AIR QUALITY PERMIT APPLICATION FOR UNIVERSITY OF MONTANA COMBINED HEAT AND POWER PROJECT

Submitted by:

UNIVERSITY OF MONTANA

32 Campus Drive

Missoula, MT 59812

Prepared by:

McKinstry

620 West Addison Street

Missoula, MT 59801

AND

BISON ENGINEERING, INC.

3143 East Lyndale Avenue

Helena, MT 59601

April 7, 2021

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

ACRONYMS

Air Permit	Missoula City-County Air Quality Permit
AQMNP	Air Quality Monitoring Network Plan
AQS	Air Quality System
ARM	Administrative Rules of Montana
ARM2	Ambient Ratio Method 2
BACT	Best Available Control Technology
Btu	British Thermal Unit
CH_4	Methane
CHP	Combined Heat and Power
CGT	Combustion Gas Turbine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
DB	Duct Burner
DEM	Digital Elevation File
DLN	Dry Low-NOx Technology
EPA	US Environmental Protection Agency
°F	Degrees Fahrenheit
FR	Federal Register
ft	Feet
ft/sec	Feet per second
GEP	Good Engineering Practice
GHG	Greenhouse Gas
HAP	Hazardous Air Pollutant
HRSG	Heat Recovery Steam Generator
H_2O	Water
hrs/yr	hours per year
kW	Kilowatt
LAER	Lowest Achievable Emission Rate
lbs/hr	Pounds per hour
M	Meters
MAAQS	Montana Air Quality Standards
MACT	Maximum Achievable Control Technology
MAPCP	Missoula City-County Air Pollution Control Program
MCCHD	Missoula City-County Health Department
MDEQ	Montana Department of Environmental Quality
MCCHD	Missoula City-County Health Department
MMBtu/hr	Million British Thermal Units per hour
MT/yr	Metric Tons per year
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAD	North American Datum
NCDC	National Climatic Data Center
NED	National Elevation Dataset
NESHAPS	National Emission Standards for Hazardous Air Pollutants
N_2O	Nitrous Oxide
NH_3	Ammonia
NO	Nitric Oxide
N_2O	Nitrous Oxide
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NSR	New Source Review
NSPS	New Source Performance Standards
O_2	Oxygen
O_3	Ozone
O&M	Operation and Maintenance
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns
$PM_{2.5}$	Particulate Matter less than 2.5 microns
ppmvd	Parts per million by volume dry
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT-BACT-LAER Clearinghouse
ROI	Radius of Impact
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
tpy	Tons per year
$\mu g/m^3$	micrograms per cubic meter
UM	University of Montana
VOC	Volatile Organic Compounds
UTM	Universal Transverse Mercator

1.0 INTRODUCTION

The University of Montana (UM) is submitting this application for a Missoula City-County Air Quality Permit (air permit) to the Missoula City-County Health Department (MCCHD) in accordance with the requirements of the Montana Clean Air Act, the Federal Clean Air Act, and the rules adopted pursuant to these Acts, including the Missoula City-County Air Pollution Control Program (MAPCP), Chapter 6, Subchapter 1, *et seq.*

With this permit application, UM seeks approval to construct, operate and maintain a combined heat and power unit (CHP) to produce steam and electricity for the UM campus. The proposed CHP will be located next to the existing UM heating plant building and will become the primary source of steam for the campus, with the existing boilers as secondary steam supply. The CHP will be natural gas-fired, with diesel fuel backup in case of a curtailed natural gas supply.

The following people can be contacted for additional information regarding this permit application:

- Brian Kerns, University of Montana, Brian.Kerns@mso.umt.edu
- Jeff Davis, McKinstry, JeffD@McKinstry.com
- Diane Lorenzen, Bison Engineering, dlorenzen@bison-eng.com

1.1 Current UM Heating Plant Air Quality Permit Status

The UM heating plant is currently equipped with three natural gas-fired boilers that provide steam to heat the campus. Because the existing boilers at UM were installed prior to March 16, 1979 [MAPCP Rule 6.101(4)], they are considered “grandfathered” sources, and are not specifically regulated by an existing air permit. In 2011, UM permitted a biomass boiler project that was never installed. MCCHD Air Quality Permit #MC1001-01 became final on September 16, 2011, and was modified by MCCHD on December 15, 2011. As per MCCHD air quality rules, the 2011 air permit expired because the biomass project was not constructed.

1.2 Proposed Permitting Action

The CHP will be permitted as an additional unit in the UM heating plant. This application and all analyses contained herein focus on the overall operation of the CHP, combined with the existing heating plant infrastructure. Equipment configurations as well as phasing out of older equipment will also be included.

Section 2.0 includes a project summary that explains the overall operation of the CHP and how the new equipment integrates with UM’s existing infrastructure. Section 3.0 analyzes the potential emissions from the proposed facility. Section 4.0 examines the regulations relevant to this application including Missoula County, State of Montana and federal air quality regulations. The analyses show that the proposed air pollution control equipment meets the requirements of Best Available Control Technology (BACT) as evaluated in Section 5.0. Section 6.0 describes the air quality impacts from the proposed project and demonstrates compliance with Montana and National Ambient Air Quality Standards (MAAQS and NAAQS).

The addition of the proposed CHP requires an air quality permit to construct and operate, per MAPCP Rule 6.102. This application will demonstrate compliance with all applicable air quality rules and provide all relevant information as required per MAPCP Rules 6.103, 6.105, and 6.106. MCCHD permit application forms have been completed and are included in **Appendix A**. Based on the facility-wide emissions inventory for the campus, UM will not be required to apply for a Title V permit after the project is complete.

2.0 PROJECT SUMMARY

2.1 Site Description

The proposed CHP equipment will be located adjacent to the existing UM heating plant, located at 840 Connell Avenue on UM's Missoula Campus in Missoula, Montana. The legal description of the site is N½ of NE¼ of Section 27, Township 13N, Range 19W , Missoula County, Montana. Site elevation is 3,214 feet mean sea level. The heating plant lies within the 154-acre footprint of the UM campus.

The climatology of the Missoula Valley is considered semi-arid with average rainfall of 14.2 inches per year. Average precipitation is highest in May and June and lowest in January and February. Average daily high temperatures over the year range from 34°F in January to 84°F in July, based on National Climatic Data Center (NCDC) 1981 – 2010 Monthly Normal Temperatures for Missoula, Montana, found at https://wrcc.dri.edu.

The air quality classification for the immediate area is "Attainment/Unclassifiable" (40 CFR 81.327) for all pollutants. Missoula was previously classified as a moderate non-attainment area for particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) and was reclassified as "Attainment" on June 24, 2019. The area was previously classified as a carbon monoxide (CO) non-attainment area as well and was declared in "Attainment" status for CO on September 17, 2007.

The closest Prevention of Significant Deterioration (PSD) Class I areas are the Selway-Bitterroot Wilderness and the Flathead Indian Reservation. Both are within 50 km of the plant site.

2.2 Site Maps

Figures associated with this application are located in the **Figures** section following the text. *Figure 1* depicts the site location of the project on a 7.5-minute topographical quadrangle map. *Figure 2* shows the proposed project location on Google Earth satellite imagery. *Figure 3* shows a preliminary process flow diagram for the project. Equipment specific information is supplied in **Appendix B** which contains a preliminary plant layout and vendor information.

2.3 Process Description

CHP technology is sometimes referred to as cogeneration because it generates both thermal energy (steam) and electricity. The fuel is initially combusted in a combustion gas turbine (CGT) which generates electricity. The combustion gases then exit to a heat recovery steam generator (HRSG) unit which produces steam for campus heat. The HRSG will be equipped with an auxiliary duct burner (DB) which can reheat the gas stream or operate the HRSG as a stand-alone boiler if needed.

Both the CGTs and the HRSG DB will be designed to burn either natural gas or liquid fuel. The liquid fuel is #2 diesel fuel.UM will only burn ultra-low-sulfur diesel fuel in the equipment. Two of the existing UM boilers have the capability to burn liquid fuel as well, so the heating plant is already equipped with fuel storage tanks. No new fuel tanks are proposed as part of this project.

The CHP project will also include an associated ‘black start’ engine that will be used to start the turbine generator. Emissions from the black start engine are included in the project emissions inventory. The CHP proposal will be installed in a separate building located east of the heating plant.

2.4 Existing Heating Plant Boiler Changes

The UM heating plant includes three existing natural gas-fired boilers. Boilers B1 and B3 are existing boilers with 70,000 pounds per hour (pph) total steam capacity each. B3 is equipped with diesel fuel firing capability but only has approximately 80% of full capacity when using fuel oil. After the CHP is installed and operational, UM intends to disable B3 and leave it in place in the building. B1 will be retrofitted with a new low-NOx burner and diesel fuel capability. Existing Boiler B2 has a capacity of 30,000 pph and has diesel fuel and natural gas firing capability.

Existing boilers B1 and B3 exhaust through vents that are approximately 10 feet higher than the roof of the heating plant building. Existing B2 exhausts through the historic 150’ brick chimney adjacent to the heating plant building.

3.0 EMISSION INVENTORY

3.1 Emissions Summary

Emissions associated with the proposed facility must be characterized and quantified to perform the various analyses and demonstrations required for an air quality permit application. Specifically, project emissions are used to determine applicability of air quality-related state, city-county and federal Clean Air Act regulations (Section 4.0), identify BACT for the proposed equipment (Section 5.0), and demonstrate impacts to ambient air quality (Section 6.0).

Pollutant emissions are quantified in terms of the maximum potential emissions that could be generated, described as the potential to emit (PTE). The following subsections describe methods used to calculate potential emissions from each emitting source associated with this project. **Appendix C** presents detailed emissions calculations and identifies sources of emission factors and other input data.

3.2 Facility-wide PTE Summary

The fuel combustion equipment associated with the CHP project are the CGTs, HRSG DB, and black start engine. All the combustion gas emissions from the CGTs and DB will exhaust through the HRSG stack.

The facility-wide PTE includes emissions from existing and proposed sources and is used for determining applicable regulations for the project. The PTE calculations for each of the facility's sources were evaluated for several design and operational factors including operational loads, best available emissions control technologies, and the heating value of fuels combusted.

Emissions from existing UM sources are included in the PTE emission inventory. This equipment information has been supplied by UM staff. *Table 3-1* summarizes the facility's estimated annual potential emission rates of oxides of nitrogen (NO_X), CO, volatile organic compounds (VOC), PM_{10}, particulate matter with aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and carbon dioxide equivalent (CO_2e). The table presents emissions data for the proposed CHP equipment and existing emissions sources.

PTE emissions for the dual-fuel equipment are based on natural gas operation for 8,760 hours per year (hrs/yr) and fuel oil operation for 720 hrs/yr. PTE emissions from small generators and other existing combustion equipment on the UM campus are also included in the facility-wide emissions inventory. Annual emissions are presented in units of tons per year (tpy).

Table 3-1: Facility-wide Annual PTE Summary

	Pollutants						
Source	**NO_X (tpy)**	**CO (tpy)**	**VOC (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**	**SO_2 (tpy)**	**$CO_2e^{(1)}$ (MT/yr)**
Proposed Sources							
Combustion Gas Turbines – NG(2)	13.1	12.9	4.22	1.55	1.55	0.80	24,939
HRSG Duct Burner – NG(2)	20.4	19.9	1.96	2.71	2.71	0.21	38,619
CGTs– Diesel Fuel(3)	1.14	0.06	0.008	0.22	0.22	0.03	---
HRSG Duct Burner - Diesel Fuel(3)	4.32	1.08	0.07	0.71	0.71	0.05	---
Black Start Engine for CGT - Diesel	1.45	1.45	0.14	0.017	0.017	0.003	261
Existing Sources to be Retained							
Boiler B1 - Natural Gas(2)	18.8	31.6	2.07	2.86	2.86	0.23	40,767
Boiler B1 - Diesel(3)	1.82	0.91	0.04	0.18	0.05	0.04	---
Boiler B2 - Natural Gas(2)	16.1	13.5	0.89	1.23	1.23	0.10	17,472
Boiler B2 - Diesel(3)	1.95	0.49	0.02	0.20	0.02	0.02	---
Small Stationary Sources	8.07	6.74	0.45	0.61	0.61	0.07	8,690
Emergency Generators	5.14	1.53	0.40	034	034	0.32	177
Total: CGTs, DB, B2, and B3 firing natural gas full-time plus small and emergency sources.	83.1	87.6	10.1	9.3	9.3	1.73	130,925

(1) GHG from the CGT, DB, B1 and B2 were estimated based on natural gas fuel for all available annual hours. GHG from the limited hours of diesel combustion are not part of this total. Units are metric tons per year (MT/yr).
(2) Fired on natural gas, 8,760 hours per year.
(3) Fired on diesel fuel, 720 hours per year.

3.3 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions are expressed in units of metric tons per year (MT/yr) CO_2e. Carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emission calculations were based on fuel factors from the Greenhouse Gas Reporting Rule, 40 CFR 98 Subpart C, Tables C-1 and C-2. Global warming potential values were obtained from 40 CFR 98 Subpart A, Table A-1.

GHG emission rates were calculated in units of tpy and MT/yr to determine applicability to various regulatory programs. GHG emissions are summarized in *Table 3-1* and presented in detail in the emissions inventory in **Appendix C**.

3.4 UM Heating Plant Existing Equipment

As discussed above, the modified UM Heating Plant will include two of the three existing boilers.

- Boiler #1 – 70,000 pounds of steam per hour
- Boiler #2 – 30,000 pounds of steam per hour

The emissions for the boilers are calculated using emission factors from the Environmental Protection Agency's (EPA's) AP-42 emission factor reference and are based on fuel input volumes. Maximum hourly heat and fuel input rates were calculated for each boiler, then multiplied by the AP-42 emission factor to determine maximum hourly and annual emission rates. Annual emission rates were based on the maximum 8,760 hours of operation available within a year.

Because Boilers B1 and B2 will be capable of firing fuel oil as a backup fuel if natural gas supply is curtailed, emissions from this fuel were also determined in a similar manner to natural gas fuels. Experience at UM has shown that fuel oil backup is rarely used. Emissions from the boilers and the CHP while burning diesel fuel are used in the emissions inventory.

3.5 Existing Emergency Generators and Small Stationary Sources

Several existing natural gas and diesel-fired emergency generators are located on campus. Emissions for these sources have been calculated based on emissions factors from AP-42, and the equipment's maximum hourly firing rate. The annual PTE was calculated based on 500 hours per year of operation for each piece of equipment, as directed by EPA policy memo dated September 6, 1995, regarding this subject.

Existing small stationary heating, cooking and conditioning sources are located throughout the UM campus. Natural gas, propane and coal-fired appliances are located on campus and are included in the PTE inventory. Each source individually is an insignificant unit. These sources will operate on an "as-needed" basis and will not run year-round; however, the potential annual emissions were calculated assuming 8,760 hours of operation per year.

3.6 Hazardous Air Pollutants Emissions

Hazardous air pollutant (HAP) emissions were calculated using emission factors from AP-42 for the natural gas and diesel combustion sources. Only factors for organic compounds and metals specifically identified as HAPs as defined by Section 112(b) of the Clean Air Act are included in the inventory. HAP emissions factors that were listed as below the detection limit in the reference materials were excluded.

The complete HAP emission inventory is included in the emissions inventory calculations in **Appendix C**. The total HAP emission potential for the UM heating plant is 2.49 tpy. HAP emissions from the UM emergency generators and small combustion sources are negligible.

4.0 REGULATORY ANALYSIS

This section evaluates applicable regulatory requirements under MCCHD regulations and those applicable in Montana and EPA air quality regulations. A review of the local, state and federal air quality regulations indicates that the requirements listed in *Table* 4-1 may apply to the proposed UM Heating Plant. An analysis of each of the regulations named in the table follows.

Table 4-1: Potentially Applicable Regulations

Rule Citation	Description	Report Section
MAPCP Chapter 4	Missoula County Air Stagnation and Emergency Episode Avoidance Plan	4.1
MAPCP Chapter 5	General Provisions	4.2
MAPCP Chapter 6, 6.102, 6.103, 6.105, 6.106	Standards for Stationary Sources – Air Quality Permits Required, General Conditions, Application Requirements, Public Review of Application	4.3
MAPCP Chapter 6, 6.501	Emission Control Requirements – BACT	4.4
MAPCP Chapter 6, 6.502	Emissions Standards – Particulate Matter from Fuel Burning Equipment	4.5
MAPCP Chapter 6, 6.503	Emissions Standards – Particulate Matter from Industrial Process	4.6
MAPCP Chapter 6, 6.504	Emissions Standards – Visible Air Pollutants	4.7
MAPCP Chapter 6, 6.506	Standards of Performance for New Stationary Sources (NSPS)	4.8
MAPCP Chapter 6, 6.508	Emission Standards for Hazardous Air Pollutants for Source Categories - Maximum Achievable Control Technology (MACT – 40 CFR 63)	4.9
ARM 17.8.1201, *et seq.*	Operating Permit Program	4.10
ARM 17.8.401	Stack Heights and Dispersion Techniques	4.11
40 CFR 98	Mandatory Greenhouse Gas Reporting	4.12

4.1 Missoula County Air Stagnation and Emergency Episode Avoidance Plan

Chapter 4 of the MAPCP lays out definitions and procedures to be followed by MCCHD in the event of high ambient concentrations of pollutants. MCCHD may issue orders for industry to curtail or shut down operations in a high ambient pollutant concentration episode. The UM heating plant is located within Impact Zone M as defined in Rule 2.101(23). UM will comply with any orders issued by MCCHD during such an episode. Additionally, as a permitted source, UM will develop an abatement plan as required in Rule 4.106(2).

4.2 General Provisions

UM will comply with all of the requirements and general provisions in MAPCP Chapter 5. MCCHD will be properly notified before any source test or variance, or after any malfunction. UM will not circumvent any air quality regulation. Concurrent with the submittal of this application, UM is submitting $925 for the associated application fee. UM will also be required to pay permit renewal fees.

4.3 Standards for Stationary Sources – Air Quality Permits Required, General Conditions, Limits on Potential to Emit

Chapter 6 of the MAPCP outlines the MCCHD rules regarding emission standards. Rule 6.102 requires a source with a potential to emit more than 25 tpy of any pollutant to obtain an air quality permit. This application to MCCHD fulfills this requirement. The remainder of Chapter 6 defines general permit conditions and permit application requirements. UM will comply with these rules.

MAPCP Rule 6.106 requires the applicant to notify the public within 10 days of submitting its application for an air quality permit by means of a newspaper of general circulation in the area affected by the facility. Such public notification will be served by advertisement in the daily *Missoulian*. An affidavit of publication will be delivered to MCCHD upon receipt from the publisher.

4.4 Emissions Control Requirements

MAPCP Rule 6.501 requires that the BACT be applied to all new sources of air pollution. UM is subject to this regulation and, in order to comply, Section 5 contains a BACT analysis for NO_x, CO, SO_2, VOC, PM_{10} and $PM_{2.5}$ emissions for the emitting units subject to the rule.

4.5 Emissions Standards – Visible Air Pollutants

MAPCP Rule 6.504 limits the visible emissions of new sources to 20% opacity averaged over a six-minute period. The proposed CHP equipment and the existing boilers operate primarily on natural gas – visible emissions from natural gas combustion are minimal.

4.6 Standards of Performance for New Stationary Sources (NSPS)

MAPCP Rule 6.506 incorporates by reference the New Source Performance Standards (NSPS) of 40 CFR 60. The applicability of the following NSPS subparts to the UM project is addressed below. Sources that are subject to any NSPS provision are also subject to the NSPS general provisions in Subpart A, including notification requirements. The UM heating plant will comply with the applicable NSPS requirements.

4.6.1 NSPS – Subpart Dc

Title 40 CFR 60, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) applies to steam generating units that commenced construction after June 9, 1989, and that have a maximum design heat input capacity of 100 million British thermal units per hour (MMBtu/hr) or less, but greater than 10 MMBtu/hr. NSPS Subpart Dc does not apply to the existing UM boilers because they pre-date the regulation.

The HRSG functions as a boiler and is regulated under NSPS Subpart KKKK as described below. Because the HRSG DB is covered under NSPS Subpart KKKK, it is exempt from NSPS Subpart Dc.

4.6.2 NSPS – Subpart IIII

National Emission Standards for Hazardous Air Pollutants (NESHAPS) Subpart IIII will apply to the proposed black start engine. UM will comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained at 40 CFR 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* (MAPCP Rule 6.506 and 40 CFR 60, Subpart IIII).

4.6.3 NSPS – Subpart KKKK

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to the CGTs and the HRSG DB. A detailed regulatory analysis for NSPS Subpart KKKK is included in **Appendix D**. The heat input to each proposed CGT is 26.8 MMBtu/hr, so each CGT is subject to the requirements of Subpart KKKK. The NO_x emission limits contained in Table 1 of Subpart KKKK apply to the CGTs and the HRSG DB. Emissions limits are provided for natural gas combustion and for other fuels, including fuel oil.

