Statement of Basis

Permit to Construct No. P-2021.0030
Project ID 62655

Riverbend Meats, LLC
Idaho Falls, Idaho

Facility ID 019-00107

Final

December 21, 2021
Aaron Hoberg
Permit Writer



The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

TABLE OF CONTENTS

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE....3
FACILITY INFORMATION....4
Description....4
Permitting History....4
Application Scope....4
Application Chronology....4
TECHNICAL ANALYSIS....5
Emissions Units and Control Equipment....5
Emissions Inventories....5
Ambient Air Quality Impact Analyses....12
REGULATORY ANALYSIS....12
Attainment Designation (40 CFR 81.313)....12
Facility Classification....12
Permit to Construct (IDAPA 58.01.01.201)....13
Tier II Operating Permit (IDAPA 58.01.01.401)....13
Visible Emissions (IDAPA 58.01.01.625)....13
Standards for New Sources (IDAPA 58.01.01.676)....13
Particulate Matter – New Equipment Process Weight Limitations (IDAPA 58.01.01.701)....13
Rules for Control of Odors (IDAPA 58.01.01.775)....14
Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)....14
PSD Classification (40 CFR 52.21)....14
NSPS Applicability (40 CFR 60)....15
NESHAP Applicability (40 CFR 61)....19
MACT/GACT Applicability (40 CFR 63)....19
Permit Conditions Review....20
PUBLIC REVIEW....24
Public Comment Opportunity....24
APPENDIX A – EMISSIONS INVENTORIES
APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES
APPENDIX C – FACILITY DRAFT COMMENTS
APPENDIX D – PROCESSING FEE

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
Btu	British thermal units
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
GACT	Generally Available Control Technology
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAH	polyaromatic hydrocarbons
PC	permit condition
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
T/yr	tons per consecutive 12 calendar month period
TAP	toxic air pollutants
VOC	volatile organic compounds

FACILITY INFORMATION

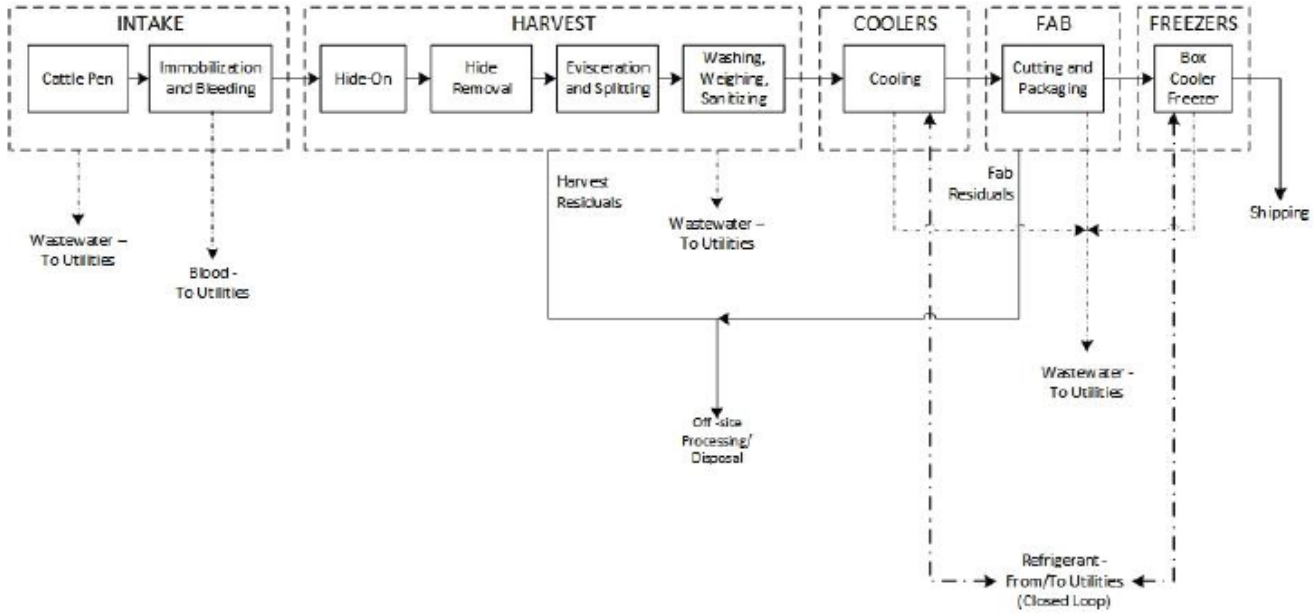
Description

Riverbend Meats, LLC has proposed a new beef processing facility near Idaho Falls, ID. The facility will process up to 600 head of cattle per day with site production activities including: animal intake, harvest and carcass handling, fabrication, cold storage, shipping, steam production combustion of biogas produced in anaerobic digestion, ammonia refrigeration, natural gas fired emergency generator, and building heating and cooling.

Emission sources include twenty natural gas fired air make-up units, digester gas and/or natural gas combustion in two process boilers and a flare, and one emergency generator. Treated wastewater will be used as irrigation water on land owned and controlled by Riverbend.

The facility will be in Bonneville County, west of Idaho Falls near the intersection of West Broadway Street and South 85th West.

Below is a process flow diagram for the facility.



Permitting History

This is the initial PTC for a new facility thus there is no permitting history.

Application Scope

This permit is the initial PTC for this facility.

The applicant has proposed to:

- Install and operate a new beef processing facility.

Application Chronology

June 24, 2021	DEQ received an application and an application fee.
June 29 – July 14, 2021	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
July 27, 2021	DEQ determined that the application was incomplete.

August 9, 2021	DEQ received supplemental information from the applicant.
September 7, 2021	DEQ determined that the application was complete.
November 15, 2021	DEQ made available the draft permit and statement of basis for peer and regional office review.
November 17, 2021	DEQ made available the draft permit and statement of basis for applicant review.
November 22, 2021	DEQ received the permit processing fee.
December 14, 2021	DEQ received comments on the draft permit.
December 21, 2021	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source ID No.	Sources	Control Equipment	Emission Point ID No.
1	Air Make-Up Units (20): Total Firing Rate: 16.561 MMBtu/hr Burner Model: Midco 2/2A Fuel: Natural Gas	Low NO_x burners	N/A
2	Anaerobic Digester: Max Digester gas generation: 400,000 scf/day Average gas generation: 203,000 scf/day	Varec Biogas Flare: Model: 244W Rated Capacity: 22,250 scf/hr Fuel: Digester Gas	Varec Biogas Flare Stack: Height: 15 ft Diameter: 19 inches Temperature: 1,832 °F Flow Rate: 65.6 ft/s Orientation: Vertical
	Boiler #1: Manufacturer: Cleaver-Brooks Model: CBEX Elite Max Rating: 35.7 MMBtu/hr Fuel: Natural Gas/Digester Gas Boiler #2: Manufacturer: Cleaver-Brooks Model: CBEX Elite Rating: 35.7 MMBtu/hr Fuel: Natural Gas/Digester Gas	Low NO_x and Low CO burners Economizers	Boiler #1 Stack: Height: 36 ft Diameter: 2.0 ft Temperature: 314 °F Flow Rate: 8,548 acfm Orientation: Vertical Boiler #2 Stack: Height: 36 ft Diameter: 2.0 ft Temperature: 314 °F Flow Rate: 8,548 acfm Orientation: Vertical
3	Emergency Engine: Manufacturer: Caterpillar Model: DG-450C or Equivalent Capacity: 450 kW Fuel: Natural Gas	4-Stroke Lean Burn	Emergency Generator #1 Stack: Height: 10 ft Diameter: 0.8 ft Temperature: 1,326 °F Flow Rate: 3,060 cfm Orientation: Vertical

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its

design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for the twenty air make-up units, two process boilers, the flare, and the emergency generator at the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant and HAP PTE were based on emission factors from AP-42, operation of 8,760 hours per year, and process information specific to the facility for this proposed project. The air make-up units used a 50% duty factor for annual emissions based on engineer assumptions on typical usage of these types of units throughout the year. Emission factors for natural gas combustion and biogas combustion are similar for most criteria pollutants and HAP pollutants with the exception of SO_2. Biogas contains H_2S which converts to SO_2 when combusted. As such, the emissions for SO_2 are combined using 100% combustion of biogas and natural gas combustion up to the rated heat capacity of the units.

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits.

The following table presents the uncontrolled Potential to Emit for regulated air pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this beef processing operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr (24 hr/day x 365day/yr) with the exception of the air make-up units that used a 50% duty factor for annual emissions. SO_2 emissions are combined on the flare and boilers because biogas has much greater SO_2 emissions than natural gas. SO_2 emissions assume maximum biogas combustion and the remaining natural gas combustion up to the rated heat inputs on those units. Other criteria pollutants used the worst-case emission rates for the two types of fuel.

Table 2 UNCONTROLLED POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
	T/yr	T/yr	T/yr	T/yr	T/yr
Air Make-Up Units (20)	0.27	0.05	3.52	2.99	0.20
Flare	0.17	20.15	1.51	6.88	14.65
Boiler #1	0.78		3.79	0.77	0.56
Boiler #2	0.78		3.79	0.77	0.56
Emergency Generator	0.003	0.0002	0.07	0.13	0.05
Total, Point Sources	**2.00**	**20.20**	**12.68**	**11.54**	**16.02**

The following table presents the uncontrolled Potential to Emit for HAP pollutants as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations and the assumptions used to determine emissions for each emissions unit. For this beef processing operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr (24 hr/day x 365day/yr) with the exception of the air make-up units that used a 50% duty factor for annual emissions. Then, the worst-case maximum HAP Potential to Emit was determined for this beef processing operation.

Table 3 **UNCONTROLLED POTENTIAL TO EMIT FOR HAZARDOUS AIR POLLUTANTS**

Hazardous Air Pollutants	PTE (T/yr)
Acenaphthene	8.16E-07
Acenaphthylene	2.00E-06
Anthracene	6.28E-07
Benz(a)anthracene	4.71E-07
Benzo(b)fluoranthene	3.60E-07
Benzo(a)pyrene	5.85E-07
Benzo(g,h,i)perylene	4.28E-07
Benzo(k)fluoroanthene	4.71E-07
Chrysene	6.62E-07
Dibenzo(a,h)anthracene	3.14E-07
7,12-Dimethylbenz(a)anthracene	4.18E-06
Fluoranthene	1.09E-06
Fluorene	2.30E-06
Indeno(1,2,3-cd)pyrene	4.71E-07
2-Methylnaphthalene	1.55E-05
3-Methylchloroanthene	4.71E-07
Naphthalene	1.80E-04
Phenanthrene	7.32E-06
Pyrene	1.68E-06
PAH	2.17E-04
POM	2.20E-04
Benzene	6.71E-04
Dichlorobenzene	3.14E-04
Formaldehyde	3.42E-02
Hexane	4.71E-01
Toluene	1.00E-03
Arsenic	5.23E-05
Beryllium	3.15E-06
Cadmium	2.88E-04
Chromium	3.65E-04
Cobalt	2.20E-05
Manganese	9.95E-05
Mercury	6.80E-05
Nickel	5.49E-04
Selenium	6.27E-06
1,1,2,2-Tetrachloroethane	1.11E-05
1,1,2-Trichloroethane	8.79E-06
1,3-Butadiene	7.38E-05
1,3-Dichloropropene	7.30E-06
2,2,4-Trimethylpentane	6.91E-05
Acetaldehyde	2.31E-03
Acrolein	1.42E-03
Biphenyl	5.86E-05
Carbon Tetrachloride	1.01E-05
Chlorobenzene	8.40E-06
Chloroform	7.88E-06
Ethylbenzene	1.10E-05
Ethylene Dibromide	1.22E-05
Methanol	6.91E-04
Methylene Chloride	5.53E-06
Phenol	6.63E-06
Styrene	6.52E-06
Tetrachloroethane	6.86E-07
Vinyl Chloride	4.12E-06
Xylene	5.09E-05
Total	**0.51**

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

This is a new facility. Therefore, pre-project emissions are set to zero for all criteria pollutants.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility as determined by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 4 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Air Make-Up Units (20)	0.12	0.27	0.02	0.05	1.61	3.52	1.36	2.99	0.09	0.20
Flare	0.07	0.17	4.64	20.15	0.68	1.51	3.10	6.88	6.60	14.65
Boiler #1	0.18	0.78			0.87	3.79	0.18	0.77	0.13	0.56
Boiler #2	0.18	0.78			0.87	3.79	0.18	0.77	0.13	0.56
Emergency Generator	0.06	0.003	0.003	0.0002	1.33	0.07	2.66	0.13	0.93	0.05
Post Project Totals	**0.61**	**2.00**	**4.66**	**20.20**	**5.36**	**12.68**	**7.48**	**11.54**	**7.88**	**16.02**

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 5 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post Project Potential to Emit	0.61	2.00	4.66	20.20	5.36	12.68	7.48	11.54	7.88	16.02
Changes in Potential to Emit	**0.61**	**2.00**	**4.66**	**20.20**	**5.36**	**12.68**	**7.48**	**11.54**	**7.88**	**16.02**

Non-Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of non-carcinogenic toxic air pollutants (TAP) is provided in the following table.

Pre- and post-project, as well as the change in, non-carcinogenic TAP emissions are presented in the following table:

Table 6 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR NON-CARCINOGENIC TOXIC AIR POLLUTANTS

Non-Carcinogenic Toxic Air Pollutants	Pre-Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Post Project 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Change in 24-hour Average Emissions Rates for Units at the Facility (lb/hr)	Non-Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Chromium	0.00	3.64E-05	3.64E-05	3.3E-02	No
Cobalt	0.00	2.19E-06	2.19E-06	3.3E-03	No
Cyclopentane	0.00	3.01E-02	3.01E-02	1.1E+02	No
Dichlorobenzene	0.00	3.12E-05	3.12E-05	2.0E+01	No
Dichloroethane	0.00	6.26E-03	6.26E-03	2.7E+01	No
Hexane	0.00	4.69E-02	4.69E-02	1.2E+01	No
Manganese	0.00	9.91E-06	9.91E-06	3.3E-01	No
Methylcyclohexane	0.00	1.63E-01	1.63E-01	1.1E+02	No
Nitrous Oxide	0.00	1.60E-01	1.60E-01	6.0E+00	No
Nonane	0.00	1.46E-02	1.46E-02	7.0E+01	No
Octane	0.00	4.66E-02	4.66E-02	9.3E+01	No
Pentane	0.00	5.34E-01	5.34E-01	1.2E+02	No
Propylene dichloride (1,2-Dichloropropane)	0.00	3.57E-03	3.57E-03	2.3E+01	No
Selenium	0.00	6.24E-07	6.24E-07	1.3E-02	No
Toluene	0.00	8.85E-05	8.85E-05	2.5E+01	No
Trimethyl benzene (mixed and individual isomers)	0.00	9.43E-03	9.43E-03	8.2E+00	No

All changes in emissions rates for non-carcinogenic TAP were below EL (screening emissions level) as a result of this project. Therefore, modeling is not required for any non-carcinogenic TAP because none of the 24-hour average non-carcinogenic screening ELs identified in IDAPA 58.01.01.585 were exceeded.

Carcinogenic TAP Emissions

A summary of the estimated PTE for emissions increase of carcinogenic toxic air pollutants (TAP) is provided in the following table.

Table 7 PRE- AND POST PROJECT POTENTIAL TO EMIT FOR CARCINOGENIC TOXIC AIR POLLUTANTS

Carcinogenic Toxic Air Pollutants	Pre-Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Post Project Annual Average Emissions Rates for Units at the Facility (lb/hr)	Change in Annual Average Emissions Rates for Units at the Facility (lb/hr)	Carcinogenic Screening Emission Level (lb/hr)	Exceeds Screening Level? (Y/N)
Arsenic	0.00	5.2E-06	5.2E-06	1.5E-06	Yes
Benzene	0.00	5.5E-05	5.5E-05	8.0E-04	No
Beryllium	0.00	3.1E-07	3.1E-07	2.8E-05	No
Cadmium	0.00	2.9E-05	2.9E-05	3.7E-06	Yes
Chromium (VI)	0.00	1.8E-06	1.8E-06	5.6E-07	Yes
Formaldehyde	0.00	2.0E-03	2.0E-03	5.1E-04	Yes
Nickel	0.00	5.5E-05	5.5E-05	2.7E-05	Yes
PAH (Idaho)	0.00	1.8E-05	1.8E-05	9.1E-05	No
POM(a) (Idaho)	0.00	3.0E-07	3.0E-07	2.0E-06	No

a) Polycyclic Organic Matter (POM) is considered as one TAP comprised of: benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, dibenzo(a,h)anthracene, chrysene, indeno(1,2,3-cd)pyrene, benzo(a)pyrene. The total is compared to benzo(a)pyrene.

Some of the PTEs for carcinogenic TAP were exceeded as a result of this project. Therefore, modeling is required for Arsenic, Cadmium, Chromium (VI), Formaldehyde, and Nickel because the annual average carcinogenic screening ELs identified in IDAPA 58.01.01.586 were exceeded.

Post Project HAP Emissions

The following table presents the post project potential to emit for HAP pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 8 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY

Hazardous Air Pollutants	PTE (lb/hr)	PTE (T/yr)
Acenaphthene	7.04E-06	8.16E-07
Acenaphthylene	3.07E-05	2.00E-06
Anthracene	1.74E-07	6.28E-07
Benz(a)anthracene	1.31E-07	4.71E-07
Benzo(b)fluoranthene	1.00E-06	3.60E-07
Benzo(a)pyrene	2.43E-06	5.85E-07
Benzo(g,h,i)perylene	2.38E-06	4.28E-07
Benzo(k)fluoroanthene	1.31E-07	4.71E-07
Chrysene	3.96E-06	6.62E-07
Dibenzo(a,h)anthracene	8.72E-08	3.14E-07
7,12-Dimethylbenz(a)anthracene	1.16E-06	4.18E-06
Fluoranthene	6.35E-06	1.09E-06
Fluorene	3.15E-05	2.30E-06
Indeno(1,2,3-cd)pyrene	1.31E-07	4.71E-07
2-Methylnaphthalene	1.85E-04	1.55E-05
3-Methylchloroanthene	1.31E-07	4.71E-07
Naphthalene	4.56E-04	1.80E-04
Phenanthrene	5.87E-05	7.32E-06
Pyrene	7.88E-06	1.68E-06
PAH	7.89E-04	2.17E-04
POM	7.95E-04	2.20E-04
Benzene	2.59E-03	6.71E-04
Dichlorobenzene	8.72E-05	3.14E-04
Formaldehyde	2.97E-01	3.42E-02
Hexane	1.37E-01	4.71E-01
Toluene	2.50E-03	1.00E-03
Arsenic	1.45E-05	5.23E-05
Beryllium	8.74E-07	3.15E-06
Cadmium	8.00E-05	2.88E-04
Chromium	1.02E-04	3.65E-04
Cobalt	6.11E-06	2.20E-05
Manganese	2.76E-05	9.95E-05
Mercury	1.89E-05	6.80E-05
Nickel	1.53E-04	5.49E-04
Selenium	1.74E-06	6.27E-06
1,1,2,2-Tetrachloroethane	2.21E-04	1.11E-05
1,1,2-Trichloroethane	1.76E-04	8.79E-06
1,3-Butadiene	1.48E-03	7.38E-05
1,3-Dichloropropene	1.46E-04	7.30E-06
2,2,4-Trimethylpentane	1.38E-03	6.91E-05
Acetaldehyde	4.62E-02	2.31E-03
Acrolein	2.84E-02	1.42E-03
Biphenyl	1.17E-03	5.86E-05
Carbon Tetrachloride	2.03E-04	1.01E-05
Chlorobenzene	1.68E-04	8.40E-06
Chloroform	1.58E-04	7.88E-06
Ethylbenzene	2.19E-04	1.10E-05
Ethylene Dibromide	2.45E-04	1.22E-05
Methanol	1.38E-02	6.91E-04
Methylene Chloride	1.11E-04	5.53E-06
Phenol	1.33E-04	6.63E-06
Styrene	1.30E-04	6.52E-06
Tetrachloroethane	1.37E-05	6.86E-07
Vinyl Chloride	8.24E-05	4.12E-06
Xylene	1.02E-03	5.09E-05
Totals	**0.54**	**0.51**

Ambient Air Quality Impact Analyses

As presented in the Modeling Memo in Appendix B, the estimated emission rates of PM_{10}, $PM_{2.5}$, SO_2, NO_X, arsenic, cadmium, chromium (VI), formaldehyde, and nickel from this project exceeded applicable screening emission levels (EL) and published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline[1]. Refer to the Emissions Inventories section for additional information concerning the emission inventories.

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP). A summary of the Ambient Air Impact Analysis for TAP is provided in Appendix A.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Bonneville County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAPs (Hazardous Air Pollutants) Only:

A = Use when any one HAP has permitted emissions > 10 T/yr or if the aggregate of all HAPS (Total HAPs) has permitted emissions > 25 T/yr.

SM80 = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits > 8 T/yr of a single HAP or ≥ 20 T/yr of Total HAPs.

SM = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits < 8 T/yr of a single HAP and/or < 20 T/yr of Total HAPs.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 10 and 25 T/yr HAP major source thresholds.

UNK = Class is unknown.

For All Other Pollutants:

A = Use when permitted emissions of a pollutant are > 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are ≥ 80 T/yr.

[1] Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

SM = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are < 80 T/yr.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 100 T/yr major source threshold.

UNK = Class is unknown.

Table 9 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM_{10}	2.0	2.0	**100**	B
$PM_{2.5}$	2.0	2.0	**100**	B
SO_2	20.2	20.2	**100**	B
NO_X	12.68	12.68	**100**	B
CO	11.54	11.54	**100**	B
VOC	16.02	16.02	**100**	B
HAP (Hexane)	0.47	0.47	**10**	B
Total HAPs	0.51	0.51	**25**	B

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 ..... Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the proposed new facility. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 ..... Tier II Operating Permit

The application was submitted for a permit to construct (refer to the Permit to Construct section), and an optional Tier II operating permit has not been requested. Therefore, the procedures of IDAPA 58.01.01.400–410 were not applicable to this permitting action.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 ..... Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.6 and 3.5.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676 ..... Standards for New Sources

The fuel burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, are subject to a particulate matter limitation of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This requirement is assured by Permit Condition 2.8.

Particulate Matter – New Equipment Process Weight Limitations (IDAPA 58.01.01.701)

IDAPA 58.01.01.701 ..... Particulate Matter – New Equipment Process Weight Limitations

IDAPA 58.01.01.700 through 703 set PM emission limits for process equipment based on when the piece of equipment commenced operation and the piece of equipment's process weight (PW) in pounds per hour (lb/hr). IDAPA 58.01.01.701 and IDAPA 58.01.01.702 establish PM emission limits for equipment that commenced operation on or after October 1, 1979, and for equipment operating prior to October 1, 1979, respectively.

For equipment that commenced operation on or after October 1, 1979, the PM allowable emission rate (E) is based on one of the following equations:

IDAPA 58.01.01.701.01.a: If PW is < 9,250 lb/hr; $E = 0.045 (PW)^{0.60}$

IDAPA 58.01.01.701.01.b: If PW is ≥ 9,250 lb/hr; $E = 1.10 (PW)^{0.25}$

For equipment that commenced prior to October 1, 1979, the PM allowable emission rate is based on one of the following equations:

IDAPA 58.01.01.702.01.a: If PW is < 17,000 lb/hr; $E = 0.045 (PW)^{0.60}$

IDAPA 58.01.01.702.01.b: If PW is ≥ 17,000 lb/hr; $E = 1.12 (PW)^{0.27}$

For the new beef processing operation proposed to be installed as a result of this project with a proposed throughput of 600 head/day, E is calculated as follows:

- Proposed throughput = 600 head/day x 1,500 lb/head x day/24 hr = 37,500 lb/hr

Therefore, E is calculated as:

- $E = 1.10 \times PW^{0.25} = 1.10 \times (37,500)^{0.25} = 15.3$ lb-PM/hr

As presented previously in the Emissions Inventories Section of this evaluation the post project PTE for this emissions unit is 0.61 lb-PM_{10}/hr. Assuming PM is 50% PM_{10} means that PM emissions will be 1.22 lb-PM/hr (0.61 lb-PM_{10}/hr ÷ 0.5 lb-PM_{10}/lb-PM). Therefore, compliance with this requirement has been demonstrated.

