Statement of Basis

Permit to Construct No. P-2021.0019
Project ID 62623

Equilon Enterprises, LLC dba Shell Oil Products US
Wendell, Idaho

Facility ID 047-00044

Final

December 9, 2021
Zach Pierce
Permit Writer

ZP

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.

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BMP	best management practices
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
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
km	kilometers
lb/hr	pounds per hour
lb/qtr	pound per quarter
m	meters
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_2	nitrogen dioxide
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
ppm	parts per million

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
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
TAP	toxic air pollutants
U.S.C.	United States Code
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

The Equilon Enterprises, LLC dba Shell Oil Products US facility will convert cow manure to renewable natural gas (RNG). It will be co-located at the Bettencourt Dairies in Wendell, Idaho. RNG, or biomethane, is a pipeline-quality gas that is fully interchangeable with conventional natural gas. Cow manure will be delivered to the facility by truck and deposited into an influent pit. The raw manure will be heated and undergo anaerobic digestion in digester vessels. Heat will be provided by two natural gas-fired water heaters. The biogas will then undergo hydrogen sulfide (H_2S) removal, feed compression and finally be sent to a membrane unit for separation of methane (CH_4) from the other biogas constituents. Air contaminant emissions associated with H_2S removal will be released through the desulfurization unit vent. Tail gas emissions produced will also be vented. Off-spec biogas or biogas associated with an equipment startup, shutdown and upset will be routed to an enclosed ground combustor (flare) with natural gas pilot. This flare will be capable of combusting unprocessed or partially processed biogas if needed. A backup generator powered by a natural gas-fired engine is also proposed in the case of power failure at the proposed 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 two water heaters, a flare, and natural-gas fired engine.

Application Chronology

May 14, 2021	DEQ received an application and an application fee.
May 17 – June 1, 2021	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
June 10, 2021	DEQ determined that the application was incomplete.
June 29, 2021	DEQ received supplemental information from the applicant.
July 29, 2021	DEQ determined that the application was incomplete.
August 30, 2021	DEQ received supplemental information from the applicant.
September 27, 2021	DEQ determined that the application was complete.
November 17, 2021	DEQ made available the draft permit and statement of basis for peer and regional office review.
November 23, 2021	DEQ made available the draft permit and statement of basis for applicant review.
December 3, 2021	DEQ received the permit processing fee.
December 9, 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	Anaerobic Digesters (2) Combined Biogas produced: 1,561 scfm, 820.5 MMscf/yr	H_2S Scrubber and Combustion (Flare)	N/A
2	Flare: Manufacturer: John Zink Hamworthy Combustion Model: ZTOF Heat input rating: 107 MMBtu/hr Max. Capacity: 1,561 scfm Fuel: Biogas	None	Exit height: 50 ft Exit diameter: 10.6 ft Exit temperature: 1,600 °F
3	Biogas Processing System Maximum Capacity: 1,479 scfm	None	N/A
4	Water Heaters (2): Manufacturer: Cleaver Brooks Model: CFLC Heat input rating: 12 MMBtu/hr Fuel: Natural Gas	None	Exit height: 25 ft Exit diameter: 1.67 ft Exit temperature: 150 °F
5	IC Engine: Manufacturer: Generac Model: QT100 Rated Power: 134 bhp Ignition Type: Spark Generating Capacity: 100 kW Fuel: Natural Gas	None	Exit height: 8 ft Exit diameter: 0.5 ft Exit flow rate: 888 acfm Exit temperature: 960 °F

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 natural gas-fired IC engine, flare, and water heater operations at the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant, HAP PTE were based on emission factors from AP-42, operation of 8,760 hours per year for the engine and the water heaters, and process information specific to the facility for this proposed project.

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 dairy digester operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr and the maximum H_2S concentration of 4,300 ppm.

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
Point Sources					
Flare	1.79	297.25	24.06	48.09	0.29
IC Engine	0.056	0.003	2.59	5.18	1.29
Water Heaters	1.05	0.11	2.52	0.74	0.17
Biogas Processing	0.00	0.00	0.00	0.00	0.00
Total, Point Sources	**2.90**	**297.36**	**29.17**	**54.01**	**1.75**

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 dairy digester operation uncontrolled Potential to Emit is based upon a worst-case for operation of the facility of 8,760 hr/yr. Then, the worst-case maximum HAP Potential to Emit was determined for this dairy digester operation.

Table 3 UNCONTROLLED POTENTIAL TO EMIT FOR HAZARDOUS AIR POLLUTANTS

Hazardous Air Pollutants	PTE (T/yr)
Acetaldehyde	4.71E-02
Acrolein	2.89E-02
Arsenic	6.72E-05
Benzene	3.18E-03
Beryllium	4.03E-06
1,3-Butadiene	1.50E-03
Cadmium	3.70E-04
Carbon Tetrachloride	2.07E-04
Chlorobenzene	1.71E-04
Chloroform	1.60E-04
Chromium	4.70E-04
Cobalt	2.82E-05
1,4-Dichlorobenzene	4.03E-04
1,3-Dichloropropene	1.49E-04
Ethylbenzene	2.23E-04
Ethylene Dibromide	2.49E-04
Formaldehyde	3.22E-01
Hexane	6.05E-01
Manganese	1.28E-04
Mercury	8.74E-05
Methanol	1.41E-02
Methylene Chloride	1.13E-04
Naphthalene	6.24E-04
Nickel	7.06E-04
Polycyclic Organic Matter	1.55E-04
Selenium	8.07E-06
Styrene	1.33E-04
1,1,2,2-Tetrachloroethane	2.25E-04
Toluene	3.44E-03
1,1,2-Trichloroethane	1.79E-04

Vinyl Chloride	8.39E-05
Xylene	1.04E-03
Polyaromatic Hydrocarbons	2.58E-05
Total	**1.03**

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)]
Flare	0.82	0.82	68.24	42.10	16.44	17.52	21.93	21.90	0.13	0.13
IC Engine	0.013	0.056	0.0007	0.003	0.59	2.59	1.18	5.18	0.30	1.29
Water Heaters	0.24	1.05	0.024	0.11	0.576	2.52	0.168	0.74	0.038	0.17
Biogas Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Post Project Totals	**1.07**	**1.93**	**68.26**	**42.21**	**17.61**	**22.63**	**23.28**	**27.82**	**0.47**	**1.59**

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	1.07	1.93	68.26	42.21	17.61	22.63	23.28	27.82	0.47	1.59
Changes in Potential to Emit	**1.07**	**1.93**	**68.26**	**42.21**	**17.61**	**22.63**	**23.28**	**27.82**	**0.47**	**1.59**

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)
Ammonia	0.00E-03	1.34E-01	1.34E-01	1.2	No
Barium	0.00E-03	4.73E-04	4.73E-04	0.033	No
Chromium	0.00E-03	1.83E-04	1.83E-04	3.30E-02	No
Cobalt	0.00E-03	1.10E-05	1.10E-05	0.0033	No
Copper (fume)	0.00E-03	9.14E-05	9.14E-05	0.013	No
1,4-Dichlorobenzene	0.00E-03	1.56E-04	1.56E-04	30	No
o-Dichlorobenzene	0.00E-03	1.29E-04	1.29E-04	20	No
1,2-Dichloropropane	0.00E-03	3.46E-05	3.46E-05	23.133	No
Hexane	0.00E-03	2.35E-01	2.35E-01	12	No
Hydrogen Sulfide	0.00E-03	7.71E-01	7.71E-01	0.933	No
Manganese (dust)	0.00E-03	4.95E-05	4.95E-05	0.333	No
Molybdenum (soluble compounds)	0.00E-03	1.18E-04	1.18E-04	0.333	No
Naphthalene	0.00E-03	7.95E-05	7.95E-05	3.33	No
Pentane	0.00E-03	2.80E-01	2.80E-01	118	No
Selenium	0.00E-03	3.13E-06	3.13E-06	0.013	No
Toluene	0.00E-03	4.43E-04	4.43E-04	25	No
Zinc	0.00E-03	3.12E-03	3.12E-03	0.667	No

The total TAP emissions exclude engine HAP emissions because they are regulated under 40 CFR 63 Subpart ZZZZ, per DEQ guidance:

It is presumed that EPA evaluated the 187 HAPs when developing the emission standards for new, modified or existing stationary sources regulated by 40 CFR Part 63; therefore, no further review is required under IDAPA 58.01.01.210 for these pollutants for sources subject to 40 CFR Part 63, including sources specifically exempted within the subpart. The Toxic Air Pollutants that are not one of the 187 Hazardous Air Pollutants will still need to be evaluated for compliance with IDAPA 58.01.01.210.

Therefore, 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	0.00E-03	9.48E-06	9.48E-06	1.50E-06	Yes
Benzene	0.00E-03	9.96E-05	9.96E-05	8.0E-04	No
Beryllium	0.00E-03	5.69E-07	5.69E-07	2.80E-05	No

Cadmium	0.00E-03	5.22E-05	5.22E-05	3.70E-06	Yes
1,1-Dichloroethane	0.00E-03	3.03E-05	3.03E-05	2.5E-04	No
1,2-Dichloroethane	0.00E-03	3.03E-05	3.03E-05	2.5E-04	No
Formaldehyde	0.00E-03	3.56E-03	3.56E-03	5.10E-04	Yes
Nickel	0.00E-03	9.96E-05	9.96E-05	2.70E-05	Yes
Polycyclic Organic Matter[a]	0.00E-03	5.41E-07	5.41E-07	2.00E-06	No
Polyaromatic Hydrocarbons	0.00E-03	3.64E-06	3.64E-06	9.10E-05	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, 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)
Acetaldehyde	1.07E-02	4.71E-02
Acrolein	6.61E-03	2.89E-02
Arsenic	9.48E-06	4.15E-05
Benzene	6.65E-04	2.91E-03
Beryllium	5.69E-07	2.49E-06
1,3-Butadiene	3.43E-04	1.50E-03
Cadmium	5.22E-05	2.28E-04
Carbon Tetrachloride	4.72E-05	2.07E-04
Chlorobenzene	3.91E-05	1.71E-04
Chloroform	3.66E-05	1.60E-04
Chromium	6.64E-05	2.91E-04
Cobalt	3.98E-06	1.74E-05
1,4-Dichlorobenzene	5.69E-05	2.49E-04
1,3-Dichloropropene	3.39E-05	1.49E-04
Ethylbenzene	5.10E-05	2.23E-04
Ethylene Dibromide	5.69E-05	2.49E-04
Formaldehyde	7.14E-02	3.13E-01
Hexane	8.53E-02	3.74E-01
Manganese	1.80E-05	7.89E-05
Mercury	1.23E-05	5.40E-05
Methanol	3.21E-03	1.41E-02
Methylene Chloride	2.57E-05	1.13E-04
Naphthalene	1.25E-04	5.45E-04
Nickel	9.96E-05	4.36E-04
Polycyclic Organic Matter	3.51E-05	1.54E-04
Selenium	1.14E-06	4.98E-06
Styrene	3.03E-05	1.33E-04
1,1,2,2-Tetrachloroethane	5.14E-05	2.25E-04
Toluene	6.86E-04	3.00E-03
1,1,2-Trichloroethane	4.09E-05	1.79E-04
Vinyl Chloride	1.91E-05	8.39E-05
Xylene	2.36E-04	1.04E-03
Polyaromatic Hydrocarbons	3.64E-06	1.59E-05
Totals	**0.18**	**0.79**

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, CO, VOC, HAP, and TAP from this project were below 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 B.

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

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 Gooding 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.

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	2.90	1.93	**100**	B
PM_{10}	2.90	1.93	**100**	B
$PM_{2.5}$	2.90	1.93	**100**	B
SO_2	297.36	42.21	**100**	SM
NO_X	29.17	22.63	**100**	B
CO	54.01	27.82	**100**	B
VOC	1.75	1.59	**100**	B
HAP (single)	0.61	0.37	**10**	B
Total HAPs	1.03	0.79	**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 emissions sources. 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 2.4, 3.4 and 4.3.

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 Conditions 2.6.

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

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

IDAPA 58.01.01.006 defines a Tier I source as “Any source located at a major facility as defined in Section 008.” IDAPA 58.01.01.008.10 defines a Major Facility as either:

- For HAP a facility with the potential to emit ten (10) tons per year (T/yr) or more of any hazardous air pollutant, other than radionuclides, or
- The facility emits or has the potential to emit twenty-five (25) T/yr or more of any combination of any hazardous air pollutants, other than radionuclides.

or, for non-attainment areas (Note: The State of Idaho currently has no serious non-attainment areas therefore the Major Source threshold is defined as follows):

- The facility emits or has the potential to emit one hundred (100) tons per year or more of any regulated air pollutant. The fugitive emissions shall not be considered in determining whether the facility is major unless the facility is a "Designated Facility":

Therefore, it needs to be determined if this facility is a HAP Major Source. As presented in the Table 8, the PTE for each HAP is less than 10 T/yr and the PTE for all HAP combined is less than 25 T/yr. Therefore, this facility is not a HAP Major Source subject to Tier I requirements.

Therefore, it needs to be determined if this facility is a criteria pollutant Major Source. As discussed previously the facility is located in Gooding County, which is designated as unclassifiable/attainment for $PM_{2.5}$, PM_{10}, SO_2, NO_X, CO, and Ozone for federal and state criteria air pollutants. Therefore, the following table compares the post-project facility-wide annual PTE for all criteria pollutants emitted by the source to the applicable criteria pollutant Major Source thresholds in order to determine if the facility is a criteria pollutant Major Source.

Table 10 PTE FOR REGULATED AIR POLLUTANTS COMPARED TO THE MAJOR SOURCE THRESHOLDS

Regulated Air Pollutants	PTE (T/yr)	Major Source Threshold (T/yr)	Exceeds the Major Source Threshold?
PM_{10}	1.93	**100**	No
$PM_{2.5}$	1.93	**100**	No
SO_2	42.21	**100**	No
NO_X	22.63	**100**	No
CO	27.82	**100**	No
VOC	1.59	**100**	No

As presented in the preceding table the PTE for each criteria pollutant is less than 100 T/yr. Therefore, this facility is not a criteria pollutant Major Source subject to Tier I requirements.

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)

The facility is subject to the requirements of 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, and 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

§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).

Each of the proposed Cleaver Brooks water heater boilers have a heat input capacity of 12 MMBtu/hr.

§60.42c Standard for sulfur dioxide (SO2).
(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: …

The proposed water heater boilers do not burn coal and are therefore not subject to an emission standard for SO2.

§60.43c Standard for particulate matter (PM).
(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

The proposed water heater boilers will only burn natural gas therefore, NSPS PM or opacity standards do not apply.

§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 required notifications will be filed at the time of installation of the water heater boilers.

(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.

Equilon will maintain records of the amount of natural gas combusted during each calendar month.

(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.

Records will be maintained as required.

(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 required reports will be submitted to the Idaho DEQ semi-annually.

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

§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. (3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is: (iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP;

The 4-stroke lean-burn natural gas-fired reciprocating engine has a power output of 134 bhp (100 kW).

§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. …

Applicable Portions of Table 1 to Subpart JJJJ of Part 60—NOX, 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

			Emission standards[(a)]					
			g/HP-hr			*ppmvd at 15% O_2*		
Engine type and fuel	*Maximum engine power*	*Manufacture date*	*NO_X*	*CO*	*VOC[(b)]*	*NO_X*	*CO*	*VOC[(b)]*
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	*100≤HP<500*	*7/1/2008*	*2.0*	*4.0*	*1.0*	*160*	*540*	*86*

The engine meets the criteria and will comply with the applicable emission limits in Table 1. The engine will be permitted to burn natural gas. A NOx limit of 2.0 g/HP-hr, CO limit of 4.0 g/HP-hr, and VOC limit of 1.0 g/HP-hr are the proposed limits in the permit application. These are the applicable NSPS Subpart JJJJ limits for the engine.

NESHAP Applicability (40 CFR 61)

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

MACT/GACT Applicability (40 CFR 63)

The facility has proposed to operate as a minor source of hazardous air pollutant (HAP) emissions, and is subject to the requirements of 40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. DEQ is delegated this Subpart.

The facility may be subject to the requirements of 40 CFR 63, Subpart JJJJJJ–National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources. DEQ is delegated this Subpart.

Refer to the Title V Classification section for additional information.

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

§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.

The engine is a stationary RICE at an area source of HAP emissions.

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

(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.

The engine is a new stationary RICE at an area source of HAP emissions.

(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;

The engine is subject to the requirements of 40 CFR Part 60 Subpart JJJJ and therefore no further requirements apply to the engine under Subpart ZZZZ.

40 CFR 63, Subpart JJJJJJ..... National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

§ 63.11193..... Am I subject to this subpart?

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

The boiler at the facility is located at an area source of HAPs. However, it is specifically specified as being not subject to this subpart in § 63.11195.

§ 63.11193…… Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

(e) A gas-fired boiler as defined in this subpart.

§ 63.11193…… What definitions apply to this subpart?

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

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

The boiler at the facility is considered a gas-fired boiler and is therefore not subject to the requirements of the subpart.

Permit Conditions Review

This section describes the permit conditions for this initial permit.

Permit Condition 1.1 establishes the permit to construct scope.

Permit Condition, Table 1.1, provides a description of the purpose of the permit and the regulated sources, the process, and the control devices used at the facility.

Anaerobic Digester

Permit Condition 2.1 provides a process description of the anaerobic digesters and biogas processing system at this facility.

Permit Condition 2.2 provides a description of the control devices used on the anaerobic digesters at this facility.

Permit Condition 2.3 establishes hourly and annual emissions limits for $PM_{10}/PM_{2.5}$, SO_2, NO_X, CO, and VOC emissions from the Flare at this facility.

As discussed previously, Permit Condition 2.4 establishes a 20% opacity limit for the Digesters, Flare, and Biogas Processing System exhaust stacks or functionally equivalent openings associated with the Digesters, Flare, and Biogas Processing System operations.

Permit Condition 2.5 establishes concentration limits for H_2S for each biogas stream entering the flare at this facility.

Permit Condition 2.6 limits the particulate emissions for the combustion of biogas in the flare.

Permit Condition 2.7 establishes that there are to be no emissions of odorous gases, liquids, or solids from the permit equipment into the atmosphere in such quantities that cause air pollution.

Permit Condition 2.8 establishes a biogas production restriction. This biogas production restriction was based on the biogas proposed by the applicant to be produced at an hourly rate. No annual biogas production restriction was required because annual anaerobic digester capacity was evaluated at maximum short term production rate for 8,760 hours/year.

Permit Condition 2.9 establishes hourly and yearly biogas flow rate limits for each stream leading to the flare as proposed by the applicant. This condition also establishes that flaring may occur for Stream 1 only, or Stream 1 combined with either Stream 2 or Stream 3. Stream 2 and Stream 3 shall not be flared concurrently.

Permit Condition 2.10 establishes the flare ignition system requirements.

Permit Condition 2.11 establishes the minimum temperature for flare operation. The operating temperature is set at a minimum value of 1,600°F. Volumetric flow rate and exit velocity release parameters for the enclosed flare are influenced by the operating temperature. A reduced operating temperature results in a lower exit velocity, reducing plume dispersion for the enclosed flare. Enclosed flare control efficiency is also related to operating temperature. At 1600°F, control of H_2S, by conversion to SO_2 is 98% efficient, and H_2S emissions are 0.721 lb/hr. If the control efficiency drops to 97%, the H_2S EL would be exceeded with a 1.08 lb/hr emission rate.

Permit Condition 2.12 lists the reasonable control of fugitive emissions that shall be taken at the facility.

Permit Condition 2.13 describes the monitoring requirements for the pilot flame in the biogas flare.

Permit Condition 2.14 describes the biogas flow rate monitoring to be conducted on an hourly basis using an installed and calibrated flow meter.