NO_x emissions from the CGTs burning natural gas are limited to 42 parts per million by volume (ppmvd) at 15% oxygen (O_2). The proposed NO_x emission rate for the CGTs burning natural gas is 15 ppmvd at 15% O_2, which is well below the Subpart KKKK limit.

NO_x emissions from the CGTs burning fuel oil natural gas are limited to 96 ppmvd at 15% O_2. According to the National Energy Technology Laboratory (www.netl.doe.gov) Gas Turbine Handbook, testing shows that pre-mixer-enabled lean-burn units produce comparable environmental performance with both natural gas and No. 2 diesel fuel. Therefore, the estimated NO_x emissions from the CGTs while burning fuel oil are estimated to be equal to the emissions while burning natural gas.

NO_x emissions from the HRSG duct burner using either fuel are limited to 54 ppmvd at 15% O_2. The manufacturer-guaranteed emission rate for the proposed Ultra Low-NO_x burner is 27 ppmvd at 3% O_2, which equates to 9 ppmvd at 15% O_2. The proposed HRSG NO_x emissions are well below the Subpart KKKK limit while burning natural gas. The estimated HRSG emissions while burning fuel oil, based on the applicable AP-42 factor, are approximately equivalent to the Subpart KKKK limit.

4.7 National Emissions Standards for Hazardous Air Pollutants for Source Categories (MACT – 40 CFR 63)

MAPCP Rule 6.508 incorporates by reference the rules contained in 40 CFR Part 63 for NESHAPs for source categories. The requirements affect listed sources and/or facilities that are major and area sources of HAPs; these source categories must implement MACT as applicable. The applicability of the following MACT subparts to the UM project is addressed below. The emission inventory presented in Section 3.0 of this report shows that the proposed UM facility is not an area source of HAPs (less than 10 tpy of an individual HAP or 25 tpy total of total HAPs). Therefore, the UM facility is only subject to MACT standards that apply to equipment at area sources of HAPs.

4.7.1 MACT – Subpart JJJJJJ

Title 40 CFR 63, Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers: Final Rule promulgated March 21, 2011) applies to boilers combusting solid fossil fuels, biomass or liquid fuels which are located at an area source of HAPs.

Under Subpart JJJJJJ, a gas-fired boiler is defined as any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or for periodic testing, maintenance, or operator training on liquid fuel. Periodic testing, maintenance, or operator training on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

The HRSG DB and the existing UM boilers qualify as gas-fired boilers because they only use fuel oil as backup as described above. Therefore, the requirements of NSPS Subpart JJJJJJ do not apply.

4.7.2 MACT – Subpart ZZZZ

NESHAP Subpart ZZZZ applies to existing internal combustion engines. UM will comply with all applicable standards, limitations, reporting, recordkeeping, and notification requirements contained in 40 CFR 63, Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, for any applicable diesel engine (MAPCP Rule 6.508 and 40 CFR 63, Subpart ZZZZ).

4.8 Operating Permit Program

The proposed PTE for all criteria pollutants is less than 100 tpy. The PTE for total HAPs is less than 25 tpy and the PTE for any single HAP is less than 10 tpy. Therefore, the source is not subject to the Title V Operating Permit program contained in Administrative Rules of Montana (ARM) 17.8.1201, *et seq.*

4.9 Stack Heights and Dispersion Techniques

Rules governing stack heights do not physically limit the height of a given stack. Rather, the rules provide no incentive for building "tall" stacks since all analyses of BACT, modeling, etc., are based upon Good Engineering Practice (GEP) stack height or actual height, whichever is less. GEP is defined as the greater of three alternatives as provided in 40 CFR 51.100(ii)(1), (2), and (3).

The proposed HRSG stack will be less than 65 meters, which is considered GEP by 40 CFR 51.100(ii)(1). The applicable part of this regulation prohibits setting an emission limit based upon a stack height in excess of GEP or a “dispersion technique.” Since all modeling was conducted at a GEP height, or below, and the UM Heating Plant will not employ any “dispersion technique,” this analysis complies with this requirement.

4.10 Mandatory Greenhouse Gas Reporting

The Greenhouse Gas Reporting Rule was published in the *Federal Register* (FR) on October 30, 2009, in 74 FR 56260 and became effective December 29, 2009. This regulation requires annual reporting of GHG emissions to EPA by direct GHG emitters, including natural gas-fired heating facilities. The Greenhouse Gas Reporting Rule applies to sources that emit greater than 25,000 MT/yr of CO_2e emissions. The applicability of the rule is based on actual emissions and not on a source's PTE.

As shown in the emission inventory included in Section 3.0 of this report, the UM facility's PTE is greater than 25,000 MT/yr of CO_2e from fossil fuel combustion. Based on the emission factors used, the UM heating plant would exceed the reporting threshold by burning more than 460,000 standard cubic feet (scf) of natural gas in a year. UM will monitor actual annual fuel use consistent with the methodologies of the rule to determine if GHG reporting is required.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

MAPCP air quality regulations (Rule 6.501) require that the proposed new source or modification employ BACT for all pollutants not previously emitted or whose emissions would increase as a result of the new source or modification. The CHP system will be a new emission source and therefore is subject to BACT analysis requirements.

BACT analysis is provided for NO_x, CO and VOC emissions from the CHP emitting units. Control of SO_2 and $PM_{10}/PM_{2.5}$ emissions are minimized by the use of natural gas fuel as the primary fuel for the CHP system. The CGTs and the HRSG DB will be equipped with fuel oil capability to provide backup in the case of a natural gas interruption. Emissions of SO_2 during fuel oil combustion will be minimized by requiring the use of ultra-low sulfur diesel fuel in all combustion equipment.

BACT is defined as the most effective control option that is technically feasible without creating unacceptable economic, energy use, or other environmental impacts. Control options can be eliminated as BACT on the basis of technical, economic, energy, or environmental considerations. The BACT analysis procedure will be conducted using the following general steps:

Step 1: Identify available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies by control effectiveness.
Step 4: Analyze energy, environmental and economic considerations, using top-down procedure.
Step 5: Select BACT and provide documentation.

5.1 BACT Analysis for Combustion Gas Turbines - NO_x

The CHP system is designed to use the exhaust gas from the CGTs as the combustion gas in the HRSG DB. BACT analysis is provided in this section for applying NO_x controls to the CGT exhaust upstream of the HRSG DB.

NO_X is formed during the combustion of natural gas in the CGTs. The formation of NO_X is dominated by the process called thermal NO_X formation. Thermal NO_X results from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. The rate of formation is sensitive to local flame temperature and, to a lesser extent, local oxygen concentrations. Virtually all thermal NO_X is formed in the region of the flame at the highest temperature. Maximum thermal NO_X production occurs at a slightly lean fuel-to-air ratio due to the excess availability of oxygen for reaction with the nitrogen in the air and fuel.

5.1.1 Identify Available Control Technologies

The following NOx reduction and control technologies were identified as having practical potential for reducing NO_x emissions from the CGTs. The following combustion technologies are listed in the order of effectiveness for reducing NO_x emissions.

- Traditional Burner Technology
- Water or Steam Injection
- Dry Low-NO_X Burners (Proposed Technology)

Further consideration of traditional burner technology and water/steam injection are not included in the BACT analysis because they have been surpassed by the proposed technology.

<u>Dry Low-NO_X Burner</u> - Dry Low-NO_X (DLN) burner technology has been chosen for the proposed CGTs. The purpose of DLN is to lower the combustion temperatures in the turbine, thereby reducing thermal NO_X formation. This is accomplished by premixing fuel and combustion air with a stoichiometric deficit of fuel prior to injection into the compressor. Additional fuel is then injected in stages throughout the combustion chamber of the turbine. This produces a lower heating value air/fuel mixture that will combust at lower temperatures, thereby reducing thermal NO_X formation.

The following post-combustion exhaust treatment processes are considered in this BACT analysis and have an equivalent potential control efficiency.

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

<u>Selective Catalytic Reduction</u> - SCR is a post-combustion gas treatment technique for chemically reducing NO and Nitrogen Dioxide (NO_2) in an exhaust stream to molecular nitrogen, water, and oxygen. Ammonia (NH_3) is used as the reducing agent which is either supplied as ammonia or urea.

Ammonia is injected into the flue gas upstream of a catalyst bed, and NO_X and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), precious noble metals such as platinum and rhodium, zeolite, and ceramics.

SCR technology achieves optimal performance at flue gas temperatures between 575°F and 750°F. Excess air would be injected at the turbine exhaust as needed to reduce temperatures to the optimum range. Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

Selective Non-Catalytic Reduction - SNCR promotes the noncatalytic decomposition of NO_X in the flue gas to nitrogen and water using a reducing agent, typically ammonia or urea. The reduction reactions take place at much higher temperatures than in an SCR system, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process rapidly diminishes when operated outside the optimum temperature band. An additional ammonia slip or excess NO_X emissions may result.

5.1.2 Eliminate Technically Infeasible NO_x Control Options

The New Source Review (NSR) Workshop Manual describes two key criteria for determining whether an alternative control technology is technically feasible. A technology must be "available" and "applicable" in order to be considered technically feasible. A technology is *available* "if it has reached the licensing and commercial sales stage of development." An identified alternative control technique may be considered *applicable* if "it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type." The following paragraphs evaluate the technical feasibility of DLN, SCR and SNCR. by applying the criteria of availability and applicability.

- DLN burner technology is feasible and is included in the AIREM Energy turbine technology which is proposed for this project (Appendix B). NO_x emissions are specified to be 15 ppmvd @ 15% O_2.

- The high temperature required for operation of an SNCR system, typically between 1,650°F and 1,800°F, is higher than the exhaust temperatures generated by the proposed turbines. Exhaust temperatures will range from 937°F to 1,037°F, depending on turbine load and ambient conditions. SNCR is considered to be technically infeasible for this application due to temperature and space considerations.

- SCR has been applied in similar commercial applications and is considered to be technically feasible for this application. SCR has been demonstrated to reduce turbine emissions to a level of 2.5 ppmvd @ 15% O_2.

5.1.3 Rank Remaining NO_x Control Technologies by Control Effectiveness

The following technologies have been deemed to be technically feasible and will be carried forward in the BACT analysis:

- Dry Low-NO_x Burner, as proposed
- Dry Low-NO_x Burner with Selective Catalytic Reduction

The manufacturer-guaranteed NO_x emission rate for the proposed DLN burner in the CGTs is 15 ppmvd @ 15% O_2, which translates to a mass emission factor of 0.056 pounds per million British Thermal Unit (lb/MMBtu). The estimated annual emissions from the two CGTs, with a combined heat input rate of 53.6 MMBtu/hr, are 3.00 lb/hr and 13.15 tpy.

Literature review shows that advanced SCR applied to a CGT can achieve an NO_x emission rate as low as 2.5 ppmvd @ 15% oxygen, which translates to a mass emission factor of 0.0094 lb/MMBtu. The estimated annual emissions from the two CGTs with SCR would be 0.50 lb/hr and 2.21 tpy.

5.1.4 Evaluate Cost Effectiveness of NOx Controls

Cost information for adding SCR to the proposed CGT units has been obtained from the U.S. EPA Combined Heat and Power Partnership Catalog of CHP Technologies, September 2017.. Table 3-5 of the CHP catalog lists estimated capital cost for representative gas turbine CHP systems. The costs for SCR and associated equipment for a facility with nominal turbine capacity of 3,510 kW is $688,700. The proposed turbines for the UM Heating Plant CHP project have a capacity of 1,788 kW each, and a combined capacity of 3,576 kW.

The estimated capital cost is in 2017 dollars and is advanced to 2021 dollars based on an industrial inflation rate of 4% per year for four years. The capital cost used in the BACT cost-effectiveness calculations is determined as follows:

$$\$688,700 * (1 + 0.04)^{(4)} = \$805,682$$

The U.S. EPA Air Economics Group has developed an Air Pollution Control Cost Estimation Spreadsheet for SCR, finalized in 2019. The SCR spreadsheet calculates capital costs and annual operation and maintenance (O&M) costs for SCR installations. The capital cost calculations in the spreadsheet are valid for sources larger than 25 megawatt hour (MWh) or 250 MMBtu/hr, which is not an applicable size range for the UM project. In lieu of using the pre-programmed cost calculation, the capital cost value from the EPA CHP catalog was entered into an SCR spreadsheet for the UM project which is available upon request.

The O&M costs estimated by the spreadsheet are based on an inlet NO_x emissions rate to the SCR of 0.056 lb/MMBtu and an outlet NO_x emission rate from the SCR of 0.009 lb/MMBtu (2.5 ppmvd @ 15% O_2). The cost analysis is based on a 20-year time frame and an annual rate of return of 5%. *Table 5-1* summarizes the cost-effectiveness calculations for installation of SCR on the proposed CGT units with DLN burners.

As shown in *Table 5-1*, the estimated cost of adding SCR to the proposed CGT units on the UM CHP project is equal to $10,727 per ton of NO_x removed. This cost per ton is very high compared to current EPA and Montana cost-effectiveness values that would trigger installation of additional controls. Therefore, addition of SCR to the CGT's upstream of the HRSG DB is not a cost-effective solution for reducing NO_x emissions.

Table 5-1: NOx BACT Analysis – CGT

Emissions Reduction Technology	% Reduction	Emissions Reduction (tons/year)	Calculations
Dry Low-NOx Burner	base case	---	15 ppmvd @ 15% O_2 13.15 tpy
Selective Catalytic Reduction	83.3 % reduction	10.94 tpy	2.5 ppmvd @ 15% O_2 2.21 tpy

SCR Parameter	SCR Calculations
SCR Capital and Installation Cost	$805,682 total installed cost[1]
Capital Recovery Cost 20 Years at 4%	$805,682 * (.05)/(1-(1.05)$^{-20}$) = $64,650/yr
O&M Control Costs	$52,706 per year[2]

Control Alternative	NOx Reduction (tons/year)	Annualized Capital Cost	Annual O & M Costs	Control Cost ($/ton)
Dry Low-NOx	Base	$0 additional	$0 additional	$0 additional
Add SCR	10.94	$64,650	$52,706	$10,727

1 Cost information from Table 3-5 of EPA CHP Catalog.
2 Based on EPA Control Cost Manual, June 2019.

The addition of SCR to the full HRSG exhaust stream, downstream of the HRSG DB, is considered in Section 5.3 below. The adverse energy and environmental effects of SCR are also detailed in that section.

5.1.5 Select NO_x BACT

The BACT analysis has concluded that the proposed DLN burner technology constitutes the best available control technology for the proposed gas combustion turbines in the UM CHP system. More advanced lower-NO_x combustion technology is not readily available for small turbines such as those proposed for this project. Addition of SCR to the turbine exhaust is not cost-effective based on the cost per ton of NO_x potentially removed.

5.2 BACT Analysis for Combustion Gas Turbines – CO and VOC

CO and VOCs are formed from incomplete combustion of organic constituents within the natural gas in the CGTs. Because CO and VOC are generated and controlled by the same mechanisms, they will be addressed in this section together. In an ideal process, complete oxidation of organics results in the formation of water (H_2O) and CO_2. When organic compounds do not oxidize completely, the result is formation of CO and various modified VOCs. Two general and nonexclusive approaches are available for reducing emissions of these compounds:

- Improve combustion conditions to facilitate complete combustion in the turbine burner;
- Complete oxidation of the combined HRSG exhaust stream.

Post-combustion CO/VOC control is accomplished via add-on equipment that creates an environment of high temperature and oxygen concentration to promote complete oxidation of the CO and VOCs remaining in the exhaust.

5.2.1 Identify Alternative Technologies for CO/VOC Reduction

A review of a variety of information sources indicates that there are three control technologies with a practical potential for application to the CGTs for reduction of CO and VOC emissions:

- Proper system design and operation
- Thermal oxidation
- Catalytic oxidation

Proper system design and operation refers to minimization of CO and VOC emissions by controlling the combination of system temperatures through operation at maximum loads, increasing oxygen concentrations, maximizing combustion residence time, and improving mixing of the fuel, exhaust gases, and combustion air. Maximizing heating efficiency, and subsequently minimizing fuel usage, will also minimize CO formation.

Thermal oxidizers are supplementary combustion chambers that complete the conversion of CO/VOC to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. They require temperatures of approximately 1,800°F to 2,000°F. This high-temperature environment is produced by the combustion of supplemental natural gas fuel.

Catalytic oxidizers employ the same principles as thermal oxidizers, but they use catalysts to lower the temperature required to effect complete oxidation. The optimum temperature range for catalytic oxidizers is generally 600 to 900°F. Because catalysts are prone to plugging and poisoning, catalytic oxidizers must be located downstream of a particulate control device if the exhaust stream contains appreciable concentrations of particulate matter.

5.2.2 Eliminate Technically Infeasible CO/VOC Control Options

Proper system design and operation serves as the baseline for CO and VOC emissions reduction and is clearly technically feasible. Installation of post-combustion CO/VOC controls to the CGTs between their exhaust point and the HRSG DB will not be considered further in this analysis. Such an installation would be physically impossible and could alter the characteristics of the turbine exhaust making it less viable as a combustion gas stream for the HRSG duct burners.

5.2.3 Select CO/VOC BACT

The key consideration for this BACT analysis is control of NOx emissions. This analysis has concluded that the proposed CGT turbines are the best option for minimization of CO and VOC emissions while controlling NOx emissions. The manufacturer-guaranteed CO emission rate for the proposed CGT DLN burners is 24 ppmvd @ 15% O_2, which translates to a mass emission factor of 0.055 lb/MMBtu. The estimated annual emissions from the two turbines, with a combined heat input rate of 53.6 MMBtu/hr, are 2.95 lb/hr and 12.86 tpy.

The manufacturer-guaranteed VOC emission rate for the proposed CGT DLN burners is 5 ppmvd @ 15% O_2, which translates to a mass emission factor of 0.018 lb/MMBtu of VOC as propane. The estimated annual emissions from the two turbines are 0.96 lb/hr and 4.22 tpy.

5.3 BACT Analysis for Full CHP Exhaust – NOx

Exhaust from the CGTs enters the HRSG and becomes the combustion gas for the HRSG DB. The oxygen content of the CGT exhaust is approximately 15%, which is adequate to support combustion. Emission controls downstream of the DB would control emissions present in the CGT exhaust and the HRSG DB exhaust. The BACT analysis provided in this section discusses applying NO_x controls to the combined HRSG DB and CGT exhaust streams.

5.3.1 Identify Available Control Technologies

The specified HRSG DB technology for the UM CHP project is an Ultra-Low-NO_x burner. This burner has a guaranteed emission rate of 9 ppm NO_x at 10% O_2, which is approximately equivalent to 0.053 lb/MMBtu NO_x, as NO_2. For permitting purposes, the mass emission rate of the HRSG DB has been set to 0.056 lb/MMBtu. The estimated annual emissions from the DB alone, with a specified heat input rate of 83.0 MMBtu/hr are 4.65 lb/hr and 20.36 tpy. Combined emissions are 7.65 lb/hr and 33.5 tpy.

Add-on NO_x controls would be available for the HRSG exhaust as discussed above for the CGT alone. Addition of SCR to the total CHP exhaust would be a feasible control technology for NO_x emissions reduction downstream of the HRSG DB.

5.3.2 Compare Technically Feasible Control Options

The two technically feasible options for NOx emissions from the CHP system are the current proposal and addition of SCR. The current proposal uses DLN burner technology on the CGTs and an Ultra-Low-NO_x burner on the HRSG DB.

Addition of SCR would be technically feasible at the outlet of the CHP system. The HRSG is essentially a boiler, and boiler exhaust can vary in volume and temperature depending on usage. EPA SCR fact sheets, available on the EPA Clean Air Technology website, indicate that SCR needs a consistent temperature rate of 500°F to 650°F to operate. The estimated HRSG exhaust temperature is 350°F and would require additional reheat for use with SCR. The EPA Control Cost Manual chapter on SCR states that test data shows that SCR units on utility boilers rarely achieve NOx emissions less than 0.04 lb/MMBtu. The emissions from the HRSG, with SCR control, is estimated to be 0.040 lb/MMBtu for this BACT analysis.

The base-case NO_x emission rate from combined CGT and HRSG DB exhaust streams is 0.056 lb/MMBtu, which equates to 7.65 lb/hr and 33.5 tpy when all equipment is operating at full power for 8,760 hours per year. The HRSG manufacturer supplied a proposal for an SCR installation on the full CHP exhaust with a guaranteed emission rate equivalent to 0.040 lb/MMBtu.

5.3.3 Evaluate Cost-Effectiveness of NOx Controls

The cost of purchasing the SCR system was provided by the HRSG design consultant, as obtained from the SCR vendor. The annual O&M cost was estimated using the EPA SCR cost estimation spreadsheet and was based on an inlet NO_x emissions rate to the SCR of 0.056 lb/MMBtu and an outlet NO_x emission rate from the SCR of 0.040 lb/MMBtu. The SCR spreadsheet is available electronically upon request.

