Fee Amount
Section II Total	$0
Section III Total	$6,516.00
Section IV Total	$0
Section V Total	$0
Total Application Review Fee	**$6,516.00**

I, the undersigned, a responsible official of the applicant company, certify that to the best of my knowledge, the information stated on this checklist, give a true and complete representation of the permit application review fees which are being submitted. I also understand that an incorrect submittal of permit application reviews may cause an incompleteness determination of the submitted permit application and that the balance of the appropriate permit application review fees shall be paid in full prior to further processing of the application.

Signed this 17 **day of** December **20**21

H. Keith Long — **Print Name**

Director, Engineering — **Print Title**

H. Keith Long

Signature

Definition of Qualified Small Business as defined in 20.11.2 NMAC:
"Qualified small business" means a business that meets all of the following requirements:

(1) a business that has 100 or fewer employees;
(2) a small business concern as defined by the federal Small Business Act;
(3) a source that emits less than 50 tons per year of any individual regulated air pollutant, or less than 75 tons per year of all regulated air pollutants combined; and
(4) a source that is not a major source or major stationary source.

Note: Beginning January 1, 2011, and every January 1 thereafter, an increase based on the consumer price index shall be added to the application review fees. The application review fees established in Subsection A through D of 20.11.2.18 NMAC shall be adjusted by an amount equal to the increase in the consumer price index for the immediately-preceding year. Application review fee adjustments equal to or greater than fifty cents ($0.50) shall be rounded up to the next highest whole dollar. Application review fee adjustments totaling less than fifty cents ($0.50) shall be rounded down to the next lowest whole dollar. The department shall post the application review fees on the city of Albuquerque environmental health department air quality program website.

City of Albuquerque

Environmental Health Department
Air Quality Program

Permit Application Checklist

Any person seeking a permit under 20.11.41 NMAC, Authority-to-Construct Permits, shall do so by filing a written application with the Department. Prior to ruling a submitted application complete each application submitted shall contain the required items listed below. **This checklist must be returned with the application.**

Applications that are ruled incomplete because of missing information will delay any determination or the issuance of the permit. The Department reserves the right to request additional relevant information prior to ruling the application complete in accordance with 20.11.41 NMAC.

All applicants shall:

1. ☐ Fill out and submit the *Pre-permit Application Meeting Request* form
   a. ☐ Attach a copy to this application

2. **X** Attend the pre-permit application meeting
   a. ☐ Attach a copy of the completed *Pre-permit Application Meeting Checklist* to this application

3. **X** Provide public notice to the appropriate parties
   a. ☐ Attach a copy of the completed *Notice of Intent to Construct* form to this form
      i. Neighborhood Association(s):_____
      _____
      ii. Coalition(s): _____
   b. ☐ Attach a copy of the completed *Public Sign Notice Guideline* form

4. Fill out and submit the *Permit Application*. All applications shall:

   A. **X** be made on a form provided by the Department. Additional text, tables, calculations or clarifying information may also be attached to the form.

   B. **X** at the time of application, include documentary proof that all applicable permit application review fees have been paid as required by 20 NMAC 11.02. Please refer to the attached permit application worksheet.

   C. **X** contain the applicant's name, address, and the names and addresses of all other owners or operators of the emission sources.

   D. **X** contain the name, address, and phone number of a person to contact regarding questions about the facility.

E. **X** indicate the date the application was completed and submitted

F. **X** contain the company name, which identifies this particular site.

G. **X** contain a written description of the facility and/or modification including all operations affecting air emissions.

H. **X** contain the maximum and standard operating schedules for the source after completion of construction or modification in terms of hours per day, days per week, and weeks per year.

I. **X** provide sufficient information to describe the quantities and nature of any regulated air contaminant (including any amount of a hazardous air pollutant) that the source will emit during:

- Normal operation
- Maximum operation
- Abnormal emissions from malfunction, start-up and shutdown

J. **X** include anticipated operational needs to allow for reasonable operational scenarios to avoid delays from needing additional permitting in the future.

K. **X** contain a map, such as a 7.5-minute USGS topographic quadrangle, showing the exact location of the source; and include physical address of the proposed source.

L. **X** contain an aerial photograph showing the proposed location of each process equipment unit involved in the proposed construction, modification, relocation, or technical revision of the source except for federal agencies or departments involved in national defense or national security as confirmed and agreed to by the department in writing.

M. **X** contain the UTM zone and UTM coordinates.

N. **X** include the four digit Standard Industrialized Code (SIC) and the North American Industrial Classification System (NAICS).

O. **X** contain the types and **potential emission rate** amounts of any regulated air contaminants the new source or modification will emit. Complete appropriate sections of the application; attachments can be used to supplement the application, but not replace it.

P. **X** contain the types and **controlled** amounts of any regulated air contaminants the new source or modification will emit. Complete appropriate sections of the application; attachments can be used to supplement the application, but not replace it.

Q. **X** contain the basis or source for each emission rate (include the manufacturer's specification sheets, AP-42 Section sheets, test data, or other data when used as the source).

R. **X** contain all calculations used to estimate **potential emission rate** and **controlled** emissions.

S. **X** contain the basis for the estimated control efficiencies and sufficient engineering data for verification of the control equipment operation, including if necessary, design drawings, test reports, and factors which affect the normal operation (e.g. limits to normal operation).

T. **X** contain fuel data for each existing and/or proposed piece of fuel burning equipment.

U. **X** contain the anticipated maximum production capacity of the entire facility and the requested production capacity after construction and/or modification.

V. **X** contain the stack and exhaust gas parameters for all existing and proposed emission stacks.

W. **X** provide an ambient impact analysis using a atmospheric dispersion model approved by the US Environmental Protection Agency (EPA), and the Department to demonstrate compliance with the ambient air quality standards for the City of Albuquerque and Bernalillo County (See 20.11.01 NMAC). If you are modifying an existing source, the modeling must include the emissions of the entire source to demonstrate the impact the new or modified source(s) will have on existing plant emissions.

X. **X** contain a preliminary operational plan defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown.

Y. ☐ contain a process flow sheet, including a material balance, of all components of the facility that would be involved in routine operations. Indicate all emission points, including fugitive points.

Z. **X** contain a full description, including all calculations and the basis for all control efficiencies presented, of the equipment to be used for air pollution control. This shall include a process flow sheet or, if the Department so requires, layout and assembly drawings, design plans, test reports and factors which affect the normal equipment operation, including control and/or process equipment operating limitations.

AA. ☐ contain description of the equipment or methods proposed by the applicant to be used for emission measurement.

BB. **X** be signed under oath or affirmation by a corporate officer, authorized to bind the company into legal agreements, certifying to the best of his or her knowledge the truth of all information submitted.

City of Albuquerque – Environmental Health Department
Air Quality Program
Please mail this application to **P.O. Box 1293, Albuquerque, NM 87103**
or hand deliver between 8:00 am – 5:00 pm Monday-Friday to:
3rd Floor, Suite 3023 – One Civic Plaza NW, Albuquerque, NM 87102
(505) 768-1972 aqd@cabq.gov

Application for Air Pollutant Sources in Bernalillo County
Source Registration (20.11.40 NMAC) and Construction Permits (20.11.41 NMAC)

Submittal Date: January 28, 2022

Corporate Information ☐ **Check here and leave this section blank if information is exactly the same as Facility Information below.**

Company Name: **Presbyterian Healthcare Services**			
Mailing Address: **PO Box 26666**	City: **Albuquerque**	State: **NM**	Zip: **87125**
Company Phone: **505-563-6221**	Company Contact: **Keith Long**		
Company Contact Title: **Director, Engineering**	Phone: **505-563-6221**	E-mail: **hlong4@phs.org**	

Stationary Source (Facility) Information: **Provide a plot plan (legal description/drawing of the facility property) with overlay sketch of facility processes, location of emission points, pollutant type, and distances to property boundaries.**

Facility Name: **Presbyterian Healthcare Services Energy Center**			
Facility Physical Address: **1002 Silver Ave. SE**	City: **Albuquerque**	State: **NM**	Zip: **87106**
Facility Mailing Address (if different): **PO Box 26666**	City: **Albuquerque**	State: **NM**	Zip: **87125-6666**
Facility Contact: **Keith Long**	Title: **Director, Engineering**		
Phone: **505-563-6221**	E-mail: **hlong4@phs.org**		
Authorized Representative Name[1]: **Keith Long**	Authorized Representative Title: **Director, Engineering**		

Billing Information ☒ **Check here if same contact and mailing address as corporate** ☐ **Check here if same as facility**

Billing Company Name:			
Mailing Address:	City:	State:	Zip:
Billing Contact:	Title:		
Phone:	E-mail:		

Preparer/Consultant(s) Information ☐ **Check here and leave section blank if no Consultant used or Preparer is same as Facility Contact.**

Name: **Paul Wade**	Title: **Principal / Senior Project Engineer**		
Mailing Address: **3500 G Comanche Rd NE**	City: **Albuquerque**	State: **NM**	Zip: **87107**
Phone: **(505) 830-9680 x6**	Email: **pwade@montrose-env.com**		

1. See 20.11.41.13.E.(13) NMAC.

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General Operation Information (if any question does not pertain to your facility, type N/A on the line or in the box)

Permitting action being requested (please refer to the definitions in 20.11.40 NMAC or 20.11.41 NMAC):			
☐ New Permit	☒ Permit Modification Current Permit #: **0273-M3-1TR**	☐ Technical Permit Revision Current Permit #:	☐ Administrative Permit Revision Current Permit #:
UTM Coordinates or Latitude – Longitude of Facility: **350,835 meters E, 3,883,175 meters N, Zone 13, NAD 83**			
Facility Type (description of your facility operations): **General Medical and Surgical Hospital**			
Standard Industrial Classification (SIC Code #): **8062**		North American Industry Classification System (NAICS Code #): **6221100**	
Is this facility currently operating in Bernalillo County? **Yes**		If **YES**, list date of original construction: If **NO**, list date of planned startup:	
Is the facility permanent? **Yes**		If **NO**, list dates for requested temporary operation: From Through	
Is the application for a physical or operational change, expansion, or reconstruction (altering process, or adding, or replacing process or control equipment, etc.) to an existing facility? **Yes**			
Provide a description of the requested changes: **Installation of a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package within the PHS Energy Center to supply electricity and steam heat for the new hospital tower. Install new burners for boilers 1 and 2 (Permit Units 3 and 4).**			
Is the facility operation: ☒ Continuous ☐ Intermittent ☐ Batch			
Estimated percent of production/operation:	Jan-Mar: **25**	Apr-Jun: **25**	Jul-Sep: **25**	Oct-Dec: **25**
Requested operating times of facility:	**24** hours/day	**7** days/week	**4.3** weeks/month	**12** months/year
Will there be special or seasonal operating times other than shown above? This includes monthly- or seasonally-varying hours. **No**				
If **YES**, please explain:				
List raw materials processed:				
List saleable item(s) produced:				

Regulated Emission Sources Table

(Generator-Crusher-Screen-Conveyor-Boiler-Mixer-Spray Guns-Saws-Sander-Oven-Dryer-Furnace-Incinerator-Haul Road-Storage Pile, etc.)
Match the Units listed on this Table to the same numbered line if also listed on Emissions Tables & Stack Table.

Unit Number and Description[1]		Manufacturer	Model #	Serial #	Manufacture Date	Installation Date	Modification Date[2]	Process Rate or Capacity (Hp, kW, Btu, ft^3, lbs, tons, yd^3, etc.)[3]	Fuel Type
1	**Internal Combustion/Generator (Diesel-Fired)**	**Caterpillar**	**3516B**	**1HZ02180**	**2002**	**2002**		**2,636 hp**	**Diesel**
2	**Internal Combustion/Generator (Diesel-Fired)**	**Caterpillar**	**3516B**	**7RN00972**	**1999**	**2000**		**2,628 hp**	**Diesel**
3	**Boiler (Natural Gas/Diesel-Fired)**	**Kewance**	**H3S500-G-06**	**Order 606391**	**Unknown**	**1979**	**2022**	**20.9 MMBtu/hr**	**Natural Gas/Diesel**
4	**Boiler (Natural Gas/Diesel-Fired)**	**Kewance**	**H3S500-G-06**	**Order 606391**	**Unknown**	**1979**	**2022**	**20.9 MMBtu/hr**	**Natural Gas/Diesel**
5	**Boiler (Natural Gas-Fired)**	**Superior**	**HPG-C5V**	**03971989P**	**1997**	**Unknown**		**8.4 MMBtu/hr**	**Natural Gas**
6	**Boiler (Natural Gas/Diesel-Fired)**	**Burnham Industrial**	**LN5P-500-50-G0-WEB**	**Burner # U66158A-1-8-02 Order # 682532**	**2002**	**2002**		**21 MMBtu/hr**	**Natural Gas/Diesel**
7	**Diesel-Fired Engine**	**Caterpillar**	**3516C**	**SBJ02005**	**6/2016**	**2016**		**2,937 hp**	**Diesel**
	Generator	**Caterpillar**	**SR5-1645**	**G2T00106**	**6/2016**	**2016**		**2,000 kW**	
8	**Internal Combustion/Electric and Steam Generator (Natural Gas-Fired)**	**Caterpillar**	**G3516H**	**NWJ01131**	**2021**	**2022**		**2,763 bhp**	**Natural Gas**
								/	
								/	
								/	
								/	
								/	

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Unit numbers must correspond to unit numbers in the previous permit unless a complete cross reference table of all units in both permits is provided.
2. Have changes been made to the unit that impact emissions or that trigger modification as defined in 20.11.41.7.U NMAC?
3. Basis for Equipment Process Rate or Capacity (Manufacturer's data, Field observation/test, etc.) **Manufacturer's Data**
   Submit information for each unit as an attachment.

Emissions Control Equipment Table

Control Equipment Units listed on this Table should either match up to the same Unit number as listed on the Regulated Emission Sources, Controlled Emissions and Stack Parameters Tables (if the control equipment is integrated with the emission unit) or should have a distinct Control Equipment Unit Number and that number should then also be listed on the Stack Parameters Table.

Control Equipment Unit Number and Description		Controlling Emissions for Unit Number(s)	Manufacturer	Model # | Serial #	Date Installed	Controlled Pollutant(s)	% Control Efficiency[1]	Method Used to Estimate Efficiency	Rated Process Rate or Capacity or Flow
8b	**Oxidation Catalyst**	**8**	**Miratech**	**IQ2-30-20 | RE-41663**	**2022**	**CO, VOC, CH_2O**	**CO – 80% VOC – 40% CH_2O – 70%**	**Manufacturer Calculated Reduction**	**2,763 bhp**

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Control Equipment % Efficiency (Manufacturers data, Field Observation/Test, AP-42, etc.). Manufacturer Calculated Reduction
   Submit information for each unit as an attachment.

Exempted Sources and Exempted Activities Table

See 20.11.41 for exemptions.

Unit Number and Description		Manufacturer	Model #	Serial #	Manufacture Date	Installation Date	Modification Date[1]	Process Rate or Capacity (Hp, kW, Btu, ft^3, lbs, tons, yd^3, etc.)[2]	Fuel Type
	N/A							/	
								/	
								/	
								/	
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NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Have changes been made to the unit that impact emissions, that trigger modification as defined in 20.11.41.7.U NMAC, or that change the status from exempt to non-exempt?
2. Basis for Equipment Process Rate or Capacity (Manufacturer's data, Field observation/test, etc.) _____
   Submit information for each unit as an attachment.

Uncontrolled Emissions Table

(Process potential under physical/operational limitations during a 24 hr/day and 365 day/year = 8760 hrs)

Regulated Emission Units listed on this Table should match up to the same numbered line and Unit as listed on the Regulated Emissions and Controlled Tables. List total HAP values per Emission Unit if overall HAP total for the facility is ≥ 1 ton/yr.

Unit Number*	Nitrogen Oxides (NO_X)		Carbon Monoxide (CO)		Nonmethane Hydrocarbons/Volatile Organic Compounds (NMHC/VOCs)		Sulfur Dioxide (SO_2)		Particulate Matter ≤ 10 Microns (PM_{10})		Particulate Matter ≤ 2.5 Microns ($PM_{2.5}$)		Hazardous Air Pollutants (HAPs)		Method(s) used for Determination of Emissions (AP-42, Material Balance, Field Tests, etc.)
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	
1	**31.1**	**7.8**	**4.6**	**1.1**	**1.3**	**0.3**	**5.4**	**1.4**	**1.0**	**0.3**	**1.0**	**0.3**	**0.11**	**0.0021**	**Permit #023-M3-1TR Emission Limits**
2	**31.1**	**7.8**	**4.6**	**1.1**	**1.3**	**0.3**	**5.4**	**1.4**	**1.0**	**0.3**	**1.0**	**0.3**	**0.11**	**0.0021**	**Permit #023-M3-1TR Emission Limits**
3	**1.46[4]**	**6.38[4]**	**0.77[4]**	**3.37[4]**	**0.52[4]**	**2.28[4]**	**0.05[4]**	**0.22[4]**	**0.10[4]**	**0.44[4]**	**0.10[4]**	**0.44[4]**	**0.042[4]**	**0.18[4]**	**Manufacturer Data – NOx, CO, VOC, PM; SO2 – Fuel Sulfur Content**
	3.06[5]	**0.07[5]**	**0.77[5]**	**0.019[5]**	**0.80[5]**	**0.019[5]**	**1.07[5]**	**0.026[5]**	**0.3[5]**	**0.007[5]**	**0.3[5]**	**0.007[5]**			**Manufacturer Data – NOx, CO, VOC, PM; SO2 – Fuel Sulfur Content**
4	**1.46[4]**	**6.38[4]**	**0.77[4]**	**3.37[4]**	**0.52[4]**	**2.28[4]**	**0.05[4]**	**0.22[4]**	**0.10[4]**	**0.44[4]**	**0.10[4]**	**0.44[4]**	**0.042[4]**	**0.18[4]**	**Manufacturer Data – NOx, CO, VOC, PM; SO2 – Fuel Sulfur Content**
	3.06[5]	**0.07[5]**	**0.77[5]**	**0.019[5]**	**0.80[5]**	**0.019[5]**	**1.07[5]**	**0.026[5]**	**0.3[5]**	**0.007[5]**	**0.3[5]**	**0.007[5]**			**Manufacturer Data – NOx, CO, VOC, PM; SO2 – Fuel Sulfur Content**
5	**1.0**	**4.4**	**0.9**	**3.7**	**0.06**	**0.2**	**0.01**	**0.03**	**0.08**	**0.34**	**0.08**	**0.34**	**0.017**	**0.073**	**Permit #023-M3-1TR Emission Limits**
6	**1.06[4]**	**4.60[4]**	**2.1[4]**	**9.3[4]**	**0.1[4]**	**0.6[4]**	**0.02[4]**	**0.07[4]**	**0.2[4]**	**0.8[4]**	**0.2[4]**	**0.8[4]**	**0.042[4]**	**0.18[4]**	**NOx Recalulated at 30 PPM per Manufacturer; Permit #023-M3-1TR Emission Limits – CO, VOC, PM, SO2**
	3.0[5]	**0.8[5]**	**0.8[5]**	**0.2[5]**	**0.05[5]**	**0.01[5]**	**1.1[5]**	**0.3[5]**	**0.3[5]**	**0.08[5]**	**0.3[5]**	**0.08[5]**			**Permit #023-M3-1TR Emission Limits**
7	**29.53**	**7.38**	**16.83**	**4.21**	**1.55**	**0.39**	**3.56**	**0.89**	**0.97**	**0.24**	**0.97**	**0.24**	**0.12**	**0.0024**	**Permit #023-M3-1TR Emission Limits**
8	**6.09**	**26.68**	**49.34**	**216.11**	**3.25**	**14.23**	**0.038**	**0.17**	**0.16**	**0.71**	**0.16**	**0.71**	**4.17**	**18.27**	**Manufacturer Data**
Totals of Uncontrolled Emissions	**102.8[4]**	**72.37**	**79.92[4]**	**242.50**	**8.61[4]**	**20.62**	**14.53[4]**	**4.74**	**3.61[4]**	**3.66**	**3.61[4]**	**3.66**	**4.65**	**18.89**	
	107.9[5]		**78.62[5]**		**9.10[5]**		**17.65[5]**		**4.11[5]**		**4.11[5]**				

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

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*A permit is required and this application along with the additional checklist information requested on the Permit Application checklist must be provided if:

(1) any one of these process units or combination of units, has an uncontrolled emission rate greater than or equal to (≥) 10 lbs/hr or 25 tons/yr for any of the above pollutants, excluding HAPs, based on 8,760 hrs of operation; or

(2) any one of these process units or combination of units, has an uncontrolled emission rate ≥ 2 tons/yr for any single HAP or ≥ 5 tons/yr for any combination of HAPs based on 8,760 hours of operation; or

(3) any one of the process units or combination of units is subject to an Air Board or federal emission limit or standard.

* If all of these process units, individually and in combination, have an uncontrolled emission rate less than (<) 10 lbs/hr or 25 tons/yr for all of the above pollutants (based on 8,760 hrs of operation), but > 1 ton/yr for any of the above pollutants, then a source registration is required. A Registration is required, at minimum, for any amount of HAP emissions. Please complete the remainder of this form.

(4) Pound per hour and ton per year when unit is operating with natural gas only

(5) Pound per hour and ton per year when unit is operating with diesel fuel for emergency, maintenance, and testing purposes only

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Controlled Emissions Table

(Based on current operations with emission controls OR requested operations with emission controls)

Regulated Emission Units listed on this Table should match up to the same numbered line and Unit as listed on the Regulated Emissions and Uncontrolled Tables. List total HAP values per Emission Unit if overall HAP total for the facility is ≥ 1 ton/yr.

Unit Number	Nitrogen Oxides (NO_x)		Carbon Monoxide (CO)		Nonmethane Hydrocarbons/Volatile Organic Compounds (NMHC/VOCs)		Sulfur Dioxide (SO_2)		Particulate Matter ≤ 10 Microns (PM_{10})		Particulate Matter ≤ 2.5 Microns ($PM_{2.5}$)		Hazardous Air Pollutants (HAPs)		Control Method	% Efficiency[1]
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr		
1	**31.1**	**7.8**	**4.6**	**1.1**	**1.3**	**0.3**	**5.4**	**1.4**	**1.0**	**0.3**	**1.0**	**0.3**	**0.11**	**0.0021**	**NA**	**NA**
2	**31.1**	**7.8**	**4.6**	**1.1**	**1.3**	**0.3**	**5.4**	**1.4**	**1.0**	**0.3**	**1.0**	**0.3**	**0.11**	**0.0021**	**NA**	**NA**
3	**1.46(2)**	**6.38(2)**	**0.77(2)**	**3.37(2)**	**0.52(2)**	**2.28(2)**	**0.05(2)**	**0.22(2)**	**0.10(2)**	**0.44(2)**	**0.10(2)**	**0.44(2)**	**0.042(2)**	**0.18(2)**	**NA**	**NA**
	3.06(3)	**0.07(3)**	**0.77(3)**	**0.019(3)**	**0.80(3)**	**0.019(3)**	**1.07(3)**	**0.026(3)**	**0.30(3)**	**0.007(3)**	**0.30(3)**	**0.007(3)**				
4	**1.46(2)**	**6.38(2)**	**0.77(2)**	**3.37(2)**	**0.52(2)**	**2.28(2)**	**0.05(2)**	**0.22(2)**	**0.10(2)**	**0.44(2)**	**0.10(2)**	**0.44(2)**	**0.042(2)**	**0.18(2)**	**NA**	**NA**
	3.06(3)	**0.07(3)**	**0.77(3)**	**0.019(3)**	**0.80(3)**	**0.019(3)**	**1.07(3)**	**0.026(3)**	**0.30(3)**	**0.007(3)**	**0.30(3)**	**0.007(3)**				
5	**1.0**	**4.4**	**0.9**	**3.7**	**0.06**	**0.2**	**0.01**	**0.03**	**0.08**	**0.34**	**0.08**	**0.34**	**0.017**	**0.073**	**NA**	**NA**
6	**1.06(2)**	**4.60(2)**	**2.1(2)**	**9.3(2)**	**0.1(2)**	**0.6(2)**	**0.02(2)**	**0.07(2)**	**0.2(2)**	**0.8(2)**	**0.2(2)**	**0.8(2)**	**0.042(2)**	**0.18(2)**	**NA**	**NA**
	3.0(3)	**0.8(3)**	**0.8(3)**	**0.2(3)**	**0.05(3)**	**0.01(3)**	**1.1(3)**	**0.3(3)**	**0.3(3)**	**0.08(3)**	**0.3(3)**	**0.08(3)**				
7	**29.53**	**7.38**	**16.83**	**4.21**	**1.55**	**0.39**	**3.56**	**0.89**	**0.97**	**0.24**	**0.97**	**0.24**	**0.12**	**0.0024**	**NA**	**NA**
8	**6.09**	**26.68**	**9.87**	**43.22**	**1.95**	**8.54**	**0.038**	**0.17**	**0.16**	**0.71**	**0.16**	**0.71**	**1.47**	**6.44**	**CO, VOC, Formaldehyde**	**80%, 40%, 70%**
Totals of Controlled Emissions (4)	**101.8(2)**	**67.97**	**39.67(2)**	**66.22**	**7.25(2)**	**14.73**	**14.52(2)**	**4.71**	**3.53(2)**	**3.32**	**3.53(2)**	**3.32**	**1.94**	**6.99**		
	106.9(3)		**38.37(3)**		**7.74(3)**		**17.64(3)**		**4.03(3)**		**4.03(3)**					

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Control Equipment % Efficiency (Manufacturers data, Field Observation/Test, AP-42, etc.). **Manufacturers Data**
   Submit information for each unit as an attachment.

(2) Pound per hour and ton per year when unit is operating with natural gas only

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(3) Pound per hour and ton per year when unit is operating with diesel fuel for emergency, maintenance, and testing purposes only
(4) Totals based on the highest maximum emission rates for three of the four boilers operating at the same time.

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Hazardous Air Pollutants (HAPs) Emissions Table

Report the Potential Emission Rate for each HAP from each source on the Regulated Emission Sources Table that emits a given HAP. Report individual HAPs with ≥ 1 ton/yr total emissions for the facility on this table. Otherwise, report total HAP emissions for each source that emits HAPs and report individual HAPs in the accompanying application package in association with emission calculations. If this application is for a Registration solely due to HAP emissions, report the largest HAP emissions on this table and the rest, if any, in the accompanying application package.

Unit Number	Total HAPs		Formaldehyde													
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
1	**0.11**	**0.0021**														
2	**0.11**	**0.0021**														
3	**0.042**	**0.18**			**HAPs Emission Rates were calculated for the boilers operating natural gas. Natural gas is the prevalent fuel combusted.**											
4	**0.042**	**0.18**														
5	**0.017**	**0.073**														
6	**0.042**	**0.18**														
7	**0.12**	**0.0024**														
8	**1.47**	**6.44**	**1.16**	**5.07**												
Totals of HAPs for all units: [1]	**1.94**	**6.99**	**1.16**	**5.07**												

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

Copy and paste the HAPs table here if need to list more individual HAPs.

(1) Totals based on the highest maximum emission rates for three (yellow highlighted) of the four boilers operating at the same time.

Purchased Hazardous Air Pollutant Table*

Product Categories (Coatings, Solvents, Thinners, etc.)	Hazardous Air Pollutant (HAP), or Volatile Hazardous Air Pollutant (VHAP) Primary To The Representative As Purchased Product	Chemical Abstract Service Number (CAS) of HAP or VHAP from Representative As Purchased Product	HAP or VHAP Concentration of Representative As Purchased Product (pounds/gallon, or %)	Concentration Determination (CPDS, MSDS, etc.)[1]	Total Product Purchases For Category	(-)	Quantity of Product Recovered & Disposed For Category	(=)	Total Product Usage For Category
1. N/A					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
2.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
3.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
4.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
5.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
6.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
7.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
8.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
9.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
.					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr
TOTALS					lbs/yr gal/yr	(-)	lbs/yr gal/yr	(=)	lbs/yr gal/yr

NOTE: To add extra rows in Word, click anywhere in the second-to-last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Submit, as an attachment, information on one (1) product from each Category listed above which best represents the average of all the products purchased in that Category.

***NOTE: A Registration is required, at minimum, for any amount of HAP or VHAP emission.**
Emissions from purchased HAP usage should be accounted for on previous tables as appropriate.
A permit may be required for these emissions if the source meets the requirements of 20.11.41.

Material and Fuel Storage Table

(Tanks, barrels, silos, stockpiles, etc.)

Storage Equipment		Product Stored	Capacity (bbls, tons, gals, acres, etc.)	Above or Below Ground	Construction (Welded, riveted) & Color	Installation Date	Loading Rate[1]	Offloading Rate[1]	True Vapor Pressure	Control Equipment	Seal Type	% Eff.[2]
UST1	**Tank #1, UL A74663**	**#2 Diesel**	**30,000 Gal**	**Below**	**Dbl wall Fiberglas**	**12/2009**	**5000**	**Various**	**<15 kPa**	**NA**	**NA**	**NA**
UST2	**Tank #2, UL A74667**	**#2 Diesel**	**30,000 Gal**	**Below**	**Dbl wall fiberglas**	**12/2009**	**5000**	**Various**	**<15 kPa**	**NA**	**NA**	**NA**

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

1. Basis for Loading/Offloading Rate (Manufacturer's data, Field Observation/Test, etc.). **Loading rate equal to delivery truck capacity; Unloading rate is various depending on demand from diesel-fired boilers and emergency generators operation**
   Submit information for each unit as an attachment.
2. Basis for Control Equipment % Efficiency (Manufacturer's data, Field Observation/Test, AP-42, etc.). **NA**
   Submit information for each unit as an attachment.

Stack Parameters Table

If any equipment from the Regulated Emission Sources Table is also listed in this Stack Table, use the same numbered line for the emission unit on both tables to show the association between the Process Equipment and its stack.