Rules for Control of Odors (IDAPA 58.01.01.775)

IDAPA 58.01.01.775……Rules for Control of Odors

IDAPA 58.01.01.775 through 776 sets standards for the control of odorous emissions from all sources for which no gaseous emission control rules apply. No person shall allow, suffer, cause or permit the emission of odorous gases, liquids or solids into the atmosphere in such quantities as to cause air pollution. For Rendering Plants, no person shall allow, suffer, cause or permit any plant engaged in the processing of animal, mineral, or vegetable matter or chemical processes utilizing animal, mineral or vegetable matter to be operated without employing reasonable measures for the control of odorous emissions including wet scrubbers, incinerators, chemicals or such other measures as may be approved by the Department. These requirements are assured by Permit Condition 2.7.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301..... Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility do not have a potential to emit greater than 100 tons per year for PM_{10}, SO_2, NO_X, CO, and VOC or 10 tons per year for any one HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 ..... Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1). This section defines a Major stationary source as:

Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any regulated NSR pollutant: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants (with thermal dryers), primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing

plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants (which does not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140), fossil-fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants, or

Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of a regulated NSR pollutant; or

Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) of this section, as a major stationary source, if the changes would constitute a major stationary source by itself.

This facility is not one of the facilities designated and does not have facility-wide emissions for any criteria pollutant that exceed 250 T/yr. In addition, the facility is not undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore, in accordance with 40 CFR 52.21(a)(2), the PSD requirements do not apply.

NSPS Applicability (40 CFR 60)

Because the facility has boilers and natural gas combustion equipment the following is an NSPS applicability analysis for the proposed equipment:

- 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.
- 40 CFR 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

40 CFR 60, Subpart Dc ..... Standards of Performance for Small Industrial–Commercial–Institutional Steam Generating Units

The two boilers at this facility combust natural gas or biogas as fuel as required by Permit Condition 2.9. Therefore, the only Sections of this subpart that are applicable to the two boilers at this facility are the Applicability and Delegation of Authority specified in § CFR 60.40c(a), the Reporting requirements of § CFR 60.48c(a)(1), (a)(2), and (a)(3), and the Recordkeeping requirements of § CFR 60.48c(g), (i), and (j).

§ 60.40c ..... Applicability and Delegation of Authority

a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

This subpart is applicable to the Facility because the three boilers will be constructed after June 9, 1989 and each boiler will have a maximum heat input rate between 30 and 100 MMBtulhr.

§ 60.41c ..... Definitions

The definitions of this section apply to the two natural gas and biogas fired boilers at this facility.

§ 60.48c ..... Reporting and recordkeeping requirements

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility will complete required initial notification requirements as follows: (1) A notification of the date construction commenced postmarked no later than 30 days after such date. (2) A notification of the actual date of initial startup postmarked within 15 days after such date.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

The facility will maintain monthly fuel usage records.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

The facility will maintain monthly fuel usage records for a minimum period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

The facility will file reports semi-annually and postmark them by the 30th day following the end of each six-month reporting period.

40 CFR 60, Subpart JJJJ..... Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The emergency generator at this facility combusts natural gas as fuel as required by Permit Condition 3.6. Therefore, the only Sections of this subpart that are applicable to the emergency generator at this facility are the applicability specified in § CFR 60.4230(a)(4)(ii), the emission standards of § CFR 60.4233(e), length of compliance with emission standards in § CFR 60.4234, monitoring requirements in § CFR 60.4237(a), compliance requirements in § CFR 60.4243(b)(1), (d), and (e), and the notification, reports, and records in § CFR 60.4245(a).

§ 60.4230..... Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

The genset at the Riverbend Meats facility will be a new engine rated at 450 kw, which equates to 718 bhp.

§ 60.4233 ..... What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

Riverbend Meats will operate a SI RICE that is greater than or equal to 75 kW.

Table 1 to Subpart JJJJ of Part 60—NO_X, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[b]	NO_X	CO	VOC[b]
Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	7/1/2010	1.0	2.0	0.7	82	270	60
Emergency	HP<130		2.0	4.0	1.0	160	540	86

§ 60.4234 ..... How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

This is applicable because Riverbend Meats will own and operate an engine subject to §60.4233

§ 60.4237 ..... What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

(a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

The genset engine proposed by Riverbend Meats meets standards applicable to nonemergency engines.

§ 60.4243 ..... What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

Riverbend Meats is subject to the emission standard specified in §60.4233(e). Riverbend Meats intends to comply by purchasing a certified engine.

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for nonemergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in nonemergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

The genset at the Riverbend Meats facility will be an emergency stationary ICE, and hence subject to these limitations and requirements.

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

The genset at the Riverbend Meats facility will be a stationary SI natural gas fired engine.

§ 60.4245 ..... What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

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

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

Provisions (a)(1) and (a)(2) are applicable. Provision (a)(3) is applicable because Riverbend Meats is relying on manufacturer to demonstrate compliance. Provision (a)(4) is not applicable because the Riverbend Meats genset engine will be a certified engine operated in a certified manner.

§ 60.4248 ..... What definitions apply to this subpart?

The definitions of this section apply to the emergency generator at this facility.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT/GACT Applicability (40 CFR 63)

Because the facility has a natural gas combustion emergency generator and proposes to operate as a minor source of hazardous air pollutant (HAP) emissions the following is a NESHAP applicability analysis for the proposed equipment:

- 40 CFR 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

40 CFR 63, Subpart ZZZZ ..... National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generator at this facility combusts natural gas as fuel as required by Permit Condition 3.6. Therefore, the only Sections of this subpart that are applicable to the emergency generator at this facility are the applicability specified in § CFR 63.6585(c) and the affected sources covered in § CFR 63.6590(a) and (c).

§ 63.6585 ..... Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(c) An area source of HAP emissions is a source that is not a major source.

The emergency engine will be located at an area source of HAP emissions and will be subject to Subpart ZZZZ requirements. None of the emergency engine exemptions apply to the proposed engine.

§ 63.6590..... What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(2) *New stationary RICE.*

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

Construction of new stationary RICE at a new area source will be commenced after applicability dates.

(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

Applicable, the engine will be subject to NSPS Subpart JJJJ (Spark Ignition Engines). No further NESHAP Subpart ZZZZ requirement will apply to the engine.

Permit Conditions Review

This section describes the permit conditions for this initial permit.

Initial Permit Condition 1.1 and Table 1.1

This permit condition establishes the purpose for the permit to construct and lists the regulated sources along with the control equipment at the site.

Initial Permit Condition 2.1

This permit condition gives a description of the processes contained in this section.

Initial Permit Condition 2.2 and Table 2.1

This permit condition describes the emission units, control devices, and stack parameters contained in this section.

Initial Permit Condition 2.3 and Table 2.2

This permit condition contains the emission limits of criteria pollutants from the boilers and flare.

Initial Permit Condition 2.4

This permit condition establishes the hydrogen sulfide emission limit for the boilers and flare.

Initial Permit Condition 2.5

This permit condition establishes the maximum daily biogas production and annual limit.

Initial Permit Condition 2.6

This permit condition limits the opacity from the boilers and flare.

Initial Permit Condition 2.7

This permit condition establishes that no odorous emissions may be released to cause air pollution.

Initial Permit Condition 2.8

This permit condition limits particulate emissions from the combustion of natural gas and biogas.

Initial Permit Condition 2.9

This permit condition requires that only natural gas or biogas may be combusted in the boilers. All biogases must be combusted in the boilers or flare.

Initial Permit Condition 2.10

This permit condition requires a flame to be present when biogas is routed to the flare. The flare can be either equipped with an auto ignition system or have a pilot flame.

Initial Permit Condition 2.11

This permit condition requires the facility to take reasonable precautions to control fugitive emissions.

Initial Permit Condition 2.12

This permit condition requires the facility to monitor the pilot flame with a thermocouple or similar device.

Initial Permit Condition 2.13

This permit condition requires the facility to record the fuel combusted during each day of operations with an option of monthly monitoring.

Initial Permit Condition 2.14

This permit condition requires the facility to maintain records for two years from the date of the record.

Initial Permit Condition 2.15

This permit condition requires the facility to monitor the biogas flow rate on a daily basis in standard cubic feet per day and to calculate the rolling 12-month average. This condition requires the facility to use flow rate meters and calibration checks to accomplish the monitoring.

Initial Permit Condition 2.16

This permit condition requires the facility to monitor hydrogen sulfide concentration downstream of the digester and upstream of the boilers and flare. Monitoring may use an inline unit or conducted using Draeger® tubes, or equivalent. Calibration, gas checks, and monitoring schedule are discussed in this condition.

Initial Permit Condition 2.17

This permit condition requires the facility to maintain an operations and maintenance manual for the biogas flow rate monitor, the H_2S monitor, and the pilot flame detector.

Initial Permit Condition 2.18

This permit condition incorporates new source performance standards from 40 CFR Part 60, Subpart Dc by reference and states that any conflict between the permit conditions and the referenced Subpart, that the Subpart document shall govern, including any amendments.

Initial Permit Condition 3.1

This permit condition gives a process description of the natural gas fired emergency generator at the facility.

Initial Permit Condition 3.2 and Table 3.1

This permit condition describes the emission unit, control device, and stack parameters.

Initial Permit Condition 3.3 and Table 3.2

This permit condition contains the emission limits of criteria pollutants for the emergency generator.

Initial Permit Condition 3.4 and Table 3.3

This permit condition contains the emission standards from NSPS, Subpart JJJJ that are applicable to the emergency generator.

Initial Permit Condition 3.5

This permit condition limits the opacity from the emergency generator.

Initial Permit Condition 3.6

This permit condition limits the fuel combusted in the emergency generator to natural gas exclusively.

Initial Permit Condition 3.7

This permit condition requires the facility to maintain the emergency generator to achieve the standards in NSPS, Subpart JJJJ over the entire life of the engine.

Initial Permit Condition 3.8

This permit condition limits the operational hours for maintenance and testing to 100 hours per year. The engine may be used for up to 50 hours per year for non-emergency use, but those hours count towards the 100-hour yearly limit. Emergency use has no time limit.

Initial Permit Condition 3.9

This permit condition describes how the generator is applicable to 40 CFR Part 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

Initial Permit Condition 3.10

This permit condition describes how the generator is applicable to 40 CFR Part 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Initial Permit Condition 3.11

This permit condition incorporates New Source Performance Standards from 40 CFR Part 60, Subpart JJJJ and National Emission Standards for Hazardous Air Pollutants, 40 CFR Part 63, Subpart ZZZ by reference and states that any conflict between the permit conditions and the referenced Subpart, that the Subpart document shall govern, including any amendments.

Initial Permit Condition 3.12

This permit condition requires the facility to install a certified engine and to maintain the engine according to the manufacturer specifications.

Initial Permit Condition 3.13

This permit condition requires the facility to maintain records of notifications, maintenance, and manufacturer documentation on the engine certification.

Initial Permit Condition 3.14

This permit condition requires the facility to maintain records of the hours of operation of the engine.

Initial Permit Condition 3.15

This permit condition lists the applicable general provisions from 40 CFR 60, Subpart JJJJ.

Initial Permit Condition 4.1

The duty to comply general compliance provision requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Initial Permit Condition 4.2

The maintenance and operation general compliance provision requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 4.3

The obligation to comply general compliance provision specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Initial Permit Condition 4.4

The inspection and entry provision requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Initial Permit Condition 4.5

The permit expiration construction and operation provision specifies that the permit expires if construction has not begun within two years of permit issuance or if construction has been suspended for a year in accordance with IDAPA 58.01.01.211.02.

Initial Permit Condition 4.6

The notification of construction and operation provision requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.01 and 211.03.

Initial Permit Condition 4.7

The performance testing notification of intent provision requires that the permittee notify DEQ at least 15 days prior to any performance test to provide DEQ the option to have an observer present, in accordance with IDAPA 58.01.01.157.03.

Initial Permit Condition 4.8

The performance test protocol provision requires that any performance testing be conducted in accordance with the procedures of IDAPA 58.01.01.157, and encourages the permittee to submit a protocol to DEQ for approval prior to testing.

Initial Permit Condition 4.9

The performance test report provision requires that the permittee report any performance test results to DEQ within 60 days of completion, in accordance with IDAPA 58.01.01.157.04-05.

Initial Permit Condition 4.10

The monitoring and recordkeeping provision requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 4.11

The excess emissions provision requires that the permittee follow the procedures required for excess emissions events, in accordance with IDAPA 58.01.01.130-136.

Initial Permit Condition 4.12

The certification provision requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Initial Permit Condition 4.13

The false statement provision requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Initial Permit Condition 4.14

The tampering provision requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Initial Permit Condition 4.15

The transferability provision specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Initial Permit Condition 4.16

The severability provision specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c or IDAPA 58.01.01.404.01.c. During this time, there was not a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

APPENDIX A – EMISSIONS INVENTORIES

Conversions							
boiler horsepower to MMBtu	0.033479	MMBtu/hr					
Fd, dry exhaust gas factor	8710	dscf/MMBtu	From Table 19-2, EPA Test Method 19				
	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))				
Fw, wet exhaust gas factor	10610	wscf/MMBtu	From Table 19-2, EPA Test Method 19				
	12,388	wscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))				
density of air at NTP	0.0765	lb/scf					
barometric pressure	0.84	atm					
Sulfur atomic weight	32.06						
H2S molecular weight	34.06						
SO2 molecular weight	64.06	2.665					
SO4 molecular weight	96						
CO molecular weight	28	1.165					
CO2 molecular weight	44						
CH4 molecular weight	16						
NO2 molecular waight	46	1.913					
standard air molecular weight	28.8						
natural gas specifications							
HHV, natural gas	1020	Btu/scf					
natural gas	0.5	grain/Ccf	per 40 CFR 72.2 requirements for pipeline natural gas				
AP-42 Chapter 1.4 criteria pollutant emission factors for NG Combustion							
	fuel based		heat based		Comments		
Natural gas	value	units	value	units			
CO	84	lb/MMscf	0.082	lb CO/MMBtu	Based on AP-42 Table 1.4-1 and natural gas heat content = 1020 MMBtu/MMscf.		
Nox - uncontrolled	100	lb/MMscf	0.098	lb NOx/MMBtu	Based on AP-42 Table 1.4-1 and natural gas heat content = 1020 MMBtu/MMscf.		
Nox - low Nox burner	50	lb/MMscf	0.049	lb NOx/MMBtu	Based on AP-42 Table 1.4-1 and natural gas heat content = 1020 MMBtu/MMscf.		
SO2	1.5	lb/MMscf	0.0015	lb SO2/MMBtu	Based on AP-42 Table 1.4-2, natural gas heat content = 1020 MMBtu/MMscf, and natural gas max sulfur content of 0.5 grain/Ccf.		
PM10	7.6	lb/MMscf	0.0075	lb PM10/MMBtu	Based on AP-42 Table 1.4-2, assuming that 100% of PM is PM10 and and natural gas heat content = 1020 MMBtu/MMscf.		
PM2.5	7.6	lb/MMscf	0.0075	lb PM10/MMBtu	Based on AP-42 Table 1.4-2, assuming that 100% of PM is PM10 and and natural gas heat content = 1020 MMBtu/MMscf.		
VOC	5.5	lb/MMscf	0.0054	lb VOC/MMBtu	Based on AP-42 Table 1.4-1 and natural gas heat content = 1020 MMBtu/MMscf.		
Pb	0.0005	lb/MMscf	4.90E-07	lb Pb/MMBtu	Based on AP-42 Table 1.4-2 and natural gas heat content = 1020 MMBtu/MMscf.		
Boiler Data							
	Blr	Units	Comments				
NOx	30	ppm 3% O2	Vendor data sheet.				
CO	10	ppm 3% O3	Vendor data sheet.				
Stack diameter	24	inches	cal Drawings_2021-4-13. Drawing M101				
at 100% firing rate							
Temp	314	°F	Vendor data sheet.				
Qs	4,786	wscfm	Vendor data sheet.				
Boiler energy output	600.0	boiler horsepower	Vendor data sheet.				
excess air	15%	-	Vendor data sheet.				
efficiency (with economizer)	84.5%	-	Vendor data sheet.				
at 50% firing rate							
Temp	288	°F	Vendor data sheet.				
at 25% firing rate							
Temp	273	°F	Vendor data sheet.				
Maximum Animal Processing							
Animal Processing Capacity							
daily	600	head/day	project design				
annual	219,000	head/yr	365 days/yr				
digester gas Data - all data for 600 head/day							
HHV	600	MMBtu/MMscf	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021				
methane content	60%	by volume	based on HHV assuming 1000 Btu/scf for methane				
maximum day digester gas generation rate	0.400	MMscf/day	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021				
	16,667	scf/hr					
	10.0	MMBtu/hr					
	44,400	MMBtu/yr					
maximum annual digester gas production	0.203	MMscf/day	email , Pepi Ursillo, HDR, to Stephen Nelson 6/4/2021				
	74	MMscf/yr	annual average				
	5.068	MMBtu/hr					
SO2 Emissions							
sulfate content of well water	49	mg/l	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021.				
Peak wastewater flow to digester							
max day	600,000	gpd	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021. 25% safety factor included.				
max annual average	400,000	gpd	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021. 25% safety factor included.				
air:water partition coefficient for H2S in anaerobic reactor	0.4		email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021				
H2S Concentration in Digester Gas	2,400	ppmw	email , Pepi Ursillo, HDR, to Stephen Nelson 4/15/2021. based on 49 mg/l sulfate in well water and 25% safety factor				

Air Pressure at Altitude Calculator

Calculate Altitude *from* Air Pressure

Pressure at Sea Level: 101325 Pa Default

Temperature: 15 °C Default

Air Pressure at Altitude: Pa

CALCULATE

Altitude = m

Calculate Air Pressure *at* Altitude

Pressure at Sea Level: 1.00 atm Default

Temperature: 60 °F Default

Altitude: 4744 ft.

CALCULATE

Air Pressure at Altitude = 0.84 atm

Flare Information																								
AP-42 Emissions data																								
CO	0.31	lb/MMBtu	AP-42, Table 13.5-2																					
VOC	0.66	lb/MMBtu	AP-42, Table 13.5-2																					
NOx	0.07	lb/MMBtu	AP-42, Table 13.5-1																					
Flare Height	15.00	ft	VAREC 244W info sheet																					
Air Makeup Unit data																								
All units																								
annual duty	50%		standard working assumption for AMIUs																					
AMUs NOx Emission factor																								
Stack Gas concentration	80	ppmvd @ 3% O2	from HMA 2 2A Installation and Service Instructions.pdf. Assume 500,000 Btu/ft																					
Exhaust Fans																								
Exhaust fan Air flow rates																								
EF-1	1,400	cfm																						
EF-2	1,205	cfm																						
EF-3	15,500	cfm																						
EF-4	13,000	cfm																						
EF-5	2,450	cfm																						
EF-6	950	cfm																						
EF-7	20,500	cfm																						
EF-8	20,500	cfm																						
EF-9	32,600	cfm																						
EF-10	32,600	cfm	MAU and exhaust info.xls																					
EF-11	26,950	cfm																						
EF-12	26,950	cfm																						
EF-13	70	cfm																						
EF-14	250	cfm																						
EF-15	1,350	cfm																						
EF-16	13,000	cfm																						
EF-17	2,175	cfm																						
EF-18	250	cfm																						
EF-19	400	cfm																						
Total	212,100	cfm																						
Genset data																								
General Data																								
annual operation	100	hrs																						
power output	450	kW	project team meeting - May 27, 2021. Likely upper end of need																					
	603	Hp	1.341 Hp/kW																					
full load fuel consumption	5420	scfh	technical data sheet LEHE1605-05 for CAT DG-450C engine.																					
	5.53	MMBtuh	from fuel consutmtion and HHV NG																					
Exhaust gas flow, full load	3060	cfm	technical data sheet LEHE1605-05 for CAT DG-450C engine.																					
Exhaust gas temperature, full load	1326.00	°F	technical data sheet LEHE1605-05 for CAT DG-450C engine.																					
stack height	10.00	ft	design parameter																					
stack diameter	10.00	in.	design parameter																					
Emissions data																								
NOx	1.0	g NOx/Hp-hr	40 CFR 60 Subpart JJJJ,. Table 1																					
CO	2.0	g CO/Hp-hr	40 CFR 60 Subpart JJJJ,. Table 1																					
SO2	0.001	lb SO2/MMBtu	From AP-42, Table 3.2-2 for 4-stroke lean-burn engines at 100% load.																					
VOC	0.70	g VOC/Hp-hr	40 CFR 60 Subpart JJJJ,. Table 1																					
PM10	0.010	lb PM10/MMBtu	From AP-42, Table 3.2-2 for 4-stroke lean-burn engines at 100% load.																					
PM2.5	0.010	lb PM2,5/MMBtu	From AP-42, Table 3.2-2 for 4-stroke lean-burn engines at 100% load.																					
Buildings																								
maximum parapet height	31	feet	Project Angus bulding height coordination.pdf																					
project baseline elevation	4816	feet MSL	email Larry Oldham 4/13/2021																					

Toxic and Hazardous Air Pollutant Emission Factors - NG Burners*			
Air Pollutant	**lb/MMBtu**	**EPA Hazardous Air Pollutant?**	**Idaho Toxic Air Pollutant?**
POM Components			
Acenaphthene	1.76E-09	Yes	Yes (General PAH)
Acenaphthylene	1.76E-09	Yes	Yes (General PAH)
Anthracene	2.35E-09	Yes	Yes (General PAH)
Benz(a)anthracene	1.76E-09	Yes	Yes (7-PAH Group)
Benzo(a)pyrene	1.18E-09	Yes	Yes (7-PAH Group)
Benzo(b)fluoranthene	1.76E-09	Yes	Yes (7-PAH Group)
Benzo(g,h,i)perylene	1.18E-09	Yes	Yes (General PAH)
Benzo(k)fluoroanthene	1.76E-09	Yes	Yes (7-PAH Group)
Chrysene	1.76E-09	Yes	Yes (7-PAH Group)
Dibenzo(a,h)anthracene	1.18E-09	Yes	Yes (7-PAH Group)
7,12-Dimethylbenz(a)anthracene	1.57E-08	Yes	Yes (General PAH)
Fluoranthene	2.94E-09	Yes	Yes (General PAH)
Fluorene	2.75E-09	Yes	Yes (General PAH)
Indeno(1,2,3-cd)pyrene	1.76E-09	Yes	Yes (7-PAH Group)
2-Methylnaphthalene	2.35E-08	Yes	Yes (General PAH)
3-Methylchloroanthene	1.76E-09	Yes	Yes (General PAH)
Naphthalene	5.98E-07	Yes	Yes (General PAH)
Phenanthrene	1.67E-08	Yes	Yes (General PAH)
Pyrene	4.90E-09	Yes	Yes (General PAH)
PAH (Idaho)	*6.73E-07*	*Yes (EPA POM component)*	*C*
POM (Idaho)	*1.12E-08*	*Yes (EPA POM component)*	*C*
POM (EPA)	*6.85E-07*	*Yes*	-
Benzene	2.06E-06	Yes	C
Dichlorobenzene	1.18E-06	Yes	NC
Formaldehyde	7.35E-05	Yes	C
Hexane	1.76E-03	Yes	NC
Pentane	2.55E-03	No	NC
Toluene	3.33E-06	Yes	NC
Arsenic	1.96E-07	Yes	C
Beryllium	1.18E-08	Yes	C
Cadmium	1.08E-06	Yes	C
Chromium	1.37E-06	Yes	NC
Chromium (VI)	6.86E-08	Yes (included in chromium)	C
Cobalt	8.24E-08	Yes	NC
Manganese	3.73E-07	Yes	NC
Mercury	2.55E-07	Yes	No
Nickel	2.06E-06	Yes	C
Selenium	2.35E-08	Yes	NC
Nitrous Oxide	2.16E-03	No	NC
EPA Total HAPs	1.85E-03	Yes	No
Largest Individual HAP	1.76E-03	Yes	Yes
*AP-42, Tables 1.4-3 and 1.4-4. Based on 1020 Btu/scf natural gas heat content			
† 5% of chromium assumed to be Cr(VI). See AB 2588 Combsution Emission Factors", Ventura County APCD, May 17, 2001			