Table 5-2 provides a derivation for the cost of additional NO_X control technology for the HRSG exhaust. The capital costs are annualized over a 20-year period at a 5% rate of return. The rate of return is lower than typically used in industrial applications because UM is a public agency.

Table 5-2: NOx BACT Analysis – Total CHP Exhaust

Emissions Reduction Technology	% Reduction	Emissions Reduction (tons/year)	Calculations
Ultra-Low-NOx Burner on HRSG DB and DLN Burner on CGTs	base case	---	15 ppmvd @ 15% O_2 33.5 tpy
SCR Added to Full CHP Exhaust	0.056 lb/MMBtu – 0.040 lb/MMBtu = 29% reduction	9.6	9 ppmvd @ 15% O_2 23.9 tpy
Ultra-Low-NOx Burner	**Ultra-Low-NOx Burner Cost Calculations**		
SCR Parameter	**SCR Calculations**		
SCR Capital and Installation Cost	$627,435 total installed cost[1]		
Capital Recovery Cost 10 Years at 5%	$\$627{,}435 * (.05)/(1-(1.05)^{-20}) = \$50{,}347/yr$		
O&M Control Costs	$77,691 per year[2]		

Control Alternative	NOx Reduction (tons/year)	Annual Capital Cost	Annual O & M Cost	Control Cost ($/ton)
Ultra-Low-NOx Burner on HRSG DB and DLN Burner on CGTs	--	--	$0 additional	--
SCR added to Full CHP Exhaust	9.6	$50,347	$77,691	$13,337

[1] Total installed cost provided by HRSG Vendor.
[2] Based on EPA Control Cost Manual, June 2019.

The estimated cost of adding SCR to the combined exhaust of the proposed UM CHP project is equal to $13,337 per ton of NO_x removed. This cost per ton is very high compared to current EPA and Montana cost-effectiveness values that trigger installation of additional controls. Addition of SCR to the UM CHP exhaust is not a cost-effective solution for reducing NO_x emissions.

5.3.4 Environmental and Energy Impacts of SCR

SCR presents several potential adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas would be emitted to the atmosphere. Of primary concern is the formation of ammonium sulfate, $(NH_4)_2SO_4$. In addition, transportation, storage, and handling of ammonia are potentially hazardous activities with safety and security implications. Finally, disposal of spent catalyst from the SCR unit is a potential environmental hazard.

Installation of an SCR system would require electricity for pumping ammonia/urea to the SCR and other ancillary power demands. According to the EPA SCR cost spreadsheet, additional electrical power required for the SCR is estimated to be 70.2 kilowatt(kW). The SCR system would consume approximately 2% of the electricity produced by the CGTs.

5.3.5 Select NOx BACT

The BACT analysis has shown that the proposed DLN burner technology on the CGTs and the Ultra-Low-NO_x burner on the HRSG DB constitute BACT for the proposed UM CHP system. Addition of SCR to the HRSG exhaust would have unacceptable environmental and energy consumption costs and is not cost-effective based on the tons of NO_x potentially removed.

5.4 BACT Analysis for Full CHP Exhaust – CO and VOC

CO and VOCs are products of incomplete combustion and are generated and controlled by the same mechanisms. CO and VOC emission control from the combined CGT and HRSG DB exhaust is addressed in this section.

5.4.1 Identify Alternative Technologies for CO/VOC Reduction

The proposed burner designs for the CGTs and the HRSG DB have been specified to achieve optimum NO_x reduction and also achieve optimum CO/VOC emissions. Alternative combustion systems with further CO/VOC minimization technology are not considered in this BACT analysis. The following post-combustion technologies for CO and VOC emissions control are considered:

- Thermal oxidation
- Catalytic oxidation

Thermal oxidizers are supplementary combustion chambers that complete the conversion of CO/VOC to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. They require temperatures of approximately 1,800°F to 2,000°F. This high-temperature environment is produced by the combustion of supplemental natural gas fuel.

Catalytic oxidizers employ the same principles as thermal oxidizers, but they use catalysts to lower the temperature required to effect complete oxidation. The optimum temperature range for catalytic oxidizers is generally 600 to 900°F.

5.4.2 Eliminate Infeasible CO/VOC Control Options

The purpose of the HRSG is to remove as much heat as possible from the CGT exhaust to create steam and optimize energy efficiency. The exhaust stream leaving the HRSG is not hot enough to support oxidation without additional heat. The use of an oxidation system for CO and VOC control, either with or without a catalyst, could require significant amounts of natural gas combustion to reheat the exhaust stream. Combustion of additional natural gas for reheat would reduce the environmental benefits of the CHP project.

5.4.3 Select CO/VOC BACT

A final step in choosing BACT for air pollutants of interest is to compare proposed control equipment performance with other BACT determinations across the country. Air pollutant control technology information is provided by EPA through EPA's Technology Transfer Network, Clean Air Technology Center website (www.epa.gov/ttn/catc). EPA has compiled control equipment determinations into an online database called the RACT/BACT/LAER clearinghouse (RBLC), which is available on the CATC website. Most of the control technology determinations in the RBLC are BACT determinations for major emissions sources.

The proposed CO emission rate of 0.055 lb/MMBtu for the CHP overall exhaust emission rate is equivalent to 24 ppm @ 15% O_2 and is consistent with CO BACT determinations found in the EPA RBLC. VOC BACT determinations for small boilers were not found in the RBLC.

6.0 AIR QUALITY IMPACT DEMONSTRATIONS

Modeling analyses for the proposed CHP project were conducted with EPA-approved dispersion models to quantify concentration impacts on ambient air quality. The air dispersion modeling analyses in this section compare model results with the following standards and/or requirements:

- National Ambient Air Quality Standards (NAAQS – 40 CFR 50),
- Montana Ambient Air Quality Standards (MAAQS – ARM 17.8.201, *et seq.*)

According to MAPCP rules, an applicant for an air quality permit must demonstrate that the subject facility or emitting unit will not "cause or contribute to a violation of a MAAQS or NAAQS" [Rule 6.107(1)(b)]. This section provides the required air quality impact demonstration.

Modeling has been performed to demonstrate compliance with the significant impact levels (SILs) and MAAQS/NAAQS. The air quality analyses were performed using EPA and State of Montana accepted modeling procedures; results from the models demonstrate that the proposed project is in compliance with applicable rules and standards.

6.1 Applicable Standards

MAAQS, NAAQS and SILs have been established for all the criteria pollutants and averaging periods. Modeling is first performed to identify the ambient impacts of the proposed project alone. If those impacts exceed the applicable SILs, then further modeling is required to verify that the conbined impacts of the proposed equipment, existing equipment in the area and background concentrations do not exceed the MAAQS/NAAQS. The values used for demonstrating compliance with each standard are listed in *Table 6-1*, with important details contained in the footnotes.

Modeling is included to compare the proposed emissions from the CHP to the SIL levels. In cases where the modeled impact of the CHP emissions exceeded the SIL, modeling has been included for the CHP and boilers B1 and B2 to determine the full impact of the UM heating plant on the impacted receptors. The full modeled impact of all sources was combined with the background concentration for comparison to the MAAQS/NAAQS to verify compliance.

Table 6-1: Ambient Air Quality Standards

Pollutant	Averaging Period	Significant Impact Levels	Regulatory Limit [a]	Regulatory Compliance Value Used[b]
PM_{10}	24-hour	5.0 μg/m^3	150 μg/m^3 [c]	Maximum 6th highest[d]
	24-hour[e]	5.0 μg/m^3	150μg/m^3 [f]	Maximum 2nd highest[g]
	Annual[e]	1.0 μg/m^3	50 μg/m^3 [h]	Maximum 1st highest[g]
$PM_{2.5}$	24-hour	1.2 μg/m^3	35 μg/m^3 [i]	Mean of maximum 8th highest[j]
	Annual	0.2 μg/m^3	12 μg/m^3 [k]	Mean of maximum 1st highest[l]
Carbon Monoxide (CO)	1-hour	2,000 μg/m^3	40,000 μg/m^3 [f]	Maximum 2nd highest[g]
	8-hour	500 μg/m^3	10,000 μg/m^3 [f]	Maximum 2nd highest[g]
Sulfur Dioxide (SO_2)	1-hour	3 ppb (7.8 μg/m^3)	75 ppb[m] (196 μg/m^3)	Mean of maximum 4th highest[n]
	1-hour[e]	NA	0.5 ppm[o] (1,300 μg/m^3)	Case-specific
	3-hour	25 μg/m^3	0.5 ppm[f] (1,300 μg/m^3)	Maximum 2nd highest[g]
	24-hour[e]	NA	0.10 ppm[f] (260 μg/m^3)	Maximum 2nd highest[g]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 μg/m^3)	100 ppb[p] (188 μg/m^3)	Mean of maximum 8th highest[q]
	1-hour[e]	NA	0.30 ppm[f] (564 μg/m^3)	Maximum 2nd highest[g]
	Annual	1.0 μg/m^3	53 ppb[h] (100 μg/m^3)	Maximum 1st highest[g]
	Annual[e]	NA	0.05 ppm[h] (94 μg/m^3)	Maximum 1st highest[g]
Lead (Pb)	3-month	NA	0.15 μg/m^3 [r]	Case-specific
Ozone (O_3)	8-hour	40 TPY VOC[s]	Refer to EPA standards	Not typically modeled

a. Regulatory limit (NAAQS or MAAQS). MAAQS-only limits are indicated by Note e, under Averaging Period. Otherwise limit is NAAQS only or NAAQS and MAAQS are equivalent.
b. The maximum 1st highest modeled value is always used for the SIL analysis unless indicated otherwise. Modeled design values are calculated for each modeled receptor.
c. Not to be exceeded more than once per year on average over three years.
d. Concentration at any modeled receptor when using five years of meteorological data.
e. MAAQS only.
f. Not to be exceeded more than once per year.
g. Concentration at any modeled receptor for each year of modeled meteorological data.
h. Not to be exceeded in any modeled calendar year.
i. Three-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. Five-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, this is the five-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. Three-year mean of annual concentration.
l. Five-year mean of annual averages at the modeled receptor.
m. Three-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
n. Five-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the five-year mean of 1st highest modeled 1-hour impacts for each year is used.
o. Not to be exceeded more than 18 times in one calendar year.
p. Three-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. Five-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the five-year mean of maximum modeled 1-hour impacts for each year is used.
r. Three-month rolling average, evaluated over three years.
s. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.

6.2 Modeling Methodology

All dispersion modeling analyses performed for this application were conducted in accordance with the methodology outlined in the *New Source Review Workshop Manual*, EPA, October 1990, Draft. The guidance found in Appendix W of 40 CFR 51, *Guideline on Air Quality Models*, January 17, 2017 (the Guideline Document) and the Montana Modeling Guideline for Air Quality Permits (November 2007 Draft) were also used as references.

This section describes the specific methods and data used in the air impact analyses. Parameters are summarized in *Table 6-2* and detailed descriptions follow.

Table 6-2: Modeling Parameters

Parameter	Description/Values	Documentation/Additional Description
General Facility Location	Attainment	The facility area is attainment or unclassified for all criteria pollutants except PM_{10}.
Model	AERMOD	AERMOD with the PRIME downwash algorithm.
Meteorological Data	Missoula Airport Surface Data, Great Falls Upper Air Data	The modeling has been performed for the years 2015-2019 using AERMET. AERMET data files are available upon request.
Terrain	Considered	Receptor elevations were obtained from USGS National Elevation Dataset (NED) files. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was calculated for existing UM structures and the CHP building. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
NO_x Chemistry	NO_x Tier 2 Analysis Used	ARM2 Option in AERMOD used for 1-hour and annual NO_x modeling for the SIL and NAAQS modeling.

6.2.1 Receptor Network

A total of 3,080 receptors were analyzed in the UM Heating Plant modeling, including ground level and elevated receptors. A plot of the ambient analysis receptor grids is included as one of the modeling figures in **Appendix E**. The following grids were created utilizing the specified spacing in meters (m) below.

- 10 m spacing surrounding the heating plant building
- 100 m spacing from 0 to 1,000 m from the facility
- 250 m spacing from 1,000 m to 3,000 m from the facility
- 1000 m spacing from 3,000 m to 10,000 m from the facility

In addition to the standard ground-level receptors, 450 elevated receptors were placed "on" UM residence halls near the heating plant. In general, these receptors were placed near the center of each building face at elevations from 1.5 meters above ground level to the top of the adjacent building with a maximum receptor elevation height of 37.5 meters. A grid of receptors called hotspot receptors was developed surrounding the peak modeled impact point for the 1-hour NO_x modeling, as shown in **Appendix E**.

6.2.2 Terrain Data

Elevations of emissions sources and buildings in the modeling analyses were determined by the AERMAP program. The BEEST modeling software's "Calc Domain" function was used to determine the modeling domain extent and to identify the USGS digital elevation model (DEM) files required by the AERMAP terrain preprocessor to properly calculate receptor elevations and maximum hill height values. The DEM files derive from USGS 7.5-minute topographic maps based on the 1927 North American Datum (NAD27).

6.2.3 Modeled Sources

The HRSG stack on the CHP was the only source included in the SIL analysis. Potential emissions from the CHP will exhaust through a new 50-foot-tall stack. Two of the existing boilers, B1 and B2, will be retained in the final UM heating plant design. *Table 6-3* presents the physical stack characteristics used in the air dispersion modeling including the coordinates in Universal Transverse Mercator (UTM),stack elevation, height, and diameter in feet (ft), temperature in degrees Fahrenheit (°F), and stack velocity in feet per second (ft/sec).

Table 6-3: Modeled Stack Parameters

Source	X-UTM (m)	Y-UTM (m)	Stack Elevation (ft)	Stack Height (ft)	Stack Temp. (°F)	Stack Velocity (ft/sec)	Stack Diameter (ft)
HRSG	272,705	5,194,210	3215	50	350	46.7	4.58
B1	272,675	5,194,213	3218	56	350	40.3	3.77
B2	272,681	5,194,216	3218	150	350	3.9	7.5

For the modeling demonstration, stack exhaust flow rates and temperatures were provided by the HRSG designer. The exhaust stack flow rate for B1 was determined based on forced draft fan theoretical air flow maximums, then decremented by measured system pressure losses. Flow rates for B2 were determined by application of an EPA Method 19 fuel-specific combustion products conversion factor, Fd, that calculates airflow based on heat input. Boiler industry standards indicate a known volume of combustion gases are generated from the combustion of a known volume (heat input) of gaseous or liquid fuels.

6.2.4 Background Concentrations

Background concentrations, also referred to as "design values," are used if a cumulative MAAQS/NAAQS air impact modeling analysis is required. Ambient background concentrations are added to modeled impacts to demonstrate compliance with applicable MAAQS/NAAQS standards.

The proposed background concentrations to be used for the MAAQS/NAAQS compliance modeling were obtained from the Montana Air Quality Monitoring Network Plan (May 2019). The values in the Network Plan clearly meet the EPA modeling requirements for background design values. Design values for PM_{10} are not defined in the Network Plan and were obtained from the EPA Air Quality Systems (AQS) website. *Table 6-4* presents the background values used in this modeling analysis and identifies the data sources.

Table 6-4: Background Concentrations for Modeling

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	Data Source
$PM_{2.5}$	24-hour	23	Montana Department of Environmental Quality (MDEQ) AQMNP 2019, Table 14 (Missoula) – NAAQS 3-year 24-hr design value. (1)
	Annual	7.2	MDEQ AQMNP 2019, Table 14 (Missoula) – NAAQS 3-year annual design value. (1)
PM_{10}	24-hour, federal	57	Average H2H 24-hour average monitored value for years 2016-2018. Average annual high monitored values for years 2016 – 2018. (2)
	24-hour, MT	57	
	Annual, MT	15	
NO_2	1-hour	19.1	MDEQ AQMNP 2019, Table 7 (Broadus). 1-hour background is 10 ppb, 19.1 $\mu g/m^3$. The annual is set at the 3- year mean value, 1.8 $\mu g/m^3$. (1)
	Annual	1.8	
SO_2	1-hour	13.1	MDEQ AQMNP 2019, Table 10 (NCore). 1-hour background is 5 ppb, 13.1 $\mu g/m^3$.(1)

(1) MDEQ Air Quality Monitoring Network Plan (AQMNP), May 2019.
(2) Average of yearly 2nd max 24-hour value, over 2017 – 2019. DEQ methodology to establish background values for a recent project near Butte. Data obtained from EPA Air Quality Systems (AQS) website.
(3) Limited NO_2 data available in Montana. Use of Broadus data approved by MDEQ for a recent project near Butte.

6.2.5 Ambient Ozone Concentrations

Ozone is monitored at a site in Missoula and presented in the MDEQ Air Quality Monitoring Network Plan. The 8-hour NAAQS design value for the 2018 ozone season for Missoula is 0.054 ppm. The 8-hour ozone NAAQS is 0.070 ppm. The proposed project is not expected to change the impacts of the UM heating plant on the ambient ozone concentrations in Missoula. Natural gas combustion is a low emitter of VOC and $PM_{2.5}$, which are precursors to ozone formation and the CHP project is not expected to change the ambient ozone impacts from the UM heating plant.

6.2.6 Meteorological Data

Modeling was performed using surface meteorological data collected from Missoula airport, processed with corresponding upper air data from the Great Falls Airport for each of the years 2015 - 2019. The met data was processed using AERMET within the BEEST program framework. An AERMET processing summary memo is included in **Appendix F**.

6.2.7 NO_x to NO_2 Conversion

The estimated emissions of NO_x from the CHP system and the existing boilers is a mixture of primarily nitric oxide (NO) and NO_2. NO_2 is a regulated criteria air pollutant, and NO is not a regulated pollutant. It is valuable to know the concentrations of NO and NO_2 in the NO_x emissions, and the rate at which the NO converts to NO_2.

Section 4.2.3.4.b of the EPA's Guideline on Air Quality Models, Appendix W to 40 CFR Part 51 (Jan. 17, 2017), contains the following description of NO_2 modeling.

> b. Due to the complexity of NO_2 modeling, a multi-tiered screening approach is required to obtain hourly and annual average estimates of NO_2. The tiers of NO_2 modeling include:
>
> i. A first-tier (most conservative) "full" conversion approach;
>
> ii. A second-tier approach that assumes ambient equilibrium between NO and NO_2; and
>
> iii. For Tier 1, use an appropriate refined model (Section 4.2.2) to estimate NO_X concentrations and assume a total conversion of NO to NO_2.

NO_2 concentrations resulting from modeled NO_x emissions were determined using the EPA 3-Tier NO_2 methodology as coded within AERMOD. The modeling utilized the Tier 2 Ambient Ratio Method 2 (ARM2) option to simulate the conversion of NO to NO_2 in the ambient air. The ARM2 option requires a minimum and maximum NO_2/NOx in-stack ratio value for use in predicting ambient concentrations of NO_2.

EPA maintains and updates an emission inventory of minimum NO_2/NOx in-stack ratio values. Research into the inventory has shown the following values of the NO_2/NOx in-stack ratio to use in the UM modeling. If the NO_2/NOx in-stack ratio value from the database is less than 0.1, a value of 0.1 is used.

- Boilers B1 and B2 burning natural gas ISR = 0.1
- Boilers B1 and B2 burning fuel oil ISR = 0.1
- CGTs burning natural gas ISR = 0.211
- CGTs burning fuel oil ISR = 0.114
- HRSG DB burning natural gas ISR = 0.167
- HRSG DB burning fuel oil ISR = 0.1

AERMOD only allows one value for the ISR for each modeling run – a value of 0.2 was used for modeling natural gas combustion emissions and a value of 0.1 was used when modeling fuel oil combustion emissions.

6.3 Analysis Results

6.3.1 SIL Results

SIL modeling was performed for NO_x, SO_2, PM_{10}, $PM_{2.5}$, and CO emissions for each pollutant regulated averaging period. The SIL modeling used the entire receptor grid and established the radius of impact (ROI) of the proposed project. The ROI is defined by the distance to the farthest receptor at which the project changes show a modeled significant impact.

Table 6-5 lists the results of the SIL modeling. Not all of the receptors falling within the ROI showed modeled concentrations in microgram per cubic meter (μg/m3) above the SIL. The actual number of SIL receptors is listed in *Table 6-6*.

Table 6-5: Results for the Significant Impact Level Analysis

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)[a]	Significant Impact Level ($\mu g/m^3$)	Cumulative NAAQS Analysis Required	Radius of Impact (km)
$PM_{2.5}$	24-hour	6.11	1.2	Yes	0.82
	Annual	0.72	0.2	Yes	0.41
PM_{10}	24-hour	7.80	5.0	Yes	0.09
NO_2	1-hour	143	7.5	Yes	13.1
	Annual	5.83	1.0	Yes	0.83
SO_2	1-hour	9.48	7.8	Yes	0.05
	3-hour	4.74	25	No	na
CO	1-hour	401	2,000	No	na
	8-hour	107	500	No	na

a. See *Table 6-1* for the compliance value used for each pollutant and averaging period.

6.3.2 Modeled Parameters for NAAQS Compliance

Table 6-6 lists the number of modeled receptors and modeling parameters used for the NAAQS compliance demonstration.