Permit Condition 2.15 describes hydrogen sulfide monitoring requirements. The permittee is required to monitor the gas stream before combustion with a H_2S monitor or with the use of Draeger Tubes according to the schedule in the permit condition. Calibrations and recordkeeping are also detailed in this condition.

Permit Condition 2.16 describes the O&M manuals required for the biogas flow monitoring, H_2S monitoring, pilot flame monitoring, and anaerobic digester monitoring. The biogas flow rate monitoring O&M manual shall include, at a minimum, the SOP for flow rate sampling, the frequency and method of calibration, and the flow rate measurement range. The H_2S O&M manual shall include, at a minimum, the SOP for H_2S sampling, the frequency and method of calibration, and the concentration range. The pilot flame detector O&M manual shall include, at a minimum, the method of ensuring continuous operation and the procedure for pilot flame re-ignition. The anaerobic digester O&M manual shall include, at a minimum, the procedure for monitoring biogas under positive pressure and the corrective action if biogas is detected outside of the pressure range.

Permit Condition 2.17 requires the permittee to keep records of odor complaints and to take appropriate corrective action to demonstrate compliance with the Odors permit condition.

Water Heaters

Permit Condition 3.1 provides a process description of the Water Heaters process at this facility.

Permit Condition 3.2 provides a description of the control devices used on the Water Heaters at this facility.

Permit Condition 3.3 establishes hourly and annual emissions limits for $PM_{10}/PM_{2.5}$, SO_2, NO_X, CO, and VOC emissions from the Water Heaters at this facility.

As discussed previously, Permit Condition 3.4 establishes a 20% opacity limit for the Water Heater exhaust stacks or functionally equivalent openings associated with the water heater operations.

Permit Condition 3.5 establishes fuel use restrictions for combustion in the Water Heaters. These fuel use restrictions were based on the fuel proposed by the applicant to be combusted in the Water Heaters.

As discussed previously, Permit Condition 3.6 through 3.7 establishes the requirements for the Water Heaters as required by 40 CFR 60, Subpart Dc Standards of Performance for Small Industrial–Commercial–Institutional Steam Generating Units.

IC Engine

Permit Condition 4.1 provides a process description of the IC engine at this facility.

Permit Condition 4.2 provides a description of the control devices used on the IC engine at this facility.

As discussed previously, Permit Condition 4.3 establishes a 20% opacity limit for the IC engine exhaust stack or functionally equivalent opening associated with the IC engine operation.

Permit Condition 4.5 establishes fuel use restrictions for combustion in the IC engine. These fuel use restrictions were based on the fuel proposed by the applicant to be combusted in the IC engine.

As discussed previously, Permit Condition 4.4 and 4.6 through 4.10 establishes the requirements for the IC engine as required by 40 CFR 60, Subpart JJJJ Standards of Performance for Stationary Spark Internal Combustion Engines.

General Provisions

Initial Permit Condition 5.1

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 5.2

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 5.3

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 5.4

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

Initial Permit Condition 5.5

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 5.6

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 5.7

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 5.8

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 5.9

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 5.10

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 5.11

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 5.12

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 5.13

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 5.14

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 5.15

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 5.16

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

SHELL DOWNSTREAM BOVARIUS EMISSION INVENTORY

Revised August 11, 2021

Potential to Emit (tons per year)

PROCESS INFORMATION

Sources	Production Rate[a]			Annual Potential Production		Notes:
	Value	Units	Hrs/yr			
Maximum Digester Biogas	1,561	scfm	8,760	820	mmscf/year	Maximum capacity when all equipment is installed.
Desulfurization Unit Vent	288	scfm	8,760	151	mmscf/year	Vented, primarily N_2, O_2 and CO_2
Biogas to Membrane Unit	1,479	scfm	8,760	777	mmscf/year	Membrane unit separates CH_4 and CO2
Natural Gas to Compression	915	scfm	8,760	481	mmscf/year	Product to Pipeline
Tail Gas from Membrane Unit	491	scfm	8,760	258	mmscf/year	Vented, primarily CO_2

[a] Gas composition in Heat and Material Balance sheet.

MAXIMUM POTENTIAL EMISSIONS (PTE), CRITERIA AIR POLLUTANTS AND HAPS

Sources	PM/PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAP	Formaldehyde
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	HAP (ton/yr)
Natural Gas Fired Water Heaters	1.05	1.05	0.11	2.52	0.17	0.74	0.043	0.04
Biogas Flare and Natural Gas Pilot	0.82	0.82	42.10	17.52	0.13	21.90	0.20	0.0081
Natural Gas Fired Generator Engine	0.056	0.056	0.0033	2.59	1.29	5.18	nil	nil
Pollutant PTE	**1.92**	**1.92**	**42.20**	**22.63**	**1.59**	**27.81**	**0.25**	**0.05**

GREENHOUSE GAS EMISSIONS SUMMARY

Sources	Fossil Fuel CO_2	Biogenic CO_2	Methane	N_2O	GHG	CO_2e[b]
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(MT/yr)
Biogas Flare and Natural Gas Pilot	26	12,540	0.77	0.15	12,567	82
Natural Gas Fired Water Heaters	12,271	0	0.23	0.023	12,271	11,143
Natural Gas Fired Generator Engine	657	0	0.01	0.001	657	598
Desulfurization Unit Vent	0	1,119	30.3	0	1,150	688
Tail Gas from Membrane Unit	0	14,501	102	0	14,603	2,318
Process Fugitive Biogas Emissions	0	20.50	12.721	0	33	289
TOTAL	**12,954**	**28,181**	**146**	**0.176**	**41,281**	**15,118**

[b] Greenhouse gases (GHGs) as defined in Title 12 means "the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride. Each gas is also individually a greenhouse gas. Total GHGs in this inventory does not include carbon dioxide emissions form the combustion or decomposition of biomass except to the extent allowed by law. The definition of biomass includes biogas from the decomposition of non-fossilized and biodegradable organic matter.

TAP POTENTIAL TO EMIT EMISSIONS SUMMARY

PROJECT TAP EMISSIONS SUMMARY POTENTIAL TO EMIT[a]

CAS Nbr.	Pollutant	Emission Rates (lb/hr) - uncontrolled for 24-hour averages, controlled for annual averages						Emission Rates (lb/hr) excluding engines	Screening Emission Level[b] (lb/hr)	Exceeds Screening Level?	IDAPA 58.01.01 Section	Notes
		Engine	Flare	Water Heaters	Desulfurization Unit Vent	Tail Gas	Fugitive and Pits					
75070	Acetaldehyde	1.07E-02						0.00E+00	3.3E-03	No	586	
107028	Acrolein	6.61E-03						0.00E+00	0.017	No	585	
7664417	Ammonia						1.34E-01	1.34E-01	1.2	No	585	
7440382	Arsenic		4.91E-06	4.57E-06				9.48E-06	1.50E-06	Yes	586	
7440393	Barium		1.08E-04					1.08E-04	0.033	No	585	
71432	Benzene	5.65E-04	5.16E-05	4.80E-05				9.96E-05	8.0E-04	No	586	
7440417	Beryllium		2.95E-07	2.74E-07				5.69E-07	2.80E-05	No	586	
106990	1,3-Butadiene	3.43E-04						0.00E+00	2.4E-05	No	586	
7440439	Cadmium		2.70E-05	2.51E-05				5.22E-05	3.70E-06	Yes	586	
56235	Carbon Tetrachloride	4.72E-05						0.00E+00	4.4E-04	No	586	
108907	Chlorobenzene	3.91E-05						0.00E+00	23.3	No	585	
67663	Chloroform	3.66E-05						0.00E+00	2.80E-04	No	586	
7440473	Chromium		3.44E-05	3.20E-05				6.64E-05	3.30E-02	No	585	
7440484	Cobalt		2.06E-06	1.92E-06				3.98E-06	0.0033	No	585	
7440508	Copper (fume)		2.09E-05					2.09E-05	0.013	No	585	
106467	1,4-Dichlorobenzene		2.95E-05	2.74E-05				5.69E-05	30	No	585	
95501	o-Dichlorobenzene		2.95E-05					2.95E-05	20	No	585	c
75343	1,1-Dichloroethane	3.03E-05						0.00E+00	2.5E-04	No	586	
107062	1,2-Dichloroethane	3.03E-05						0.00E+00	2.5E-04	No	586	
78875	1,2-Dichloropropane	3.46E-05						0.00E+00	23.133	No	585	
542756	1,3-Dichloropropene	3.39E-05						0.00E+00	1.7E-03	No	586	
100414	Ethylbenzene	5.10E-05						0.00E+00	29	No	585	
106934	Ethylene Dibromide	5.69E-05						0.00E+00	3.0E-05	No	586	
50000	Formaldehyde	6.79E-02	1.84E-03	1.71E-03				3.56E-03	5.10E-04	Yes	586	
110543	Hexane		4.42E-02	4.11E-02				8.53E-02	12	No	585	
7783064	Hydrogen Sulfide		1.02E-01		1.55E-03	1.05E-02	3.43E-02	1.48E-01	0.933	No	585	
7439965	Manganese (dust)		9.33E-06	8.69E-06				1.80E-05	0.333	No	585	
7439976	Mercury		6.38E-06	5.94E-06				1.23E-05	0.0029	No	Non-TAP	e
67561	Methanol	3.21E-03						0.00E+00	17.3	No	585	
75092	Methylene Chloride	2.57E-05						0.00E+00	1.60E-03	No	586	
7439987	Molybdenum (soluble compounds)		2.70E-05					2.70E-05	0.333	No	585	
91203	Naphthalene	9.56E-05	1.50E-05	1.39E-05				2.89E-05	3.33	No	585	
7440020	Nickel		5.16E-05	4.80E-05				9.96E-05	2.70E-05	Yes	586	
109660	Pentane		6.38E-02					6.38E-02	118	No	585	
NA	Polycyclic Organic Matter (7-PAH Group) - added and compared to EL for benzo(a)pyrene	3.46E-05	2.80E-07	2.61E-07				5.41E-07	2.00E-06	No	586	
7782492	Selenium		5.89E-07	5.49E-07				1.14E-06	0.013	No	585	

CAS Nbr.	Pollutant	Emission Rates (lb/hr) - uncontrolled for 24-hour averages, controlled for annual averages						Emission Rates (lb/hr) excluding engines	Screening Emission Level[b] (lb/hr)	Exceeds Screening Level?	IDAPA 58.01.01 Section	Notes
		Engine	Flare	Water Heaters	Desulfurization Unit Vent	Tail Gas	Fugitive and Pits					
100425	Styrene	3.03E-05						0.00E+00	6.67	No	585	
79345	1,1,2,2-Tetrachloroethane	5.14E-05						0.00E+00	1.1E-05	No	586	
108883	Toluene	5.24E-04	8.35E-05	7.77E-05				1.61E-04	25	No	585	
79005	1,1,2-Trichloroethane	4.09E-05						0.00E+00	4.2E-04	No	586	
75014	Vinyl Chloride	1.91E-05						0.00E+00	9.40E-04	No	586	
1330207	Xylene	2.36E-04						0.00E+00	29	No	585	
7440666	Zinc		7.12E-04					7.12E-04	0.667	No	585	
Polyaromatic Hydrocarbons (except 7-PAH group)								3.64E-06	9.10E-05	No	586	d
91576	2-Methylnaphthalene		5.89E-07	5.49E-07				1.14E-06				
56495	3-Methylcholanthrene		4.42E-08	4.11E-08				8.53E-08				
57976	7,12-Dimethylbenz(a)anthracene		3.93E-07	3.66E-07				7.59E-07				
83329	Acenaphthene		4.42E-08	4.11E-08				8.53E-08				
208968	Acenaphthylene		4.42E-08	4.11E-08				8.53E-08				
120127	Anthracene		5.89E-08	5.49E-08				1.14E-07				
191242	Benzo(g,h,i)perylene		2.95E-08	2.74E-08				5.69E-08				
206440	Fluoranthene		7.37E-08	6.86E-08				1.42E-07				
86737	Fluorene		6.87E-08	6.40E-08				1.33E-07				
85018	Phenanthrene		4.17E-07	3.89E-07				8.06E-07				
129000	Pyrene		1.23E-07	1.14E-07				2.37E-07				

Notes:

(a) Potential emission rate is based on total emissions for the project.

(b) Emission rate screening levels per IDAPA 58.01.01.585 and IDAPA 58.01.01.586.

(c) AP-42 provides an emission factor for total Dichlorobenzene which comprise of three chemical compounds: ortho-, meta-, and para-dichlorobenzene. The total factor will be used for each individual compound. IDAPA 58.0101.585 provides emission limits for ortho- and para- compounds.

(d) Polyaromatic Hydrocarbons are considered TAPs (excluding the 7-PAH) group per IDAPA 58.0101.586

(e) Hg standard in lb/year for compliance with IDAPA 58.01.01.215 standard of 25 lb/year.

SHELL PROJECT BOVARIUS
HEAT AND MATERIAL BALANCE - MAXIMUM CASE

	7	10	11	13	15	18	19	20	44
	Biogas from Digesters (Note 17)	Biogas to Desulfurization Unit Package (Note 17)	Biogas to Desulfurization Unit Scrubber (Note 17)	Biogas to Membrane Package	Desulfurization Unit Vent, Draft	Offgas from Membrane Unit	Renewable Natural Gas to Compression	Renewable Natural Gas to Pipeline	Natural Gas to Water Heaters (Note 11)
Temperature [F]	98.5	149.9	77.0	103.1	105	70.0	51.8	120	80
Pressure [psig]	0.5 " H2O	3.25	2.49	1.90		1.0	159.5	480	15 (TBC)
Molar Flow [lbmole/hr]	246.6	246.6	236.39	233.8	45.48	77.56	144.59	144.59	30.1
Mass Flow [lb/hr]	6,375	6,375	6,191	5,844	1,358.00	3,368	2,385	2,385	497
Flow, SCFM	1,561	1,561	1,495	1,479	288	491	915	915	191
Flow, gpm	---	---	---	---		---	---	---	---
Mole Fractions									
Methane	0.5777	0.5777	0.6027	0.6093		0.0188	0.9758	0.9758	0.9758
Nitrogen	0.0086	0.0086	0.0089	0.0090		0.0026	0.0133	0.0133	0.0133
Carbon Dioxide	0.3389	0.3389	0.3535	0.3102		0.9701	0.0100	0.0100	0.0100
Oxygen	0.0019	0.0019	0.0019	0.0020		0.0045	0.0009	0.0009	0.0009
Hydrogen Sulfide	0.0033	0.0033	0.0034	25 ppmv max		0.0000	Note 4	Note 4	Note 4
Water	0.0697	0.0697	0.0295	0.0695		0.0040	Note 4	Note 4	Note 4
Biogas Stream HHV, Btu/scf		586		617			987		

Notes:
3. Limited information available for Streams 14-15 and 40-43.

4. Pipeline specifications are no more than 7 lbs water/MMSCF, 0.25 gr H2S/100 SCF, 2 vol% Carbon Dioxide, 0.2 vol% Oxygen, 3 vol% total diluent gases, and gross heating value of 985-1100 Btu/SCF
11. Natural Gas flow and vent properties assumes 85% furnace efficiency. To be confirmed by water heater vendor
17. Normal maximum H_2S concentration used for HMB. Max 1-hour is 4300 ppm.

CONTINUOUS VENT FROM DESULFURIZATION UNIT AND HIGH BTU PACKAGE

Stream Name	Desulfurization Unit Vent			High BTU Package Vent		
Case	Turndown	Normal	Max.	Turndown	Normal	Max.
Molar Flow [lbmole/hr]	22.16	35.51	45.48	38.78	60.56	77.56
Mass Flow [lb/hr]	662	1,061	1,358	1,684	2,630	3,368
Flow, SCFM	140	225	288	245	383	491
Temperature [F]	105.0			67.0		
Pressure [psig]	1.0			4.4		
Vol %						
Methane	0.95%			1.70%		
Carbon Dioxide	12.77%			97.70%		
Nitrogen	63.86%			< 0.1%		
Oxygen	15.50%			0.30%		
Hydrogen Sulfide	<1 ppmv			-		
Water	6.92%			0.20%		

NATURAL GAS GENERATOR ENGINE

INTERNAL COMBUSTION ENGINE - CRITERIA POLLUTANTS

Engine Type: 4 stroke lean burn spark ignition		
Generac Model QT100		ENGINE INFORMATION
Electrical Power Output:	100	kW
Engine Power Output:	134	bhp
Engine Heat Rate	9591	Btu/BHP-hr, 1260 scf/hr @ 134 hp
Heat Input to engine:	1.29	MMBtu/hr
Natural Gas Heating Value	1020	Btu/scf
Max Gas Flow to Engine	1,260	scf/hr
Hours per Year per Engine	8,760	hrs/yr/engine

Pollutant	Emission Factor	Units	Emission Factor Reference	Hourly Emissions (lbs/hr)	Annual Emissions (ton/yr)
NO_x	2.0	g/bhp-hr	NSPS Subpart JJJJ	0.591	2.588
SO_x	5.88E-04	lb/mmBtu	AP-42 Table 3.2-2	0.00076	0.0033
CO	4.0	g/bhp-hr	NSPS Subpart JJJJ	1.18	5.18
VOC	1.0	g/bhp-hr	NSPS Subpart JJJJ	0.30	1.29
$PM_{2.5}$	0.010	lb/mmBtu	AP-42 Table 3.2-2	0.0128	0.056
PM/PM_{10}	0.010	lb/mmBtu	AP-42 Table 3.2-2	0.0128	0.056

Greenhouse Gas Pollutants	Emission Factor		Calculated Emissions (tpy)	Calculated Emissions (MT/yr)	GWP[(1)]	CO_2e		Reference/Notes
Carbon Dioxide (CO_2)	53.06	kg/mmBtu	657	597	1	597	MT/yr	40 CFR 98.3,Table C-1
Methane (CH_4)	1.0E-03	kg/mmBtu	0.012	1.13E-02	25	0.281	MT/yr	40 CFR 98.3,Table C-2
Nitrous Oxide (N_2O)	1.00E-04	kg/mmBtu	0.001	1.13E-03	298	0.335	MT/yr	40 CFR 98.3,Table C-2
						598	MT/yr	

(1) Table A-1 to Subpart A, 40 CFR Part 98

Emission Factor Source: AP-42 Chapter 3.2, 7/00, Natural Gas-fired Reciprocating Engines; Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean-Burn Engines

Potential Hazardous Air Pollutant Emissions

CAS Nbr.	Pollutant	Emission Factor (lb/mmBtu)	Emission Rates (lb/hr)	Emission Rates (tpy)	Notes
75343	1,1-Dichloroethane	2.36E-05	3.03E-05	1.33E-04	
79345	1,1,2,2-Tetrachloroethane	4.00E-05	5.14E-05	2.25E-04	
79005	1,1,2-Trichloroethane	3.18E-05	4.09E-05	1.79E-04	
107062	1,2-Dichloroethane	2.36E-05	3.03E-05	1.33E-04	
78875	1,2-Dichloropropane	2.69E-05	3.46E-05	1.51E-04	
106990	1,3-Butadiene	2.67E-04	3.43E-04	1.50E-03	
542756	1,3-Dichloropropene	2.64E-05	3.39E-05	1.49E-04	
75070	Acetaldehyde	8.36E-03	1.07E-02	4.71E-02	
107028	Acrolein	5.14E-03	6.61E-03	2.89E-02	
71432	Benzene	4.40E-04	5.65E-04	2.48E-03	
56235	Carbon Tetrachloride	3.67E-05	4.72E-05	2.07E-04	
108907	Chlorobenzene	3.04E-05	3.91E-05	1.71E-04	
67663	Chloroform	2.85E-05	3.66E-05	1.60E-04	
100414	Ethylbenzene	3.97E-05	5.10E-05	2.23E-04	
106934	Ethylene Dibromide	4.43E-05	5.69E-05	2.49E-04	
50000	Formaldehyde	5.28E-02	6.79E-02	2.97E-01	
110543	Hexane		---	---	
67561	Methanol	2.50E-03	3.21E-03	1.41E-02	
75092	Methylene Chloride	2.00E-05	2.57E-05	1.13E-04	
91203	Naphthalene	7.44E-05	9.56E-05	4.19E-04	
	PAH (from AP-42)	2.69E-05	3.46E-05	1.51E-04	
100425	Styrene	2.36E-05	3.03E-05	1.33E-04	
108883	Toluene	4.08E-04	5.24E-04	2.30E-03	
75014	Vinyl Chloride	1.49E-05	1.91E-05	8.39E-05	
1330207	Xylene	1.84E-04	2.36E-04	1.04E-03	
		TOTAL	0.09	0.40	