Toxic and Hazardous Air Pollutant Emission Factors - NG Engines 4-stroke Lean Burn. AP-42 Table 3.2-2					
Air Pollutant	**lb/MMBtu**	**EPA Hazardous Air Pollutant?**	**Idaho Toxic Air Pollutant?**	**EL**	**AAC**
POM Components					
Acenaphthene	1.25E-06	Yes	Yes (General PAH)		
Acenaphthylene	5.53E-06	Yes	Yes (General PAH)		
Benzo(b)fluoranthene	1.66E-07	Yes	Yes (7-PAH Group)		
Benzo(e)pyrene	4.15E-07	Yes	Yes (General PAH)		
Benzo(g,h,i)perylene	4.14E-07	Yes	Yes (General PAH)		
Chrysene	6.93E-07	Yes	Yes (7-PAH Group)		
Fluoranthene	1.11E-06	Yes	Yes (General PAH)		
Fluorene	5.67E-06	Yes	Yes (General PAH)		
2-Methylnaphthalene	3.32E-05	Yes	Yes (General PAH)		
Naphthalene	7.44E-05	Yes	Yes (General PAH)		
Phenanthrene	1.04E-05	Yes	Yes (General PAH)		
Pyrene	1.36E-06	Yes	Yes (General PAH)		
PAH (single value)	2.69E-05	Yes	Yes (General PAH)		
PAH (Idaho) - Maximum of PAH or Summation of individual PAH values except 7-PAH group:	1.34E-04	*Yes (EPA POM component)*	C	9.10E-05	1.40E-02
POM (Idaho): Summation of ID POM 7-PAH components	8.59E-07	*Yes (EPA POM component)*	C	2.00E-06	3.00E-04
POM (EPA): Maximum of PAH or Summation of individual PAH values	1.35E-04	*Yes*	-		
1,1,2,2-Tetrachloroethane	<4.00E-05	Yes	C	1.10E-05	1.70E-02
1,1,2-Trichloroethane	<3.18E-05	Yes	C	4.20E-04	6.20E-02
Dichloroethane	<4.72E-05		NC	2.70E+01	2.03E+01
1,1-Dichloroethane	<2.36E-05		NC		
1,2-Dichloroethane	<2.36E-05		NC		
Trimethyl benzene (mixed and individual isomers)	7.11E-05		NC	8.20E+00	6.15E+00
1,2,3-Trimethylbenzene	2.30E-05				
1,2,4-Trimethylbenzene	1.43E-05				
1,3,5-Trimethylbenzene	3.38E-05				
Propylene dichloride (1,2-Dichloropropane)	<2.69E-05		NC	2.31E+01	1.74E+01
1,3-Butadiene	2.67E-04	Yes	C	2.40E-05	3.60E-03
1,3-Dichloropropene	<2.64E-05	Yes	C	1.70E-03	2.50E-01
2,2,4-Trimethylpentane	2.50E-04	Yes	NC	2.33E+01	1.75E+01
Acetaldehyde	8.36E-03	Yes	C	3.00E-03	4.50E-01
Acrolein	5.14E-03	Yes	NC	1.70E-02	1.25E-02
Benzene	4.40E-04	Yes	C	8.00E-04	1.20E-01
Biphenyl	2.12E-04	Yes	NC		
Butane	5.41E-04		No		
Butyr/Isobutyraldehyde	1.01E-04		No		
Carbon Tetrachloride	<3.67E-05	Yes	C		
Chlorobenzene	<3.04E-05	Yes	NC		
Chloroethane	1.87E-06		No		
Chloroform	<2.85E-05	Yes	C		
Cyclopentane	2.27E-04		NC	1.15E+02	8.60E+01
Ethane	1.05E-01		No		
Ethylbenzene	3.97E-05	Yes	NC	2.90E+01	2.18E+01
Ethylene Dibromide	<4.43E-05	Yes	C	3.00E-05	4.50E-03
Formaldehyde	5.28E-02	Yes	C	5.10E-04	7.70E-02
Methanol	2.50E-03	Yes	NC	1.73E+01	1.30E+01
Methylcyclohexane	1.23E-03		NC	1.07E+02	8.05E+01
Methylene Chloride	2.00E-05	Yes	C	1.60E-03	2.40E-01
Hexane	1.11E-03	Yes	NC	1.20E+01	9.00E+00
Nonane	1.10E-04		NC	7.00E+01	5.25E+01
Octane	3.51E-04		NC	9.33E+01	7.00E+01
Pentane	2.60E-03		NC	1.18E+02	8.85E+01
Phenol	2.40E-05	Yes	NC	1.27E+00	9.50E-01
Propane	4.19E-02		No		
Styrene	<2.36E-05	Yes	NC	6.67E+00	1.00E+00
Tetrachloroethane	2.48E-06	Yes	NC	1.10E-05	1.70E-02
Toluene	4.08E-04	Yes	NC	2.50E+01	1.88E+01
Vinyl Chloride	1.49E-05	Yes	C	9.40E-04	1.40E-01
Xylene	1.84E-04	Yes	NC	2.90E+01	2.18E+01
EPA Total HAPs	7.22E-02				

	MBH	**CFM**	
MAU-1	2,145	26,000	Greenheck DGX-127-H38
MAU-2	1,279	15,000	Greenheck DGX-P127-H32-MF3
RTU-1	340	7,000	AAON
RTU-2	120	2,475	AAON
RTU-3	164	4,050	AAON
RTU-4	126	2,375	AAON
RTU-5	126	3,000	AAON
RTU-6	164	4,000	AAON
RTU-7	126	3,075	AAON
RTU-8	163	3,925	AAON
RTU-9	245	6,000	AAON
RTU-10	164	4,200	AAON
RTU-11	101	2,000	AAON
RTU-12	1,614	20,000	AAON
RTU-13	1,614	20,000	AAON
RTU-14	1,614	21,750	AAON
RTU-15	1,614	21,750	AAON
RTU-16	1,614	21,450	AAON
RTU-17	1,614	26,250	AAON
RTU-18	1,613.9	20,850	AAON
Total	16.561	235,150	

ID	TAG	CFM	MODEL	Dimensions*, in.	Geometry	Orientation*	effective diameter, in.	Stickup, inches	
Exhaust Fan 1	EF-1	1,400	GREENHECK G-120A	24.000	Circular	Raincap	24	6	Greenheck GGB_catalog.pdf
Exhaust Fan 2	EF-2	1,205	GREENHECK GB-120-VG	24.000	Circular	Raincap	24	6	Greenheck GGB_catalog.pdf
Exhaust Fan 3	EF-3	15,500	GREENHECK GB-420	65.000	Circular	Raincap	65	12	Greenheck GGB_catalog.pdf
Exhaust Fan 4	EF-4	13,000	GREENHECK CUBE-300-50	48.000	Circular	Horizontal	48	30	SeriesC_catalog.pdf
Exhaust Fan 5	EF-5	2,450	GREENHECK BSQ-180	24x24	Rectangular	Raincap	27	6	SQBSQ_catalog.pdf. Assume raincap and minimal sticup
Exhaust Fan 6	EF-6	950	GREENHECK SQ-100-A	14x14	Rectangular	Raincap	16	6	SQBSQ_catalog.pdf. Assume raincap and minimal sticup
Exhaust Fan 7	EF-7	20,500	GREENHECK CUBE-480	72.000	Circular	Horizontal	72	37	SeriesC_catalog.pdf
Exhaust Fan 8	EF-8	20,500	GREENHECK CUBE-480	72.000	Circular	Horizontal	72	37	SeriesC_catalog.pdf
Exhaust Fan 9	EF-9	32,600	GREENHECK GB-540	82.000	Circular	Raincap	82	16	Greenheck GGB_catalog.pdf
Exhaust Fan 10	EF-10	32,600	GREENHECK GB-540	82.000	Circular	Raincap	82	16	Greenheck GGB_catalog.pdf
Exhaust Fan 11	EF-11	26,950	GREENHECK TBI-CA-3H42	42.000	Circular	Raincap	42	6	TDITBI-CALevel3_catalog.pdf. Assume raincap and minimal stickup
Exhaust Fan 12	EF-12	26,950	GREENHECK TBI-CA-3H42	42.000	Circular	Raincap	42	6	TDITBI-CALevel3_catalog.pdf. Assume raincap and minimal stickup
Exhaust Fan 13	EF-13	70	GREENHECK SP-80-VG	4.000	Circular	Raincap	4	6	SPCSP_catalog.pdf
Exhaust Fan 14	EF-14	250	GREENHECK G-080-VG	21.750	Circular	Raincap	22	6	Greenheck GGB_catalog.pdf
Exhaust Fan 15	EF-15	1,350	GREENHECK BSQ-140	19.75x19.75	Rectangular	Raincap	21	6	SQBSQ_catalog.pdf. Assume raincap and minimal sticup
Exhaust Fan 16	EF-16	13,000	GREENHECK CUBE-300-50	48.000	Circular	Horizontal	48	30	SeriesC_catalog.pdf
Exhaust Fan 17	EF-17	2,175	GREENHECK GB-160-7	28.000	Circular	Raincap	28	6	Greenheck GGB_catalog.pdf
Exhaust Fan 18	EF-18	250	GREENHECK GB-100HP-VG	24.375	Circular	Raincap	24	6	Greenheck GGB_catalog.pdf
Exhaust Fan 19	EF-19	400	GREENHECK G-095-VG	24.375	Circular	Raincap	24	6	Greenheck GGB_catalog.pdf
		209,425							
	* From product catalog								

PARAMETER	VALUE	UNITS	DISCUSSION/BASIS
Boiler Operations and Emissions (full fire)			
Boiler Output	600	boiler horsepower	
Boiler efficiency with economizer	0.845		
Boiler Heat input	23.77	MMBtuh	
flue gas with 3% oxygen	4,786	wscfm	
	8,354	acfm	
	30	ppm 3% O2	
NOx Emissions	0.00000358	lb/dscf @ 3% O2	
	0.0364	lb NOx/MMBtu	=E*Fd adjusted to 3% O2
	10	ppm 3% O3	
CO Emissions	0.00000073	lb/dscf @ 3% O2	
	0.0074	lb CO/MMBtu	=E*Fd adjusted to 3% O2
Flue gas with DG cofiring - full fire			
Maximum Day			
flue gas at full NG firing	4,786	wscfm	
max digester gas generatiom	16,667	scf/hr	
digester gas inerts	111	scfm	
flue gas at full fire with biogas	4,897	wscfm	
	8,548	acfm	
Annual Day			
flue gas at full NG firing	4,786	wscfm	
average digester gas generatiom	8,447	scf/hr	
digester gas inerts	56	scfm	
flue gas at full fire with biogas	4,842	wscfm	
	8,452	acfm	
Boiler Operations and Emissions (DG only)			
Maximum Day			
Heat input	10.0	MMBtuh	
stack temp	288.0	°F	stack temp at 50% of full fire
	1,806	dscfm	
flue gas with 3% oxygen + DG inerts	2,176	wscfm	
	3,798	acfm	
Annual Average			
Heat input	5.1	MMBtuh	
stack temp	273.0	°F	stack temp at 25% of full fire
digester gas inerts	0	scfm	
	915	dscfm	
flue gas with 3% oxygen + DG inerts	1,103	wscfm	

	1,925	acfm	
SO2 emissions from digester gas combustion			Biogas CO2
average molecular weight of digester gas	27		
digester gas density	0.0607	lb/cf (68 °F)	
H2S concentration in digester gas	1,917	ppmv	
	145.66	lb/MMscf	
SO2 emission factor	0.457	lb SO2/MMBtu	
SO2 emission factor for NG/Biogas blend (full fire)			
Maximum Day			
maximum biogas heat supply, max day	10	MMBtuh	
% of heat from biogas, max day	42%		
SO2 emission factor	0.19	lb SO2/MMBtu	SO2 from NG trivial
Annual Average			
maximum biogas heat supply, annual average	5.07	MMBtuh	
% of heat from biogas, annual average	21%		
SO2 emission factor	0.10	lb SO2/MMBtu	SO2 from NG trivial
NOx emission factor for MAUs			
FW, formula weight	46	-	NOx as NO2
E, emissions	0.00000956	lb/dscf	=PPM*FW/(385.1*10^6)
Fa, Fd adjusted to 3% O2	10,170	dscf/MMBtu @ 3% O2	=Fd*(20.9/(20.9-3))
heat rate emission factor	0.097	lb/MMBtu	=E*Fa
Flare release parameters - Oklahoma method			
Flare Height	15	ft	
Maximum Day			
Heat Release	10	MMBtuh	
Effective release height	7.4126	meters	
Effective diameter	0.5543	meters	Calculated using BEEST Flare tool.
Effective exit velocity	20	m/s	
Effective stack temperature	1273	°K	
Average Annual			
Heat Release	5.07	MMBtuh	
Effective release height	6.6251	meters	
Effective diameter	0.3947	meters	Calculated using BEEST Flare tool.
Effective exit velocity	20	m/s	
Effective stack temperature	1273	°K	
Allocation of AMU emissions to roof vents and AREAPOLY source			

% to area polysource	10.9%		
% to roof vents	89.1%		
Exhaust Fan 3	6.6%		GREENHECK GB-420
Exhaust Fan 4	5.5%		
Exhaust Fan 5	1.0%		
Exhaust Fan 6	0.4%		
Exhaust Fan 7	8.7%		
Exhaust Fan 8	8.7%		
Exhaust Fan 9	13.9%		
Exhaust Fan 10	13.9%		
Exhaust Fan 11	11.5%		
Exhaust Fan 12	11.5%		
Exhaust Fan 14	0.1%		
Exhaust Fan 15	0.6%		
Exhaust Fan 16	5.5%		
Exhaust Fan 17	0.9%		
Exhaust Fan 18	0.1%		
Exhaust Fan 19	0.2%		

Genset exhaust rate

genset exhaust flows corrected to station pressure	3,643	ft

Emission Units	Description	CO	NOx	SO2	PM	VOC	Pb	HAP
Process Energy								
Boiler #1 - NG/biogas blend	Combustion source - process steam	x	x	x	x	x	x	x
Boiler #1 - NG only	Combustion source - process steam	x	x	x	x	x	x	x
Boiler #1 - DG only	Combustion source - process steam	x	x	x	x	x	x	x
Boiler #2 - NG/biogas blend	Combustion source - process steam	x	x	x	x	x	x	x
Boiler #2 - NG only	Combustion source - process steam	x	x	x	x	x	x	x
Boiler #2 - DG only	Combustion source - process steam	x	x	x	x	x	x	x
Site Utilities								
Flare	Combustion source - Digester gas	x	x	x	x	x	x	x
Genset	Combustion source - NG-fired standy power	x	x	x	x	x	x	x
Air Makeup	direct fired air supply	x	x	x	x	x	x	x

Emission Units	Release Point	Control Device							
		PM	NOx	SO2	CO	VOC	Pb	HAPs	TAPs
Process Energy									
Boiler #1 - NG/biogas blend	Boiler #1	None	low NOx burners	None	None	None	None	None	None
Boiler #1 - NG only	Boiler #1	None	low NOx burners	None	None	None	None	None	None
Boiler #1 - DG only	Boiler #1	None	low NOx burners	None	None	None	None	None	None
Boiler #2 - NG/biogas blend	Boiler #2	None	low NOx burners	None	None	None	None	None	None
Boiler #2 - NG only	Boiler #2	None	low NOx burners	None	None	None	None	None	None
Boiler #2 - DG only	Boiler #2	None	low NOx burners	None	None	None	None	None	None
Site Utilities									
Flare	Flare	None	None	None	None	None	None	None	None
Genset	Genset	None	None	None	None	None	None	None	None
Air Makeup	89.1% allocated to roof vents. 10.9% allocated to AREAPOLY source.	None	low NOx burners	None	None	None	None	None	None

	MAXIMUM CONTROLLED POTENTIAL TO EMIT									
	CO		NOX		SO2		PM2.5		PM10	
Emission Unit	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Process Energy										
Boiler #1 - NG/biogas blend	0.18	0.77	0.87	3.79	4.57	20.00	0.18	0.78	0.18	0.78
Boiler #1 - NG only	0.18	0.77	0.87	3.79	0.03	0.15	0.18	0.78	0.18	0.78
Boiler #1 - DG only	0.07	0.16	0.36	0.81	4.57	10.14	0.07	0.17	0.07	0.17
Boiler #2 - NG/biogas blend	0.18	0.77	0.87	3.79	4.57	20.00	0.18	0.78	0.18	0.78
Boiler #2 - NG only	0.18	0.77	0.87	3.79	0.03	0.15	0.18	0.78	0.18	0.78
Boiler #2 - DG only	0.07	0.32	0.36	0.81	4.57	10.14	0.07	0.17	0.07	0.17
Site Utilities										
Flare	3.10	6.88	0.68	1.51	4.57	10.14	0.07	0.17	0.07	0.17
Genset	2.66	0.13	1.33	0.07	0.00	0.00	0.06	0.00	0.06	0.00
Air Makeup	1.36	2.99	1.61	3.52	0.02	0.05	0.12	0.27	0.12	0.27
Totals:	***7.98***	***13.57***	***7.81***	***21.90***	***22.93***	***70.76***	***1.11***	***3.87***	***1.11***	***3.87***
Potential to Emit - digester gas to Flare	***7.48***	***11.54***	***5.35***	***12.69***	***4.66***	***10.50***	***0.61***	***1.99***	***0.61***	***1.99***
Potential to Emit - digester gas to Boilers	***4.38***	***4.66***	***4.67***	***11.18***	***4.63***	***20.20***	***0.53***	***1.82***	***0.53***	***1.82***
Maximum Controlled Potential to Emit	***7.48***	***11.54***	***5.35***	***12.69***	***4.66***	***20.20***	***0.61***	***1.99***	***0.61***	***1.99***

VOC		LEAD		HAP	
lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
0.13	0.56	1.2E-05	5.1E-05	0.04	0.19
0.13	0.56	1.2E-05	5.1E-05	0.04	0.19
0.05	0.12	4.9E-06	1.1E-05	0.02	0.04
0.13	0.56	1.2E-05	5.1E-05	0.04	0.19
0.87	3.79	1.2E-05	5.1E-05	0.04	0.19
0.05	0.12	4.9E-06	1.1E-05	0.02	0.04
6.60	14.65	4.9E-06	1.1E-05	0.02	0.04
0.93	0.05	6.5E-07	3.3E-08	0.40	0.02
0.09	0.20	8.1E-06	1.8E-05	0.03	0.07
8.98	***20.61***	***7.0E-05***	***2.5E-04***	***0.66***	***0.98***
8.62	***19.25***	***3.7E-05***	***1.3E-04***	***0.54***	***0.51***
2.02	***4.60***	***3.2E-05***	***1.2E-04***	***0.52***	***0.47***
8.62	***19.25***	***3.7E-05***	***1.3E-04***	***0.54***	***0.51***

	CO		**NOx**		**SO_2**		**PM2.5**		**PM10**		**Pb**
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/month
Potential to Emit	7	12	5.4	12.7	4.66	20.20	0.61	1.99	0.61	2.0	2.66E-02
Level I Threshold	15	-	0.2	1.2	0.21	1.2	0.05	0.35	0.22		14
% of Threshold	50%		2676%	1057%	2221%	1684%	1125%	569%	276%		0%

Emission Units	Control Device	Uncontrolled Emissions		Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Boiler #1 - NG only	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Boiler #1 - DG only	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Boiler #2 - NG/biogas blend	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Boiler #2 - NG only	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Boiler #2 - DG only	None	0.0074	lb CO/MMBtu	0%	0.0074	lb CO/MMBtu
Site Utilities						
Flare	None	0.310	lb CO/MMBtu	0%	0.3100	lb CO/MMBtu
Genset	None	2.0	g CO/Hp-hr	0%	2.0	g CO/Hp-hr
Air Makeup	None	0.0824	lb CO/MMBtu	0%	0.0824	lb CO/MMBtu

	Emission Factor			Operating Rate				Potential to Emit			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolled**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	0.007	0.007	lb CO/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.77	0.18	0.77
Boiler #1 - NG only	0.007	0.007	lb CO/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.77	0.18	0.77
Boiler #1 - DG only	0.007	0.007	lb CO/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.07	0.16	0.07	0.16
Boiler #2 - NG/biogas blend	0.007	0.007	lb CO/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.77	0.18	0.77
Boiler #2 - NG only	0.007	0.007	lb CO/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.77	0.18	0.77
Boiler #2 - DG only	0.007	0.007	lb CO/MMBtu	10.00	MMBtuh	87,600	MMBtu	0.07	0.32	0.07	0.32
Site Utilities						44,400					
Flare	0.310	0.310	lb CO/MMBtu	10.0	MMBtuh	44,400	MMBtu	3.10	6.88	3.10	6.88
Genset	2.000	2.000	g CO/Hp-hr	603	Hp/hr	60,346	Hp/yr	2.66	0.13	2.66	0.13
Air Makeup	0.082	0.082	lb CO/MMBtu	16.56	MMBtuh	72,536	MMBtu	1.36	2.99	1.36	2.99
						Digester gas to Flare		**7.48**	**11.54**	**7.48**	**11.54**
						Digester gas to Boilers		**4.38**	**4.66**	**4.38**	**4.66**
Notes:											
1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.											