Table 6-6: NAAQS Compliance Demonstration Values

Pollutant	Averaging Period	# of SIL Rec.	Modeled Value	Met Data Set
PM_{10}	24-hour	13	High 6th high of 5 met years	5 year combined met data set
$PM_{2.5}$	24-hour	95	H8H of max daily values averaged over 5 years (BEEST function)	5 year combined met data set
	Annual	64	Average of annual high values over 5 years	5 year combined met data set
NO_2	1-hour	1107	H8H of max daily values averaged over 5 years (BEEST function)	5 year combined met data set
	Annual	91	Highest annual average over 5 years	Individual met year files
SO_2	1-hour	3 (use 9)	H4H of max daily values averaged over 5 years (BEEST function)	5 year combined met data set

6.3.3 NAAQS Compliance Modeling Results

Table 6-7 provides results of cumulative NAAQS impact analyses for the project design configuration with the CHP, B1 and B2 operating simultaneously on natural gas. No exceedances of the NAAQS standards were modeled.

Table 6-7: Results for Cumulative NAAQS Impact Analysis, Natural Gas

Pollutant	Avg. Period	Modeled Conc. (μg/m³)	Background Conc. (μg/m³)	Total Conc. (μg/m³)	NAAQS (μg/m³)	% of NAAQS
$PM_{2.5}$	24-hour	9.10[a]	23	32.1	35	91%
	Annual	1.47[b]	7.2	8.67	12	72%
PM_{10}	24-hour	12.2[c]	57	69.2	150	46%
NO_2	1-hour	143[a]	19.1	162	188	86%
	Hot Spot	144[a]	19.1	163	188	87%
	Annual	9.32[d]	1.8	11.1	100	11%
SO_2	1-hour	9.88[e]	13.1	23.0	196	12%

a. Maximum of five-year means of 8th highest modeled concentrations for each year modeled.
b. Five-year mean of annual concentration.
c. Maximum of 6th highest modeled concentrations for a five-year period.
d. Maximum annual impact of five years modeled.
e. Maximum of five-year means of 8th highest modeled concentrations for each year modeled.

NAAQS modeling was also performed to evaluate the NO_2 1-hour modeled impacts from the CHP, B1 and B2 operating on fuel oil. As shown in *Table 6-8*, the modeled impact is higher when burning fuel oil but is still in compliance with the NAAQS.

Table 6-8: One-hour NO_2 NAAQS Results, Fuel Oil

Sources Operating	Modeled Conc. (μg/m³)	Background Conc. (μg/m³)	Total Conc. (μg/m³)	NAAQS (μg/m³)	% of NAAQS
CGTs, DB, B1 and B2	163[a]	19.1	182	188	97%

a. Maximum of five-year means of 8th highest modeled concentrations for each year modeled.

6.3.4 MAAQS Compliance Modeling Results

The MAAQS included in *Table 6-1* have slightly different values and compliance formats than the corresponding NAAQS. The MAAQS compliance value for 24-hour PM_{10} is the high-2nd-high value modeled. This modeled value was 12.1 μg/m³ as compared to the NAAQS compliance modeled value of 9.85 μg/m³.

The NO_2 annual MAAQS is 94 μg/m³ whereas the NO_2 annual NAAQS is 100 μg/m³. Both are determined by the maximum annual average modeled - the NO_2 annual impacts for this project are only 19% of the MAAQS. The NO_2 1-hour MAAQS is 564 μg/m³ based on the high-2nd-high modeled value. The 1-hour NAAQS is far more stringent than the MAAQS; compliance with the NAAQS also indicates compliance with the MAAQS.

6.4 Modeling Figures

A number of figures have been developed showing the AERMOD modeling inputs. The captions on the figures describe the information being shown. These figures can be found in **Appendix E**.

APPENDIX A: MCCHD AIR QUALITY PERMIT APPLICATION FORMS

MISSOULA CITY-COUNTY AIR QUALITY PERMIT APPLICATION FOR INDUSTRIAL SOURCES IN MISSOULA COUNTY

3/30/2020

Permits are required for all gravel crushers, asphalt plants, concrete batch plants, and incinerators regardless of size. Also, all other sources that potentially emit $\geq$ 25 tons of any pollutant (or $\geq$ 0.6 tons for lead) per year are required to get an Air Quality Permit.

Application is complete when Missoula City-County Health Department (MCCHD), 301 W. Alder, Missoula, MT 59802-4123 has received:

1. requested information and signature (see pages 2, 3 and 4, use additional paper as needed).
2. fee payable to MCCHD, (most sources pay $975.00, see page 5).
3. a valid Zoning Compliance Permit.
4. Proof of Public Notice in paper of general circulation in area affected (see below).
5. **Incinerators/Crematoriums contact MCCHD for additional requirements.**

The notice below **must be published no earlier than 10 days prior to the date your application** will be submitted to the Department, **or no later than 10 days following the date of submittal**. The notice must be published for **one day** in the legal notice section of a newspaper in general circulation in the area affected. **Submit a copy of the published notice or proof of publication** to the Department with the application, if possible, or as soon thereafter as possible. This notice is required by the Missoula City-County Air Pollution Control Program.

Public Notice Format in Box Below

PUBLIC NOTICE

Notice of Application for Air Quality Permit pursuant to the Missoula City-County Air Pollution Control Program.

University of Montana *(Name of Applicant and Address)* (has filed/will file) on or about April 1, 2021 *(date)* an application for an air quality permit from the Environmental Health Division of the Missoula City-County Health Department. The applicant seeks approval for operation of a Combined Heat and Power system *(brief description of construction, modification, or project for which permit is being applied for)* at the UM Heating Plant on the Missoula campus *(Address and Section, Township, & Range)*.

Any member of the public who wishes to review the application, obtain a copy of the application, or who wishes to submit comments should contact the Department at 301 W. Alder, Missoula, MT 59802-4123 or phone 258-4755 prior to May 8, 2021 *(30 days from date Notice is published)*.

The Health Department will make a preliminary determination on whether a permit will be issued and provide notice to the public for comment on the determination. The notification will contain the date when the Department intends to make a final decision. The address and phone number at which interested persons may obtain further information or obtain a copy of the proposed permit will also be included with the preliminary determination.

MISSOULA COUNTY INDUSTRIAL SOURCE PERMIT APPLICATION
SECTION I: General Plant Information

NAME: University of Montana

(Circle One) INDIVIDUAL CORPORATION PARTNERSHIP GOVERNMENT

ADDRESS: 32 Campus Drive
Missoula, Montana Zip 59802

TELEPHONE NUMBER: (   )

SUBMITTED BY (principle executive officer or authorized representative responsible for overall operation of the source): ______ DATE: ______
(Name and Title)

SIGNATURE: ______

1. EQUIPMENT LOCATION:
   Legal Address or other specific location: UM Heating Plant
   NE ¼ of Section 27 Township 13 North, Range 19 West
   Longitude -113.9822 Latitude 46.8626
   Property Dimensions CHP Building: 13.4 m x 40.2 m meters

2. APPROXIMATE VEHICLE MILES PER DAY:
   Haul Trucks: None VMT/DAY
   Loaders: None VMT/DAY

3. NORMAL & MAXIMUM PLANT PROCESS/PRODUCTION RATE:
Maximum and normal electricity production: 3.4 MW.
Maximum heat input - 136.6 MMBtu/hr. Normal heat input - estimated 80 MMBtu/hr.

4. OPERATING SCHEDULE: 8760 hours per year as needed for heat and electricity.

Starting Date: June 2021 Estimated Completion Date: To Be Determined

5. AIR POLLUTION CONTROL METHODS (fugitive and point sources of pollution):
Dry Lo-NOX combustion technology on the natural gas turbines.
Ultra Low NOx burners on the HSRG duct burner.

6. PLANS AND SPECIFICATIONS: The application for a Construction Permit shall be accompanied by plans and specifications of all emissions sources and control equipment. Attach process flow diagram.

MISSOULA COUNTY INDUSTRIAL SOURCE PERMIT APPLICATION

SECTION II: Electrical Generator or Stationary Engine Information

To show compliance with the 2010 national ambient air quality standard for NOx, the following additional **electrical generator or stationary engine** information must be supplied with the permit application.

The information for the turbines, HRSG duct burner and Black Start Engine is included in the permit application.

For each generator, supply the following information.

Type of Equipment: ELECTICAL GENERATOR or STATIONARY ENGINE

Make and Model: ______

Year of Manufacture: ______

Serial Number: ______

Maximum kW output: ______

Horsepower: ______ hp

Type of Fuel Used: ______

Maximum Fuel Use: ______

Air Pollution Control Equipment (circle one): Manufacturer Installed or Other (explain other)

______

Stack Height from Ground: ______ feet

Generator Inside Stack Diameter: ______ inches

Maximum NOx emission rate: ______ lbs/hr

Required Site Information:

Site Elevation: ______

Depth of Pit: ______

Size and shape of parcel where operation will occur. For instance, a parcel could be 90 meters by 155 meters. Pictures/drawings with dimensions accepted.

MISSOULA COUNTY INDUSTRIAL SOURCE PERMIT APPLICATION

SECTION III: Equipment Information

Individual Equipment Information (i.e. baghouses, gravel crushers, screens, asphalt plant, asphalt heaters, incinerators, etc.)

For each piece of equipment, supply the following information. Hot plants must specify type(s) of fuel used in burner. Put NA when not applicable.

Type of Equipment:______________________________

Make and Model:______________________________

Year of Manufacture:______________________________

Serial Number:______________________________

Stack Height:______________________________feet___

Maximum Process Rate (tons produced, horsepower etc.):______________________________

Type of Fuel Used:______________________________

Maximum Fuel Use:______________________________

Air Pollution Control Equipment:______________________________

____

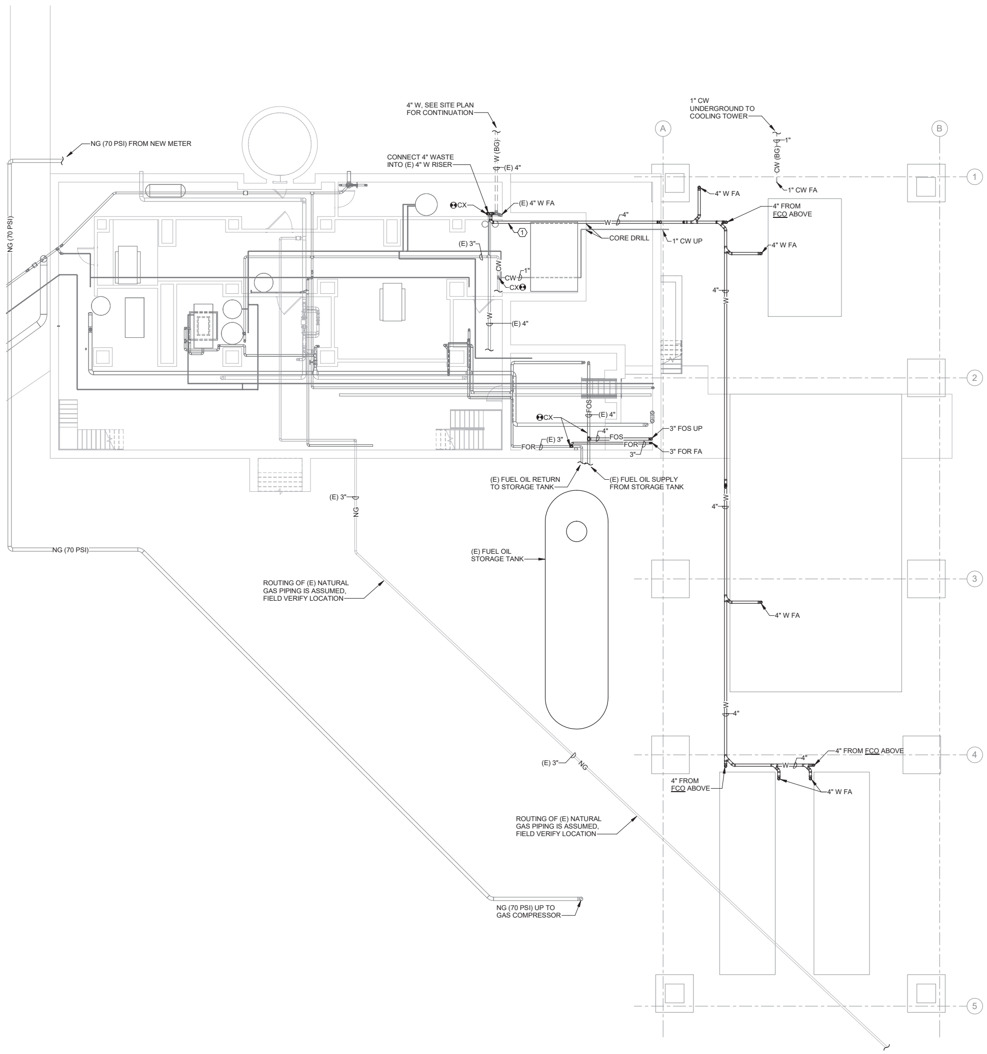
APPENDIX B: PLANT LAYOUT AND DESIGN DATA

SHEET NOTES

1. ROUTE 4" WASTE TIGHT TO WALL IN BASEMENT.

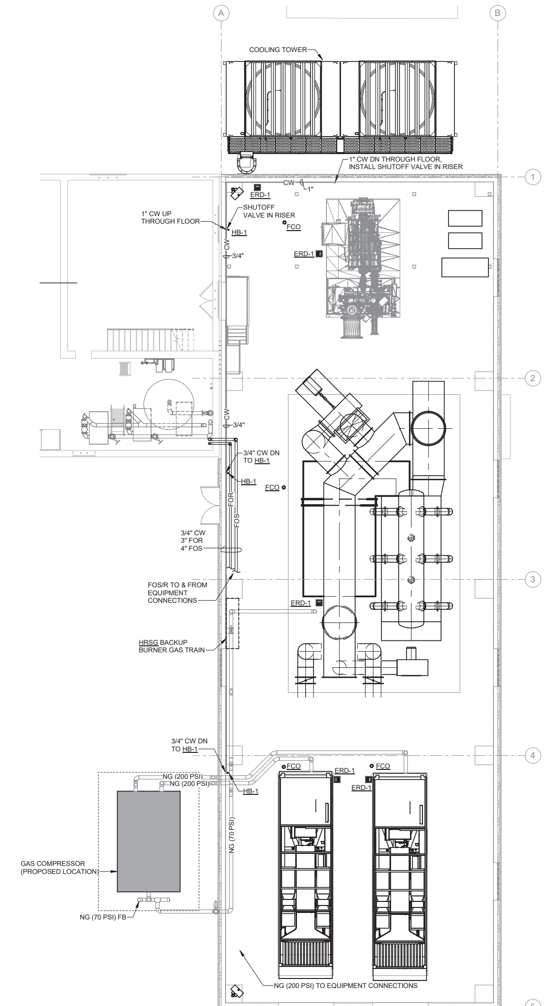
Cushing Terrell.

cushingterrell.com
800.757.9522



1 P100 PARTIAL BASEMENT AND FOUNDATION PLUMBING PLAN

1/8" = 1'-0"



2 P100 MAIN FLOOR PLUMBING PLAN

1/8" = 1'-0"

NOT FOR CONSTRUCTION - PRELIMINARY DESIGN

UNIVERSITY OF MONTANA

COMBINED HEAT AND POWER SYSTEM

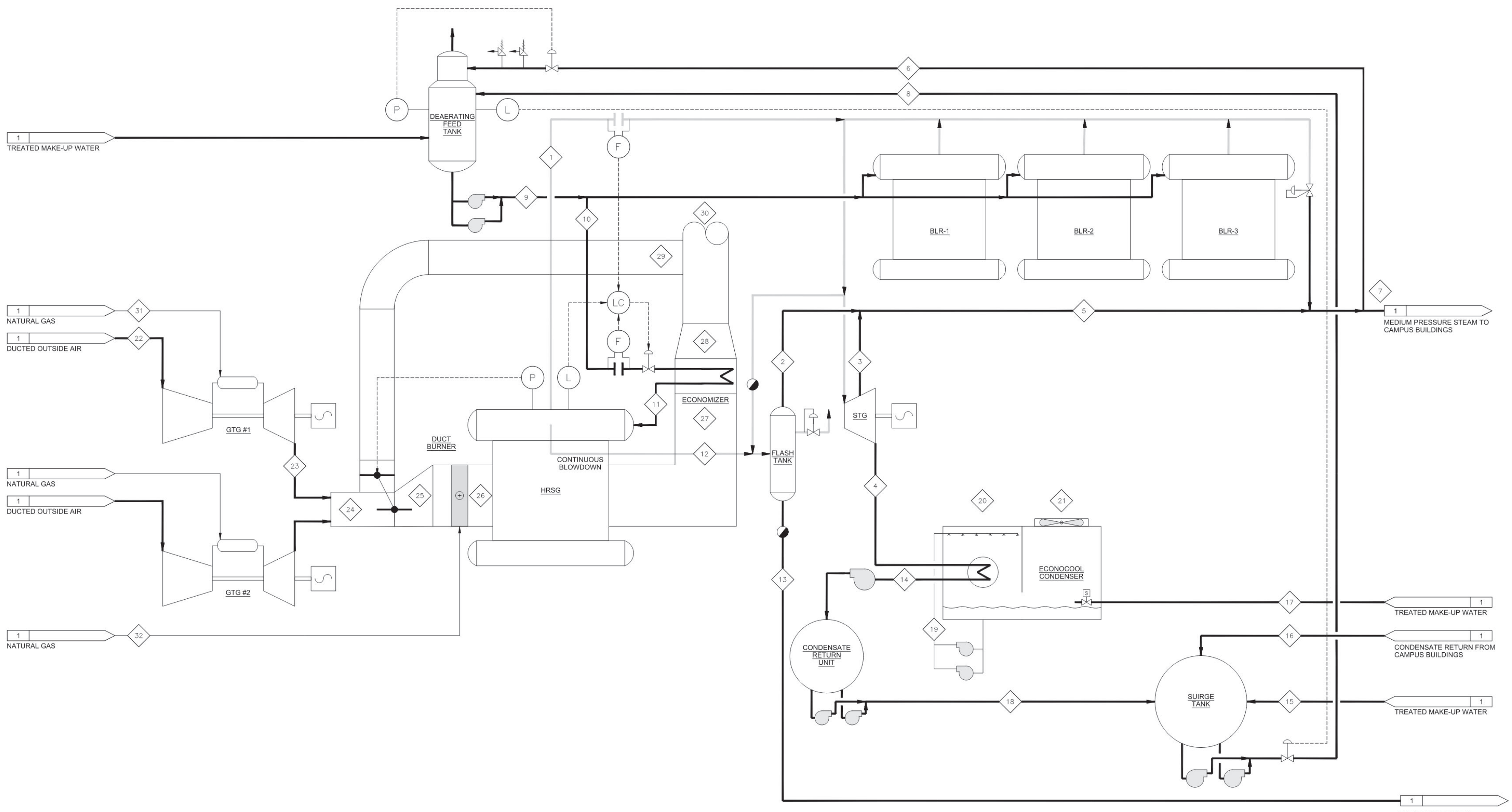
PROGRESS SET

03.01.2021
PROJECT# | MCKIN_UMCHP
DESIGNED BY | RATZ
DRAWN BY | HERBST
REVISIONS

PLUMBING PLANS

P100

Cushing Terrell.
cushingterrell.com
800.757.9522



	STREAM	1	2	3	4	5	6	7	8	9	10	11
FLOW	[LBS/HR X 10^3]	*	*	*	*	*	*	*	*	*	*	*
PRESSURE	[PSIA]	*	*	*	*	*	*	*	*	*	*	*
TEMPERTURE	[°F]	*	*	*	*	*	*	*	*	*	*	*
ENTHALPY	[BTU/LB]	*	*	*	*	*	*	*	*	*	*	*