Unit Number	Description	Pollutant (CO, NOx, PM10, etc.)	UTM Easting (m)	UTM Northing (m)	Stack Height (ft)	Stack Exit Temp. (°F)	Stack Velocity (fps)	Stack Flow Rate (ACFM)	Stack Inside Diameter (ft)	Stack Type
3	**Internal Combustion/ Generator (Diesel-Fired)**	**NOx, CO, S02,** PMio, $PM_{2.5}$	350833.1	3883177.0	37.0	400.0	27.57	7,073	2.33	**Rain Cap**
4	**Boiler (Natural Gas/Diesel-Fired)**	**NOx, CO, S02,** PM_{io}, $PM_{2.5}$	350835.9	3883176.6	37.0	400.0	27.57	7,073	2.33	**Rain Cap**
5	**Boiler (Natural Gas/Diesel-Fired)**	**NOx, CO, S02,** **PM_{io}, $PM_{2.5}$**	350837.9	3883176.2	37.0	400.0	**21.66**	2,835	1.67	**Rain Cap**
6	**Boiler (Natural Gas-Fired)**	**NOx, CO, S02,** PMio, $PM_{2.5}$	350849.2	3883175.4	37.0	400.0	43.85	8,265	2.00	**Rain Cap**
8	**Internal Combustion/ Electric and Steam Generator (Natural-Fired)**	**NOx, CO, S02,** **PMio, $PM_{2.5}$**	350838.3	3883182.2	49.0	375.0	64.54	8,448	1.67	**Vertical**

NOTE: To add extra rows in Word, click anywhere in the last row. A plus (+) sign should appear on the bottom right corner of the row. Click the plus (+) sign to add a row. Repeat as needed.

I, the undersigned, an authorized representative of the applicant company, certify that to the best of my knowledge, the information stated on this application, together with associated drawings, specifications, and other data, give a true and complete representation of the existing, modified existing, or planned new stationary source with respect to air pollution sources and control equipment. **I** also understand that any significant omissions, errors, or misrepresentations in these data will be cause for revocation of part or all of the resulting registration or permit.

Signed this 28 day of January, 20 22

Keith Long
Print Name

Director, Engineering
Print Title

Keith Long
Signature

Attachment A
Facility Process Flow Diagram and Plot Plan

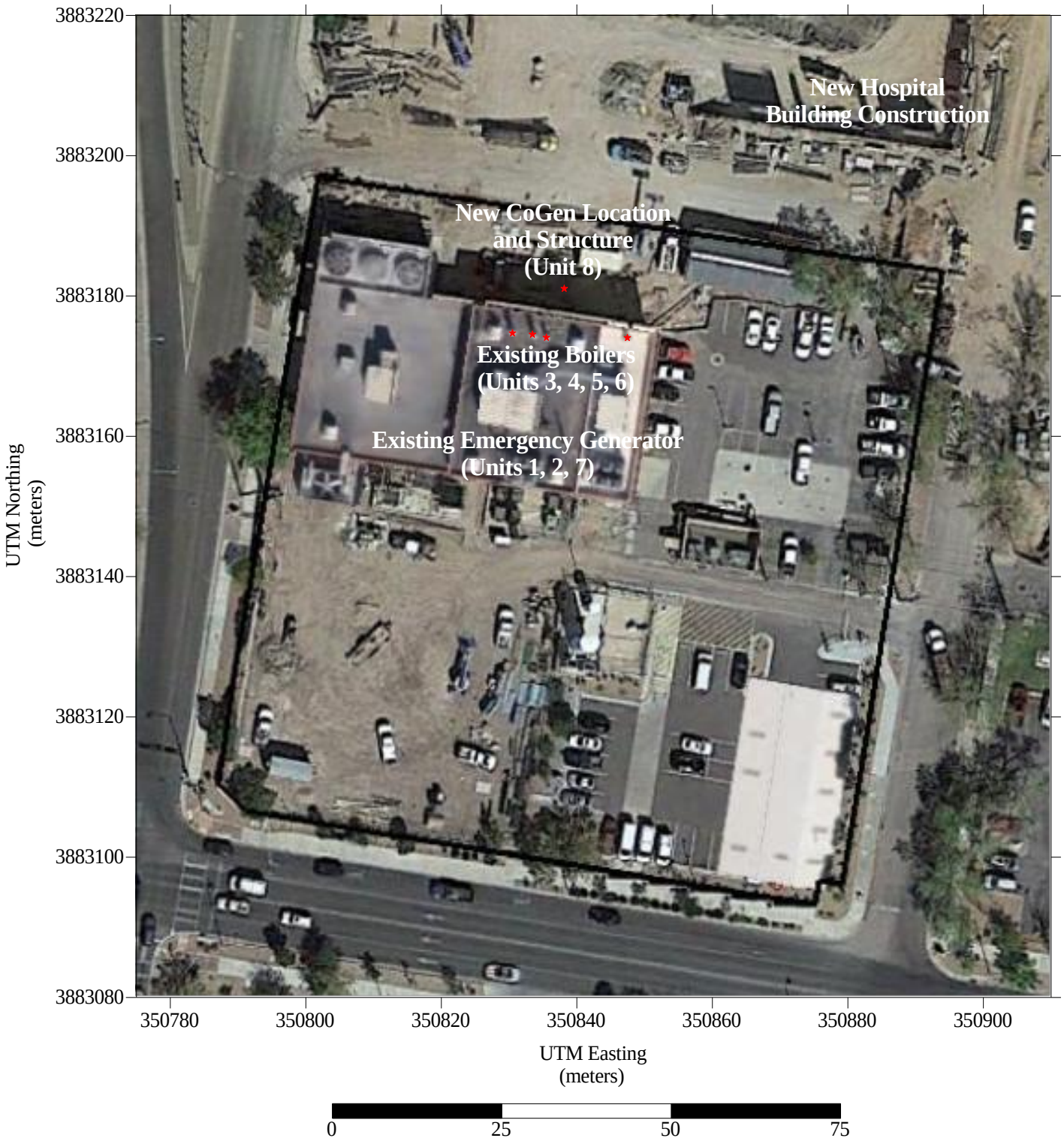

FIGURE A-1: PHS Energy Center Facility Layout

Attachment B
Emissions Calculations

There will be no emission change in existing Permitted Units 1, 2, 5 and 7 steam boilers and emergency generators emission rates with the exception of CO annual emission rates for Units 1 and 2. For these identical units all emissions are the same. In the present permit, CO annual emission rates are different and PHS has corrected the CO annual emission rate so they are the same for each unit.

For this significant permit application, PHS will add a new CoGen plant at the existing PHS Energy Center, and replacing the burners for steam boilers 1 and 2 (Units 3 and 4) with revised emission rate calculation based on manufacturers specifications. Additionally, for steam boiler 4 (Unit 6) the NOx emission rate will be recalculated per the original burner manufacturers emission rate guarantee (see Attachment C) of 30 PPM.

CoGen (Permit Unit 8) Emission Rates

The CoGen will be permitted to operating at maximum emissions rates as supplied by the manufacturer, mass balance, or AP-42 emission factors, and operating for 8,760 hours per year. An oxidation catalyst is proposed for the CoGen engine. The oxidation catalyst will control emission of CO, VOC, and Formaldehyde potentially resulting from natural gas fuel combustion by the CoGen engine. Based on information provided by the oxidation catalyst manufacturer (Miratech), CO control efficiency is 80%, VOC is 40%, and Formaldehyde is 70%. To estimate the uncontrolled emission rate for CO, VOC, and Formaldehyde, the CAT allowable emission factors were adjusted by the pollutant control efficiency.

NO_X, CO, VOC, formaldehyde, and CO_2 emission factors are extracted from the Caterpillar emission document found in Attachment C. Particulate emission factor for natural gas combustion for RICE engines is found in AP-42 Section 3.2 **"**Natural Gas-fired Reciprocating Engines".

Sulfur dioxide (SO_2) emission rates were determined by mass balance based on the sulfur content in New Mexico natural gas and the amount of natural gas combusted. Based on Public Regulatory Commission documents (see Attachment C), the maximum sulfur content in New Mexico natural gas is 0.75 grains per 100 standard cubic feet (scf). The amount of Btu per hour combusted in the CoGen engine was extracted from Caterpillar emission document found in Attachment C and a lower heating value for natural gas of 905 Btu/scf.

The following is the emission calculations for the CoGen engine.

Engine BHP =	2,763	Manufacturer Data			
Hours/Yr =	8,760				
Fuel Consumption =	5,843	Btu/BHP-Hr, Manufacturer Data			
Fuel Consumption =	16,144,209	Btu/Hr			
Fuel Consumption =	17,700.0	scf/hr	LHV=	905	Btu/scf
Sulfur Content	0.75	grains/100 scf (NM regulatory limit)			

Catalyst Control Efficiency		(see Section C)
CO =	80	%
VOC =	40	%
Formaldehyde =	70	%

Manufacturer Emission Rates (see Section C)

	Uncontrolled	Manufacturer	Uncontrolled		Controlled	
	g/BHP-hr	g/BHP-hr	lbs/hr	tpy	lbs/hr	tpy
NOx =	1.00	1.00	6.09	26.68	6.09	26.68
CO =	8.10	1.62	49.34	216.11	9.87	43.22
VOC =	0.53	0.32	3.25	14.23	1.95	8.54
Formaldehyde =	0.63	0.19	3.86	16.90	1.16	5.07
CO2 =	412	412	2,510	10,992	2,510	10,992

SO_2 = 0.75 grains/100 scf * 17,700.0 scf/hr/100 / 7,000 grains/pound * 2 S/SO_2

	lbs/hr	tpy
SO_2 =	0.038	0.17

AP-42 Section 3.2 **"**Natural Gas-fired Reciprocating Engines", Table 3.2-2

	lb/MMBtu	lbs/hr	tpy
PM Filterable =	7.71E-05	0.0012	0.0055
PM Condensable =	9.91E-03	0.16	0.70
PM Total =		0.16	0.71

Boilers 1 and 2 (Permit Units 3 and 4) Emission Rates

As part of this permit application, PHS will be installing new Power Flame Burners on Boilers 1 and 2 (Permit Units 3 and 4). The manufacturer's data sheet is found in Section C. These two boilers are permitted to combust both natural gas and diesel with manufacturer's emission rate represented in the manufacturer's data. For SO_2, the emissions are based on the sulfur content of the fuel combusted, 0.75 grains/100 scf for natural gas and 500 PPM (0.05%) for diesel.

Emission Units 3 and 4 (Boiler 1 and 2) NG

Emission Factor	0.070	lb/NOx per MMBTU Input		Manufacturer
Emission Factor	0.037	lb/CO per MMBTU Input		Manufacturer
Emission Factor	0.0048	lb/PM per MMBTU Input		Manufacturer
Emission Factor	0.025	lb/VOC per MMBTU Input		Manufacturer
MBH	20925			Manufacturer
MMBTU/Hr	20.925			Manufacturer
BTU/Hr	20925000			Manufacturer
scf/hr	23121.55	LHV=	905	Btu/scf

Hours per year 8712

lbs/hr = lb/MMBTU * MMBTU/Hr
tpy = lbs/hr * hr/yr / 2000 lbs/ton

	lbs/hr	tpy	
NOx	1.46	6.38	Based on Emission Factor
CO	0.77	3.37	Based on Emission Factor
PM	0.10	0.44	Based on Emission Factor
VOC	0.52	2.28	Based on Emission Factor

Sulfur Content 0.75 grains/100 scf (NM regulatory limit)

SO2 = grains/100 scf * scf/hr/100 / 7000 grains/lb * 2S/SO2

	lbs/hr	tpy
SO2 =	0.050	0.22

Emission Units 3 and 4 (Boiler 1 and 2) Diesel

Emission Factor	0.146	lb/NOx per MMBTU Input		Manufacturer
Emission Factor	0.037	lb/CO per MMBTU Input		Manufacturer
Emission Factor	0.0143	lb/PM per MMBTU Input		Manufacturer
Emission Factor	0.038	lb/VOC per MMBTU Input		Manufacturer
MBH	20925			Manufacturer
MMBTU/Hr	20.925			Manufacturer
BTU/Hr	20925000			Manufacturer
gallon/hr	152.74	LHV=	137000	Btu/gallon
Hours per year	48			

lbs/hr = lb/MMBTU * MMBTU/Hr
tpy = lbs/hr * hr/yr / 2000 lbs/ton
Manufacture Spec

	lbs/hr	tpy	
NOx	3.06	0.073	Based on Emission Factor
CO	0.77	0.019	Based on Emission Factor
PM	0.30	0.0072	Based on Emission Factor
VOC	0.80	0.019	Based on Emission Factor

Sulfur Content 500 PPM

SO2 = gal/hr * 7 lbs/gal * PPM/1000000 * 2S/SO2

	lbs/hr	tpy
SO2 =	1.069	0.026

Boiler 4 (Permit Unit 6) Emission Rates

For this application, PHS will be recalculate the NOx emission rate for Permit Unit 6 combusting natural gas. The new NOx emission rate for natural gas will be calculated using a parts per million (PPM) of 30 of the exhaust in standard cubic feet per minute (SCFM). The manufacturer's data sheet is found in Section C. NOx emission rate was calculated by converting PPM to pounds per hour.

Emission Unit 6 (Boiler 4) Natural Gas

Boiler	**Stack Flowrate (ACFM)**	
Unit 6	8265	
Hours/Year on Natural Gas	8712	
NOx PPM	30	Manufacturer Data

SCFM = ACFM * Standard Temperature (R) / High Temperature (R)

ACFM	Boiler High Temperature F	Standard Temperature F	Boiler High Temperature R	Standard Temperature R	SCFM
8265	400	70	860	530	5094

NOx lbs/hr = PPM/1000000 *Air Density (lbs/ft3) * SCFM * min/hr * Molecular Weight (mw) / mw air

NOx lbs/hr	PPM	Air Density lbs/ft3	SCFM	min/hr	mw NOx	mw air
1.06	30	0.0749	5094	60	46.1	29.95

Tons per Year (tpy) = lbs/hr * hr/yr / 2000 lbs/ton

NOx tpy	NOx lbs/hr	hr/yr	lbs/ton
4.60	1.06	8712	2000

Table B-1 Summary of Uncontrolled NOx, CO, SO2, and PM Emission Rates

Uncontrolled Emission Totals															
Unit #	Description	NO_X		NO_X + NMHC		CO		SO_2		VOC		PM_{10}		$PM_{2.5}$	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	lbs/hr	lbs/hr	tons/yr	lbs/hr	tons/yr
1	Internal Combustion/Emergency Generator (Diesel-Fired)	31.1	7.8	----	----	4.6	1.1	5.4	1.4	1.3	0.3	1.0	0.3	1.0	0.3
2	Internal Combustion/Emergency Generator (Diesel-Fired)	31.1	7.8	----	----	4.6	1.1	5.4	1.4	1.3	0.3	1.0	0.3	1.0	0.3
3	Boiler (Natural Gas/Diesel-Fired)	1.46(1)	6.38(1)	----	----	0.77(1)	3.37(1)	0.050(1)	0.22(1)	0.52(1)	2.28(1)	0.10(1)	0.44(1)	0.10(1)	0.44(1)
		3.06(2)	0.073(2)	----	----	0.77(2)	0.0.19(2)	1.07(2)	0.026(2)	0.80(2)	0.019(2)	0.30(2)	0.0072(2)	0.30(2)	0.0072(2)
4	Boiler (Natural Gas/Diesel-Fired)	1.46(1)	6.38(1)	----	----	0.77(1)	3.37(1)	0.050(1)	0.22(1)	0.52(1)	2.28(1)	0.10(1)	0.44(1)	0.10(1)	0.44(1)
		3.06(2)	0.073(2)	----	----	0.77(2)	0.0.19(2)	1.07(2)	0.026(2)	0.80(2)	0.019(2)	0.30(2)	0.0072(2)	0.30(2)	0.0072(2)
5	Boiler (Natural Gas-Fired)	1.0	4.4	----	----	0.9	3.7	0.01	0.03	0.06	0.2	0.08	0.34	0.08	0.34
6	Boiler (Natural Gas/Diesel-Fired)	1.06(1)	4.60(1)	----	----	2.1(1)	9.3(1)	0.02(1)	0.07(1)	0.1(1)	0.6(1)	0.2(1)	0.8(1)	0.2(1)	0.8(1)
		3.0(2)	0.8(2)	----	----	0.8(2)	0.2(2)	1.1(2)	0.3(2)	0.05(2)	0.01(2)	0.3(2)	0.08(2)	0.3(2)	0.08(2)
7	Internal Combustion/Emergency Generator (Diesel-Fired)	29.53	7.38	31.08	7.77	16.83	4.21	3.56	0.89	1.55	0.39	0.97	0.24	0.97	0.24
8	Internal Combustion/Electric and Steam Generator (Natural Gas-Fired)	6.09	26.68	----	----	49.34	216.1	0.038	0.17	3.25	14.2	0.16	0.71	0.16	0.71
Total		**102.8**(1)	**72.37**			**79.92**(1)	**242.5**	**14.53**(1)	**4.74**	**8.61**(1)	**20.62**	**3.61**(1)	**3.66**	**3.61**(1)	**3.66**
		107.9(2)				**78.62**(2)		**17.65**(2)		**9.10**(2)		**4.11**(2)		**4.11**(2)	

(1) Pound per hour and ton per year when unit is operating with natural gas only
(2) Pound per hour and ton per year when unit is operating with diesel fuel for emergency, maintenance, and testing purposes only

Correct information received 03/07/2022 cgmd

Table B-2 Summary of Allowable NOx, CO, SO2, and PM Emission Rates

Allowable Emission Totals															
Unit #	Description	NO_X		NO_X + NMHC		CO		SO_2		VOC		PM_{10}		$PM_{2.5}$	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	lbs/hr	lbs/hr	tons/yr	lbs/hr	tons/yr
1	Internal Combustion/Emergency Generator (Diesel-Fired)	31.1	7.8	----	----	4.6	1.1	5.4	1.4	1.3	0.3	1.0	0.3	1.0	0.3
2	Internal Combustion/Emergency Generator (Diesel-Fired)	31.1	7.8	----	----	4.6	1.1	5.4	1.4	1.3	0.3	1.0	0.3	1.0	0.3
3	Boiler (Natural Gas/Diesel-Fired)	1.46(1)	6.38(1)	----	----	0.77(1)	3.37(1)	0.050(1)	0.22(1)	0.52(1)	2.28(1)	0.10(1)	0.44(1)	0.10(1)	0.44(1)
		3.06(2)	0.073(2)	----	----	0.77(2)	0.019(2)	1.07(2)	0.026(2)	0.80(2)	0.019(2)	0.30(2)	0.0072(2)	0.30(2)	0.0072(2)
4	Boiler (Natural Gas/Diesel-Fired)	1.46(1)	6.38(1)	----	----	0.77(1)	3.37(1)	0.050(1)	0.22(1)	0.52(1)	2.28(1)	0.10(1)	0.44(1)	0.10(1)	0.44(1)
		3.06(2)	0.073(2)	----	----	0.77(2)	0.019(2)	1.07(2)	0.026(2)	0.80(2)	0.019(2)	0.30(2)	0.0072(2)	0.30(2)	0.0072(2)
5	Boiler (Natural Gas-Fired)	1.0	4.4	----	----	0.9	3.7	0.01	0.03	0.06	0.2	0.08	0.34	0.08	0.34
6	Boiler (Natural Gas/Diesel-Fired)	1.06(1)	4.60(1)	----	----	2.1(1)	9.3(1)	0.02(1)	0.07(1)	0.1(1)	0.6(1)	0.2(1)	0.8(1)	0.2(1)	0.8(1)
		3.0(2)	0.8(2)	----	----	0.8(2)	0.2(2)	1.1(2)	0.3(2)	0.05(2)	0.01(2)	0.3(2)	0.08(2)	0.3(2)	0.08(2)
7	Internal Combustion/Emergency Generator (Diesel-Fired)	29.53	7.38	31.08	7.77	16.83	4.21	3.56	0.89	1.55	0.39	0.97	0.24	0.97	0.24
8	Internal Combustion/Electric and Steam Generator (Natural Gas-Fired)	6.09	26.68	----	----	9.87	43.22	0.038	0.17	1.95	8.54	0.16	0.71	0.16	0.71
Total(3)		**101.8(1)**	**67.97**			**39.67(1)**	**66.22**	**14.52(1)**	**4.71**	**7.25(1)**	**14.73**	**3.53(1)**	**3.32**	**3.53(1)**	**3.32**
		106.9(2)				**38.37(2)**		**17.64(2)**		**7.74(2)**		**4.03(2)**		**4.03(2)**	

(1) Pound per hour and ton per year when unit is operating with natural gas only
(2) Pound per hour and ton per year when unit is operating with diesel fuel for emergency, maintenance, and testing purposes only
(3) Total is sum of the maximum emission of 3 of the 4 boilers operating at any one time as proposed in the permit application.

cgmd

Correct information received 03/07/2022

Estimates for Federal Hazardous Air Pollutants (HAPs)

The combustion Units 1 - 8, are sources of HAPs as it appears in Section 112 (b) of the 1990 CAA. Emissions of HAPs were determined with all boiler sources combusting natural gas. Emergency diesel-fired generator/engine (Units 1, 2, and 7) used AP-42 Section 3.3 and 1.3 HAP emission factors. Steam boilers combusting natural gas (Units 3, 4, 5, and 6) used AP-42 Section 1.4 HAP emission factors. CoGen system combusting natural gas (Unit 8) used AP-42 Section 3.2 HAP emission factors.

The following tables summarize the HAPs emission rates from the Units 1 - 8. Total combined HAPs emissions from the PHS Energy Center is 1.95 pounds per hour or 7.06 tons per year. Total combined HAPs emissions from the PHS Energy Center with only 3 of the 4 boilers operating at a time is 1.94 pounds per hour or 6.99 tons per year.

Table B-3: HAPs Emission Rates from the Unit 1 (Emergency Generator)

EPA HAPS Emissions Diesel Fired Engines

Horsepower Rating:	2,636	horsepower	
Fuel Usage:	131.8	gallons/hr	
MMBtu/hr:	16.8704	Btu	(based on 128000 Btu/gallon)
Btu x 10^-12/hr:	1.68704E-05	Btu x10^-12	(based on 128000 Btu/gallon)
Yearly Operating Hours:	500	hours per year	

Type of Fuel: Diesel
Emission Factors AP-42 Section 3.3 and Section 1.3

Non-PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acetalehyde	75-07-0	7.67E-04	0.012940	0.003235
Acrolein	107-02-8	9.25E-05	0.001561	0.000390
Benzene	71-43-2	9.33E-04	0.015740	0.003935
1,3-Butadiene	106-99-0	3.91E-05	0.000660	0.000165
Formaldehyde	50-00-0	1.18E-03	0.019907	0.004977
Propylene	115-07-1	2.58E-03	0.043526	0.010881
Toluene	108-88-3	4.09E-04	0.006900	0.001725
Xylene	1330-20-7	2.85E-04	0.004808	0.001202
	Total Non-PAH HAPS	6.29E-03	0.106041	0.026510

PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acenaphthene	83-32-9	1.42E-06	0.000024	0.000006
Acenaphthylene	208-96-8	5.06E-06	0.000085	0.000021
Anthracene	120-12-7	1.87E-06	0.000032	0.000008
Benzo(a)anthracene	56-55-3	1.68E-06	0.000028	0.000007
Benzo(a)pyrene	50-32-8	1.88E-07	0.000003	0.000001
Benzo(b)fluoranthene	205-99-2	9.91E-08	0.000002	0.000000
Benzo(a)pyrene	192-97-2	1.55E-07	0.000003	0.000001
Benzo(g,h,I)perylene	191-24-2	4.89E-07	0.000008	0.000002
Benzo(k)fluoranthene	207-08-9	1.55E-07	0.000003	0.000001
Dibenz(a,h)anthracene		5.83E-07	0.000010	0.000002
Chrysene	218-01-9	3.53E-07	0.000006	0.000001
Fluoranthene	206-44-0	7.61E-06	0.000128	0.000032
Fluorene	86-73-7	2.92E-05	0.000493	0.000123
Indeno(1,2,3-cd)pyrene	193-39-5	3.75E-07	0.000006	0.000002
Naphthalene	91-20-3	8.48E-05	0.001431	0.000358
Phenanthrene	85-01-8	2.94E-05	0.000496	0.000124
Pyrene	129-00-0	4.78E-06	0.000081	0.000020
	Total PAH HAPS	1.68E-04	0.002838	0.000709

HAPS Metals		**Emission Factor (lbs/Btu^12)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Arsenic		4	0.000067	0.000017
Beryllium		3	0.000051	0.000013
Cadmium		3	0.000051	0.000013
Chromium		3	0.000051	0.000013
Lead		9	0.000152	0.000038
Manganese		6	0.000101	0.000025
Mercury		3	0.000051	0.000013
Nickel		3	0.000051	0.000013
Selenium		15	0.000253	0.000063
	Total Metals HAPS	49	0.000827	0.000207
	Total HAPS		**0.10971**	**0.00212**

Table B-4: HAPs Emission Rates from the Unit 2 (Emergency Generator)

EPA HAPS Emissions Diesel Fired Engines

Horsepower Rating:	2628	horsepower	
Fuel Usage:	131.4	gallons/hr	
MMBtu/hr:	16.8192	Btu	(based on 128000 Btu/gallon)
Btu x 10^-12/hr:	1.68192E-05	Btu x10^-12	(based on 128000 Btu/gallon)
Yearly Operating Hours:	500	hours per year	

Type of Fuel: Diesel
Emission Factors AP-42 Section 3.3 and Section 1.3

Non-PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acetalehyde	75-07-0	7.67E-04	0.012900	0.003225
Acrolein	107-02-8	9.25E-05	0.001556	0.000389
Benzene	71-43-2	9.33E-04	0.015692	0.003923
1,3-Butadiene	106-99-0	3.91E-05	0.000658	0.000164
Formaldehyde	50-00-0	1.18E-03	0.019847	0.004962
Propylene	115-07-1	2.58E-03	0.043394	0.010848
Toluene	108-88-3	4.09E-04	0.006879	0.001720
Xylene	1330-20-7	2.85E-04	0.004793	0.001198
	Total Non-PAH HAPS	6.29E-03	0.105719	0.026430

PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acenaphthene	83-32-9	1.42E-06	0.000024	0.000006
Acenaphthylene	208-96-8	5.06E-06	0.000085	0.000021
Anthracene	120-12-7	1.87E-06	0.000031	0.000008
Benzo(a)anthracene	56-55-3	1.68E-06	0.000028	0.000007
Benzo(a)pyrene	50-32-8	1.88E-07	0.000003	0.000001
Benzo(b)fluoranthene	205-99-2	9.91E-08	0.000002	0.000000
Benzo(a)pyrene	192-97-2	1.55E-07	0.000003	0.000001
Benzo(g,h,I)perylene	191-24-2	4.89E-07	0.000008	0.000002
Benzo(k)fluoranthene	207-08-9	1.55E-07	0.000003	0.000001
Dibenz(a,h)anthracene		5.83E-07	0.000010	0.000002
Chrysene	218-01-9	3.53E-07	0.000006	0.000001
Fluoranthene	206-44-0	7.61E-06	0.000128	0.000032
Fluorene	86-73-7	2.92E-05	0.000491	0.000123
Indeno(1,2,3-cd)pyrene	193-39-5	3.75E-07	0.000006	0.000002
Naphthalene	91-20-3	8.48E-05	0.001426	0.000357
Phenanthrene	85-01-8	2.94E-05	0.000494	0.000124
Pyrene	129-00-0	4.78E-06	0.000080	0.000020
	Total PAH HAPS	1.68E-04	0.002829	0.000707

HAPS Metals		Emission Factor (lbs/Btu^12)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Arsenic		4	0.000067	0.000017
Beryllium		3	0.000050	0.000013
Cadmium		3	0.000050	0.000013
Chromium		3	0.000050	0.000013
Lead		9	0.000151	0.000038
Manganese		6	0.000101	0.000025
Mercury		3	0.000050	0.000013
Nickel		3	0.000050	0.000013
Selenium		15	0.000252	0.000063
	Total Metals HAPS	49	0.000824	0.000206
	Total HAPS		**0.10937**	**0.00211**

Table B-5: HAPs Emission Rates from the Unit 3 (Boiler)

EPA HAPS Emissions Natural Gas Boilers

Btu Rating	20.9	mmBtu/hr	
Fuel Usage:	22000.0	scf/hr	(based on 950 Btu/scf)
MMscf/hr:	0.022	MMscf/hr	
Yearly Operating Hours:	8760	hours per year	

Type of Fuel:	Natural Gas
Emission Factors	AP-42 Section 1.4

Organic Compounds	**CAS#**	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Benzene	71-43-2	2.10E-03	0.000046	0.000202
Formaldehyde	50-00-0	7.50E-02	0.001650	0.007227
Hexane	110-54-3	1.80E+00	0.039600	0.173448
Naphthalene	91-20-3	6.10E-04	0.000013	0.000059
Toluene	108-88-3	3.40E-03	0.000075	0.000328
	Total Organic Compounds	1.88E+00	0.041384	0.181264

HAPS Metals	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Arsenic	2.00E-04	0.000004	0.000019
Beryllium	1.20E-05	0.000000	0.000001
Cadmium	1.10E-03	0.000024	0.000106
Chromium	1.40E-03	0.000031	0.000135
Cobalt	8.40E-05	0.000002	0.000008
Lead	5.00E-04	0.000011	0.000048
Manganese	3.80E-04	0.000008	0.000037
Mercury	2.60E-04	0.000006	0.000025
Nickel	2.10E-03	0.000046	0.000202
Selenium	2.40E-05	0.000001	0.000002
Total Metals HAPS	6.06E-03	0.000133	0.000584
Total HAPS		**0.041518**	**0.181848**

Table B-6: HAPs Emission Rates from the Unit 4 (Boiler)

EPA HAPS Emissions Natural Gas Boilers

Btu Rating	20.9	mmBtu/hr	
Fuel Usage:	22000.0	scf/hr	(based on 950 Btu/scf)
MMscf/hr:	0.022	MMscf/hr	
Yearly Operating Hours:	8760	hours per year	

Type of Fuel:	Natural Gas
Emission Factors	AP-42 Section 1.4

Organic Compounds	**CAS#**		**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Benzene	71-43-2		2.10E-03	0.000046	0.000202
Formaldehyde	50-00-0		7.50E-02	0.001650	0.007227
Hexane	110-54-3		1.80E+00	0.039600	0.173448
Naphthalene	91-20-3		6.10E-04	0.000013	0.000059
Toluene	108-88-3		3.40E-03	0.000075	0.000328
		Total Organic Compounds	1.88E+00	0.041384	0.181264