NATURAL GAS FIRED HEATERS

Inputs			References/Notes
Natural Gas-fired Water Heaters. Cleaver Brooks ClearFire Condensing Boilers			
Model: CFLC Nominal 12 MMBtu/hr			
Heat Input per Heater	12.00	mmBtu/hr	Cleaver Brooks
Max NG Flow per Heater	11,431	scf/hr	From HMB Page
Number of Heaters	2		Only one will run at once
Annual Hours, Per Heater	8,760	hrs/yr	hrs/yr, per heater
Annual Hours, All Heaters	17,520	hrs/yr	hours per year, combined

CRITERIA POLLUTANTS

	Emission Factor		Emissions per Heater				All Heaters		Reference/Notes
$PM/PM_{10}/PM_{2.5}$	0.01	lb/mmBtu	0.120	lb/hr	0.526	tpy	1.05	tpy	Table 5, Model CFLC Boilers
Sulfur Dioxide (natural gas)	0.001	lb/mmBtu	0.012	lb/hr	0.053	tpy	0.11	tpy	Table 5, Model CFLC Boilers
Nitrogen Oxides (NO_x)	0.024	lb/mmBtu	0.288	lb/hr	1.261	tpy	2.52	tpy	Table 5, Model CFLC Boilers
Carbon Monoxide (CO)	0.007	lb/mmBtu	0.084	lb/hr	0.368	tpy	0.74	tpy	Table 5, Model CFLC Boilers
VOC	0.0016	lb/mmBtu	0.019	lb/hr	0.084	tpy	0.17	tpy	Table 5, Model CFLC Boilers

GREENHOUSE GAS POLLUTANTS - ALL FROM COMBUSTION OF FOSSIL FUELS

	Emission Factor		Emissions From All Heaters				GWP[(1)]	CO_2e		Reference/Notes
Carbon Dioxide (CO_2)	53.06	kg/mmBtu	12,271	tpy	11,132	MT/yr	1	11,132	MT/yr	40 CFR 98.3,Table C-1
Methane (CH_4)	1.0E-03	kg/mmBtu	2.3E-01	tpy	2.1E-01	MT/yr	25	5.26	MT/yr	40 CFR 98.3,Table C-2
Nitrous Oxide (N_2O)	1.00E-04	kg/mmBtu	2.3E-02	tpy	2.1E-02	MT/yr	298	6.27	MT/yr	40 CFR 98.3,Table C-2
						TOTAL		11,143	MT/yr	

(1) Table A-1 to Subpart A, 40 CFR Part 98

HAZARDOUS AIR POLLUTANTS (HAPs)

HAP Emission factor source: AP-42 Tables 1.4-3 and -4.

Pollutant	Uncontrolled e.f.		Emissions per Heater				All Heaters				CAS Nbr.
Arsenic	2.0E-04	lb/mmscf	2.29E-06	lb/hr	1.00E-05	tpy	4.57E-06	lb/hr	2.00E-05	tpy	7440382
Benzene	2.1E-03	lb/mmscf	2.40E-05	lb/hr	1.05E-04	tpy	4.80E-05	lb/hr	2.10E-04	tpy	71432
Beryllium	1.2E-05	lb/mmscf	1.37E-07	lb/hr	6.01E-07	tpy	2.74E-07	lb/hr	1.20E-06	tpy	7440417
Cadmium	1.1E-03	lb/mmscf	1.26E-05	lb/hr	5.51E-05	tpy	2.51E-05	lb/hr	1.10E-04	tpy	7440439
Chromium	1.4E-03	lb/mmscf	1.60E-05	lb/hr	7.01E-05	tpy	3.20E-05	lb/hr	1.40E-04	tpy	7440473
Cobalt	8.4E-05	lb/mmscf	9.60E-07	lb/hr	4.21E-06	tpy	1.92E-06	lb/hr	8.41E-06	tpy	7440484
Dichlorobenzene	1.2E-03	lb/mmscf	1.37E-05	lb/hr	6.01E-05	tpy	2.74E-05	lb/hr	1.20E-04	tpy	25321226
Formaldehyde	7.5E-02	lb/mmscf	8.57E-04	lb/hr	3.75E-03	tpy	1.71E-03	lb/hr	7.51E-03	tpy	50000
Hexane	1.8E+00	lb/mmscf	2.06E-02	lb/hr	9.01E-02	tpy	4.11E-02	lb/hr	1.80E-01	tpy	110543
Manganese	3.8E-04	lb/mmscf	4.34E-06	lb/hr	1.90E-05	tpy	8.69E-06	lb/hr	3.80E-05	tpy	7439965
Mercury	2.6E-04	lb/mmscf	2.97E-06	lb/hr	1.30E-05	tpy	5.94E-06	lb/hr	2.60E-05	tpy	7439976

Pollutant	Uncontrolled e.f.		Emissions per Heater				All Heaters				CAS Nbr.
Naphthalene	6.1E-04	lb/mmscf	6.97E-06	lb/hr	3.05E-05	tpy	1.39E-05	lb/hr	6.11E-05	tpy	91203
Nickel	2.1E-03	lb/mmscf	2.40E-05	lb/hr	1.05E-04	tpy	4.80E-05	lb/hr	2.10E-04	tpy	7440020
Selenium	2.4E-05	lb/mmscf	2.74E-07	lb/hr	1.20E-06	tpy	5.49E-07	lb/hr	2.40E-06	tpy	7782492
Toluene	3.4E-03	lb/mmscf	3.89E-05	lb/hr	1.70E-04	tpy	7.77E-05	lb/hr	3.40E-04	tpy	108883
Polyaromatic Hydrocarbons (except 7-PAH group)											
2-Methylnaphthalene	2.4E-05	lb/mmscf	2.74E-07	lb/hr	1.20E-06	tpy	5.49E-07	lb/hr	2.40E-06	tpy	91576
3-Methylcholanthrene	1.8E-06	lb/mmscf	2.06E-08	lb/hr	9.01E-08	tpy	4.11E-08	lb/hr	1.80E-07	tpy	56495
7,12-Dimethylbenz(a)anthracene	1.6E-05	lb/mmscf	1.83E-07	lb/hr	8.01E-07	tpy	3.66E-07	lb/hr	1.60E-06	tpy	57976
Acenaphthene	1.8E-06	lb/mmscf	2.06E-08	lb/hr	9.01E-08	tpy	4.11E-08	lb/hr	1.80E-07	tpy	83329
Acenaphthylene	1.8E-06	lb/mmscf	2.06E-08	lb/hr	9.01E-08	tpy	4.11E-08	lb/hr	1.80E-07	tpy	203968
Anthracene	2.4E-06	lb/mmscf	2.74E-08	lb/hr	1.20E-07	tpy	5.49E-08	lb/hr	2.40E-07	tpy	120127
Benzo(g,h,i)perylene	1.2E-06	lb/mmscf	1.37E-08	lb/hr	6.01E-08	tpy	2.74E-08	lb/hr	1.20E-07	tpy	191242
Fluoranthene	3.0E-06	lb/mmscf	3.43E-08	lb/hr	1.50E-07	tpy	6.86E-08	lb/hr	3.00E-07	tpy	206440
Fluorene	2.8E-06	lb/mmscf	3.20E-08	lb/hr	1.40E-07	tpy	6.40E-08	lb/hr	2.80E-07	tpy	86737
Phenanthrene	1.7E-05	lb/mmscf	1.94E-07	lb/hr	8.51E-07	tpy	3.89E-07	lb/hr	1.70E-06	tpy	85018
Pyrene	5.0E-06	lb/mmscf	5.72E-08	lb/hr	2.50E-07	tpy	1.14E-07	lb/hr	5.01E-07	tpy	129000
PAH (sum of 7 below)	1.1E-05	lb/mmscf	1.30E-07	lb/hr	5.71E-07	tpy	2.61E-07	lb/hr	1.14E-06	tpy	
Benz(a)anthracene	1.8E-06	lb/mmscf									56553
Benzo(b)fluoranthene	1.8E-06	lb/mmscf									205992
Benzo(k)fluoranthene	1.8E-06	lb/mmscf									207089
Dibenzo(a,h)anthracene	1.2E-06	lb/mmscf									53703
Chrysene	1.8E-06	lb/mmscf									218019
Indenol(1,2,3-cd)pyrene	1.8E-06	lb/mmscf									193395
Benzo(a)pyrene	1.2E-06	lb/mmscf									50328
						TOTAL	0.04	lb/yr	0.19	tpy	
						Maximum	0.04	lb/yr	0.18	tpy	

BIOGAS FLARE (COMBUSTOR)

The flare will burn natural gas in the pilot and three biogas streams.

Natural Gas Fired in Flare

Pilot Gas	50	scf/hr	Pipeline natural gas pilot with electric backup
Pilot Load Capacity	0.05	mmBtu/hr	Calculated based on 1020 Btu/SCF
Pilot Hours of Operation	8,760	hr/yr	Pilot always on.

Criteria Pollutants	Emission Factor		Calculated Emissions				Reference/Notes
$PM/PM_{10}/PM_{2.5}$:	7.6	lb/mmscf	3.80E-04	lb/hr	1.66E-03	tpy	AP-42 Table 1.4-2
Sulfur Dioxide (SO_2):	0.6	lb/mmscf	3.00E-05	lb/hr	1.31E-04	tpy	AP-42 Table 1.4-2
Nitrogen Oxides (NO_x):	94	lb/mmscf	4.70E-03	lb/hr	2.06E-02	tpy	AP-42 Table 1.4-1
Volatile Organics (VOC):	5.5	lb/mmscf	2.75E-04	lb/hr	1.20E-03	tpy	AP-42 Table 1.4-2
Carbon Monoxide (CO):	40	lb/mmscf	2.00E-03	lb/hr	8.76E-03	tpy	AP-42 Table 1.4-1

Greenhouse Gas Pollutants	Emission Factor		Calculated Emissions				GWP[1]	CO_2e		Reference/Notes
Carbon Dioxide (CO_2)	53.06	kg/mmBtu	26	tpy	24	MT/yr	1	24	MT/yr	40 CFR 98.3,Table C-1
Methane (CH_4)	1.0E-03	kg/mmBtu	4.91E-04	tpy	4.47E-04	MT/yr	25	0.011	MT/yr	40 CFR 98.3,Table C-2
Nitrous Oxide (N_2O)	1.00E-04	kg/mmBtu	4.91E-05	tpy	4.47E-05	MT/yr	298	0.013	MT/yr	40 CFR 98.3,Table C-2
					TOTAL			24	MT/yr	

(1) Table A-1 to Subpart A, 40 CFR Part 98

Stream 1: Biogas from digester, upstream of H_2S scrubber.

Inputs			References/Notes
Peak hourly gas input	93,660	scf/hr	Total maximum digester gas emissions.
Maximum annual gas flared	150	mmscf/yr	Conservative Maximum (based on 1600 hrs/yr)
Biogas HHV	586	mmBtu/mmscf	Flare Gas Stream 1 (Btu/scf)
Flare Design Heat Load Capacity	54.9	mmBtu/hr	Calculated

Criteria Pollutants	Emission Factor		Calculated Emissions				Reference/Notes
$PM/PM_{10}/PM_{2.5}$:	7.6	lb/mmscf					AP-42 Table 1.4-2
e.f. Based on MMBtu:	7.45E-03	lb/MMBtu	0.409	lb/hr	0.327	tpy	Based on MMBtu for use with biogas
Sulfur Dioxide (SO_2):							
1-hour Emission Factor:	724.55	lb/mmscf	67.9	lb/hr			AP-42, Table 5.3-1, H_2S = 4300 ppm
Annual Emission Factor:	556.05	lb/mmscf			41.70	tpy	AP-42, Table 5.3-1, H_2S = 3300 ppm
Hydrogen Sulfide (H_2S)	2.00%	uncombusted	0.721	lb/hr	0.44	tpy	98% Removal of H_2S
Nitrogen Oxides (NO_x):	0.10	lb/mmBtu	5.49	lb/hr	4.40	tpy	Vendor Data
Volatile Organics (VOC):	1.20E-03	lb/mmBtu	0.07	lb/hr	0.05	tpy	AP-42, Table 13.5-1, THC
Carbon Monoxide (CO):	0.20	lb/mmBtu	10.98	lb/hr	8.79	tpy	Vendor Data

Stream 2: Feed Compression Biogas, downstream of H_2S scrubber.

Inputs			References/Notes
Peak hourly gas input	88,730	scf/hr	Maximum short term
Maximum annual gas flared	142	mmscf/yr	Conservative Maximum (based on 1600 hrs/yr)
Biogas HHV	617	mmBtu/mmscf	Flare Gas Stream 2 (Btu/scf)
Flare Heat Load	54.7	mmBtu/hr	Calculated

Criteria Pollutants	Emission Factor		Calculated Emissions				Reference/Notes
$PM/PM_{10}/PM_{2.5}$:	7.6	lb/mmscf					AP-42 Table 1.4-2
e.f. Based on MMBtu:	7.45E-03	lb/MMBtu	0.408	lb/hr	0.326	tpy	Based on MMBtu, 1020 Btu/scf n.g.
Sulfur Dioxide (SO_2):							
1-hour and Annual H_2S:	4.21	lb/mmscf	0.374	lb/hr	0.299	tpy	AP-42, Table 5.3-1, H_2S = 25 ppm
Hydrogen Sulfide (H_2S)	2.00%	uncombusted	0.004	lb/hr	0.0032	tpy	98% Removal of H_2S
Nitrogen Oxides (NO_x):	0.20	lb/mmBtu	10.95	lb/hr	8.76	tpy	Vendor data, worst case
Volatile Organics (VOC):	1.20E-03	lb/mmBtu	0.066	lb/hr	0.05	tpy	AP-42, Table 13.5-1, THC
Carbon Monoxide (CO):	0.20	lb/mmBtu	10.95	lb/hr	8.76	tpy	Vendor data, worst case

Stream 3: Membrane Product, downstream of Gas Processing Unit.

Inputs			References/Notes
Peak hourly gas input	54,870	scf/hr	Maximum short term 915 scfm
Maximum annual gas flared	44	mmscf/yr	Conservative Maximum (based on 800 hrs/yr)
Biogas HHV	987	mmBtu/mmscf	Flare Gas Stream 3 (Btu/scf)
Flare Heat Load	54.2	mmBtu/hr	Calculated

Criteria Pollutants	Emission Factor		Calculated Emissions				Reference/Notes
$PM/PM_{10}/PM_{2.5}$:	7.6	lb/mmscf					AP-42 Table 1.4-2
e.f. Based on mmBtu:	7.45E-03	lb/mmBtu	0.404	lb/hr	0.162	tpy	Based on MMBtu, 1020 Btu/scf n.g.
Sulfur Dioxide (SO_2):							
1-hour and Annual H_2S:	4.21	lb/mmscf	0.231	lb/hr	0.093	tpy	AP-42, Table 5.3-1, H_2S = 25 ppm
Nitrogen Oxides (NO_x):	0.200	lb/mmBtu	10.83	lb/hr	4.343	tpy	Vendor Data, worst case
Volatile Organics (VOC):	1.20E-03	lb/mmBtu	0.06	lb/hr	0.026	tpy	AP-42, Table 13.5-1, THC
Carbon Monoxide (CO):	0.20	lb/mmBtu	10.83	lb/hr	4.343	tpy	Vendor Data, worst case

Maximum Emission: Sum of Streams 1 and 2 - hourly. Sum of Stream 1, 2 and 3, plus pilot.

Criteria Pollutants	Emission Factor		Calculated Emissions				Reference/Notes
$PM/PM_{10}/PM_{2.5}$:							
e.f. Based on MMBtu:			0.817	lb/hr	0.817	tpy	
Sulfur Dioxide (SO_2):							
1-hour and Annual			68.235	lb/hr	42.096	tpy	
Hydrogen Sulfide (H_2S)			0.725	lb/hr	0.446	tpy	Less than EL in 58.01.01.585
Nitrogen Oxides (NO_x):			16.442	lb/hr	17.520	tpy	
Volatile Organics (VOC):			0.132	lb/hr	0.133	tpy	
Carbon Monoxide (CO):			21.928	lb/hr	21.903	tpy	

Peak Hourly Heat Content of Biogas Burned	109.63	mmBtu/hr
Total Annual Heat Content of Biogas Burned	218,942	mmBtu/yr

GREENHOUSE GAS POLLUTANTS - FROM BIOGAS COMBUSTION IN THE FLARE

	Emission Factor		Calculated Emissions				GWP[(1)]	CO_2e		Reference/Notes
Carbon Dioxide (CO_2)	52.07	kg/mmBtu	12,540	tpy	11,400	MT/yr	1		MT/yr	40CFR98.3,Table C-1
Methane (CH_4)	3.2E-03	kg/mmBtu	0.77	tpy	0.70	MT/yr	25	17.5	MT/yr	40CFR98.3,Table C-2
Nitrous Oxide (N_2O)	6.3E-04	kg/mmBtu	0.152	tpy	0.138	MT/yr	298	41.1	MT/yr	40CFR98.3,Table C-2
						TOTAL		58.6	MT/yr	

(1) Table A-1 to Subpart A, 40 CFR Part 98

Peak Hourly Heat Content of Biogas and Natural Gas Burned	109.68	mmBtu/hr
Total Annual Heat Content of Biogas and Natural Gas Burned	219,389	mmBtu/yr

HAZARDOUS AIR POLLUTANTS (HAPs)