UNIVERSITY OF MONTANA
COMBINED HEAT AND POWER SYSTEM

NOT FOR CONSTRUCTION - PRELIMINARY DESIGN

PROGRESS SET

03.01.2021
PROJECT# | MCKIN_UMCHP
DESIGNED BY | Designer
DRAWN BY | Author
REVISIONS

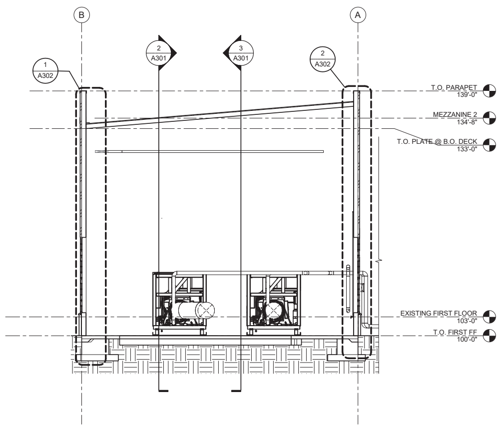
FLOW DIAGRAM

M401

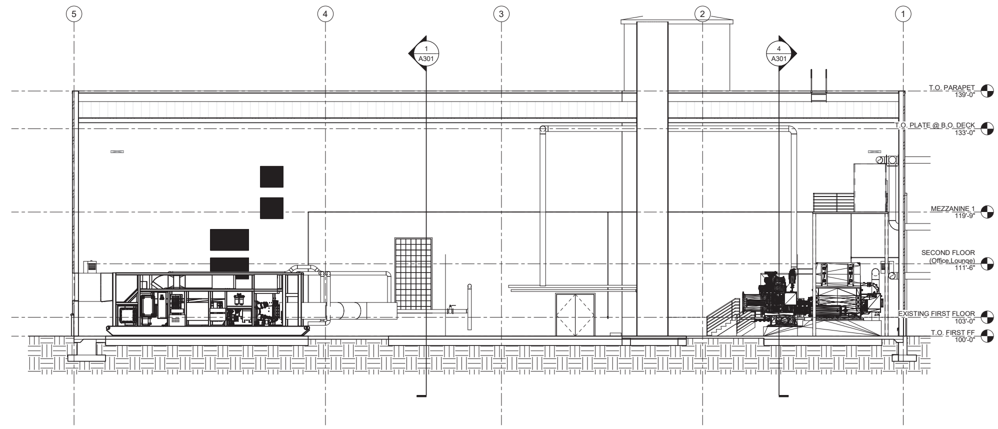
FIGURE 3: CHP PROCESS FLOW DIAGRAM

Cushing Terrell

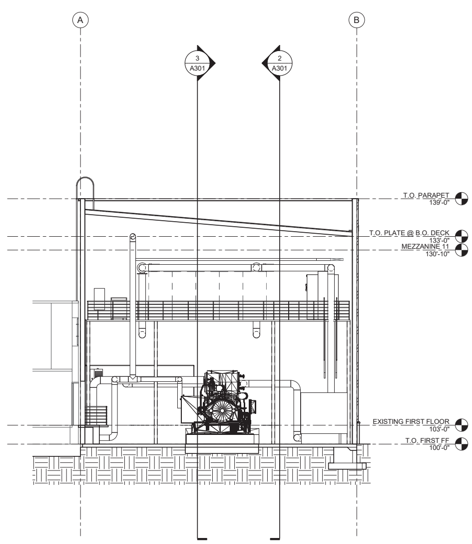
cushingterrell.com
800.757.9522



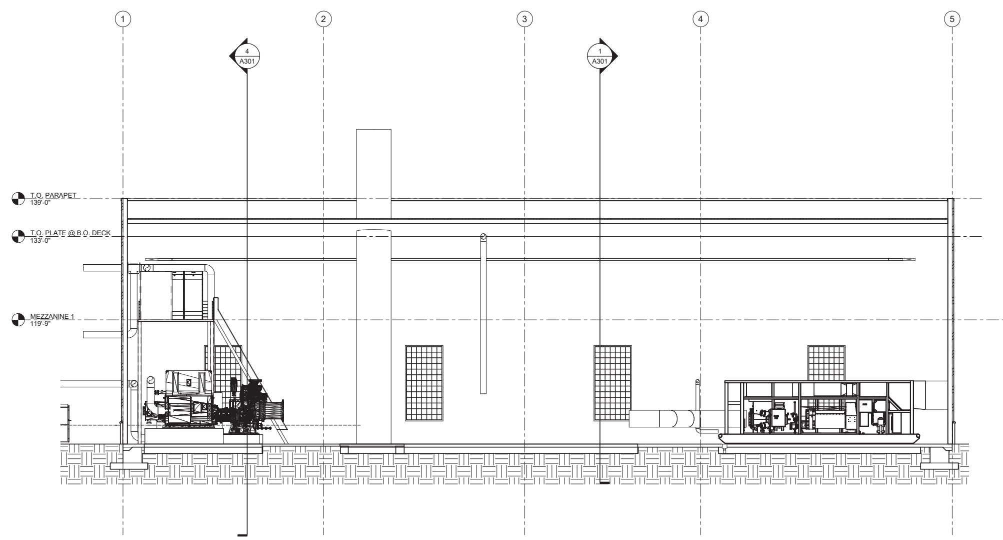
1 A301 E-W BUILDING SECTION
1/8" = 1'-0"



2 A301 BUILDING SECTION
1/8" = 1'-0"



4 A301 Section 4
1/8" = 1'-0"



3 A301 BUILDING SECTION
1/8" = 1'-0"

NOT FOR CONSTRUCTION - PRELIMINARY DESIGN

UNIVERSITY OF MONTANA
COMBINED HEAT AND POWER SYSTEM

30% CONSTRUCTION DOCUMENTS

03.03.2021
DESIGNED BY | SCHAPER
DRAWN BY | THOME, WOLDTVEDT
REVISIONS

BUILDING SECTIONS

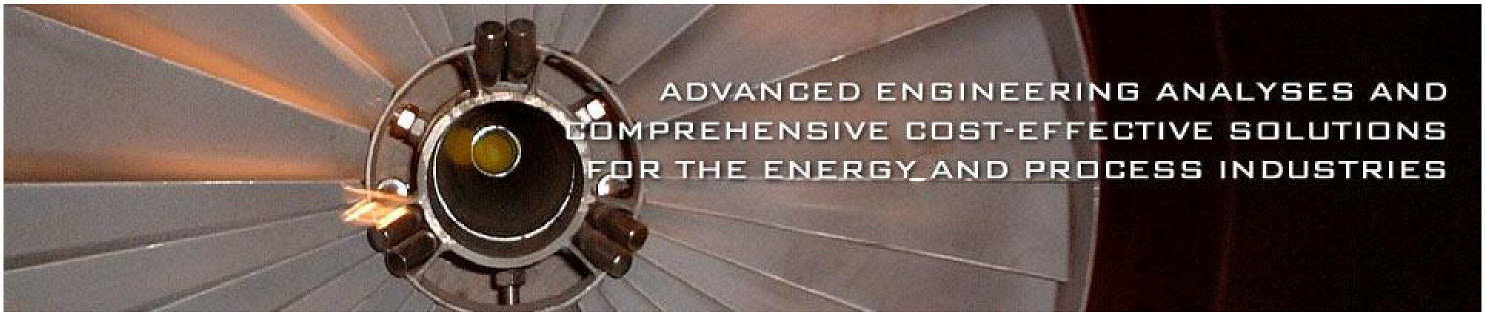
A301

INNOVATIVE ENERGY SOLUTIONS RJM INTERNATIONAL [(http://www.rjm-international.com/)](http://www.rjm-international.com/)

Sitemap | Accessibility | Contact us

Search Go

Proud winner of the Innovation Award



About RJM | Products and Equipment | Consultancy and Services | Biomass and Co-firing | References | Spare Parts Ordering | News and Events | Regions | Links

- Ultra-Low NOx burners
- Overfire air systems
- CFD modelling
- Videos

Home > Products and Equipment > Ultra-Low NOx burners

Ultra-Low NOx burners

RJM's engineering team has been at the forefront of designing, developing, manufacturing and installing its own range of innovative, high-performance low NOx burners and components for over 30 years. RJM's innovations have been recognised through a number of industry awards, most recently the UK government's Queen's Award for Enterprise: Innovation 2017. More... (News-Events/News/RJM-wins-2017-Queen-s-Award-for-Innovation)

Most projects at customer sites today still involve a signifcant low NOx element. More (About-RJM/Customer-quotes).

The company has recently developed a new range of Ultra-Low NOx Burners and they are enabling customers, who include many of the world's leading power generators, to meet the latest emissions regulations and maintain operational flexibility, without having to invest in costly SCR or SNCR systems.

RJM's Ultra-Low NOx burner experience

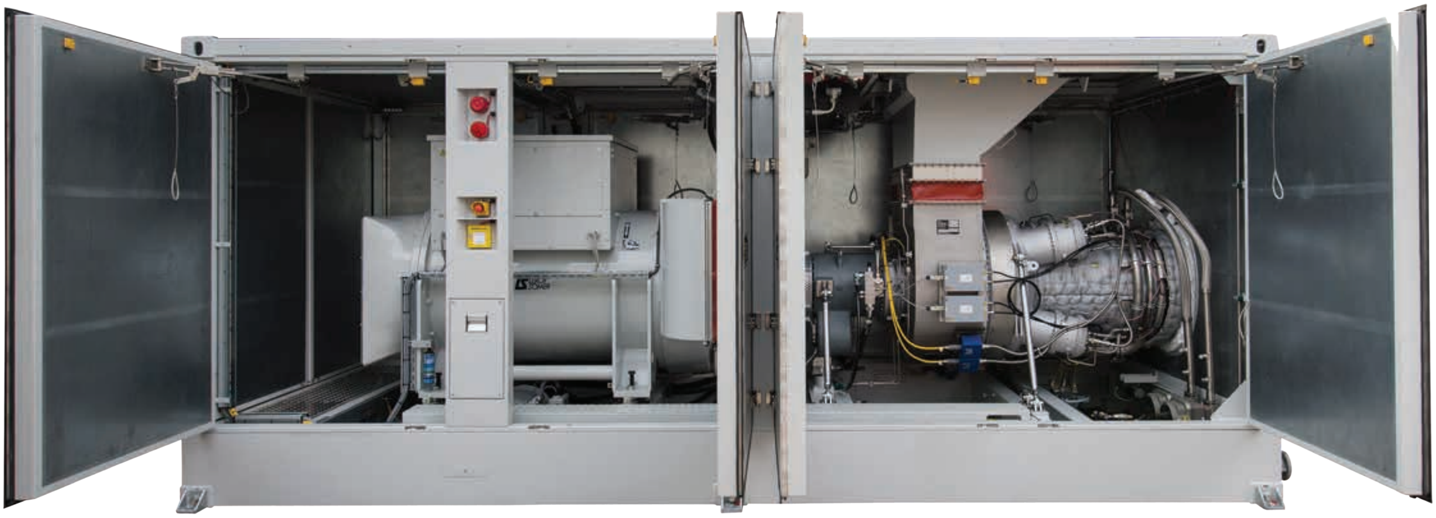
Related links

- Combustion audit

AIREM ENERGY

1.8MW TURBINE GENSETS

Energy Independence Through On-Site Generation



On-Site Generation

Airem Energy’s 1.8MW turbine gensets incorporate OPRA’s OP16 all-radial, single-shaft gas turbine into a compact and robust package for a range of applications. This durable design results in a highly reliable source of electricity and heat to be used in facilities ranging from industrial manufacturing plants to onshore and offshore oil & gas facilities, agricultural facilities, biofuel production plants, and marine applications.

Smarter Solutions

The ever-increasing push for carbon reduction and energy independence requires innovative solutions that can be deployed today. The modern design of our turbine gensets allows industry leaders to achieve these goals through the generation of low-carbon electricity and heat, often resulting in total-site reductions in emissions.

Applications

Industrial and Commercial:

— Pulp and paper
— Food processing
— Chemical
— Automotive

Oil & Gas:

— Flare gas to power
— Onshore sites
— Offshore platforms and FPSOs
— Refineries

Waste to Power:

— Biogas and syngas
— Fertilizer plants
— Landfills
— Pyrolysis oil

Marine:

— Tankers
— VOCs
— Military
— On-board power

Key Features

— Simple, robust, and reliable
— Compact, skid-mounted and sound attenuated
— Operates in extreme environments
— Continuous or intermittent duty
— Fast start and stop
— Integrates with factory control system
— Replaces standby/emergency backup power
— Operates grid-connected or island mode

Fuel Options

High Calorific Gases:

— Natural gas
— Flare gas/wellhead gas
— Propane
— LPG (liquefied petroleum gas)
— Contaminated gas

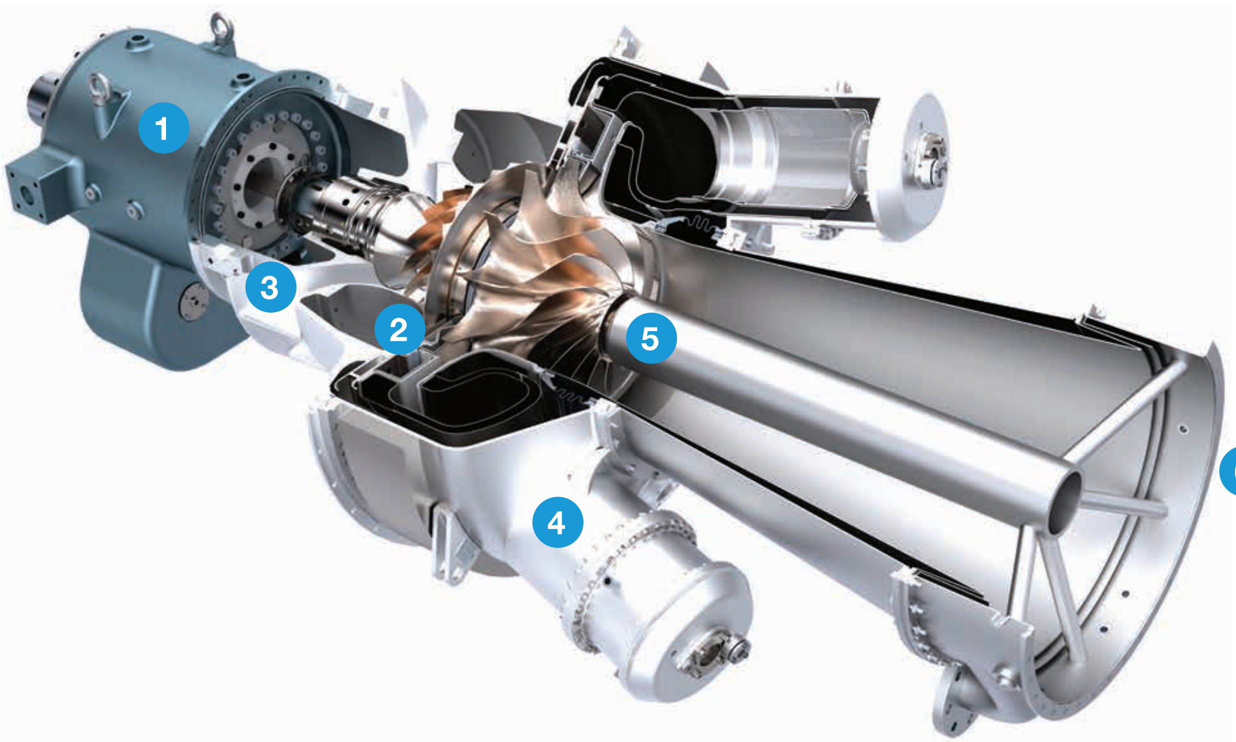
Low and Ultra-Low Calorific Gases:

— Syngas
— Biogas
— VOCs (Volatile Organic Compounds)
— Industrial waste gas

Liquid Fuels:

— Diesel
— Ethanol
— Pyrolysis oil
— Condensate

OPRA OP16 Gas Turbine



1. Reduction gear: Allows the use of compact 4-pole generators for 50 or 60 Hz applications.

2. Compressor: Our low compression ratio allows for direct use of low fuel gas pressures, minimizing the need for external gas compression.

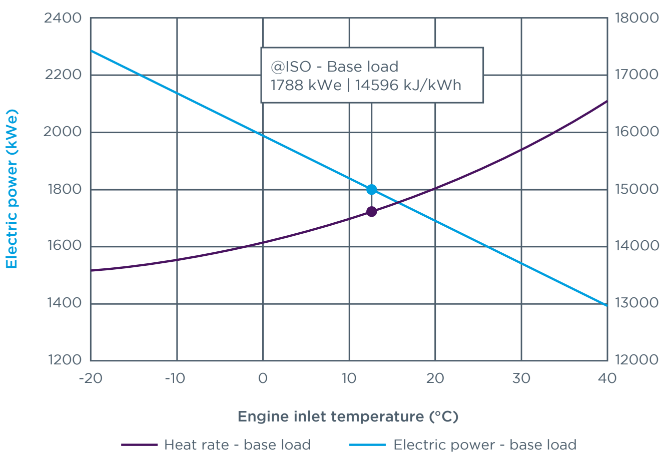
3. Bearings: Bearings in the cold section allow minimal oil consumption and a guaranteed oil-free exhaust

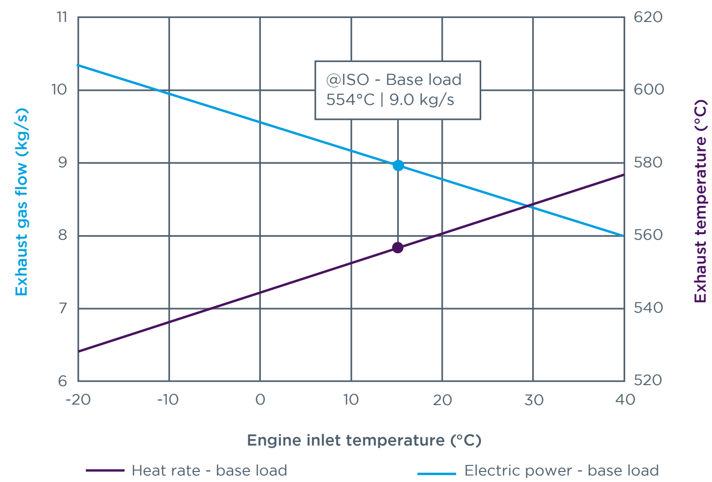
4. Combustors: Can be fitted and exchanged based on fuel requirements. All combustor types are interchangeable.

5. Radial turbine: Allows for high fuel flexibility due to lack of cooling holes and robust forged design.

6. Exhaust: Oil-free and high temperature resulting in clean, oxygen-rich exhaust with high mass flow.

Performance Curves





GENERAL SPECIFICATIONS	
Electrical output (ISO)	1788kWe
Generator voltage	0.4-13.8kV
Total system efficiency	>90%
Time between major overhaul	40,000 hours
Time between minor inspection	8,000 hours
Start and stop time	~3 minutes
Steam generation capacity	13,000 lbs/hr
Fuel consumption (ISO)	25.7 MMBtu/hr
Thermal output (ISO)	18 MMBtu/hr
Heat rate (ISO)	13,661 BTU/kWh
Exhaust gas temperature (ISO)	1064°F
Pressure ratio	6.7:1
Total mass	55,000 - 70,000 lbs

For more information, visit www.airemenergy.com
Contact us at info@airemenergy.com

AIREM ENERGY

3701 10th Street | Brookshire, Texas 77423 USA

APPENDIX C: EMISSIONS INVENTORY

University of Montana

Steam Plant with CHP

Potential to Emit Emissions Inventory - Following Completion of the CHP Project

Source	Annual Steam Production (thousand pounds per year)	Annual Operating Hours	Pollutants									
			NOx (tpy)	CO (tpy)	VOC (tpy)	SO_X (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	Pb (tpy)	CO_2e[1] (Mtpy)	HAPS (tpy)
Combustion Gas Turbines (2) - Natural Gas	613,200	8,760	13.1	12.9	4.22	0.80	1.55	1.55	1.55	-	24,939	8.51E-02
HRSG Duct Burner - Natural Gas		8,760	20.4	19.91	1.96	0.21	2.71	2.71	2.71	1.8E-04	38,619	6.73E-01
Combustion Gas Turbines (2) - Diesel	50,400	720	1.14	0.06	7.9E-03	0.029	0.22	0.22	0.22	2.7E-04		2.38E-02
HRSG Duct Burners - Diesel		720	4.32	1.08	0.07	0.05	0.71	0.71	0.71	2.7E-04		1.53E-02
Boiler #1 - Natural Gas	613,200	8,760	18.8	31.6	2.07	0.23	2.86	2.86	2.86	1.9E-04	40,767	1.72E+00
Boiler #1 - Diesel	40,320	720	1.82	0.91	0.04	0.04	0.36	0.18	0.05			
Boiler #2 - Natural Gas	262,800	8,760	16.1	13.5	0.89	0.10	1.23	1.23	1.23	8.1E-05	17,472	
Boiler #2 - Diesel	21,600	720	1.95	0.49	0.02	0.02	0.20	0.10	0.02	1.2E-04		
Black Start Engine - Diesel		500	1.45	1.45	0.14	2.7E-03	1.7E-02	1.7E-02	1.7E-02		261	2.63E-03
Small Stationary Sources		8,760	8.07	6.74	0.45	0.07	0.61	0.61	0.61		8,690	
Emergency Generators		100	5.14	1.53	0.40	0.32	0.34	0.34	0.34		177	
Full facility-wide PTE after project, burning natural gas.	**1,489,200**		**83.10**	**87.64**	**10.13**	**1.73**	**9.31**	**9.31**	**9.31**	**4.47E-04**	**130,925**	**2.49**
Full facility-wide PTE after project, burning fuel oil.	**112,320**		**23.89**	**12.26**	**1.13**	**0.53**	**2.46**	**2.18**	**1.97**	**6.61E-04**		**0.04**

Notes:

1. Greenhouse gas emissions from the CTG, HRSG duct burners, and #1, #2, and #3 Boilers were estimated assuming they were fired on natural gas for 8,760 hours. Values are Metric tons per year (Mtpy)

University of Montana
Combined Heat and Power Plant
Potential to Emit Emissions Inventory
CHP Plant Fired on Natural Gas

Two Airem Energy OP16-3B Combustion Gas Turbine (CGT) Generator Sets with Dry Low Emission (DLE)
Tulsa Combustion Heat Recovery Steam Generator (HRSG) with single Duct Burner (DB)

Operating hours, turbine - NG	8,760	hr/yr	Potential to emit
Operating hours, duct burner(s) - NG	8,760	hr/yr	
Heating content of NG	1,020	Btu/scf	EPA AP-42, Chapter 1.4 (7/98), section 1.4.1
Maximum Steam Capacity of CHP	70,000	pounds/hr	CTG with DB, or DB alone
Maximum Annual Steam	613,200	thousand pounds/yr from CHP	

CHP Process Information	**Heat Input[1] MMBtu/hr**	**Output Power kWe**	**Heat Rate[2] Btu/kWh**	**Max NG Burned scf/hr**	**Max NG Burned MMscf/yr**
OP16-3B DLE Turbine A	26.8	1,788	14,966	26,275	230.2
OP16-3B DLE Turbine B	26.8	1,788	14,966	26,275	230.2
OP16-3B DLE Turbines Total	**53.6**	**3,576**	**29,932**	**52,549**	**460.3**
HRSG Duct Burner 1	83.0	--	--	81,373	712.8
HRSG Duct Burner 2	0.0	--	--	0	0.0
HRSG Duct Burners Total	**83.0**	**--**	**--**	**81,373**	**712.8**
Maximum Heat Input CHP	**136.6**	--	--	**133,922**	**1173.2**

[1] Single HRSG Duct Burner heat input information, single-pass Ultra Low-NOx burner
[2] The annual average Btu/kWh is listed for the individual turbines (14,966); range 12,987 - 22,388 Btu/kWh

CRITERIA AIR POLLUTANTS - NATURAL GAS

Calculated Emissions	**CGT**			**HRSG DB**			**Total**	**Total**
Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)
SO_2[a]	0.003	0.182	0.80	5.88E-04	0.0488	0.214	0.231	1.012
PM (Total)[b]	0.0066	0.354	1.55	7.45E-03	0.618	2.709	0.972	4.26
PM_{10} (Total)[b]	0.0066	0.354	1.55	7.45E-03	0.618	2.709	0.972	4.26
$PM_{2.5}$ (Total)[b]	0.0066	0.354	1.55	7.45E-03	0.618	2.709	0.972	4.26
CO, all loads[c]	0.055	2.94	12.86	0.055	4.55	19.91	7.48	32.8
NO_X, all loads[d]	0.056	3.00	13.15	0.056	4.65	20.36	7.65	33.5
VOC, all loads [e]	0.018	0.963	4.22	5.39E-03	0.448	1.960	1.41	6.18
Formaldehyde[f]		0.004	0.018	7.35E-05	0.006	0.027	0.0101	0.0443
Pb[a]	ND			4.9E-07	4.1E-05	1.8E-04	4.1E-05	1.8E-04

(a) CGT: AP-42 Table 3.1-2a (4/00). HRSG DB: AP-42 Table 1.4-2.
(b) CGT: AP-42 Table 3.1-2a (4/00) - sum of filterable and condensible; assume $PM_{2.5}$ = PM_{10}. HRSG DB: AP-42 Table 1.4-2.
(c) CGT: Airem Section 4.3 Spreadsheet, CO - 24 ppmvd @ 15% O_2. HRSG DB - 24 ppmvd @ 15% O_2.
(d) CGT: Airem Section 4.3 Spreadsheet, NOx (as NO2) - 15 ppmvd @ 15% O_2. HRSG DB Ultra Low-NOx Burner - 10 ppmvd @ 15% O_2.
(e) CGT: Airem Section 4.3 Spreadsheet, VOC (as propane) - 5 ppmvd @ 15% O_2. HRSG DB - AP-42, Table 1.4-2.
(f) CGT: Airem Section 4.3 Spreadsheet, 0.002 lb/hr. HRSF DB - AP-42 Table 1.4-3.

GREENHOUSE GASES - NATURAL GAS

Calculated Emissions		**CGT**		**HRSG**			**Total**
Pollutant	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)	GWP[c]	CO_2e Emission Rate (MT/yr)[b]
CO_2	117.0	6,270	27,463	9,709	42,526	1	63,492
CH_4	2.20E-03	1.18E-01	0.518	1.83E-01	0.801	25	29.9
N_2O	2.20E-04	1.18E-02	0.0518	1.83E-02	0.0801	298	35.7
						Total CO2e:	63,558
						CGT	24,939
						HRSG	38,619

(a) 40 CFR 98 Tables C-1 and C-2 to Subpart C
(b) Metric tons per year (MT/yr)
(c) Global Warming Potential (GWP); 40 CFR 98, Subpart A, Table A-1

University of Montana
Combined Heat and Power Plant
Potential to Emit Emissions Inventory
CHP Plant Fired on Diesel

Two Airem Energy OP16-3B Gas Turbine Generator Sets with Dry Low Emission (DLE)
Tulsa Combustion Heat Recovery Steam Generator (HRSG) with single Duct Burner (DB)

Operating hours, turbine - Oil	720	hr/yr	
Operating hours, duct burner(s) - Oil	720	hr/yr	30 days, could become permit limit
Heating content of diesel	138,490	Btu/gallon	https://afdc.energy.gov/fuels/fuel_comparison_chart.pdf
Maximum Steam Capacity of CHP	70,000	pounds/hr	Includes GTG and Duct Burners
Maximum Annual Steam	50,400	thousand pounds/yr	

CHP Process Information	**Heat Input[1] MMBtu/hr**	**Output Power kWe**	**Heat Rate[2] Btu/kWh**	**Max Diesel Burned gal/hr**	**Max Diesel Burned gal/yr**
OP16-3B DLE Turbine A	26.8	1,788	14,966		0
OP16-3B DLE Turbine B	26.8	1,788	14,966		0
OP16-3B DLE Turbines Total	**53.6**	**3,576**	**29,932**	**0**	**0**
HRSG Duct Burner 1	83.0	--	--	599	431,511
HRSG Duct Burner 2		--	--	0	0
HRSG Duct Burners Total	**83.0**	**--**	**--**	**599**	**431,511**
Maximum Heat Input CHP	**136.6**	**--**	**--**	**599**	**431,511**

[1] HRSG Duct Burning heat input information from Tulsa Combustion HRSG proposal, TC-16-09-1992-5/22/20, page 7 of 20, both burners fired
[2] The annual average Btu/kWh is listed for the individual turbines fired on NG (14,966); range 12,987 - 22,388 Btu/kWh.
Assumes diesel heat rate = NG heat rate.

CRITERIA AIR POLLUTANTS

Calculated Emissions	**CGT**			**HRSG DB**			**Total**	**Total**
Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)
SO_2[a]	1.52E-03	0.081	0.03	1.54E-03	0.1277	0.046	0.209	0.075
PM (Total)[b]	0.012	0.616	0.22	0.024	1.978	0.712	2.59	0.93
PM_{10} (Total)[b]	0.012	0.616	0.22	0.024	1.978	0.712	2.59	0.93
$PM_{2.5}$ (Total)[b]	0.012	0.616	0.22	0.024	1.978	0.712	2.59	0.93
CO, all loads[c]	3.30E-03	0.18	0.064	0.036	3.00	1.079	3.2	1.14
NO_X, all loads[d]	0.059	3.18	1.14	0.144	11.99	4.315	15.2	5.5
VOC[e]	4.10E-04	0.022	0.008	2.46E-03	0.204	0.073	0.23	0.081
Pb[e]	1.40E-05	7.50E-04	2.70E-04	9.00E-06	7.47E-04	2.69E-04	1.5E-03	5.4E-04

(a) CGT: AP-42 Table 3.1-2a (4/00) - assumes ultra low-sulfur diesel 0.0015 wt%. HRSG DB AP-42 Table 1.3-1.
(b) CGT: AP-42 Table 3.1-2a (4/00) - sum of filterable and condensible; assume $PM_{2.5}$ = PM_{10}. HRSG DB Table 1.3-2.
(c) CGT: AP-42 Table 3.1-1 (4/00), uncontrolled. HRSG DB AP-42 Table 1.3-2
(d) 15 pppm @ 15% oxygen
(e) CGT: AP-42 Table 3.1-2a (4/00). HRSG Table 1.3-3.

University of Montana
Combined Heat and Power Plant
Potential to Emit Emissions Inventory
Black Start Engine

Black Start Engine Generator

Diesel S content	0.0015	%	Ultra low-sulfur diesel
Generator Power Output =	750	kW	
Horsepower =	1,006	bhp	750 kW engine-based estimate
Hours of Operation =	500	hr/yr	Potential permit limit
Max. Fuel Combustion Rate =	7.04	MMBtu/hr	
	50.8	gallon/hr	
Fuel Heating Value=	138,490	Btu/gallon	AP-42 Table 3.1-1 (4/00), footnote f
Avg BSFC =	7000	Btu/hp-hr	AP-42 Table 3.3-1 (10/96), footnote c

Pollutant	Emission Factor	Units[1]	Emission Factor Reference	Potential Emissions (lb/hr)	Potenital Emissions (ton/yr)
PM/PM10/PM2.5	0.04	g/kW-hr	EPA Tier 4	0.066	0.017
NOx	3.5	g/kW-hr	EPA Tier 4	5.787	1.45
CO	3.5	g/kW-hr	EPA Tier 4	5.787	1.45
VOC (Non-methane hydrocarbon)	0.19	g/kW-hr	EPA Tier 4	0.314	0.08
SOx	1.52E-03	lb/MMBtu	AP-42 Table 3.4-1 (10/96)	0.011	2.67E-03
VOC (Non-methane hydrocarbon)	8.19E-02	lb/MMBtu	AP-42 Table 3.4-1 (10/96) & footnote f	0.577	0.14
CO_2	73.96	kg/ MMBtu	40 CFR 98, Subpart C, Table C-1	1,148	287
CH_4	3.0E-03	kg/ MMBtu	40 CFR 98, Subpart C, Table C-2	0.047	0.012
N_2O	6.0E-04	kg/ MMBtu	40 CFR 98, Subpart C, Table C-2	0.009	2.33E-03
CO_2e[2]					288
	Metric tons per year (Mtpy):				261

(1) The EPA Tier emission limits are based on engine power output - see 40 CFR 89 Subpart E.
https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf
(2) Global warming potentials: CO_2 = 1, CH_4 = 25, N_2O = 25, Table A-1 to Subpart A of 40 CFR 98

Existing Boiler Emissions - B1, B2, and B3
Boilers B2 and B3 currently have have dual fuel capability.
After the CHP is installed, B3 will be decommissioned and B1 will have dual fuel capabiliy.

Operational Parameters on NG	Boiler 1	Boiler 2	Boiler 3	
Heat Content of Saturated Steam	1001	1001	1001	Btu/lb, from client previously
Steam Production Capacity on NG	70,000	30,000	70,000	pounds steam per hour
Efficiency on Natural Gas	80%	80%	80%	overall efficiency, from client
Heat Input Capacity on NG	87.6	37.5	87.6	mmBtu/hr, calculated
Natural Gas HHV	1,020	1,020	1,020	Btu/scf, from AP-42 Section 1.4
Natural Gas Combustion Rate	85,898	36,814	85,898	scf/hr, calculated

Future Boiler Operations after CHP Project, Annual Basis				
Hours of Operation, burning NG	8,760	8,760		hours/yr, PTE
Steam Production to Augment CHP	70,000	30,000		pounds per hour, PTE
NG Combustion to Augment CHP	85,898	36,814		scf/hr annual basis
Annual Steam Production after CHP	613,200	262,800		Annual Basis

Future Boiler Emissions after CHP Project, Burning Natural Gas

Pollutant	Emission Factor	Units	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 1 (ton/yr)	Boiler 2 (ton/yr)	Boiler 3 (ton/yr)
NOx(1)	100	lb/mmscf		3.681			16.12	0.00
NOx(1)	50	lb/mmscf	4.295			18.81		0.00
SO_2(2)	0.6	lb/mmscf	0.052	0.022		0.226	0.097	0.00
CO(1)	84	lb/mmscf	7.215	3.092		31.60	13.54	0.00
VOC(2)	5.5	lb/mmscf	0.472	0.202		2.069	0.887	0.00
PM(3)	7.6	lb/mmscf	0.653	0.280		2.859	1.225	0.00
PM_{10}(3)	7.6	lb/mmscf	0.653	0.280		2.859	1.225	0.00
$PM_{2.5}$(3)	7.6	lb/mmscf	0.653	0.280		2.859	1.225	0.00
Pb(2)	0.0005	lb/mmscf	4.29E-05	1.84E-05		1.88E-04	8.06E-05	0.00

(1) EPA AP-42, Table 1.4-1, Small Boilers, Uncontrolled. July 1998. B1 will be retrofitted with LNB.

(2) EPA AP-42, Table 1.4-2, July 1998.

(3) EPA AP-42, Table 1.4-2, all PM is assumed to be less than 1.0 ug, therefore PM emission factors , Small Boilers, Uncontrolled. July 1998.

Future Boiler Greenhouse Gas Emissions after CHP, Primary Fuel Only (natural gas)

Pollutant	Emission Factor	Units	Boiler 1 (ton/yr)	Boiler 2 (ton/yr)	Boiler 3 (ton/yr)	Boiler 1 (MT/yr)	Boiler 2 (MT/yr)	Boiler 3 (MT/yr)
CO_2(1)	117.0	lb/MMBtu	44,891	19,239	0	40,725	17,454	0
CH_4(2)	2.20E-03	lb/MMBtu	0.846	0.363	0.000	0.77	0.33	0.00
N_2O(2)	2.20E-04	lb/MMBtu	0.085	0.036	0.000	0.077	0.033	0.000
		CO_2e(3)				40,767	17,472	0
		Total CO_2e					58,239	

(1) Table C-1, to Subpart C of 40 CFR 98

(2) Table C-2, to Subpart C of 40 CFR 98

(3) Global warming potentials: CO_2 = 1, CH_4 = 25, N_2O = 25, Table A-1 to Subpart A of 40 CFR 98

Future Operations, Existing Boilers Burning Fuel Oil to Augment CHP

Operational Parameters on Fuel Oil	Boiler 1*	Boiler 2	Boiler 3	
Steam Enthalpy Increase	1001	1001		Btu/lb, from client previously
Steam Production Capacity on Fuel Oil	56,000	30,000		pph when burning diesel
Efficiency on Fuel Oil	80%	80%		overall efficiency, from client
Heat Input Capacity on Fuel Oil	70.1	37.5		mmBtu/hr, calculated
Fuel Oil HHV	138,490	138,490		Btu/gallon, afdc.energy.gov
Fuel Oil Combustion Rate	506	271		gallons/hour, calculated
Allowable Hours of Operation on FO	720	720		hrs/yr, will become a permit limit
Annual Steam Production	40,320	21,600		Normal Maximum

* Assume B1 can only reach ~80% of capacity on fuel oil.

Future Boiler Emissions augmenting CHP, burning fuel oil

Pollutant	Emission Factor	Units	Boiler 1 (lb/hr)	Boiler 2 (lb/hr)	Boiler 3 (lb/hr)	Boiler 1 (ton/yr)	Boiler 2 (ton/yr)	Boiler 3 (ton/yr)
NOx(1)	20	$lb/10^3$ gal		5.42			1.95	
	10	$lb/10^3$ gal	5.06			1.82		
SO_2(2)	0.213	$lb/10^3$ gal	0.11	0.058		0.04	0.02	
CO(1)	5	$lb/10^3$ gal	2.53	1.36		0.91	0.49	
VOC(3)	0.2	$lb/10^3$ gal	0.10	0.05		0.04	0.02	
PM(4)	2.00	$lb/10^3$ gal	1.01	0.54		0.36	0.20	
PM_{10}(4)	1.00	$lb/10^3$ gal	0.51	0.27		0.18	0.10	
$PM_{2.5}$(4)	0.25	$lb/10^3$ gal	0.13	0.07		0.05	0.02	
Pb(5)	9	$lb/10^{12}$ Btu	6.31E-04	3.38E-04		2.27E-04	1.22E-04	

(1) EPA AP-42, Table 1.3-1, May 2010.

(2) EPA AP-42, Table 1.3-1, May 2010. Assume ultra low-sulfur Diesel Fuel, sulfur content is 15 ppm, S = 0.0015%.

(3) EPA AP-42, Table 1.3-3, Non-Methane Total Organic Compounds (NMTOC).

(4) EPA AP-42, Table 1.3-6. May 2010.

(5) EPA AP-42, Table 1.3-10. May 2010

University of Montana
Combined Heat and Power Plant
Potential to Emit Emissions Inventory
CHP Plant

HAZARDOUS AIR POLLUTANTS

CGT on Natural Gas	**Heat input:**	53.6	MMBtu/hr
	Annual operating hours:	8,760	hr/yr

Pollutant	**Emission Factor lb/MMBtu**	**lb/hr**	**tpy**	**Notes**
Acetaldehyde	4.0E-05	2.14E-03	9.39E-03	a
Acrolein	6.4E-06	3.43E-04	1.50E-03	a
Benzene	1.2E-05	6.43E-04	2.82E-03	a
Ethylbenzene	3.2E-05	1.72E-03	7.51E-03	a
Formaldehyde	--	4.0E-03	1.75E-02	b
Naphthalene	1.3E-06	6.97E-05	3.05E-04	a
PAH	2.2E-06	1.18E-04	5.16E-04	a
Toluene	1.3E-04	6.97E-03	3.05E-02	a
Xylenes	6.4E-05	3.43E-03	1.50E-02	a
TOTAL HAPS			**8.51E-02**	

[a] CGT on NG. Emission factors from AP-42 Table 3.1-3 (4/00); pollutants not dectected were excluded from this calculation.
[b] Manufacturer emission rate for formaldehyde.

HRSG on Natural Gas	**Heat input:**	83.0	MMBtu/hr
	Annual operating hours:	8,760	hr/yr

Pollutant	**Emission Factor lb/MMscf**	**lb/MMBtu**	**lb/hr**	**tpy**	**Notes**
2-Methylnaphthalene	2.4E-05	2.35E-08	1.95E-06	8.55E-06	c
Benzene	2.1E-03	2.06E-06	1.71E-04	7.48E-04	c
Dichlorobenzene	1.2E-03	1.18E-06	9.76E-05	4.28E-04	c
Fluoranthene	3.0E-06	2.94E-09	2.44E-07	1.07E-06	c
Fluorene	2.8E-06	2.75E-09	2.28E-07	9.98E-07	c
Formaldehyde	7.5E-02	7.35E-05	6.10E-03	2.67E-02	c
Hexane	1.8E+00	1.76E-03	1.46E-01	6.42E-01	c
Naphthalene	6.1E-04	5.98E-07	4.96E-05	2.17E-04	c
Phenanthrene	1.7E-05	1.67E-08	1.38E-06	6.06E-06	c
Pyrene	5.0E-06	4.90E-09	4.07E-07	1.78E-06	c
Toluene	3.4E-03	3.33E-06	2.77E-04	1.21E-03	c
Arsenic	2.0E-04	1.96E-07	1.63E-05	7.13E-05	c
Cadmium	1.1E-03	1.08E-06	8.95E-05	3.92E-04	c
Chromium	1.4E-03	1.37E-06	1.14E-04	4.99E-04	c
Cobalt	8.4E-05	8.24E-08	6.84E-06	2.99E-05	c
Manganese	3.8E-04	3.73E-07	3.09E-05	1.35E-04	c
Mercury	2.6E-04	2.55E-07	2.12E-05	9.27E-05	c
Nickel	2.1E-03	2.06E-06	1.71E-04	7.48E-04	c
TOTAL HAPS				**6.73E-01**	

[c] HRSG on NG. Emission factors from AP-42 Tables 1.4-3 and 1.4-4 (7/98); pollutants below dectection were excluded from this calculation. lb/MMscf converted to lb/MMBtu by dividing by 1,020 MMBtu/MMscf per footnote a.

CGT on Diesel **Heat input:** 53.6 MMBtu/hr
Annual operating hours: 720 hr/yr

Pollutant	Emission Factor lb/MMBtu	lb/hr	tpy	Notes
Benzene	5.5E-05	2.95E-03	1.06E-03	d
Formaldehyde	2.8E-04	1.50E-02	5.40E-03	d
Naphthalene	3.5E-05	1.88E-03	6.75E-04	d
PAH	4.0E-05	2.14E-03	7.72E-04	d
Cadmium	4.8E-06	2.57E-04	9.26E-05	d
Chromium	1.1E-05	5.90E-04	2.12E-04	d
Lead	1.4E-05	7.50E-04	2.70E-04	d
Manganese	7.9E-04	4.23E-02	1.52E-02	d
Mercury	1.2E-06	6.43E-05	2.32E-05	d
TOTAL HAPS			**2.38E-02**	

[d] CGT on diesel; Emission factors from AP-42 Tables 3.1-4 and 3.1-5 (4/00); pollutants below dectection were excluded from this calculation.

HRSG on Diesel **Heat input:** 83.0 MMBtu/hr
Annual operating hours: 720 hr/yr
Heating content of diesel: 138,490 Btu/gallon
https://afdc.energy.gov/fuels/fuel_comparison_chart.pdf

Pollutant	Emission Factor lb/10^3 gal	lb/MMBtu	lb/hr	tpy	Notes
Formaldehyde	6.1E-02	4.40E-04	3.66E-02	1.32E-02	d
Polycyclic organic matter (POM)	3.3E-03	2.38E-05	1.98E-03	7.12E-04	d
Arsenic		4.00E-06	3.32E-04	1.20E-04	d
Beryllium		3.00E-06	2.49E-04	8.96E-05	d
Cadmium		3.00E-06	2.49E-04	8.96E-05	d
Chromium		3.00E-06	2.49E-04	8.96E-05	d
Lead		9.00E-06	7.47E-04	2.69E-04	d
Mercury		3.00E-06	2.49E-04	8.96E-05	d
Manganese		6.00E-06	4.98E-04	1.79E-04	d
Nickel		3.00E-06	2.49E-04	8.96E-05	d
Selenium		1.50E-05	1.25E-03	4.48E-04	d
TOTAL HAPS				**1.53E-02**	

(d) HRSG on diesel; Emission factors from AP-42 Tables 1.3-8 and 1.3-10 (5/10); pollutants below dectection were excluded from this calculation. lb/10^3 gal converted to lb/MMBtu based on diesel heat content

Black Start Engine **Heat input:** 7.0 MMBtu/hr
Annual operating hours: 500 hr/yr

Pollutant	Emission Factor lb/MMBtu	lb/hr	tpy	Notes
Benzene	7.76E-04	5.46E-03	1.37E-03	e
Naphthalene	1.30E-04	9.15E-04	2.29E-04	e
Toluene	2.81E-04	1.98E-03	4.95E-04	e
Xylenes	1.93E-04	1.36E-03	3.40E-04	e
Formaldehyde	7.89E-05	5.56E-04	1.39E-04	e
Acetaldehyde	2.52E-05	1.77E-04	4.44E-05	e
Acrolein	7.88E-06	5.55E-05	1.39E-05	e

TOTAL HAPS	**2.63E-03**

(e) Black Start Engine on diesel;emission factors from AP-42, Table 3.4-3

Existing Boiler Units - Boiler 1, Boiler 2, and Boiler 3 on NG

Operational Parameters on NG	Boiler 1	Boiler 2	Boiler 3	
Heat Input Capacity on NG	87.6	37.5	87.6	mmBtu/hr, calculated
Total heat input, Boilers 1, 2, & 3:	212.8	MMBtu/hr		
Annual operating hours:	8,760	hr/yr		

	Emission Factor				
Pollutant	**lb/MMscf**	**lb/MMBtu**	**lb/hr**	**tpy**	**Notes**
2-Methylnaphthalene	2.4E-05	2.35E-08	5.01E-06	2.19E-05	f
Benzene	2.1E-03	2.06E-06	4.38E-04	1.92E-03	f
Dichlorobenzene	1.2E-03	1.18E-06	2.50E-04	1.10E-03	f
Fluoranthene	3.0E-06	2.94E-09	6.26E-07	2.74E-06	f
Fluorene	2.8E-06	2.75E-09	5.84E-07	2.56E-06	f
Formaldehyde	7.5E-02	7.35E-05	1.56E-02	6.85E-02	f
Hexane	1.8E+00	1.76E-03	3.75E-01	1.64E+00	f
Naphthalene	6.1E-04	5.98E-07	1.27E-04	5.57E-04	f
Phenanthrene	1.7E-05	1.67E-08	3.55E-06	1.55E-05	f
Pyrene	5.0E-06	4.90E-09	1.04E-06	4.57E-06	f
Toluene	3.4E-03	3.33E-06	7.09E-04	3.11E-03	f
Arsenic	2.0E-04	1.96E-07	4.17E-05	1.83E-04	f
Cadmium	1.1E-03	1.08E-06	2.29E-04	1.01E-03	f
Chromium	1.4E-03	1.37E-06	2.92E-04	1.28E-03	f
Cobalt	8.4E-05	8.24E-08	1.75E-05	7.68E-05	f
Manganese	3.8E-04	3.73E-07	7.93E-05	3.47E-04	f
Mercury	2.6E-04	2.55E-07	5.42E-05	2.38E-04	f
Nickel	2.1E-03	2.06E-06	4.38E-04	1.92E-03	f
TOTAL HAPS				**1.72E+00**	

(f) Existing Boilers 1, 2, and 3 on NG. Emission factors from AP-42 Tables 1.4-3 and 1.4-4 (7/98); pollutants below dectection were excluded from this calculation. lb/MMscf converted to lb/MMBtu by dividing by 1,020 MMBtu/MMscf per footnote a.

	lb/hr	tpy
Total HAP[g]:	**0.69**	**2.52**

(g) The total HAP calculation includes potential HAP emissions from all Boilerhouse combustion equipment.

University of Montana
Steam Plant with CHP
Emergency Generators

Diesel Generators

Inputs			Reference	Notes
Operating Hours	100	hours/year	4	
Heat Content of fuel:	0.13849	MMBtu/gallon	5	
Conversion Factor (power output)	1.3407	hp (elec)/kWe	1	
Power output to heat input conversion	7,000	Btu/hp-hr	7	
Pollutant	Emission factor	Units		
NO_X	4.41	lb/MMBtu	6	
CO	0.95	lb/MMBtu	6	
TOC	0.36	lb/MMBtu	6	a
SO_X	0.29	lb/MMBtu	6	
PM_{10}	0.31	lb/MMBtu	6	b

Diesel Generator Location (Building)	**Size (kWe)**	**Engine Power (hp)**	**Heat Input (MMBtu/hr)**	**NO_X (tpy)**	**CO (tpy)**	**TOC (tpy)**	**SO_X (tpy)**	**PM (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**
Adams Center	150	201	1.41	0.31	0.07	0.03	0.02	0.02	0.02	0.02
Chemistry Building	200	268	1.88	0.41	0.09	0.03	0.03	0.03	0.03	0.03
Craig Hall	15	20	0.14	0.03	0.01	0.00	0.00	0.00	0.00	0.00
Curry Health Center	20	27	0.19	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Curry Pump Station	60	80	0.56	0.12	0.03	0.01	0.01	0.01	0.01	0.01
Education New	250	335	2.35	0.52	0.11	0.04	0.03	0.04	0.04	0.04
Elrod hall	5	7	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Facilities Portable	150	201	1.41	0.31	0.07	0.03	0.02	0.02	0.02	0.02
Fine arts	25	34	0.23	0.05	0.01	0.00	0.00	0.00	0.00	0.00
Fitness & Rec Center	75	101	0.70	0.16	0.03	0.01	0.01	0.01	0.01	0.01
Gallagher Building	50	67	0.47	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Heating Plant	175	235	1.64	0.36	0.08	0.03	0.02	0.03	0.03	0.03
ISB/Health Sicence	250	335	2.35	0.52	0.11	0.04	0.03	0.04	0.04	0.04
Mansfield Library	30	40	0.28	0.06	0.01	0.01	0.00	0.00	0.00	0.00
Miller	20	27	0.19	0.04	0.01	0.00	0.00	0.00	0.00	0.00
PARTV	50	67	0.47	0.10	0.02	0.01	0.01	0.01	0.01	0.01
Physical Plant	30	40	0.28	0.06	0.01	0.01	0.00	0.00	0.00	0.00
PJ Washington Ed. Center	250	335	2.35	0.52	0.11	0.04	0.03	0.04	0.04	0.04
Skaggs Addition	200	268	1.88	0.41	0.09	0.03	0.03	0.03	0.03	0.03
Social Sciences	300	402	2.82	0.62	0.13	0.05	0.04	0.04	0.04	0.04
Stadium Lighting	20	27	0.19	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Stadium Lighting	20	27	0.19	0.04	0.01	0.00	0.00	0.00	0.00	0.00
Subtotals:			**22.0**	**4.85**	**1.05**	**0.40**	**0.32**	**0.34**	**0.34**	**0.34**

Natural Gas Generators

Inputs			Reference
Operating Hours	100	hours/year	4
Heat Content of fuel:	1020	Btu/scf	3
Conversion Factor (power output)	1.3407	hp (elec)/kWe	1
Power output to heat input conversion	7,000	Btu/hp-hr	7
Pollutant	Emission Factors	Units	
NO_X	2.21	lb/MMBtu	9
CO	3.72	lb/MMBtu	9
SO_2	5.88E-04	lb/MMBtu	9
CPM	9.91E-03	lb/MMBtu	9
PM_{10} (filterable)	9.50E-03	lb/MMBtu	9
$PM_{2.5}$ (filterable)	9.50E-03	lb/MMBtu	9
VOC	2.96E-02	lb/MMBtu	9
Power Conversion	3413	Btu/kW-hr	1

Natural Gas Generator Location (Building)	Size (kWe)	Engine Power (hp)	Heat Input (MMBtu/hr)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_X (tpy)	PM[c] (tpy)	PM_{10}[c] (tpy)	$PM_{2.5}$[c] (tpy)
Aber Hall	30	40.22	0.282	0.03	0.05	4.17E-04	8.28E-06	2.73E-04	2.73E-04	2.73E-04
Anderson Hall	35	46.92	0.328	0.04	0.06	4.86E-04	9.66E-06	3.19E-04	3.19E-04	3.19E-04
Jesse Hall	10	13.41	0.094	0.01	0.02	1.39E-04	2.76E-06	9.11E-05	9.11E-05	9.11E-05
Native American Center	30	40.22	0.282	0.03	0.05	4.17E-04	8.28E-06	2.73E-04	2.73E-04	2.73E-04
Skaggs Complex	100	134.07	0.938	0.10	0.17	1.39E-03	2.76E-05	9.11E-04	9.11E-04	9.11E-04
Todd Building	20	26.81	0.188	0.02	0.03	2.78E-04	5.52E-06	1.82E-04	1.82E-04	1.82E-04
University Center	55	73.74	0.516	0.06	0.10	7.64E-04	1.52E-05	5.01E-04	5.01E-04	5.01E-04
Subtotals:			**2.63**	**0.29**	**0.49**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes

a. Sum of Exhaust and Crankcase emission factors in Table 3.3-1
b. Per EPA AP-42 Table 3.3-1, all particulate is assumed to be ≤1 µm
c. Total PM emissions are the sum of filterable "front-half" emissions and condensible "back-half" emissions

References

1. AP-42 Appendix A
2. Reserved
3. AP-42 3.2. Table 3.2-3 (7/00), footnote b
4. Assumed permit limit for non-emergency operation
5. Table C-1, 40 CFR 98.3 Subpart C General Stationary Fuel Combustion Sources
6. EPA AP-42 Table 3.3-1 (10/96); note the SOx emission estimate is highly conservative since only ULSD is not available
7. AP-42 Table 3.3-1, footnote a (10/96)
8. Caterpillar Power Systems sample specification sheets for generators 12kWe through 1000kWe
9. AP-42 3.2. Table 3.2-3 (7/00), 4SRB
10. EPA AP-42 Table 1.4-2 (7/98)

Greenhouse Gases - All Emergency Generators

Calculated Emissions	Diesel			Natural Gas				Total	Total
Pollutant	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	GWP[c]	CO_2e Emission Rate (tpy)	CO_2e Emission Rate (Mtpy)[b]
CO_2	163.1	3,588	179	117.0	307	15	1	195	177
CH_4	6.61E-03	1.46E-01	7.28E-03	2.20E-03	5.79E-03	2.90E-04	25	0.2	0.17
N_2O	1.32E-03	2.91E-02	1.46E-03	2.20E-04	5.79E-04	2.90E-05	298	0.4	0.40
							Total CO_2e:	195	177

(a) 40 CFR 98 Tables C-1 and C-2 to Subpart C
(b) Metric tons per year (Mtpy)
(c) Global Warming Potentials (GWPs); 40 CFR 98, Subpart A, Table A-1

University of Montana
Steam Plant with CHP
Small Stationary Combustion Sources

Natural Gas-Fired Small Sources

Inputs			Reference
Operating Hours	8760	hrs/yr	
Heat Content of fuel:	1020	Btu/scf	2

Emission Factors			Reference
Pollutant		Units	
NOx	100	lb/10^6 scf	1
CO	84	lb/10^6 scf	1
SO2	0.6	lb/10^6 scf	3
PM (Total)	7.6	lb/10^6 scf	3
VOC	5.5	lb/10^6 scf	3

Emission Rate Calculations

Source	Location	Heat Input (MMBtu/hr)	Fuel Flow (scf/hr)	Fuel Flow (MMscf/yr)	NOX (tpy)	CO (tpy)	VOC (tpy)	SOx (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
Lochinvar Boiler	Prescott House	0.14	137	1.2	0.06	0.05	0.003	0.000	0.005	0.005	0.005
Applied Air direct fired MAU	Chem Stores	0.77	755	6.6	0.33	0.28	0.018	0.002	0.025	0.025	0.025
Applied Air direct fired MAU-1	University Center	2.6	2532	22.2	1.11	0.93	0.061	0.007	0.084	0.084	0.084
Applied Air direct fired MAU-2	University Center	3.5	3453	30.2	1.51	1.27	0.083	0.009	0.115	0.115	0.115
Commercial Kitchen Appliances	University Center	3.6	3513	30.8	1.54	1.29	0.085	0.009	0.117	0.117	0.117
Commercial Kitchen Appliances	Lommenson Center	2.3	2208	19.3	0.97	0.81	0.053	0.006	0.073	0.073	0.073
Commercial Kitchen Appliances	WGS North Skybox	0.56	549	4.8	0.24	0.20	0.013	0.001	0.018	0.018	0.018
Unit heaters (4)	Wash. Griz Stadium WGS	0.16	157	1.4	0.07	0.06	0.004	0.000	0.005	0.005	0.005
Hot water Heaters (2)	Wash. Griz Stadium WGS	0.36	353	3.1	0.15	0.13	0.009	0.001	0.012	0.012	0.012
Applied Air direct fired MAU	Wash. Griz Stadium WGS	0.45	444	3.9	0.19	0.16	0.011	0.001	0.015	0.015	0.015
Aaon RTU	Wash. Griz Stadium WGS	0.34	335	2.9	0.15	0.12	0.008	0.001	0.011	0.011	0.011
Unimac Dryers (2)	Athletics Equipment	0.6	588	5.2	0.26	0.22	0.014	0.002	0.020	0.020	0.020
Unit Heaters (2)	Labor Shop	0.28	270	2.4	0.12	0.10	0.006	0.001	0.009	0.009	0.009
Hot water Heater	Labor Shop	0.04	39	0.3	0.02	0.01	0.001	0.000	0.001	0.001	0.001
Unit Heater	Pesticide Storage	0.03	29	0.3	0.01	0.01	0.001	0.000	0.001	0.001	0.001
Unit Heaters (3)	Vehicle Shop	0.4	392	3.4	0.17	0.14	0.009	0.001	0.013	0.013	0.013
Unit Heaters (3)	Bus Barn	0.23	221	1.9	0.10	0.08	0.005	0.001	0.007	0.007	0.007
Geil #1	Art Annex (Indoor)	0.20	196	1.7	0.09	0.07	0.005	0.001	0.007	0.007	0.007
Geil #2	Art Annex (Indoor)	0.10	98	0.9	0.04	0.04	0.002	0.000	0.003	0.003	0.003
Kilns (4)	Art Annex (Outdoor)	1.2	1176	10.3	0.52	0.43	0.028	0.003	0.039	0.039	0.039
Foundery	Art Annex	0.25	245	2.1	0.11	0.09	0.006	0.001	0.008	0.008	0.008
Reheat Kiln	Art Annex	0.15	147	1.3	0.06	0.05	0.004	0.000	0.005	0.005	0.005
Subtotal		18.2			**7.8**	**6.6**	**0.43**	**0.05**	**0.59**	**0.59**	**0.59**

Propane-Fired Small Sources

Assumptions			Reference	Notes
Sulfur content of propane	10	gr/100 cu.ft.	10	a

Inputs			Reference
Operating Hours	8760	hrs/yr	
Heat Content of fuel:	91.5	MMBtu/1000 ga	9

Emission Factors			Reference
Pollutant		Units	
NOx	13	lb/1000 gal	4
CO	7.5	lb/1000 gal	4
SO2	1.0	lb/1000 gal	4
PM (Total)	0.7	lb/1000 gal	4
VOC/TOC	1.0	lb/1000 gal	4

Emission Rate Calculations

Source	Location	Heat Input (MMBtu/hr)	Fuel Use (gallons/hr)	Fuel Use (10^3 gal/yr)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_X (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
Propane Pizza ovens (3)	WGS concessions	0.405	4.4262	38.8	**0.25**	**0.15**	**0.019**	**0.019**	**0.014**	**0.014**	**0.014**

Coke Retorts

Assumptions

		Reference
Sulfur Content of Coal	1 Weight %	Conservative Estimate
Heat Content of Coal	8500 Btu/lb	PRB average

Inputs

		Reference
Fuel input	400 lb/year	Conservative Estimate
	0.2 tons/year	

Emission Factors

Pollutant		Reference
NOx	9.1 lb/ton	7
CO	275 lb/ton	7
SO2	31 lb/ton	7
FPM (Total)	15 lb/ton	7
FPM-10	6.2 lb/ton	7
CPM	0.04 lb/MMBtu	12
VOC/TOC	10 lb/ton	13

Emission Rate Calculations

Source	Location	Heat Input (MMBtu/yr)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_X (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
Coke Retorts (3)	Art Annex Appliance	3.40	**9.10E-04**	**0.028**	**1.00E-03**	**3.10E-03**	**1.57E-03**	**6.88E-04**	**6.88E-04**

Notes:
a. HD-5 propane assumed to be combusted, most commonly sold grade of propane in US. See https://www.propane101.com/propanegradesandquality.htm

References:

1. EPA AP-42 Table 1.4-1 (7/98)
2. EPA AP-42 Section 1.4.1 (7/98)
3. EPA AP-42 Table 1.4-2 (7/98)
4. EPA AP-42 Table 1.5-1 (7/08)
5. Reserved
6. Engineering Toolbox: http://www.engineeringtoolbox.com/classification-coal-d_164.html
7. EPA AP-42 Tables 1.1-3 and 1.1-4 (9/98), Hand-fed units
8. Reserved
9. EPA AP-42, Chapter 1.5, Section 1.5.3.1 (7/08)
10. https://www.ourair.org/wp-content/uploads/sulfur01.pdf
11. Reserved
12. EPA AP-42 Table 1.1-5 (9/98)

Greenhouse Gases - All Small Stationary Sources

Calculated Emissions	**Natural Gas**			**Propane**			**Coke**				**Total**	**Total**
Pollutant	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Factor[a] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)	GWP[c]	CO_2e Emission Rate (tpy)	CO_2e Emission Rate (Mtpy)[b]
CO_2	117.0	2,128	9,322	138.6	56	246	250.6	9.73E-02	4.26E-01	1	9,569	8,681
CH_4	2.20E-03	4.01E-02	1.76E-01	6.61E-03	2.68E-03	1.17E-02	2.43E-02	9.41E-06	4.12E-05	25	4.7	4.3
N_2O	2.20E-04	4.01E-03	1.76E-02	1.32E-03	5.36E-04	2.35E-03	3.53E-03	1.37E-06	6.00E-06	298	5.9	5.4
										Total CO_2e:	9,579	8,690

(a) 40 CFR 98 Tables C-1 and C-2 to Subpart C
(b) Metric tons per year (Mtpy)
(c) Global Warming Potentials (GWPs); 40 CFR 98, Subpart A, Table A-1

University of Montana
Steam Plant with CHP

Small Stationary Combustion Sources and Emergency Generators PTE Total

	NO_X (tpy)	CO (tpy)	TOC/VOC (tpy)	SO_X (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
Diesel Generators	4.85	1.05	0.40	0.32	0.34	0.34	0.34
Natural Gas Generators	0.29	0.49	0.00	0.00	0.00	0.00	0.00
Natural Gas-Fired Small Sources	7.81	6.56	0.43	0.05	0.59	0.59	0.59
Propane-Fired Small Sources	0.25	0.15	0.02	0.02	0.01	0.01	0.01
Coke Retorts	9.10E-04	2.75E-02	1.00E-03	3.10E-03	1.57E-03	6.88E-04	6.88E-04
	13.21	8.27	0.85	0.39	0.95	0.95	0.95
Generators	5.14	1.53	0.40	0.32	0.34	0.34	0.34
Small Sources	8.07	6.74	0.45	0.07	0.61	0.61	0.61

APPENDIX D: NSPS SUBPART KKKK REGULATORY ANALYSIS

Code of Federal Regulations Title 40: Protection of Environment
Part 60—Standards of Performance for New Stationary Sources
Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

SOURCE: 71 FR 38497, July 6, 2006, unless otherwise noted.