HAPS Metals		**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Arsenic		2.00E-04	0.000004	0.000019
Beryllium		1.20E-05	0.000000	0.000001
Cadmium		1.10E-03	0.000024	0.000106
Chromium		1.40E-03	0.000031	0.000135
Cobalt		8.40E-05	0.000002	0.000008
Lead		5.00E-04	0.000011	0.000048
Manganese		3.80E-04	0.000008	0.000037
Mercury		2.60E-04	0.000006	0.000025
Nickel		2.10E-03	0.000046	0.000202
Selenium		2.40E-05	0.000001	0.000002
	Total Metals HAPS	6.06E-03	0.000133	0.000584
	Total HAPS		**0.041518**	**0.181848**

Table B-7: HAPs Emission Rates from the Unit 5 (Boiler)

EPA HAPS Emissions Natural Gas Boilers

Btu Rating	8.4	mmBtu/hr	
Fuel Usage:	8842.1	scf/hr	(based on 950 Btu/scf)
MMscf/hr:	0.0088421	MMscf/hr	
Yearly Operating Hours:	8760	hours per year	

Type of Fuel:	Natural Gas
Emission Factors	AP-42 Section 1.4

Organic Compounds	**CAS#**	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Benzene	71-43-2	2.10E-03	0.000019	0.000081
Formaldehyde	50-00-0	7.50E-02	0.000663	0.002905
Hexane	110-54-3	1.80E+00	0.015916	0.069711
Naphthalene	91-20-3	6.10E-04	0.000005	0.000024
Toluene	108-88-3	3.40E-03	0.000030	0.000132
	Total Organic Compounds	1.88E+00	0.016633	0.072852

HAPS Metals	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Arsenic	2.00E-04	0.000002	0.000008
Beryllium	1.20E-05	0.000000	0.000000
Cadmium	1.10E-03	0.000010	0.000043
Chromium	1.40E-03	0.000012	0.000054
Cobalt	8.40E-05	0.000001	0.000003
Lead	5.00E-04	0.000004	0.000019
Manganese	3.80E-04	0.000003	0.000015
Mercury	2.60E-04	0.000002	0.000010
Nickel	2.10E-03	0.000019	0.000081
Selenium	2.40E-05	0.000000	0.000001
Total Metals HAPS	6.06E-03	0.000054	0.000235
Total HAPS		**0.016687**	**0.073087**

Table B-8: HAPs Emission Rates from the Unit 6 (Boiler)

EPA HAPS Emissions Natural Gas Boilers

Btu Rating	21	mmBtu/hr	
Fuel Usage:	22105.3	scf/hr	(based on 950 Btu/scf)
MMscf/hr:	0.0221053	MMscf/hr	
Yearly Operating Hours:	8760	hours per year	

Type of Fuel:	Natural Gas
Emission Factors	AP-42 Section 1.4

Organic Compounds	**CAS#**	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Benzene	71-43-2	2.10E-03	0.000046	0.000203
Formaldehyde	50-00-0	7.50E-02	0.001658	0.007262
Hexane	110-54-3	1.80E+00	0.039789	0.174278
Naphthalene	91-20-3	6.10E-04	0.000013	0.000059
Toluene	108-88-3	3.40E-03	0.000075	0.000329
	Total Organic Compounds	1.88E+00	0.041582	0.182131

HAPS Metals	**Emission Factor (lbs/MM scf)**	**Emission Rate (lbs/hr)**	**Emission Rate (ton/yr)**
Arsenic	2.00E-04	0.000004	0.000019
Beryllium	1.20E-05	0.000000	0.000001
Cadmium	1.10E-03	0.000024	0.000107
Chromium	1.40E-03	0.000031	0.000136
Cobalt	8.40E-05	0.000002	0.000008
Lead	5.00E-04	0.000011	0.000048
Manganese	3.80E-04	0.000008	0.000037
Mercury	2.60E-04	0.000006	0.000025
Nickel	2.10E-03	0.000046	0.000203
Selenium	2.40E-05	0.000001	0.000002
Total Metals HAPS	6.06E-03	0.000134	0.000587
Total HAPS		**0.041716**	**0.182718**

Table B-9: HAPs Emission Rates from the Unit 7 (Emergency Generator)

EPA HAPS Emissions Diesel Fired Engines

Horsepower Rating:	2937	horsepower	
Fuel Usage:	146.85	gallons/hr	
MMBtu/hr:	18.7968	Btu	(based on 128000 Btu/gallon)
Btu x 10^-12/hr:	1.87968E-05	Btu x10^-12	(based on 128000 Btu/gallon)
Yearly Operating Hours:	500	hours per year	

Type of Fuel: Diesel
Emission Factors AP-42 Section 3.3 and Section 1.3

Non-PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acetalehyde	75-07-0	7.67E-04	0.014417	0.003604
Acrolein	107-02-8	9.25E-05	0.001739	0.000435
Benzene	71-43-2	9.33E-04	0.017537	0.004384
1,3-Butadiene	106-99-0	3.91E-05	0.000735	0.000184
Formaldehyde	50-00-0	1.18E-03	0.022180	0.005545
Propylene	115-07-1	2.58E-03	0.048496	0.012124
Toluene	108-88-3	4.09E-04	0.007688	0.001922
Xylene	1330-20-7	2.85E-04	0.005357	0.001339
	Total Non-PAH HAPS	6.29E-03	0.118149	0.029537

PAH HAPS	CAS#	Emission Factor (lbs/mmBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Acenaphthene	83-32-9	1.42E-06	0.000027	0.000007
Acenaphthylene	208-96-8	5.06E-06	0.000095	0.000024
Anthracene	120-12-7	1.87E-06	0.000035	0.000009
Benzo(a)anthracene	56-55-3	1.68E-06	0.000032	0.000008
Benzo(a)pyrene	50-32-8	1.88E-07	0.000004	0.000001
Benzo(b)fluoranthene	205-99-2	9.91E-08	0.000002	0.000000
Benzo(a)pyrene	192-97-2	1.55E-07	0.000003	0.000001
Benzo(g,h,I)perylene	191-24-2	4.89E-07	0.000009	0.000002
Benzo(k)fluoranthene	207-08-9	1.55E-07	0.000003	0.000001
Dibenz(a,h)anthracene		5.83E-07	0.000011	0.000003
Chrysene	218-01-9	3.53E-07	0.000007	0.000002
Fluoranthene	206-44-0	7.61E-06	0.000143	0.000036
Fluorene	86-73-7	2.92E-05	0.000549	0.000137
Indeno(1,2,3-cd)pyrene	193-39-5	3.75E-07	0.000007	0.000002
Naphthalene	91-20-3	8.48E-05	0.001594	0.000398
Phenanthrene	85-01-8	2.94E-05	0.000553	0.000138
Pyrene	129-00-0	4.78E-06	0.000090	0.000022
	Total PAH HAPS	1.68E-04	0.003162	0.000790

HAPS Metals		Emission Factor (lbs/Btu^12)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
Arsenic		4	0.000075	0.000019
Beryllium		3	0.000056	0.000014
Cadmium		3	0.000056	0.000014
Chromium		3	0.000056	0.000014
Lead		9	0.000169	0.000042
Manganese		6	0.000113	0.000028
Mercury		3	0.000056	0.000014
Nickel		3	0.000056	0.000014
Selenium		15	0.000282	0.000070
	Total Organic Compounds	49	0.000921	0.000230
	Total HAPS		**0.12223**	**0.00236**

Table B-10: HAPs Emission Rates from the Unit 8 (CoGen)

EPA HAPS Natural Gas-fired Reciprocating Engines

Brake HP	2763	BHP
Btu Rating	5843	Btu/bhp-hr
Fuel Usage:	16144209.0	Btu/hr
MMscf/hr:	16.144209	MMBtu/hr
Yearly Operating Hours:	8760	hours per year
Type of Fuel:	Natural Gas	
Emission Factors	AP-42 Section 3.2	

Organic Compounds	CAS#		Emission Factor (lbs/MMBtu)	Emission Rate (lbs/hr)	Emission Rate (ton/yr)
1,1,2,2-Tetrachloroethane	71-55-6		4.00E-05	0.000646	0.002828
1,1,2-Trichloroethane	79-00-5		3.18E-05	0.000513	0.002249
1,3-Butadiene	106-99-0		2.67E-04	0.004311	0.018880
1,3-Dichloropropene	78-87-5		2.64E-05	0.000426	0.001867
2-Methylnaphthalene	91-57-6		3.32E-05	0.000536	0.002348
2,2,4-Trimethylpentane	540-84-1		2.50E-04	0.004036	0.017678
Acenaphthene	83-32-9		1.25E-06	0.000020	0.000088
Acenaphthylene	208-96-8		5.53E-06	0.000089	0.000391
Acetaldehyde	75-07-0		8.36E-03	0.134966	0.591149
Acrolein	107-02-8		5.14E-03	0.082981	0.363458
Benzene	71-43-2		4.40E-04	0.007103	0.031113
Benzo(b)fluoranthene	205-99-2		1.66E-07	0.000003	0.000012
Benzo(e)pyrene	192-97-2		4.15E-07	0.000007	0.000029
Benzo(g,h,i)perylene	191-24-2		4.14E-07	0.000007	0.000029
Biphenyl	92-52-4		2.12E-04	0.003423	0.014991
Carbon Tetrachloride	56-23-5		3.67E-05	0.000592	0.002595
Chlorobenzene	108-90-7		3.04E-05	0.000491	0.002150
Chloroform	67-66-3		2.85E-05	0.000460	0.002015
Chrysene	218-01-9		6.93E-07	0.000011	0.000049
Ethylbenzene	100-41-4		3.97E-05	0.000641	0.002807
Ethylene Dibromide	106-93-4		4.43E-05	0.000715	0.003133
Fluoranthene	206-44-0		1.11E-06	0.000018	0.000078
Fluorene	86-73-7		5.67E-06	0.000092	0.000401
Formaldehyde	50-00-0	Controlled CAT Emission Data		1.157340	5.069150
Methanol	67-56-1		2.50E-03	0.040361	0.176779
Methylene Chloride	75-09-2		2.00E-05	0.000323	0.001414
n-Hexane	110-54-3		1.11E-03	0.017920	0.078490
Naphthalene	91-20-3		7.44E-05	0.001201	0.005261
PAH			2.69E-05	0.000434	0.001902
Phenanthrene	85-01-8		1.04E-05	0.000168	0.000735
Phenol	108-95-2		2.40E-05	0.000387	0.001697
Pyrene	129-00-0		1.36E-06	0.000022	0.000096
Styrene	100-42-5		2.36E-05	0.000381	0.001669
Tetrachloroethane	79-34-5		2.48E-06	0.000040	0.000175
Toluene	108-88-3		4.08E-04	0.006587	0.028850
Vinyl Chloride	75-01-4		1.49E-05	0.000241	0.001054
Xylene	1330-20-7		1.84E-04	0.002971	0.013011
		Total Organic Compounds	7.18E-05	1.470462	6.440623
		Total HAPS		**1.470462**	**6.440623**

Attachment C
Emission Calculations Supporting Documents

AP-42 Section 1.3

1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

Table 1.3-9. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM FUEL OIL COMBUSTION[a]

Organic Compound	Average Emission Factor[b] ($lb/10^3$ Gal)	EMISSION FACTOR RATING
Benzene	2.14E-04	C
Ethylbenzene	6.36E-05[c]	E
Formaldehyde[d]	3.30E-02	C
Naphthalene	1.13E-03	C
1,1,1-Trichloroethane	2.36E-04[c]	E
Toluene	6.20E-03	D
o-Xylene	1.09E-04[c]	E
Acenaphthene	2.11E-05	C
Acenaphthylene	2.53E-07	D
Anthracene	1.22E-06	C
Benz(a)anthracene	4.01E-06	C
Benzo(b,k)fluoranthene	1.48E-06	C
Benzo(g,h,i)perylene	2.26E-06	C
Chrysene	2.38E-06	C
Dibenzo(a,h) anthracene	1.67E-06	D
Fluoranthene	4.84E-06	C
Fluorene	4.47E-06	C
Indo(1,2,3-cd)pyrene	2.14E-06	C
Phenanthrene	1.05E-05	C
Pyrene	4.25E-06	C
OCDD	3.10E-09[c]	E

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.
[b] References 64-72. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[c] Based on data from one source test (Reference 67).
[d] The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43.

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

Metal	Average Emission Factor[b, d] ($lb/10^3$ Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03[c]	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.

[c] References 29-32,40-44.

[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

AP-42 Section 1.4

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

1.4.3 Emissions[3-4]

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire

in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how "good" the factor is, with "A" being excellent and "E" being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

- Text was revised concerning Firing Practices, Emissions, and Controls.
- All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

- Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)(CON)(C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

References For Section 1.4

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2. *Chemical Engineers' Handbook, Fourth Edition*, J. H. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.

3. *Background Information Document For Industrial Boilers*, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

4. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S . Environmental Protection Agency, Research Triangle Park, NC, 1987.

5. J. L. Muhlbaier, "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", *Journal Of The Air Pollution Control Association*, December 1981.

6. L. P. Nelson, *et al.*, *Global Combustion Sources Of Nitrous Oxide Emissions*, Research Project 2333-4 Interim Report, Sacramento: Radian Corporation, 1991.

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8. S. D. Piccot, *et al.*, *Emissions and Cost Estimates For Globally Significant Anthropogenic Combustion Sources Of NO_x, N_2O, CH_4, CO, and CO_2,* EPA Contract No. 68-02-4288, Research Triangle Park, NC: Radian Corporation, 1990.

9. *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992* (1994) DOE/PO-0028, Volume 2 of 3, U.S. Department of Energy.

10. J. P. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium On Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

11. *Emission Factor Documentation for AP-42 Section 1.4—Natural Gas Combustion*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1997.

12. *Alternate Control Techniques Document - NO_x Emissions from Utility Boilers*, EPA-453/R-94-023, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1994.

AP-42 Section 1.4: Natural Gas Combustion Data Files

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is in Microsoft Access 97®. The file is located on the CHIEF web site at http://www.epa.gov/ttn/chief/ap42c1.html.

AP-42 Section 3.2

3.2 Natural Gas-fired Reciprocating Engines

3.2.1 General[1-3]

Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50 - 60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.

At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500 - 2000 psig) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.

A compressor in storage service pumps gas from a low-pressure storage field (500 - 800 psig) to a higher pressure transmission pipeline (700 - 1000 psig) and/or pumps gas from a low-pressure transmission line (500 - 800 psig) to a higher pressure storage field (800 - 2000 psig).

Storage reciprocating compressors must be flexible enough to allow operation across a wide band of suction and discharge pressures and volume variations. The compressor must be able to compress at high compression ratios with low volumes and compress at low compression ratios with high volumes. These conditions require varying speeds and load (horsepower) conditions for the reciprocating engine powering the reciprocating compressor.

Reciprocating compressors are used at processing plants for process compression needs (e.g. refrigeration cycles). The volume of gas compressed varies, but the pressure needed for the process is more constant than the other two cases mentioned above.

3.2.2 Process Description[1-3]

Natural gas-fired reciprocating engines are separated into three design classes: 2-cycle (stroke) lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn. Two-stroke engines complete the power cycle in a

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES (Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Acenaphthylene[k]	5.53 E-06	C
Acetaldehyde[k,l]	8.36 E-03	A
Acrolein[k,l]	5.14 E-03	A
Benzene[k]	4.40 E-04	A
Benzo(b)fluoranthene[k]	1.66 E-07	D
Benzo(e)pyrene[k]	4.15 E-07	D
Benzo(g,h,i)perylene[k]	4.14 E-07	D
Biphenyl[k]	2.12 E-04	D
Butane	5.41 E-04	D
Butyr/Isobutyraldehyde	1.01 E-04	C
Carbon Tetrachloride[k]	<3.67 E-05	E
Chlorobenzene[k]	<3.04 E-05	E
Chloroethane	1.87 E-06	D
Chloroform[k]	<2.85 E-05	E
Chrysene[k]	6.93 E-07	C
Cyclopentane	2.27 E-04	C
Ethane	1.05 E-01	C
Ethylbenzene[k]	3.97 E-05	B
Ethylene Dibromide[k]	<4.43 E-05	E
Fluoranthene[k]	1.11 E-06	C
Fluorene[k]	5.67 E-06	C
Formaldehyde[k,l]	5.28 E-02	A
Methanol[k]	2.50 E-03	B
Methylcyclohexane	1.23 E-03	C
Methylene Chloride[k]	2.00 E-05	C
n-Hexane[k]	1.11 E-03	C
n-Nonane	1.10 E-04	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
n-Octane	3.51 E-04	C
n-Pentane	2.60 E-03	C
Naphthalene[k]	7.44 E-05	C
PAH[k]	2.69 E-05	D
Phenanthrene[k]	1.04 E-05	D
Phenol[k]	2.40 E-05	D
Propane	4.19 E-02	C
Pyrene[k]	1.36 E-06	C
Styrene[k]	<2.36 E-05	E
Tetrachloroethane[k]	2.48 E-06	D
Toluene[k]	4.08 E-04	B
Vinyl Chloride[k]	1.49 E-05	C
Xylene[k]	1.84 E-04	B

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM-10 = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})\ (\text{heat input, MMBtu/hr})\ (\text{1/operating HP, 1/hp})$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and

h = heating value of natural gas (assume 1020 Btu/scf at 60°F).

[e] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6scf.

[f] Emission factor for TOC is based on measured emission levels from 22 source tests.

[g] Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor. Measured emission factor for methane compares well with the calculated emission factor, 1.31 lb/MMBtu vs. 1.25 lb/MMBtu, respectively.

[h] VOC emission factor is based on the sum of the emission factors for all speciated organic compounds less ethane and methane.

[i] Considered $\leq$ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

[j] PM Condensable = PM Condensable Inorganic + PM-Condensable Organic

[k] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

[l] For lean burn engines, aldehyde emissions quantification using CARB 430 may reflect interference with the sampling compounds due to the nitrogen concentration in the stack. The presented emission factor is based on FTIR measurements. Emissions data based on CARB 430 are available in the background report.

AP-42 Section 3.3

3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Unit 8
CAT CoGen
Specifications

PRESBYTERIAN HOSPITAL
COGEN PLANT
EXTENDED DESCRIPTION FOR QUOTATION NO. 30686733.01

G3516H

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
PHS COGEN

CATERPILLAR®

GENSET - WITHOUT RADIATOR

ENGINE SPEED (rpm):	1500
COMPRESSION RATIO:	12.1
AFTERCOOLER TYPE:	SCAC
AFTERCOOLER - STAGE 2 INLET (°F):	120
AFTERCOOLER - STAGE 1 INLET (°F):	198
JACKET WATER OUTLET (°F):	210
ASPIRATION:	TA
COOLING SYSTEM:	JW+OC+1AC, 2AC+GB
CONTROL SYSTEM:	ADEM4 W/ IM
EXHAUST MANIFOLD:	DRY
COMBUSTION:	LOW EMISSION
NOx EMISSION LEVEL (g/bhp-hr NOx):	1.0
SET POINT TIMING:	18

RATING STRATEGY:	HIGH ALTITUDE/AMBIENT
FUEL SYSTEM:	CAT LOW PRESSURE WITH AIR FUEL RATIO CONTROL
SITE CONDITIONS:	
FUEL:	Nat Gas
FUEL PRESSURE RANGE(psig): (See note 1)	1.5-5.0
FUEL METHANE NUMBER:	84.7
FUEL LHV (Btu/scf):	905
ALTITUDE(ft):	5098
INLET AIR TEMPERATURE(°F):	66
STANDARD RATED POWER:	2763 bhp@1500rpm
POWER FACTOR:	1.0
VOLTAGE(V):	12470

				MAXIMUM RATING	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE		
RATING		**NOTES**	**LOAD**	**100%**	**100%**	**75%**	**50%**
GENSET POWER	(WITH GEARBOX, WITHOUT FAN)	(2)(3)	ekW	1978	1978	1484	989
GENSET POWER	(WITH GEARBOX, WITHOUT FAN)	(2)(3)	kVA	1978	1978	1484	989
ENGINE POWER	(WITHOUT GEARBOX, WITHOUT FAN)	(3)	bhp	2746	2746	2065	1387
INLET AIR TEMPERATURE			°F	86	86	86	86
GENERATOR EFFICIENCY		(2)	%	97.5	97.5	97.2	96.5
GENSET EFFICIENCY	(ISO 3046/1)	(4)(5)	%	43.5	43.5	42.5	40.2
THERMAL EFFICIENCY		(4)(6)	%	42.3	42.3	43.5	45.8
TOTAL EFFICIENCY		(4)(7)	%	85.8	85.8	86.0	86.0
ENGINE DATA							
GENSET FUEL CONSUMPTION	(ISO 3046/1)	(8)	Btu/ekW-hr	7839	7839	8026	8482
GENSET FUEL CONSUMPTION	(NOMINAL)	(8)	Btu/ekW-hr	8110	8110	8302	8775
ENGINE FUEL CONSUMPTION	(NOMINAL)	(8)	Btu/bhp-hr	5843	5843	5964	6258
AIR FLOW (@inlet air temp, 14.7 psia)	(WET)	(9)	ft3/min	5130	5130	3862	2630
AIR FLOW	(WET)	(9)	lb/hr	22370	22370	16843	11471
FUEL FLOW (60°F, 14.7 psia)			scfm	295	295	227	160
INLET MANIFOLD PRESSURE		(10)	in Hg(abs)	135.0	135.0	102.1	70.4
EXHAUST TEMPERATURE - ENGINE OUTLET		(11)	°F	768	768	824	911
EXHAUST GAS FLOW (@engine outlet temp, 14.5 psia)	(WET)	(12)	ft3/min	12424	12424	9790	7136
EXHAUST GAS MASS FLOW	(WET)	(12)	lb/hr	23179	23179	17464	11909
MAX INLET RESTRICTION		(13)	in H2O	9.93	9.93	5.62	2.49
MAX EXHAUST RESTRICTION		(13)	in H2O	19.86	19.86	11.24	5.37
EMISSIONS DATA - ENGINE OUT							
NOx (as NO2)		(14)(15)	g/bhp-hr	1.00	1.00	1.00	1.00
CO		(14)(15)	g/bhp-hr	1.62	1.62	1.57	1.56
THC (mol. wt. of 15.84)		(14)(15)	g/bhp-hr	1.88	1.88	2.27	2.41
NMHC (mol. wt. of 15.84)		(14)(15)	g/bhp-hr	0.32	0.32	0.39	0.41
NMNEHC (VOCs) (mol. wt. of 15.84)		(14)(15)(16)	g/bhp-hr	0.30	0.30	0.36	0.39
HCHO (Formaldehyde)		(14)(15)	g/bhp-hr	0.19	0.19	0.19	0.21
CO2		(14)(15)	g/bhp-hr	412	412	417	433
EXHAUST OXYGEN		(14)(17)	% DRY	9.4	9.4	9.5	8.8
HEAT REJECTION							
LHV INPUT		(18)	Btu/min	267382	267382	205301	144656
HEAT REJ. TO JACKET WATER (JW)		(19)	Btu/min	26808	26808	22617	17981
HEAT REJ. TO ATMOSPHERE	(INCLUDES GENERATOR)	(19)	Btu/min	6655	6655	5833	5221
HEAT REJ. TO LUBE OIL (OC)		(19)	Btu/min	10727	10727	9669	8365
HEAT REJECTION TO EXHAUST (LHV TO 248°F)		(19)	Btu/min	53492	53492	44811	35449
HEAT REJ. TO A/C - STAGE 1 (1AC)		(19)(21)	Btu/min	22570	22570	12083	4278
HEAT REJ. TO A/C - STAGE 2 (2AC)		(19)(21)	Btu/min	12543	12543	8563	4891
HEAT REJECTION FROM GEARBOX (GB)		(19)	Btu/min	1060	1060	797	535
PUMP POWER		(20)	Btu/min	963	963	963	963
COOLING SYSTEM SIZING CRITERIA							
TOTAL JACKET WATER CIRCUIT (JW+OC+1AC)		(22)	Btu/min	72452	72452		
TOTAL STAGE 2 AFTERCOOLER CIRCUIT (2AC+GB)		(22)	Btu/min	15836	15836		
HEAT REJECTION TO EXHAUST (LHV TO 248°F)		(22)	Btu/min	58842	58842		
A cooling system safety factor of 0% has been added to the cooling system sizing criteria.							
MINIMUM HEAT RECOVERY							
TOTAL JACKET WATER CIRCUIT (JW+OC+1AC)		(23)	Btu/min	54150	54150		
TOTAL STAGE 2 AFTERCOOLER CIRCUIT (2AC+GB)		(23)	Btu/min	12923	12923		
HEAT REJECTION TO EXHAUST (LHV TO 248°F)		(23)	Btu/min	41483	41483		

CONDITIONS AND DEFINITIONS

Engine rating obtained and presented in accordance with ISO 3046/1, adjusted for fuel, site altitude and site inlet air temperature. 100% rating at maximum inlet air temperature is the maximum engine capability for the specified fuel at site altitude and maximum site inlet air temperature. Maximum rating is the maximum capability at the specified aftercooler inlet temperature for the specified fuel at site altitude and reduced inlet air temperature. Lowest load point is the lowest continuous duty operating load allowed. No overload permitted at rating shown.

Application & Performance Warranty Data

Project Information

Site Location:	Albuquerque, NM
Project Name:	PHS-New Tower
Application:	Continuous Power, Cogen
Number Of Engines:	1
Operating Hours per Year:	8760

Engine Specifications

Engine Manufacturer:	Caterpillar
Model Number:	G3516H
Rated Speed:	1500 RPM
Type of Fuel:	Natural Gas
Type of Lube Oil:	0.6 wt% sulfated ash or less
Lube Oil Consumption:	0.1 % Fuel Consumption
Number of Exhaust Manifolds:	1

Engine Cycle Data

Load	Speed	Power	Exhaust Flow	Exhaust Temp.	Fuel Cons.	NO_x	CO	NMNEHC	CH_2O	O_2	H_2O
%		*bhp*	*lb/hr*	*F*		*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*g/bhp-hr*	*%*	*%*
100	Rated	2,611	23,040	779		0.5	1.78	0.4	0.22	9.5	17.5

Emission Data (100% Load)

Emission	Raw Engine Emissions						Target Outlet Emissions						Calculated Reduction
	g/bhp-hr	*g/kW-hr*	*tons/yr*	*ppmvd @ 15% O_2*	*ppmvd*	*lb/MW-hr*	*g/bhp-hr*	*g/kW-hr*	*tons/yr*	*ppmvd @ 15% O_2*	*ppmvd*	*lb/MW-hr*	
NO_x*	0.5	0.671	2.59	49	96	1.48							
CO	1.78	2.387	9.22	289	558	5.26	0.36	0.477	1.84	58	112	1.05	80%
NMNEHC**	0.4	0.536	2.07	113	219	1.18	0.24	0.322	1.24	68	131	0.71	40%
CH_2O	0.22	0.295	1.14	33	64	0.65	0.07	0.089	0.34	10	19	0.2	70%

* MW referenced as NO_2

** MW referenced as CH_4. Propane in the exhaust shall not exceed 15% by volume of the NMNEHC compounds in the exhaust, excluding aldehydes. The 15% (vol.) shall be established on a wet basis, reported on a methane molecular weight basis. The measurement of exhaust NMNEHC composition shall be based upon EPA method 320 (FTIR), and shall exclude formaldehyde.

Units 3 and 4
Boiler Manufacture
Specifications

Power Flame Incorporated

9/28/2006
Rev. 06/11/2010

Typical Flue Product Emissions Data for Power Flame Burners

	Natural Gas	L.P. Gas	# 2 Fuel Oil [1]
Carbon Monoxide - CO	.037 lb CO 10^6 BTU input (50 PPM)	.037 lb CO 10^6 BTU input (50 PPM)	.037 lb per 10^6 BTU INPUT (50 PPM)
Sulfur Dioxide - SO_2	(1.05) x (% Sulfur by weight in fuel) = lb SO_2 per 10^6 BTU Input		
Particulate Matter	.0048 lb PM per 10^6 BTU input	.0048 lb PM per 10^6 BTU input	.0143 lb PM per 10^6 BTU input
Hydrocarbons	.025 lb HC's per 10^6 BTU input	.025 lb HC's per 10^6 BTU input	.038 lb HC's per 10^6 BTU input
CO_2	9 % to 10%	10% to 12%	10% to 13%
Nitrogen Oxides - NO_x			
Standard J, FDM & X4 Gas Burners	.088 lb NO_x per 10^6 BTU input (75 PPM)	.092 lb NO_x per 10^6 BTU input (75 PPM)	N/A N/A
Standard C(R) Burners	.088 lb NO_x per 10^6 BTU input (75 PPM)	.092 lb NO_x per 10^6 BTU input (75 PPM)	.159 lb NO_x per 10^6 BTU Input (90) PPM[2]
LNIC(R) Burners Fire box/Cast Iron boilers	.029 lb NO_x per 10^6 BTU input (25 PPM)	.031 lb NO_x per 10^6 BTU input (25 PPM)	.159 lb NO_x per 10^6 BTU Input (90) PPM[2]
LNIC(R) Burners Water tube boilers	.024 lb NO_x per 10^6 BTU input (20 PPM)	.031 lb NO_x per 10^6 BTU input (25 PPM)	.159 lb NO_x per 10^6 BTU Input (90) PPM[2]
LNIAC Burners	.029 lb NO_x per 10^6 BTU input (25 PPM)	.031 lb NO_x per 10^6 BTU input (25 PPM)	.12 lb NO_x per 10^6 BTU Input (90) PPM
CM Burners	.070 lb NO_x per 10^6 BTU input (60 PPM)[4]	.074 lb NO_x per 10^6 BTU input (60 PPM)[4]	.146 lb NO_x per 10^6 BTU Input (110) PPM
LNICM Burners Fire box/Cast Iron boilers	.029 lb NO_x per 10^6 BTU input (25) PPM	.031 lb NO_x per 10^6 BTU input (25) PPM	.12 lb NO_x per 10^6 BTU Input (90) PPM
LNICM Burners Water tube boilers	.029 lb NO_x per 10^6 BTU input (20) PPM	.031 lb NO_x per 10^6 BTU input (20) PPM	.12 lb NO_x per 10^6 BTU Input (90) PPM
NPM Premix Burners	.029 lb NO_x per 10^6 BTU input (25) PPM	.031 lb NO_x per 10^6 BTU input (25) PPM	N/A N/A
Nova Plus Burners NVC AND NP2	.010 lb NO_x per 10^6 BTU input (9) PPM	.015 lb NO_x per 10^6 BTU input (12) PPM	N/A N/A

(1) NOx emissions at 3 % 02 will vary based on the percent of fuel bound nitrogen (these are based on .02%) and boiler or heat exchanger configurations

(2) 90 PPM NOx on cast iron sectional, fire box and water tube boiler, 120 PPM on fire tube boilers.