Pollutant	Emission Factor[2]		Calculated Emissions				AP-42 Emission Factor (lb/mmscf)[1]	CAS Nbr.
Arsenic	1.96E-07	lb/mmBtu	2.15E-05	lb/hr	2.15E-05	tpy	2.0E-04	7440382
Benzene	2.06E-06	lb/mmBtu	2.26E-04	lb/hr	2.26E-04	tpy	2.1E-03	71432
Beryllium	1.18E-08	lb/mmBtu	1.29E-06	lb/hr	1.29E-06	tpy	1.2E-05	7440417
Cadmium	1.08E-06	lb/mmBtu	1.18E-04	lb/hr	1.18E-04	tpy	1.1E-03	7440439
Chromium	1.37E-06	lb/mmBtu	1.51E-04	lb/hr	1.51E-04	tpy	1.4E-03	7440473
Cobalt	8.24E-08	lb/mmBtu	9.03E-06	lb/hr	9.03E-06	tpy	8.4E-05	7440484
Dichlorobenzene	1.18E-06	lb/mmBtu	1.29E-04	lb/hr	1.29E-04	tpy	1.2E-03	25321226
Formaldehyde	7.35E-05	lb/mmBtu	8.06E-03	lb/hr	8.07E-03	tpy	7.5E-02	50000
Hexane	1.76E-03	lb/mmBtu	1.94E-01	lb/hr	1.94E-01	tpy	1.8E+00	110543
Manganese	3.73E-07	lb/mmBtu	4.09E-05	lb/hr	4.09E-05	tpy	3.8E-04	7439965
Mercury	2.55E-07	lb/mmBtu	2.80E-05	lb/hr	2.80E-05	tpy	2.6E-04	7439976
Naphthalene	5.98E-07	lb/mmBtu	6.56E-05	lb/hr	6.56E-05	tpy	6.1E-04	91203
Nickel	2.06E-06	lb/mmBtu	2.26E-04	lb/hr	2.26E-04	tpy	2.1E-03	7440020
Selenium	2.35E-08	lb/mmBtu	2.58E-06	lb/hr	2.58E-06	tpy	2.4E-05	7782492
Toluene	3.33E-06	lb/mmBtu	3.66E-04	lb/hr	3.66E-04	tpy	3.4E-03	108883
Polyaromatic Hydrocarbons (except 7-PAH group)								
2-Methylnaphthalene	2.35E-08	lb/mmBtu	2.58E-06	lb/hr	2.58E-06	tpy	2.4E-05	91576
3-Methylcholanthrene	1.76E-09	lb/mmBtu	1.94E-07	lb/hr	1.94E-07	tpy	1.8E-06	56495
7,12-Dimethylbenz(a)anthracene	1.57E-08	lb/mmBtu	1.72E-06	lb/hr	1.72E-06	tpy	1.6E-05	57976
Acenaphthene	1.76E-09	lb/mmBtu	1.94E-07	lb/hr	1.94E-07	tpy	1.8E-06	83329
Acenaphthylene	1.76E-09	lb/mmBtu	1.94E-07	lb/hr	1.94E-07	tpy	1.8E-06	203968
Anthracene	2.35E-09	lb/mmBtu	2.58E-07	lb/hr	2.58E-07	tpy	2.4E-06	120127
Benzo(g,h,i)perylene	1.18E-09	lb/mmBtu	1.29E-07	lb/hr	1.29E-07	tpy	1.2E-06	191242
Fluoranthene	2.94E-09	lb/mmBtu	3.23E-07	lb/hr	3.23E-07	tpy	3.0E-06	206440
Fluorene	2.75E-09	lb/mmBtu	3.01E-07	lb/hr	3.01E-07	tpy	2.8E-06	86737
Phenanathrene	1.67E-08	lb/mmBtu	1.83E-06	lb/hr	1.83E-06	tpy	1.7E-05	85018
Pyrene	4.90E-09	lb/mmBtu	5.38E-07	lb/hr	5.38E-07	tpy	5.0E-06	129000
PAH (sum of 7 below)	1.12E-08	lb/mmBtu	1.23E-06	lb/hr	1.23E-06	tpy	1.1E-05	

Benz(a)anthracene	1.76E-09	lb/mmBtu					1.8E-06	56553
Benzo(b)fluoranthene	1.76E-09	lb/mmBtu					1.8E-06	205992
Benzo(k)fluoranthene	1.76E-09	lb/mmBtu					1.8E-06	207089
Dibenzo(a,h)anthracene	1.18E-09	lb/mmBtu					1.2E-06	53703
Chrysene	1.76E-09	lb/mmBtu					1.8E-06	218019
Indenol(1,2,3-cd)pyrene	1.76E-09	lb/mmBtu					1.8E-06	193395
Benzo(a)pyrene	1.18E-09	lb/mmBtu					1.2E-06	50328

TOTAL	0.20	tpy
Maximum	0.19	tpy

(1) HAP Emission factor source: AP-42 Tables 1.4-3 and -4.

(2) lb/mmscf values converted to lb/mmBtu bu dividing by natural gas heating value of 1020 Btu/scf

TOXIC AIR POLLUTANTS (NON-HAPs)

Pollutant	Emission Factor(2)		Calculated Emissions				AP-42 Emission Factor (lb/mmscf)(1)	CAS Nbr.
Dichlorobenzene	1.18E-06	lb/mmBtu	1.29E-04	lb/hr	1.29E-04	tpy	1.20E-03	25321226
Barium	4.31E-06	lb/mmBtu	4.73E-04	lb/hr	4.73E-04	tpy	4.40E-03	7440393
Copper (fume)	8.33E-07	lb/mmBtu	9.14E-05	lb/hr	9.14E-05	tpy	8.50E-04	7440508
Molybdenum (soluble compounds	1.08E-06	lb/mmBtu	1.18E-04	lb/hr	1.18E-04	tpy	1.10E-03	7439987
Pentane	2.55E-03	lb/mmBtu	2.80E-01	lb/hr	2.80E-01	tpy	2.60E+00	109660
Zinc	2.84E-05	lb/mmBtu	3.12E-03	lb/hr	3.12E-03	tpy	2.90E-02	7440666

MANURE PIT AMMONIA

Ammonia emissions are estimated from the manure influent pit and the leach field.

Emission Factor:	31.2	µg $NH_3m^{-2}s^{-1}$	Grant and Boehm[a]

Source	Length	Width	Area	Emissions	
	(ft)	(ft)	(m^2)	(µg/s)	lb/hr
Parlor Water Lagoon Feed Pit	16	26	38.6	1,206	0.01
Digester Effluent Lagoon Feed Pit	16	26	38.6	1,206	0.01
Parlor Water Centrifuge Feed Pit	42	21	81.9	2,557	0.02
Digester Effluent Centrifuge Feed Pit	42	21	81.9	2,557	0.02
Influent Pit	35	60	195.1	6,087	0.05
Manure Pre-Heating Pit	38	30	105.9	3,304	0.03
TOTAL					0.13

[a] Ammonia Emissions from Differing Manure Storage Facilities at Two Midwestern Free-Stall Dairies, Richard H. Grant and Matthew T. Boehm, Department of Agronomy, Purdue University. Published in *Atmosphere* 2020, *11*,1108; doi:10.3390/atmos11101188. www.mdpi.com/journal/atmosphere.

The screening emissions level (EL) for ammonia in IDAPA 58.01.01.585 is 1.2 lb/hr. No additional analyses are required for ammonia.

Table 3. Seasonal NH_3 emissions.

Farm	Period	NH_3 Emissions				
		Mean g NH_3 s^{-1}	SD ‡ g NH_3 s^{-1}	Mean µg NH_3 $m^{-2}s^{-1}$	Mean g NH_3 hd $^{\dagger-1}d^{-1}$	Mean g NH_3 AU $^{*-1}$ d^{-1}
WI	Spring	0.20	0.105	28.8	31.6	24.9
	Summer	0.42	0.137	58.7	64.3	50.6
	Fall	0.17	0.075	24.6	24.3	21.0
	Winter	0.07	0.015	9.2	10.1	8.0
	Annual	0.21		30.3	40.0	32.1
	Total	0.22		31.2	33.1	26.8
IN	Spring	0.24	0.033	28.4	8.96	6.79
	Summer	0.39	0.039	38.2	14.2	9.27
	Fall	0.26	0.086	24.3	9.52	6.52
	Winter	0.17	0.016	17.8	5.22	4.47
	Annual	0.26		27.2	10.0	7.08
	Total	0.27		30.4	9.47	6.76

‡: SD = standard deviation. *: animal unit (1 AU = 500 kg live mass). †: hd = animal "head".

DESULFURIZATION UNIT VENT

Desulfurization Unit Vent Parameters		
Q =	17,259	scf/hr, Max
Flow =	45.48	lbmol/hr

Desulfurization Unit Vent Gas Composition - Not Combusted.

Gas	Mol%	MW	lb/hr	tpy	MT/yr
C1 (methane)	0.95	16	6.9	30.3	28
CO_2	12.77	44	256	1,119	1,018
O_2	15.50	32	226	988	
N_2	63.86	28	813	3,562	
H_2S[(1)]	0.0001	34	0.0015	0.0068	
H_2O	6.92	18	57	248	

[(1)] H_2S < 1 ppmv, =0.0001 Mol%.

Desulfurization UnitVent Gas Carbon Dioxide Equivalent (CO_2e):

Emissions:	GWP[(1)]	MT/yr	CO_2e	Reference/Notes
CO_2	1			CO_2 from biogas is not included in CO_2e. There is no N_2O e.f. for gas combustion.
Methane (CH_4)	25	28	688	
N_2O	298			

[(1)] Table A-1 to Subpart A, 40 CFR Part 98

TAIL GAS VENT

Tail Gas Parameters		
Q =	29,434	scf/hr
Flow =	77.56	lbmol/hr

Tail Gas Composition - Not Combusted

Gas	Mol%	MW	lb/hr	tpy	MT/yr
C1 (methane)	1.88	16	23.33	102.19	93
CO_2	97.01	44	3,311	14,501	13,183
O_2	0.45	32	11.12	48.70	
N_2	0.26	28	5.62	24.62	
H_2S[(1)]	0.0004	34	0.0105	0.0462	
H_2O	0.40	18	5.59	24.50	

[(1)] H_2S = 4 ppmv, =0.0004 Mol%.

Tail Gas Carbon Dioxide Equivalent (CO_2e):

Emissions:	GWP[(1)]	MT/yr	CO_2e	Reference/Notes
CO_2	1			CO_2 from biogas is not included in CO_2e. There is no N_2O e.f. for gas combustion.
Methane (CH_4)	25	93	2,318	
N_2O	298			

[(1)] Table A-1 to Subpart A, 40 CFR Part 98

PROCESS FUGITIVES

The digester contains liquid manure with biogas forming in the vapor space below the membrane roof. Standing Idle Losses are estimated based on the AP-42 calculation method for tanks with floating roofs. Of the three standing idle loss mechanisms, the majority of rim seal vapor losses have bound to be wind induced. Only wind losses are considered in this emissions inventory.

RIM SEAL WIND-INDUCED VAPOR LOSS ESTIMATION

Rim Seal Loss (L_R), AP-42 Section 7.1.3.2.1, eqn. 2.3		
L_R = rim seal loss (lb/yr). $L_R = (K_{Ra}+K_{Rb}v^n)DP^*M_VK_C$		
Calculated L_R =	27,396	lb/yr biogas, per digester
Number of digesters	2	
Total for all digesters L_R =	54,791	lb/yr biogas, total
Biogas released	3,414	scf/yr, all digesters
Digester Area, per digester	40,171	square feet, per digester
Equivalent Diameter (D)	226	feet, each digester
Zero WS Loss Factor (K_{Ra})	0.4	lbmol/ft-yr, from Table 7.1-8
WS Dependent Loss (K_{Rb})	0.4	lbmol/(mph)^{n}ft-yr, from Table 7.1-8
Avg WS at Tank Site (v)	10.7	mph, average of met data
Seal-related WS exponent (n)	1.0	unitless, from Table 7.1-8
Average vapor MW (M_V)	25.82	lb/lbmol, calculated below
Product Factor (K_C)	1	for organic liquid not crude oil
Vapor Pressure Function (P*)	1.0024	unitless, eqn. 2-4
VP, digester (P_{VA})	14.79	psia, 1" w.c. above P_A
Atmospheric Pressure (P_A)	14.75	psia, online data for Wendell, ID

BIOGAS COMPOSITION AND EMISSIONS

	Mol%	MW	MW fraction	lb/yr	tpy
C1 (methane)	57.77	16	9.24	19,614	10
CO_2	33.89	44	14.91	31,643	16
O_2	0.19	32	0.06	126	
N_2	0.86	28	0.24	511	
H_2S[(1)]	0.33	34	0.11	235	0.12
H_2O	6.97	18	1.25	2,662	
	100		25.82	54,791	

[(1)] H_2S = 3300 ppmv normal maximum

DIGESTER RIM SEAL LOSS REGULATED POLLUTANTS

	GWP	tpy	MT/yr	CO_2e	Reference/Notes
CO_2	1	16	14.4		CO_2 from biogas not considered part of CO_2e.
Methane (CH_4)	25	10	8.9	223	GWP from 40 CFR 98 Subpart A, Table A-1
N_2O	298	0			

FUGITIVE PROCESS EMISSIONS FROM VALVES AND CONNECTORS
POPULATION COUNT AND EMISSION FACTORS

PARAMETERS

Geographic Location?	Western
Calculation method	Component Count Method 2
Concentration of CO_2 in biogas	0.3389 (fraction)
Concentration of CH_4 in biogas	0.5777 (fraction)
Concentration of H2S in biogas	0.0033 (fraction)
Hours of Operation	8760 Hours
Density of CO_2 at standard	0.0526 kg/ft^3
Density of CH_4 at standard	0.0192 kg/ft^3
Density of H_2S at standard	0.0385 kg/ft^3
Conversion from kg to metric	0.0010

EQUIPMENT COUNTS [98.236(r)(3)(ii)(B)]

Required Data	Count of Major Equipment Type	EPA's Default Leaking Components per Equipment Count*					
Major Equipment Type		# of Valves	# of Connectors	# of Open Ended Lines	# of Pressure Relief Valves	# of Flanges	# of other components
Gas Meter/piping	3	42	153	3	3	NA	NA
Gas compressor Count	1	73	179	3	4	NA	NA
In-Line Gas Heater Count	2	28	130	4	2	NA	NA
	Totals	143	462	10	9	0	0

*Natural gas production and Gathering and boosting equipment (Table W-1B) [98.236(r)(3)(ii)]

Emission Source Type (Eq. W-32A) [98.232(c)(21)] [98.233(r)]	Total number of this type of emission source at the facility	Population e.f. for the specific component type (scf/hr-component)(1)	Annual Volumetric CO_2 Emissions (scf/yr)	Annual Volumetric CH_4 Emissions (scf/yr)	Annual CO_2 Emissions (MT CO_2) 98.236(r)(1)(iv)	Annual CH_4 Emissions (MT CH_4) 98.236(r)(1)(v)	H_2S Emissions (lb/hr H_2S) for Idaho TAP analysis
Gas Service - Valves	143	0.121	51,369	87,564	2.70	1.68	0.0048
Gas Service - Connectors	462	0.017	23,317	39,746	1.23	0.76	0.0022
Gas Service - Open ended lines	10	0.031	920	1,569	0.05	0.03	0.0001
Gas Service - Pressure relief valves	9	0.193	5,157	8,790	0.27	0.17	0.0005
				Total	4.25	2.64	0.0075

(1) 40 CFR Appendix Table W-1A to Subpart W of Part 98
-Natural gas distribution [98.230(a)(8)] 66.08158896
-Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)] CO2e

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

M E M O R A N D U M

DATE: November 22, 2021

TO: Zach Pierce, Permit Writer, Air Program

FROM: Darrin Mehr, Air Quality Dispersion Modeling Analyst, Air Program

PROJECT: P-2021.0019 PROJ 62623, Permit to Construct for the Equilon Enterprises, LLC dba Shell Oil Products U.S. Shell Downstream Bovarius facility located near Wendell, Idaho

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) Related to Air Quality Impact Analyses

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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
AERMAP	The terrain data preprocessor for AERMOD
AERMET	The meteorological data preprocessor for AERMOD
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
Appendix W	40 CFR 51, Appendix W – Guideline on Air Quality Models
ARM	Ambient Ratio Method
ASOS	Automated Surface Observing System
bhp	Brake horsepower
Bison	Bison Engineering, Inc. (project permitting and modeling consultant)
BPIP	Building Profile Input Program
BRC	Below Regulatory Concern
Btu/scf	British thermal unit per standard cubic feet
CFR	Code of Federal Regulations
CMAQ	Community Multi-Scale Air Quality Modeling System
CO	Carbon Monoxide
DEQ	Idaho Department of Environmental Quality
EL	Emissions Screening Level of a TAP
EPA	United States Environmental Protection Agency
EE/SOPUS	Equilon Enterprises, LLC dba Shell Oil Products U.S. (permittee)
ft	Feet
ft/sec	Feet per second
GEP	Good Engineering Practice
HAP	Hazardous Air Pollutant
hp	Horsepower
hr	Hour
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
lb/hr	Pounds per hour
m	Meters
m/sec	Meters per second
MACT	Maximum Achievable Control Technology
MERPs	Modeled Emission Rates for Precursors
MMBtu	Million British Thermal Units
MMscf/year	Million standard cubic feet per year
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Dataset
NESHAP	National Emission Standards for Hazardous Air Pollutants
NLCD	National Land Cover Database
NO	Nitrogen Oxide

N_2O	Nitrous Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NW AIRQUEST	Northwest International Air Quality Environmental Science and Technology Consortium
NWS	National Weather Service
O_3	Ozone
OLM	Ozone Limiting Method
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
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
PTE	Potential to Emit
scf/day	Standard cubic feet per day
scf/hour	Standard cubic feet per hour
scf/year	Standard cubic feet per year
scfm	Standard cubic feet per minute
SDP	Shell Downstream Bovarius (proposed facility)
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
tons/year	Tons per year
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOCs	Volatile Organic Compounds
^oF	Degrees Fahrenheit
$\mu g/m^3$	Micrograms per cubic meter of air

1.0 Summary

Equilon Enterprises, LLC dba Shell Oil U.S. (EE/SOPUS) submitted a Permit to Construct (PTC) application for the Shell Downstream Bovarius facility located in Gooding County, Idaho. This project will be constructed on a property parcel located on the Bettencourt Dairy facility located at 2901 S 2300 East. The EE/SOPUS will use raw manure generated on dairies to generate biogas in anaerobic digesters. The raw manure will be transported by truck to the new facility and transferred to a lagoon for storage before it is transferred to the anaerobic digesters. Two natural gas-fired boilers will supply heat to the digesters as needed to maximize the biogas generation. The biogas will be treated to remove H_2S and will be upgraded to a higher methane and heat content to pipeline grade specifications. The upgraded biogas will be delivered into the commercial natural gas pipeline. Biogas is combusted in an elevated open flare when biogas does not meet specifications, periods where delivery of upgraded biogas to the pipeline is interrupted, or emergencies.

Project-specific air quality analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to 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 Sections 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.