Emission Units	Control Device	Uncontrolled Emissions		Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Boiler #1 - NG only	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Boiler #1 - DG only	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Boiler #2 - NG/biogas blend	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Boiler #2 - NG only	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Boiler #2 - DG only	low NOx burners	0.036	lb NOx/MMBtu	0%	0.0364	lb NOx/MMBtu
Site Utilities						
Flare	None	0.068	lb NOx/MMBtu	0%	0.0680	lb NOx/MMBtu
Genset	None	1.0	g NOx/Hp-hr	0%	1.0	g NOx/Hp-hr
Air Makeup	low NOx burners	0.097	lb NOx/MMBtu	0%	0.0972	lb NOx/MMBtu

	Emission Factor			Operating Rate				Potential to Emit							
	Value			Hourly		Annual		Uncontrolled		Controlled					
Emission Units	Uncontrolled	Controlled	Units	Value	Units	Value	Units	lb/hr	ton/yr	lb/hr	ton/yr				
Process Energy															
Boiler #1 - NG/biogas blend	0.036	0.036	lb NOx/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.87	3.79	0.87	3.79				
Boiler #1 - NG only	0.036	0.036	lb NOx/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.87	3.79	0.87	3.79				
Boiler #1 - DG only	0.036	0.036	lb NOx/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.36	0.81	0.36	0.81				
Boiler #2 - NG/biogas blend	0.036	0.036	lb NOx/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.87	3.79	0.87	3.79				
Boiler #2 - NG only	0.036	0.036	lb NOx/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.87	3.79	0.87	3.79				
Boiler #2 - DG only	0.036	0.036	lb NOx/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.36	0.81	0.36	0.81				
Site Utilities															
Flare	0.068	0.068	lb NOx/MMBtu	10.0	MMBtuh	44,400	MMBtu	0.68	1.51	0.68	1.51				
Genset	1.000	1.000	g NOx/Hp-hr	603	Hp/hr	60,346	Hp/yr	1.33	0.07	1.33	0.07				
Air Makeup	0.097	0.097	lb NOx/MMBtu	16.56	MMBtuh	72,536	MMBtu	1.61	3.52	1.61	3.52				
						Digester gas to Flare		**5.35**	**12.69**	**5.35**	**12.69**				
						Digester gas to Boilers		**4.67**	**11.18**	**4.67**	**11.18**				
Notes:															
1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.															
															1.433336

			Maximum Day				Average Annual Emissions			
Emission Units	**Control Device**	**Control Device**	**Uncontrolled Emissions**		**Controlled Emissions**		**Uncontrolled Emissions**		**Controlled Emissions**	
Process Energy										
Boiler #1 - NG/biogas blend	None	0%	0.192	lb SO2/MMBtu	0.192	lb SO2/MMBtu	0.097	lb SO2/MMBtu	0.097	lb SO2/MMBtu
Boiler #1 - NG only	None	0%	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu
Boiler #1 - DG only	None	0%	0.457	lb SO2/MMBtu	0.457	lb SO2/MMBtu	0.457	lb SO2/MMBtu	0.457	
Boiler #2 - NG/biogas blend	None	0%	0.192	lb SO2/MMBtu	0.192	lb SO2/MMBtu	0.097	lb SO2/MMBtu	0.097	
Boiler #2 - NG only	None	0%	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu
Boiler #2 - DG only	None	0%	0.457	lb SO2/MMBtu	0.457	lb SO2/MMBtu	0.457	lb SO2/MMBtu	0.457	lb SO2/MMBtu
Site Utilities										
Flare	None	0%	0.457	#REF!	0.457	#REF!	0.457	#REF!	0.457	#REF!
Genset	None	0%	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu
Air Makeup	None	0%	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu	0.001	lb SO2/MMBtu

	Emission Factor												
	Maximum Day		Annual Average			Operating Rate				Potential to Emit			
	Value					Hourly		Annual		Uncontrolled		Controlled	
Emission Units	Uncontrolled	Controlled			Units	Value	Units	Value	Units	lb/hr	ton/yr	lb/hr	ton/yr
Process Energy													
Boiler #1 - NG/biogas blend	0.192	0.192	0.097	0.097	lb SO2/MMBtu	23.77	MMBtuh	208,243	MMBtu	4.57	20.00	4.57	20.00
Boiler #1 - NG only	0.001	0.001	0.001	0.001	lb SO2/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.03	0.15	0.03	0.15
Boiler #1 - DG only	0.457	0.457	0.457	0.457	lb SO2/MMBtu	10.00	MMBtuh	44,400	MMBtu	4.57	10.14	4.57	10.14
Boiler #2 - NG/biogas blend	0.192	0.192	0.097	0.097	lb SO2/MMBtu	23.77	MMBtuh	208,243	MMBtu	4.57	20.00	4.57	20.00
Boiler #2 - NG only	0.001	0.001	0.001	0.001	lb SO2/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.03	0.15	0.03	0.15
Boiler #2 - DG only	0.457	0.457	0.457	0.457	lb SO2/MMBtu	10.00	MMBtuh	44,400	MMBtu	4.57	10.14	4.57	10.14
Site Utilities													
Flare	0.457	0.457	0.457	0.457	#REF!	10.000	MMBtuh	44,400	MMBtu	4.57	10.14	4.57	10.14
Genset	0.001	0.001	0.001	0.001	lb SO2/MMBtu	5.5	MMBtuh	553	MMBtu	0.00	0.00	0.00	0.00
Air Makeup	0.001	0.001	0.001	0.001	lb SO2/MMBtu	16.56	MMBtuh	72,536	MMBtu	0.02	0.05	0.02	0.05
								Digester gas to Flare		**4.66**	**10.50**	**4.66**	**10.50**
								Digester gas to Boilers		**4.63**	**20.20**	**4.63**	**20.20**
Notes:													
1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of													

Emission Units	Control Device	Uncontrolled Emissions		Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Boiler #1 - NG only	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Boiler #1 - DG only	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Boiler #2 - NG/biogas blend	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Boiler #2 - NG only		0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Boiler #2 - DG only	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Site Utilities						
Flare	None	0.007	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu
Genset	None	0.010	lb PM2.5/MMBtu	0%	0.0100	lb PM2.5/MMBtu
Air Makeup	None	0.0075	lb PM2.5/MMBtu	0%	0.0075	lb PM2.5/MMBtu

	Emission Factor			Operating Rate				Potential to Emit			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolled**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	0.0075	0.0075	lb PM2.5/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #1 - NG only	0.0075	0.0075	lb PM2.5/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #1 - DG only	0.0075	0.0075	lb PM2.5/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Boiler #2 - NG/biogas blend	0.0075	0.0075	lb PM2.5/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #2 - NG only	0.0075	0.0075	lb PM2.5/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #2 - DG only	0.0075	0.0075	lb PM2.5/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Site Utilities											
Flare	0.0075	0.0075	lb PM2.5/MMBtu	10.0	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Genset	0.0100	0.0100	lb PM2.5/MMBtu	5.53	MMBtuh	553	MMBtu	0.06	0.00	0.06	0.00
Air Makeup	0.0075	0.0075	lb PM2.5/MMBtu	16.56	MMBtuh	72,536	MMBtu	0.12	0.27	0.12	0.27
							Digester gas to Flare	**0.61**	**1.99**	**0.61**	**1.99**
							Digester gas to Boilers	**0.53**	**1.82**	**0.53**	**1.82**
Notes:											

1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.

Emission Units	Control Device	Uncontrolled Emissions		Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Boiler #1 - NG only	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Boiler #1 - DG only	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Boiler #2 - NG/biogas blend	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Boiler #2 - NG only		0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Boiler #2 - DG only	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Site Utilities						
Flare	None	0.007	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu
Genset	None	0.010	lb PM10/MMBtu	0%	0.0100	lb PM10/MMBtu
Air Makeup	None	0.0075	lb PM10/MMBtu	0%	0.0075	lb PM10/MMBtu

	Emission Factor			Operating Rate				Potential to Emit			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolled**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	0.0075	0.0075	lb PM10/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #1 - NG only	0.0075	0.0075	lb PM10/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #1 - DG only	0.0075	0.0075	lb PM10/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Boiler #2 - NG/biogas blend	0.0075	0.0075	lb PM10/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #2 - NG only	0.0075	0.0075	lb PM10/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.18	0.78	0.18	0.78
Boiler #2 - DG only	0.0075	0.0075	lb PM10/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Site Utilities											
Flare	0.0075	0.0075	lb PM10/MMBtu	10.0	MMBtuh	44,400	MMBtu	0.07	0.17	0.07	0.17
Genset	0.0100	0.0100	lb PM10/MMBtu	5.53	MMBtuh	553	MMBtu	0.06	0.00	0.06	0.00
Air Makeup	0.0075	0.0075	lb PM10/MMBtu	16.56	MMBtuh	72,536	MMBtu	0.12	0.27	0.12	0.27
							Digester gas to Flare	**0.61**	**1.99**	**0.61**	**1.99**
							Digester gas to Boilers	**0.53**	**1.82**	**0.53**	**1.82**
Notes:											

1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.

Emission Units	Control Device	Uncontrolled Emissions		Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Boiler #1 - NG only	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Boiler #1 - DG only	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Boiler #2 - NG/biogas blend	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Boiler #2 - NG only	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Boiler #2 - DG only	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu
Site Utilities						
Flare	None	0.660	lb VOC/MMBtu	0%	0.660	lb VOC/MMBtu
Genset	None	0.700	g VOC/Hp-hr	0%	0.700	g VOC/Hp-hr
Air Makeup	None	0.005	lb VOC/MMBtu	0%	0.005	lb VOC/MMBtu

	Emission Factor			Operating Rate				Potential to Emit			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolled**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	0.0054	0.0054	lb VOC/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.128	0.56	0.13	0.56
Boiler #1 - NG only	0.0054	0.0054	lb VOC/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.128	0.56	0.13	0.56
Boiler #1 - DG only	0.005	0.005	lb VOC/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.054	0.12	0.05	0.12
Boiler #2 - NG/biogas blend	0.0054	0.0054	lb VOC/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.128	0.56	0.13	0.56
Boiler #2 - NG only	0.036	0.036	lb NOx/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.87	3.79	0.87	3.79
Boiler #2 - DG only	0.0054	0.005	lb PM10/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.054	0.12	0.05	0.12
Site Utilies											
Flare	0.6600	0.6600	lb VOC/MMBtu	10.000	MMBtuh	44,400	MMBtu	6.600	14.65	6.60	14.65
Genset	0.7000	0.7000	g VOC/Hp-hr	603	Hp/hr	60,346	Hp/yr	0.93	0.05	0.93	0.05
Air Makeup	0.005	0.0054	lb VOC/MMBtu	16.56	MMBtuh	72,536	MMBtu	0.09	0.20	0.09	0.20
						Digester gas to Flare		**8.62**	**19.25**	**8.62**	**19.25**
						Digester gas to Boilers		**2.02**	**4.60**	**2.02**	**4.60**
Notes:											

1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.

Emission Units	Control Device	Uncontrolled Emissions	Units	Control Device Efficiency	Controlled Emissions	
Process Energy						
Boiler #1 - NG/biogas blend	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Boiler #1 - NG only	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Boiler #1 - DG only	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Boiler #2 - NG/biogas blend	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Boiler #2 - NG only	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Boiler #2 - DG only	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Site Utilities						
Flare	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Genset	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu
Air Makeup	None	4.9E-07	lb Pb/MMBtu	0%	4.9E-07	lb Pb/MMBtu

	Emission Factor			Operating Rate				Potential to Emit			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolled**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	4.9E-07	4.9E-07	lb Pb/MMBtu	23.77	MMBtuh	208,243	MMBtu	1.2E-05	5.1E-05	1.2E-05	5.1E-05
Boiler #1 - NG only	4.9E-07	4.9E-07	lb Pb/MMBtu	23.77	MMBtuh	208,243	MMBtu	1.2E-05	5.1E-05	1.2E-05	5.1E-05
Boiler #1 - DG only	4.9E-07	4.9E-07	lb Pb/MMBtu	10.00	MMBtuh	44,400	MMBtu	4.9E-06	1.1E-05	4.9E-06	1.1E-05
Boiler #2 - NG/biogas blend	4.9E-07	4.9E-07	lb Pb/MMBtu	23.77	MMBtuh	208,243	MMBtu	1.2E-05	5.1E-05	1.2E-05	5.1E-05
Boiler #2 - NG only	4.9E-07	4.9E-07	lb Pb/MMBtu	23.77	MMBtuh	208,243	MMBtu	1.2E-05	5.1E-05	1.2E-05	5.1E-05
Boiler #2 - DG only	4.9E-07	4.9E-07	lb Pb/MMBtu	10.00	MMBtuh	44,400	MMBtu	4.9E-06	1.1E-05	4.9E-06	1.1E-05
Site Utilies											
Flare	4.9E-07	4.9E-07	lb Pb/MMBtu	10.0	MMBtuh	44,400	MMBtu	4.9E-06	1.1E-05	4.9E-06	1.1E-05
Genset	4.9E-07	4.9E-07	lb Pb/MMBtu	603.46	Hp/hr	60,346	Hp/yr	6.5E-07	3.3E-08	6.5E-07	3.3E-08
Air Makeup	4.9E-07	4.9E-07	lb Pb/MMBtu	16.56	MMBtuh	72,536	MMBtu	8.1E-06	1.8E-05	8.1E-06	1.8E-05
						Digester gas to Flare		**0.00**	**0.00**	**0.00**	**0.00**
						Digester gas to Boilers		**0.00**	**0.00**	**0.00**	**0.00**
Notes:											
1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.											

	Emission Factor			Operating Rate				HAP PTE			
	Value			Hourly		Annual		Uncontrolled		Controlled	
Emission Units	**Uncontrolle**	**Controlled**	**Units**	**Value**	**Units**	**Value**	**Units**	**lb/hr**	**ton/yr**	**lb/hr**	**ton/yr**
Process Energy											
Boiler #1 - NG/biogas blend	1.85E-03	1.85E-03	lb/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.04	0.19	0.04	0.19
Boiler #1 - NG only	1.85E-03	1.85E-03	lb/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.04	0.19	0.04	0.19
Boiler #1 - DG only	1.85E-03	1.85E-03	lb/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.02	0.04	0.02	0.04
Boiler #2 - NG/biogas blend	1.85E-03	1.85E-03	lb/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.04	0.19	0.04	0.19
Boiler #2 - NG only	1.85E-03	1.85E-03	lb/MMBtu	23.77	MMBtuh	208,243	MMBtu	0.04	0.19	0.04	0.19
Boiler #2 - DG only	1.85E-03	1.85E-03	lb/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.02	0.04	0.02	0.04
Site Utilies											
Flare	1.85E-03	1.85E-03	lb/MMBtu	10.00	MMBtuh	44,400	MMBtu	0.02	0.04	0.02	0.04
Genset	7.22E-02	7.22E-02	lb/MMBtu	5.53	MMBtuh	553	MMBtu	0.40	0.02	0.40	0.02
Air Makeup	1.85E-03	1.85E-03	lb/MMBtu	16.5607	MMBtuh	72535.87	*MMBtu*	*0.03*	*0.07*	*0.03*	*0.07*
						Digester gas to Flare		**0.54**	**0.51**	**0.54**	**0.51**
						Digester gas to Boilers		**0.52**	**0.47**	**0.52**	**0.47**
Notes:											
1. Calculations for boiler emissions with digester gas firing assume that the boiler is receiving all available biogas. Emission totals correct for double-counting of digester gas.											

								digester gas to Flare								
				Boiler #1 - full fire, either NG or blend		Boiler #2 - full fire, either NG or blend										
								Flare		Air Makeup Units						
	Applicable MACT Review?			Yes		Yes		No		No		Maximum TAP Emissions				
Toxic Air Pollutant	Emission Factor	Units	EPA HAP?	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/day	lb/yr		AMU lb/hr ann avg
PAH (Idaho)	6.73E-07	lb/MMBtu	Yes	-	-	-	-	6.7E-06	2.99E-02	1.1E-05	4.9E-02	1.8E-05	4.3E-04	7.9E-02		5.58E-06
POM (Idaho)	1.12E-08	lb/MMBtu	Yes	-	-	-	-	1.1E-07	4.96E-04	1.9E-07	8.1E-04	3.0E-07	7.1E-06	1.3E-03		9.25E-08
Benzene	2.06E-06	lb/MMBtu	Yes	-	-	-	-	2.1E-05	9.14E-02	3.4E-05	1.5E-01	5.5E-05	1.3E-03	2.4E-01		1.70E-05
Dichlorobenzene	1.18E-06	lb/MMBtu	Yes	-	-	-	-	1.2E-05	5.22E-02	1.9E-05	8.5E-02	3.1E-05	7.5E-04	1.4E-01		9.74E-06
Formaldehyde	7.35E-05	lb/MMBtu	Yes	-	-	-	-	7.4E-04	3.26E+00	1.2E-03	5.3E+00	2.0E-03	4.7E-02	8.6E+00		6.09E-04
Hexane	1.76E-03	lb/MMBtu	Yes	-	-	-	-	1.8E-02	7.84E+01	2.9E-02	1.3E+02	4.7E-02	1.1E+00	2.1E+02		1.46E-02
Pentane	2.55E-03	lb/MMBtu	No	6.1E-02	5.3E+02	6.1E-02	5.3E+02	2.5E-02	1.13E+02	4.2E-02	1.8E+02	1.9E-01	4.5E+00	1.4E+03		2.11E-02
Toluene	3.33E-06	lb/MMBtu	Yes	-	-	-	-	3.3E-05	1.48E-01	5.5E-05	2.4E-01	8.9E-05	2.1E-03	3.9E-01		2.76E-05
Arsenic	1.96E-07	lb/MMBtu	Yes	-	-	-	-	2.0E-06	8.70E-03	3.2E-06	1.4E-02	5.2E-06	1.2E-04	2.3E-02		1.62E-06
Beryllium	1.18E-08	lb/MMBtu	Yes	-	-	-	-	1.2E-07	5.24E-04	2.0E-07	8.6E-04	3.1E-07	7.5E-06	1.4E-03		9.77E-08
Cadmium	1.08E-06	lb/MMBtu	Yes	-	-	-	-	1.1E-05	4.80E-02	1.8E-05	7.8E-02	2.9E-05	6.9E-04	1.3E-01		8.94E-06
Chromium	1.37E-06	lb/MMBtu	Yes	-	-	-	-	1.4E-05	6.08E-02	2.3E-05	9.9E-02	3.6E-05	8.7E-04	1.6E-01		1.13E-05
Chromium (VI)	6.86E-08	lb/MMBtu	Yes	-	-	-	-	6.9E-07	3.05E-03	1.1E-06	5.0E-03	1.8E-06	4.4E-05	8.0E-03		5.68E-07
Cobalt	8.24E-08	lb/MMBtu	Yes	-	-	-	-	8.2E-07	3.66E-03	1.4E-06	6.0E-03	2.2E-06	5.3E-05	9.6E-03		6.82E-07
Manganese	3.73E-07	lb/MMBtu	Yes	-	-	-	-	3.7E-06	1.66E-02	6.2E-06	2.7E-02	9.9E-06	2.4E-04	4.4E-02		3.09E-06
Mercury	2.55E-07	lb/MMBtu	Yes	-	-	-	-	2.6E-06	1.13E-02	4.2E-06	1.8E-02	6.8E-06	1.6E-04	3.0E-02		2.11E-06
Nickel	2.06E-06	lb/MMBtu	Yes	-	-	-	-	2.1E-05	9.15E-02	3.4E-05	1.5E-01	5.5E-05	1.3E-03	2.4E-01		1.71E-05
Selenium	2.35E-08	lb/MMBtu	Yes	-	-	-	-	2.4E-07	1.04E-03	3.9E-07	1.7E-03	6.2E-07	1.5E-05	2.7E-03		1.95E-07
Nitrous Oxide	2.16E-03	lb/MMBtu	No	5.1E-02	4.5E+02	5.1E-02	4.5E+02	2.2E-02	9.58E+01	3.6E-02	1.6E+02	1.6E-01	3.8E+00	1.2E+03		1.79E-02
Hydrogen Sulfide	#NAME?	lb/ton	No	-	-	-	-	-	-	-	-	-	-	-		
Ammonia	#NAME?	lb/ton	No	-	-	-	-	-	-	-	-	-	-	-		
AP-42, Tables 1.4-3 and 1.4-4. Based on 1020 Btu/scf natural gas heat content																

1	2	3	4	5
TAP Emissions from Engines				
Toxic Air Pollutant	**Emission Factor, lb/MMBtu**	**lb/hr**	**lb/day**	**lb/yr**
Dichloroethane	4.72E-05	2.6E-04	6.3E-03	2.6E-02
Trimethyl benzene (mixed and individual isomers)	7.11E-05	3.9E-04	9.4E-03	3.9E-02
Propylene dichloride (1,2-Dichloropropane)	2.69E-05	1.5E-04	3.6E-03	1.5E-02
Cyclopentane	2.27E-04	1.3E-03	3.0E-02	1.3E-01
Methylcyclohexane	1.23E-03	6.8E-03	1.6E-01	6.8E-01
Nonane	1.10E-04	6.1E-04	1.5E-02	6.1E-02
Octane	3.51E-04	1.9E-03	4.7E-02	1.9E-01
Pentane	2.60E-03	1.4E-02	3.4E-01	1.4E+00
Annual emissions based on 100 hours of operation per year. TAPs listed are those that are not EPA HAPs.				