(3) Burning natural gas the VOC are estimated at 0.003 # per million BTU and SO_X are 0.0005 # per million BTU.

(4) In some applications the CMAX will achieve less than 60 PPM without flue gas recirculation - consult factory.

These emission rates are general estimates and do not constitute guarantees by Power Flame Inc.
In instances where guarantees are required, please consult the factory with the specific application information.
All NOx numbers stated are corrected to 3% O_2

Unit 6
Boiler Manufacture
Specifications

2.6 PERFORMANCE DATA

A. Emissions shall not exceed the following PPM when burning natural gas:

Firing Rate	25%	50%	75%	100%
NOx	30	30	30	30
CO	108	102	100	97

2.7 APPROVED MANUFACTURERS

A. Burnham, Superior

PART 3 - EXECUTION

3.1 INSTALLATION

A. Rigging: Verify that housekeeping pad is level in accordance with manufacturer's recommendations, rig boiler into place on housekeeping pad, verify that unit is level in accordance with manufacturer's recommendations, and anchor.

B. Piping: Provide boiler feed, steam, fuel, blowdown, blowoff, compressed air and safety relief piping as per drawings, specifications, and manufacturer's recommendations. Provide new chemical feeder and piping as per drawings and specification.

C. Wiring: Electrical contractor shall provide power wiring as per manufacturer's recommendations, electrical drawings and Division 16. Provide additional control wiring as per control drawings, specifications, and manufacturer's recommendations.

3.2 Provide services of a factory trained technician for all necessary start-up services, including boil-out, start-up, and verification of all safety and operating controls. Submit start-up report including all items required by manufacturer, and:

A. Efficiency per flue gas analysis at 100%, 75%, 50% and 25% firing on natural gas and fuel oil.

B. Emissions at 100% firing on both natural gas and fuel oil, including NOx, CO, SO2, UHC, and PM10

3.3 Demonstrate to Owner's operating personnel that all aspects of system operation are functioning properly.

3.4 Provide three 2-hour training sessions to instruct Owner's personnel in all aspects of unit operation. Training sessions will be on different days. Schedule training minimum two weeks in advance and submit attendance list to Owner's Representative.

3.5 Spare Parts: Supply the following spare parts and test instruments, properly labeled in boxes:

A. One set of sight glasses and gauge glasses

B. One set of bulbs

C. One set of fuses

D. One set of waterside gaskets

Public Regulatory Commission
Natural Gas Sulfur Requirements

NEW MEXICO GAS COMPANY

FIRST REVISED SAMPLE FORM NO. 46
CANCELLING ORIGINAL SAMPLE FORM NO. 46

RESIDENTIAL AND SMALL VOLUME END-USER TRANSPORTATION CONTRACT

Please see attached Residential and Small Volume End-User Transportation Contract Form.

Advice Notice No. 5

John M. Fernald
Director, Regulatory Affairs

FIRST REVISED SAMPLE FORM NO. 46
CANCELLING ORGINAL SAMPLE FORM NO. 46

RESIDENTIAL AND SMALL VOLUME END-USER TRANSPORTATION CONTRACT

CONTRACT NO. _____

DATE _____

TRANSPORTATION CUSTOMER

AND

NEW MEXICO GAS COMPANY

TABLE OF CONTENTS

EXHIBITS

NOTE: This page is not considered a part of the Contract but is for the convenience of the parties only and may be removed at any time by either party hereto.

(b) Shall be commercially free of water in their liquid state at the temperature and pressure at which delivered, and in no event contain water vapor in excess of seven (7) pounds per million cubic feet. The water vapor content shall be determined by use of dew-point apparatus approved by the Bureau of Mines, or by any other method that is deemed appropriate for the conditions.

(c) Shall not contain more than three quarters (3/4) grains of total sulfur per one hundred (100) standard cubic feet, which includes hydrogen sulfide, carbonyl sulfide, carbon disulfide, mercaptans, and mono-, di- and poly-sulfides. The Gas shall also meet the following individual specifications for hydrogen sulfide (H_2S) and mercaptans:

i. Hydrogen Sulfide: The Gas shall not contain more than one-quarter (1/4) grain per one hundred (100) standard cubic feet.

ii. Mercaptan Sulfur: The Gas shall not have mercaptan sulfur content greater than three tenths (0.3) grain per one hundred (100) standard cubic feet.

(d) Shall not contain in excess of 2-mol% of Carbon Dioxide (CO_2).

(e) Shall not contain in excess of 0.2-mol% of Oxygen (O_2). Every effort shall be made to keep the Gas free of oxygen.

(f) Shall not contain in excess of 5-mol% of total inert gasses.

(g) Shall be commercially free of hydrocarbons and not have a hydrocarbon dew point that exceeds fifteen degrees Fahrenheit (15° F) between 100 and 1000 Psia.

(h) Shall not be delivered into any of the Company's transmission or distribution pipeline systems at a temperature less than forty degrees Fahrenheit (40° F) nor greater than one hundred twenty degrees Fahrenheit (120° F).

(h) Have a minimum heating value of not less than nine hundred fifty (950) British thermal units (Btu) per cubic foot, and not to exceed greater than eleven hundred (1100) Btu per standard cubic foot.

(i) Shall not contain hydrocarbons with a molecular carbon content of C_5 and above (C_5+) in excess of 0.2 gallon per one thousand (1000) standard cubic feet.

EFFECTIVE
DEC 15 2009
REPLACED BY NMPRC
BY Operation of Law

Maintenance Procedures for Boilers

Facilities Engineering
1011 Coal S.E.
P.O. Box 26666
Albuquerque, New Mexico
87125-6666

Presbyterian Hospital Boiler Operations Overview January 28, 2022

4 Boilers operate at the PHS Energy Center. They are used for steam production for our sterilizers and building heat exchangers.

- 2- 500 HP Kewanee boilers (#1 and #2)
- 1- 500 HP Burnham boiler (#4)
- 1- 250 HP Superior boiler (#3)
- Boilers are run on natural gas. Diesel fuel oil is available as an emergency backup on 1, 2 and 4.

In 2021, the hours ran on each boiler were:

- Boiler 1- 6075
- Boiler 2- 1907 (17.5 of these hours on fuel oil for natural gas line rerouting due to construction)
- Boiler 3- 470
- Boiler 4- 6245 (5 of these hours on fuel oil for natural gas line rerouting due to construction)
- Boilers 1 and 4 are run the most hours because of the updated burners and VFD controls on the fans.
- Two 500 hp boilers are generally required in the winter months.
- 1 500 hp boiler is generally sufficient through the summer months.
- Operational steam pressure is 60 psi, steam flow is not monitored.

Boilers are monitored on site, 24/7 by BO2 licensed boiler operators.

- Rounds conducted hourly and recorded. Temperatures, water and steam pressures and water levels are checked.
- Daily maintenance includes blowdowns as needed and once a shift safety checks. This is just normal routine and noted on the daily logs.
- Preventive maintenance is scheduled and performed weekly, monthly and annually from our computerized maintenance management system.
- Weekly preventive maintenance includes water treatment checks and safety checks. Noted on PM reports.
- Monthly preventive maintenance includes safety checks of the high-pressure relief valves. Noted on PM reports.
- Annual preventive maintenance involves a complete teardown on each boiler and internal inspection by the operators, water treatment personnel and city inspectors. All actions, problems and resolutions are noted on the PM reports. Corrective work orders are generated as needed to complete repairs
- D/A tanks and associated pumps are all inspected daily on each shift and have their own maintenance schedule.
- Each boiler is opened annually for inspection by our insurance carrier and to check internal components.
- Water treatment service are performed with automated controllers and chemical tests are performed to monitor chemical levels. Adjustments are made as warranted from the water tests.

Keith Long, Presbyterian EW Director Engineering
Email: hlong4@phs.org
Phone: 505-563-6221

Maintenance Procedures for

CoGen

(Complete O&M Document in Electronic File Included)

SEBU9173-19 (en-us)
August 2021

Operation and Maintenance Manual

G3500H 60Hz Generator Sets

GLN 1-UP (G3516H Generator Set)
GFR 1-UP (G3520H Generator Set)
GF4 1-UP (G3512H Generator Set)
NWJ 1-UP (G3516H Generator Set)

Language: Original Instructions

Scan to access the latest service information, purchase additional media, and buy genuine Cat® parts.

Important Safety Information

Most accidents that involve product operation, maintenance and repair are caused by failure to observe basic safety rules or precautions. An accident can often be avoided by recognizing potentially hazardous situations before an accident occurs. A person must be alert to potential hazards, including human factors that can affect safety. This person should also have the necessary training, skills and tools to perform these functions properly.

Improper operation, lubrication, maintenance or repair of this product can be dangerous and could result in injury or death.

Do not operate or perform any lubrication, maintenance or repair on this product, until you verify that you are authorized to perform this work, and have read and understood the operation, lubrication, maintenance and repair information.

Safety precautions and warnings are provided in this manual and on the product. If these hazard warnings are not heeded, bodily injury or death could occur to you or to other persons.

The hazards are identified by the “Safety Alert Symbol” and followed by a “Signal Word” such as “DANGER”, “WARNING” or “CAUTION”. The Safety Alert “WARNING” label is shown below.

The meaning of this safety alert symbol is as follows:

Attention! Become Alert! Your Safety is Involved.

The message that appears under the warning explains the hazard and can be either written or pictorially presented.

A non-exhaustive list of operations that may cause product damage are identified by “NOTICE” labels on the product and in this publication.

Caterpillar cannot anticipate every possible circumstance that might involve a potential hazard. The warnings in this publication and on the product are, therefore, not all inclusive. You must not use this product in any manner different from that considered by this manual without first satisfying yourself that you have considered all safety rules and precautions applicable to the operation of the product in the location of use, including site-specific rules and precautions applicable to the worksite. If a tool, procedure, work method or operating technique that is not specifically recommended by Caterpillar is used, you must satisfy yourself that it is safe for you and for others. You should also ensure that you are authorized to perform this work, and that the product will not be damaged or become unsafe by the operation, lubrication, maintenance or repair procedures that you intend to use.

The information, specifications, and illustrations in this publication are on the basis of information that was available at the time that the publication was written. The specifications, torques, pressures, measurements, adjustments, illustrations, and other items can change at any time. These changes can affect the service that is given to the product. Obtain the complete and most current information before you start any job. Cat dealers have the most current information available.

NOTICE

When replacement parts are required for this product Caterpillar recommends using original Caterpillar® replacement parts.

Other parts may not meet certain original equipment specifications.

When replacement parts are installed, the machine owner/user should ensure that the machine remains in compliance with all applicable requirements.

In the United States, the maintenance, replacement, or repair of the emission control devices and systems may be performed by any repair establishment or individual of the owner's choosing.

Table of Contents

Maintenance Section

Refill Capacities

i07585620

Refill Capacities

SMCS Code: 1000; 1348; 1395; 7560

Lubricant Capacities

Engine Lubricant Capacities

The capacity of the engine lubrication system includes the capacity of the oil filters that are installed at the factory. Auxiliary oil filter systems (if equipped) will require more oil. Refer to the specifications that are provided by the OEM of the auxiliary oil filter system.

Table 11

Approximate Refill Capacities for G3500H Lubrication Systems			
System	**G3512H**	**G3516H**	**G3520H**
Engine Crankcase	291 L (77 US gal)	462 L (122 US gal)	568 L (150 US gal)

Gearbox Lubricant Capacities

Table 12

Gearbox Configuration(1)	Capacity
Type 1	74 L (19.5 US gal)
Type 2	55 L (14.5 US gal)

(1) Refer to this Operation and Maintenance Manual, Model Views to identify the gearbox type.

Coolant Capacities

To maintain the cooling system, the total cooling system capacity must be determined. The total cooling system capacity will vary between individual installations. The total cooling system capacity equals the capacity of the jacket water circuit plus the aftercooler circuit plus the external system capacity. The external system capacity may include the following components: expansion tank, heat exchanger, radiator, and piping. Refer to the specifications that are provided by Caterpillar or by the OEM of the equipment. The customer is to record the external and total cooling system capacities in the following table:

Table 13

Approximate Refill Capacities for G3500H Cooling Systems			
System	**G3512H**	**G3516H**	**G3520H**
Jacket Water Circuit(1)	139 L (37 US gal)	208 L (55 US gal)	285 L (75 US gal)
SCAC	31 L (8.2 US gal)	31 L (8.2 US gal)	31 L (8.2 US gal)
External(2)			
Total Cooling System			

(1) Capacities including pumps.
(2) Filled in by customer.

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Fluid Recommendations

SMCS Code: 1280; 1348; 1395; 7560

Lubricant Recommendations

Due to the significant variations in the quality and in the performance of commercially available oils, Caterpillar recommends the following in order of oil performance:

- **Cat Natural Gas Engine Oil (NGEO) ULTRA 40**
- **Cat Natural Gas Engine Oil (NGEO) Synthetic HP (SYN HP)**

Cat natural gas engine oils are the preferred oils for use in ALL Cat natural gas fueled engines that are covered by Special Publication, SEBU6400. Commercial alternative natural gas engine oils are, as a group, second choice oils.

The proper SAE viscosity grade of oil is determined by the minimum ambient temperature during cold engine start-up. The proper SAE viscosity grade of oil is also determined by the maximum ambient temperature during engine operation. To determine the oil viscosity that is required for starting a cold soaked engine, refer to the minimum temperature. To select the oil viscosity for operation at the highest anticipated ambient temperature, refer to the maximum temperature in the Table. Use the highest oil viscosity that is available to meet the required temperature during start-up.

Table 14

Cat NGEO Recommendations Based on Engine Ratings	
Engine Oil	**Engine Rating in Megawatts (MW)**
Cat NGEO Advanced 40	2.0/2.1
Cat NGEO Synthetic HP (Syn HP)	2.5/2.6

For additional information about oils for gas engines, see Special Publication, SEBU6400, “Cat Gas Engine Lubricant, Fuel, and Coolant Recommendations”.

Synthetic Base Stock Oil

Note: Refer to M0120065, “Procedure to Change Natural Gas Engine Oil (NGEO) on Certain G3500 Engines” for flushing procedures.

Note: Refer to M012495, “Rework Procedure for Installing NGEO SYN HP Compatible Hardware on Certain G3500 Engines” for required engine hardware updates.

Synthetic base stock oils may have different material compatibilities than compared to typical mineral base stock oils. Table 15 lists material recommendations for all lube oil components that have been determined to be compatible with CAT NGEO SYN HP. The table also lists materials that are not recommended for use with CAT NGEO SYN HP. Other Commercially available synthetic oils may not share material compatibilities. Material compatibilities of the oil with your engine should be understood to prevent engine damage.

Material compatibilities of the oil with your engine should be understood to prevent engine damage.

Table 15

Material Compatibility Recommendations for use with Cat NGEO SYN HP	
Recommended Materials	**Comments**
Fluorocarbon (FKM, FFKM, Viton)	
Fluorosilicone (FVMO, FSI)	
Polytetrafluoroethylene (PTFE, Teflon)	
Acrylonitrile - Butadiene (NBR)	ACN (Acrylonitrile Content) >32% Recommended
Highly Saturated Nitrile (HNBR)	ACN (Acrylonitrile Content) >32% Recommended
Not Recommended Materials	
Natural Rubber (NR)	
Polyisoprene ((IR, Synthetic Rubber)	

(continued)

(Table 15, contd)

Isobutylene-Isoprene (IIR, Butyl)	
Acrylonitrile-Butadiene (NBR)	ACN (Acrylonitrile Content) <32% Not Recommended, typically low temperature NBR

Oil Consumption

The rate of oil consumption is called Brake-Specific Oil Consumption (BSOC). The unit of measure is grams per brake kilowatt hour or pounds per brake horsepower hour. The BSOC depends on the engine model, the aspiration, the operating load, and the oil that is used. For more information on BSOC, refer to Engine Data Sheet, LEKQ4028, “Oil Consumption Data” at the following website:

emc.cat.com

Table 16

BSOC for G3500H Turbocharged Aftercooled Engines		
Engine Oil	**BSOC (g/bkw-h)**	**BSOC (lb/bhp-h)**
Cat NGEO Ultra 40	0.122	0.0002
Cat NGEO SYN HP	0.085	0.0001

S·O·S Services Oil Analysis

Caterpillar recommends the S·O·S oil analysis program to monitor the condition of the oil. The analysis can help determine the maintenance requirements for the engine. The S·O·S program is part of the preventive maintenance program. For further information about the S·O·S program, see this Special Publication, “S·O·S Services Oil Analysis” topic.

Gearbox Lubricant

Use only Caterpillar approved oils in the gearbox. Use of unapproved oils may compromise the operation of the gearbox. For more information on gearbox oil, consult your Cat dealer.

NOTICE
Use only the oils that are specified.

Table 17

Gearbox Oil	
Gearbox Configuration	**Oil**

(continued)

(Table 17, contd)

Type 1	Cat NGEO Advanced 40
Type 2	Synthetic Compactor Oil: Cat part number 143-5466

Coolant Recommendations

During shipping and storage, the engine must be protected from damage that can be caused by freezing of the cooling system. If the engine is shipped to a location with freezing temperatures, the cooling system must contain an antifreeze mixture that will withstand the lowest ambient temperature. If the engine is stored at a location with freezing temperatures, the cooling system must contain an antifreeze mixture that will withstand the lowest ambient temperature. Frequently check the concentration of glycol in the coolant/antifreeze. Make sure that the concentration is adequate to prevent freezing. Otherwise, drain the cooling system.

Coolant/antifreeze is normally composed of three elements: water, glycol, and additives. Each element must meet specific guidelines.

Water

Deionized water or distilled water is recommended for use in engine cooling systems. If distilled water or deionized water is not available, use water with the properties that are listed in Table 18 .

Table 18

Caterpillar Minimum Acceptable Water Requirements		
Property	**Maximum Limit**	**ASTM Test**
Chloride $^{-}$)	40 mg/L (2.4 gr per US gal)	“D512”, “D4327”
Sulfate (SO_4^-)	100 mg/L (5.9 gr per US gal)	“D516”
Total Hardness	170 mg/L (10 gr per US gal)	“D1126”
Total Solids	340 mg/L (20 gr per US gal)	“D1888”
Acidity	pH of 5.5 to 9.0	“D1293”

NOTICE
Use of water that does not meet the recommendations for the cooling system will damage the cooling system.

Do not use these types of water in the cooling system: sea water, softened water that has been conditioned with salt, hard water and tap water.

Only use water that meets the recommendations for the cooling system.

If you are not sure about the properties of your water, consult one of the following sources for a water analysis:

- Cat dealer
- Local water utility company
- Agricultural agent
- Independent laboratory

Glycol

NOTICE
Do not use Extended Life Coolant (ELC) with Cat Gas Engines.

ELC was not formulated for use in Cat Gas Engines.

Do not use heat transfer fluids in Cat Gas Engines.

Use only the coolant/antifreeze that is recommended.

Preferred – Cat Natural Gas Engine Coolant (NGEC)

Alternatively, use Cat Diesel Engine Antifreeze/ Coolant (DEAC) or a commercial heavy-duty coolant/ antifreeze that meets “ASTM D6210” or “ASTM D4985” specifications.

NOTICE
Do not use a commercial coolant/antifreeze that only meets the ASTM “D3306” or equivalent specification. This type of coolant/antifreeze is made for light duty automotive applications.

Use only the coolant/antifreeze that is recommended.

Acceptable – In applications that do not require protection from boiling or freezing, a mixture of Cat SCA and water that meets the required properties is acceptable.

Note: The preferred coolant/antifreeze and the acceptable mixture of SCA and water require different concentrations of SCA. Refer to the Special Publication, SEBU6400, “Supplemental Coolant Additive (SCA)” topic.

Table 19 is a list of the coolant/antifreeze that is recommended for Cat Gas Engines. The service life of the coolant/antifreeze that is used in Cat Gas Engines is also listed. **To achieve this service life, the coolants must be maintained. The maintenance program includes S·O·S coolant analysis.**

Table 19

Recommended Coolant/Antifreeze and Service Life of the Coolant/Antifreeze	
Coolant/Antifreeze	**Service Life (1)**
Cat NGEC	Three Years
Cat DEAC	
Commercial Heavy-Duty Coolant/Antifreeze that meets “ASTM D6210”	Two Years
Commercial Heavy-Duty Coolant/Antifreeze that meets “ASTM D4985”	One Year
Cat SCA and Water	Two Years
Commercial SCA and Water	One Year

(1) The service life of coolant is also limited by use (service hours). Refer to the specific engine Operation and Maintenance Manual, “Maintenance Interval Schedule”.

Additives

Preferred – Cat Supplemental Coolant Additive (SCA)

Acceptable – A commercial SCA that provides 1200 mg/L (70 gr per US gal) or 1200 ppm of nitrites in the final mixture of coolant/antifreeze

Note: A 50/50 concentration of Cat NGEC or of Cat DEAC does not require a treatment with an SCA at the initial fill. Commercial heavy-duty coolant/antifreeze that meets “ASTM D6210” or “ASTM D4985” specifications may require a treatment with an SCA at the initial fill. Read the label or the instructions that are provided by the OEM of the product.

To ensure that the correct amount of SCA is in the cooling system, the concentration of SCA must be tested on a scheduled basis. Obtain an S·O·S coolant analysis (Level 1) or use a test kit to check the concentration of the SCA at the recommended interval.

For further information on coolant, see Special Publication, SEBU6400, “Cat Gas Engine Lubricant, Fuel, and Coolant Recommendations”.

Fuel Recommendations

Cat gas engines will operate successfully on a broad range of gaseous fuels. Pipeline natural gas has been used for many years. Commercial fuel gases are mixtures of gases. These fuels consist primarily of hydrocarbons (combinations of hydrogen and carbon) and some inert gases. The compositions of these gas mixtures have extreme variations. Fuels such as wellhead gas, bio-gas, and manufactured gas must be reviewed for acceptability. Analyze the fuel to determine the following characteristics:

- Composition
- Contaminants
- Heat value
- Methane number
- Specific gravity

Field gas can have varying characteristics of combustion. Field gas can contain numerous harmful impurities. The impurities can alter the BTU content. The impurities can also alter the methane number. The impurities include everything from water up to complex hydrocarbons that can lead to detonation and severe engine damage. To minimize these effects, Caterpillar recommends the following guidelines:

1. Evaluate the fuel with the Cat methane number program that is contained in Gas Engine Rating Pro (GERP) which can be found on Power Net.

Reference the engine performance data sheet for fuel usage.

2. If necessary, use an engine that is configured for a fuel that has a high energy. Consult the appropriate manual for the engine to determine the recommended engine timing.

3. Reduce the oil change interval according to the results of the oil analysis.

For further information on fuels, see Special Publication, SEBU6400, “Cat Gas Engine Lubricant, Fuel, and Coolant Recommendations”.

Maintenance Recommendations

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General Maintenance Information

SMCS Code: 4450; 7000

Note: Read the warnings and read the instructions that are contained in the Safety Section of this manual. These warnings and instructions must be understood before you perform any operation or any maintenance procedures.

Rotating electric machines are complex structures that are exposed to the following forms of stress:

- mechanical
- electrical
- thermal
- environmental

These stresses may be of varying magnitudes. The insulation systems are susceptible to damage that is caused by the stresses that are listed above. Exposure to these stresses may shorten the effective life of the insulation system. Therefore, the service life of an electric machine will largely depend on the serviceability of the insulation systems. An inspection program and a testing procedure are recommended. An inspection program and a testing procedure will ensure that the equipment is maintained in satisfactory condition. This procedure will increase field reliability.

A regular maintenance and inspection program can provide an evaluation of the present condition of the equipment. A regular maintenance program and a regular inspection program can also reveal future problems. The frequency of this maintenance program will depend on the following factors:

- application
- environmental conditions
- operator experience
- operator philosophy

A regular maintenance program is recommended. This program would involve the following steps:

- periodic disassembly
- knowledgeable visual examination of the equipment
- the application of electrical tests

Never perform a test over the rated potential. These tests can damage insulation that is contaminated or insulation that is in marginal condition. For more information, refer to “I.E.E.E. Standard 432-1992” or consult a Caterpillar dealer.

Space Heaters

The SR4B and SR5 generators used on this product can operate in high humidity conditions without problems. However, problems can occur when the generator is idle and the surrounding air is warmer than the generator. Moisture can form on the windings that will result in poor performance from the windings. Moisture can also result in damage to the windings. Whenever the generator is not active, ensure that the space heaters are in operation.

NOTICE
Ensure that power has been disconnected before servicing the generator terminal box.

Note: An optional attachment for space heaters may be utilized in the generator terminal box. The space heaters are a source of heat.

Whenever the generator is operating, ensure that the space heaters are disconnected.

An external source of either 115 VAC or 230 VAC is required to operate the space heaters.

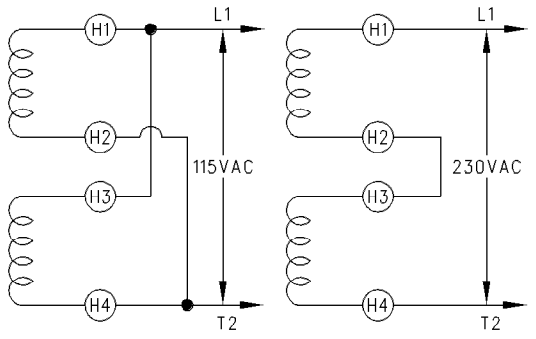

Illustration 48 g00556903

Space heater connection to external source (H1)(H2), (H3), and (H4) terminals.

If a 115 VAC source is available, connect both heaters in parallel across the source. If a 230 VAC source is available, connect both heaters in series across the source. Refer to Illustration 48 .

Gearbox Heater (If Equipped)

The gearbox can operate in normal ambient conditions without problems. Low oil temperatures can result in damage to the gearbox oil pump and sensors due to high pressure. Whenever the gearbox is not operating, ensure that the oil heater is in operation to maintain an oil temperature at or above 30° C (86° F).

The gearbox heater can be operated while the gearbox is operating. A built-in thermostat will turn off the heater element as the oil temperature rises.

A 120 or 240 VAC external source is required to operate the gearbox heater. The external power source voltage depends on the heater utilized on the unit. Confirm the voltage required for your specific unit prior to connecting power.

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System Pressure Release

SMCS Code: 1250; 1300; 1350; 5050

Coolant System

⚠ WARNING

Pressurized system: Hot coolant can cause serious burn. To open cap, stop engine, wait until radiator is cool. Then loosen cap slowly to relieve the pressure.

To relieve the pressure from the coolant system, turn off the engine. Allow the cooling system pressure cap to cool. Remove the cooling system pressure cap slowly to relieve pressure.

Fuel System

To relieve pressure from the fuel system, close the manual valves, and purge the generator set.

Generator Set Oil

To relieve pressure from the lubricating systems, turn off the engine.

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Welding on Engines with Electronic Controls

SMCS Code: 1000

NOTICE
Because the strength of the frame may decrease, some manufacturers do not recommend welding onto a chassis frame or rail. Consult the OEM of the equipment or your Cat dealer regarding welding on a chassis frame or rail.

Proper welding procedures are necessary to avoid damage to the engine ECM, sensors, and associated components. When possible, remove the component from the unit and then weld the component. If removal of the component is not possible, the correct procedure must be followed. When welding on a unit that is equipped with a Cat Electronic Engine, the following is considered to be the safest procedure:

NOTICE
Do not ground the welder to electrical components such as the ECM or sensors. Improper grounding can cause damage to the drive train, the bearings, hydraulic components, electrical components, and other components.

Do not ground the welder across the centerline of the package. Improper grounding could cause damage to the bearings, the crankshaft, the rotor shaft, and other components.

Clamp the ground cable from the welder to the component that will be welded. Place the clamp as close as possible to the weld. This will help reduce the possibility of damage.

Note: Perform the welding in areas that are free from explosive hazards.

1. Stop the engine. Turn the switched power to the OFF position.

2. Disconnect the negative battery cable from the battery. If a battery disconnect switch is provided, open the switch.

3. Disconnect the J1/P1 and J2/P2 connectors from the ECM. Move the harness to a position that will not allow the harness to move back accidentally, and contact any of the ECM pins.

4. Disconnect any component with a microprocessor from the engine harness, such as:

- Engine ECM
- Product Link
- Cell/Sat Radio
- DOC Identity Modules

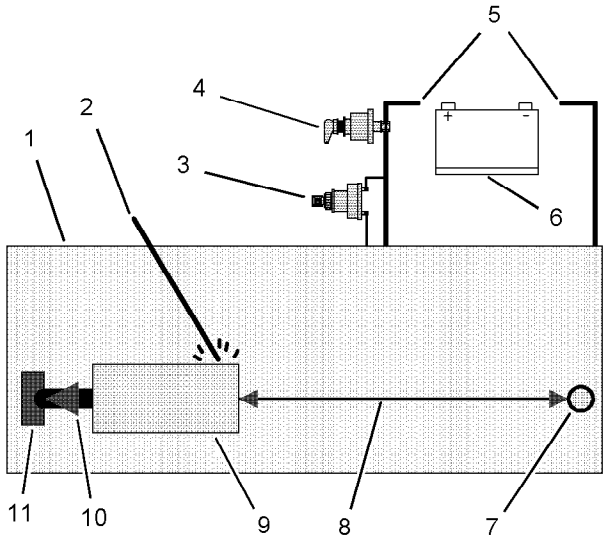

Illustration 49 g01075639

Use the example above. The current flow from the welder to the ground clamp of the welder will not damage any associated components.