Bison, on behalf of EE/SOPUS, prepared the PTC application and performed ambient air impact analyses for this project. DEQ review of submitted data and analyses (and any DEQ verification 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
General Emission Rates. Emission rates used in the air impact analyses, as listed in this memorandum, 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. Emissions of NO_x[a], SO_2[b] PM_{10}[c], $PM_{2.5}$[d] were modeled for the project to demonstrate compliance with SIL and cumulative NAAQS impact analyses. Emissions of, CO[e] , and lead (Pb) were below the BRC, ¼ SER, or SIL-based modeling thresholds.	Compliance has not been demonstrated for emission rates greater than those used in the air impact analyses.
Digester Biogas Production Rates The application-represented digester capacity was based on the following production rates: • Facility-wide capacity is limited to 93,660 scf/hour of biogas, or 54.88 MMBtu/hr at 586 Btu/scf, for the two anaerobic digesters combined. • Annual biogas production was unlimited at 820.5 MM scf/year based on 8,760 hours/year at 93,660 scf/hour.	Raw biogas and upgraded biogas (renewable natural gas) will not be emitted directly to atmosphere. Raw biogas or upgraded biogas is either combusted in a flare or is transferred to the existing commercial natural gas pipeline. Annual anaerobic digester capacity was evaluated at maximum short term production rate for 8,760 hours/year.
Biogas Flaring Biogas not introduced into the natural gas pipeline as renewable natural gas is flared. Three separate biogas streams were evaluated for flaring emissions and ambient impacts based on three individual stages of processing the raw biogas directly from the anaerobic digesters to final product. H_2S[f] content, heat content of the gas, and biogas flow rates are unique for each of the three stages. The biogas streams included the following maximum flow rates: 1) Raw biogas from digester - H_2S uncontrolled 93,660 scfm/hour and 150 MMscf/year 2) Feed compression – H_2S controlled 88,730 scf/hour and 142 MMscf/year 3) Post-Membrane RNG – H_2S controlled 54,870 scf/hour and 44 MMscf/year Maximum short-term capacity for each stage was incorporated in the modeling analyses. Annual flaring capacity was limited for all three of the streams. Flaring may occur for Stream 1 only, or Stream 1 combined with either Stream 2 or Stream 3. Stream 2 and Stream 3 will not be flared concurrently.	Maximum short term digester production capacity was incorporated in the emission inventory and the NAAQS and TAPs ambient impact analyses based on biogas combustion in the enclosed flare. Flaring of biogas was limited below the unlimited annual biogas production capacity.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
FLARING-Biogas H_2S Content (Model IDs FLARE_1, FL12) Short term modeled 1-hr avg SO_2 emission rates applied a maximum of 4,300 ppm_v[g] Annual average limitation for SO_2 PTE applied an H_2S concentration limit of 3,300 ppm_v	Compliance with the 1-hour SO_2 NAAQS used maximum hourly emission rates based on the maximum biogas generation capacity and 4,300 ppmv. 24-hour average H_2S emissions complied with the Section 585 TAP EL based on the 98% destruction efficiency of the maximum short term production capacity of raw biogas containing 4,300 ppm_v H_2S. An annual average SO_2 NAAQS does not exist so the annual average H_2S limitation is for PTE purposes only.
Enclosed Flare Operating Temperature The enclosed flare will operate at a minimum temperature of 1,600°F at all operation loads.	The operating temperature is set at a minimum value of 1,600° and this temperature will be maintained by varying the amount of excess air introduced to the flare for combustion. Volumetric flow rate and exit velocity release parameters for the enclosed flare are influenced by the operating temperature. A reduced operating temperature results in a lower exit velocity, reducing plume dispersion for the enclosed flare. Enclosed flare control efficiency is related to operating temperature. At 1600°F, control of H_2S, by conversion to SO_2 is 98% efficient, and H_2S emissions are 0.721 lb/hr. If the control efficiency drops to 97%, the H_2S EL would be exceeded with a 1.08 lb/hr emission rate.
Fuel Type Hot Water Heaters (model IDs WH_1, WH_2) The two 12 MMBtu/hr hot water heaters combust natural gas. Biogas produced on-site is not combusted in the hot water heater. Upgraded pipeline grade biogas or raw biogas will not be combusted in the hot water heater.	Natural gas is the only fuel type for the hot water heaters. The hot water heaters were both modeled operating at maximum rated capacity for 8,760 hours/year. Operation was described as being limited to a single hot water heater at any time but compliance with all standards was demonstrated assuming both emissions units operated concurrently. Operating hour and capacity restrictions are not required.
Generator Engine Operating Hours and Fuel Type (model ID GEN) The engine is a natural gas-fired internal combustion (IC) engine rated at 134 bhp. The electrical generator powered by the IC engine has a maximum output of 100 kW. The engine is not an emergency engine and was modeled continuously at rated capacity emission rates for 24 hours/day and 8,760 hours/year.	Emergency IC engines limited to 100 hours per year are exempt from modeling for the 1-hour NO_2 SIL and NAAQS. This engine was not treated as an emergency engine. Permit limitations restricting hours of operation are not warranted because NAAQS compliance was demonstrated based on continuous operation at 100% load emission rates. The IC engine combusts natural gas exclusively. Biogas generated on-site will not be combusted in this emissions unit. IC engine SO_2 emissions are minimal based on combustion of pipeline grade natural gas.

[a.] Nitrogen dioxide.
[b.] Sulfur dioxide.
[c.] Particulate matter with a mean aerodynamic diameter of 10 microns or less.
[d.] Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
[e.] Carbon monoxide.
[f.] Hydrogen sulfide.
[g.] Parts per million by volume.

Summary of Submittals and Actions

May 11, 2021 EE/SOPUS submitted a permit application to DEQ.

May 14, 2021	Regulatory start date.
June 10, 2021	DEQ declared the permit application incomplete.
June 29, 2021	EE/SOPUS submitted a response to the incompleteness determination.
July 29, 2021	DEQ declared the application incomplete.
August 30, 2021	EE/SOPUS submitted a response to the second incompleteness determination.
September 27, 2021	DEQ declared the application complete.

2.0 Background Information

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

2.1 Project Description

EE/SOPUS applied for a facility-wide PTC that includes the following emissions units at the proposed Shell Downstream Bovarius facility:

- Two above-ground anaerobic digesters with biogas generation capacity listed as: 1,561 standard cubic feet per minute (scfm), 93,660 scf/hour, 2.248 MMscf/day, and 820.46 MM scf/year. Raw biogas was assumed to contain a maximum H_2S concentration of 4,300 ppm_v for 1-hour (SO_2 combustion byproduct emissions) and 24-hour averaging periods (H_2S TAP emissions) and 3,300 ppm_v for annual potential to emit estimates.

- All biogas generated on-site is either flared in an enclosed flare (Model ID FLARE) or is upgraded to remove H_2S and other compounds to increase methane concentration in order to increase specific heat content to meet pipeline grade specifications and is transferred to the commercial natural gas pipeline as a finished product. The flare will have a rated heat input capacity of 107 MMBtu/hr.

- Two 12 MMBtu/hr hot water boilers (model ID WH_1 and WH_2) fired exclusively on pipeline natural gas will supply heat to the anaerobic digesters. Biogas produced on-site will not be used in the hot water heaters.

- One natural gas-fired electrical generator engine will be installed. This unit was not treated as an emergency backup generator. Unlimited operation at full load capacity was modeled.

- Biogas Processing System rated at 1,479 scfm (88,740 scf/hour and 2.13 MMscf/day). The biogas processing system has a tail-gas vent emission point that emits CO_2, methane, and N_2O which are not regulated air pollutants subject to modeling.

2.2 Facility Location and Area Classification

The facility is located in Gooding County, Idaho (Easting: 693,515 m; Northing: 4,740,550 m; UTM Zone 11) or (42.7930° latitude; -114.6338° longitude). The land use in the immediate area is primarily agricultural with the majority of the area consisting of cultivated fields and arid open and undeveloped land. The facility is located approximately 5 kilometers northeast of the town of Wendell.

Gooding County is a Class II area that is designated as attainment or unclassifiable 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 ($PM_{2.5}$), ozone (O_3), carbon monoxide (CO), for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and lead (Pb).

2.3 Air Impact Analyses Required for All Permits to Construct

Idaho Air Rules[1] Sections 203.02 and 203.03:

> *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] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	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 $\mu g/m^3$)	75 ppb[p] (196 $\mu g/m^3$)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 $\mu g/m^3$)	100 ppb[s] (188 $\mu g/m^3$)	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[2]; 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 facility were estimated by Bison for various applicable averaging periods and multiple flare operational loads. 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 Modeling Protocol

A modeling protocol was not submitted for this project. The air impact modeling analyses were generally conducted using data and methods described in the *Idaho Air Modeling Guideline*.[3]

3.1.2 Modeling Applicability and Modeled Criteria Pollutant Emission Rates

If a project 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 Section 221.01 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.[2]" 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 analysis 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 generally be used to exempt a project from a pollutant-specific NAAQS compliance demonstration where a PTC is required for the action regardless of emission quantities, such as the modification of an existing emission or throughput limit. However, in this instance, if post-project facility-wide emissions of the criteria pollutant are also below BRC thresholds, then a NAAQS compliance demonstration is not required.

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. DEQ recently revised emission *de minimis* threshold levels, below which project-specific air impact modeling is not necessary to confidently demonstrate NAAQS compliance. Revised thresholds are a function of the Significant Emission Rates (SERs) defined in Idaho Air Rules Section 005.108. The SERs are expressed as annual emission rates. To use SERs for NAAQS with short-term averaging periods, the SER is divided by 8,760 hours/year and compared to maximum hourly emissions for 1-hour standards or maximum daily emissions divided by 24 for 24-hour standards.

DEQ also developed SIL thresholds for modification projects where facility-wide emissions exceed SER-based thresholds; emissions less than these rates are reasonably assured to have impacts less than the applicable SIL. SIL thresholds were developed by DEQ using dispersion modeling analyses of a generic facility with one point source. If emissions from affected units/processes exceed SIL modeling thresholds, then air impact modeling is required for permitting.

Table 3 summarizes applicability to NAAQS compliance demonstration requirements and project-specific air impact modeling analyses. The modeling applicability threshold for a new facility is established as the $1/4^{th}$ of the SER (or $1/4^{th}$ of the SER divided by 8,760 hour/year for NAAQS with an averaging period less than annual).

This is a proposed new facility. The facility's emissions include PM_{10}, $PM_{2.5}$, CO, VOCs, NO_x, and SO_2. Lead emissions will be negligible. A modeling protocol and accompanying emission inventory were not submitted to DEQ prior to submittal of the permit application. DEQ's evaluation of modeling applicability was based on the project's August 30, 2021, emission inventory submittal, and is summarized in Table 3.

Ambient air impact analyses are not required for the rolling 3-month average lead standard based on the emissions remaining below the annual BRC threshold. Ambient impact modeling analyses are not required for the 24-hour PM_{10}, annual $PM_{2.5}$, 1-hour CO, and 8-hour CO standards based on the emissions increases remaining below the $1/4^{th}$ SER-based thresholds.

Project-specific air impact modeling analyses were required for 24-hour $PM_{2.5}$, 1-hour NO_2, annual NO_2, and 1-hour SO_2 because emissions increases were above the modeling thresholds based on $1/4^{th}$ the SER.

Bison elected to perform 24-hour PM_{10} and annual $PM_{2.5}$ SIL and NAAQS analyses.

Compliance demonstration requirements for secondary formation of ozone and $PM_{2.5}$ due to VOCs, NO_x, and SO_2 precursor emissions are discussed below.

Table 3. APPLICABILITY OF NAAQS COMPLIANCE DEMONSTRATION REQUIREMENTS AND PROJECT-SPECIFIC AIR IMPACT MODELING ANALYSES						
Pollutant and Averaging Period	**BRC Exemption from NAAQS Compliance Demonstration**			**Project-Specific Impact Analysis Applicability**		
	Annual PTE for Permit Applicability[a] (tons/year)	**BRC Level[b] (tons/year)**	**NAAQS Compliance Demonstration Required?**	**Total Project Emission Increase**	**Modeling Threshold (SER/4)[c]**	**Project-Specific Modeling Required?**
PM_{10} 24-hour	1.9	1.5	Yes	0.66 lb/hr	0.86 lb/hour	No
$PM_{2.5}$ 24-hour	1.9	1.0	Yes	0.66 lb/hour	0.57 lb/hour	Yes
$PM_{2.5}$ annual			Yes	1.9 ton/year	2.5 tons/year	No
NO_2 1-hour	22.6	4.0	Yes	11.47 lb/hour[d]	2.28 lb/hour	Yes
NO_2 annual				22.6 ton/year	10 ton/year	Yes
SO_2 1-hour	42.2	4.0	Yes	68.26 lb/hour[h]	2.28 lb/hour	Yes
SO_2 3-hour					2.28 lb/hour	
CO 1- hour	27.8	10	Yes	12.2 lb/hour	5.7 lb/hour[e] (84 lb/hour SIL-based)	No
CO 8-hour				12.2 lb/hour	5.7 lb/hour[e] (26 lb/hour SIL-based)	No
O_3 8-hour[f]	1.6	4.0	No	NA	See below[g]	No[g]
Pb 3-month	Not listed in EI	0.06	No[h]	Not listed in EI	24.7 lb/month	No[h]

a. Calculated potential to Emit (PTC) for permit applicability purposes. Fugitive emissions are not considered in the BRC evaluation unless required by federal rule. Note that permit applicability is based only on annual emission rates.
b. Below Regulatory Concern (BRC) thresholds in tons/year.
c. The project-specific air impact modeling threshold for a new facility is 1/4th of the Significant Emission Rate (SER). For NAAQS with a 1-hour averaging period, this value is converted to pounds and divided by 8,760 hour/year to generate a pound/hour threshold.
d. Maximum hourly emissions including emergency generator engines.
e. SIL-based CO modeling thresholds may be used if the ¼ SER threshold is exceeded.
f. VOC emissions are evaluated for ozone impact.
g. See section below on secondary formation from precursor emissions.
h. Emissions units will combust biogas and natural gas exclusively. Lead emissions from the facility are presumed to be negligible.

Secondary Formation Ambient Impacts Due to Precursor Emissions

EPA issued final Modeled Emission Rates as Precursors (MERPs) guidance[5] that may be used for Tier 1 compliance demonstrations using default minimum MERP values specific to regions within the U.S. The guidance establishes the applicability criteria and methods to evaluate secondary impacts for this project. EPA has modeled hypothetical sources for secondary formation of $PM_{2.5}$ and ozone, including two new sources in Idaho that are not included in the final MERPs guidance pointed out above. This resource can be accessed at: https://www.epa.gov/scram/merps-view-qlik. EPA issued revised guidance[6] for assessing ambient impacts for $PM_{2.5}$ and ozone in permitting projects attributed to precursor emissions of SO_2, NO_x, and VOCs. The analyses follow the current EPA guidance issued on September 20, 2021.

An 8-hour ozone SIL compliance demonstration for secondary formation of ozone from VOCs and/or NO_x precursor emissions is triggered by an emission increase of either pollutant greater than the significant emission rate (SER) of 40 tons/year, as specified in Section 006.108 of the Idaho *Air Rules*. Only ozone precursor(s) with potential annual emissions exceeding the SER are required to be included in the SIL analysis. The project's annual emission increase of NO_x was estimated at 22.6 tons/year and an annual emissions increase of VOCs was estimated at 1.6 tons/year. The requested potential annual

emission rates of NO_x and VOCs are both below the SERs of 40 tons/year for each pollutant. A compliance demonstration for the 8-hour ozone SIL is not required for this project.

Secondary formation of $PM_{2.5}$ is caused by NO_x and SO_2 precursor emissions. The project's emission increases of NO_x and SO_2 precursor emissions were estimated to be 22.6 tons/year of NO_x and 42.2 tons/year of SO_2. Annual emission rate increases of SO_2 are above the SER and a secondary $PM_{2.5}$ formation analysis is required.

Bison submitted a secondary impact assessment using the MERPs Qlik website ambient impact data for the Morrow, Oregon hypothetical source with a 10-meter release height as a reasonably comparative source for the Bovarius Downstream facility located near Wendell, Idaho, shown in Table 4. The secondary formation analysis was submitted in the initial application and reflected project potential emissions of 345.7 tons/year of SO_2 and 77.1 tons/year of NO_x precursor emissions. DEQ updated the Tier 1 analyses based on the project's final PTE values.

Secondary impacts for the precursor pollutants are determined by multiplying the maximum modeled ambient impact by the ratio of the project's potential emissions rate to the Qlik modeled emission rate.

Table 4. EPA QLIK MODELED SECONDARY IMPACTS – MORROW, OREGON SOURCE

Pollutant/Averaging Period	Precursor Pollutant	Modeled Emission Rate (tons/year)	Maximum Concentration (µg/m³)[a]
Annual $PM_{2.5}$	NO_x	500	0.012590836
Annual $PM_{2.5}$	SO_2	500	0.008419393
24-hour $PM_{2.5}$	NO_x	500	0.199790135
24-hour $PM_{2.5}$	SO_2	500	0.259274006

a. Micrograms per cubic meter.

24-hour $PM_{2.5}$:

$$\frac{22.6\ \frac{tons}{year}\ NOx}{500\ \frac{tons}{year}\ NOx\ Qlik\ Emissions} \text{ x (} 0.199790135 \text{ µg/m}^3 \text{) } + \frac{42.2\ \frac{tons}{year}\ SO2}{500\ \frac{tons}{year}\ SO2\ Qlik\ Emissions} \text{ x (} 0.259074006 \text{ µg/m}^3 \text{)}$$

= **0.0309 µg/m³**

Annual $PM_{2.5}$:

$$\frac{22.6\ \frac{tons}{year}\ NOx}{500\ \frac{tons}{year}\ NOx\ Qlik\ Emissions} \text{ x (} 0.012590836 \text{ µg/m}^3 \text{) } + \frac{42.2\ \frac{tons}{year}\ SO2}{500\ \frac{tons}{year}\ SO2\ Qlik\ Emissions} \text{ x (} 0.008419393 \text{ µg/m}^3 \text{)}$$

= **0.00128 µg/m³**

The calculated predicted maximum impacts due to facility-wide SO_2 and NOx precursor emissions are very low. The values are added to the direct $PM_{2.5}$ ambient impacts and the ambient background values to determine the total impact for the cumulative NAAQS demonstrations. The annual $PM_{2.5}$ secondary impact is inconsequential and the 24-hour $PM_{2.5}$ secondary impact is very small in relation to the ambient background and 24-hour $PM_{2.5}$ design value for direct $PM_{2.5}$ emissions.

Modeled Emission Rates

Tables 5 and 6 list the emission rates modeled in the SIL analyses. Hourly emissions were modeled 8,760 hours/year.

Table 5. SIL ANALYSES SHORT-TERM CRITERIA POLLUTANT EMISSION RATES

Emissions Point	Description	1-hour NO_2 (lb/hr)	1-hour SO_2 (lb/hr)	24-hour $PM_{2.5}$ (lb/hr)	24-hour PM_{10} (lb/hr)
FLARE_1	Flare (Stream 1)	Not modeled	78.9	Not modeled	Not modeled
FL12	Flare (Streams 1 & 2)	16.442	Not modeled	0.817	0.817
WH_1	Water Heater #1	0.288	0.012	0.120	0.120
WH_2	Water Heater #2	0.288	0.012	0.120	0.120
ENG	Engine/Generator	0.59	7.53E-04	0.0128	0.0128

Table 6. SIL ANALYSES ANNUAL AVERAGE CRITERIA POLLUTANT EMISSION RATES

Emissions Point	Description	NO_2 (lb/hr)	$PM_{2.5}$ (lb/hr)
FLARE_1	Flare (Stream 1)	Not modeled	Not modeled
FL12	Flare (Streams 1 & 2)[a]	4.000	0.187
WH_1	Water Heater #1	0.288	0.120
WH_2	Water Heater #2	0.288	0.12
ENG	Engine/Generator	0.59	0.0128

[a.] Flaring both biogas Streams 1 and 2 produced maximum emissions and accounts for the scenario of flaring Stream 3 concurrently with Stream 1.

Tables 7 and 8 list the emission rates modeled in the cumulative NAAQS analyses. Hourly emissions were modeled 8,760 hours/year.

DEQ requested Bison perform ambient impact analyses for multiple operating load levels for the enclosed flare based on the margin of compliance with the 1-hour SO_2 NAAQS in the initial and first incompleteness response submittals those were based on requested allowable emission rates and release parameters applied in those submittals. An enclosed flare is essentially a stack with the combustion source located within the flare jacket and is modeled as a point source with an exit velocity based on the quantity of biogas combusted at a particular load level. Bison and EE/SOPUS identified the minimum intended operational load, normal operating load, and maximum 100% operating load as the appropriate loads to reflect in the modeling analyses to verify that the flare's SO_2 emissions would not cause a predicted exceedance of the 1-hour SO_2 NAAQS. SO_2 emissions formed by combustion of biogas were limited based on 4,300 ppm_v H_2S in the final modeling, replacing the 5,000 ppm_v H_2S maximum uncontrolled concentration in the project's earlier ambient impact analyses. Bison included ambient impact analyses for all criteria air pollutants and averaging periods triggering modeling for each load level.

The modeled flare operations reflected conditions where "Stream 1" was modeled as a separate scenario from the "Stream 1 and Stream 2" combined scenario. Stream 1 reflects combustion of the untreated biogas from the anaerobic digesters with a maximum H_2S content of 4,300 ppm_v, and the 50%, 78%, and 100% raw biogas flow rate levels were modeled for Stream 1. Stream 2 reflects flared biogas following H_2S removal, and the combined "Stream 1 and Stream 2" scenario presents maximum emission rates for combustion of the two biogas flows.