			NG burners		Engines		Total		
Air Pollutant	Idaho Toxic Air Pollutant?	EL, lb/hr	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr	lb/yr	lb/hr as % of EL
Chromium	NC	3.3E-02	3.6E-05	1.6E-01	-	-	3.64E-05	1.6E-01	0.1%
Cobalt	NC	3.3E-03	2.2E-06	9.6E-03	-	-	2.19E-06	9.6E-03	0.1%
Cyclopentane	NC	1.1E+02	-	-	3.0E-02	1.3E-01	3.01E-02	1.3E-01	0.0%
Dichlorobenzene	NC	2.0E+01	3.1E-05	1.4E-01	-	-	3.12E-05	1.4E-01	0.0%
Dichloroethane	NC	2.7E+01	-	-	6.3E-03	2.6E-02	6.26E-03	2.6E-02	0.0%
Hexane	NC	1.2E+01	4.7E-02	2.1E+02	-	-	4.69E-02	2.1E+02	0.4%
Manganese	NC	3.3E-01	9.9E-06	4.4E-02	-	-	9.91E-06	4.4E-02	0.0%
Methylcyclohexane	NC	1.1E+02	-	-	1.6E-01	6.8E-01	1.63E-01	6.8E-01	0.2%
Nitrous Oxide	NC	6.0E+00	1.6E-01	1.2E+03	-	-	1.60E-01	1.2E+03	2.7%
Nonane	NC	7.0E+01	-	-	1.5E-02	6.1E-02	1.46E-02	6.1E-02	0.0%
Octane	NC	9.3E+01	-	-	4.7E-02	1.9E-01	4.66E-02	1.9E-01	0.0%
Pentane	NC	1.2E+02	1.9E-01	1.4E+03	3.4E-01	1.4E+00	5.34E-01	1.4E+03	0.5%
Propylene dichloride (1,2-Dichloropropane)	NC	2.3E+01	-	-	3.6E-03	1.5E-02	3.57E-03	1.5E-02	0.0%
Selenium	NC	1.3E-02	6.2E-07	2.7E-03	-	-	6.24E-07	2.7E-03	0.0%
Toluene	NC	2.5E+01	8.9E-05	3.9E-01	-	-	8.85E-05	3.9E-01	0.0%
Trimethyl benzene (mixed and individual isomers)	NC	8.2E+00	-	-	9.4E-03	3.9E-02	9.43E-03	3.9E-02	0.1%
Arsenic	C	1.5E-06	5.2E-06	2.3E-02	-	-	5.21E-06	2.3E-02	174.4%
Benzene	C	8.0E-04	5.5E-05	2.4E-01	-	-	5.47E-05	2.4E-01	3.4%
Beryllium	C	2.8E-05	3.1E-07	1.4E-03	-	-	3.13E-07	1.4E-03	0.6%
Cadmium	C	3.7E-06	2.9E-05	1.3E-01	-	-	2.87E-05	1.3E-01	389.6%
Chromium (VI)	C	5.6E-07	1.8E-06	8.0E-03	-	-	1.82E-06	8.0E-03	163.5%
Formaldehyde	C	5.1E-04	2.0E-03	8.6E+00	-	-	1.95E-03	8.6E+00	192.5%
Nickel	C	2.7E-05	5.5E-05	2.4E-01	-	-	5.47E-05	2.4E-01	101.8%
PAH (Idaho)	C	9.1E-05	1.8E-05	7.9E-02	-	-	1.79E-05	7.9E-02	9.9%
POM (Idaho)	C	2.0E-06	3.0E-07	1.3E-03	-	-	2.97E-07	1.3E-03	7.5%
Based on 1020 Btu/scf natural gas heat content									

Emission Units	Release Point	Stack ID	Flat	Description	Type	East m	North m	Elev ft	Height ft	temp °F
Boiler #1 - NG/biogas blend	Boiler #1	Br1MIX		Boiler #1 - NG/biogas blend	Raincap	402742.50	4816171.19	4816.00	36.00	314
Boiler #1 - NG only	Boiler #1	Br1NG		Boiler #1 - NG only	Raincap	402742.50	4816171.19	4816.00	36.00	314
Boiler #1 - DG only max day	Boiler #1	Br1DGMAX		Boiler #1 - DG only max day	Raincap	402742.50	4816171.19	4816.00	36.00	288
Boiler #1 - DG only avg	Boiler #1	Br1DGAVG		Boiler #1 - DG only avg	Raincap	402742.50	4816171.19	4816.00	36.00	273
Boiler #2 - NG/biogas blend	Boiler #2	Br2MIX		Boiler #2 - NG/biogas blend	Raincap	402746.46	4816171.19	4816.00	36.00	314
Boiler #2 - NG only	Boiler #2	Br2NG		Boiler #2 - NG only	Raincap	402746.46	4816171.19	4816.00	36.00	314
Flare - maximum day	Flare	FlareMax		Flare - maximum day	Default	402943.66	4816052.63	4801.48	24.32	1,832
Flare - average	Flare	FlareAvg		Flare - average	Default	402943.66	4816052.63	4801.48	21.74	1,832
Genset	Genset	Genset		Genset	Default	402712.02	4816181.25	4816.00	10.00	1,326
Roof and Building Exhaust Fans										
ROOF MOUNTED EXHAUST	Exhaust Fan 3	EF_3		ROOF MOUNTED EXHAUST	Raincap	402733.05	4816163.27	4816.00	32.00	70
ROOF MOUNTED EXHAUST	Exhaust Fan 4	EF_4		ROOF MOUNTED EXHAUST	Default	402749.20	4816170.58	4816.00	33.50	70
INLINE EXHAUST	Exhaust Fan 5	EF_5		INLINE EXHAUST	Default	402776.02	4816171.92	4816.00	31.50	70
INLINE EXHAUST	Exhaust Fan 6	EF_6		INLINE EXHAUST	Default	402713.31	4816114.19	4816.00	31.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 7	EF_7		ROOF MOUNTED EXHAUST	Default	402842.47	4816113.89	4816.00	34.08	70
ROOF MOUNTED EXHAUST	Exhaust Fan 8	EF_8		ROOF MOUNTED EXHAUST	Default	402781.89	4816115.87	4816.00	34.08	70
ROOF MOUNTED EXHAUST	Exhaust Fan 9	EF_9		ROOF MOUNTED EXHAUST	Raincap	402772.06	4816115.87	4816.00	32.33	70
ROOF MOUNTED EXHAUST	Exhaust Fan 10	EF_10		ROOF MOUNTED EXHAUST	Raincap	402721.54	4816121.74	4816.00	32.33	70
INLINE EXHAUST	Exhaust Fan 11	EF_11		INLINE EXHAUST	Default	402748.59	4816111.76	4816.00	31.50	70
INLINE EXHAUST	Exhaust Fan 12	EF_12		INLINE EXHAUST	Default	402803.46	4816114.96	4816.00	31.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 14	EF_14		ROOF MOUNTED EXHAUST	Raincap	402860.45	4816167.61	4816.00	31.50	70
INLINE EXHAUST	Exhaust Fan 15	EF_15		INLINE EXHAUST	Default	402751.03	4816116.79	4816.00	31.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 16	EF_16		ROOF MOUNTED EXHAUST	Default	402749.13	4816165.00	4816.00	33.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 17	EF_17		ROOF MOUNTED EXHAUST	Raincap	402741.37	4816125.14	4816.00	31.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 18	EF_18		ROOF MOUNTED EXHAUST	Raincap	402718.65	4816125.41	4816.00	31.50	70
ROOF MOUNTED EXHAUST	Exhaust Fan 19	EF_19		ROOF MOUNTED EXHAUST	Raincap	402778.39	4816122.49	4816.00	31.50	70
AREAPOLY - excess AMU air	areapoly source representing fugitive building emissions	AMU								See AREAPOLY worksheet

Discharge	Exit vel	Dia	NO2_HR	NO2_ANN	SO2_HR	SO2_ANN	PM2.5_HR	PM2.5_ANN	PM10_HR	As_E6	Cd_E6	Cr+6_E6	HCOH_E6	Ni_E6
acfm	fps	inches	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
8,548	45.35	24.00	0.866	3.795	4.566	19.998	0.177	0.776	0.177					
8,354	44.32	24.00	0.866	3.795	0.035	0.153	0.177	0.776	0.177					
3,798	20.15	24.00	0.364		4.566		0.075		0.075					
1,925	10.21	24.00		0.809		10.136		0.165						
8,548	45.35	24.00	0.866	3.795	4.566	19.998	0.177	0.776	0.177					
8,354	44.32	24.00	0.866	3.795	0.035	0.153	0.177	0.776	0.177					
	65.62	21.82	0.680		4.566		0.075		0.075					
	65.62	15.54		1.510		10.136		0.165		0.993	5.474	0.348	372.683	17.06
3,643	111.32	10.00	0.000	0.067	0.003	0.000	0.055	0.003	1.330					
15,500	11.21	65	0.106	0.232	0.002	0.004	0.008	0.018	0.008	0.107	0.589	0.037	40.133	1.124
13,000	17.24	48	0.089	0.195	0.001	0.003	0.007	0.015	0.007	0.090	0.494	0.031	33.660	0.943
2,450	10.21	27	0.017	0.037	0.000	0.001	0.001	0.003	0.001	0.017	0.093	0.006	6.344	0.178
950	11.63	16	0.007	0.014	0.000	0.000	0.000	0.001	0.000	0.007	0.036	0.002	2.460	0.069
20,500	12.08	72	0.140	0.307	0.002	0.005	0.011	0.024	0.011	0.141	0.780	0.050	53.079	1.487
20,500	12.08	72	0.140	0.307	0.002	0.005	0.011	0.024	0.011	0.141	0.780	0.050	53.079	1.487
32,600	14.82	82	0.223	0.489	0.003	0.007	0.017	0.037	0.017	0.225	1.240	0.079	84.408	2.365
32,600	14.82	82	0.223	0.489	0.003	0.007	0.017	0.037	0.017	0.225	1.240	0.079	84.408	2.365
26,950	46.69	42	0.184	0.404	0.003	0.006	0.014	0.031	0.014	0.186	1.025	0.065	69.779	1.955
26,950	46.69	42	0.184	0.404	0.003	0.006	0.014	0.031	0.014	0.186	1.025	0.065	69.779	1.955
250	1.61	22	0.002	0.004	0.000	0.000	0.000	0.000	0.000	0.002	0.010	0.001	0.647	0.018
1,350	8.98	21	0.009	0.020	0.000	0.000	0.001	0.002	0.001	0.009	0.051	0.003	3.495	0.098
13,000	17.24	48	0.089	0.195	0.001	0.003	0.007	0.015	0.007	0.090	0.494	0.031	33.660	0.943
2,175	8.48	28	0.015	0.033	0.000	0.000	0.001	0.002	0.001	0.015	0.083	0.005	5.631	0.158
250	1.29	24	0.002	0.004	0.000	0.000	0.000	0.000	0.000	0.002	0.010	0.001	0.647	0.018
400	2.06	24	0.003	0.006	0.000	0.000	0.000	0.000	0.000	0.003	0.015	0.001	1.036	0.029
			0.176	0.386	0.000	0.000	0.013	0.030	0.013	0.178	0.978	0.062	66.607	1.866
		AMU total	1.61	3.52	0.022	0.048	0.123	0.270	0.123	1.62	8.94	0.57	608.85	17.06

Vertex #	AREAPOLY vertices											
	1		2		3		4		5		6	
1	E	N	E	N	E	N	E	N	E	N	E	N
2	402712.02	4816175.15	402776.71	4816175.15	402776.71	4816166.01	402829.37	4816166.01	402829.37	4816110.38	402712.02	4816110.38
3												
4												
5												
6												
7												
8												

The AREAPOLY source is created by following the outline of the main building production area.

RELEASE PARAMETERS

Parameter	Value	Units	Basis
elevation	4816.00	ft MSL	same as main building
Building height	31.00	ft	same as main building
relase height	15.50	ft	one half of building height. Equivalent to uniform mixing
			assume the release has initial vertical mixing through the height of the building.
Szinit	14.42	ft	SZINIT = building height ÷ 2.15 (AERMOD Users Guide)
temp	70	°F	room temperature

Pollutant	NAAQS, µg/m^3	Background, as listed value	units	Background, µg/m^3	Available Increment, µg/m^3
CO 1 hr	40,000	1.84	ppm	2,143	39,998
CO 8 hr	10,000	1	ppm	1,165	9,999
NO2 1 hr	188	11.3	ppb	21.6	176.7
NO2 annual (ppb)	100	1.8	ppb	3.4	98.2
PM2.5 24 hr (µg/m3)	35	13.7	µg/m^3	13.7	21.3
PM2.5 annual (µg/m3)	12	4.7	µg/m^3	4.7	7.3
PM10 24 hr	150	71.1	µg/m^3	71.1	78.9
SO2 1 hr (ppb)	196	4.9	ppb	13.1	191.1
SO2 3 hr (ppb)	1,300	6.5	ppb	17.3	1,293.5
SO2 24 hr (ppb)	365	2.7	ppb	7.2	362.3
SO2 annual (ppb)	80	0.5	ppb	1.3	79.5

ppb to µg/m^3

Latitude	43.51
Longitude	-112.2

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

M E M O R A N D U M

DATE: October 29, 2021 (Updated December 27, 2021)

TO: Aaron Hoberg, Permit Writer, Air Program

FROM: Pao Baylon, Modeling Review Analyst, Air Program

PROJECT: P-2021.0030 PROJ 62655, Initial Permit for a New Beef Processing Facility located in Idaho Falls, Idaho.

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

Contents

Acronyms, Units, and Chemical Nomenclature 3

1.0 Summary 5

2.0 Background Information 7

2.1 Project Description 7

2.2 Facility Location and Area Classification 8

2.3 Air Impact Analyses Required for All Permits to Construct 8

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses 8

2.5 Toxic Air Pollutant Analyses 11

3.0 Analytical Methods and Data 11

3.1 Emission Source Data 11

3.1.1 Criteria Pollutant Modeling Applicability and Modeled Emission Rates 12

3.1.2 TAPs Modeling Applicability and Modeled Emission Rates 16

3.1.3 Emission Release Parameters 17

3.1.4 Emission Release Parameter Justification 19

3.2 Background Concentrations 23

3.3 Impact Modeling Methodology 23

3.3.1 General Overview of Impact Analyses 23

3.3.2 Modeling Protocol 24

3.3.3 Modeling Methodology 24

3.3.4 Model Selection 24

3.3.5 Meteorological Data 25

3.3.6 Effects of Terrain on Modeled Impacts 26
3.3.7 Facility Layout and Downwash 26
3.3.8 NOx Chemistry 27
3.3.9 Ambient Air Boundary 28
3.3.10 Receptor Network 28
3.3.11 Good Engineering Practice Stack Height 29
4.0 NAAQS and TAPs Impact Modeling Results 29
4.1 Results for NAAQS Analyses 29
4.1.1 Significant Impact Level Analysis 29
4.1.2 Cumulative NAAQS Impact Analysis 29
4.2 Results for TAPs Impact Analyses 31
5.0 Conclusions 32
References 33

Acronyms, Units, and Chemical Nomenclature

AAC	Acceptable Ambient Concentration of a Non-carcinogenic TAP
AACC	Acceptable Ambient Concentration of a Carcinogenic TAP
acfm	Actual cubic feet per minute
ADB	Anaerobic Digester Building
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AMU	Air Makeup Unit
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
ASOS	Automated Surface Observing System
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
Btu	British thermal units
Btu/hr	British thermal units per hour
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
Coal Creek	Coal Creek Environmental Associates, LLC (permittee's permitting and modeling consultant)
DEQ	Idaho Department of Environmental Quality
D_{equiv}	Equivalent diameter of the flare
DG	Digester Gas
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
GEP	Good Engineering Practice
H_2S	Hydrogen sulfide
hr	Hours
Idaho Air Rules	Rules for the Control of Air Pollution in Idaho, located in the Idaho Administrative Procedures Act 58.01.01
ISCST3	Industrial Source Complex Short Term 3 dispersion model
K	Kelvin
km	Kilometers
kW	Kilowatt
lb	Pounds
lb/hr	Pounds per hour
m	Meters
m/sec	Meters per second
MAU	Makeup air unit
MBM	Meat and Bone Meal
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Dataset

NG	Natural Gas
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NW AIRQUEST	Northwest International Air Quality Environmental Science and Technology Consortium
O_3	Ozone
Pb	Lead
PM_{10}	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic particle diameter less than or equal to a nominal 2.5 micrometers
ppb	Parts per billion
ppmv	Parts per million by volume
ppmw	Parts per million by weight
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
PTE	Potential to Emit
Q_c	Flared gas heat release
Riverbend	Riverbend Meats, LLC (permittee)
scfm	Standard cubic feet per minute
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
T/day	Tons per day
TAP	Toxic Air Pollutant
tpy	Tons per year
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
º	Degrees Latitude or Longitude
ºF	Degrees Fahrenheit
µg/m^3	Micrograms per cubic meter of air

1.0 Summary

Riverbend Meats, LLC (Riverbend) submitted a Permit to Construct (PTC) application for the construction of a new greenfield beef processing facility located west of Idaho Falls, Idaho. The facility plans to process up to 600 head of cattle per day. Site production activities will include animal intake, animal harvest and carcass handling, fabrication, cold storage, and shipping. Site support activities will include steam production (boilers), anaerobic digestion of process wastewater, ammonia refrigeration, natural gas (NG)-fired emergency generators, and air makeup units (AMUs) for building ventilation and space heating. Digester gas (DG) produced in the anaerobic digester will either be blended with the NG feed to boilers or will be combusted in an on-site flare. Treated wastewater will be land-applied as reuse irrigation water on nearby lands that are also owned or controlled by Riverbend. Project-specific air quality analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to the Idaho Department of Environmental Quality (DEQ) to demonstrate that applicable emissions do not result in violation of a National Ambient Air Quality Standard (NAAQS) or Toxic Air Pollutant (TAP) increment as required by the Idaho Administrative Procedures Act 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03). This memorandum provides a summary of the applicability assessment for analyses and air impact analyses used to demonstrate compliance with applicable NAAQS and TAP increments, as required by Idaho Air Rules Section 203.02 and 203.03.

Riverbend and their modeling consultant, Coal Creek Environmental Associates, LLC (Coal Creek), prepared the PTC application and performed ambient air impact analyses for this project. DEQ review of submitted data and DEQ analyses summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that estimated emissions associated with operation of the facility will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not address/evaluate compliance with other rules or analyses not pertaining to the air impact analyses. Evaluation of emission estimates was the responsibility of the DEQ permit writer and is addressed in the main body of the DEQ Statement of Basis, and emission calculation methods were not evaluated in this modeling review memorandum.

Table 1 presents key assumptions and results to be considered in the development of the permit. Idaho Air Rules require air impact analyses be conducted in accordance with methods outlined in 40 CFR 51, Appendix W *Guideline on Air Quality Models* (Appendix W). Appendix W requires that air quality impacts be assessed using atmospheric dispersion models with emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

The submitted information and analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emission estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a NAAQS compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that TAP emission increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments. This conclusion assumes that conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition. The DEQ permit writer should use Table 1 and other information presented in this memorandum to generate appropriate permit

provisions/restrictions to assure emissions do not exceed applicable regulatory thresholds requiring further analyses and to assure the requirements of Appendix W are met regarding emissions representative of design capacity or permit allowable rates.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES.	
Criteria/Assumption/Result	**Explanation/Consideration**
NAAQS Compliance Margin. Design value impacts of all criteria pollutants were well below applicable NAAQS. After consideration of background concentrations, impacts were still less than 51.2% of applicable NAAQS.	NAAQS compliance is demonstrated if modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the Significant Impact Levels (SILs).
General Emission Rates. Emission rates used in the air impact analyses must represent maximum potential emissions as given by design capacity, inherently limited by the nature of the process or configuration of the facility, or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emission rates substantially greater than those used in the air impact analyses.
Air Impact Analyses for Criteria Pollutant Emissions. Project-specific emission increases for 24-hour PM_{10}, 24-hour and annual $PM_{2.5}$, 1-hour and annual NO_2, and 1-hour and 3-hour SO_2 exceed Level I modeling applicability thresholds. Therefore, these pollutants are subject to NAAQS Compliance Demonstration requirements.	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutant increases above Below Regulatory Concern (BRC) thresholds, or for pollutants having an emission increase that is greater than Level I modeling applicability thresholds (where the BRC exclusion cannot be used).
Cumulative NAAQS Impact Analysis Initially Performed. A SIL analysis was not conducted for the Riverbend Meats (Riverbend) facility. Coal Creek proceeded directly to the more comprehensive cumulative NAAQS impact analysis.	A SIL analysis, which is performed to evaluate whether the proposed project could have a significant impact to ambient air, requires modeling project emissions only. Because this is a new facility, the entire facility emissions are considered new project emissions. Therefore, a SIL analysis was considered redundant and not performed for the project.
Air Impact Analyses for TAP Emissions. Allowable emissions of arsenic, cadmium, chromium (VI), formaldehyde, and nickel exceed screening emission levels (ELs). Analyses demonstrating compliance with arsenic, cadmium, chromium (VI), formaldehyde, and nickel TAP increments were performed.	A TAP increment compliance demonstration, as required by Idaho Air Rules Section 203.03, would be required for any TAPs with emission increases above ELs.
Modeled Operating Scenarios. Three different operating scenarios were modeled: • Digester Gas (DG) blended with Natural Gas (NG) fuel to Boilers. This will be the most common operating scenario. For modeling purposes, the scenario assumes that both boilers are operating at full fire. All digester gas is routed to Boiler 1, along with additional NG as needed for Boiler 1 to operate at full fire. Meanwhile, Boiler 2 operates at full fire using NG. • DG routed to Flare. Boilers 1 and 2 operate at full fire using NG. • Boiler 1 operating only with DG. In this scenario, Boiler 1 does not combust any NG. This limits Boiler 1 firing to the amount of DG being produced. Meanwhile, Boiler 2 continues to operate at full fire with NG. SO_2 emissions from combusting DG were calculated assuming a hydrogen sulfide (H_2S) concentration of 2,400 parts per million by weight (ppmw) in the digester gas.	Compliance has been demonstrated only for the operating scenarios described in the application. Worst-case impacts among the three operating scenarios were reported in the cumulative NAAQS impact analyses. Worst-case impacts for 24-hour and annual $PM_{2.5}$, 24-hour PM_{10}, and 1-hour and annual NO_2 were modeled when assuming that all DG is combusted in the flare. Worst-case impacts for 1-hour and 3-hour SO_2 were modeled when assuming that Boiler 1 operates only with DG. Compliance has not been demonstrated for an H_2S concentration exceeding 2,400 ppmw in the digester gas.
Testing and Maintenance of Emergency Generator. An emergency generator will provide electrical backup power to the Riverbend facility in the event electric power is interrupted for facility operations. For testing and maintenance purposes, the emergency generator will be limited to 100 hours per year.	Limited daily and annual operation assumptions for the emergency generator were applied to the cumulative NAAQS impact analyses. The annual limit of 100 hours per year for the emergency generator is appropriate given that the 1-hour NO_2 modeling

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES.	
Criteria/Assumption/Result	**Explanation/Consideration**
Testing and maintenance operation of the emergency generator is subject to modeling requirements except for 1-hour NO_2 SIL and NAAQS. True operation of the emergency generator, during an actual emergency, is not subject to modeling requirements.	exemption requires this operating limit.
Ambient Air Boundary. The ambient air boundary will be a continuous barbed wire fence with "No Trespassing" signage.	Compliance has not been demonstrated for areas within the ambient air boundary. Therefore, it is critical that the facility be constructed as described in the application.
Release Parameters for Emission Points. Stack heights are no shorter than what is indicated in this memorandum. Stack diameters are no larger than what is indicated in this memorandum. Typical exhaust flow rates and temperatures at the point of release are not less than the values indicated in this memorandum.	Compliance with applicable air quality standards is not assured if release parameters vary substantially from what was used in impact analyses.

Summary of Submittals and Actions

June 24, 2021	Application received by DEQ.
June 29, 2021	Regulatory start date.
July 27, 2021	Application determined incomplete by DEQ.
August 9, 2021	Incompleteness response received by DEQ.
September 7, 2021	Application determined complete by DEQ.

2.0 Background Information

This section provides background information applicable to the project and the site proposed for the facility. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

Riverbend is proposing to construct a new greenfield beef processing facility in Idaho Falls, Idaho. The facility plans to process up to 600 head of cattle per day. Site production activities will include:

- animal intake;
- animal harvest and carcass handling;
- fabrication;
- cold storage; and
- shipping.

Site support activities will include:

- steam production (boilers);
- anaerobic digestion of process wastewater;
- ammonia refrigeration;

- NG-fired emergency generators; and
- AMUs for building ventilation and space heating.

DG produced in the anaerobic digester will either be blended with the NG feed to boilers or will be combusted in an on-site open flare. Treated wastewater will be land-applied as reuse irrigation water on nearby lands that are also owned or controlled by Riverbend.

The PTC addresses all air pollutant-emitting activities associated with the project.

2.2 Facility Location and Area Classification

The facility will be located in Bonneville County, west of Idaho Falls, south of West Broadway Street near South 85th West (Northing: 4,816,136 meters [m]; Easting: 402,844 m; UTM Zone 12), which is designated as an attainment or unclassifiable area for particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$), carbon monoxide (CO), ozone (O_3), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and lead (Pb). The area is not classified as non-attainment for any criteria pollutant.

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules Sections 203.02 and 203.03 state:

> *No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:*
>
> ***02. NAAQS**. The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*
>
> ***03. Toxic Air Pollutants.** Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

> ***02. Estimates of Ambient Concentrations**. All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix W (Guideline on Air Quality Models).*

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

If specific criteria pollutant emission increases associated with the proposed permitting project cannot qualify for a BRC exemption as per Idaho Air Rules Section 221, then the permit cannot be issued unless the application demonstrates that applicable emission increases will not cause or significantly contribute to a violation of NAAQS, as required by Idaho Air Rules Section 203.02.

The first phase of a NAAQS compliance demonstration is to evaluate whether the proposed facility/project could have a significant impact to ambient air. Section 3.1.1 of this memorandum describes the applicability evaluation of Idaho Air Rules Section 203.02. The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted in accordance with methods outlined in Appendix W. Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a "significant contribution" in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

Table 2. APPLICABLE REGULATORY LIMITS.

Pollutant	Averaging Period	Significant Impact Levels[a] (µg/m^3)[b]	Regulatory Limit[c] (µg/m^3)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.2	12[k]	Mean of maximum 1st highest[l]
Carbon Monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 µg/m^3)	75 ppb[p] (196 µg/m^3)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 µg/m^3)	100 ppb[s] (188 µg/m^3)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	70 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-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, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-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 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-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 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

If modeled maximum pollutant impacts to ambient air from the emission sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from potential/allowable emissions resulting from the project and emissions from any nearby co-contributing sources (including existing emissions from the facility that are unrelated to the project), and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

If the cumulative NAAQS impact analysis indicates an exceedance of NAAQS, a culpability analysis can determine if this exceedance is due to emissions from the proposed project. The permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. If project-specific impacts are below the SIL, then the project does not have a significant contribution to the specific violations.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) applicable specific criteria pollutant emission increases are at a level defined as BRC, using the criteria established by DEQ regulatory interpretation[1]; or b) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or c) modeled design values of the

cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or d) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emission increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emission increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP. The DEQ permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion.