(1) Engine
(2) Welding electrode
(3) Keyswitch in the OFF position
(4) Battery disconnect switch in the open position
(5) Disconnected battery cables
(6) Battery
(7) Electrical/Electronic component
(8) Minimum distance between the component that is being welded and any electrical/electronic component
(9) The component that is being welded
(10) Current path of the welder
(11) Ground clamp for the welder

5. Connect the welding ground cable directly to the part that will be welded. Place the ground cable as close as possible to the weld. This location will reduce the possibility of welding current damage to bearings, hydraulic components, electrical components, and ground straps.

Note: If electrical/electronic components are used as a ground for the welder, current flow from the welder could severely damage the component. Current flow from the welder could also severely damage electrical/electronic components that are located between the welder ground and the weld.

6. Protect the wiring harness from welding debris and spatter.

7. Use standard welding practices to weld the materials.

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Generator Start-up Checklist

SMCS Code: 4450

Table 20

GENERATOR START-UP CHECKLIST							
RATING INFORMATION							
Engine Serial Number: _____				Arrangement Number: _____			
Generator Serial Number: _____				Arrangement Number: _____			
Gearbox Serial Number: _____							
GENERATOR NAME PLATE INFORMATION							
Voltage: _____			Package (prime, continuous, standby): _____				
Amperage: _____			Kilowatts: _____				
Storage Location:							
Generator and Gearbox Alignment:							
Main Stator Megohmmeter Reading:		Before Storage:		After Storage:			
Generator dried for 24 hours prior to start-up?		(Y/N)		Drying method:			
HEATERS		**Yes**	**No**	**Comments**			
Space heaters operating properly?							
Gearbox oil heater is operating properly? (If Equipped)							
Type 1 Gearbox Utilizing Cat NGEO Advanced 40 Oil. Gearbox oil temperature above 10° C (50° F) before start-up?							
Type 2 Gearbox Utilizing Cat Synthetic Compactor Oil. Gearbox oil temperature above 0° C (32° F) before start-up?							
Space heater operated 48 hrs. before start-up?							
MEGOHMMETER TEST (SEHS9124)		30 sec. reading	60 sec. reading	30 sec. corrected	60 sec. corrected	Ambient temp.	Comments
Beginning of Storage	Main Stator						
	Main Rotor						
	Exciter Stator						
	Exciter Rotor						
	PMG Stator						
Start-up	Main Stator						
	Main Rotor						

(continued)

(Table 20, contd)

GENERATOR START-UP CHECKLIST							
	Exciter Stator						
	Exciter Rotor						
	PMG Stator						
Regulator		**Voltage**	**Amps**	**Comments**			
No Load	F1 to F2	DC					
	20 to 22	AC					
	20 to 24	AC					
	22 to 24	AC					
	26 to 28	AC					
	26 to 30	AC					
	28 to 30	AC					
Full Load	Generator Excitation Name Plate Information:	DC		Compare with F1 to F2			
	F1 to F2	DC					
	20 to 22	AC					
	20 to 24	AC					
	22 to 24	AC					
	26 to 28	AC					
	26 to 30	AC					
	28 to 30	AC					

Table 21

GENERATOR START-UP CHECKLIST (CONT.)				
ELECTRICAL		**Yes**	**No**	**Comments**
	Unit properly grounded			
	Check diodes			
	Over current protection			
	Over voltage protection			
	Check for loose wiring			
	Adjust voltage			
	Adjust frequency			
MECHANICAL		**Data**		**Comments**
	Bearing temperature readings at full load	Front _____ Rear _____		
	Stator temperature readings at full load	A0 _____ B0 _____ C0 _____		
	Air gap on main stator	Top _____ Bottom _____		
	Air gap on exciter stator	Top _____ Bottom _____		
	Air gap of PMG	Top _____ Bottom _____		
	Ambient air to generator at full load	Temperature _____		

(continued)

(Table 21, contd)

	Supplier air opening to generator				Size of Opening _____			
SWITCH GEAR/PARALLEL OPERATION								
	Manufacturer:							
				Setting 1	**Setting 2**	**Setting 3**	**Comments**	
	Circuit breaker type							
	Overload setting							
	Reverse power relay							
	VAR/PF Controller							
	Load share							
INSTALLATION & LOAD INFORMATION								
	Neutral grounding system				UPS			
	Enclosure type				Size			
	Motor:				Other loads:			
	- Total SKVA				- Lighting			
	- Total HP				- Computers			
					- Welding			
					- Non-linear			
					- Other			
FULL LOAD DATA								
Voltage	Amps		kW	KVARS	P.F.			

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Maintenance Interval Schedule

SMCS Code: 1000; 4450; 7500

Ensure that all safety information, warnings, and instructions are read and understood before any operation or any maintenance procedures are performed. The user is responsible for the performance of maintenance, including all adjustments, the use of proper lubricants, fluids, and filters. The user is also responsible for the replacement of components due to normal wear and aging. Failure to adhere to proper maintenance intervals and procedures may result in diminished performance of the product and/or accelerated wear of components. Use fuel consumption, service hours, or calendar time, WHICH EVER OCCURS FIRST, to determine the maintenance intervals. Products that operate in severe operating conditions may require more frequent maintenance. Before each consecutive interval is performed, all maintenance from the previous interval must be performed.

When Required

Daily

Initial 250 Service Hours

Every 250 Service Hours

Every 1000 Service Hours

Every 2000 Service Hours

Every 3000 Service Hours

Every 4000 Service Hours

Every 8000 Service Hours

Every 10 000 Service Hours

Between 12 000 and 16 000 Service Hours

Between 18 000 and 22 000 Service Hours

Every 24 000 Service Hours or 3 Years

Between 35 000 and 45 000 Service Hours

Between 70 000 and 90 000 Service Hours

Attachment D
Site Location Aerial Map

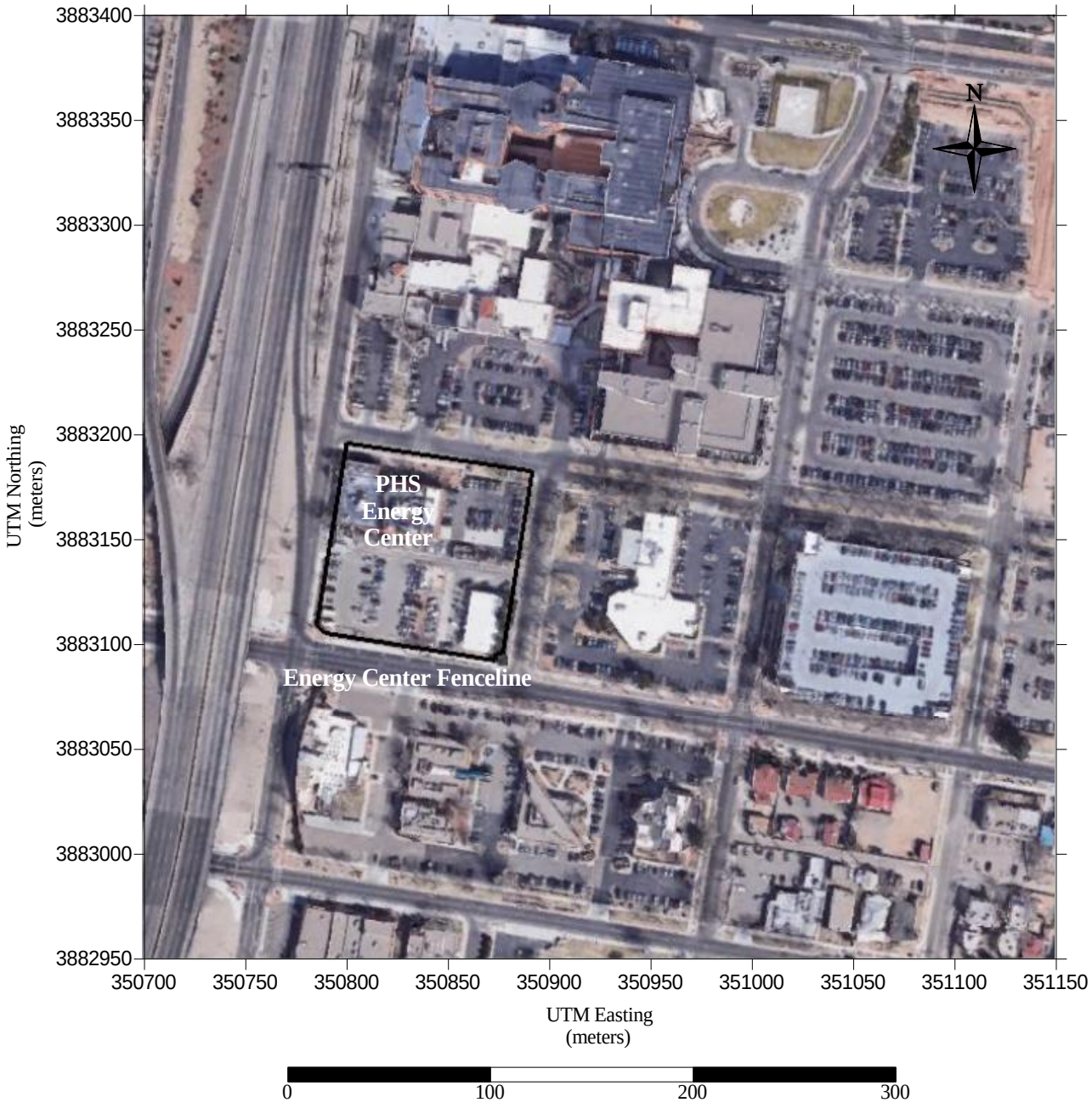

Figure D-1: Aerial Map Showing Site Location
NAD 83

Attachment E
Facility Process Description

Facility Process Description

Presbyterian Healthcare Services (PHS) Energy Center provides steam from the four existing facility boilers (Units #3 – 6) as comfort heating for the Presbyterian hospital. The facility also consists of three emergency generators (Units #1, #2, #7) to provide electrical power against the loss of commercial line power.

Presently, the boilers are permitted to each operate 8,760 hours per year. With this significant permit revision, the boilers will be limited to only three of the four boilers operating at any one time. PHS will install new burners in Permit Units 3 and 4, and recalculate emission rate of Permit Unit 6 per the manufacturer's guarantee emission rate for NOx of 30 PPM. No other change for Units 1, 2, 5, and 7 will be included in this significant permit revision.

With this significant permit revision, PHS will be adding to the Energy Center installation of a new Caterpillar (CAT) Model G3516H Natural Gas Cogeneration (CoGen) Package (Unit #8). The CoGen will produce electricity and steam (heat) for the new hospital building under construction. The package includes a G3516H natural gas engine, SR4B generator, and a Superior Boiler heat recovery steam generator (HRSG). All regulated emissions are generated by the G3516H natural gas engine. CAT rates the engine brake horsepower (BHP) for the CoGen at 2,763. The installation of the CoGen will include additional building construction to accommodate the new CoGen. The CoGen will be installed with an oxidation catalyst to control carbon monoxide (CO), volatile organic compounds (VOC), and formaldehyde (CH_2O). The CoGen will be permitted to allow 8,760 hours of operation per year.

Attachment F

Regulatory Applicability Determination

The following is a list of city and federal regulations that may or may not be applicable to PHS

Albuquerque/Bernalillo County Regulations

20.11.1 NMAC– General Provisions: Applicable to PHS

Requirement: Compliance with ambient air quality standards.

Compliance: Compliance with 20.11.8 NMAC is compliance with this regulation.

20.11.2 NMAC– Permit Fees: Applicable to PHS

Requirement: A one-time permit application fee will be assessed by the Albuquerque/Bernalillo County Environmental Department.

Compliance: PHS will pay all required permit revision application fees applicable to their facility.

20.11.5 NMAC– Visible Air Contaminants: Applicable to PHS

Requirement: Places limits of 20 percent opacity on stationary combustion equipment.

Compliance: PHS will perform any required opacity observations using Method 9 and/or Method 22 with certified opacity observers.

20.11.8 NMAC– Ambient Air Quality Standards: Applicable to PHS

Requirement: Compliance with all federal, state and local ambient air quality standards.

Compliance: PHS's Energy Center demonstrated compliance by performing and submitting dispersion modeling analysis for applicable pollutants per Albuquerque/ Bernalillo County and New Mexico State Environmental Department's modeling guidelines.

20.11.20 NMAC– Airborne Particulate Matter: Applicable to PHS

Requirement: Requires the facility to obtain a permit prior to start of surface disturbances.

Compliance: PHS will apply for a 20.11.20 NMAC permit prior to the start of surface disturbances.

20.11.41 NMAC– Authority to Construct: Applicable to PHS

Requirement: Requires the facility to obtain a permit prior to start of construction.

Compliance: PHS is applying for a new 20.11.41 NMAC permit with this application.

20.11.49 NMAC– Excess Emissions: Applicable to PHS

Requirement: To implement requirements for the reporting of excess emissions and establish affirmative defense provisions for facility owners and operators for excess emissions.

Compliance: PHS will report all excess emissions following 20.11.49 NMAC guidelines.

20.11.63 NMAC– New Source Performance Standards: Applicable to PHS

Requirement: Adoption of all federal 40 CFR Part 60 new source performance standards.

Compliance: PHS will comply with all applicable 40 CFR Part 60 NSPS that have been identified for this facility. For this facility, 40 CFR Part 60 Subpart Db, IIII, and JJJJ have been identified as applicable standards.

20.11.64 NMAC– Emission Standards for Hazardous Air Pollutants for Stationary Sources: Applicable to PHS

Requirement: Adoption of all federal 40 CFR Part 61 and 63 National Emissions Standards for Hazardous Air Pollutants (HAPS).

Compliance: 40 CFR Part 63 Subpart ZZZZ has been identified as an applicable standard for Units #7 and #8.

20.11.66 NMAC– Process Equipment: Applicable to PHS

Requirement: The objective of this Part is to achieve attainment of regulatory air pollution standards and to minimize air pollution emissions.

Compliance: Except as otherwise provided in this section, PHS shall not cause or allow the emission of particulate matter to the atmosphere from process equipment in any one hour in total quantities in excess of the amount shown in 20.11.66.18 NMAC Table 1.

20.11.90 NMAC– Administration, Enforcement, Inspection: Applicable to PHS

Requirement: General requirement on record keeping and data submission. PHS will notify the bureau regarding periods of excess emissions along with the cause(s) of the excess emissions and actions taken to minimize the duration and avoid recurrence.

Compliance: It is expected that specific record keeping and data submission requirements will be specified in the 20.11.41 NMAC permit issued to PHS. It is expected the 20.11.41 NMAC permit issued to PHS will contain specific methods for determining compliance with each specific emission limitation. PHS's Energy Center will report any periods of excess emissions as required by specific 20.11.90 NMAC provisions.

Federal Regulations

40 CFR 50 – National Ambient Air Quality Standards: Applicable to PHS

Requirement: Compliance with federal ambient air quality standards.

Compliance: PHS's Energy Center will demonstrate compliance by performing and submitting dispersion modeling analysis for applicable pollutants per the Albuquerque/ Bernalillo County and New Mexico State Environmental Department's modeling guidelines.

40 CFR 60 Dc – NSPS Standards of Performance for Small Industrial-Commercial-Institutional Stream Generating Units: Applicable to PHS

Requirement: For any affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 100 million Btu per hour of less, but greater than or equal to 10 million Btu per hour. A steam generating unit is defined as a device that combusts any fuel and produces steam or heats water or any other heat transfer medium.

Compliance: Unit #6 is subject to NSPS 40 CFR 60 Subpart Dc and shall comply with all applicable requirements of 40 CFR Part 60 Subparts A and Dc.

40 CFR 60 Kb – NSPS Standards of Performance for Volatile Liquid Storage Vessels: Not applicable to PHS

Requirement: Regulation applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984

Compliance: PHS has two underground 30,000 gallon (113.6 m^3 each) volatile liquid storage vessels each greater than 75 m^3 will, but with a vapor pressure less than 15.0 kPa, so neither are applicable to 40 CFR 60 Kb.

40 CFR 60 IIII – NSPS Standards of Performance for Stationary Compression Ignition Internal Combustion Engine: Applicable to PHS

Requirement: The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE).

Compliance: Unit #7 is applicable to Subpart IIII as an emergency stationary ICE. Pursuant to 40 CFR 60 Subpart IIII §60.4211(f), Unit #7 shall be limited to 100 hours per year of maintenance checks and readiness testing. Unit #7 may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for the facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity. Routine or non-emergency operation of the unit or operation for any other purposes, except as stated above, shall be a violation of this permit.

40 CFR 60 JJJJ – NSPS Standards of Performance for Stationary Compression Ignition Internal Combustion Engine: Applicable to PHS

Requirement: The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE).

Compliance: Unit #8 is applicable to NSPS Subpart JJJJ. This rule does apply to the 2,763 bhp Caterpillar G3516H engine because the maximum engine power is greater than 500 HP and the engine was manufactured on or after 07/01/08 (§60.4230(a)(4)(i)). Requirements include NOx, CO and VOC emission limits (§60.4233(e)); engine maintenance (§60.4243(b)(2)(ii)); performance testing (§60.4244(a-d)); and notification and recordkeeping (§60.4245).

Emission Limits

§60.4233(e) Unit #8 must meet a nitrogen oxides (NO_X) emission standard of 1.0 grams per HP-hour (g/HP-hr), a CO emission standard of 2.0 g/HP-hr, and a volatile organic compounds (VOC) emission standard of 0.7 g/HP-hr,

Maintenance Requirements

Per §60.4243(b)(2)(ii) Unit #8 must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, an initial performance test must be conducted for Unit #8 within 1 year of engine startup, with subsequent performance testing conducted every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

Performance Testing Requirements

Per §60.4244(a-d) for Unit #8 each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Subpart JJJJ Table 2.

Recordkeeping Requirements

Per §60.4245 (a)(1-4) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section .

40 CFR 63 JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources: Not Applicable to PHS

Requirement: You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in §63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in §63.2, except as specified in §63.11195.

Compliance: Units #3, 4, and 6 are located at an area source of hazardous air pollutants (HAPs) as defined by 40 CFR 63 Subpart A §63.2. Units #3, 4, and 6 are defined as a "gas-fired boiler" in accordance with 40 CFR 63 Subpart JJJJJJ §63.11237, since the unit operates 48 hours per calendar year or less firing liquid fuel, it is not currently subject to the NESHAP. If Units #3, 4, or 6 exceed 48 hours per calendar year firing liquid fuel, then the unit becomes an affected source that will be subject to 40 CFR 63 Subpart JJJJJJ.

40 CFR 63 ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: Applicable to PHS

Requirement: Facilities are subject to this subpart if they own or operate a stationary RICE, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

Compliance: Unit #7 is subject to National Emissions Standard for Hazardous Air Pollutants (NESHAP) found in 40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Source Category: Stationary Reciprocating Internal Combustion Engines apply and this facility shall comply with the specific requirements found in this subpart as well as the general requirements of 40 CFR 63 Subpart A - General Provisions. The permittee shall comply with the specific requirements of Subpart ZZZZ applicable to new engines.

Unit #8 is subject to 40 CFR 63 Subpart ZZZZ under §63.6590(c). Since Unit #8 has to meet the requirements of 40 CFR 40 Subpart JJJJ, no applicable requirements under 40 CFR 63 Subpart ZZZZ apply.

Attachment G

Dispersion Modeling Summary

DISPERSION MODEL REPORT
FOR PRESBYTERIAN HEALTHCARE SERVICES
ENERGY CENTER
PERMIT #0273-M3 REVISION APPICATION

Albuquerque, New Mexico

PREPARED FOR
PRESBYTERIAN HEALTHCARE SERVICES

January 28, 2022

Prepared by

Montrose Air Quality Services, LLC

MONTROSE
AIR QUALITY SERVICES

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1.0 INTRODUCTION

This dispersion modeling analysis will be conducted by Montrose Air Quality Service, LLC (Montrose) on behalf of Presbyterian Healthcare Services (PHS), to evaluate ambient air quality impacts from a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package to be included as a permitted emission source to Permit #0273-M3-1TR. The location for the new CoGen will be in the expanded Energy Center at 1002 Silver Ave SE. The UTM coordinates of the Energy Center is; 350,835 meters E, 3,883,175 meters N, Zone 13, NAD 83. The objective of this evaluation is to determine whether ambient air concentrations from the maximum operation of the proposed CoGen for nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter; both 10 microns or less (PM_{10}) and 2.5 microns or less ($PM_{2.5}$); are below Class II federal and state ambient air quality standards (NAAQS and NMAAQS) found in 40 CFR Part 50 and the City of Albuquerque/Bernalillo County Health Division (AEHD) air quality regulation 20.11.8 NMAC, respectively.

The dispersion modeling will be conducted using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee Dispersion Model (AERMOD), *Version 21112*. This model is recommended by EPA for determining Class II impacts within 50 km of the source being assessed. Additionally, AERMOD was developed to handle complex terrain. In this analysis, AERMOD will be used to estimate pollutant ambient air concentrations from the all existing and new PHS Energy Center emission sources. Montrose employs the general modeling procedures outlined in "Permit Modeling Guidelines, Albuquerque Environmental Health Department", revised 10/10/2019, "New Mexico Air Pollution Control Bureau, Dispersion Modeling Guidelines", revised 10/26/2020, and the most up to date EPA's *Guideline on Air Quality Models*.

With this permit modification, PHS will install the CoGen plant to produce electricity and steam (heat) for the new hospital wing building under construction. Presently, the permit for the Energy Center included four (4) steam boilers and three (3) emergency generators. In addition to installation of the CoGen, PHS will be installing new and more efficient burners on steam boilers 1 and 2 (Permit Units 3 and 4). For steam boiler 4 (Permit Unit 6), the NO_X emission rate will be recalculated using the manufacturer's PPM guarantee of 30. The revised emission rates will be included in the permit modification application.

Three of the four boilers are allowed to combust both natural gas or #2 diesel, while the other can only combust natural gas. Per Permit #0273-M3-1TR Condition I.1.d.viii, Units #3, 4, and 6 are allowed to operate 48 hours per year combusting #2 diesel. Over the last 5 years the total hours combusting #2 diesel is 17.5 hours for Unit 4 and 5 hours for Unit 6 (see Attachment A). Because of the limited time the facility combusts #2 diesel, all modeled emission rates from the boiler will be based on combusting natural gas.

For the boilers modeled exhaust parameters, the boiler manufacturers were contacted and the manufacturer provided the following information; stack exhaust temperature at maximum and exhaust flowrate at maximum (see Attachment B). Stack height and stack diameter were determined by site inspection.

The three (3) emergency generators included in Permit #0273-M3-1TR will not be included in the dispersion modeling analysis, because these sources are intermittent. Emergency generators, with exception of loss of generating power, are tested monthly. Testing takes less than an hour per engine, so total testing hours is approximately 12 hours per year per emergency generator.

Presently, the boilers are allowed to operate 8760 hours each. For this permit modification, PHS will restrict the use of the boilers to only three boilers operating under maximum conditions at any one time for 8760 hours per year. This requested permit change will add additional permit conditions to the present operation of the boilers, recordkeeping and reporting.

With four existing boilers, there are four combinations of three boilers operating at any one time. The dispersion model analysis will be run for these 4 "Model Group" sources. To present these scenarios, each boiler combination will be modeled with maximum operation of the CoGen, applicable neighboring sources, and representative background.

Figure 1 below shows the PHS Energy Center and location of the existing permitted boiler stacks and proposed CoGen stack. Figure 2 shows the PHS Energy Center, PHS Energy Center restricted boundary, and surrounding area. Fencing around the PHS Energy Center and the PHS Energy Center building will be used as the modeling boundary. The fenced area is restricted to PHS employees only, specifically the PHS Energy Center employees or authorized contractors.

PHS will model any additional neighboring sources identified by the AEHD ADP Modeling Section. Initial neighboring source proposed to include in the modeling is the University of New Mexico's Ford Energy Center (1643-M1), University of New Mexico's Steam Plant (1601-M1-RV1), Lovelace Medical Center (1509-M2-1AR), NM Scientific Labs (2165-M1-RV1), WR-AAT (0051-M1-3TR), Clean Energy (0649-RV1), Ameripride (1518-M1), and US Transport (1523-M1-3AR).

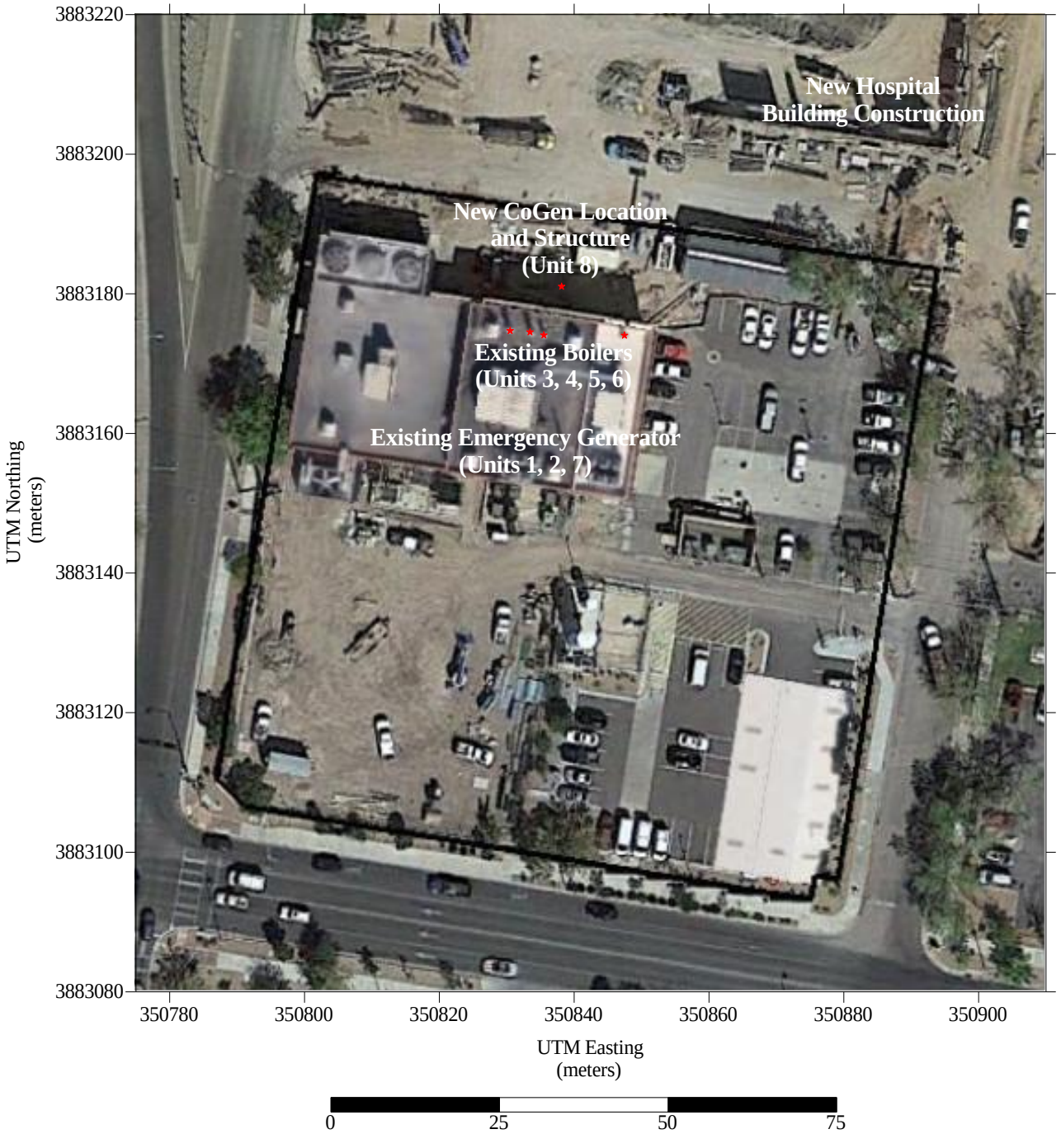


FIGURE 1: PHS Energy Center Stack Locations

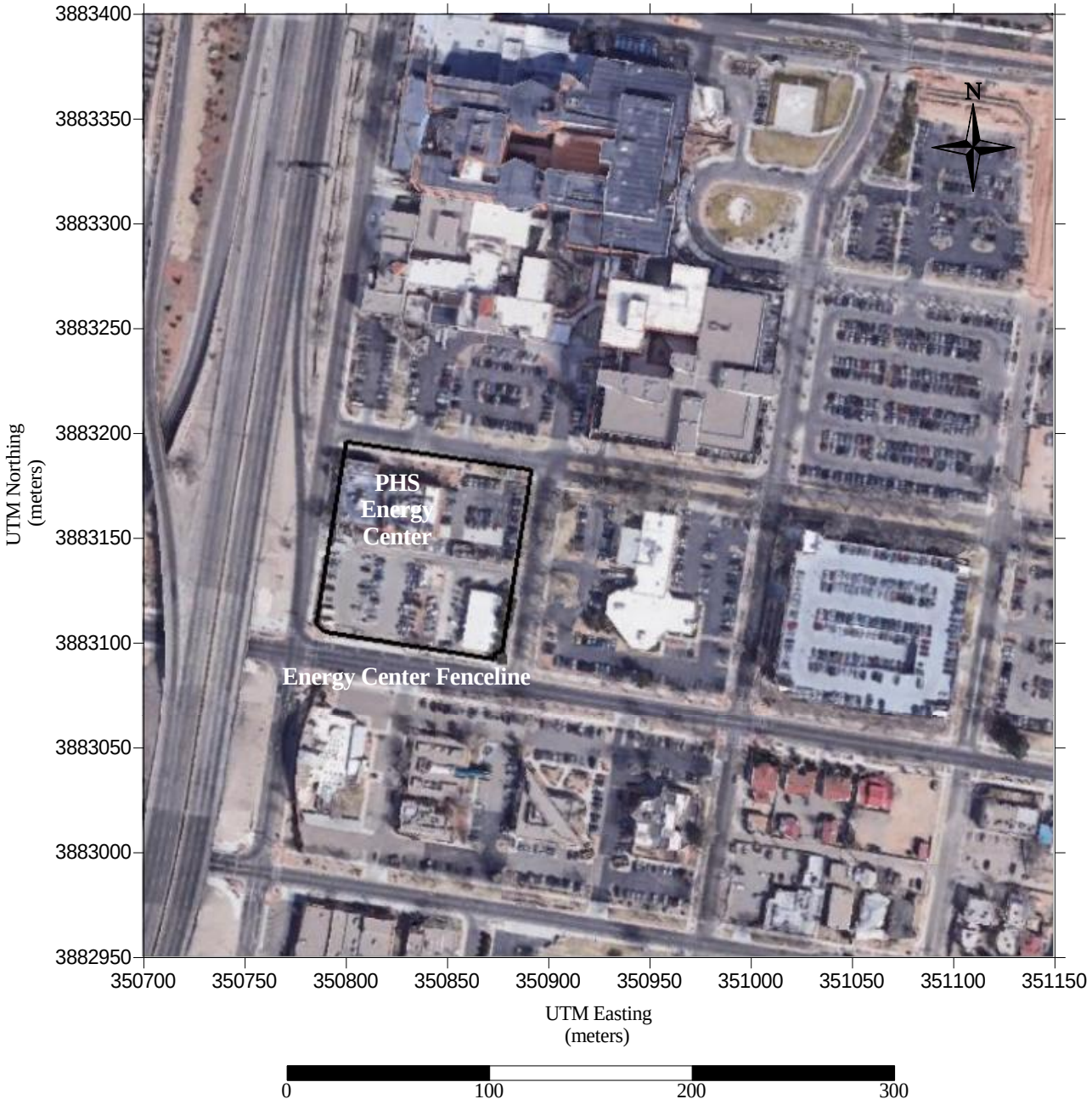


FIGURE 2: PHS Energy Center Location and Surrounding Area

2.0 DISPERSION MODELING PROTOCOL

This section identifies the technical approach and dispersion model inputs that will be used for the Class II federal and State ambient air quality standards for this permit application. AEHD AQP requires that all applicable criteria pollutant emissions be modeled using the most recent versions of US EPA's approved models and be compared with National Ambient Air Quality Standards (NAAQS), and New Mexico Ambient Air Quality Standards (NMAAQS). Table 1 shows the NAAQS and NMAAQS that the source's ambient impacts must meet in order to demonstrate compliance. Table 1 also lists the Class II Significant Impact Levels (SILs) which are used to assess whether a source has a significant impact at downwind receptors.