Table 7. NAAQS SHORT-TERM CRITERIA POLLUTANT EMISSION RATES				
Emissions Point	**Description**	**1-hour NO_2 (lb/hr)[a]**	**1-hour SO_2 (lb/hr)**	**24-hour PM_{10} / $PM_{2.5}$ (lb/hr)**
FLARE_1[a]	Enclosed Flare – Biogas Stream 1 only - 50% load	2.74	33.9	0.20
	Enclosed Flare – Biogas Stream 1 only - 78% load	4.50	55.7	0.34
	Enclosed Flare – Biogas Stream 1 only - 100% load	5.49	67.9	0.41
FL12[a]	Enclosed Flare –Biogas Streams 1 and 2 - 100% load both streams	16.44	Not modeled[b]	0.82
WH_1	Natural gas-fired Water Heater #1	0.29	0.012	0.12
WH_2	Natural gas-fired Water Heater #2	0.29	0.012	0.12
ENG	Natural gas-fired Generator Engine	0.59	0.0008	0.013

a. Pounds per hour.

b. Worst-case 1-hour SO_2 impacts are based on flaring Stream 1 biogas which has more conservative flare stack exit velocity release parameters than for flaring Streams 1 and 2 combined.

Table 8. NAAQS ANNUAL AVERAGE CRITERIA POLLUTANT EMISSION RATES			
Emissions Point	**Description**	**Annual NO_2 (lb/hr)**	**Annual $PM_{2.5}$ (lb/hr)**
FLARE_1	Enclosed Flare – Biogas Stream 1 only - 50% load	1.00	0.075
	Enclosed Flare – Biogas Stream 1 only - 78% load	1.00	0.075
	Enclosed Flare – Biogas Stream 1 only - 100% load	1.00	0.075
FL12	Enclosed Flare –Biogas Streams 1 and 2 – 100% load both streams	4.00	0.19
WH_1	Natural gas-fired Water Heater #1	0.29	0.12
WH_2	Natural gas-fired Water Heater #2	0.29	0.12
ENG	Natural gas-fired Generator Engine	0.59	0.013

a. Pounds per hour.

3.1.3 TAPs Modeling Applicability

TAP emissions regulated under Section 210 of the Idaho Air Rules are only applicable for new or modified sources constructed after July 1, 1995. TAP emission increases for the project, for those TAPs with an increase exceeding the ELs of Idaho Air Rules Section 585 or 586, are subject to modeling unless exempted from modeling pursuant to Section 210.20 of the Idaho *Air Rules*[1]. The natural gas-fired generator engine was determined by Bison and DEQ's permit writer to qualify for an exemption from modeling in accordance with Section 210.20 of the Idaho *Air Rules*[1] as an emission unit in a source category regulated by 40 CFR 63 Subpart ZZZZ.

Emissions of non-carcinogenic TAPs did not exceed the applicable screening ELs. Emissions of arsenic, cadmium, chromium, formaldehyde, and nickel exceeded carcinogenic TAP ELs. Hourly emissions of carcinogenic TAPs listed in Table 9 were modeled for 8,760 hours/year. The rates modeled for each of the water heaters were reflected the emissions rates for both water heaters combined, which is a conservative approach.

Table 9. CARCINOGENIC TOXIC AIR POLLUTANT EMISSION RATES					
Model ID	**Description**	**Arsenic (lb/hr)**	**Cadmium (lb/hr)**	**Formaldehyde (lb/hr)**	**Nickel (lb/hr)**
FLARE	Enclosed Flare	4.91E-06	2.70E-05	0.00184	5.16E-05
WH_1	Water Heater #1	4.57E-06	2.51E-05	0.00171	4.80E-05
WH_2	Water Heater #2	4.57E-06	2.51E-05	0.00171	

a. Pounds per hour.

3.1.4 Emission Release Parameters

Table 10 lists the emission release parameters, including stack height, exhaust temperature, exhaust velocity, and stack diameter for the modeled point sources. Values are listed in metric units and in English units below in parentheses.

Table 10. POINT SOURCE EMISSION RELEASE PARAMETERS IN METRIC UNITS (ENGLISH UNITS IN PARENTHESES)

Model ID	Description	UTM Coordinates NAD83 Datum, Zone 11[a]		Stack Height m (ft)[c]	Stack Exhaust Temperature K[d] (°F)[e]	Stack Exhaust Velocity m/sec[f] (ft/sec)[g]	Stack Diam.[h] m (ft)	Release Orien-tation[i]
		Easting-X (m)[b]	Northing-Y (m)					
FLARE_1	Enclosed Flare – Biogas Stream 1 only - 50% load	693,580.7	4,740,548.5	15.24 (50)	1,144.3 (1,600)	3.14 (10.3)	3.23 (10.6)	Default
	Enclosed Flare – Biogas Stream 1 only - 78% load					4.90 (16.1)		
	Enclosed Flare – Biogas Stream 1 only - 100% load					6.28 (20.59)		
FL12	Enclosed Flare – Biogas Streams 1 and 2 – 100% load					12.46 (40.9)		
WH_1	Natural gas-fired Water Heater #1	693,519.8	4,740,534.5	7.62 (25)	338.7 (150)	10.0 (32.8)	0.51 (1.67)	Default
WH_2	Natural gas-fired Water Heater #2	693,523.9	4,740,534.5	7.62 (25)	338.7 (150)	10.0 (32.8)	0.51 (1.67)	Default
ENG	Natural gas-fired Generator Engine	693,556.4	4,740,497.0	2.44 (8)	788.7 (960)	23.0 (75.4)	23.0 (75.4)	Default

a. Universal Transverse Mercator, North American Datum of 1983, Zone 12.
b. Meters.
c. Feet.
d. Kelvin.
e. Degrees Fahrenheit.
f. Meters per second
g. Feet per second.
h. Diameter.
i. Default = uninterrupted vertical release orientation; CAP = Impeded by a Raincap; Horiz = Horizontally-oriented.

3.1.5 Emission Release Parameter Justification

Exhaust stacks for all emissions units were modeled as point sources with uninterrupted vertical release orientations.

Flare (model ID FLARE_1 and FL12)
The flare is an enclosed design that has an insulated metal jacket. The multiple flare burner tips are located near ground level and the jacket surrounds the burner array and extends a number of feet above to function as a stack, providing a controlled environment for biogas combustion with extended residence time and control of excess air that provides effective control efficiencies at desired operating temperatures. The enclosed flare offers reduced noise and visibility of the flame during operation compared to an elevated open (or candlestick) flare.

The flare will be a model ZTOF enclosed flare manufactured by John Zink Hamworthy Combustion with a maximum listed heat input capacity of 107 MMBtu/hr. A manufacturer's specification sheet and a design schematic drawing, including dimensions specific to this project, were submitted to support the modeled release parameters. Bison provided a spreadsheet with calculations of the volumetric flow rates of the exhaust for the four modeled operating load conditions of biogas flaring.

The design schematic provided dimensional specifications establishing the overall shell height, used for the modeled release height, and the inner diameter of the flare shell, taking into account two layers of thermal insulation. The dimensional diagram specifies an internal diameter of 10 feet 7.25 inches. This matches the 10.6 feet diameter modeled. The diagram specified an overall height of 50 feet 1.25 inches for the flare jacket. The flare's modeled stack release height of 50 feet and exit diameter of 10.6 feet were fully substantiated.

Bison modeled four operating scenarios for the flare to identify worst-case ambient impacts were presented in the NAAQS analyses.

Three operating levels for Stream 1 combusting raw biogas with maximum uncontrolled H_2S content of 4,300 ppm_v were analyzed:

1. Stream 1 at 50% load
2. Stream 1 at 78% load
3. Stream 1 at 100% load
4. Combined Stream 1 and Stream 2 with Stream 1 at 100% load plus Stream 2 or Stream 3

The 100% Stream 1 scenario identifies the worst-case impacts for SO_2 because H_2S is reduced from the maximum content of 4,300 ppm_v to a concentration of 25 ppm_v for Streams 2 and 3.

Stream 2 accounts for flaring of biogas post-H_2S control with a concentration of 25 ppm_v at the high-pressure manifold at the feed compression stage prior to CO_2 removal where 1,479 scfm of biogas with 60% methane content is combusted (approximately 49.2 MMBtu/hr).

Stream 3 accounts for flaring of 916 scfm of biogas with a methane content of 98% (or approximately 49.0 MMBtu/hr) with H_2S controlled to 25 ppm_v.

The flare is designed to have accommodate Streams 1, 2, and 3 individually; Streams 1 and 2 concurrently; or Streams 2 and 3 concurrently. Flaring of Streams 2 and 3 concurrently will not occur. Streams 2 and 3 have nearly identical heat input rates and Stream 2 was included in the modeling demonstration.

The ambient impact analyses included Stream 1 only at three separate loads to identify worst-case 1-hour SO_2 impacts, and a fourth scenario reflecting Stream 1 at 100% load combined with Stream 2 that presented maximum emission rates for the combined stream flaring scenario. Although maximum emission rates occur for this scenario, an increased exhaust flow rate and exit velocity occur with the combined stream biogas flow rate.

Bison's final volumetric flow rate calculation spreadsheet titled "Shell Bovarius Combustion Flowrates R2" reflected updated information from John Zink Hamworthy establishing a higher 12.7% oxygen content in the flare exhaust from 10%, increasing estimated exit velocities. The biogas heat content for Stream 2 was increased from 531 Btu/scf to 617 Btu/scf for the maximum combined flow case. Bison applied a uniform 1,600˚F exit temperature applied in the calculations on Shell Oil Products U.S.'s

confirmation that the flare operating temperature will be maintained at a minimum of 1,600˚F for all flaring scenarios. The flow rates were corrected for the atmospheric pressure at the Wendell site.

The exhaust flow rates and exit velocities for the modeled operating scenarios are listed in Table 11, and the modeled exit velocities matched the calculated values. The enclosed flare was modeled with an exit temperature of 1,600˚F for all load analyses.

Bison's documentation adequately supported the modeled release parameters for the enclosed flare.

Table 11. ENCLOSED FLARE FLOW MODELED EXHAUST FLOW RATES		
Operating Scenario	**Exhaust Volumetric Flow Rate (ACFM)**	**Exhaust Exit Velocity (feet/sec)**
Stream 1 - 100% load 93,660 scf/hr and 55.49 MMBtu/hr biogas	109,025	20.59
Stream 1 – 78% load (normal) 73,080 scf/hr and 42.82 MMBtu/hr biogas	85,069	16.07
Stream 1 – 50% load **(worst-case dispersion and SO_2 impacts)** 46,800 scf/hr and 24.85 MMBtu/hr	54,478	10.29
Streams 1 and 2 – 100% load for both streams 182,400 scf/hr total (93,360 scf/hr + 88,740 scf/hr) and 109.7 MMBtu/hr	216,435	40.88

Hot Water Heaters (model IDs WH_1 and WH_2)

The two hot water heaters are identical units. They will combust natural gas exclusively. The units will be Cleaver Brooks ClearFire Condensing boilers identified as Model CFLC 12000. Each hot water heater will have a rated heat input capacity of 12 MMBtu/hr. A manufacturer's brochure and an additional flue requirements specification sheet were submitted to support physical release height and stack exit diameter parameters. The modeled release height of 25 feet for each stack was based on the Cleaver Brooks specification sheet requirement that the exhaust stack terminate a minimum of 2 feet above the peak height of a gabled roofline. The structure housing the hot water heaters was modeled with a 23 feet peak roof height, reflecting the final proposed structure and stack release heights.

The modeled 20-inch (1.67 feet or 0.51 meters) exit diameter matched the flue diameter listed in an Engineering Data specification sheet included in the project's 6-29-2021 incompleteness response submittal for Model CFLC 12000 water heaters.

Exit temperatures were not provided in the Cleaver Brooks documentation. These units are condensing boilers and Bison submitted a US Department of Energy Steam Tip Sheet #25A for installation of condensing economizers to support the modeled 150˚F stack exit temperature for each emissions unit. The DOE document listed a stack gas temperature range of 75˚F to 125˚F for a unit with a feedwater and condensing economizer, with a combustion efficiency of 95% at the 75˚F exit temperature and 92% at the 125˚F exit temperature. DEQ downloaded a complete copy of the manufacturer's information sheet manual and located an efficiency rating of 87.3% to 94.5% for the hot water heaters depending on feedwater return temperature. DEQ accepted the 150˚F exit temperature as a reasonable approximation.

The 150˚F exit temperature was used for the flow rate calculations which were corrected to Wendell's site elevation atmospheric pressure and the assumed exit temperature. Shell Oil provided the mass flow rate of the exhaust for each boiler as 14,259 lb/hr at 100% load. DEQ noted the Cleaver Brooks specification

brochure listed a flue gas flow rate of 13,596 lb/hr for a site location at 2,000 feet of elevation or lower. The values were within 5% and appeared to be appropriate.

Each stack was modeled with an uninterrupted vertical release. The Cleaver Brooks documentation recommends that standard raincaps not be used on exhaust stacks for these condensing boilers.

Internal Combustion Generator Engine (model ID ENG)
The IC engine/generator set is a Generac Model QT100 unit with a rated power output of 100 kW with an estimated 134 bhp rated engine capacity. A manufacturer's specification sheet was submitted to support modeled release parameters. DEQ did not locate the release parameters in the application's substantiation materials and downloaded an equipment brochure for the QT100 model generator set and found the modeled values of 888 ACFM and 960°F "exhaust temperature at the muffler outlet" listed in the specification sheet's operating data section matched the modeled values.

An exhaust stack exit diameter was not found on the manufacturer's specification sheet. Bison modeled a single exhaust stack with an exit diameter of 0.5 feet and a release height of 8 feet. The June 29, 2021, incompleteness response acknowledges support documentation does not exist for these parameters and confirmed the IC engine will be constructed with a stack matching these parameters. The supported 888 ACFM flow rate and modeled 0.5 feet diameter provide an exit velocity of 75.4 feet/sec (23.0 m/sec). This velocity is viewed as conservative and the exit diameter DEQ accepted the single stack exit diameter without additional substantiation.

A schematic diagram is available on the Generac website at the following link: generac-home-backup-generators-qt-series-70kw-80kw-100kw-130kw-150kw_spec-sheet.pdf.
The relief view 100 kW model indicated the termination height is approximately 5 feet above the level of the concrete mounting pad. EE/SOPUS will construct the stack to meet the modeled 8 feet above grade release height.

DEQ determined the release parameters for the ambient impact analyses were adequately substantiated.

3.2 Background Concentrations

Modeling was required for 1-hour NO_2, annual NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, annual $PM_{2.5}$, and 24-hour PM_{10} NAAQS. The ambient background concentration values used for this project are listed in Table 12 under the Bison Grid Cell Coordinates column. Bison obtained ambient backgrounds for the criteria pollutants modeled for cumulative NAAQS analyses from the NW AIRQUEST background lookup tool, which are based on updated 2014-2017 monitoring and regional-scale photochemical modeling data with refined interpolation methods to establish values for the Pacific Northwest states. The background lookup tool may be accessed at: https://arcg.is/1jXmHH. Bison applied the ambient backgrounds for the single background grid cell located coordinates of 42.82° latitude and -114.70° longitude. DEQ's recommended background values are based on the values in the grid cell closest to the proposed facility at coordinates of 42.78° latitude and -114.66° longitude.
DEQ finds compliance with all ambient standards is assured regardless of which set of ambient backgrounds is used for this project.

Table 12. DEQ-RECOMMENDED CRITERIA POLLUTANT AMBIENT BACKGROUNDS			
Pollutant Averaging	**Period**	**Background Concentration (ppb)[a] / (µg/m³)[b]**	
		Bison Grid Cell Coordinates 42.82° latitude, -114.70° longitude	**DEQ-recommended Grid Cell Coordinates** 42.78° latitude, -114.66° longitude
NO_2	1-hour	11.4 ppb or 21.4 µg/m³	12.4 ppb or 23.3 µg/m³
	Annual	1.9 ppb or 3.6 µg/m³	2.1 ppb or 3.9 µg/m³
SO_2	1-hour	4.7 ppb or 12.3 µg/m³	4.7 ppb or 12.3 µg/m³
$PM_{2.5}$	24-hour	13.5 µg/m³	13.7 µg/m³
	Annual	5.2 µg/m³	5.5 µg/m³
PM_{10}	24-hour	78.2 µg/m³	77.0 µg/m³

a. Parts per billion.
b. Micrograms per cubic meter.

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

Bison performed the project-specific air pollutant emission inventory and air impact analyses that were submitted with the application. The submitted information/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 13 provides a brief description of parameters used in the modeling analyses.

Table 13. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
General Facility Location	Wendell, Idaho	The area is an attainment or unclassified area for all criteria pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 19191.
Meteorological Data	Jerome airport surface data with Boise upper air data	This is a five-year data set covering 2014-2018. See Section 3.3.4 of this memorandum for additional details of the meteorological data.
Terrain	Considered	1 arc second (approximately 30-meter resolution) National Elevation Dataset (NED) files were acquired from the USGS for the surrounding area. AERMAP version 18081 was used to process terrain elevation data for all emission points and receptors. See Section 3.3.5 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 3.3.6.
NO_x Chemistry	Tier 2	Bison applied a Tier 2 Ambient Ratio Method (ARM2) with an alternative default minimum (0.2) and the default maximum (0.9) ambient ratios of NO_2/NO_x. See Section 3.3.7.
Receptor Grid	**SIL and 1-hour SO_2 NAAQS Analyses (10,780 receptors)**	
	Grid 1	22-meter spacing along the ambient air boundary.
	Grid 2	50-meter spacing extending outward from the ambient air boundary for a minimum distance of approximately 950 meters. Grid 2 is circular in shape.
	Grid 3	250-meter spacing extending approximately 1,900 meters from Grid 2

Table 13. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
		centered on the facility.
	Grid 4	500-meter spacing extending approximately 7,000 meters from Grid 3 centered on the facility.
	Grid 5	1,000-meter spacing extending approximately 40 kilometers from Grid 4 centered on the facility.
	NAAQS Analyses (1,709 receptors)	
	Grid 1	22-meter spacing along the ambient air boundary.
	Grid 2	50-meter spacing extending outward from the ambient air boundary for a minimum distance of approximately 950 meters. Grid 2 is circular in shape.
	Grid 3	250-meter spacing in a rectangular grid covering 2,750 meters (x) by 3,000 meters (y) centered on the facility.
	1-hour SO_2 NAAQS Hotspot Grid (121 receptors)	
	Grid 1	10-meter spacing in a 100-meter (x) by 100-meter (y) square grid located in the region of highest 1-hour SO_2 ambient impacts.
	TAPs Analyses (3,304 receptors)	
	Grid 1	22-meter spacing along the ambient air boundary.
	Grid 2	50-meter spacing extending outward from the ambient air boundary for a minimum distance of approximately 950 meters. Grid 2 is circular in shape.
	Grid 3	250-meter spacing extending approximately 1,900 meters from Grid 2 centered on the facility.
	Grid 4	500-meter spacing extending approximately 7,000 meters from Grid 3 centered on the facility.

3.3.2 Modeling Methodology

Project-specific modeling and other required impact analyses were generally conducted using data and methods described in the modeling protocol and the *Idaho Air Quality Modeling Guideline*[3].

3.3.3 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 19191 was used by Bison for the modeling analyses to evaluate impacts of the facility. The initial permit application and modeling submittal was received by DEQ on May 11, 2021. AERMOD version 21112 is the current version of AERMOD and was released on April 22, 2021, and posted by EPA on the SCRAM website on May 11, 2021. DEQ approves the use of AERMOD version 19191 for this project because there are no changes that were made to AERMOD version 21112 that would affect the ambient impact analyses for this project and the revised AERMOD code was made available on the same date the initial application was received by DEQ.