3.0 Analytical Methods and Data

This section describes the methods and data used in the analyses to demonstrate compliance with applicable air quality impact requirements. The DEQ Statement of Basis provides a discussion of the methods and data used to estimate criteria and TAP emission rates.

3.1 Emission Source Data

Emissions of criteria pollutants and TAPs resulting from operation of the Riverbend facility were estimated by Coal Creek for various applicable averaging periods. The calculation of potential emissions

is the responsibility of the DEQ permit writer, and the representativeness and accuracy of emission estimates is not addressed in this modeling memorandum. DEQ air impact analysts are responsible for assuring that potential emission rates provided in the emission inventory are properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emission rates used in the impact modeling applicability analyses and any modeling analyses, as listed in this memorandum, should be reviewed by the DEQ permit writer and compared with those in the final emission inventory. All modeled criteria air pollutant and TAP emission rates must be equal to or greater than the facility's potential emissions calculated in the PTC emission inventory or proposed permit allowable emission rates.

3.1.1 Criteria Pollutant Modeling Applicability and Modeled Emission Rates

If project-specific emission increases for criteria pollutants would qualify for a BRC permit exemption as per Idaho Air Rules Section 221 if it were not for potential emissions of one or more pollutants exceeding the BRC threshold of 10 percent of emissions defined by Idaho Air Rules as significant, then a NAAQS compliance demonstration may not be required for those pollutants with emissions below BRC levels. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant.[1]" The interpretation policy also states that the exemption criteria of uncontrolled potential to emit (PTE) not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year. The BRC exemption cannot be used to exempt a project from a pollutant-specific NAAQS compliance demonstration in most cases where a PTC is required for the action regardless of emission quantities, such as the modification of an existing emission or throughput limit.

A NAAQS compliance demonstration must be performed for pollutant increases that would not qualify for the BRC exemption from the requirement to demonstrate compliance with NAAQS.

Site-specific air impact modeling analyses may not be necessary for some pollutants, even where such emissions do not qualify for the BRC exemption. DEQ has developed modeling applicability thresholds, below which a site-specific modeling analysis is not required. DEQ generic air impact modeling analyses that were used to develop the modeling thresholds provide a conservative SIL analysis for projects with emissions below identified threshold levels. Project-specific modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*[2]. These thresholds were based on assuring an ambient impact of less than the established SIL for specific pollutants and averaging periods.

If total project-specific emission rate increases of a pollutant are below Level I Modeling Applicability Thresholds, then project-specific air impact analyses are not necessary for permitting. Use of Level II Modeling Applicability Thresholds is conditional, requiring DEQ approval. DEQ approval is based on dispersion-affecting characteristics of the emission sources such as stack height, stack gas exit velocity, stack gas temperature, distance from sources to ambient air, presence of elevated terrain, and potential exposure to sensitive public receptors.

Table 3 provides a comparison between project-specific emission increases and Modeling Applicability Thresholds.

Table 3. SITE-SPECIFIC CRITERIA POLLUTANT MODELING APPLICABILITY.					
Pollutant	**Averaging Period**	**Emissions**	**Level I Modeling Thresholds**	**Level II Modeling Thresholds[a]**	**Site-Specific Modeling Required?**
PM_{10}	24-hour	0.61 lb/hr[b]	0.22	2.6	Yes
$PM_{2.5}$	24-hour	0.61 lb/hr	0.054	0.63	Yes
	Annual	1.99 tpy[c]	0.35	4.1	Yes
Carbon Monoxide (CO)	1-hour, 8-hour	7.0 lb/hr	15	175	No
Sulfur Dioxide (SO_2)	1-hour, 3-hour	4.66 lb/hr	0.21	2.5	Yes
Nitrogen Oxides (NOx)	1-hour	5.4 lb/hr	0.20	2.4	Yes
	Annual	12.7 tpy	1.2	14	Yes

a. Level II thresholds were not evaluated for the project.
b. Pounds per hour.
c. Tons per year.

As indicated in Table 3, modeling was required for 24-hour PM_{10}, 24-hour and annual $PM_{2.5}$, 1-hour and 3-hour SO_2, and 1-hour and annual NO_2 based on the Level I Modeling Applicability Thresholds. Site-specific dispersion modeling was not required for CO. Level II thresholds were not evaluated for the project.

Table 4 lists criteria pollutant emission rates used in the cumulative NAAQS impact analyses. A SIL analysis was not performed for this project. Per Appendix A of the *State of Idaho Guideline for Performing Air Quality Impact Analysis*, modeling for 1-hour NO_2 is not required for emergency engine generators that run intermittently.[2] Therefore, the emergency generator (GENSET) was excluded from the air impact analysis for 1-hour NO_2.

The two boilers will combust NG, DG, or a blend of NG and DG. Because there is a difference between maximum day and average annual DG production, separate release points were created for peak day and annual operations for scenarios when a boiler is combusting *only* DG. These two scenarios differ in both emission rates and stack release parameters. This leads to four operating scenarios for each of the boilers:

- Full fire with NG/DG Blend.
- Full fire with only NG.
- Combustion of DG only at peak day DG production.
- Combustion of DG only at average annual DG production.

Operation of Boiler 2 with only DG was not modeled. This is because the release parameters and emission rates are identical for Boilers 1 and 2, and the stacks are sufficiently close (refer to Figure 3 of this modeling memo for an illustration of the model setup) that differences in modeled impacts would be trivial. For the same reason, operation of Boiler 2 with a mix of NG/DG was also not modeled. In conducting modeling with DG, all DG was routed through Boiler 1.

Three different operating scenarios were modeled:

1. DG blended with NG fuel to Boilers (source group "BLR1_MIX" in submitted modeling files)
   - In this scenario DG is blended with the NG feed to the boilers. This will be the most common operating scenario. For modeling purposes, the scenario assumes that both boilers are operating at full fire. All digester gas is routed to Boiler 1, along with additional NG as needed for Boiler 1 to operate at full fire. Meanwhile, Boiler 2 operates at full fire using NG.

- This scenario included the following emission sources (refer to Table 4 for description of each model ID): BR1MIX, BR2NG, GENSET, EF_3 through EF_12, EF_14 through EF_19, and AMU.

2. DG routed to Flare (source group "DG_FLR" in submitted modeling files)
   - In this scenario, all DG is combusted in the flare. Boilers 1 and 2 operate at full fire using NG. Modeling for hourly and daily pollutant averaging times assumes that DG is produced at maximum day rates. For annual averaging, DG production at maximum annual rates is assumed.
   - This scenario included the following emission sources (refer to Table 4 for description of each model ID): BR1NG, BR2NG, FLAREMAX, FLAREAVG, GENSET, EF_3 through EF_12, EF_14 through EF_19, and AMU.
3. Boiler 1 operating only with DG (source group "BLR1_DG" in submitted modeling files)
   - In this scenario, Boiler 1 does not combust any NG. This limits Boiler 1 firing to the amount of DG being produced. Modeling for hourly and daily pollutant averaging times assumes that DG is produced at maximum day rates. For annual averaging, DG production is assumed at maximum annual rates. Meanwhile, Boiler 2 continues to operate at full fire with NG.
   - This scenario included the following emission sources (refer to Table 4 for description of each model ID): BR1DGMAX, BR1DGAVG, BR2NG, GENSET, EF_3 through EF_12, EF_14 through EF_19, and AMU.

Table 4. MODELED EMISSION RATES FOR CUMULATIVE NAAQS IMPACT ANALYSIS.								
Source ID	**Description**	**24-hr $PM_{2.5}$ (lb/hr)[a]**	**Annual $PM_{2.5}$ (tpy)[b]**	**24-hr PM_{10} (lb/hr)**	**1-hr NO_2 (lb/hr)**	**Annual NO_2 (tpy)**	**1-hr SO_2 (lb/hr)**	**3-hr SO_2 (lb/hr)**
BR1MIX[c]	Boiler #1 - NG[d]/DG[e] blend	1.77E-01	7.76E-01	1.77E-01	8.66E-01	3.79E+00	4.57E+00	4.57E+00
BR1NG[f]	Boiler #1 - NG only	1.77E-01	7.76E-01	1.77E-01	8.66E-01	3.79E+00	3.50E-02	3.50E-02
BR1DGMAX[g]	Boiler #1 - DG only – maximum DG production	7.45E-02	0	7.45E-02	3.64E-01	0	4.57E+00	4.57E+00
BR1DGAVG[g]	Boiler #1 - DG only – average DG production	0	1.65E-01	0	0	8.09E-01	0	0
BR2NG[h]	Boiler #2 - NG only	1.77E-01	7.76E-01	1.77E-01	8.66E-01	3.79E+00	3.50E-02	3.50E-02
FLAREMAX[f]	Flare combusting DG with maximum daily DG production	7.45E-02	0	7.45E-02	6.80E-01	0	4.57E+00	4.57E+00
FLAREAVG[f]	Flare combusting DG with average DG production	0	1.65E-01	0	0	1.51E+00	0	0
GENSET[h]	Emergency Generator	5.52E-02	2.76E-03	1.33E+00	0[i]	6.65E-02	3.25E-03	3.25E-03
EF_3[h]	Roof-Mounted Exhaust	8.13E-03	1.78E-02	8.13E-03	1.06E-01	2.32E-01	1.61E-03	1.61E-03
EF_4[h]	Roof-Mounted Exhaust	6.82E-03	1.49E-02	6.82E-03	8.90E-02	1.95E-01	1.35E-03	1.35E-03
EF_5[h]	Inline Exhaust	1.29E-03	2.82E-03	1.29E-03	1.68E-02	3.67E-02	2.54E-04	2.54E-04
EF_6[h]	Inline Exhaust	4.99E-04	1.09E-03	4.99E-04	6.50E-03	1.42E-02	9.84E-05	9.84E-05
EF_7[h]	Roof-Mounted Exhaust	1.08E-02	2.36E-02	1.08E-02	1.40E-01	3.07E-01	2.12E-03	2.12E-03
EF_8[h]	Roof-Mounted Exhaust	1.08E-02	2.36E-02	1.08E-02	1.40E-01	3.07E-01	2.12E-03	2.12E-03
EF_9[h]	Roof-Mounted Exhaust	1.71E-02	3.75E-02	1.71E-02	2.23E-01	4.89E-01	3.38E-03	3.38E-03
EF_10[h]	Roof-Mounted Exhaust	1.71E-02	3.75E-02	1.71E-02	2.23E-01	4.89E-01	3.38E-03	3.38E-03
EF_11[h]	Inline Exhaust	1.41E-02	3.10E-02	1.41E-02	1.84E-01	4.04E-01	2.79E-03	2.79E-03
EF_12[h]	Inline Exhaust	1.41E-02	3.10E-02	1.41E-02	1.84E-01	4.04E-01	2.79E-03	2.79E-03
EF_14[h]	Roof-Mounted Exhaust	1.31E-04	2.87E-04	1.31E-04	1.71E-03	3.75E-03	2.59E-05	2.59E-05
EF_15[h]	Inline Exhaust	7.08E-04	1.55E-03	7.08E-04	9.24E-03	2.02E-02	1.40E-04	1.40E-04
EF_16[h]	Roof-Mounted Exhaust	6.82E-03	1.49E-02	6.82E-03	8.90E-02	1.95E-01	1.35E-03	1.35E-03
EF_17[h]	Roof-Mounted Exhaust	1.14E-03	2.50E-03	1.14E-03	1.49E-02	3.26E-02	2.25E-04	2.25E-04
EF_18[h]	Roof-Mounted Exhaust	1.31E-04	2.87E-04	1.31E-04	1.71E-03	3.75E-03	2.59E-05	2.59E-05
EF_19[h]	Roof-Mounted Exhaust	2.10E-04	4.60E-04	2.10E-04	2.74E-03	6.00E-03	4.14E-05	4.14E-05
AMU[h]	Building Fugitives	1.35E-02	2.96E-02	1.35E-02	1.76E-01	3.86E-01	3.56E-04	3.56E-04

a. Pounds per hour.
b. Tons per year.
c. Emission source was modeled for Scenario 1: DG blended with NG fuel to Boilers.
d. Natural Gas.
e. Digester Gas.
f. Emission source was modeled for Scenario 2: DG routed to Flare.
g. Emission source was modeled for Scenario 3: Boiler 1 operating only with DG.
h. Emission source was modeled for all three scenarios.
i. Per Appendix A of the *State of Idaho Guideline for Performing Air Quality Impact Analysis*, modeling for 1-hour NO_2 is not required for emergency engine generators that run intermittently.

Ozone (O_3) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O_3 is formed in the atmosphere through reactions of VOCs, NOx, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses cannot be used to estimate O_3 impacts resulting from VOC and NOx emissions from an industrial facility. O_3 concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource-intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O_3 within the context of permitting a new stationary source has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

> *. . . footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."*
>
> *The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."*

DEQ determined it was not appropriate or necessary to require a quantitative source-specific O_3 impact analysis because allowable emission estimates of VOCs and NOx are below the 100 tons/year threshold.

3.1.2 TAPs Modeling Applicability and Modeled Emission Rates

Facility-wide emissions of arsenic, cadmium, chromium (VI), formaldehyde, and nickel exceed the applicable emission screening levels (ELs) of Idaho Air Rules Section 585 and 586. Air impact modeling analyses were then required to demonstrate that maximum impacts of arsenic, cadmium, chromium (VI), formaldehyde, and nickel are below applicable ambient increment standards expressed in Idaho Air Rules Section 585 and 586 as AACs and AACCs.

Arsenic, cadmium, chromium (VI), formaldehyde, and nickel are carcinogenic TAPs that are regulated on a long-term averaging basis. Therefore, the appropriate emission rates for impact analyses are maximum annual emissions, expressed as an average pound/hour value over an 8,760-hour period.

Table 5 provides a summary of TAP emission increases for the five TAPs that had an increase exceeding the ELs of Idaho Air Rules Section 585 or 586.

Table 5. TAP EMISSION INCREASES THAT TRIGGER MODELING.

Toxic Air Pollutant	Emissions (lb/hr)[a]	Screening Emissions Level (lb/hr)
Arsenic[b]	2.62E-06	1.50E-06
Cadmium[b]	1.44E-05	3.70E-06
Chromium (VI)[b]	9.16E-07	5.60E-07
Formaldehyde[b]	9.82E-04	5.10E-04
Nickel[b]	2.75E-05	2.70E-05

[a.] Pounds per hour.

b. Carcinogenic TAP. ELs are annual maximum emissions expressed as pounds/hour. The emission rate is the annual emissions divided by 8,760 hours/year.

Table 6 lists the emission rates used in the TAPs impact analysis. The total modeled emission rate for each TAP is greater than or equal to the emission increase for that TAP listed in Table 5. As noted in Section 2.5 of this modeling memorandum, if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP. The permit writer evaluates the applicability of specific TAPs to the Section 210.20 exclusion.

Table 6. MODELED EMISSION RATES FOR TAPS IMPACT ANALYSIS.

Source ID	Description	Arsenic[a] (×10^6 lb/hr)[b]	Cadmium[a] (×10^6 lb/hr)	Chromium (VI)[a] (×10^6 lb/hr)	Formaldehyde[a] (×10^6 lb/hr)	Nickel[a] (×10^6 lb/hr)
FLAREAVG	Flare combusting DG[c] with average DG production	9.93E-01	5.47E+00	3.48E-01	3.73E+02	1.71E+01
EF_3	Roof-Mounted Exhaust	1.07E-01	5.89E-01	3.74E-02	4.01E+01	1.12E+00
EF_4	Roof-Mounted Exhaust	8.97E-02	4.94E-01	3.14E-02	3.37E+01	9.43E-01
EF_5	Inline Exhaust	1.69E-02	9.32E-02	5.92E-03	6.34E+00	1.78E-01
EF_6	Inline Exhaust	6.56E-03	3.61E-02	2.29E-03	2.46E+00	6.89E-02
EF_7	Roof-Mounted Exhaust	1.41E-01	7.80E-01	4.95E-02	5.31E+01	1.49E+00
EF_8	Roof-Mounted Exhaust	1.41E-01	7.80E-01	4.95E-02	5.31E+01	1.49E+00
EF_9	Roof-Mounted Exhaust	2.25E-01	1.24E+00	7.87E-02	8.44E+01	2.36E+00
EF_10	Roof-Mounted Exhaust	2.25E-01	1.24E+00	7.87E-02	8.44E+01	2.36E+00
EF_11	Inline Exhaust	1.86E-01	1.02E+00	6.51E-02	6.98E+01	1.95E+00
EF_12	Inline Exhaust	1.86E-01	1.02E+00	6.51E-02	6.98E+01	1.95E+00
EF_14	Roof-Mounted Exhaust	1.73E-03	9.51E-03	6.04E-04	6.47E-01	1.81E-02
EF_15	Inline Exhaust	9.32E-03	5.13E-02	3.26E-03	3.50E+00	9.79E-02
EF_16	Roof-Mounted Exhaust	8.97E-02	4.94E-01	3.14E-02	3.37E+01	9.43E-01
EF_17	Roof-Mounted Exhaust	1.50E-02	8.27E-02	5.25E-03	5.63E+00	1.58E-01
EF_18	Roof-Mounted Exhaust	1.73E-03	9.51E-03	6.04E-04	6.47E-01	1.81E-02
EF_19	Roof-Mounted Exhaust	2.76E-03	1.52E-02	9.66E-04	1.04E+00	2.90E-02
AMU	Building Fugitives	1.78E-01	9.78E-01	6.21E-02	6.66E+01	1.87E+00
Total Modeled Emission Rates		2.62	14.42	0.92	981.53	34.12

a. Carcinogenic TAP. The emission rate is the annual emissions divided by 8,760 hours/year.
b. Pounds per hour.
c. Digester Gas.

3.1.3 Emission Release Parameters

Table 7 lists the emission release parameters, including stack height, exhaust temperature, exhaust velocity, and stack diameter for all emission point sources (English units are in parentheses). Emission point release parameters were based on information provided in the application. Justification for emission release parameters is summarized in the next section.

Table 7. POINT SOURCE EMISSION RELEASE PARAMETERS IN METRIC UNITS (ENGLISH UNITS IN PARENTHESES).

Release Point	Description	UTM[a] Coordinates		Stack Height in m (ft)[c]	Stack Exhaust Temp. in K (°F)[d]	Stack Exhaust Velocity in m/sec (fps)[e]	Stack Diameter in m (ft)	Orient. Of Release[f]
		Easting-X in m[b]	Northing-Y in m					
BR1MIX	Boiler #1 -	402,742.50	4,816,171.19	11.0	430	13.8	0.61	R

Table 7. POINT SOURCE EMISSION RELEASE PARAMETERS IN METRIC UNITS (ENGLISH UNITS IN PARENTHESES).								
Release Point	**Description**	**UTM[a] Coordinates**		**Stack Height in m (ft)[c]**	**Stack Exhaust Temp. in K (°F)[d]**	**Stack Exhaust Velocity in m/sec (fps)[e]**	**Stack Diameter in m (ft)**	**Orient. Of Release[f]**
		Easting-X in m[b]	**Northing-Y in m**					
	NG[c]/DG[d] blend			(36.0)	(314)	(45.4)	(2.0)	
BR1NG	Boiler #1 - NG only	402,742.50	4,816,171.19	11.0 (36.0)	430 (314)	13.5 (44.3)	0.61 (2.0)	R
BR1DGMAX	Boiler #1 - DG only – maximum DG production	402,742.50	4,816,171.19	11.0 (36.0)	415 (288)	6.1 (20.2)	0.61 (2.0)	R
BR1DGAVG	Boiler #1 - DG only – average DG production	402,742.50	4,816,171.19	11.0 (36.0)	407 (273)	3.1 (10.2)	0.61 (2.0)	R
BR2NG	Boiler #2 - NG only	402,746.46	4,816,171.19	11.0 (36.0)	430 (314)	13.5 (44.3)	0.61 (2.0)	R
FLAREMAX	Flare combusting DG with maximum daily DG production	402,943.66	4,816,052.63	7.4 (24.3)	1,273 (1,832)	20.0 (65.6)	0.55 (1.8)	D
FLAREAVG	Flare combusting DG with average DG production	402,943.66	4,816,052.63	6.6 (21.7)	1,273 (1,832)	20.0 (65.6)	0.39 (1.3)	D
GENSET	Emergency Generator	402,712.02	4,816,181.25	3.0 (10.0)	992 (1,326)	33.9 (111.3)	0.25 (0.8)	D
EF_3	Roof-Mounted Exhaust	402,733.05	4,816,163.27	9.8 (32.0)	294 (70)	3.4 (11.2)	1.65 (5.4)	R
EF_4	Roof-Mounted Exhaust	402,749.20	4,816,170.58	10.2 (33.5)	294 (70)	5.3 (17.2)	1.22 (4.0)	D
EF_5	Inline Exhaust	402,776.02	4,816,171.92	9.6 (31.5)	294 (70)	3.1 (10.2)	0.69 (2.3)	D
EF_6	Inline Exhaust	402,713.31	4,816,114.19	9.6 (31.5)	294 (70)	3.5 (11.6)	0.41 (1.3)	D
EF_7	Roof-Mounted Exhaust	402,842.47	4,816,113.89	10.4 (34.1)	294 (70)	3.7 (12.1)	1.83 (6.0)	D
EF_8	Roof-Mounted Exhaust	402,781.89	4,816,115.87	10.4 (34.1)	294 (70)	3.7 (12.1)	1.83 (6.0)	D
EF_9	Roof-Mounted Exhaust	402,772.06	4,816,115.87	9.9 (32.3)	294 (70)	4.5 (14.8)	2.08 (6.8)	R
EF_10	Roof-Mounted Exhaust	402,721.54	4,816,121.74	9.9 (32.3)	294 (70)	4.5 (14.8)	2.08 (6.8)	R
EF_11	Inline Exhaust	402,748.59	4,816,111.76	9.6 (31.5)	294 (70)	14.2 (46.7)	1.07 (3.5)	D
EF_12	Inline Exhaust	402,803.46	4,816,114.96	9.6 (31.5)	294 (70)	14.2 (46.7)	1.07 (3.5)	D
EF_14	Roof-Mounted Exhaust	402,860.45	4,816,167.61	9.6 (31.5)	294 (70)	0.5 (1.6)	0.56 (1.8)	R
EF_15	Inline Exhaust	402,751.03	4,816,116.79	9.6 (31.5)	294 (70)	2.7 (9.0)	0.53 (1.8)	D
EF_16	Roof-Mounted Exhaust	402,749.13	4,816,165.00	10.2 (33.5)	294 (70)	5.3 (17.2)	1.22 (4.0)	D
EF_17	Roof-Mounted Exhaust	402,741.37	4,816,125.14	9.6 (31.5)	294 (70)	2.6 (8.5)	0.71 (2.3)	R
EF_18	Roof-Mounted Exhaust	402,718.65	4,816,125.41	9.6 (31.5)	294 (70)	0.4 (1.3)	0.61 (2.0)	R

Table 7. POINT SOURCE EMISSION RELEASE PARAMETERS IN METRIC UNITS (ENGLISH UNITS IN PARENTHESES).								
Release Point	Description	UTM[a] Coordinates		Stack Height in m (ft)[c]	Stack Exhaust Temp. in K (°F)[d]	Stack Exhaust Velocity in m/sec (fps)[e]	Stack Diameter in m (ft)	Orient. Of Release[f]
		Easting-X in m[b]	Northing-Y in m					
EF_19	Roof-Mounted Exhaust	402,778.39	4,816,122.49	9.6 (31.5)	294 (70)	0.6 (2.1)	0.61 (2.0)	R

a. Universal Transverse Mercator.
b. m: meters.
c. ft: feet.
d. K: Kelvin; °F: degrees Fahrenheit.
e. m/sec: meters per second; fps: feet per second.
f. Orientation of release: D (default, vertical, uninterrupted release); H (horizontal release); R (rain-capped release).