INTRODUCTION

§60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

APPLICABILITY

§60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

UM is proposing two combustion turbines with rated capacity of 26.8 MMBtu/hr. This subpart applies to each turbine.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

This is noted.

§60.4310 What types of operations are exempt from these standards of performance?

No exemptions apply to UM.

EMISSION LIMITS

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

The project will meet the applicable NOx limits in Table 1 (below).

§60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

The turbines burn natural gas or diesel independently. The corresponding limits will be met for each fuel.

§60.4330 What emission limits must I meet for sulfur dioxide (SO2?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

The UM turbine emissions convert to 0.000065 lb/MWh.

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

The natural gas sulfur content is less than 0.0017 lb/MMBtu. The ultra low sulfur diesel will have less than or equal to 0.00077 lb/MMBtu.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

GENERAL COMPLIANCE REQUIREMENTS

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

UM will meet this requirement.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

UM intends to determine compliance (source testing) at the outlet of the heat recover unit for the turbines and the HRSG duct burner. The details will be provided in a source testing protocol which will be submitted prior to the planned initial source test date.

MONITORING

§60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

The UM project does not use water or steam injection.

§60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_x emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_x emission result from the performance test is less than or equal to 75 percent of the NO_x emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_x emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_x formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_x mode.

UM is proposing lean premix stationary combustion turbines. Following the initial compliance test, UM will continuously monitor operating parameters to determine whether the unit is operating in low-NOx mode. UM will submit a monitoring plan as required.

(iii) For any turbine that uses SCR to reduce NO_x emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

The UM turbines will not use SCR.

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option? _N/A_

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions? _N/A_

§60.4355 How do I establish and document a proper parameter monitoring plan?

NSPS Subpart A General Provisions §60.8 requires an initial performance test. UM will collect monitoring parameter data during the test. UM will develop and implement the required parameter monitoring plan.

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_x emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_x emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

UM will maintain the required records for verifying sulfur content of the natural gas and diesel fuel used in the CHP.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas.

UM will elect not to monitor the total sulfur content of the fuel.

§60.4370 How often must I determine the sulfur content of the fuel?

UM will maintain the required records for verifying sulfur content of the natural gas and diesel fuel used in the CHP.

REPORTING

§60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

UM will prepare and submit the required reports for compliance monitoring.

§60.4380 How are excess emissions and monitor downtime defined for NOX?

UM will follow these requirements.

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§60.4385 How are excess emissions and monitoring downtime defined for SO2?

UM will not monitor fuel sulfur.

§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine? *N/A*

§60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

UM will provide a source testing protocol prior to the initial performance test.

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Details omitted.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3)…

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If…

(6) The ambient temperature must be greater than 0 °F during the performance test.

§60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS? N/A

§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

UM will comply with fuel sulfur monitoring and recordkeeping.

DEFINITIONS

§60.4420 What definitions apply to this subpart? *Applicable Definitions.*

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight

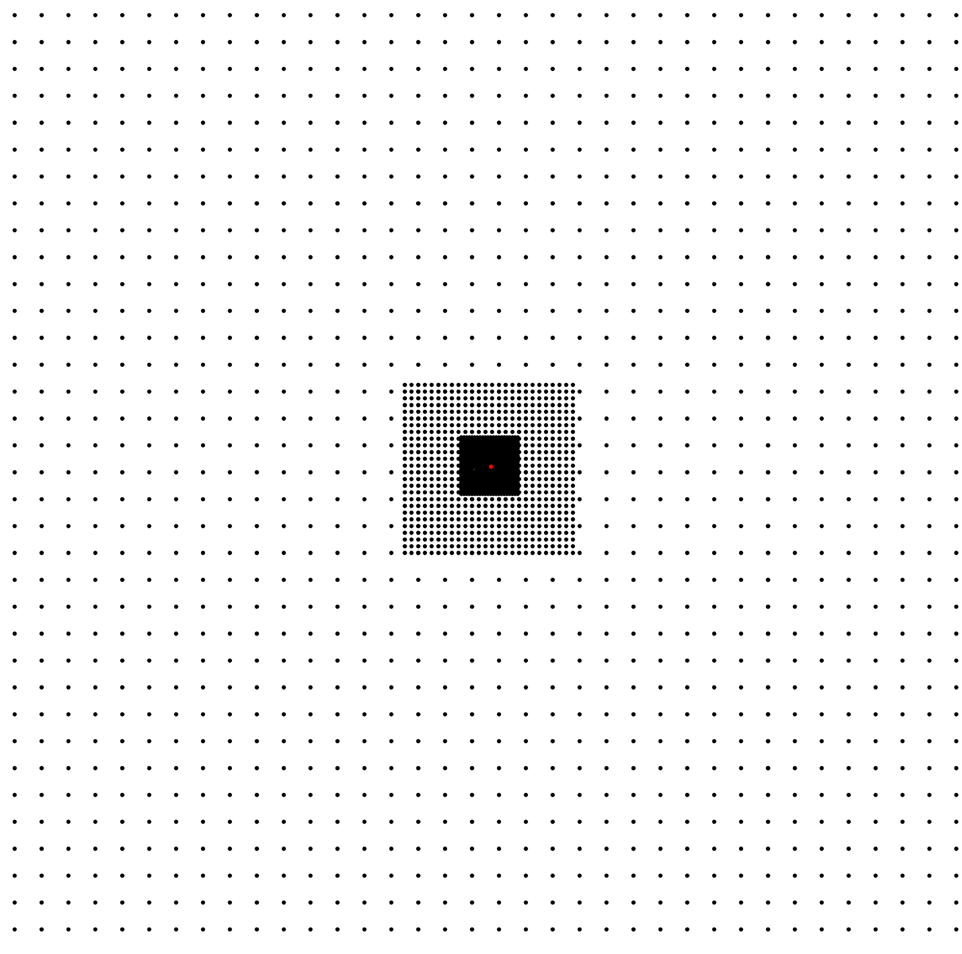
[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines Applicable Standards

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_x emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

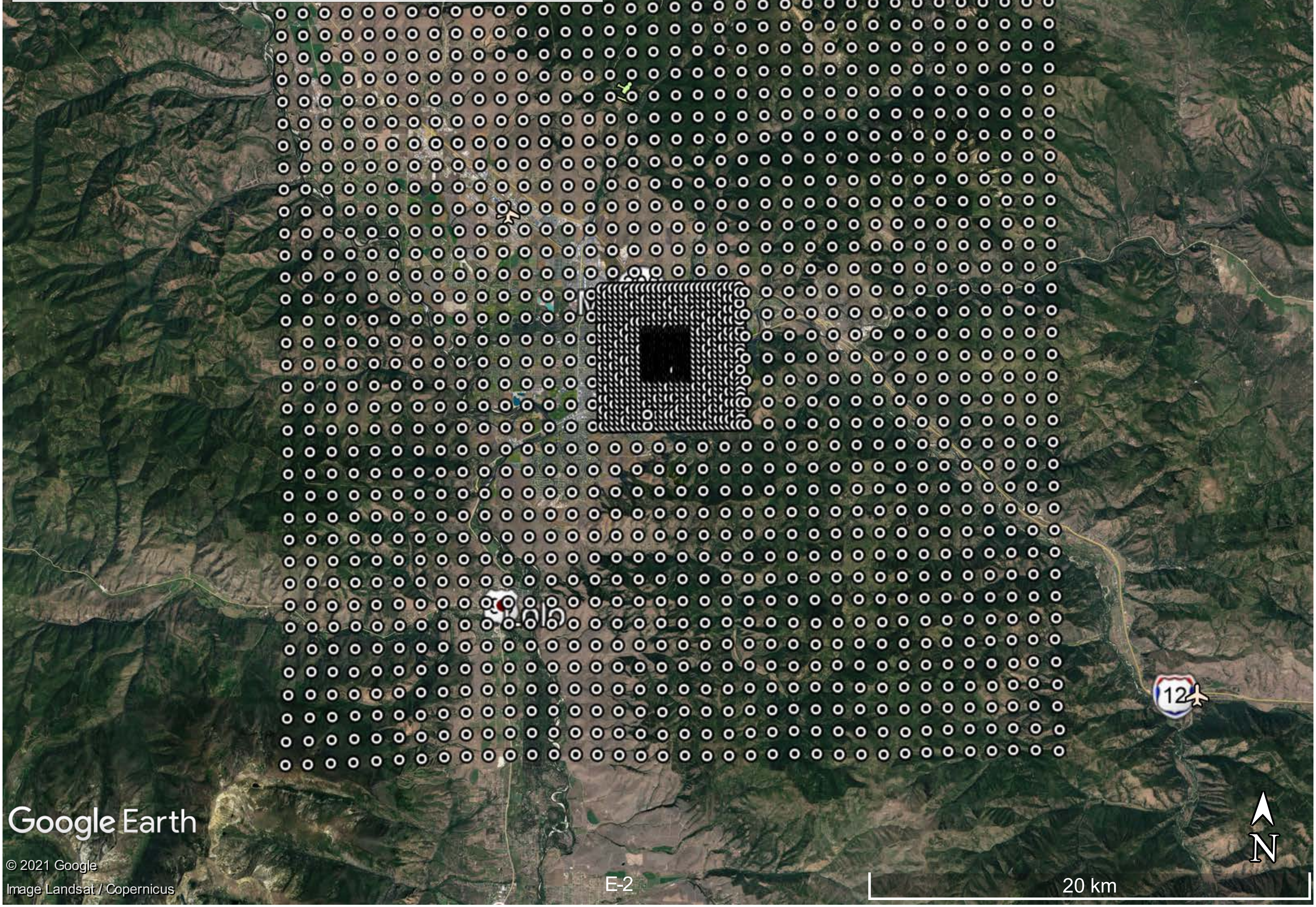
APPENDIX E: MODELING FIGURES

Full Receptor Grid for SIL Modeling

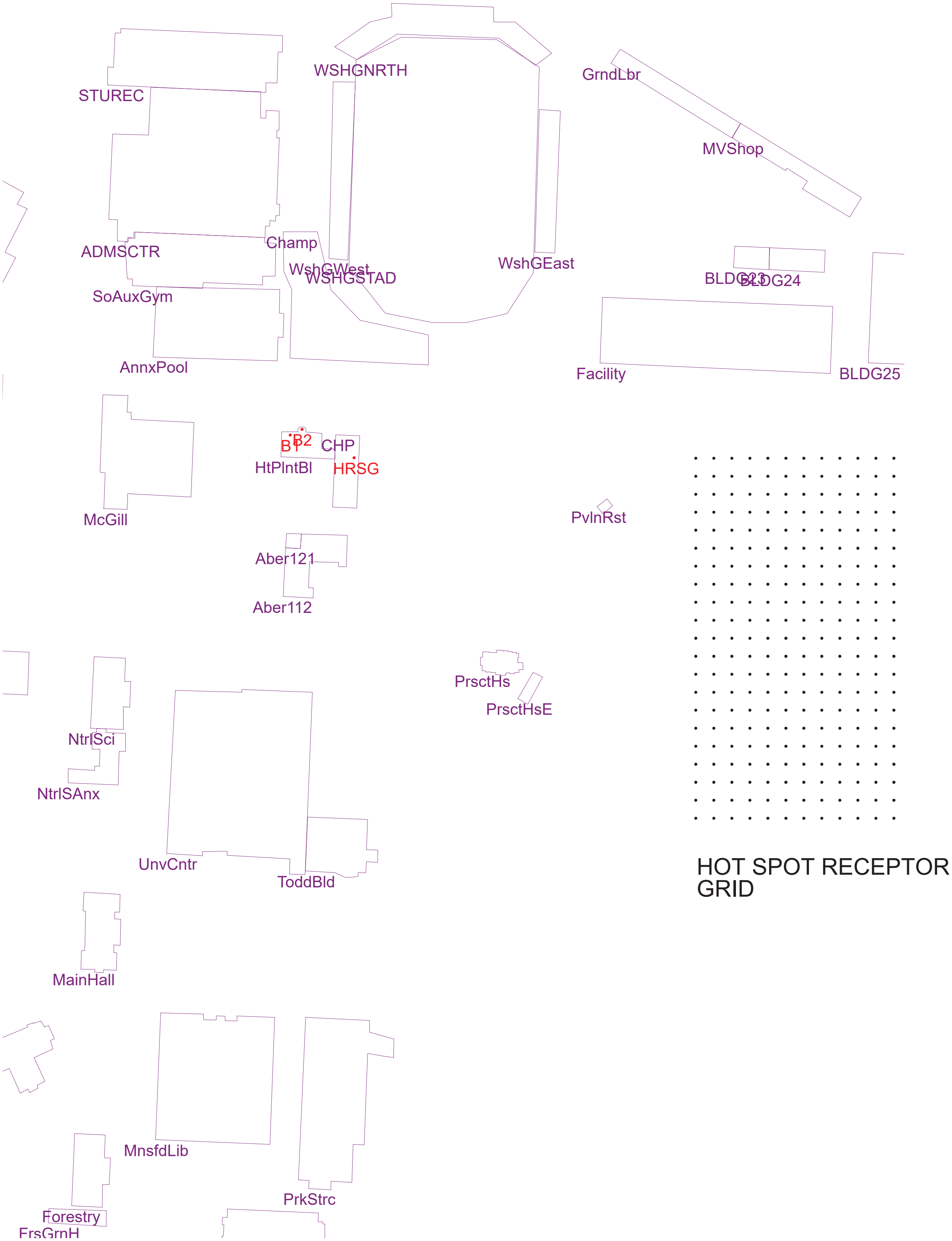


Scale: 1" = 7136.6 Meters

Receptors for UM Heating Plant Model



NO2 1-hour Average - Hot Spot Receptors



Scale: 1" = 77.0 Meters

APPENDIX F: METEOROLOGICAL DATA PROCESSING

Meteorological Data Processing Summary for
Modeling UM Heating Plant– Missoula, Montana

Bison Engineering, Inc. has processed a meteorological data set for the five-year period of 2015 – 2019 within the AERMET pre-processor. This dataset is used in the AERMOD modeling system for air dispersion modeling on behalf of McKinstry and the University of Montana (UM) for the UM heating plant at the campus in Missoula, Montana.

The following observational meteorological data were used in this analysis:

Surface Data: Missoula, MT, Station KMSO
Upper Air Data: Great Falls, MT, Station KTFX

Selection of Surface Data:

AERMET utilizes surface meteorological data files to provide information on wind speed and direction, ambient temperature, and cloud cover. These parameters are used to estimate dispersion parameters within AERMOD. Meteorological data is available at the Missoula International Airport ASOS site in Missoula, MT. The station is located roughly 7 miles northwest of the campus. Station metadata is provided in Table 1.

Table 1: KMSO Surface Meteorological Station Metadata

Location	Station Type	Call Name	WBAN	Lat	Lon	Elev. (ft)
Missoula International Airport, Missoula, Montana	ASOS	KMSO	24153	45.9208	-114.094	3,197

The following information describes the qualifications of an ASOS meteorological station:

Automated Surface Observing System (ASOS) units are operated and controlled cooperatively in the United States by the NWS, FAA, and DOD. ASOS systems generally report at hourly intervals, but also report special observations if weather conditions change rapidly and cross aviation operation thresholds. Besides serving commercial aviation needs, the ASOS serves as a primary climatological observing network in the United States, designated as the first-order network of climate stations. The program supports forecast activities, aviation operations, and the needs of the meteorological, hydrological, and climatological research communities. The ASOS stations provide a more complete data record and are generally subjected to more rigorous quality assurance.

Data Processing:

National Weather Service (NWS) surface data from the Missoula Airport meteorological station, KMSO, were downloaded from the National Climatic Data Center (NCDC) website in standard ISHD format for the years 2015, 2016, 2017, 2018, and 2019.[1] The dataset was processed prior to the completion of 2020. One-minute ASOS data were also collected for KMSO from the NCDC site in monthly files for the same five-year period.

The upper air soundings required by AERMET were collected at the Great Falls, MT meteorological station, KTFX (WBAN 24143). Data were downloaded from the radiosonde data website in standard FSL format.[2]

Land Use data were collected in 1992 NLCD format from the Interim Access data repository on the EPA Support Center for Regulatory Atmospheric Modeling website.[3] AERSURFACE currently only supports data in the 1992 format.

The latest EPA-recommended versions of the modeling programs were used, which include:

AERMET Version 19191
AERMINUTE Version 15272
AERSURFACE Version 13016

Average site precipitation data for use in AERSURFACE was based on thirty years of met data for the AERSURFACE analysis (1989 – 2019). Moisture data was accessed through the NOAA Climate Data Online Search tool.[4] A summary of the moisture data findings is listed in the Tables 2 and 3 below. Average conditions occurred in years 2016, 2017, and 2019. While dry conditions occurred in 2015 and wet conditions in 2018. Continuous snow cover for extended periods was evident from examination of local climatological records for the last five years and was assessed in the processing.

Table 2: Missoula Airport (KMSO) 30-Year Moisture Analysis (1988 – 2018)

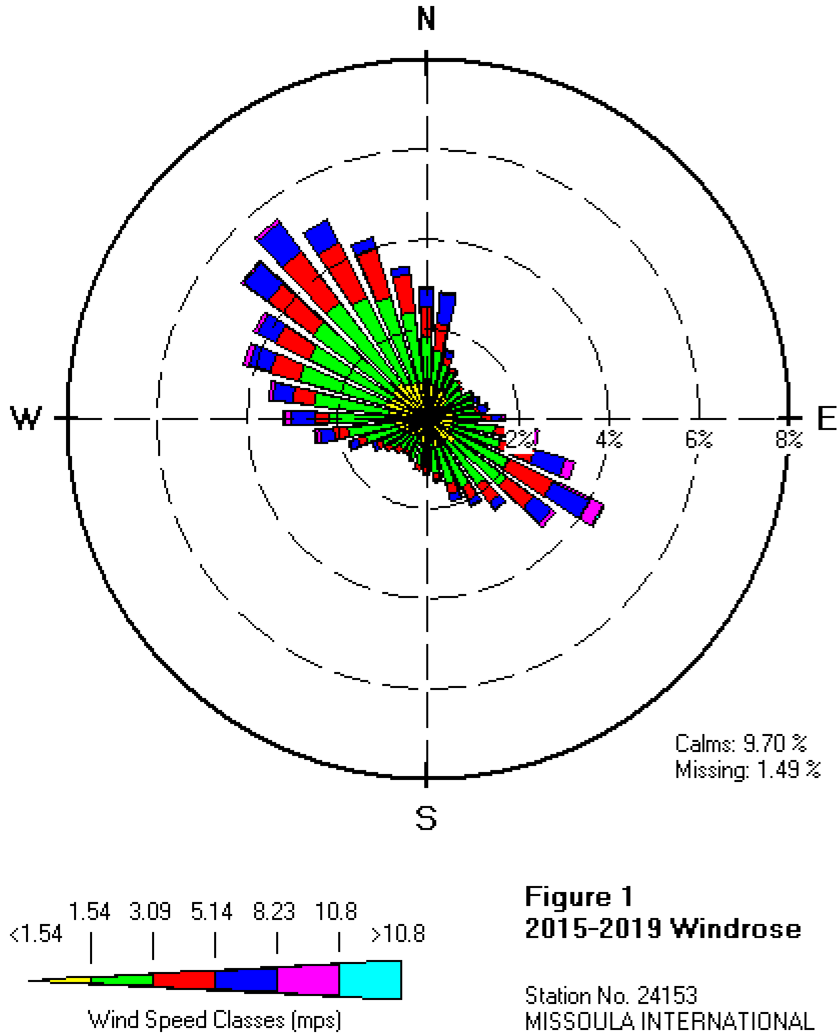
Data Representation	Value (inches)
30-Year Mean	14.08
30th Percentile	12.43
70th Percentile	15.27

1) NCDC data located at ftp://ftp.ncdc.noaa.gov/pub/data/noaa/
2) Radiosonde data located at http://esrl.noaa.gov
3) LULAC92 interim access at https://www.epa.gov/scram/interim-access-and-process-use-1992-nlcd-and-ned
4) Moisture data access at https://www.ncdc.noaa.gov/cdo-web/search

Table 3: Missoula Airport (KMSO) AERSURFACE Moisture Summary

Year	Total (inches)	AERSURFACE Rating
2015	10.11	Dry
2016	14.06	Average
2017	15.27	Average
2018	16.01	Wet
2019	15.15	Average

The met data have been processed without the ADJ_U* switch enabled. Calm distribution the five-year period is 1%. Missing data accounts for approximately 4% of the data period. Wind roses from the 5 years of *.SCF files generated by AERMAP are included below.



Note: Diagram of the frequency of occurrence of each wind direction.

Met File Type: AERMET SFC
File: MSO_2015_2019.SFC

Figure 1
2015-2019 Windrose

Station No. 24153
MISSOULA INTERNATIONAL AIRPOR, MT
Period: 1/1/2015 - 12/31/2019