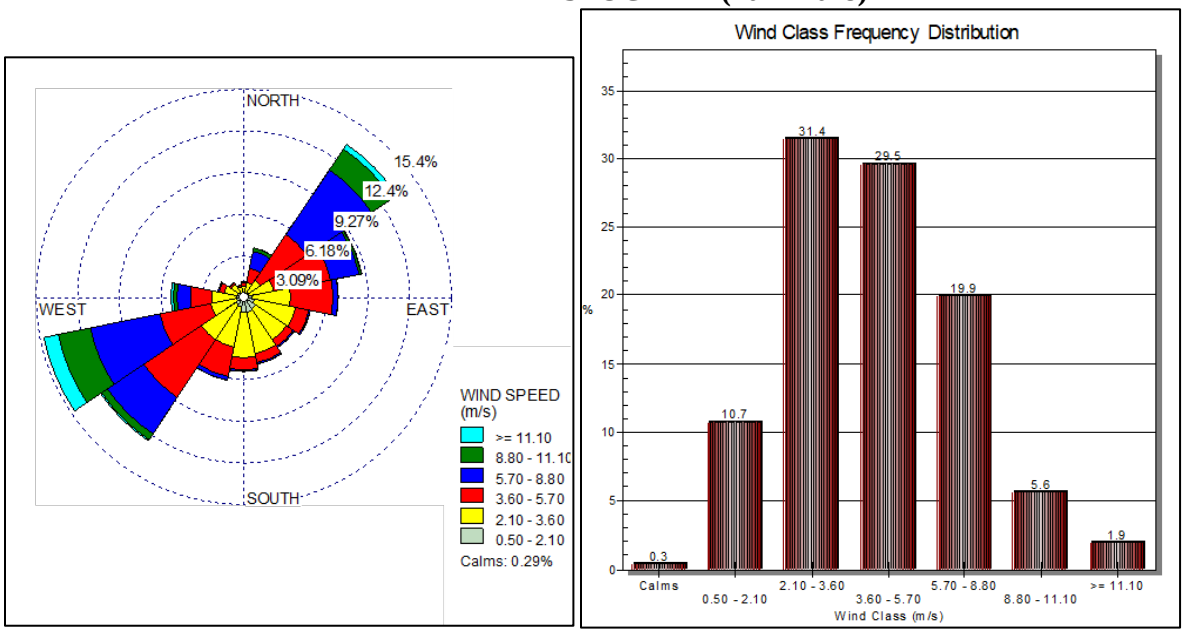
3.3.4 Meteorological Data

DEQ processed a meteorological dataset from data collected at the Jerome airport (KJER) for a five-year data period covering the years 2014-2018. National Weather Service (Station ID 726816-04110) data and

one-minute ASOS data from the Jerome airport NCDC site for 2014-2018 was used for surface meteorological data. 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 13016. DEQ modeling staff evaluated annual moisture conditions for the AERSURFACE runs based on the last thirty years of Jerome airport precipitation data. Conditions were determined to be "wet" for 2014 and 2015, "average" for 2016 and 2017, and "dry" for 2018. Average moisture content is defined as within a 30 percentile of the 30-year mean of 10.1 inches of precipitation. Continuous snow cover did not exist during period of 2014 to 2018. Calms were 0.29% of the data, and less than 1 percent of the data were missing from the 5-year record.

Figure 1 shows a wind rose and wind speed histogram of the Jerome 2014-2018 data. AERMINUTE version 15272 was used to process Automated Surface Observing Systems (ASOS) wind data for use in AERMET. 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 Bison, with and without the ADJ_U* option enabled. Bison used the meteorological data with the ADJ_U* option enabled. DEQ determined that these data are adequately representative of the meteorology at the EE/SOPUS facility site near Wendell, Idaho, for minor source permitting.

Figure 1. JEROME AIRPORT MONITORING SITE WIND ROSE AND WIND SPEED HISTOGRAM (2014-2018)



3.3.5 Effects of Terrain on Modeled Impacts

The ambient air impact analyses used terrain data extracted from four United States Geological Survey (USGS) National Elevation Dataset (NED) files with approximately 30-meter resolution. The terrain preprocessor AERMAP version 18081 was used by Bison 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 emission plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

DEQ determined the treatment of terrain was appropriate for the ambient air impact analyses.

3.3.6 Facility Layout and Building Downwash

DEQ verified proper identification of the site location, emission point locations, structure dimensions, and the ambient air boundary by comparing a graphical representation of a modeling input file to a scaled site plan diagram submitted with the permit application. Modeled emission points and structure layout is shown in Figures 2 and 3.

Potential downwash effects on emission plumes were accounted for in the model by using building dimensions and locations. Dimensions and orientation of the structures 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. DEQ determined Bison properly evaluated building downwash effects in the ambient impact analyses.

Figure 2. MODELED EMISSION SOURCES

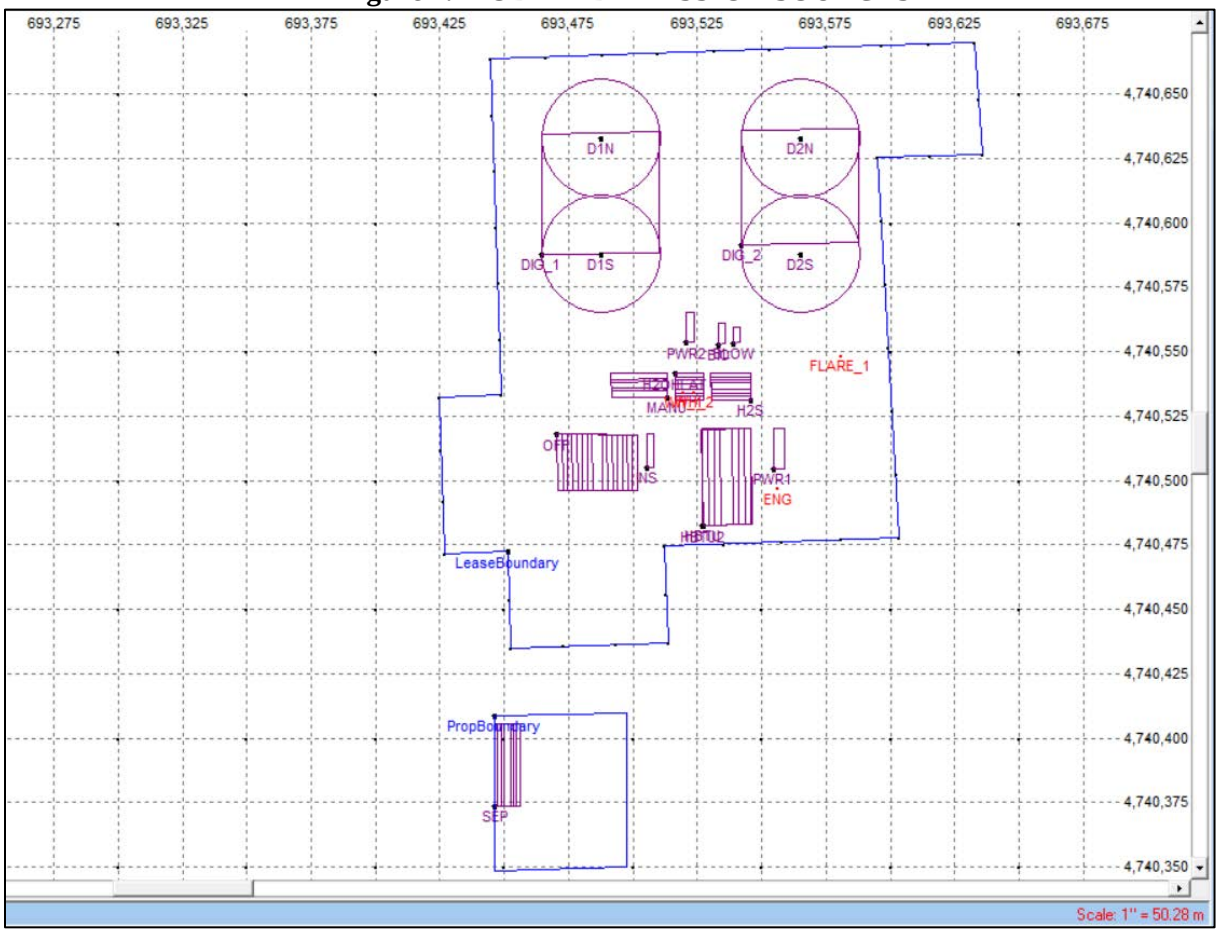
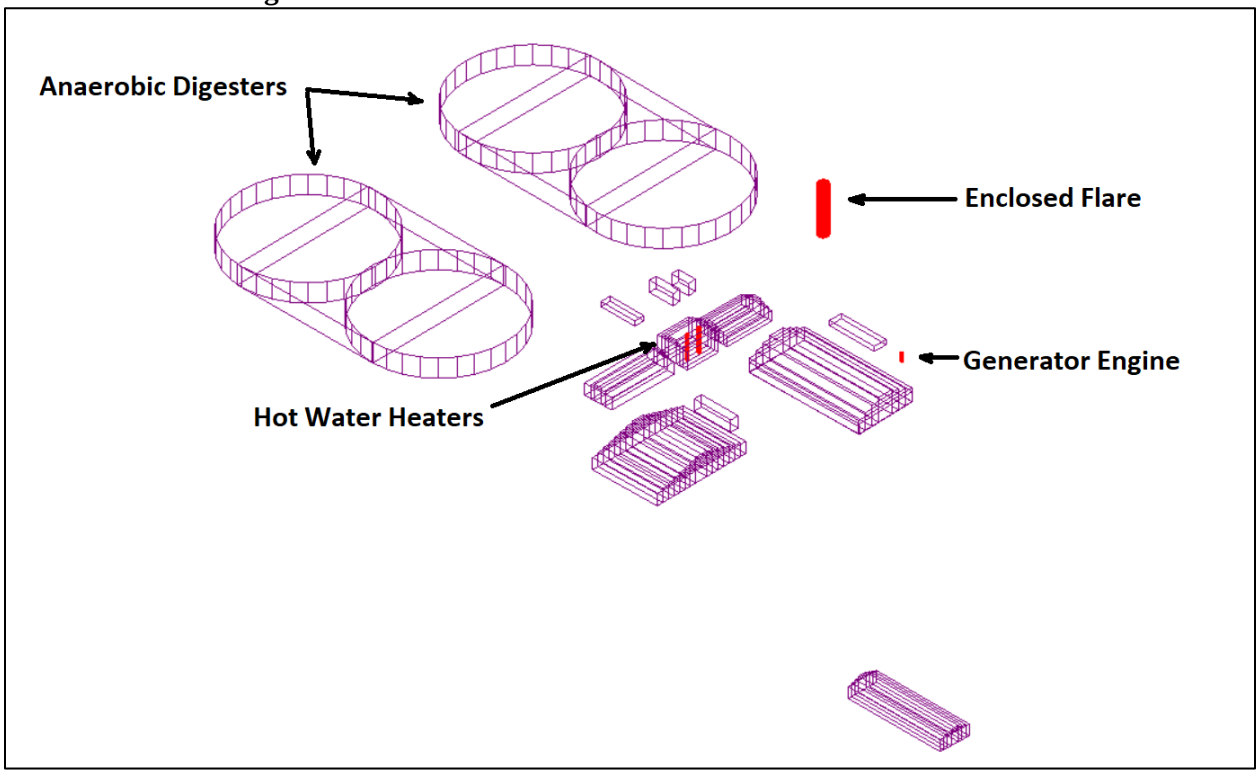


Figure 3. FACILITY LAYOUT VIEWED FROM THE EAST



3.3.7 NOx Chemistry

The atmospheric chemistry of NO, NO_2, and O_3 complicates accurate prediction of NO_2 impacts resulting from NO_x emissions. The conversion of NO to NO_2 can be conservatively addressed using several methods as outlined in a *2014 EPA NO_2 Modeling Clarification Memorandum*.[7] 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).

Bison 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 NO_x monitoring data. ARM2 has been adopted by the EPA as a default regulatory Tier 2 option. Bison applied an alternative minimum NO_2/NO_x ratio of 0.2 and the regulatory default maximum NO_2/NO_x ratio of 0.9. All emissions units combust biogas or natural gas. DEQ did not identify the 0.167 NO_2/NO_x in-stack ratio value for a flare combusting biogas or natural gas in the EPA database for combustion sources, available at: Nitrogen Dioxide/Nitrogen Oxide In-Stack Ratio (ISR) Database | US EPA.

DEQ ran a sensitivity analysis using the project's initial modeling submittal setup and the regulatory

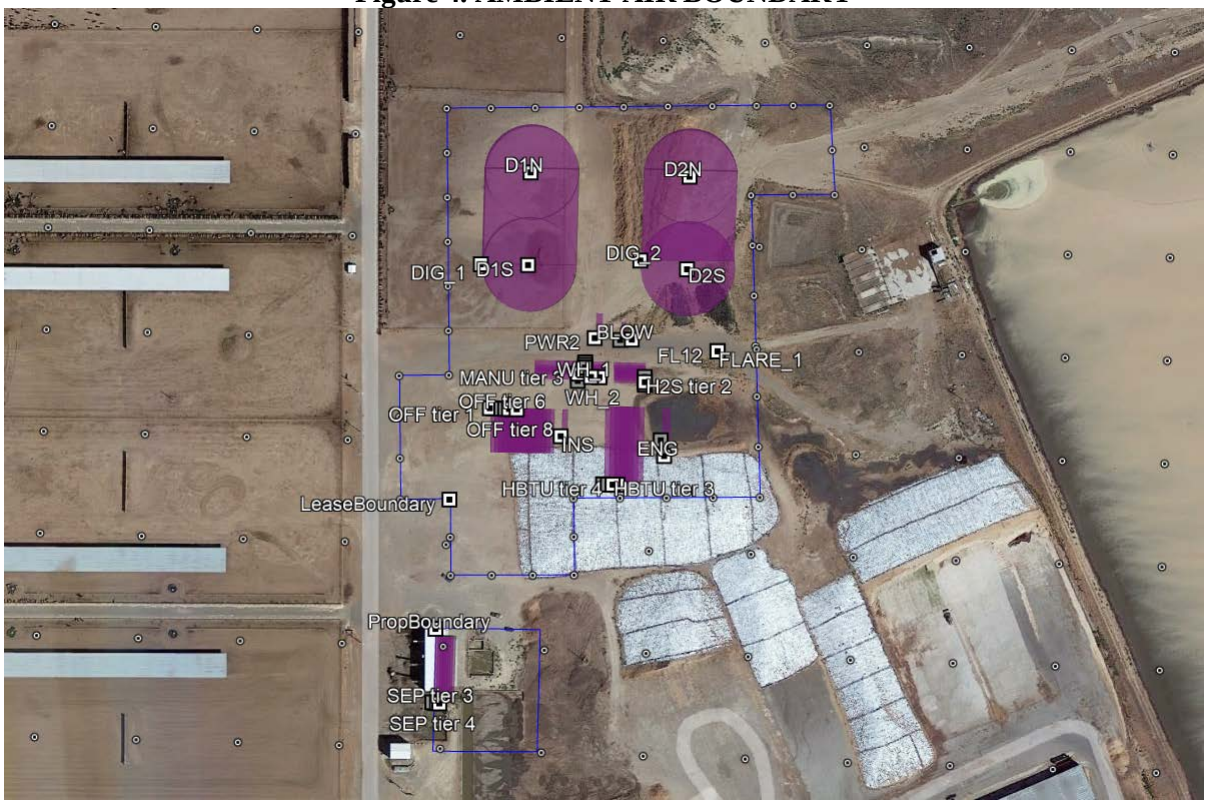
default ARM2_MIN value of 0.5. The sensitivity run determined that the 1-hour NO_2 NAAQS design values were not affected by use of an alternative minimum value, and the use of an alternative minimum value is not necessary given the 1-hour NO_2 cumulative NAAQS results have a large margin of compliance with the NAAQS. DEQ generally requests that applicants establish that an analysis based on the regulatory default values does not demonstrate compliance with the NAAQS prior to requesting the use of an alternative minimum NO_2/NO_x ISR.

3.3.8 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 was established along the digester and biogas separation sources project leased property parcel boundaries. The proposed EE/SOPUS facility is entirely contained within the Bettencourt Dairy facility property. The digester area will be fenced. The facility's ambient air boundary depicted by the blue line and initial line of receptors in Figure 4.

DEQ determined the methods used to preclude public access to the areas not treated as ambient air are acceptable, per Section 6.5 of the DEQ *Modeling Guideline*[3].

Figure 4. AMBIENT AIR BOUNDARY



3.3.9 Receptor Network

Table 13 describes the receptor network used in the submitted modeling analyses. SIL analyses used a

receptor grid extending 50 kilometers radially from the proposed facility and containing a total of 10,780 receptors.

Bison's SIL analyses determined that the radial distance of impacts exceeding any of the criteria air pollutant SILs (referred to as the radius of influence—or ROI) ranged from 0.24 kilometers for annual average $PM_{2.5}$ to 46.1 kilometers for 1-hour SO_2. The maximum ROI of the pollutants and averaging periods other than 1-hour SO_2 was 1.12 kilometers for 1-hour NO_2. The 1.12-kilometer ROI for 1-hour NO_2 SIL impacts was used to establish the extent of receptor grid coverage for all criteria pollutants and averaging periods except 1-hour SO_2 which used the 46.1-kilometer ROI. The 1-hour SO_2 ROI results are shown in Figure 5.

A receptor grid extending a minimum of 1.3 kilometers in all directions and containing 1,709 receptors, was used for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10} cumulative NAAQS analyses shown in Figure 6. Bison used the full coverage receptor grid extending 50 kilometers from the facility for the 1-hour SO_2 NAAQS shown in Figure 7. Bison used a high-density receptor grid, shown in Figure 8, with 10-meter spacing covering a 100-meter by 100-meter area in the region of the highest 1-hour SO_2 impacts to resolve the maximum design value impact for the worst-case 50% load scenario.

The TAPs receptor grid extended a minimum distance of 10 kilometers in all directions from the facility and utilized 3,304 receptors.

The receptor grid provided excellent resolution of the maximum design concentrations for the project and provided extensive coverage to verify that maximum impacts were identified in the analyses. Additional refinement of the receptor grid density was not necessary. The receptor grids used met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*[3] and were effective in reasonably assuring compliance with applicable air quality standards at all ambient air locations.