The dispersion modeling analysis will be performed to estimate concentrations resulting from the maximum permitted operation of the PHS Energy Center sources using the proposed maximum permitted emission rates while specified emission sources are operating. The modeling will determine the maximum off-site concentrations for NO_2, CO, SO_2, PM_{10} and $PM_{2.5}$, for comparison with modeling significance levels, national/New Mexico/Bernalillo County ambient air quality standards (AAQS). For this modeling analysis, particulate emissions from PHS sources assumes PM = PM_{10} = $PM_{2.5}$ are equal. The modeling will follow the guidance and protocols outlined in the "Permit Modeling Guidelines, Albuquerque Environmental Health Department", revised 10/10/2019, "New Mexico Air Pollution Control Bureau, Dispersion Modeling Guidelines", revised 01/01/2019, and the most up to date EPA's *Guideline on Air Quality Models*.

Initial radius of impact (ROI) modeling will be performed for all PHS Energy Center sources only to determine pollutants and averaging periods that exceed significant impact levels (SILs). If initial modeling for any pollutant and averaging period exceeds SILs, then cumulative modeling will be performed for those pollutants and averaging periods. The cumulative impacts model will include all receptors for which the ROI model indicates that the SILs are exceeded and will include any identified neighboring emission sources and will incorporate background ambient concentrations. Table 1 lists the SILs, NAAQS and NMAAQS for each pollutant averaging period. Table 2 lists ambient air quality standards for which modeling is not required by NMED AQB, when an approved surrogate standard is modeled.

TABLE 1: National and New Mexico Ambient Air Quality Standard Summary

Pollutant	Avg. Period	Sig. Lev. ($\mu g/m^3$)	Class I Sig. Lev. ($\mu g/m^3$)	NAAQS	NMAAQS	PSD Increment Class I	PSD Increment Class II
CO	8-hour	500		9,000 ppb(1)	8,700 ppb(2)		
	1-hour	2,000		35,000 ppb(1)	13,100 ppb(2)		
NO_2	annual	1.0	0.1	53 ppb(3)	50 ppb(2)	2.5 $\mu g/m^3$	25 $\mu g/m^3$
	24-hour	5.0			100 ppb(2)		
	1-hour	7.52		100 ppb(4)			
$PM_{2.5}$	annual	0.2	0.05	12 $\mu g/m^3$(5)		1 $\mu g/m^3$	4 $\mu g/m^3$
	24-hour	1.2	0.27	35 $\mu g/m^3$(6)		2 $\mu g/m^3$	9 $\mu g/m^3$
PM_{10}	annual	1.0	0.2			4 $\mu g/m^3$	17 $\mu g/m^3$
	24-hour	5.0	0.3	150 $\mu g/m^3$(7)		8 $\mu g/m^3$	30 $\mu g/m^3$
SO_2	annual	1.0	0.1		20 ppb(2)	2 $\mu g/m^3$	20 $\mu g/m^3$
	24-hour	5.0	0.2		100 ppb(2)	5 $\mu g/m^3$	91 $\mu g/m^3$
	3-hour	25.0	1.0	500 ppb(1)		25 $\mu g/m^3$	512 $\mu g/m^3$
	1-hour	7.8		75 ppb(8)			

Standards converted from ppb to $\mu g/m^3$ use a reference temperature of 25° C and a reference pressure of 760 millimeters of mercury.
(1) Not to be exceeded more than once each year.
(2) Not to be exceeded.
(3) Annual mean.
(4) 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years.
(5) Annual mean, averaged over 3 years.
(6) 98th percentile of 24-hour daily maximum concentrations, averaged over 3 years.
(7) Not to be exceeded more than once per year on average over 3 years.
(8) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years.

TABLE 2: Standards for Which Modeling Is Not Required by NMED AQB

Standard not Modeled	Surrogate that Demonstrates Compliance
CO 8-hour NAAQS	CO 8-hour NMAAQS
CO 1-hour NAAQS	CO 1-hour NMAAQS
NO_2 annual NAAQS	NO_2 annual NMAAQS
NO_2 24-hour NMAAQS	NO_2 1-hour NAAQS
O_3 8-hour	Regional modeling
SO_2 annual NMAAQS	SO_2 1-hour NAAQS
SO_2 24-hour NMAAQS	SO_2 1-hour NAAQS
SO_2 3-hour NAAQS	SO_2 1-hour NAAQS

2.1 DISPERSION MODEL SELECTION

The dispersion modeling will be conducted using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee Dispersion Model (AERMOD), *Version 21112*. This model is recommended by EPA for determining Class II impacts within 50 km of the source being assessed. Additionally, AERMOD was developed to handle complex terrain. In this analysis, AERMOD will be used to estimate pollutant ambient air concentrations for NO_2, CO, SO_2, PM_{10} and $PM_{2.5}$, from the modified PHS Energy Center plant emission sources.

AERMOD is a Gaussian plume dispersion model that is based on planetary boundary layer principles for characterizing atmospheric stability. The model evaluates the non-Gaussian vertical behavior of plumes during convective conditions with the probability density function and the superposition of several Gaussian plumes. The AERMOD modeling system has three components: AERMAP, AERMET, and AERMOD. AERMAP is the terrain preprocessor program. AERMET is the meteorological data preprocessor. AERMOD includes the dispersion modeling algorithms and was developed to handle simple and complex terrain issues using improved algorithms. AERMOD uses the dividing streamline concept to address plume interactions with elevated terrain. AERMOD will be run using all the regulatory default options.

Urban or Rural

The dispersion modeling meteorological data set was created using rural attributes, but because the meteorological data uses NWS data and not site-specific data the use of this meteorological data for AERMOD urban mode is acceptable. While a large area surrounding PHS Energy Center is low level housing with trees, the PHS hospital structures supported by the Energy Center, nearby freeway, and the proximity of downtown Albuquerque should be considered a potential for urban heat island influence across the full modeling domain. To account for the dispersive nature of the "convective-like" boundary layer that forms during nighttime conditions due to the urban heat island effect, AERMOD enhances the turbulence for urban nighttime conditions over that which is expected in the adjacent rural, stable boundary layer, and also defines an urban boundary layer height to account for limited mixing that may occur under these conditions For this modeling analysis, the Urban mode will be used with the July 1, 2019 Albuquerque population input of 560,513 (https://www.census.gov/quickfacts/albuquerquecitynewmexico) and default surface roughness height of 1.

2.2 BUILDING WAKE EFFECTS

Buildings are located at the site that will impact plume downwash effects on the PHS Energy Center sources. These buildings located near point sources will be included in building downwash calculations. Figure 3 shows proposed buildings and location to the Energy Center.

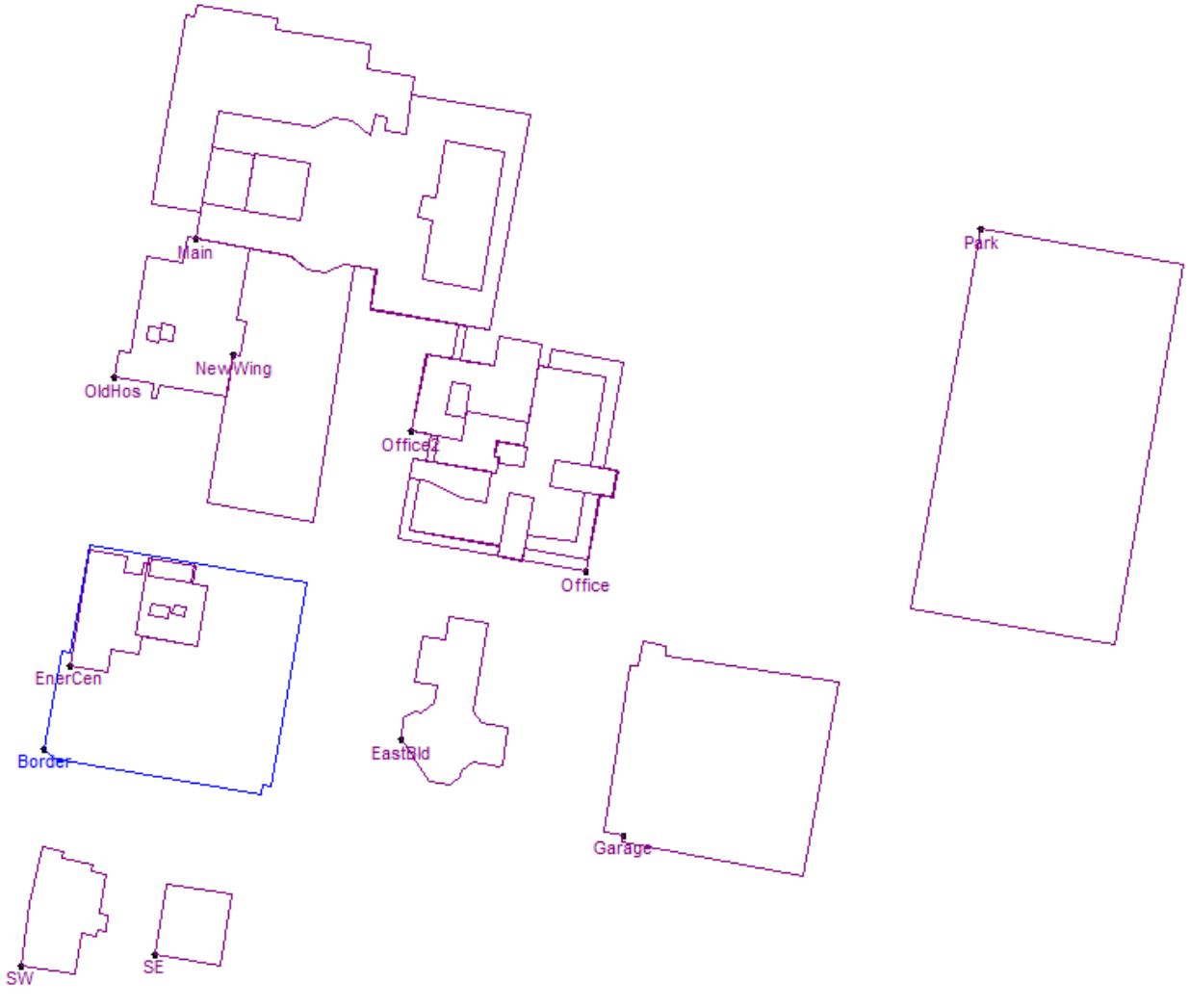


FIGURE 3: Nearby Buildings Included in the Model Analysis

2.3 METEOROLOGICAL DATA

The meteorological data input file to be used in this dispersion modeling analysis is Albuquerque met data covering years 2014 through 2018 (AERMET *Version 19191* dated 01/31/2020) available from the AEHD AQP.

2.4 RECEPTORS AND TOPOGRAPHY

Modeling will be completed using as many receptor locations as required to ensure that the maximum estimated impacts are identified. ROI modeling will be performed with receptors within 15 kilometers of the model boundary. Because of the nature of the emissions from the site, it is expected the maximum modeled concentrations will be on or near the site's fenceline.

The refined receptor grid will include receptors located at 10-meter spacing from the facility boundary out to 100 meters; 25-meter spacing from 100 meters out to 400 meters; 50-meter spacing from 400 meters out to 500 meters; 100-meter spacing from 500 meters out to 1,000 meters; 250-meter spacing from 1,000 meters out to 3,000 meters; and 500-meter spacing from 3,000 meters out to 5,000 meters, and 1000-meter spacing from 5,000 meters out to 15,000 meters. Fenceline receptor spacing will be 10 meters. Fenceline receptors are located at the fence that surrounds the Energy Center employee parking lot and along the north and west sides of the Energy Center where the public may walk or drive.

For elevate public locations, both PHS parking garages, flagpole receptors will be used surrounding each parking garage open level height, plus the top of the parking garages. The flagpole height matches the height above the base elevation of the parking structure to the various parking levels opening in the side of each parking structure building.

For the I-40 elevated freeway located next to the Energy Center, additional receptors are placed down the center of northbound lane and adjusted using flagpole receptors that determine the concentration at these receptors by adding to the NED determined elevation height to the elevation at the 15-foot height from base elevation of the PHS Energy Center, based on visual observations of freeway to Energy Center height. For all PHS and neighboring buildings, with the exception of the two PHS parking structures and Rachel's Courtyard on the 6th floor of the main hospital, the public will be restricted, so receptors that fall onto the top of buildings will be deleted.

All model receptors will be preprocessed using the AERMAP software (*Version 18081*) associated with AERMOD. The AERMAP software establishes a base elevation and a height scale for each receptor location. The height scale is a measure of the receptor's location and base elevation and its relation to the terrain feature that has the greatest influence in dispersion for that receptor. AERMAP will be processed using U.S. Geological Survey (USGS) national elevation data (NED). Output from AERMAP will be used as input to the AERMOD runstream file for each model run.

2.5 MODELED EMISSION SOURCES INPUTS

PHS presently operated 4 steam boilers under Permit #0273-M3-1TR. Each boiler is allowed to operate 8760 hours per year. For this permit modification, PHS will install a new CoGen and limit the boilers to operation of only three boilers at any one time. Emissions from exhaust stacks will be modeled as point sources. Model input parameters are based on actual release height, release diameter, release velocity or flow rate, and release temperature. PHS Energy Center boilers modeled stack releases are vertical and include raincaps. The new CoGen modeled stack release will be a vertical. Table 3 summarize the model inputs for the PHS Energy Center emission sources.

TABLE 3: Summary of Model Inputs for Point Sources at the PHS Energy Center Plant – NO_X, CO, SO_2 and PM

Source Description	Model ID	Stack Height (m)	Stack Temp. (K)	Exit Vel. (m/s)	Stack Dia. (m)	NOx Emission Rate (lb/hr)	CO Emission Rate (lb/hr)	SO2 Emission Rate (lb/hr)	PM Emission Rate (lb/hr)
PHS NG Boiler Unit 3	B3	11.2776	477.5944	8.403038	0.7112	1.46475	0.77423	0.04955	0.10044
PHS NG Boiler Unit 4	B4	11.2776	477.5944	8.403038	0.7112	1.46475	0.77423	0.04955	0.10044
PHS NG Boiler Unit 5	B5	11.2776	477.5944	6.601035	0.5080	1.00000	0.90000	0.01000	0.08000
PHS NG Boiler Unit 6	B6	11.2776	477.5944	13.364623	0.6096	1.05701	2.10000	0.02000	0.20000
PHS New CoGen	COGEN	14.9352	463.7056	19.670385	0.5080	6.09127	9.86786	0.03793	0.16123

2.6 PARTICLE SIZE DISTRIBUTION

No particle size distribution will be included in the particulate modeling for either PHS or neighboring sources.

2.7 NO_2 DISPERSION MODELING ANALYSIS

The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled NO_X emission rate will give ground-level modeled concentrations of NO_X. NAAQS values are presented as NO_2.

EPA has a three-tier approach to modeling NO_2 concentrations.

- Tier I – total conversion, or all NOx = NO_2
- Tier II –Ambient Ratio Method 2 (ARM2)
- Tier III – case-by-case detailed screening methods, such as Ozone Limiting Method (OLM) and Plume Volume Molar Ratio Method (PVMRM) and NO_2/NO_X in-stack ratio

Initial modeling will be performed using the Tier II methodology (ARM2). If these modeling iterations demonstrate that less conservative methods for determining 1-hour and annual NO_2 compliance would be needed for this project, then the ambient impact of 1-hour and annual NOx predicted by the model will use Tier III – OLM or PVMRM.

When using ARM2, two inputs can be selected in the model. For this modeling analysis, EPA default minimum and maximum ambient NO_2/NO_X ratios for the ambient air of 0.50 and 0.90, respectively, will be used. For OLM or PVMRM, three inputs can be selected in the model: the in-stack-ratio (ISR), the NO_2/NO_X equilibrium ratio for the ambient air, and the ambient ozone concentration. The ISR will be determined for each source or group of sources. The NO_2/NO_X equilibrium ratio will be the EPA default of 0.90. Ozone input is determined from monitored ozone data collected from Del Norte city monitoring station matching the modeled met years 2014 – 2018.

PVMRM is known to work best with relatively isolated sources, but it can potentially overestimate the NO-to-NO_2 conversion when plumes have significant overlap, as it can overestimate the amount of entrained ozone. OLM is somewhat less sophisticated than PVMRM as it does not estimate entrained ozone, but bases the NO-to-NO_2 conversion on the total amount of ozone present in the atmosphere. PHS Energy Center sources are located within a 50-foot area causing plume overlap. Since PVMRM is known for over estimation of the amount of entrained ozone for overlapping plumes, OLM modeling will be used for the PHS Energy Center NO2 1-Hour modeling analysis. For PHS Energy Center OLM modeling, the model will be run with all PHS Energy Center sources and all included neighbor sources combined into an OLM Group All (OLMGPALL) sources. This will limit the NO-to-NO_2 conversion for overlapping plumes.

To determine the ISR for each source, a search was performed for the PHS boilers and proposed CoGen. A document prepared by the California Air Pollution Control Officers Association

(CAPCOA) released a guidance document named "Modeling Compliance of The Federal 1-Hour NO2 NAAQS", October 27, 2011. In an effort to provide data needed for modeling and to address issues noted in EPA's NO_2 guidance memoranda, the San Joaquin Valley APCD has started gathering data from internal and external resources and has compiled a NO_2/NO_X ratio for a variety of sources. The document's Appendix C is found in Attachment C. Based on this ISR summary, the ISR range for natural gas boilers is 0.00 to 0.1579 with the CAPCOA recommendation of 0.10. PHS proposes an ISR for the 4 natural gas boilers a conservative ISR of 0.20. Based on this ISR summary, the ISR range for natural gas IC engines (Lean Burn, CO Catalyst) is 0.00 to 0.3962 with the CAPCOA recommendation of 0.10. PHS proposes an ISR for the CoGen a conservative 0.20. For neighboring sources, since the ISR has a diminishing impact on ambient NO_2/NO_X ratios as a plume is transported farther downwind due to mixing and reaction towards background ambient NO_2/NO_X ratios, neighboring sources within 1 kilometer of the site will use an ISR of 0.30 or available source specific ISR data. For Lovelace and UNM sources that combust natural gas the ISR used will be 0.20. For neighboring sources extended beyond 1 kilometer a default ISR of 0.20[1] will be used.

Model Ozone Data

For OLM or PVMRM, modeling of the project-generated 1-hour NO_2 concentrations requires use of ambient monitored ozone concentrations. This ozone data was provided by the AEHD AQP from the Del Norte monitoring station for the years 2014 – 2018. The Del Norte monitor best represents the PHS area consisting of mostly vehicle traffic emissions.

2.8 $PM_{2.5}$ SECONDARY EMISSIONS MODELING

Particulate matter includes both "primary" PM, which is directly emitted into the air, and "secondary" PM, which forms in the atmosphere from chemical reactions involving primary gaseous emissions of precursor air contaminants. Primary PM consists of carbon (soot)—emitted from cars, trucks, heavy equipment, forest fires, and burning waste—and crustal material from unpaved roads, stone crushing, construction sites, and metallurgical operations. Secondary PM forms in the atmosphere from gases. Some of these reactions require sunlight and/or water vapor. Secondary PM includes:

- Sulfates formed from SO_2 emissions from power plants and industrial facilities;
- Nitrates formed from NO_X emissions from cars, trucks, industrial facilities, and power plants; and
- Carbon formed from reactive organic gas (ROG or VOC) emissions from cars, trucks, industrial facilities, forest fires, and biogenic sources such as trees.

AERMOD does not account for secondary formation of $PM_{2.5}$ for near-field modeling. Any secondary contribution of the PHS Energy Center source emissions is not explicitly accounted for in the model results. While representative background monitoring data for $PM_{2.5}$ should adequately account for secondary contribution from existing background sources, the PHS

[1] Technical support document (TSD) for NO2-related AERMOD modifications, EPA- 454/B-15-004, July 2015

assessment of their potential contribution to cumulative impacts as secondary $PM_{2.5}$ was performed based on guidance from the NMED Modeling Section and using prescribed equations. The permit application for PHS Energy Center emissions of precursors include:

- NO_X – 68.4 tons per year (above SER)
- SO_2 – 4.5 tons per year (below SER)
- Volatile Organic Compounds (VOC) – 12.3 tons per year (below SER)
- Particulate Matter with an aerodynamic diameter of 2.5 micron or less ($PM_{2.5}$) – 3.2 tons per year (below SER).

The $PM_{2.5}$ secondary emission concentration analysis will follow EPA and NMED AQB guidelines. Following recent EPA guidelines for conversion of NO_X and SO_2 emission rates to secondary $PM_{2.5}$ emissions, PHS Energy Center emissions are compared to appropriate western MERPs values (NO_X 24-Hr – 1155 tpy; NO_X Annual – 3184 tpy; SO_2 24-Hr – 225 tpy; SO_2 Annual – 2289 tpy). The following equation, found in NMED AQB modeling guidance document on MERPs, will be added to determine if secondary emission would cause violation with $PM_{2.5}$ NAAQS.

$PM_{2.5}$ annual = ((NO_X emission rate (tpy)/3184 + (SO_2 emission rate (tpy)/2289)) x 0.2 µg/m^3

$PM_{2.5}$ annual = ((68.4/3184) + (4.5/2289)) x 0.2 µg/m^3 = **0.005 µg/m^3**

$PM_{2.5}$ 24 hour = ((NO_X emission rate (tpy)/1155 + (SO_2 emission rate (tpy)/225)) x 1.2 µg/m^3

$PM_{2.5}$ 24 hour = ((68.4/1155) + (4.5/225)) x 1.2 µg/m^3 = **0.10 µg/m^3**

2.9 AMBIENT MODELING BACKGROUND

Conservative ambient background concentrations, based on the South Valley Monitoring Station for CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$ will be added to the dispersion modeling results and compared to the NAAQS and NMAAQS. Background concentrations were obtained from the AEHD AQP Modeling Section.

CO 1-hr:	2366 micrograms per cubic meter
CO 8-hr:	1450 micrograms per cubic meter
NO_2 Annual:	30 micrograms per cubic meter
SO_2 1-hr:	13.1 micrograms per cubic meter
PM_{10} 24-hr:	42 micrograms per cubic meter
$PM_{2.5}$ 24-hr:	22 micrograms per cubic meter
$PM_{2.5}$ annual:	8.4 micrograms per cubic meter

NO_2 1-hour Background data

NO_2 1-hour background data was developed by the AEHD AQP based on the Tier 2 procedure found in EPA guidance documents[2] for determining background concentrations.

> *"Based on this guidance, we believe that an appropriate methodology for incorporating background concentrations in the cumulative impact assessment for the 1-hour NO_2 standard would be to use multiyear averages of the 98th-percentile of the available background concentrations by season and hour-of-day, excluding periods when the source in question is expected to impact the monitored concentration (which is only relevant for modified sources). For situations involving a significant mobile source component to the background monitored concentrations, inclusion of a day-of-week component to the temporal variability may also be appropriate. The rank associated with the 98th-percentile of daily maximum 1-hour values should be generally consistent with the number of "samples" within that distribution for each combination based on the temporal resolution but also account for the number of samples "ignored" in specifying the 98th-percentile based on the annual distribution. For example, Table 1 in Section 5 of Appendix S specifies the rank associated with the 98th-percentile value based on the annual number of days with valid data. Since the number of days per season will range from 90 to 92, Table 1 would indicate that the 2nd-highest value from the seasonal distribution should be used to represent the 98th-percentile. On the other hand, use of the 2nd-highest value for each season would effectively "ignore" only 4 values for the year rather than the 7 values "ignored" from the annual distribution. Balancing these considerations, we recommend that background values by season and hour-of-day used in this context should be based on the 3rd-highest value for each season and hour-of-day combination, whereas the 8th-highest value should be used if values vary by hour-of-day only. For more detailed temporal pairing, such as season by hour-of- day and day-of-week or month by hour-of-day, the 1st-highest values from the distribution for each temporal combination should be used."*

The NO_2 background data was provided by the AEHD AQP Modeling Section and is presented below in Table 4.

[2] Memo: "Additional Clarification Regarding Application of Appendix W Modeling Guidance for 1-hour N02 National Ambient Air Quality Standard" Tyler Fox, Leader, Air Quality Modeling Group, C439-01, dated March 1, 2011.

TABLE 4: Monitored Seasonal NO_2 Background – 3rd Highest Hourly µg/m³

Hour	Winter	Spring	Summer	Fall
1	72.1	47.6	29.3	65.6
2	67.8	48.3	27.7	59.7
3	67.7	46.0	26.4	57.9
4	68.4	48.9	26.6	58.9
5	69.1	51.7	32.7	58.0
6	69.7	63.9	39.3	57.8
7	72.8	70.7	46.4	63.5
8	77.6	71.8	48.5	64.5
9	80.0	61.1	34.2	65.9
10	71.4	48.0	27.3	55.0
11	62.0	28.6	24.3	47.3
12	48.1	18.9	19.9	35.4
13	36.9	17.6	17.0	28.2
14	35.1	15.7	15.9	25.3
15	33.6	14.8	17.4	24.2
16	37.2	15.3	19.4	28.0
17	48.4	17.1	20.4	38.0
18	73.0	19.4	19.3	69.6
19	79.3	38.5	21.7	79.1
20	78.1	53.2	30.9	77.1
21	77.3	48.0	34.1	73.4
22	76.5	56.3	30.8	70.4
23	75.0	58.8	34.9	69.7
24	72.4	57.9	33.6	70.9

3.0 MODEL SUMMARY

This section summarizes the model results, following the technical approach discussed in Section 2 of this report for Class II federal ambient air quality standards for this facility. Model results show for each criteria pollutant and applicable averaging periods for nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter with aerodynamic diameter less than 10 micrometers (PM_{10}) and particulate matter with aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$), the installation of a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package to be included as a permitted emission source to Permit #0273-M3-1TR does not contribute to an exceedance of the national/New Mexico ambient air quality standards (AAQS). The modeling followed the guidance and protocols outlined in the protocol found in Section 2 of this report, the modeling procedures outlined in "Permit Modeling Guidelines, Albuquerque Environmental Health Department", revised 10/10/2019, "New Mexico Air Pollution Control Bureau, Dispersion Modeling Guidelines", revised 10/26/2020, and the most up to date EPA's *Guideline on Air Quality Models*. As discussed in Section 2.1, because of the location of PHS Energy Center with relation to the main hospital and downtown Albuquerque, all modeling was performed using the "Urban" modeling option.

With this permit modification, PHS will install the CoGen plant to produce electricity and steam (heat) for the new hospital wing building under construction. Presently, the permit for the Energy Center included four (4) steam boilers and three (3) emergency generators. In addition to installation of the CoGen, PHS will be installing new and more efficient burners on steam boilers 1 and 2 (Permit Units 3 and 4). For steam boiler 4 (Permit Unit 6), the NO_X emission rate will be recalculated using the manufacturer's PPM guarantee of 30. The revised emission rates will be included in the permit modification application.

Three of the four boilers are allowed to combust both natural gas or #2 diesel, while the other can only combust natural gas. Per Permit #0273-M3-1TR Condition I.1.d.viii, Units #3, 4, and 6 are allowed to operate 48 hours per year combusting #2 diesel. Over the last 5 years the total hours combusting #2 diesel is 17.5 hours for Unit 4 and 5 hours for Unit 6 (see Attachment A). Because of the limited time the facility combusts #2 diesel, all modeled emission rates from the boiler will be based on combusting natural gas.

For the expected boilers modeled exhaust parameters, the boiler manufacturers were contacted and the manufacturer provided the following information; stack exhaust temperature at maximum and exhaust flowrate at maximum (see Attachment B). Stack height and stack diameter were determined by site inspection.

The three (3) emergency generators included in Permit #0273-M3-1TR will not be included in the dispersion modeling analysis, because these sources are intermittent. Emergency generators, with exception of loss of generating power, are tested monthly. Testing takes less than an hour per engine, so total testing hours is approximately 12 hours per year per emergency generator.

Presently, the boilers are allowed to operate 8760 hours each. For this permit modification, PHS will restrict the use of the boilers to only three boilers operating under maximum conditions at any one time for 8760 hours per year. This requested permit change will add additional permit conditions to the present operation of the boilers, recordkeeping and reporting.

With four existing boilers, there are four combinations of three boilers operating at any one time. The dispersion model analysis will be run for these 4 "Model Group" sources. To present these scenarios, each boiler combination will be modeled with maximum operation of the CoGen, applicable neighboring sources, and representative background.

Neighboring source included in the modeling is the University of New Mexico's Ford Energy Center (1643-M1), Lovelace Medical Center (1509-M2-1AR), Clean Energy (0649-RV1), Ameripride (1518-M1), and US Transport (1523-M1-3AR). The information on these sources was provided by the city air quality dispersion modeling section.

3.1 SIGNIFICANT IMPACT LEVEL (SILs) MODELING ANALYSIS

Significant impact level AERMOD dispersion modeling was completed for PM_{10}, $PM_{2.5}$, NO_X, CO, and SO_2. All significant impact models were run in terrain mode and building downwash with PHS modeled Energy Center emission sources only. Table 5 lists the results of the modeling for pollutant and averaging period that falls below the applicable SILs.

TABLE 5: Summary of Air Dispersion Modeling Results below SILs

Parameter	Maximum Modeled Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	% of SIL
CO 1 Hr.	306	2000	15.3
CO 8 Hr.	219	500	43.8

For CO, the results show impacts below the NAAQS SILs for the 1-hour averaging period of 2000 $\mu g/m^3$ and for the 8-hour averaging period of 500 $\mu g/m^3$, so no further CO modeling was performed.

3.2 CUMULATIVE IMPACT ANALYSIS (CIA) MODEL RESULTS

The following CIA dispersion models were used to show compliance with all applicable state and national AAQS. The list in Table 6 discussed which standards are the most stringent.

TABLE 6: Standards for Which Modeling Is Not Required

Standard not Modeled	Surrogate that Demonstrates Compliance
NO_2 annual NAAQS	NO_2 annual NMAAQS
NO_2 24-hour NMAAQS	NO_2 1-hour NAAQS
SO2 annual NMAAQS	SO2 1-hour NAAQS
SO2 24-hour NMAAQS	SO2 1-hour NAAQS
SO2 3-hour NAAQS	SO2 1-hour NAAQS

The model results using the maximum operation for the maximum of each of the 4 "Model Group" operating scenarios at PHS Energy Center, significant neighboring sources, approved ambient background (see Section 2.9), and $PM_{2.5}$ secondary emissions (see Section 2.8) are summarized below in Table 7. Dispersion modeling analysis followed the modeling protocol outline in Section 2 of this report.

TABLE 7: Summary of CIA Modeling Results Including all Applicable Neighboring Sources, Approved Ambient Background, and for $PM_{2.5}$ Secondary Emissions

Parameter	Maximum PHS Modeled Concentration with Neighbors ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Maximum Modeled Concentration With Neighbor and Background ($\mu g/m^3$)	Lowest Applicable Standard ($\mu g/m^3$)	% of Standard
NO_2 1 Hr. 8th highest 1-hour daily maximum	130.5	7.54	187.4	188.1	99.7
NO_2 Annual	26.8	1.0	45.8	94.0	48.7
SO_2 1 Hr. 4th highest 1-hour daily maximum	8.4	7.8	21.5	196.4	10.9
$PM_{2.5}$ 24 Hr. High 8th High	6.0	1.2	28.0	35	80.0
$PM_{2.5}$ Annual	2.13	0.2	10.53	12	87.8
PM_{10} 24 Hr. High 6th High	13.6	5	55.6	150	37.1

Note: Background concentrations are found in Section 2.9 of the modeling protocol. $PM_{2.5}$ secondary emission concentrations are found in Section 2.8 of the modeling protocol. Dispersion modeling inputs and settings are presented in Section 2.

3.2.1 NO_2 Cumulative Impact Analysis Modeling Results

NO_2 modeling was performed with terrain elevations and building downwash for PHS Energy Center and neighboring sources. NO_X emission rates represented the maximum hourly rate for PHS Energy Center modeled point sources and significant neighboring sources.

Dispersion modeling meteorology for this analysis included 5 years of data, 2014–2018 Albuquerque Meteorological data, was obtained from the AEHD AQP.

For NO_2 1-hour modeling, the Tier 3 OLM approach found in Section 2.6 of this report was used for the analysis. For OLM, background ambient O_3 concentrations for the project area during the 2014-2018 meteorological data years was obtained from the Albuquerque Del Norte monitoring station.

The seasonal NO_2 background – 3rd highest hourly, 1-hour NO_2 background concentrations found in Section 2.9 of this report was added to the modeled results and compared to the lowest applicable ambient standard.

CIA dispersion modeling showed exceedance of the NO_2 8th highest 1-hour daily maximum NAAQS. The exceedance was the result of modeled emissions near neighboring sources. For each of the receptors that showed an exceedance of the NAAQS, it was determine that the

contribution from PHS Energy Center sources were below the NO_2 1-Hour SIL. For the 4 "Model Group" scenarios, where the contribution from PHS Energy Center sources were above the SIL, the 8th highest 1-hour daily maximum is near or on the Energy Center modeled fenceline with Boiler Units 3, 4, and 5 in operation.

For NO_2 annual modeling, the highest concentrations result where PHS Energy Center was a significant contributor occurred near the Lovelace Hospital on Martin Luther King with Boiler Units 3, 4, and 5 in operation.

Table 8 shows the NO_2 1-Hour 8th highest 1-hour daily maximum and annual model results and locations where PHS Energy Center is above the SILs.

TABLE 8: NO_2 CIA MODEL RESULTS

	PHS Modeled Concentration With Neighbor ($\mu g/m^3$)	**Modeled Concentration With Neighbor and Background ($\mu g/m^3$)**	**Location UTMs E/N**	
NO_2 1 Hr. 8th highest 1-hour daily maximum	130.5	187.4	350887.7	3883150.5
NO_2 Annual	26.8	45.8	350700.0	3883700.0

Figures 4 and 5 shows an aerial map of the NO_2 8th highest 1-hour daily maximum and annual average concentrations and the location of the maximum modeled concentrations which includes background where PHS Energy Center sources contribute above the NO_2 SIL.

Figure 4: Aerial Map of NO_2 8th Highest 1-Hour Daily Maximum Model Results ($\mu g/m^3$)

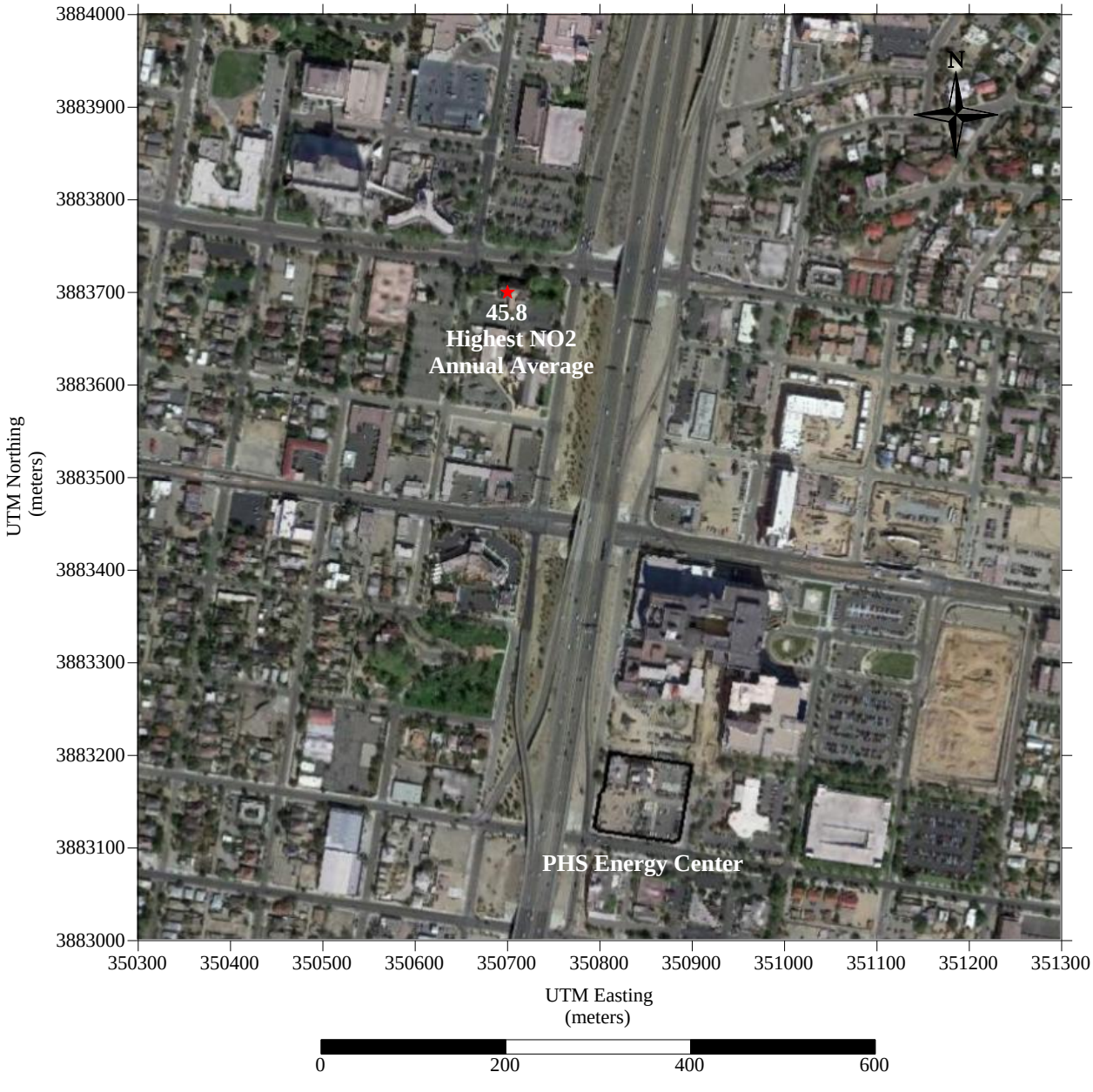


Figure 5: Aerial Map of NO_2 Annual Average Model Results ($\mu g/m^3$)

3.2.2 SO_2 Cumulative Impact Analysis Modeling Results

SO_2 1-hour modeling was performed with terrain elevations and building downwash for PHS Energy Center and neighboring sources. SO_2 emission rates represented the maximum hourly rate for PHS Energy Center proposed permitted point sources and significant neighboring sources.

Table 9 shows the SO_2 4th highest 1-hour daily maximum model result and location.

TABLE 9: SO_2 CIA MODEL RESULTS

	PHS Modeled Concentration ($\mu g/m^3$)	Modeled Concentration With Neighbor and Background ($\mu g/m^3$)	Location UTMs E/N	
SO_2 1 Hr. 4th highest 1-hour daily maximum	8.4	21.5	350824.7	3883189.0

For SO_2 1-hour modeling, dispersion modeling meteorology for this analysis included 5 years of data, 2014 – 2018 Albuquerque Meteorological data, obtained from the AEHD AQP.

SO_2 1-hour background concentration, found in Section 2.9 of this report, was added to the 4th highest 1 hour daily maximum modeled results and compared to the lowest applicable ambient standard.

CIA dispersion modeling showed the highest concentrations of the SO_2 4th highest 1-hour daily maximum NAAQS on PHS Energy Center boundary with Boiler Units 3, 4, and 5 in operation.

Figure 6 shows an aerial map of the 4th highest 1-hour SO_2 daily maximum concentration and the location of the maximum modeled concentration including background where PHS Energy Center sources contribute above the 1-hour SO_2 SIL.

Figure 6: Aerial Map of SO_2 1 Hour Model Results ($\mu g/m^3$)

3.2.3 $PM_{2.5}$ Direct and Secondary Formation CIA Modeling Results

Particulate matter includes both "primary" PM, which is directly emitted into the air, and "secondary" PM, which forms in the atmosphere from chemical reactions involving primary gaseous emissions of precursor air contaminants. Primary PM consists of carbon (soot)—emitted from cars, trucks, heavy equipment, forest fires, and burning waste—and crustal material from unpaved roads, stone crushing, construction sites, and metallurgical operations. Secondary PM forms in the atmosphere from gases. Some of these reactions require sunlight and/or water vapor. Secondary PM includes:

- Sulfates formed from SO_2 emissions from power plants and industrial facilities;
- Nitrates formed from NO_X emissions from cars, trucks, industrial facilities, and power plants; and
- Carbon formed from reactive organic gas (ROG or VOC) emissions from cars, trucks, industrial facilities, forest fires, and biogenic sources such as trees.

AERMOD does not account for secondary formation of $PM_{2.5}$ for near-field modeling. Any secondary contribution of the PHS Energy Center source emissions is not explicitly accounted for in the model results. While representative background monitoring data for $PM_{2.5}$ should adequately account for secondary contribution from existing background sources, the PHS assessment of their potential contribution to cumulative impacts as secondary $PM_{2.5}$ was performed based on guidance from the NMED Modeling Section and using prescribed equations. The permit application for PHS Energy Center emissions of precursors include:

- NO_X – 68.4 tons per year (above SER)
- SO_2 – 4.5 tons per year (below SER)
- Volatile Organic Compounds (VOC) – 12.3 tons per year (below SER)
- Particulate Matter with an aerodynamic diameter of 2.5 micron or less ($PM_{2.5}$) – 3.2 tons per year (below SER).

The $PM_{2.5}$ secondary emission concentration analysis will follow EPA and NMED AQB guidelines. Following recent EPA guidelines for conversion of NO_X and SO_2 emission rates to secondary $PM_{2.5}$ emissions, PHS Energy Center emissions are compared to appropriate western MERPs values (NO_X 24-Hr – 1155 tpy; NO_X Annual – 3184 tpy; SO_2 24-Hr – 225 tpy; SO_2 Annual – 2289 tpy). The following equation, found in NMED AQB modeling guidance document on MERPs, will be added to determine if secondary emission would cause violation with $PM_{2.5}$ NAAQS.

$PM_{2.5}$ annual = ((NO_X emission rate (tpy)/3184 + (SO_2 emission rate (tpy)/2289)) x 0.2 µg/m^3

$PM_{2.5}$ annual = ((68.4/3184) + (4.5/2289)) x 0.2 µg/m^3 = **0.005 µg/m^3**

$PM_{2.5}$ 24 hour = ((NO_X emission rate (tpy)/1155 + (SO_2 emission rate (tpy)/225)) x 1.2 µg/m^3

$PM_{2.5}$ 24 hour = ((68.4/1155) + (4.5/225)) x 1.2 µg/m^3 = **0.10 µg/m^3**

Results of the secondary formation from the facility were added to the modeled value.

South Valley monitor representative annual and 24-hour $PM_{2.5}$ background concentrations was added to the modeled results and compared to the lowest applicable ambient standard.

The annual average results show that significant direct "primary" $PM_{2.5}$ from PHS Energy Center sources combined with neighboring sources are located on the PHS Energy Center northern facility boundary with Boiler Units 4, 5, and 6 in operation.

The 24-hour average highest 8th high concentrations showed that significant direct "primary" $PM_{2.5}$ from PHS Energy Center sources combined with neighboring sources are located on the PHS Energy Center west facility boundary with Boiler Units 4, 5, and 6 in operation.

The result from direct "primary" $PM_{2.5}$ emissions dispersion modeling, secondary PM emissions, applicable neighboring sources, plus a representative $PM_{2.5}$ background concentrations from Section 2.9 of this report, which includes monitored secondary $PM_{2.5}$ concentrations, were used to show compliance with national $PM_{2.5}$ annual and 24-hour average AAQS. $PM_{2.5}$ model results are summarized in Table 10.

TABLE 10: $PM_{2.5}$ CIA Model Results

	Modeled Concentration with Neighboring Sources and Secondary PM ($\mu g/m^3$)	**Modeled Concentration With Background ($\mu g/m^3$)**	**Location UTMs E/N**	
24 Hour Average Highest 8th High	6.0	28.0	350803.8	3883183.9
Annual Average	2.13	10.53	350815.0	3883191.0

Figures 7 and 8 summarize the results of the modeling analysis.

Figure 7: Aerial Map of $PM_{2.5}$ 8th Highest Daily Maximum High 24 Hour Model Result ($\mu g/m^3$)

Figure 8: Aerial Map of $PM_{2.5}$ Annual Model Result ($\mu g/m^3$)

3.2.4 PM_{10} Cumulative Impact Analysis Modeling Results

CIA PM_{10} 24-hour average modeling was performed with terrain elevations and building downwash for PHS Energy Center, neighboring sources and meteorology which included 5 years of data, 2014 – 2018 Albuquerque Meteorological data, obtained from the AEHD AQP. PM_{10} emissions rates represented the maximum hourly rate for all emission sources, including applicable neighboring sources. South Valley monitor representative 24-hour PM_{10} background concentrations was added to the modeled results and compared to the lowest applicable ambient standard. The 24-hour background concentrations that were used for PM_{10} 24-hour averaging period is found in Section 2.9 of this report.

Based on the New Mexico Modeling Guideline "…[W]hen n years are modeled, the $(n+1)^{th}$ highest concentration over the n-year period is the design value, since this represents an average or expected exceedance rate of one per year." For 5 years of modeled met data, the design value is the highest 6^{th} high.

The 24-hour average highest 6^{th} high concentrations showed, where significant PM_{10} (above SIL) from PHS Energy Center sources, are located on the PHS Energy Center west facility boundary with Boiler Units 4, 5, and 6 in operation.

Table 11 summarizes the 24-hour average highest 6^{th} high and receptor location.

TABLE 11: PM_{10} CIA Model Results

	Modeled Concentration with Neighboring Sources ($\mu g/m^3$)	**Modeled Concentration With Background ($\mu g/m^3$)**	**Location UTMs E/N**	
24 Hour Average Highest 6^{th} High	8.6	50.6	350803.8	3883183.9

Figure 9 summarize the results of the modeling analysis.

Figure 9: Aerial Map of PM_{10} Highest 6th High 24-Hour Model Result ($\mu g/m^3$)

Modeling File List

Model File Name	Description
PHS ROI	PHS Energy Center Sources Only ROI modeling

Model File Name	Description
PHS CIA NO2 1hrOLMUrban	Cumulative NO_2 Modeling – 1-Hour
PHS CIA NO2 AnnualARMUrban	Cumulative NO_2 Modeling – Annual Average
PHS CIA SO2 1hrUrban	Cumulative SO_2 Modeling – 1-Hour
PHS CIA PM10 24hrUrban	Cumulative PM_{10} Modeling – 24-Hour
PHS CIA PM25 24hrUrban	Cumulative $PM_{2.5}$ Modeling – 24-Hour
PHS CIA PM25 AnnualUrban	Cumulative $PM_{2.5}$ Modeling – Annual Average

Attachment A

Boiler Hours on Oil

The table below is a summary of the boiler hours on oil for the years 2016 through April, 2021.

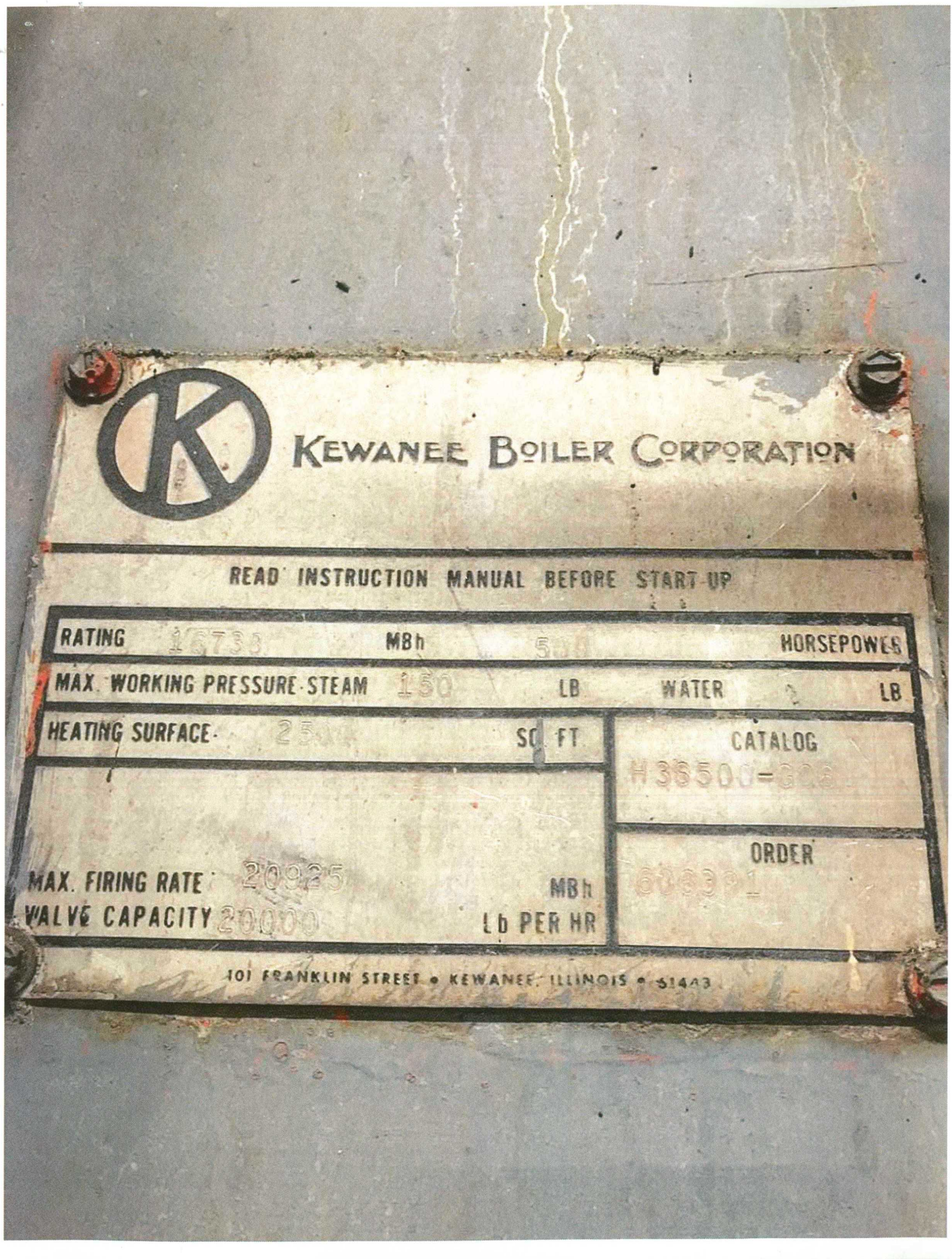
	2016	2017	2018	2019	2020	2021	Total
Unit 3	0	0	0	0	0	0	0
Unit 4	0	0	0	0	0	17.5	17.5
Unit 5	0	0	0	0	0	0	0
Unit 6	0	0	0	0	0	5	5

Attachment B

Boiler Stack Parameters

ENERGY CENTER BOILERS

DATA	Boiler # 1	Boiler # 2	Boiler # 3	Boiler # 4
MANUFACTURER	KEWANEE	KEWANEE	SUPERIOR	BURNHAM
ASSET NUMBER	PM # 5517	PM # 5518	PM # 5519	PM # 5727
TYPE OF BOILER	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE
NATIONAL BOARD NUMBER	33550	33529	13398	27718
MAXIUM PSI	150 PSI	150 PSI	150 PSI	150 PSI
TOTAL HEATING SURFACE	2500 sq. ft.	2500 sq. ft.	1022 sq. ft.	2500 sq. ft.
REQUIRED RELIEF CAP.	20,000	20,000	8,176	19,527
NUMBER OF RELIEF VALVES	2	2	2	2
RELIEF VALVE LIFT, PSI	125 psi	125 psi	125 psi	150 psi
CAP. BTU/HR	2 @10,660	2 @10,660	1 @3,500 1@5,592	2 @10,660
NUMBER OF LOW WATER CUTOUTS	2	2	2	2
LOW WATER CUTOUT TYPE	2 float	2 float	2 float	1-float 1-probe
SECONDARY MANUAL RESET	YES	YES	YES	YES
SOFT WATER	YES	YES	YES	YES
D.A. TANK	YES	YES	YES	YES
HIGH PSI / LIMIT W / MAN. RESET	YES	YES	YES	YES
GAS VENTS OUTSIDE	YES	YES	YES	YES
CHEMICAL TREATMENT	YES	YES	YES	YES
TREATMENT POLYMER FOR SCALE	YES	YES	YES	YES
SULFITE FOR OXYGEN PITTING	YES	YES	YES	YES
MAINTENANCE CONTRACT	NO	NO	NO	NO
BREAKDOWNS	NO	NO	NO	NO
NEXT INTERNAL INSPECTION, (ANNUAL P.M.)				
DATA	Boiler # 1	Boiler # 2	Boiler # 3	Boiler # 4
MANUFACTURER	KEWANEE	KEWANEE	SUPERIOR	BURNHAM
ASSET NUMBER	PM # 5517	PM # 5518	PM # 5519	PM # 5727
TYPE OF BOILER	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE	FIRE TUBE, HIGH PRESSURE


KEWANEE BOILER CORPORATION
READ INSTRUCTION MANUAL BEFORE START UP
RATING 16733 MBh 500 HORSEPOWER
MAX. WORKING PRESSURE STEAM 150 LB WATER LB
HEATING SURFACE 25 SQ. FT.
CATALOG
H36500-G
ORDER
MAX. FIRING RATE 20925 MBh
VALVE CAPACITY 20000 Lb PER HR
101 FRANKLIN STREET • KEWANEE, ILLINOIS • 61443

Randal Toledo

From: Jason Paxson <jason@csinm.com>
Sent: Tuesday, June 08, 2021 2:43 PM
To: Randal Toledo
Subject: Re: Emailing: Burner 1 (2)

Hi Randal,

Here's what I got from Powerflame...Still waiting on Webster.

Thanks,

Jason Paxson

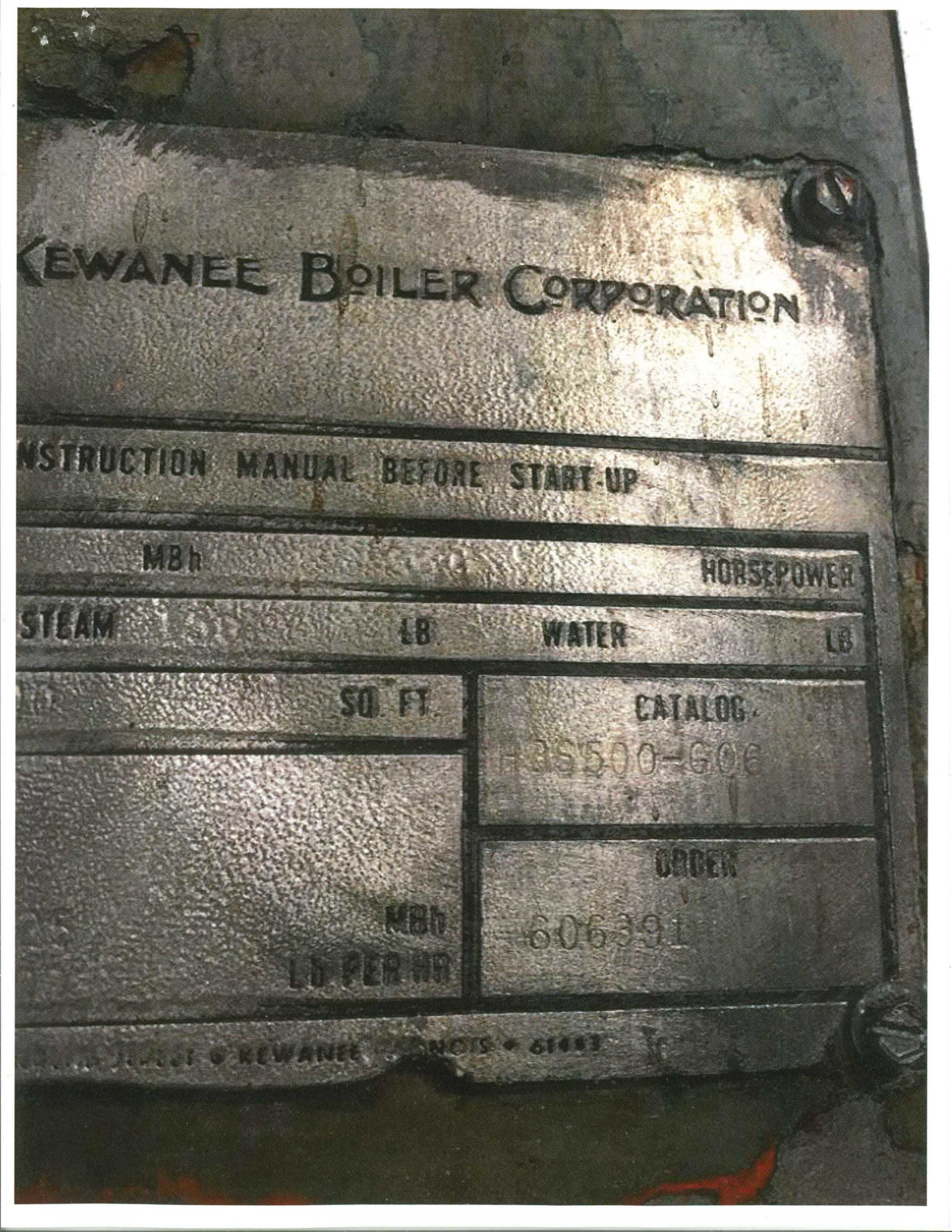
Combustion Systems

Below is the requested information.

At the high fire of 20,925 Mbh and 400 deg F stack temp the stack flow will be approximately 7,073 ACFM.

On 6/8/2021 12:47 PM, Randal Toledo wrote:

> This Burner is for the two KEWANEE Boilers
>
> Randal Toledo
> Special Projects Manager / DSR
>
> 4538 McLeod Rd. Albuquerque New Mexico 87109
> Main: (505) 881-0220 | Office: (505) 962-2823 | Mobile: (505) 991-2918
>
>


KEWANEE BOILER CORPORATION
NSTRUCTION MANUAL BEFORE START-UP
MBh
HORSEPOWER
STEAM
LB
WATER
LB
SQ. FT.
CATALOG
H36500-G06
MBh
LB PER HR
ORDER
606391
KEWANEE

Randal Toledo

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>
>

SEMINOLE

BOILER-BURNER UNIT

MODEL NO. 6-X-1000

NAT'L BOARD NO. 13398

SERIAL NO. 13398

HEATING SURFACE 1022 SQ. FT. YEAR BUILT 1997

SHELL THICKNESS 1/2 IN. HEAD THICKNESS 3/4 IN.

MAX. STEAM W.P. 150 P.S.I. MAX. WATER W.P. P.S.I.

STEAM CAPACITY LBS./HR.

MIN. VALVE CAPACITY 8176 LBS./HR. (BTU./HR)

INSTALLATION: The boiler assemblies are intended for installation in accordance with the appropriate standards of the NATIONAL FIRE PROTECTION ASSOCIATION.

For boilers operating at not more than 50 psi - 18 in. at top, sides, and rear, 48 in. from front and 18 in. from flue pipe.

For boilers operating at more than 50 psi - 48 in. at top, 36 in. at sides, and rear, 96 in. from front, and 36 in. from flue pipe.

For installation on noncombustible flooring.

SUPERIOR BOILER WORKS, INC.
3524 E. FOURTH HUTCHINSON, KS. A/C 316 662-6693

Randal Toledo

From: Jason Paxson <jason@csinm.com>
Sent: Tuesday, June 08, 2021 12:22 PM
To: Randal Toledo
Subject: Re: Emailing: Burner 3

Hi Randal,

Here's what I got back from the Powerflame rep.

Below is what I received from one of our senior engineers.

The exhaust gas flow rate will be approximately 2,835 ACFM. This is based on the high fire rate of 8400 Mbh and a 400 degree F stack temp.

On 6/7/2021 1:19 PM, Randal Toledo wrote:
> Jason , the last one was the Boiler name plate this is the BURNER name plate.
>
>
>
> Randal Toledo
> Special Projects Manager / DSR
>
>
> 4538 McLeod Rd. Albuquerque New Mexico 87109
> Main: (505) 881-0220 | Office: (505) 962-2823 | Mobile: (505) 991-2918
>
>
>

FAILURE TO DO SO COULD RESULT IN SERIOUS INJURY OR DEATH.

If you do not have a copy of the manual, Contact: Burnham Corporation, P.O. Box 3079, Lancaster, PA 17604
Tel. (717) 397-4701

81460261

BURNHAM™ INDUSTRIAL

THREE PASS BOILER

MODEL NO. LN5P-5[illegible]-50-G0-W-13 NATL BD NO. 27718

GROSS OUTPUT 500.0 BHP 16738.6 MBH 17250.0 LBS/HR

GAS INPUT 20923.[illegible] MBH NO. 2 OIL INPUT 150.2 GPH

MAX. WORKING PRESSURE 150 PSI STEAM PSI WATER

MIN. SAFETY VALVE CAP. 13527 LBS/HR STEAM MBH WATER

ASME SYMBOL STAMPED ON SHELL S ORDER NO. 082532

LANCASTER, PA 17604 USA

81460109

Office: (505) 962-2823 | Mobile: (505) 991-2918
Begin forwarded message:

From: Randal Toledo <RToledo@millerbonded.com>
Date: June 10, 2021 at 2:51:37 PM MDT
To: Nils Madden <nmadden@webstercombustion.com>
Subject: Re: 500 HP Burner - Flue Gas Flow Rate

Got it Thx!

Sent from my iPhone

On Jun 10, 2021, at 2:49 PM, Nils Madden <nmadden@webstercombustion.com> wrote:

Hello,

Numbers you asked for:

- 21,000 MBH burner (500 HP boiler)
- Natural Gas
- 3% O2 stack (15% Excess Air)
- 400 Fahrenheit stack temperature
- 5,000 FASL

Results:

- Total flue gas flow – 18,280 lb/hr
- Flue gas density at conditions – 0.03686 lb/ft^3
- Total flue gas flow – 8,265 ACFM

Regards,
Nils Madden
Director of Engineering
Webster Combustion Technology, LLC

Attachment C

ISR Ratio
CAPCOA Guidance Document
October 27, 2011
Appendix C

Appendix C - In-Stack NO_2/NOx Ratios

Recommend In-stack NO2/NOx Ratios				
Refer #	**Fuel**	**Equipment Category (Controls)**	**Range of Ratios (%)**	**Recommended Ratio (%)**
Boilers				
1	**NG**	Default	10	10
2		6.6 MMBtu/Hr (Force Draft)*[L]	0.0 – 2.90	1.58**
2		7.6 MMBtu/Hr (SCR / FGR)*	3.45 – 15.79	9.65**
2		11.4 MMBtu/Hr (Force Draft)*[L]	1.81 – 3.51	2.68**
Compressor IC Engines				
1	**NG**	Default	60	60
2a		225 BHP IGN Timing BTC 17***	11.61 – 11.86	11.76**
2a		350 BHP IGN Timing BTC 18***	4.37 – 4.83	4.66**
2a		550 BHP IGN Timing BTC 20***	0.93 – 2.98	1.96**
2a		625 BHP IGN Timing BTC 10***	10.97 – 11.96	11.6**
2a		773 BHP IGN Timing BTC 9***	58.04 – 58.54	58.3**
2a		773 BHP IGN Timing BTC 20***	72.65 – 73.42	73.12**
2a		880 BHP IGN Timing BTC 8***	9.79 – 14.14	11.93**
2a		880 BHP IGN Timing BTC 15***	0.7 – 8.28	2.52**
2a		1500 BHP IGN Timing BTC 12***	10.32 – 12.03	11.47**
2a		1500 BHP IGN Timing BTC 6.5***	18.42 – 21.33	19.97**
2a		4000 BHP IGN Timing BTC 5***	22.36 – 25.69	23.82**
2a	**Waste Gas (Field Gas)**	880 BHP IGN Timing BTC 20***	1.77 – 6.10	3.86**
2a		1000 BHP***	0.40 – 0.81	0.64**
Dryer				
	NG	20 MMBTU/Hr (Milk -Tower Dryer)*	3.85 – 11.11	6.88**
Glass Furnace				
2	**NG**	**Glass Furnace**	2.45 – 11.59	4.32**
Heaters				
2	**NG / Refinery Gas**	14.1 MMBTU/Hr (John Zink PSMR)*	11.54 – 52.63	32.0**

Recommend In-stack NO2/NOx Ratios						
Refer #	**Fuel**	**Equipment Category (Controls)**	**Range of Ratios (%)**			**Recommended Ratio (%)**
IC Engines						
2	**Biogas**	200 BHP*	0.0 – 1.90			0.37**
1	**Diesel**	Default	20			20
		322 BHP (WP)*	0.0 – 50.0			15.64**
4	**NG**	Default – Lean Burn	5-10			10
2		120 BHP (3-Way Catalyst)*	0.1 – 2.83			0.9**
2		162 BHP (catalytic converter, air/fuel ratio)*	0.0 – 12.5			1.81**
2		165 BHP (3-Way Catalyst)*	0.0 – 17.58			3.16**
2		180 BHP (NSCR)*	1.02 – 3.41			1.82**
2		208 BHP (catalytic converter, air/fuel ratio)*	0.0 – 1.44			0.48**
2		1,070 BHP (LB/WP–Turbocharger/Intercooler)*	20.91 – 39.62			34.41**
2		1,529 BHP (LB - CO Catalyst, SCR)*	2.70 – 4.58			3.59**
2		2,775 BHP (SCR)*	14.53 – 26.33			19.46**
2		4,175 BHP (SCR,CO & VOC Catalysts)*	0.0 – 21.28			1.15**
Transportation Refrigeration Units (TRUs)						
5		CARB= CARB Diesel GTL = Gas To Liquid	Fuel	Eng Speed	Exhaust	NO_2/ NO_x Ratio
			CARB	High	Muffler	15.37
			GTL	High	Muffler	16.17
			CARB	High	pDPF	25.71
			CARB	Low	Muffler	22.66
			GTL	Low	Muffler	25.12
			CARB	Low	pDPF	12.98
Truck / Cars						
6	**Gas/Diesel**	Light / Medium Duty	16-25			25
	Diesel	Heavy Duty	6-11			11
Turbines						
3	**NG**	GE Turbines	8.33 – 9.1			9.1

Recommend In-stack NO2/NOx Ratios				
Refer #	**Fuel**	**Equipment Category (Controls)**	**Range of Ratios (%)**	**Recommended Ratio (%)**
2a		Solar Centaur T-4702 (3.4 MW)***	8.43 – 12.42	10.32**

* Samples taken each minute or several minutes

**Value represents the statistical average of all data points

*** 30 min / 1 hour Source Test

L = Load ratings have been included in average

LB = Lean Burn

WP = Water Pump

References

1. Barrie Lawrence, Environmental Scientist, Government of Newfoundland and Labrador, "Guideline for Plume Dispersion Modeling" 1st Revision: November 20, 2006, Page 14

2. District Database "NO2 -NOx Ratio.mdb" - Data is based on CEMs, source test, and portable analyzer data collected in the San Joaquin Valley

a. District Database "NO2 -NOx Ratio.mdb" - Data is based on source test data collected from out of state (Arkansas Department of Environmental Quality Office of Air Quality)

3. Roointon Pavri and Gerald D. Moore, GE Energy Services Atlanta, GA, "Gas Turbine Emissions and Control" March 2001 Page 63

4. Nigel N. Clark, Center for Alternative Fuels, Engines and Emissions Department of Mechanical and Aerospace Engineering West Virginia University Morgantown, WV 26506, "Selective NOx Recirculation for Stationary Lean-Burn Natural Gas Engines" April 30, 2007 Page 64

5. Robb A. Barnitt, National Renewable Energy Laboratory, "Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices", May 1, 2010

6. P G Boulter, I S McCrae, and J Green, Transportation research Laboratory, "Primary NIO2 Emissions From Road Vehicles in the Hatfield and Bell Commons Tunnels", July 2007

Attachment H
Public Notice Documents

Timothy M. Keller, Mayor

Public Participation

List of Neighborhood Associations and Neighborhood Coalitions MEMORANDUM

To: Paul Wade, Principal, Montrose Air Quality Services, LLC
From: Elizabeth Pomo, Environmental Health Scientist
Subject: Determination of Neighborhood Associations and Coalitions within 0.5 mile of 1002 Silver Ave SE in Bernalillo County, NM
Date: October 28, 2021

DETERMINATION:

On October 28, 2021 I used the City of Albuquerque Zoning Advanced Map Viewer (http://coagisweb.cabq.gov/) to verify which City of Albuquerque Neighborhood Associations (NA), Homeowner Associations (HOA) and Neighborhood Coalitions (NC) are located within 0.5 mile of 1002 Silver Ave SE in Bernalillo County, NM.

I then used the City of Albuquerque Office (COA) of Neighborhood Coordination's Monthly Master NA List dated October 2021 and the Bernalillo County (BC) Monthly Neighborhood Association October 2021 Excel file to determine the contact information for each NA and NC located within 0.5 mile of 1002 Silver Ave SE in Bernalillo County, NM.

The table below contains the contact information, which will be used in the City of Albuquerque Environmental Health Department's public notice. Duplicates have been deleted.

COA/BC Association or Coalition	Name	Email or Mailing Address*
Citizens Information Committee of Martineztown	Frank Martinez Kristi Houde Association Email	501 Edith Blvd NE, Albuquerque, NM 87102; kris042898@live.com; cicm-na@comcast.net;
EDo Neighborhood Association	Terry Keene David Tanner	keenecafe@aol.com; david@edoabq.com;
Huning Highland Historic District Association	Ann Carson Bonnie Anderson	a.louisa.carson@gmail.com; andersonbonnie505@gmail.com;
Silver Hill Neighborhood Association	Don McIver James Montalbano Association Email	dbodinem@gmail.com; ja.montalbano@gmail.com silverhillabq@gmail.com;
South Broadway Neighborhood Association	Tiffany Broadus Frances Armijo Association Email	tiffany.hb10@gmail.com; fparmijo@gmail.com; abqsbna@gmail.com;
Spruce Park Neighborhood Association	Bart Cimenti John Cochran	bartj505@gmail.com; jrcochr@gmail.com;
Sycamore Neighborhood Association	Richard Vigilano Mardon Gardella	richard@vigliano.net; mg411@q.com;

If email address is not listed, provide public notice via certified mail and include a copy of each mail receipt with the application submittal.

NOTICE FROM THE APPLICANT

Notice of Intent to Apply for Air Quality Construction Permit

You are receiving this notice because the New Mexico Air Quality Control Act (20.11.41.13B NMAC) requires any owner/operator proposing to construct or modify a facility subject to air quality regulations to provide public notice by certified mail or electronic mail to designated representatives of recognized neighborhood associations and coalitions within 0.5-mile of the property on which the source is or is proposed to be located.

This notice indicates that the owner/operator intends to apply for an Air Quality Construction Permit from the Albuquerque – Bernalillo County Joint Air Quality Program. Currently, no application for this proposed project has been submitted to the Air Quality Program. Applicants are required to include a copy of this form and documentation of mailed notices with their Air Quality Construction Permit Application.

Proposed Project Information

Applicant's name and address:
Nombre y domicilio del solicitante: Presbyterian Healthcare Services, 1100 Central Ave. SE, Albuquerque, NM 87106

Owner / operator's name and address:
Nombre y domicilio del propietario u operador: Presbyterian Healthcare Services, 1100 Central Ave. SE, Albuquerque, NM 87106

Contact for comments and inquires:
Datos actuales para comentarios y preguntas:

Name *(Nombre)*: Keith Long
Address *(Domicilio)*: 1100 Central Ave. SE, Albuquerque, NM 87106
Phone Number *(Número Telefónico)*: 505-563-6221
E-mail Address *(Correo Electrónico)*: hlong4@phs.org

Actual or estimated date the application will be submitted to the department:
Fecha actual o estimada en que se entregará la solicitud al departamento: Estimated - November 30, 2021

Description of the source:
Descripción de la fuente: Energy center for Presbyterian Hospital and Medical Center, provides heat and electricity

Exact location of the source or proposed source:
Ubicación exacta de la fuente o fuente propuesta: 1002 Silver Ave. SE, Albuquerque, NM 87106

Nature of business:
Tipo de negocio: Presbyterian Healthcare Services is a Medical Hospital and Healthcare Provider

Process or change for which the permit is requested:
Proceso o cambio para el cuál de solicita el permiso: Addition of a Caterpillar model G3516H natural gas cogeneration plant. Install new burners for boilers 1 and 2.

Maximum operating schedule:
Horario máximo de operaciones: Caterpillar model G3516H natural gas cogeneration plant and boilers will operate 8760 hours per year. Only 3 boilers operate at any one time.

Normal operating schedule:
Horario normal de operaciones: Caterpillar model G3516H natural gas cogeneration plant and boilers will operate 8760 hours per year. Only 3 boilers operate at any one time.

Preliminary estimate of the maximum quantities of each regulated air contaminant the source will emit:
Estimación preliminar de las cantidades máximas de cada contaminante de aire regulado que la fuente va a emitir:

Air Contaminant *Contaminante de aire*	**Proposed Construction Permit** *Permiso de Construcción Propuesto*		**Net Changes (for permit modification or technical revision)** *Cambio Neto de Emisiones (para modificación de permiso o revisión técnica)*	
	pounds per hour *libras por hora*	tons per year *toneladas por año*	pounds per hour *libras por hora*	tons per year *toneladas por año*
CO	39.7	66.2	9.27	39.9
NOx	Includes NOx+NMHC - 108.5	Includes NOx+NMHC - 68.4	5.27	1.83
VOC	6.20	12.3	3.04	9.27
SO2	17.6	4.50	-0.07	-2.79
PM10	4.03	3.21	0.08	-1.61
PM2.5	4.03	3.21	0.08	-1.61
HAP	1.94	7.02	1.46	6.40

Questions or comments regarding this Notice of Intent should be directed to the Applicant. Contact information is provided with the Proposed Project Information on the first page of this notice. To check the status of an Air Quality Construction Permit application, call 311 and provide the Applicant's information, or visit www.cabq.gov/airquality/air-quality-permits.

The Air Quality Program will issue a Public Notice announcing a 30-day public comment period on the permit application for the proposed project when the application is deemed complete. The Air Quality Program does not process or issue notices on applications that are deemed incomplete. More information about the air quality permitting process is attached to this notice.

Air Quality Construction Permitting Overview

This is the typical process to obtain an Air Quality Construction Permit for Synthetic Minor and Minor sources of air pollution from the Albuquerque – Bernalillo County Joint Air Quality Program.

Step 1: Pre-application Meeting: The Applicant and their consultant must request a meeting with the Air Quality Program to discuss the proposed action. If air dispersion modeling is required, Air Quality Program staff discuss the modeling protocol with the Applicant to ensure that all proposed emissions are considered.

> **Notice of Intent from the Applicant:** Before submitting their application, the Applicant is required to notify all nearby neighborhood associations and interested parties that they intend to apply for an air quality permit or modify an existing permit. The Applicant is also required to post a notice sign at the facility location.

Step 2: Administrative Completeness Review and Preliminary Technical Review: The Air Quality Program has 30 days from the day the permit is received to review the permit application to be sure that it is administratively complete. This means that all application forms must be signed and filled out properly, and that all relevant technical information needed to evaluate any proposed impacts is included. If the application is not complete, the permit reviewer will return the application and request more information from the Applicant. Applicants have three opportunities to submit an administratively complete application with all relevant technical information.

> **Public Notice from the Department:** When the application is deemed complete, the Department will issue a Public Notice announcing a 30-day public comment period on the permit application. This notice is distributed to the same nearby neighborhood associations and interested parties that the Applicant sent notices to, and published on the Air Quality Program's website.
>
> During this 30-day comment period, individuals have the opportunity to submit written comments expressing their concerns or support for the proposed project, and/or to request a Public Information Hearing. If approved by the Environmental Health Department Director, Public Information Hearings are held after the technical analysis is complete and the permit has been drafted.

Step 3: Technical Analysis and Draft Permit: Air Quality Program staff review all elements of the proposed operation related to air quality, and review outputs from advanced air dispersion modeling software that considers existing emission levels in the area surrounding the proposed project, emission levels from the proposed project, and meteorological data. The total calculated level of emissions is compared to state and federal air quality standards and informs the decision on whether to approve or deny the Applicant's permit.

Draft Permit: The permit will establish emission limits, standards, monitoring, recordkeeping, and reporting requirements. The draft permit undergoes an internal peer review process to determine if the emissions were properly evaluated, permit limits are appropriate and enforceable, and the permit is clear, concise, and consistent.

> **Public Notice from the Department:** When the technical analysis is complete and the permit has been drafted, the Department will issue a second Public Notice announcing a 30-day public comment period on the technical analysis and draft permit. This second Public Notice, along with the technical analysis documentation and draft permit, will be published on the Air Quality Program's website, and the public notice for availability of the technical analysis and draft permit will only be directly sent to those who requested further information during the first comment period.

During this second 30-day comment period, residents have another opportunity to submit written comments expressing their concerns or support for the proposed project, and/or to request a Public Information Hearing.

Possible Public Information Hearing: The Environmental Health Department Director may decide to hold a Public Information Hearing for a permit application if there is significant public interest and a significant air quality issue. If a Public Information Hearing is held, it will occur after the technical analysis is complete and the permit has been drafted.

Step 4: Public Comment Evaluation and Response: The Air Quality Program evaluates all public comments received during the two 30-day public comment periods and Public Information Hearing, if held, and updates the technical analysis and draft permit as appropriate. The Air Quality Program prepares a response document to address the public comments received, and when a final decision is made on the permit application, the comment response document is published on the Air Quality Program's website and distributed to the individuals who participated in the permit process. If no comments are received, a response document is not prepared.

Step 5: Final Decision on the Application: After public comments are addressed and the final technical review is completed, the Environmental Health Department makes a final decision on the application. If the permit application meets all applicable requirements set forth by the New Mexico Air Quality Control Act and the federal Clean Air Act, the permit is approved. If the permit application does not meet all applicable requirements, it is denied.

Notifications of the final decision on the permit application and the availability of the comment response document is published on the Air Quality Program's website and distributed to the individuals who participated in the permit process.

The Department must approve a permit application if the proposed action will meet all applicable requirements and if it demonstrates that it will not result in an exceedance of ambient air quality standards. Permit writers are very careful to ensure that estimated emissions have been appropriately identified or quantified and that the emission data used are acceptable.

The Department must deny a permit application if it is deemed incomplete three times, if the proposed action will not meet applicable requirements, if estimated emissions have not been appropriately identified or quantified, or if the emission data are not acceptable for technical reasons.

For more information about air quality permitting, visit www.cabq.gov/airquality/air-quality-permits

SUBJECT: Public Notice of Proposed Air Quality Construction Permit Application

Dear Neighborhood Association/Coalition Representative(s),

Why did I receive this public notice?
You are receiving this notice in accordance with New Mexico Administrative Code (NMAC) 20.11.41.13.B(1) which requires any applicant seeking an Air Quality Construction Permit pursuant to 20.11.41 NMAC to provide public notice by certified mail or electronic mail to the designated representative(s) of the recognized neighborhood associations and recognized coalitions that are within one-half mile of the exterior boundaries of the property on which the source is or is proposed to be located.

What is the Air Quality Permit application review process?
The City of Albuquerque, Environmental Health Department, Air Quality Program (Program) is responsible for the review and issuance of Air Quality Permits for any stationary source of air contaminants within Bernalillo County. Once the application is received, the Program reviews each application and rules it either complete or incomplete. Complete applications will then go through a 30-day public comment period. Within 90 days after the Program has ruled the application complete, the Program shall issue the permit, issue the permit subject to conditions, or deny the requested permit or permit modification. The Program shall hold a Public Information Hearing pursuant to 20.11.41.15 NMAC if the Director determines there is significant public interest and a significant air quality issue is involved.

What do I need to know about this proposed application?

Applicant Name	Presbyterian Healthcare Services
Site or Facility Name	Presbyterian Energy Center
Site or Facility Address	1002 Silver Ave SE, Albuquerque, NM 87106
New or Existing Source	EXISTING
Anticipated Date of Application Submittal	November 31 2021
Summary of Proposed Source to Be Permitted	This 20.11.41.2 permit application is for a significant modification of Presbyterian Healthcare Services (PHS) Permit #0273-M3-1TR to include installation of a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package. The CoGen will produce electricity and steam (heat) for the new hospital building under construction. Caterpillar rates the engine at 2,746 BHP. Additionally, PHS will be installing new burners on existing boilers 1 and 2 (Permit Units 3 and 4) which will reduce emissions of NOx, VOC, and Particulate. PHS will restrict to only operating 3 of the 4 boilers at any one time.

What emission limits and operating schedule are being requested?
See attached Notice of Intent to Construct form for this information.

How do I get additional information regarding this proposed application?
For inquiries regarding the proposed source, contact:
- Keith Long
- hlong4@phs.org
- 505-563-6221

For inquiries regarding the air quality permitting process, contact:
- City of Albuquerque Environmental Health Department Air Quality Program
- aqd@cabq.gov
- (505) 768-1972

MONTROSE ENVIRONMENTAL

Paul Wade <pwade@montrose-env.com>

Presbyterian Healthcare Permit #0273-M3-1TR Revision

1 message

Paul Wade <pwade@montrose-env.com> Tue, Nov 16, 2021 at 12:13 PM
To: kris042898@live.com, cicm-na@comcast.net, keenecafe@aol.com, a.louisa.carson@gmail.com, andersonbonnie505@gmail.com, dbodinem@gmail.com, ja.montalbano@gmail.com, silverhillabq@gmail.com, tiffany.hb10@gmail.com, fparmijo@gmail.com, abqsbna@gmail.com, bartj505@gmail.com, jrcochr@gmail.com, richard@vigliano.net, mg411@q.com, david@edoabq.com
Cc: Keith Long <hlong4@phs.org>, "Munoz-Dyer, Carina G." <cmunoz-dyer@cabq.gov>, Charles Massegee <charles.massegee@jaynescorp.com>, david@edoabq.com

Dear Neighborhood Association/Coalition Representative(s)

This email is sent to you per the requirements of Bernalillo County/City of Albuquerque Air Quality Regulation 20.11.41.B.1 NMAC “Applicant’s Public Notice Requirements”. The attached “Notice of Intent” (NOI) addresses a modification to “Authority to Construct” Permit #0273-M3-1TR. Presbyterian Healthcare Systems is proposing installation of a new Caterpillar Model G3516H Natural Gas Cogeneration (CoGen) Package at the Presbyterian Energy Center. The CoGen will produce electricity and steam (heat) for the new hospital building under construction. Attached also is the NOI cover letter.

Thank You

--

MEG Logo_Signature

Paul Wade

Principal

Montrose Air Quality Services, LLC

3500 G Comanche Rd. NE, Albuquerque, NM 87107

T: 505.830.9680 x6 | F: 505.830.9678

PWade@montrose-env.com

www.montrose-env.com

2 attachments

PHS Energy Center Notice of Intent.pdf
146K

PHS Energy Center Public Notice Cover Letter.pdf
74K

Proposed Air Quality Construction Permit
Permiso de Construcción de Calidad del Aire Propuesto

1. **Applicant's Name:**
   Nombre del solicitante: Presbyterian Healthcare Services
   Owner or Operator's Name:
   Nombre del Propietario u Operador: Presbyterian Healthcare Services
2. **Actual or Estimated Date the Application will be Submitted to the Department:**
   Fecha Actual o Estimada en que se Entragará la Solicitud al Departamento: Estimated - November 30, 2021
3. **Exact Location of the Source or Proposed Source:**
   Ubicación Excata de la Fuente o Fuente Propuesta: 1102 Silver Ave SE, Albuquerque, NM
4. **Description of the Source:**
   Descripción del Fuente: Energy center for Presbyterian Hospital + Medical Center
   Nature of Business:
   Tipo de Negocio: Provides heat and electricity to Presbyterian Hospital + Medical Center
   Process or change for which a permit is requested:
   Proceso o cambio para el cuál se solicita el permiso: Addition of a CAT G3516H natural gas cogeneration
   Plant. Install new burners for boilers 1 + 2

Preliminary estimate of the maximum quantities of each regulated air contaminant the source will emit:
Estimación preliminar de las cantidades máximas de cada contaminante de aire regulado que la fuente va a emitir:

Air Contaminant *Contaminante de Aire*	Proposed Construction Permit *Permiso de Construcción Propuesto*		Net Change Emissions (for permit modification or technical revision) *Cambio Neto de Emisiones (para modificación de permiso o revisión técnica)*	
	Pounds per hour *libras por hora*	Tons per year *toneladas por año*	Pounds per hour *libras por hora*	Tons per year *toneladas por año*
CO	39.7	66.2	9.27	39.9
NOX + NMHC	108.5	68.4	5.27	1.83
SO2	17.2	4.50	-0.07	-2.79
PM10	4.03	3.21	0.08	-1.61
PM2.5	4.03	3.21	0.08	-1.61
HAP	1.94	7.02	1.46	6.40
VOC	6.20	12.3	3.04	9.27

5. **Maximum Operating Schedule:**
   Horario Máximo de Operaciones: 24 hr/day, 7 day/week, 8760 hr/year
   Normal Operation Schedule:
   Horario Normal de Operaciones: 24 hr/day, 7 day/week, 8760 hr/year

6. **Current Contact Information for Comments and Inquiries**
   Datos actuales para Comentarios y Preguntas
   Name *(Nombre):* Keith Long
   Address *(Domicilio):* 1100 Central Ave. SE, Albuquerque, NM 87106
   Phone Number *(Número Telefónico):* 505-563-6221
   Email Address *(Correo Electrónico):* hlong4@phs.org

Call 311 for additional information concerning this project, the Air Quality Program, or to file a complaint.
Llame al 311 para obtener información adicional sobre este proyecto, del Programa de Calidad del Aire, o para presenter una queja.
Gọi 311 để biết thêm thông tin hoặc để khiếu nại về dự án này, Chương Trình Chất Lượng Không Khí

City of Albuquerque, Environmental Health Department, Air Quality Program – Stationary Source Permitting
Ciudad de Albuquerque, Departamento de Salud Ambiental, Programa de Calidad del Aire - Permisos para Fuentes Inmóviles
(505) 768-1972, aqd@cabq.gov

THIS SIGN SHALL REMAIN POSTED UNTIL THE DEPARTMENT TAKES FINAL ACTION ON THE PERMIT APPLICATION
ESTE AVISO DEBERÁ DE MANTENERSE PUESTO HASTA QUE EL DEPARTAMENTO TOME UNA DECISIÓN SOBRE LA SOLICITUD DE PERMISO

Vendor 1168 **753733**

NOTE	INVOICE NUMBER	PURCHASE ORDER	INVOICE DATE	AMOUNT	DISCOUNT	NET AMOUNT
Air Quality Permit Application Review Fee for CoGen project at PH	RFD121321		12/13/2021	6,516.00	0.00	6,516.00
			TOTALS	**$6,516.00**	**$0.00**	**$6,516.00**

THE ORIGINAL DOCUMENT HAS A WHITE REFLECTIVE WATERMARK ON THE BACK. HOLD AT AN ANGLE TO VIEW. DO NOT CASH IF NOT PRESENT.

PRESBYTERIAN
PO BOX 26666 ACCOUNTS PAYABLE
ALBUQUERQUE, NM 87125-6666
Phone (505) 923-8519

WELLS FARGO, N.A.
check clears through positive pay

56-382
412

Void After 90 Days

DATE	CHECK NO.	NET AMOUNT
12/16/2021	753733	*****6,516.00

PAY *Six Thousand Five Hundred Sixteen and 00/100 Dollars*----------

TO THE ORDER OF
CITY OF ALBUQUERQUE
ONE CIVIC PLAZA NW
STE 3023
ALBUQUERQUE NM 87103

⑈0753733⑈ ⑆041203824⑆960004718⑆