Table 8 lists the emission release parameters, including release height and initial vertical dimension for the AREAPOLY source representing building fugitive emissions from AMUs (English units are in parentheses). Emission point release parameters were based on information provided in the application. Justification for emission release parameters is summarized in the next section.

Table 8. AREAPOLY SOURCE EMISSION RELEASE PARAMETERS IN METRIC UNITS (ENGLISH UNITS IN PARENTHESES).						
Release Point	Description	Vertex Number	UTM[a] Coordinates		Release Height in m (ft)[c]	Init. Vert. Dim. in m (ft)
			Easting-X in m[b]	Northing-Y in m		
AMU	Building Fugitives	1	402,712.02	4,816,175.15	4.7 (15.5)	4.4 (14.4)
		2	402,776.71	4,816,175.15		
		3	402,776.71	4,816,166.01		
		4	402,829.37	4,816,166.01		
		5	402,829.37	4,816,110.38		
		6	402,712.02	4,816,110.38		

a. Universal Transverse Mercator.
b. m: meters.
c. ft: feet.

3.1.4 Emission Release Parameter Justification

Boilers

Model IDs: BR1MIX, BR1NG, BR1DGMAX, BR1DGAVG, and BR2NG

The listed manufacturer for Boilers 1 and 2 is Cleaver-Brooks. Each boiler will have a rated heat input of 23.8 Million British thermal units per hour (MMBtu/hr) and will be equipped with low-NOx and low-CO burners. Both boilers will have economizers.

Each boiler will be capable of firing NG, DG, or a blend of NG and DG, leading to three different fueling options for each boiler:

- NG only.
- NG/DG blend.
- DG only.

Each fueling option is treated as a distinct emission activity. For the NG/DG blend scenario, the boiler is assumed to operate at full fire, with the blend containing the maximum amount of DG. For the DG only scenario, the boiler operating rate is limited to the amount of DG available. Because there is a difference between maximum day and average annual DG production, separate release points were created for peak day and annual operations for scenarios when a boiler is combusting only DG. These two scenarios differ in both emission rate and stack release parameters. This leads to four operating scenarios for each of the boilers:

- Full fire with NG/DG Blend ("BR1MIX" and "BR2MIX").
- Full fire with only NG ("BR1NG" and "BR2NG").
- Combustion of DG only at peak day DG production ("BR1DGMAX" and "BR2DGMAX").
- Combustion of DG only at average annual DG production ("BR1DGAVG" and "BR2DGAVG").

Operation of Boiler 2 with only DG ("BR2DGMAX" and "BR2DGAVG") was not modeled. This is because the release parameters and emission rates are identical for Boilers 1 and 2, and the stacks are sufficiently close that differences in modeled impacts would be trivial. Similarly, operation of Boiler 2 with NG/DG blend ("BR2MIX") was not modeled. In conducting modeling with DG, all DG was routed through Boiler 1. DEQ determined that exclusion of BR2DGMAX, BR2DGAVG, and BR2MIX from modeling was justified given the magnitude of modeled impacts.

Modeled stack height (36 feet) and exit diameter (2.0 feet) for both boilers were established for this project and must be verified upon final construction.

For full fire with only NG ("BR1NG" and "BR2NG"), exit temperature (430 Kelvin) and flow rate (8,354 actual cubic feet per minute [acfm]) were derived from vendor data for full load (with economizer). The corresponding modeled exit velocity is 13.5 meter/second, which is adequately reasonable for the source.

$$BR1NG\ and\ BR2NG\ exit\ velocity = 8{,}354 \frac{\cancel{feet^3}}{\cancel{minute}} \times \frac{4}{\pi(2.0\ \cancel{feet})^2} \times \frac{1\ \cancel{minute}}{60\ seconds} \times \frac{1\ meter}{3.28\ \cancel{feet}} = 13.5 \frac{meter}{second}$$

For full fire with NG/DG blend ("BR1MIX"), exit temperature (430 Kelvin) was derived from vendor data (with economizer). Flow rate (8,548 acfm) was calculated from the sum of NG (4,786 standard cubic feet per minute [scfm]) and DG (111 scfm) firing. The corresponding modeled exit velocity is 13.8 meter/second, which is adequately reasonable for the source.

$$BR1MIX\ exit\ velocity = 8{,}548 \frac{\cancel{feet^3}}{\cancel{minute}} \times \frac{4}{\pi(2.0\ \cancel{feet})^2} \times \frac{1\ \cancel{minute}}{60\ seconds} \times \frac{1\ meter}{3.28\ \cancel{feet}} = 13.8 \frac{meter}{second}$$

When combusting only DG, the maximum heat rates for the boiler will be 10 MMBtu/hr and 5.1 MMBtu/hr for maximum day ("BR1DGMAX") and for maximum annual ("BR1DGAVG") operations, respectively. This corresponds to 42% and 21% of the 23.8 MMBtu/hr maximum boiler operating rate. The stack gas temperatures corresponding to 50% firing rate (415 Kelvin) and 25% firing (407 Kelvin) were used for maximum day and average annual operations, respectively. Exhaust flow rates (3,798 acfm for BR1DGMAX and 1,925 acfm for BR1DGAVG) were determined from combustion chemistry using DG heat rate and accounting for DG inerts. The corresponding modeled exit velocities are 6.1 meter/second and 3.1 meter/second, respectively, which are adequately conservative for the source.

$$BR1DGMAX\ exit\ velocity = 3{,}798 \frac{\cancel{feet^3}}{\cancel{minute}} \times \frac{4}{\pi(2.0\ \cancel{feet})^2} \times \frac{1\ \cancel{minute}}{60\ seconds} \times \frac{1\ meter}{3.28\ \cancel{feet}} = 6.1 \frac{meter}{second}$$

$$BR1DGAVG\ exit\ velocity = 1{,}925 \frac{\cancel{feet^3}}{\cancel{minute}} \times \frac{4}{\pi(2.0\ \cancel{feet})^2} \times \frac{1\ \cancel{minute}}{60\ seconds} \times \frac{1\ meter}{3.28\ \cancel{feet}} = 3.1 \frac{meter}{second}$$

All boiler stacks were modeled with a rain-capped release.

Release parameters for all boiler emission points were appropriately documented and justified.

Open Flare

Model ID: FLAREMAX and FLAREAVG

A flare will be used to vent DG that is not combusted in boilers. The flare will be a Varec Model 244W, or equivalent, open flare.

Flare release parameters are a function of heat release rate. For hourly and daily averaging, the flare heat release is equal to the maximum daily estimated MMBtu in DG. For annual averaging, the flare heat release is equal to the maximum annual MMBtu in DG. Separate flare release points were created from maximum day (FLAREMAX) and average annual (FLAREAVG) releases. Modeled stack parameters were developed using flare release parameter estimating procedures described in Appendix B of the Oklahoma Department of Environmental Quality (ODEQ) Air Dispersion Modeling Guideline.[3] The calculation of flare release parameters was performed using the Flare Tool included in the BEEST AERMOD interface, Version 12.04.

The BEEST Flare Tool (Oklahoma option) assumes an exhaust temperature of 1,273 Kelvin and an exit velocity of 20 meter/second, similar to EPA's AERSCREEN method. Equivalent diameter of the flare (in meters), D_{equiv}, was calculated using the following equation:

$$D_{equiv} = 1.752 \times 10^{-4} \sqrt{Q_c}$$

where

Q_c: flared gas heat release in British thermal units per hour (Btu/hr).

Riverbend used a Q_c value of 10.0 MMBtu/hr, which represents the peak daily production, for FLAREMAX. The equivalent diameter is therefore 0.55 meters (1.8 feet). The actual stack height (15 feet) was used as an input to the Flare Tool, which resulted in an effective release height of 7.4 meters or 24.3 feet.

For FLAREAVG, Riverbend used a Q_c value of 5.1 MMBtu/hr. The equivalent diameter is therefore 0.39 meters (1.3 feet). The actual stack height (15 feet) was also used as an input to the Flare Tool, which resulted in an effective release height of 6.6 meters or 21.7 feet.

The flare was modeled with vertical, uninterrupted release.

DEQ is satisfied that the stack parameter values used in the model for the flare are adequately accurate for the source.

Emergency Generator

Model IDs: GENSET

A 450-kilowatt (kW) NG-fired generator set will provide backup power during electricity outages. The listed manufacturer is Caterpillar. The engine will be a 4-stroke lean-burn engine and is assumed to operate no more than 100 hours per year for testing and maintenance.

Modeled stack height (10.0 feet) was established for the project and must be verified upon final construction. Exit diameter (0.8 feet) was based on vendor data and must be verified upon final construction. Exhaust temperature (1,326°F) and flow rate (3,060 acfm) were based on the specification sheet at full load. The corresponding exit velocity is therefore 30.9 meter/second.

$$GENSET\ exit\ velocity = 3{,}060\,\frac{\cancel{feet^3}}{\cancel{minute}} \times \frac{4}{\pi(0.8\,\cancel{feet})^2} \times \frac{1\,\cancel{minute}}{60\,seconds} \times \frac{1\,meter}{3.28\,\cancel{feet}} = 30.9\,\frac{meter}{second}$$

However, GENSET was modeled with an exit velocity of 33.9 meter/second. Given the intermittent nature of the emergency generator and the small contribution to design value impacts, DEQ accepted this value for modeling purposes.

GENSET was modeled with vertical, uninterrupted release.

Release parameters for the emergency generator were appropriately documented and justified.

Air Makeup Units

Model IDs: EF_3 through EF_12, EF_14 through EF_19, and AMU

Twenty NG direct-fired AMUs will provide building ventilation air. Most of this air is exhausted through roof vents with exhaust fans.

To allocate AMU emissions, the percentage of makeup air supply exhausted through roof vents was determined, and that fraction of the makeup air unit emissions was assigned to roof vents. This roof vent allocation was then prorated to 16 individual roof vents (EF_3 through EF_12 and EF_14 through EF_19) based on the exhaust rate of the specific roof vent. The total makeup air supply is 235,150 acfm, and the combined roof vent exhaust fan capacity is 209,425 acfm, which is 89.1% of the makeup air supply.

Exhaust points EF_3 through EF_12 and EF_14 through EF_19 were modeled with an ambient temperature of 70°F. Exit diameters (ranging from 1.3 feet to 6.8 feet) were based on manufacturer's specifications and must be verified upon final construction. Stack heights (ranging from 31.5 feet to 34.1 feet) were established for this project and must be verified upon final construction. Modeled exit velocities were calculated based on the exhaust flow rate and were reasonably acceptable for the source.

The remainder of the makeup air emissions (10.9%) was assumed to be released as a fugitive emission and was assigned to an AREAPOLY source (model ID: AMU) aligned with the portion of the building used for processing activities. The procedure for creating this AREAPOLY source is described below.

- An AREAPOLY source was created with sides that follow the outside walls of the main production area of the plant. This aligns with the portions of the plant from which fugitive AMU emissions are expected to occur.
- The initial vertical dimension of each building volume (14.4 feet) was set equal to the building height divided by 2.15. This is equivalent to assuming initial vertical mixing equal to the height of the building not counting the basement level.
- The release height (15.5 feet) was set equal to half of the building height (31.0 feet).

Release parameters for all AMUs were appropriately justified.

Because modeled impacts were far below the applicable standards, it was not necessary to review release parameters in greater detail.

3.2 Background Concentrations

Background concentrations are used if a cumulative NAAQS impact analysis is needed to demonstrate compliance with applicable NAAQS. Background design values (DV) for all criteria pollutants and averaging periods were obtained from the Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST; https://arcg.is/1jXmHH) using the project site coordinates. These background air pollutant levels are based on regional scale air pollution modeling of pollutants in Washington, Oregon, and Idaho, with modeling results adjusted according to available monitoring data. These background concentrations are listed in Table 9.

Table 9. CRITERIA POLLUTANT AMBIENT BACKGROUND CONCENTRATIONS.

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)[a,b]
$PM_{2.5}$	24-hour	13.7
	Annual	4.7
PM_{10}	24-hour	71.1
NO_2	1-hour	21.6
	Annual	3.4
SO_2	1-hour	13.1
	3-hour	17.3

a. Micrograms per cubic meter.
b. NW AIRQUEST ambient background lookup tool, mid 2014–mid 2017.

3.3 Impact Modeling Methodology

This section describes the modeling methods used by the applicant to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Impact Analyses

Coal Creek performed the project-specific air pollutant emission inventory and air impact analyses that were submitted with the application. The submitted information/analyses, in combination with results from DEQ's air impact analyses, demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 10 provides a brief description of parameters used in the modeling analyses.

Table 10. MODELING PARAMETERS.		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Idaho Falls, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 21112.
Meteorological Data	Idaho Falls surface station; Boise upper air station	The meteorological model input files for this project were developed by DEQ. The data were processed using the latest version of AERMET (version 19191) and the "ADJ_U*" option. See Section 3.3.5 of this memorandum for additional details of the meteorological data.
Terrain	Considered	National Elevation Dataset (NED) was acquired from the USGS for the surrounding area. AERMAP version 18081 was used to process terrain elevation data for all buildings and receptors. See Section 3.3.6 for more details.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD. See Section 3.3.7 for more details.
NOx Chemistry	ARM2	The ARM2 method is a Tier 2 analysis method which assumes an ambient equilibrium between NO and NO_2, in which the conversion of NO to NO_2 is predicted using hourly ambient NOx monitoring data. ARM2 has been adopted by the EPA as a default regulatory Tier 2 option. See Section 3.3.8 for more details.
Receptor Grid	**SIL Analysis** A SIL analysis was not performed for this project.	
	Cumulative NAAQS Impact Analysis The selection of receptors for use in the cumulative NAAQS impact analysis is as follows (see Section 3.3.10 for more details):	
	Grid 1	25-meter spacing along the ambient air boundary, extending 50 meters beyond the ambient air boundary.
	Grid 2	25-meter corner grid, with southwest corner at 402,500 meters Easting/4,815,500 meters Northing and northeast corner at 403,000 meters Easting/4,816,800 meters Northing. This grid provides added receptor density to the west and northwest of the site, where the plant is closest to the fenceline.
	Grid 3	100-meter corner grid, extending a minimum of 1,000 meters beyond the ambient air boundary.
	TAPs Analysis The same receptor grid was used for the TAPs analysis as for the cumulative NAAQS impact analysis.	

3.3.2 Modeling Protocol

A modeling protocol was not submitted for this project.

3.3.3 Modeling Methodology

Project-specific modeling and other required impact analyses were generally conducted using data and methods described in the *Idaho Air Quality Modeling Guideline.*[2]

3.3.4 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in Appendix W. The refined, steady-state, multiple-source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight-line trajectory of ISCST3, but it includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

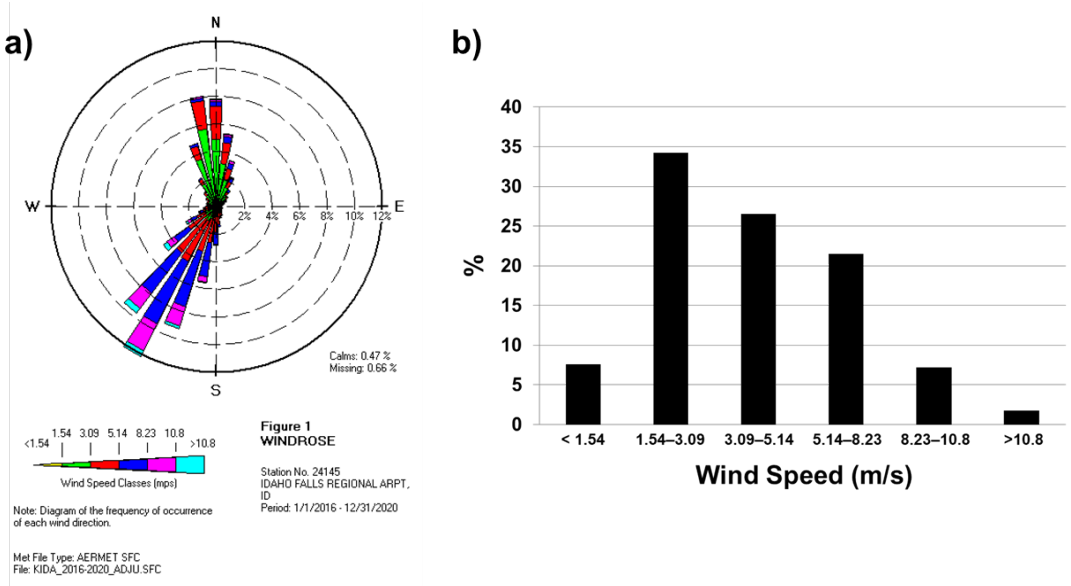
AERMOD version 21112 was used by Coal Creek for the modeling analyses to evaluate impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.5 Meteorological Data

DEQ processed a meteorological dataset from Idaho Falls, Idaho (KIDA; station ID 725785-24145) covering the years 2016-2020. The upper air soundings required by AERMET were obtained from the Boise airport station (site ID 24131). Surface characteristics were determined by DEQ staff using AERSURFACE version 20060. DEQ modeling staff evaluated annual moisture conditions for the AERSURFACE runs based on 31 years of Idaho Falls Airport precipitation data. Two of the five years, 2018 and 2020, were assessed as having average moisture content, defined as total annual precipitation that is within the 30th and 70th percentiles of the 31-year precipitation data. The years 2016, 2017, and 2019 were assessed as wet years, defined as total annual precipitation larger than the 70th percentile of the 31-year precipitation data. There was no snow cover data from the NOAA National Climatic Data Center website for the Idaho Falls Airport from 2016-2020. However, continuous snow cover for extended periods was evident from examination of local climatological records for the nearby Idaho Falls KIFI Station for the years 2016-2020 and therefore was assessed in the processing.

Figure 1 shows a wind rose and wind speed histogram at the Idaho Falls Airport. AERMINUTE version 15272 was used to process Automated Surface Observing Systems (ASOS) wind data for use in AERMET. The percent calm distribution for the period from 2016-2020 is 0.47%. Missing data account for 0.66% of the data period. AERMET version 19191 was used to process surface and upper air data and to generate a model-ready meteorological data input file. The "adjust u star" (ADJ_U*) option was applied in AERMET to enhance model performance during low wind speeds under stable conditions. DEQ provided meteorological data to the applicant, with and without the ADJ_U* option enabled. In the submitted modeling files, Coal Creek used the meteorological data with the ADJ_U* option enabled. DEQ determined that these data are adequately representative of the meteorology at the Riverbend site for minor source permitting.

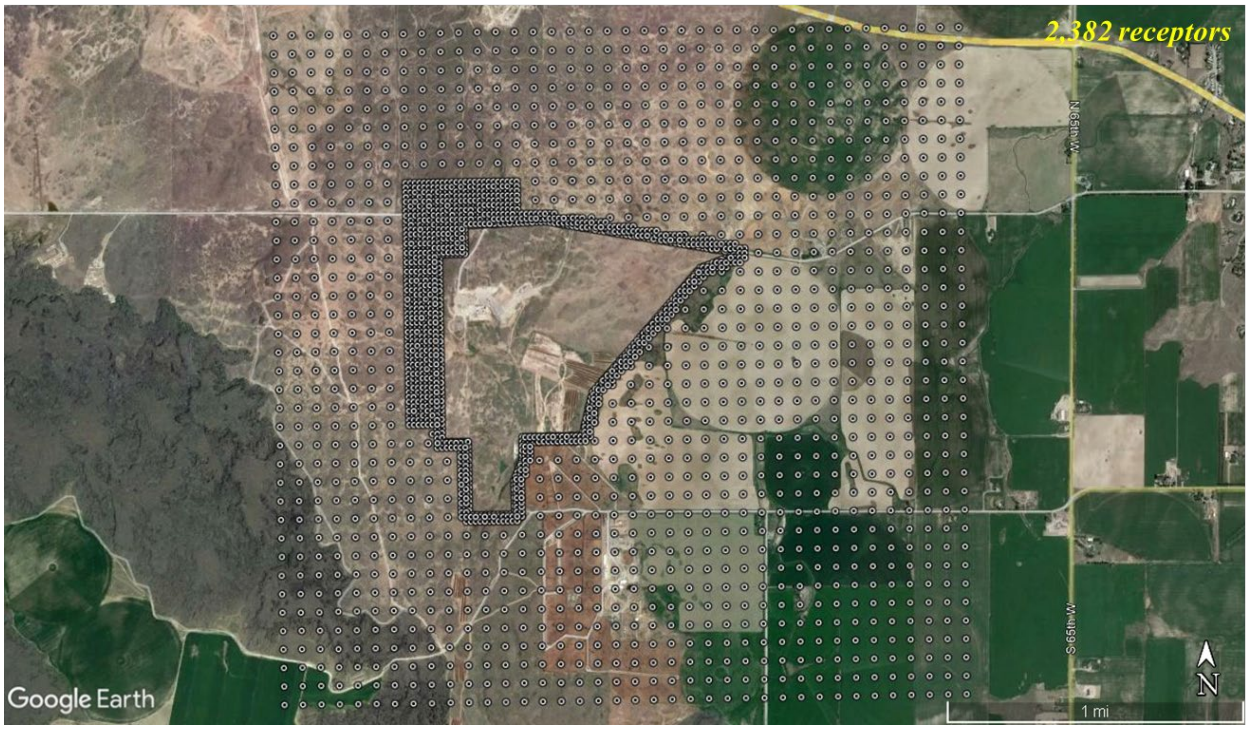
Figure 1. (a) WIND ROSE AND (b) WIND SPEED HISTOGRAM AT THE IDAHO FALLS AIRPORT IN IDAHO (2016–2020).



3.3.6 Effects of Terrain on Modeled Impacts

Submitted ambient air impact analyses used terrain data extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) 1/3-arc second TIFF files. The terrain preprocessor AERMAP version 18081 was used by Coal Creek to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain. Figure 2 depicts the receptor grid used in the analyses, overlaid on a terrain image from Google Earth.

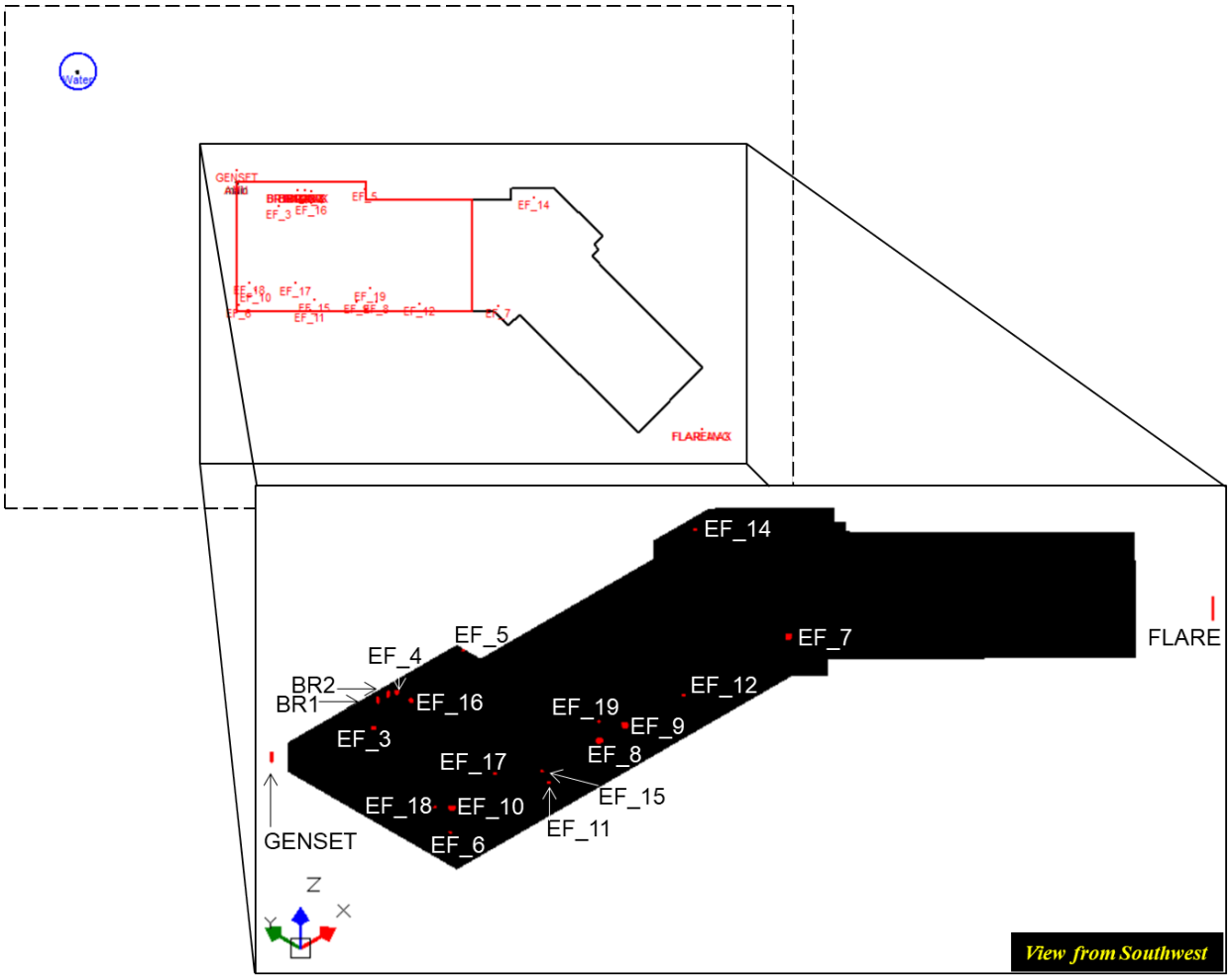
Figure 2. THE FULL RECEPTOR GRID CENTERED AT THE RIVERBEND MEATS FACILITY IN IDAHO FALLS, IDAHO.



3.3.7 Facility Layout and Downwash

Figure 3 shows the facility's model setup showing locations of emission sources. The inset illustrates a three-dimensional view of the model setup as viewed from the southwest.

Figure 3. RIVERBEND MEATS' MODEL SETUP SHOWING EMISSION SOURCES, AND (INSET) THREE-DIMENSIONAL VIEW OF THE MODEL SETUP AS VIEWED FROM THE SOUTHWEST.



DEQ verified proper identification of the site location, equipment locations, and the ambient air boundary by comparing a graphical representation of the modeling input file to aerial photographs on Google Earth (available at https://www.google.com/earth).

Potential downwash effects on emission plumes were accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of buildings were used as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME version 04274) to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information for input to AERMOD.

3.3.8 NOx Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NOx emissions. The conversion of NO to NO_2 can be conservatively addressed through the use of several methods as outlined in a *2014 EPA NO_2 Modeling Clarification Memorandum*.[4] The guidance

outlines a three-tiered approach:

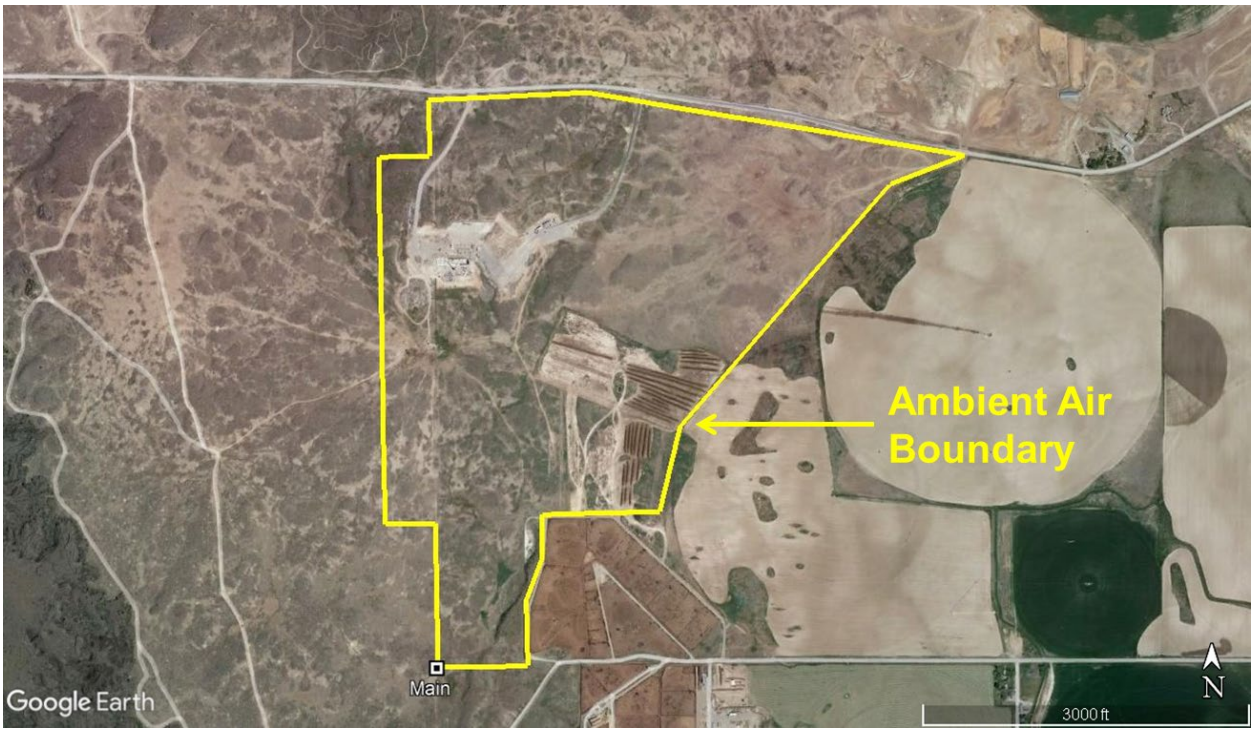
- Tier 1 – assume full conversion of NO to NO_2 where total NOx emissions are modeled and modeled impacts are assumed to be 100 percent NO_2.
- Tier 2 – use an ambient ratio to adjust impacts from the Tier 1 analysis.
- Tier 3 – use a detailed screening method to account for $NO/NO_2/O_3$ chemistry such as the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM).

Coal Creek used the ARM2 method, a Tier 2 analysis method which assumes an ambient equilibrium between NO and NO_2, in which the conversion of NO to NO_2 is predicted using hourly ambient NOx monitoring data. ARM2 has been adopted by the EPA as a default regulatory Tier 2 option. A minimum and maximum NO_2/NOx ratio of 0.5 and 0.9, respectively, were specified in the model.

3.3.9 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as "that portion of the atmosphere, external to buildings, to which the general public has access." The ambient air boundary for this project (illustrated in Figure 4 below) will be a continuous barbed wire fence with "No Trespassing" signage. DEQ has determined that measures described in the application to preclude public access to areas of the site excluded from ambient air are adequate.

Figure 4. RIVERBEND MEATS FACILITY'S AMBIENT AIR BOUNDARY.



3.3.10 Receptor Network

Table 10 describes the receptor network used in the submitted modeling analyses. The receptor grids used in the model provided good resolution of the maximum design concentrations for the project and provided extensive coverage. The receptor network has a 25-meter fence line grid, extending 50 meters beyond the ambient air boundary, and a 100-meter corner grid extending a minimum of 1,000 meters from the ambient air boundary. Coal Creek also used a 25-meter corner grid, with southwest corner at 402,500 meters Easting/4,815,500 meters Northing, and northeast corner at 403,000 meters Easting/4,816,800 meters Northing. This grid provides added receptor density to the west and northwest areas of the site, where the plant is closest to the fenceline.

The full receptor grid consists of 2,382 receptors and is depicted in Figure 2. The full receptor grid was used for the cumulative NAAQS impact and TAPs analyses. DEQ determined that the receptor grid used in the submitted modeling analyses was adequate to resolve maximum modeled impacts.

The receptor grid used in the submitted modeling analyses met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[2], and DEQ determined that the receptor network was effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations.

3.3.11 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

H = S + 1.5L, where:

H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.

S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.

L = lesser dimension, height or projected width, of the nearby structure.

Sources from the Riverbend facility are below GEP stack height. Therefore, consideration of downwash caused by nearby buildings was required.

4.0 NAAQS and TAPs Impact Modeling Results

This section describes the air impact modeling results for both NAAQS and TAPs analyses.

4.1 Results for NAAQS Analyses

4.1.1 Significant Impact Level Analysis

A significant impact level (SIL) analysis was not performed for this project.

4.1.2 Cumulative NAAQS Impact Analysis

Table 11 provides results for the cumulative NAAQS impact analysis. For each modeled pollutant, the

total impact was calculated by adding the design value (DV) of the impact to the ambient background value. The sum was then compared to the NAAQS. The modeled design values listed in Table 11 represent the highest impacts among the three modeled operating scenarios. Modeled emission rates were adjusted by DEQ's modeling staff to match the emission inventory. Ambient impacts for the facility, when combined with approved ambient backgrounds, were safely below the NAAQS at all receptors.

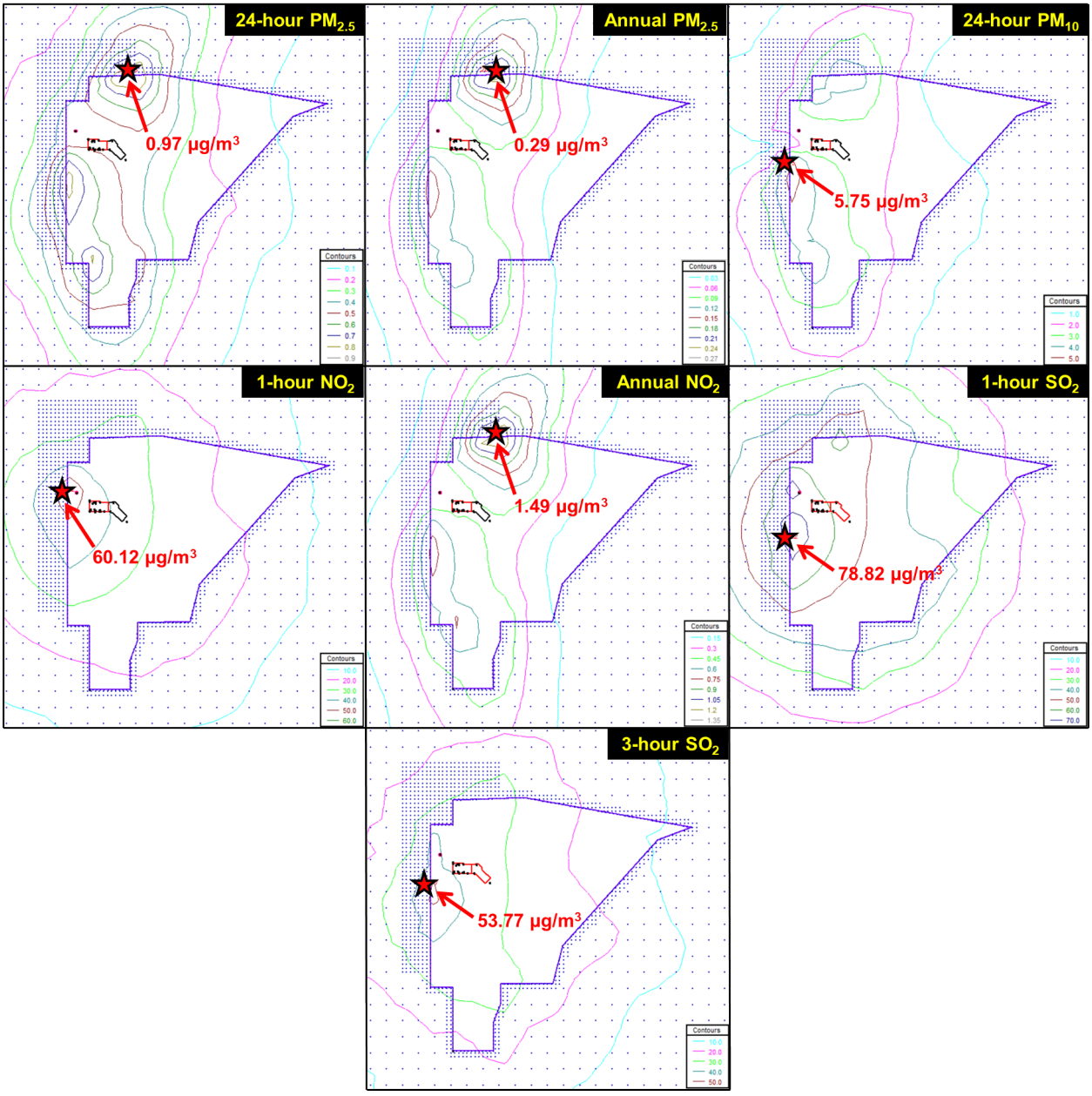
Table 11. RESULTS FOR CUMULATIVE NAAQS IMPACT ANALYSIS.

Pollutant	Averaging Period	Worst-Case Modeled Design Value Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Ambient Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
$PM_{2.5}$	24-hour	0.97[b]	13.7	14.67	35	41.9%
	Annual	0.29[b]	4.7	4.99	12	41.6%
PM_{10}	24-hour	5.75[b]	71.1	76.85	150	51.2%
NO_2	1-hour	60.12[b]	21.6	81.72	188	43.5%
	Annual	1.49[b]	3.4	4.89	100	4.9%
SO_2	1-hour	78.82[c]	13.1	91.92	196	46.9%
	3-hour	53.77[c]	17.3	71.07	1,300	5.5%

a. Micrograms per cubic meter.
b. Operating scenario: Digester Gas routed to Flare.
c. Operating scenario: Boiler 1 operating only with Digester Gas.

Figure 5 illustrates the maximum modeled design value concentrations for all pollutants and averaging periods that were modeled in the cumulative NAAQS impact analysis. The red star denotes the location of maximum impacts. High impacts are limited to a relatively small area close to the facility, mostly along the northern and western sections of the ambient air boundary.

Figure 5. MAXIMUM MODELED DESIGN CONCENTRATIONS IN µg/m^3 FOR CUMULATIVE NAAQS IMPACT ANALYSIS.



4.2 Results for TAPs Impact Analyses

Dispersion modeling was required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 and 586 for those TAPs with emission increases exceeding screening emission levels (ELs). Table 12 lists the maximum modeled impacts for the five carcinogenic TAPs that required modeling. All modeled impacts are safely below applicable AACCs.

Table 12. TAPS AIR IMPACT ANALYSIS RESULTS.			
TAP	**Maximum Modeled Impact (µg/m³)[a]**	**AAC or AACC (µg/m³)**	**Percent of AAC/AACC**
Arsenic[b]	1.3E-06	2.30E-04	0.6%
Cadmium[b]	7.3E-06	5.60E-04	1.3%
Chromium (VI)[b]	4.7E-07	8.30E-05	0.6%
Formaldehyde[b]	5.0E-04	7.70E-02	0.6%
Nickel[b]	1.5E-05	4.20E-03	0.4%

a. Micrograms per cubic meter.
b. Carcinogenic TAP. Modeled impact and AACC represent annual or period-average concentration.

5.0 Conclusions

The information submitted with the PTC application, combined with DEQ's air impact analyses, demonstrated to DEQ's satisfaction that emissions from the Riverbend Meats, LLC facility in Idaho Falls, Idaho will not cause or significantly contribute to a violation of any applicable ambient air quality standard or TAP increment.

References

1. *Policy on NAAQS Compliance Demonstration Requirements.* Idaho Department of Environmental Quality Policy Memorandum. July 11, 2014.

2. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf.

3. *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits*. Oklahoma Department of Environmental Quality, Air Quality Division. June 2016.

4. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard*. Office of Air Quality Planning and Standards. Air Quality Modeling Group. Research Triangle Park, NC. Guidance memorandum from R. Chris Owen and Roger Brode to Regional Dispersion Modeling Contacts. September 30, 2014.

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on December 14, 2021:

Facility Comment: Permit Condition 2.1 – Requested edits to the process description – The suggested language is from the application. At this point it is not certain whether biogas will be routed primarily to the boilers or the flare.

DEQ Response: DEQ changed the description of the biogas and flare as requested.

Facility Comment: Permit Condition 2.2 – Requested edits to flare rated capacity and diameter as well as boiler stack heights - This is for Varec 244W size code 4, for 22,250 cfs gas supply. Note that 65.6 fps is not an actual stack velocity. That is an effective velocity that was calculated for the stack for modeling purposes based upon flare height and heat release rate. This height is not correct. Should be 36 ft. Based on 31 ft roof height and 5 ft stickup above roof.

DEQ Response: DEQ changed the rated capacity of the flare from 17,000 scf/hr to 22,250 scf/hr and the diameter from 1.8 ft to 19 inches as requested based on the provided Varec specification sheet. DEQ changed the boiler stacks heights from 30 feet to 36 feet as requested and verified with modeling. DEQ also updated Table 1.1 with the flare rated capacity.

Facility Comment: Permit Condition 2.3 – Requested the addition of monitoring and recordkeeping to footnote c) in Table 2.2 – The permit requires monitoring of both biogas flow and H_2S concentration. These can be used to directly determine compliance with the SO_2 emissions limits in Table 2 and should be acceptable for demonstrating compliance with the emissions limits.

DEQ Response: Monitoring and recordkeeping is a DEQ approved alternative and already included in the footnote. DEQ will not make the requested change to this permit condition.

Facility Comment: Permit Condition 2.4 and 2.5 – Delete. Surrogate compliance demonstrations are not needed when direct compliance demonstration is available. The permit requires monitoring of both biogas flow and H2S concentration. These can be used to directly determine compliance with the SO_2 emissions limits in Table 2.

DEQ Response: DEQ believes that limiting the H_2S concentration and biogas flow rate are appropriate for sources that produce and combust biogas. These permit conditions are included for facilities that produce and combust biogas as standard conditions for regulatory consistency.

Facility Comment: Permit Condition 2.7 – How is compliance demonstrated?

DEQ Response: The DEQ regional office will be available to answer questions like this on the permit hand off meeting.

Facility Comment: Permit Condition 2.10 – This requires continuous operation of a pilot flame, even when biogas is going to the boilers. There should be an option to allow autoignition of a pilot flame when gas is diverted to the flares, with a flame detector used to verify ignition before gas flow to the flare is initiated.

DEQ Response: DEQ revised the permit condition to include an automatic ignition system or a pilot flame in the flare. Permit Conditions 2.12 and 2.17 also revised to include the automatic ignition system.

Facility Comment: Permit Condition 2.15 – There is no need to separately monitor the biogas to each boiler; one meter into the boiler house and one meter for the flare is adequate for calculating SO2 emissions. Alternately, one meter on the total digester biogas and one meter on either the leg to the boiler house or the flare will give the same information.

DEQ Response: This permit condition is a standard that DEQ uses to determine how much biogas is combusted in the various sources. The permit condition has a paragraph for DEQ approval of alternative monitoring and recordkeeping. This question can be brought up with the DEQ regional office for discussion during the permit hand off meeting.

Facility Comment: Permit Condition 2.16 – Does a gas check apply if Draeger tubes are used? Is weekly recordkeeping of H_2S the same if Draeger tubes are used? What is the time basis for the value to be recorded? A spot value (comparable to what would be provided by a Draeger tube), a one-hour average, a daily average? This language indicates that is not necessary to operate the H2S monitor 24/7. Is that correct? Facility also requests to edit the 90% of the H_2S limit to 90% of the SO_2 limit because the limit should be based on 90% of the SO2 emissions limit, not the surrogate limit.

DEQ Response: Gas checks only apply to an inline H_2S monitor. Monitoring is conducted according to the schedule regardless of the type of monitor used. The time basis for recordkeeping depends on the monitoring system used. An inline monitor will give instantaneous readings 24/7, while a Draeger Tube must follow manufacturer's specifications for each sampling event. The permit condition describes the methods that must be followed if an inline monitor is out of service. If the facility uses an inline monitor and removes it from service between sampling events, it must be cleaned and calibrated before being put back into service. Questions about Draeger tube use and recordkeeping requirements can be discussed further during the permit hand off meeting. The requested edits to the 90% H_2S limit will remain as written in the draft permit. DEQ limits the H_2S per the discussion above.

Facility Comment: Permit Condition 2.17 – Facility requested that the O&M manual include the flare and remove the anaerobic digester. Facility requested to add "when biogas is routed to the flare" to the bullet point for the method of ensuring continuous operation. The facility commented that there needs to be a provision to allow for variances from manufacturer recommendations when appropriate.

DEQ Response: DEQ will include the flare to the O&M manual and keep the anaerobic digester in the requirements. All equipment must be maintained. DEQ added the requested "when biogas is routed to the flare" to the bullet point as requested. Deviations from manufacturer's recommendations can be discussed with the regional office at the permit hand off meeting.

Facility Comment: Permit Condition 3.3 and 3.4 – The limits in Section 3.3 are based on the standards in Section 3.4, these sections are redundant. Compliance with 3.3 and the operating requirements assures compliance with Section 3.4. For simplicity and streamlining, choose one or the other, but not both. In other words, if the engine meets Table 3.3 emission standards, and is operated in accordance with the operating limits starting at 3.6, then Table 3.2 will not net be exceeded. Hence Table 3.2 isn't really needed.

DEQ Response: The emission limits in permit condition 3.3 include calculated values using the emission standards from permit condition 3.4. Permit condition 3.3 is emission limits per state regulations while permit condition 3.4 is federally regulated emission standards. While showing compliance with one assures compliance with the other, they are still separately enforceable and applicable to the facility.

Facility Comment: Permit Condition 3.8 – What is the regulatory basis for the 1-hour per day limitation? This is not a condition that was requested by Riverbend, so why is it being imposed?

DEQ Response: DEQ investigated the basis for the 1-hour limitation and finding none, removed the requirement from the permit condition.

Facility Comment: Permit Condition 4.8 – The facility requested to add "If a test protocol is submitted 30 days prior to conducting a performance test and DEQ fails to either approve or disapprove the protocol within 30 days of submittal, the test protocol shall be approved by default." In case DEQ doesn't respond.

DEQ Response: This permit condition is a general provision, standard condition included in all PTC permits and will not be changed.

APPENDIX D – PROCESSING FEE

PTC Processing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Riverbend Meats, LLC**
Address:	**8143 W. Broadway**
City:	**Idaho Falls**
State:	**Idaho**
Zip Code:	**83402**
Facility Contact:	**Devin Belnap**
Title:	**Vice President, Real Estate**
AIRS No.:	**311611**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	12.7	0	12.7
SO_2	20.2	0	20.2
CO	11.5	0	11.5
PM10	2.0	0	2.0
VOC	16.0	0	16.0
Total:	62.4	0	**62.4**
Fee Due	**$ 5,000.00**		

Comments: Initial PTC permit for a beef processing facility