Figure 5. RADIUS OF IMPACTS EXCEEDING THE 1-HOUR SO_2 SIL

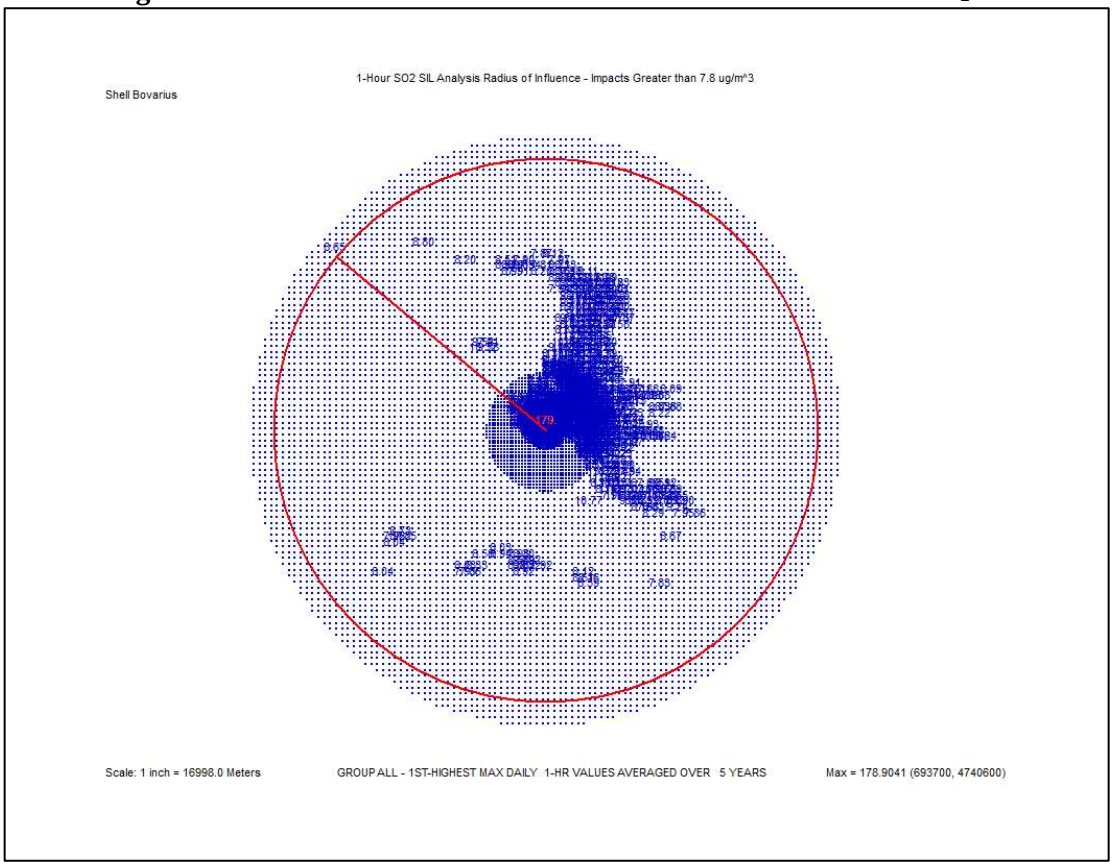


Figure 6. $PM_{10}/PM_{2.5}/ NO_2$ NAAQS ANALYSES RECEPTOR GRID

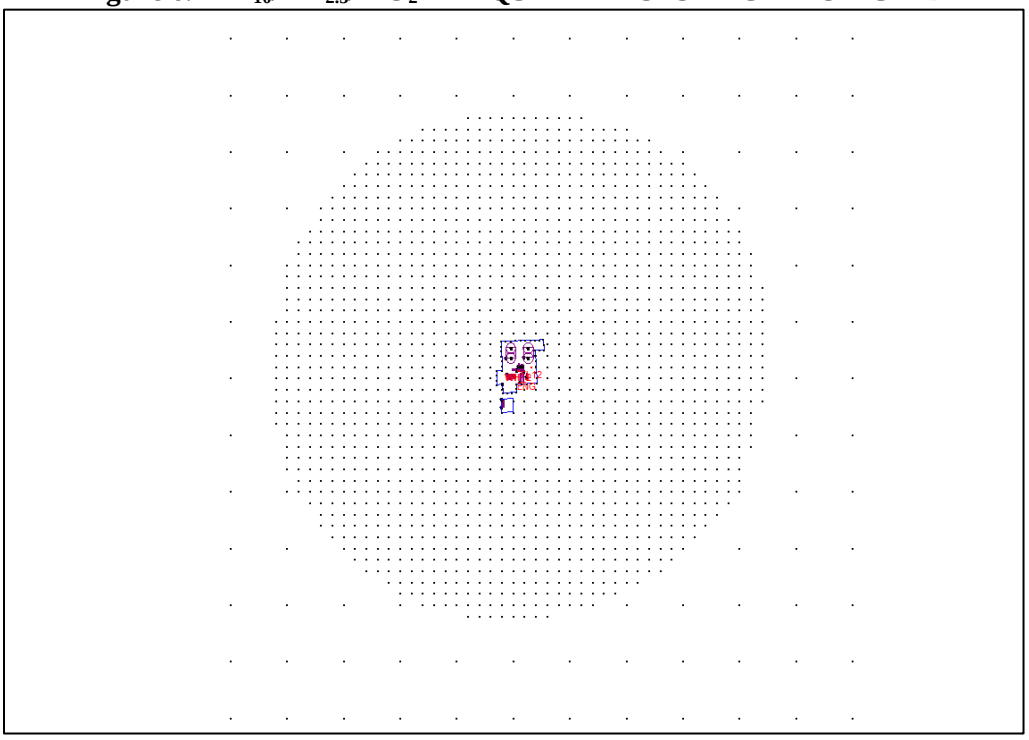


Figure 7. SIL AND 1-HOUR SO_2 NAAQS ANALYSES RECEPTOR GRID

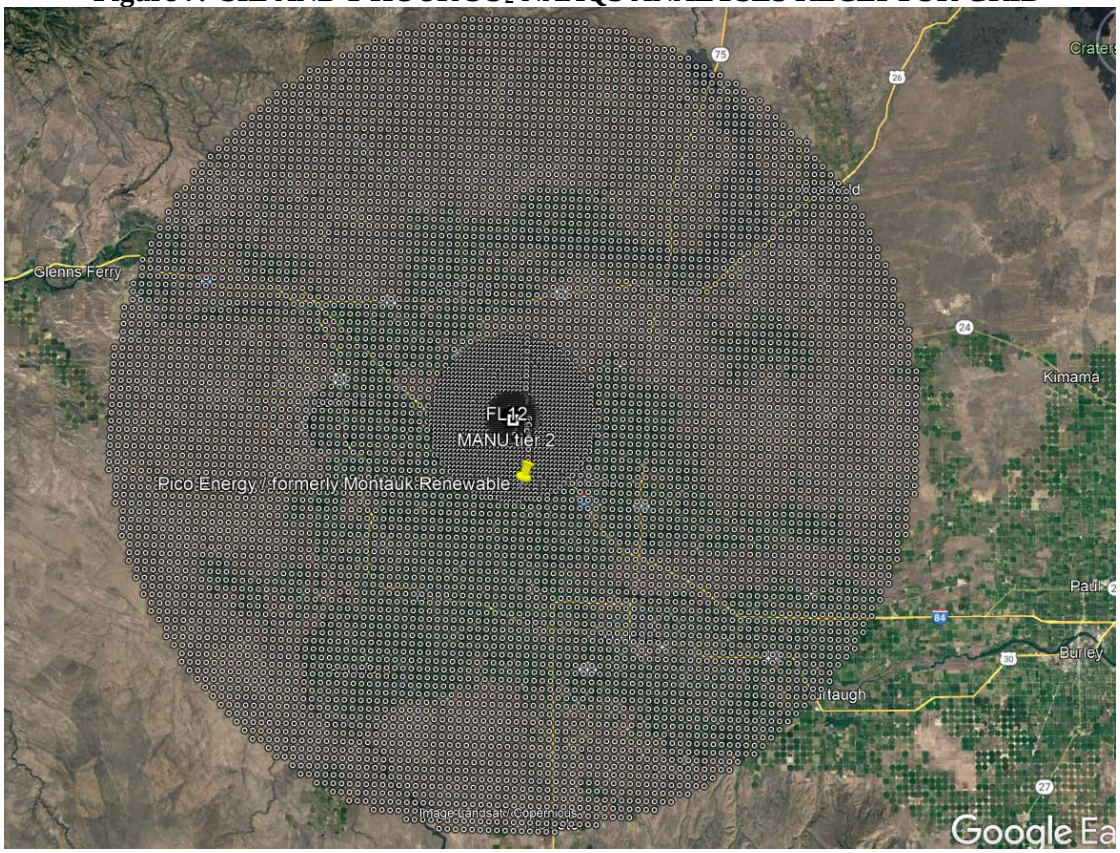
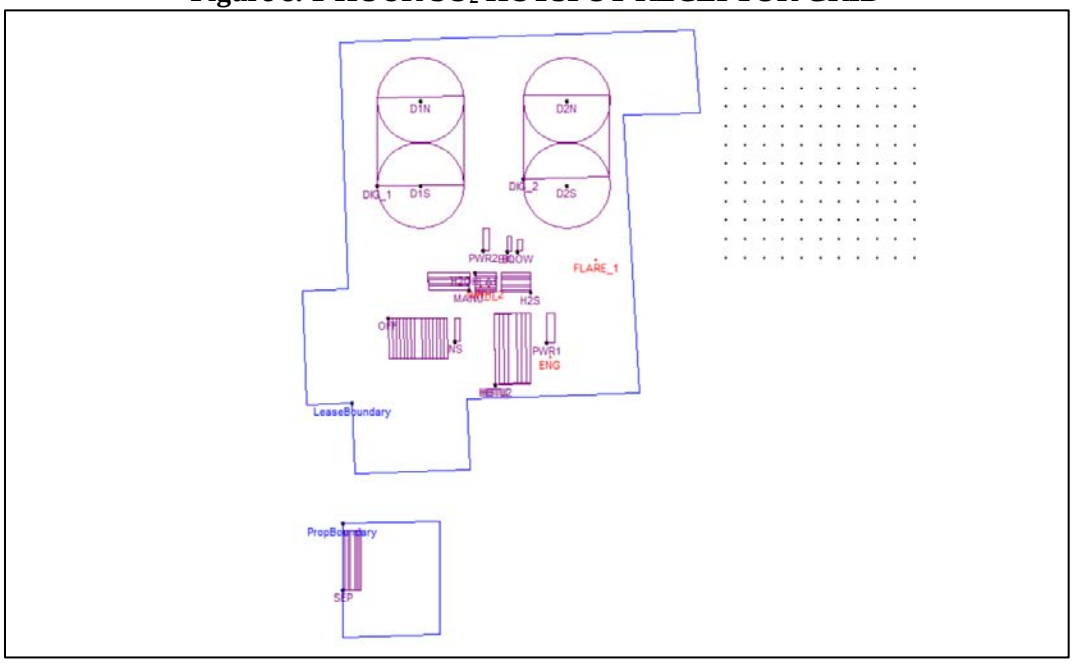


Figure 8. 1-HOUR SO_2 HOTSPOT RECEPTOR GRID



3.3.10 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.

The boiler stacks and IC engine stack at the facility are below GEP stack height. Consideration of downwash caused by nearby buildings was required and Bison included all structures in the model setup, including the two anaerobic digesters located north of the point sources and the separator building located south of the emission sources. DEQ determined that Bison included all structures affecting building-induced downwash.

4.0 SIL, NAAQS, and TAPs Impact Modeling Results

4.1 Results for SIL and NAAQS Analyses

4.1.1 Significant Impact Level Analysis

SIL analyses were performed for the 1-hour NO_2, annual NO_2, 1-hour SO_2, 24-hour PM_{10}, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ standards for this project. Results are shown in Table 14. Cumulative impact analyses were required for all these pollutants and averaging periods. Bison used the SIL analyses to determine a radius of influence for the cumulative NAAQS impact analyses

SO_2 emissions were not modeled to demonstrate compliance with the 3-hour SO_2 SIL. The 1-hour SO_2 SIL and NAAQS are more restrictive than the 3-hour average standards and DEQ determined this is not a deficiency for this modeling demonstration because an exceedance of the 3-hour SO_2 NAAQS is unlikely if compliance with the 1-hour SO_2 NAAQS has been demonstrated.

Table 14. RESULTS FOR SIGNIFICANT IMPACT LEVEL ANALYSES.

Pollutant	Averaging Period	Modeled Design Value Concentration ($\mu g/m^3$)[a]	SIL ($\mu g/m^3$)	Percent of SIL
NO_2	1-hour	105.06[b]	7.5	1,401%
	Annual	10.45[c]	1	1,045%
SO_2	1-hour	178.90[b]	7.8	2,294%
$PM_{2.5}$	24-hour	7.89[d]	1.2	658%
	Annual	1.23[e]	0.2	615%
PM_{10}	24-hour	8.43[f]	5	169%

a. Micrograms per cubic meter.
b. Maximum of 5-year means of 1st high maximum daily 1-hour modeled concentrations at each receptor.
c. Maximum annual average impact of 5 individual years.
d. Maximum of 5-year means of 1st high 24-hour concentrations at each receptor.
e. Maximum of 5-year means of 1st high annual concentrations.
f. Maximum of 1st high concentrations of five years of meteorological data.

4.1.2 Cumulative NAAQS Impact Analysis

Table 15 provides results for the cumulative NAAQS impact analyses performed for the 1-hour NO_2, annual NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, annual $PM_{2.5}$, and 24-hour PM_{10} standards. The total impact for each pollutant and averaging period was calculated by adding the design value of the impact to the DEQ-approved ambient background value. The sum was then compared to the NAAQS. Ambient impacts were below the ambient standards for all modeled criteria pollutants.

Secondary $PM_{2.5}$ impacts due to SO_2 and NO_x precursor emissions were not added to the ambient backgrounds and design values in Table 15. The secondary impacts are small and do not affect the compliance status for the ambient impact analyses.

Table 15. RESULTS FOR CUMULATIVE NAAQS IMPACT ANALYSES.

Pollutant	Averaging Period	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
50% Flare Load Scenario						
NO_2	1-hour	97.27[b]	21.4	118.67	188	63%
	Annual	10.49[c]	3.6	14.09	100	14%
SO_2	1-hour	146.27[d]	12.3	158.57	196	81%
	1-hour – Hotspot Grid	**150.69[d]**		**162.99**		**83%**
$PM_{2.5}$	24-hour	5.99[e]	13.5	19.49	35	56%
	Annual	1.23[f]	5.2	6.43	12	54%
PM_{10}	24-hour	7.44[g]	78.2	85.64	150	57%
78% Flare Load Scenario – Normal Operating Level						
NO_2	1-hour	97.27[b]	21.4	118.67	188	63%
	Annual	10.46[c]	3.6	14.06	100	14%
SO_2	1-hour	132.94[d]	12.3	145.24	196	74%
$PM_{2.5}$	24-hour	5.98[e]	13.5	19.48	35	56%
	Annual	1.23[f]	5.2	6.43	12	54%
PM_{10}	24-hour	7.42[g]	78.2	85.62	150	57%
100% Flare Load Scenario – Only Stream A Flared (Worst-Case 1-hour SO_2 Impacts)						
NO_2	1-hour	97.27[b]	21.4	118.67	188	63%
	Annual	10.45[c]	3.6	14.05	100	14%
SO_2	1-hour	114.84[d]	12.3	127.14	196	65%
$PM_{2.5}$	24-hour	5.96[e]	13.5	19.46	35	56%
	Annual	1.23[f]	5.2	6.43	12	54%
PM_{10}	24-hour	7.41[g]	78.2	85.61	150	57%
100% Flare Load Scenario – Both Stream A and Stream B Flared						
NO_2	1-hour	97.28[b]	21.4	118.68	188	63%
	Annual	10.45[c]	3.6	14.05	100	14%
$PM_{2.5}$	24-hour	5.94[e]	13.5	19.44	35	56%
	Annual	1.23[f]	5.2	6.43	12	54%
PM_{10}	24-hour	7.39[g]	78.2	85.59	150	57%

a. Micrograms per cubic meter.
b. Maximum of 5-year means of 8th high maximum daily 1-hour modeled concentrations at each receptor.
c. Maximum annual average impact of 5 individual years.
d. Maximum of 5-year means of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled.
e. Maximum of 5-year means of the 8th highest modeled 24-hour average concentrations at the modeled receptor for each year of meteorological data modeled.
f. Maximum of 5-year mean of annual averages.
g. Maximum 6th highest 24-hour average concentration using 5 years of meteorological data.

4.2 Results for TAPs Impact Analyses

Facility-wide emissions of non-carcinogenic TAPs did not exceed the ELs of Section 585 of the Idaho Air Rules. Emissions of arsenic, cadmium, formaldehyde, and nickel exceeded the ELs specified in Section 586 of the Idaho Air Rules for carcinogenic TAPs.

The TAPs compliance demonstration was based on emissions from the enclosed flare and two hot water heaters. The impacts are conservative because emissions exceeding the PTE for each hot water heater were modeled. The emissions from the IC engine were exempted from modeling based on the unit being in a source category regulated by 40 CFR 63 Subpart ZZZZ, as allowed by Section 210.20 of the Idaho *Air Rules*. DEQ's permit writer agreed the emission unit qualified for this exemption. Table 16 provides a summary of TAP impacts for the project for those TAPs with emission increases exceeding the ELs. Impacts for all modeled TAPs were below the increments.

Table 16. TAP IMPACT ANALYSES RESULTS

TAP	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)[a]	AACC ($\mu g/m^3$)	Percent of AACC
Arsenic	Annual	6.0E-05[b]	2.3E-04	26%
Cadmium	Annual	3.2E-04[b]	5.6E-04	57%
Formaldehyde	Annual	2.2E-02[b]	7.7E-02	28%
Nickel	Annual	6.1E-04[b]	4.2E-03	15%

a. Micrograms per cubic meter.
b. Maximum annual impact of 5 individual years.

5.0 Conclusions

The information submitted with the PTC application and DEQ's sensitivity analyses demonstrated to DEQ's satisfaction that emissions from the Equilon Enterprises, LLC/dba Shell Oil Products U.S., facility, located near Wendell, will not cause or significantly contribute to a violation of any applicable ambient air quality standard or TAP increment.

References

1. IDAPA 58.01.01 et. al., Rules for the Control of Air Pollution in Idaho. Available at https://adminrules.idaho.gov/rules/current/58/580101.pdf.

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

3. *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.

4. Justification of Revised Modeling Thresholds. Idaho Department of Environmental Quality Memorandum. Kevin Schilling, Air Quality Dispersion Modeling Supervisor, Air Program. January 14, 2020 (sic 2021).

5. *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program.* United States Environmental Protection Agency, Office of Air Quality Planning and Standards. April 30, 2019. EPA-454-R-19-003. Available at https://www3.epa.gov/ttn/scram/guidance/guide/EPA-454_R-19-003.pdf.

6. *Revised Draft Guidance for Ozone and Fine Particulate Matter Permit Modeling*. Richard Wayland and Scott Mathias, United States Environmental Protection Agency, Office of Air Quality Planning and Standards. September 20, 2021. EPA-454-P-21-001. Available at: https://www.epa.gov/system/files/documents/2021-09/revised_draft_guidance_for_o3_pm25_permit_modeling.pdf.

7. *Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard.* R. Chris Owen and Roger Brode, Environmental Protection Agency, Office of Air Quality Planning and Standards. September 30, 2014.

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on December 2, 2021:

Facility Comment: Table 1.1 Regulated Sources includes specific make and model information about the equipment. The flare and water heaters are locked in as proposed. Shell requests that the manufacturer and model of the IC Engine be set to "TBD" status because of market uncertainty. Shell will purchase a certified engine that complies with NSPS Subpart JJJJ. If the purchased engine has different emissions or stack parameters than listed in the permit and review report, we will request to amend the PTC appropriately.

DEQ Response: DEQ cannot issue a permit for equipment to be determined. Therefore, the final permit will use the IC Engine make and model included in the application. If the facility ends up using a different engine than originally applied for, they will need to go through the PTC process again like stated in the comment.

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:	**Equilon Enterprises, LLC – dba Shell Oil Products US**
Address:	**150 N. Dariy Ashford Rd**
City:	**Houston**
State:	**TX**
Zip Code:	**77079**
Facility Contact:	**Jose Hernandez**
Title:	**Production HSSE Coordinator**
AIRS No.:	**047-00044**

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	22.6	0	22.6
SO_2	42.2	0	42.2
CO	27.8	0	27.8
PM10	1.9	0	1.9
VOC	1.6	0	1.6
Total:	0.0	0	**96.2**
Fee Due	**$ 5,000.00**		

Comments: