Lane Regional Air Protection Agency
Standard Air Contaminant Discharge Permit

REVIEW REPORT
Addendum No. 2
Non-NSR/PSD Simple Technical Permit Modification

Equilon Enterprises LLC dba Shell Oil Products US – **Permit No. 203147**
Shell New Energies, Junction City
92757 Highway 99
Junction City, Oregon 97448
Website: www.shell.us/about-us/projects-and-locations

Source Information:

Primary SIC	4922
Secondary SIC	4911
Primary NAICS	486210
Secondary NAICS	221117
Public Notice Category	I

Source Category (LRAPA title 37, Table 1)	B:25. Electrical power generation from combustion B.48: Natural gas and oil production and processing and associated fuel burning equipment

Compliance and Emissions Monitoring Requirements:

Unassigned emissions	N
Emission credits	N
Compliance schedule	N
Source test [date(s)]	EU-1: 8760 hrs operation or 3 years

COMS	N
CEMS	N
CPMS	N
Ambient monitoring	N

Reporting Requirements

Annual report (due date)	March 15
Emission fee report (due date)	N
Semi-Annual Report (due date)	N
Greenhouse Gas Report (due date)	March 31

Quarterly report (due dates)	N
Monthly report (due dates)	N
Excess emissions report	Immediately
Other reports	N

Air Programs

NSPS (list subparts)	A, JJJJ
NESHAP (list subparts)	A, ZZZZ
CAM	N
Regional Haze (RH)	N
Synthetic Minor (SM)	N
SM-80	N
Title V	N
Part 68 Risk Management	N
Major HAP source	N

Federal major source	N
NSR	N
PSD	N
Acid Rain	N
Clean Air Mercury Rule	N
TACT	Y
>20 Megawatts	N
Cleaner Air Oregon	N

Permittee Identification

1. The Equilon Enterprises LLC dba Shell Oil Products US – Shell New Energies, Junction City facility ('Shell' or 'the facility'), owns and operates a renewable natural gas and biogas electric power generation facility located at 92757 Highway 99, Junction City, Oregon

General Background

2. Shell's primary operation consists of generating biogas derived from an anaerobic digester, then cleaning the biogas to produce pipeline quality gas which is injected into the natural gas pipeline. The secondary operation consists of biogas to produce electricity for the electrical power grid. The facility consists of a 1,550 ekW bio-fired generator, two (2) 7.0 MMBtu/hr natural gas-fired boilers, Type 1 and Type 2 feedstock handling systems with baghouse and carbon filter, solid/liquid mixing pump unit hoppers with carbon filter, a CO_2 stripper vessel – biogas upgrade vent, and paved roads. The facility also has the following categorically insignificant activities an anaerobic digester, dewatering tank, diesel storage tank, four (4) condensate tanks, and two (2) 200 kW emergency generators.

Reason for Permit Action and Fee Basis

3. After a Full Compliance Evaluation done by LRAPA, Shell was required to apply for a modification to correct the generators information from 'stand-by' to emergency, to change the flare ignition fuel to propane and remove 'continuous' from the pilot light condition in the current permit.

4. This action was designated a Non-PSD/NSR Simple Technical Permit Modification based on the facility's application to correct information and conditions of the permit.

Emission Unit Descriptions

5. The emission units (EU) regulated by the permit are the following (all additions in **bold**):

Emission Unit	Emission Unit Description	Pollution Control Device
EU-1	Biogas-fired Generator, Combined Heat and Power manufactured by 2G/MWM in 2012, Rated at 1,550 ekW, (at 1800 rpm, 60Hz)	None
EU-2	Enclosed waste flare	None
EU-3	Two (2) boilers, manufactured 2018, natural gas-fired, 7.0 MMBtu/hr	None
EU-4	Type 1 Feedstock Handling System	Baghouse, BH1
EU-5	Type 2 Feedstock Handling System	Carbon Filter, Odor Control
EU-7	Solid/Liquid Mixing Pump Unit Hoppers	Carbon Filter, Odor Control
EU-8	CO_2 Stripper Vessel, biogas upgrade vent	None
Fugitive Emissions	Paved Road Dust	None

Emission Unit	Emission Unit Description	Pollution Control Device
Categorically Insignificant Activities	• Dewatering Tank Vent • Anaerobic digesters using green feedstock • Diesel Storage Tank • Four (4) Condensate Tanks • Two (2) **Emergency** Generators, natural gas-fired, 200 KW each	None

Production and Operating Limits

6. The proposed permit action does not result in any changes to the applicable limitations.

General Emission Limits and Standards

7. Conditions 11.a and 11.b. have been updated to reflect the current operation at the facility. For Condition 11.a 'continuous' and 'If any excess emission events occur due to pilot flame ignition malfunction, then the flare must be operated with a continuous pilot flame regardless of the demand to combust biogas' have been removed. Also, for Condition 11.a, "Utilizing biogas or natural gas' was replaced with 'propane'. In Condition 11.b, 'supplemental fuel, either natural gas or' has been removed.

8. No other general emissions limits or standards have been changed in this proposed permit action.

Plant Site Emission Limits (PSELs)

9. The proposed permit action does not result in any changes to the PSELs.

Significant Emission Rate (SER)

10. The proposed permit action does not result in any changes to the baseline, netting, or SER.

New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

11. The proposed permit action does not result in a new evaluation for NSR or PSD.

New Source Performance Standards (NSPS)

12. The proposed permit action does not result in any changes to conditions referencing 40 CFR part 60 subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, but 'Stand-by' generators has been replaced with 'Emergency' generators.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

13. The proposed permit action does not result in changes to the current NESHAPs requirements.

Toxic Release Inventory

14. The proposed permit action does not result in any changes to the Toxic Release Inventory.

Performance Testing

15. The proposed permit action does not result in any changes to current performance test requirements.

Monitoring and Recordkeeping Requirements

16. The proposed permit action does not result in any changes to the current monitoring and recordkeeping requirements.

Reporting Requirements

17. The proposed permit action does not result in any changes to the current reporting requirements.

Public Notice

18. In accordance with LRAPA 37-0066(4)(b)(A), the proposed modification has been evaluated to be a Category I permit action as a simple modification which does not require a public notice in accordance with LRAPA 31-0030(3)(a).

BE/cmw
1/8/2024

Lane Regional Air Protection Agency
Standard Air Contaminant Discharge Permit

REVIEW REPORT

ADDENDUM NO. 1
NON-PSD/NSR BASIC TECHNICAL PERMIT MODIFICATION

Equilon Enterprises LLC dba Shell Oil Products US–
Shell New Energies, Junction City
92757 Highway 99
Junction City, Oregon 97448
www.shell.us/about-us/projects-and-locations/

Permit No. 203147

Source Information:

Primary SIC	4922
Primary NAICS	486210
Secondary SIC	4911
Secondary NAICS	221117

Source Categories (LRAPA Title 37, Table 1)	B.25: Electrical power generation from combustion B.48: Natural gas and oil production and processing and associated fuel burning equipment
Public Notice Category	I

Compliance and Emissions Monitoring Requirements:

Unassigned emissions	n
Emission credits	n
Compliance schedule	n
Source test date	EU-1: 8760 hrs operation or 3 years

COMS	n
CEMS	n
Ambient monitoring	n

Reporting Requirements:

Annual report (due date)	March 15
SACC (due date)	n
Quarterly report (due dates)	n

Monthly report (due dates)	n
Excess emissions report	y
GHG (due date)	March 15

Air Programs:

NSPS (subparts)	A, JJJJ
NESHAP (subparts)	A, ZZZZ
CAM	n
Regional Haze (RH)	n
Synthetic Minor (SM)	n
Part 68 Risk Management	n
Title V	n

ACDP (SIP)	n
New Source Review (NSR)	n
Prevention of Significant Deterioration (PSD)	n
Acid Rain	n
Clean Air Mercury Rule (CAMR)	n
TACT	y

1. Permittee Identification

The Equilon Enterprises LLC dba Shell Oil Products US – Shell New Energies, Junction City facility ("the facility"), located at 92757 Highway 99 Junction City, Oregon, operates a biogas generating and upgrading plant that delivers pipeline quality gas to the natural gas pipeline.

2. General Background Information

Prior to this addendum, the primary revenue generating activity at the facility was the combustion of biogas, derived from an anaerobic digester, in the combined heat and power (CHP) generator in EU-1 to produce and deliver electricity to the grid. A facility expansion has been completed, which includes the addition of six (6) anaerobic digesters, two (2) boilers (used to produce hot water), an enclosed waste biogas flare, and a gas upgrading system used to convert biogas into pipeline quality gas. With the completion of the expansion, the biogas upgrading system for natural gas pipeline injection is now considered the primary revenue generating activity.

3. Reasons for Permit Action

The facility is proposing to remove emissions units from the permit that were not installed as part of the facility expansion, update installed equipment specifications, and expand on the NSPS Subpart JJJJ applicable requirement language for EU-1. This addendum also proposes to change the primary SIC from 4911 Electrical Power Generation to 4922 Natural Gas Power Generation, which has been updated on the cover page of the permit. LRAPA has determined that this request is a Non-PSD/NSR Basic Technical Permit Modification under Title 37, Table 2, Part 4.

4. Emission Unit Description

The proposed permit action updated the kilowatt (KW) rating for the two (2) stand-by generators from 250 KW to 200 KW and the heat capacity of the boilers in EU-3 from 10.0 MMBtu/hr to 7.0 MMBtu/hr in Condition 2 of permit. The proposed permit action also removed the following emissions units from the emission unit table in Condition 2 of the permit. There are no other changes to the emission units or emissions unit descriptions as a result of this permit modification.

Emission Unit	Emission Unit Description	Pollution Control Device
EU-6	Type 3 Feedstock Handling System	Ozone-UV, Odor Control
EU-9	Boiler #3, Propane, Stand-by	None
EU-10	Two (2) open waste biogas flares	None
Categorically Insignificant Activities	• Fire pump engine, diesel-fired, 210 HP	None

5. General Emissions Limitations

The proposed permit action does not result in any changes to the applicable limitations at this facility.

6. Plant Site Emission Limit (PSEL) Pollutant

The facility has not requested any change to the PSEL as part of this permit action. The emission contributions of the remaining emissions units are detailed in the Attachment to the Review Report.

7. New Source Performance Standards (NSPSs)

This permitting action includes previously omitted NSPS Subpart JJJJ language clarifying testing requirements when the CHP in EU-1 is non-operational. The additional language states that, if the CHP is not operational, then the facility does not need to start the engine up solely to conduct testing. The CHP has not been in operation since June 14, 2019.

The references to the NSPS Subpart Dc language for the boilers in EU-3 have been removed from Condition 12 of the permit because the modification application updated the heat input values for the boilers to 7.0 MMBtu/hr, which is below the applicability threshold of the subpart at greater than or equal to 10 MMBtu/hr. The language in Condition 12 requiring recordkeeping of the amount of natural gas combusted in the boilers has been maintained in the permit and the rule reference has been updated to the applicable section in LRAPA Title 35 Stationary Source Testing and Monitoring.

The NSPS Subpart IIII language, previously Condition 21 of the permit, has been removed for the categorically insignificant fire pump since the one installed is electric and not diesel fired.

8. National Emissions Standards for Hazardous Air Pollutants (NESHAPs)

This permitting action does not change current NESHAPs for the facility.

9. Monitoring and Recordkeeping Requirements

The proposed permit action removes the following monitoring and recordkeeping requirements from the permit:

Emission Unit (EU)	Monitoring Parameter (units)	Minimum Recording Frequency
Ozone–UV Odor Control (EU-6)	Updated and Reviewed O&M Plan	Annually
Boiler #3, Propane, Stand-by (EU-9)	Propane burned in the boilers (gallons)	Monthly
Waste Biogas Flares, Open (EU-10)	Biogas burned by the gas upgrade start-up biogas flares (MMBtu)	Monthly

10. Emission Factors

The proposed permit action removes the following emission factors for Boiler #3 in EU-9 from the permit:

Emission Unit	Pollutant	Emission Factor	Emission Factor Units	Reference
Boiler #3 (EU-9)	$PM/PM_{10}/PM_{2.5}$	0.7	lb/10^3 gallon	AP-42 Table 1.5-1
	SO_x	0.054	lb/10^3 gallon	AP-42 Table 1.5-1
	NO_x	13	lb/10^3 gallon	AP-42 Table 1.5-1
	VOC	1.0	lb/10^3 gallon	AP-42 Table 1.5-1
	CO	7.5	lb/10^3 gallon	AP-42 Table 1.5-1

11. Reporting Requirements

There are no changes to the facility reporting requirements as a result of this permit action.

12. Public Notice

In accordance with LRAPA 37-0066(4)(b)(A), as a Non-NSR Basic Technical Permit Modification, Title 31 Category I public notice is required. There is no prior public notice or opportunity for participation; however, LRAPA will maintain a list of all permit actions processed under Category I and make the list available for public review.

KE/cmw
7/12/2021

Post-Modification Plant Site Potential to Emit

Emission Unit	Description	PM	PM_{10}	$PM_{2.5}$	CO	NO_x	SO_x	VOC
		tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
EU-1	CHP [Existing]	0.44	0.44	0.44	30.77	30.66	13.30	0.94
EU-2	Flare [New - Enclosed]	1.02	1.02	1.02	45.16	2.43	14.56	0.51
	~~Flare [Existing]~~ (1)	~~0.033~~	~~0.033~~	~~0.033~~	~~1.46~~	~~0.078~~	~~0.47~~	~~0.0008~~
EU-3	Boiler #1 (2)	**0.23**	**0.23**	**0.23**	**2.51**	**1.49**	**0.02**	**0.16**
	Boiler #2 (2)	**0.23**	**0.23**	**0.23**	**2.51**	**1.49**	**0.02**	**0.16**
EU-4	Type 1 Feedstock Handling	1.33	0.63	0.095				
	Type 1 Feedstock Baghouse	0.612	0.612	0.367				
EU-5	Type 2 Feedstock Handling	0.091	0.043	0.006	0.0001			0.002
	Type 2 Feedstock Odor Control	0.18	0.086	0.013	0.0002			0.004
	Type 2 Feedstock Reception Pit	0.18	0.086	0.013	0.0003			0.004
~~EU-6~~	~~Type 3 Feedstock Handling~~ (1)				~~0.0017~~			~~0.33~~
	~~Type 3 Feedstock Odor Control~~ (1)				~~0.0159~~			~~2.94~~
EU-7	Solid/Liquid Mixing Hoppers				3.56E-6			0.0001
	Solid/Liquid Mixing Odor Control				3.20E-5			0.00064
EU-8	Gas Upgrade Vent				0.0069			1.27
~~EU-9~~	~~Boiler #3 (Propane, Stand-by)~~ (1)	~~0.0080~~	~~0.0080~~	~~0.0080~~	~~0.085~~	~~0.148~~	~~0.00061~~	~~0.006~~
~~EU-10~~	~~(2) Open Flares~~ (1)	~~0.008~~	~~0.008~~	~~0.008~~	~~0.34~~	~~0.018~~	~~0.11~~	~~0.0039~~
Fugitives	Paved Road - Vehicular	11.51	2.30	0.56				
Categorically Insignificant	Dewatering & Solids Bins				6.40E-5			0.0013
	Stand-by Generators (2)	**0.006**	**0.006**	**0.006**	**0.059**	**0.030**	**0.00008**	**0.021**
	Dewatering Tank Vent (2)				**0.0079**			**0.158**
	~~Firewater Pump~~ (1)	~~0.002~~	~~0.002~~	~~0.002~~	~~0.03~~	~~0.16~~	~~0.01~~	~~0.02~~
	Diesel Storage Vent (2)							**0.00023**
	Condensate Tank #1							0.017
	Condensate Tank #2							0.017
	Condensate Tank #3							0.078
	Condensate Tank #4							0.017
-	Piping, Valves & Equipment				0.023			0.32
	Total	15.82	5.68	2.99	80.93	36.08	27.90	3.68
	PSELs	24	14	9	99	39	39	39
	Current Permit PTE	16.08	5.94	3.23	85.23	37.79	28.50	7.05
	Change to PTE with Modification	-0.26	-0.26	-0.24	-4.30	-1.71	-0.60	-3.37
	SER	25	15	10	100	40	40	40

(1)NOTE: Emissions with a strike through are not included in the emissions totals.
(2)NOTE: Numbers in bold have been updated utilizing current equipment specifications.

Lane Regional Air Protection Agency
Standard Air Contaminant Discharge Permit

REVIEW REPORT

Shell New Energies, Junction City **Permit No. 203147**
92757 Hwy 99
Junction City, OR 97448

Source Information:

SIC	Primary: 4911 Secondary: 4922
NAICS	Primary: 221117 Secondary: 486210

Source Categories (LRAPA Title 37, Table 1)	B.25: Electrical power generation from combustion B.48: Natural gas and oil production and processing and associated fuel burning equipment
Public Notice Category	II

Compliance and Emissions Monitoring Requirements:

Unassigned emissions	n
Emission credits	n
Compliance schedule	n
Source test date	EU-1: 8760 hrs operation or 3 years

COMS	n
CEMS	n
Ambient monitoring	n

Reporting Requirements:

Annual report (due date)	March 15
SACC (due date)	n
Quarterly report (due dates)	n
Monthly report (due dates)	n

Excess emissions report	y
GHG (due date)	March 15
Other reports	n

Air Programs:

NSPS (list subparts)	A, JJJJ, IIII, Dc
NESHAP (list subparts)	ZZZZ
CAM	n
Regional Haze (RH)	n
Synthetic Minor (SM)	n
Part 68 Risk Management	n
Title V	n
ACDP (SIP)	n
New Source Review (NSR)	n
Prevention of Significant Deterioration (PSD)	n

Acid Rain	n
Clean Air Mercury Rule (CAMR)	n
TACT	y

1. General Background Information

Shell New Energies, Junction City currently operates an electricity generating plant that delivers power to the grid. The facility uses one (1) 2G/MWM biogas-fired internal combustion engine generator to produce electrical power. As the facility is presently operated, the biogas is derived from an anaerobic digester tank using “green feedstock” consisting of food processing residuals. A waste biogas flare controls excess biogas. Using continuous gas analysis data, the facility estimates that this biogas fuel is approximately 60% methane and 40% CO_2.

A construction application was submitted by the facility on September 28, 2018 for the expansion of the existing biogas plant. This expansion includes the addition of six (6) anaerobic digesters, two (2) boilers (used to produce hot water), two additional waste biogas flares, and a gas upgrading system used to convert biogas into pipeline quality gas. The feedstock for the expansion will change from predominantly Type 3 to a combination of Type 1 and Type 2 waste feedstocks. Although the final plant design includes the removal of the biogas-fired engine generator, a transition period where the generator will be needed to combust the biogas from the remaining feedstock at the plant will require that all emission units be included in the permit renewal. The emissions units regulated by the permit are the following:

Emission Unit	Emission Unit Description	Pollution Control Device
EU-1	Biogas-fired Generator, Combined Heat and Power manufactured by 2G/MWM in 2012, Rated at 1,550 ekW, (at 1800 rpm, 60Hz)	None
EU-2	Two (2) enclosed waste biogas flares	None
EU-3	Two (2) boilers, manufactured 2018, natural gas-fired, 10 MMBtu/hr	None
EU-4	Type 1 Feedstock Handling System	Baghouse, BH1
EU-5	Type 2 Feedstock Handling System	Carbon Filter, Odor Control
EU-6	Type 3 Feedstock Handling System	Ozone-UV, Odor Control
EU-7	Solid/Liquid Mixing Pump Unit Hoppers	Carbon Filter, Odor Control
EU-8	CO_2 Stripper Vessel, biogas upgrade vent	None
EU-9	Boiler #3, Propane, Stand-by	None
EU-10	Two (2) open waste biogas flares	None
Fugitive Emissions	Paved Road Dust	None

Emission Unit	Emission Unit Description	Pollution Control Device
Categorically Insignificant Activities	• Dewatering Tank Vent • Anaerobic digesters using green feedstock • Diesel Storage Tank • Four (4) Condensate Tanks • (2) Stand-by generators, natural gas-fired, 250 KW each • Fire pump engine, diesel-fired, 210 HP	None

2. <u>Reasons for Permit Action</u>

The facility operates processes listed in Title 37, Table 1, Part B (B.25 - Electrical Power Generation from combustion and B.48 - Natural gas and oil production and processing and associated fuel burning equipment) and is therefore required to obtain an air contaminant discharge permit (ACDP). The proposed permit is a renewal and modification of an existing Standard ACDP that was issued on September 6, 2011 and scheduled to expire on September 6, 2016. The existing ACDP remains in effect until the final action has been taken on the renewal application because the facility submitted a timely and complete application for renewal. The contents of the renewal application, construction modification application and additional correspondence with the facility were the basis for the calculations and content within this review report. The primary reasons for this permit action are to renew the expired permit and to include equipment associated with process modifications.

3. <u>Fee Basis</u>

In accordance with LRAPA 37-0025(5)(a), the facility is required, at a minimum, to obtain a Simple ACDP because it operates an activity listed in Table 1, Part B of LRAPA 37-8010 that does not qualify for a General ACDP and its emissions are not above the SER for any pollutants. The initial fee basis for the permit was determined as a Standard ACDP because the facility was subject to a New Source Performance Standard (NSPS), which was detailed as a requirement in LRAPA Title 37, Table 1, Part C before LRAPA regulation updates in January of 2018. Current LRAPA rules have removed this requirement from LRAPA Title 37, Table 1, Part C, making the source eligible for a Simple ACDP. From correspondence with the facility and per LRAPA 37-0025(6)(a)(C), the facility has elected to maintain their Standard ACDP.

4. <u>Compliance Summary</u>

There have been no enforcement actions against this facility.

5. Emissions

Pollutant	Baseline Emission Rate (BER)	Plant Site Emission Limit (PSEL)			Increase over Baseline	Significant Emission Rate (SER)
	(tons/yr)	Previous PSEL (tons/yr)	Proposed PSEL (tons/yr)	PSEL Increase (tons/yr)	(tons/yr)	(tons/yr)
PM	0	24	24	0	24	25
PM_{10}	0	14	14	0	14	15
$PM_{2.5}$	N/A	9	9	0	N/A	10
SO_2	0	39	39	0	39	40
NO_x	0	39	39	0	39	40
VOC	0	39	39	0	39	40
CO	0	99	99	0	99	100
Single HAP	N/A	N/A	9	9	N/A	10
Total HAP	N/A	N/A	24	24	N/A	25
GHG	N/A	N/A	74,000	74,000	N/A	75,000

i. The BER has been set at zero (0) tons per year for all pollutants, with the exception of $PM_{2.5}$, Single HAP, Total HAP and GHG as specified in LRAPA 42-0048, since this facility was not in operation during the 1978 baseline year. The facility does not have a baseline for GHG because it was not in operation during the calendar years 2000 through 2010.

ii. The PSELs are set in accordance with LRAPA 42-0040, 42-0041 and 42-0060. The facility has the potential to emit over the de minimis levels for all pollutants, so the proposed PSELs are included at the Generic PSEL as defined in LRAPA Title 12. The emissions calculation sheet is attached to this review report.

iii. The PSEL increase over the baseline is less than the SER, as defined in LRAPA Title 12 for all criteria pollutants, so no further air quality analysis is required.

6. Additional Emission Limitations

The facility is subject to the visible emissions standards in LRAPA 32-010(3), the non-combustion particulate grain loading standards in LRAPA 32-015(2)(c), and the combustion particulate grain loading standards in LRAPA 32-030(1)(b) and LRAPA 32-030(2). The facility is subject to the highest and best requirement of LRAPA 32-005. Operation of well-maintained fuel burning equipment and emission control devices should assure compliance with the grain loading and visible emissions limits.

To ensure the highest and best operation of the waste gas flares in EU-2 and EU-10, the permit utilizes requirements for flares that are subject to the general control device requirements of 40 CFR 60.18(b) under Subpart A of the New Source Performance Standards (NSPS). Although the flares are not subject to a NSPS, the NSPS requirements provide an achievable set of operational requirements to ensure maximum efficiency under LRAPA 32-007.

The facility is required to conduct inspections and maintenance of the baghouse in EU-4 and the carbon filter odor control vessels in EU-5, EU-6 and EU-7 to assure compliance with the highest and best requirement. The facility must also prepare and follow an LRAPA-approved Operation and Maintenance (O&M) Plan to formalize procedures related to pollution control devices to maintain odors at the lowest practicable levels.

7. Performance Testing

In accordance with NSPS Subpart JJJJ, performance testing must be conducted to demonstrate compliance with the NO_x, CO, and VOC emission standards for the biogas generator in EU-1. The facility was required to conduct an initial performance test within one (1) year of engine startup, which was completed on November 18, 2014. Subsequent performance testing is required every 8,760 hours of operation or three (3) years, whichever is earlier. If the gas-fired stand-by generators in the Categorically Insignificant Activity emission unit are non-certified or are not operated and maintained according to the manufacturer's written emission-related instructions, then an initial performance test is required per NSPS Subpart JJJJ.

8. Emission Factor Development

The NO_x, VOC, and CO emission factors for the biogas generator in EU-1 were updated in this permit renewal to incorporate all acceptable source test data from 2014 through 2018. The SO_2 emission factors for EU-1 and the waste gas flare in EU-2 were updated to reflect the hydrogen sulfide, or H_2S, data acquired by the facility’s gas analyzer over the past three years. Emission factors for vehicle traffic fugitive particulate emissions were added to the permit and developed using AP-42 Chapter 13.2.1 Fugitive Dust Sources for Paved Roads. The permit only includes the fugitive emission factors for the highest contributors to the particulate emissions, which are generated by feedstock delivery and facility vehicles.

9. Hazardous Air Pollutants (HAP)/Toxic Air Contaminants

The aggregated potential HAP emissions from the fuel-burning equipment in EU-1, EU-2, EU-3, EU-9 and EU-10 are 7.02 tons per year, with the highest single HAP contributor as formaldehyde at 6.05 tons per year. The HAP emissions from the remaining emission units aggregate to less than one (1) ton per year of total HAP. A major source of HAPs is a facility that has the potential to emit 10 tons/year or more of any single HAP or 25 tons/year or more of combined HAPs; therefore, this facility is considered an area source of HAPs. Detailed HAP calculations can be found in the attachment to this review report.

Being located at an area source of HAP, the biogas generator in EU-1 could be subject to 40 CFR 63 Subpart ZZZZ NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE). In accordance with 40 CFR 63.6590(a)(2)(iii), the biogas generator is considered a new stationary source because the facility commenced construction of the stationary RICE on or after June 12, 2006. Since EU-1 is already subject to the requirements of 40 CFR 60 NSPS Subpart JJJJ, the engine is considered compliant with the Subpart ZZZZ NESHAP per 40 CFR 63.6590(c)(1). The boilers in EU-3 and EU-9 are not applicable to the 40 CFR 63 Subpart JJJJJJ NESHAP for Industrial, Commercial, and Institutional Boilers at Area Sources due to the operation of a gas-fired boiler as defined by 40 CFR 63.11195(e).

Under the Cleaner Air Oregon program, only existing sources that have been notified by LRAPA and new sources are required to perform risk assessments. This facility has not been notified by LRAPA and is therefore, not yet required to perform a risk assessment or report annual emissions of toxic air contaminants.

LRAPA required reporting of approximately 600 toxic air contaminants in 2016 and regulates approximately 260 toxic air contaminants that have Risk Based Concentrations established in rule. All 187 hazardous air pollutants are on the list of approximately 600 toxic air contaminants. The hazardous air pollutants and toxic air contaminants listed below were reported by the source in 2016 and verified by LRAPA. After the facility is notified by LRAPA, they must update their inventory and perform a risk assessment to see if they must reduce risk from their toxic air contaminant emissions. Until then, facilities will be required to report toxic air contaminant emissions triennially.

2016 Cleaner Air Oregon Reporting		
Hazardous Air Pollutant	Emissions (lbs/yr)	Emission Source(1)
Acetaldehyde	550.3	EU-1, Biogas Production
Benzene	28.3	EU-1, EU-2, EU-9
Ethyl benzene	2.41	Biogas Production
Ethylene glycol	1.09	Biogas Production
Ethylene glycol monobutyl ether	0.418	Biogas Production
Formaldehyde	3388	EU-1, EU-2, EU-9
Hexane	111.1	EU-1, EU-2, EU-9
Methanol	166.2	EU-1, Biogas Production
Naphthalene	50.4	Biogas Production
Nickel	0.047	EU-2, EU-9
Toluene	0.099	EU-2, EU-9, Biogas Production
Xylenes (mixed)	5.51	Biogas Production
Total	**4304 lbs/yr**	**2.15 tons/yr**
Toxic Air Contaminant	Emissions (lbs/yr)	Emission Source
Ammonia	1558	Biogas Production, Facility Maintenance & Cleaning
Isopropyl alcohol	4271	
sec-Butyl alcohol (2-Butanol)	39.3	Facility Maintenance & Cleaning
Hydrogen sulfide	0.009	
Zinc	0.826	
Zinc oxide	0.041	
Total	**4311 lbs/yr**	**2.15 tons/yr**

(1)NOTE: The 2016 hazardous air pollutant contributions from the fuel burning equipment in EU-1, EU-2 and EU-9 reported in this table only include the five (5) highest HAP species emissions emitted by this equipment, utilizing the emission factors detailed on page 7 through 9 of the attachment to this review report.

10. Typically Achievable Control Technology (TACT)

LRAPA Title 32-008 requires an existing emission unit at a facility to meet TACT if the emissions unit has emissions of criteria pollutants greater than ten (10) tons per year of any gaseous pollutant or five (5) tons per year of particulate, the emissions unit is not subject to the emissions standards under LRAPA Title 32, Title 33, Title 44, or Title 46 for the pollutants emitted, and the facility is required to have a permit. The biogas generator in EU-1 emits more than 10 tons/year of

CO and NO_x, but it is subject to the NSPS Subpart JJJJ for CO and NO_x; therefore, it is not required to meet TACT.

LRAPA Title 32-008 requires a new emission unit at a facility to meet TACT if the emissions unit is not subject to the emissions standards under LRAPA Title 32, Title 33, Title 39, or Title 46 for the pollutants emitted, and the facility is required to have a permit. The boilers in EU-3 will emit more than one (1) ton per year of CO and NO_x, so the emission unit is required to meet TACT for those pollutants emitted; good combustion practices employed by this facility are considered TACT. The waste biogas flares in EU-2 have the potential to emit more than one (1) ton per year of CO, NO_x, and SO_2, so this emission unit is required to meet TACT for those pollutants emitted; as with EU-3, good combustion practices employed by this facility will be considered TACT.

11. New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

Because the proposed PSELs for all regulated pollutants are below the Significant Emission Rates (SERs) in LRAPA Title 12, the facility is not subject to LRAPA New Source Review (NSR) requirements. The facility is located in an attainment area for all regulated pollutants.

12. New Source Performance Standards (NSPS)

Subpart Dc – Boilers: EU-3 is subject to 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. The facility is required to maintain records of the amount of each fuel type combusted in the boilers in EU-3 each calendar month. The boiler in EU-9 is not subject to 40 CFR 60 Subpart Dc because the boiler is rated below 10 MMBtu/hr.

Subpart JJJJ – Biogas Generator: EU-1 is subject to 40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. The pollutants regulated by Subpart JJJJ are nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC). The Subpart JJJJ Table 1 emission standards for landfill/digester gas engines with maximum engine power greater than or equal to 500 Hp and manufactured after July 1, 2010 are the following: NO_x at 2.0 g/Hp-hr or 150 ppmvd, the CO at 5.0 g/Hp-hr or 610 ppmvd, and VOC at 1.0 g/Hp-hr or 80 ppmvd. All emissions standards are adjusted to 15% oxygen. The facility will demonstrate compliance with all emission standards by conducting performance testing.

Subpart JJJJ – Stand-by Generator: The spark ignition internal combustion engine in the Categorically Insignificant Activity emission unit is subject to the requirements of 40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. The facility must either purchase a certified engine, operating and maintaining it according to the manufacturer's emission-related written instructions and keep records of maintenance, or purchase a non-certified engine, demonstrating compliance to the emission standards through a maintenance plan and an initial performance test. The emission standards based on model year and maximum engine power are detailed in the permit.

Subpart IIII – Diesel-fired Fire Pump Engine: The diesel-fired fire pump engine in the Categorically Insignificant Activity emission unit is subject to the requirements of 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The facility has no time limit for the use of the diesel-fired fire pump engine, also defined as an emergency stationary ICE per the subpart, during an emergency situation. The limit on use for readiness testing and maintenance checks is 50 hours per year. This 50-hour maximum operational limitation for non-emergency situations is based on LRAPA policy and reflects the May 1, 2015 D.C. Circuit Court ruling restricting the use of backup generators as part of emergency demand response programs. The emission standards based on model year and maximum engine power are detailed in the permit.

13. Continuous Compliance

To ensure compliance with the annual PSELs, the permittee is required to perform monthly emissions calculations and keep a 12-month rolling record of the following information for a period of five (5) years from date of entry:

Emission Source	Recordkeeping	Minimum Recording Frequency
Biogas Generator (Combined Heat and Power) (EU-1)	Biogas burned in the engine generator (MMBtu)	Monthly
	Hours of Operation for the engine generator (hrs)	Monthly
	Maintenance performed in accordance with the Subpart JJJJ NSPS	Upon occurrence
	Results of biogas fuel analysis for heat content and/or composition	Upon occurrence
Waste Biogas Flares, Enclosed (EU-2)	Biogas burned by the excess biogas flares (MMBtu)	Monthly
Boilers (EU-3)	Natural gas burned in the boilers (cubic feet)	Monthly
Baghouse (EU-4)	Pressure drop readings (inches of water)	Monthly
	Inspections as required by Condition 13.b of the permit	Monthly
Stand-by Generator (Categorically Insignificant Activity)	Maintenance conducted	As performed
	Maintenance Plan	Maintain current (non-certified engines only)
	Propane usage (hours)	Upon occurrence

Emission Source	Recordkeeping	Minimum Recording Frequency
Carbon Filter Odor Control (EU-5 and EU-7) Ozone Filter Odor Control (EU-6)	Updated and Reviewed O&M Plan	Annually
Upgrade Vent (EU-8)	Hours of operation	Monthly
Boiler, Stand-by (EU-9)	Propane burned in the boiler (gallons)	Monthly
Waste Biogas Flares, Open (EU-10)	Biogas burned by the gas upgrade start-up biogas flares (MMBtu)	Monthly
Type 1 Feedstock, Type 2 Feedstock and Digestate Removal (Fugitive Emissions)	Number of loads received/outgoing	Annually
All Emission Units	Odor complaints received by the permittee	Upon occurrence
	EPA Method 9 or Method 22 visible emission observations	As performed

14. Reporting Requirements

The facility is required to submit an annual report by ***March 15th*** of each year that includes 12-month rolling emissions, updates to the O&M Plan, greenhouse gas emission per OAR 340 Division 215, and any entries in the upset log as required by Condition G15 of the permit.

15. Public Notice

The draft permit was on public notice from July 23, 2019 to August 27, 2019. No written comments were submitted during the 35-day comment period.

KHE/cmw
08/28/2019

Plant Site Potential to Emit Summary

Emission Unit	Description	PM	PM_{10}	$PM_{2.5}$	CO	NO_x	SO_x	VOC
		tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr	tons/yr
EU-1	CHP [Existing]	0.44	0.44	0.44	30.77	30.66	13.30	0.94
EU-2	Flare [Existing]	0.033	0.033	0.033	1.46	0.078	0.47	0.0008
	Flare [New - Enclosed]	1.02	1.02	1.02	45.16	2.43	14.56	0.51
EU-3	Boiler #1	0.32	0.32	0.32	3.59	2.13	0.026	0.23
	Boiler #2	0.32	0.32	0.32	3.59	2.13	0.026	0.23
EU-4	Type 1 Feedstock Handling	1.33	0.63	0.095				
	Type 1 Feedstock Baghouse	0.612	0.612	0.367				
EU-5	Type 2 Feedstock Handling	0.091	0.043	0.006	0.0001			0.002
	Type 2 Feedstock Odor Control	0.18	0.086	0.013	0.0002			0.004
	Type 2 Feedstock Reception Pit	0.18	0.086	0.013	0.0003			0.004
EU-6	Type 3 Feedstock Handling				0.0017			0.33
	Type 3 Feedstock Odor Control				0.0159			2.94
EU-7	Solid/Liquid Mixing Hoppers				3.56E-6			0.0001
	Solid/Liquid Mixing Odor Control				3.20E-5			0.00064
EU-8	Gas Upgrade Vent				0.0069			1.27
EU-9	Boiler #3 (Propane, Stand-by)	0.0080	0.0080	0.0080	0.085	0.148	0.00061	0.006
EU-10	(2) Open Flares	0.008	0.008	0.008	0.34	0.018	0.11	0.0039
Fugitives	Paved Road - Vehicular	11.51	2.30	0.56				
Categorically Insignificant	Dewatering & Solids Bins				6.40E-5			0.0013
	Stand-by Generators	0.028	0.028	0.028	0.296	0.148	0.00035	0.103
	Dewatering Tank Vent				0.0093			0.185
	Firewater Pump	0.002	0.002	0.002	0.03	0.16	0.01	0.02
	Condensate Tank #1[(1)]							0.017
	Condensate Tank #2							0.017
	Condensate Tank #3							0.078
	Condensate Tank #4							0.017
-	Piping, Valves & Equipment				0.023			0.32
	Total	16.08	5.94	3.23	85.23	37.79	28.50	7.05
	Generic PSELs	24	14	9	99	39	39	39
	Current Permit PTE	0.5	0.5	0.5	35.68	15.7	4.03	5.00
	Increase to PTE with Mod	15.58	5.44	2.73	49.55	22.09	24.47	2.05
	SER	25	15	10	100	40	40	40

[(1)]NOTE: Condensate Tank #1-#4 VOC emissions calculated using the method from EPA AP-42 Chapter 7 Liquid Storage Tanks.

EU-1 Biogas Generator (Combined Heat and Power) Emissions and Emission Factor Development

CHP Heat Input	111,100	MMBtu/yr

CHP Generator Emission Factors

Pollutant	Current Permit	Renewal
	lb/MMBtu	lb/MMBtu
PM	0.008	0.008
PM_{10}	0.008	0.008
$PM_{2.5}$	0.008	0.008
CO	0.929	0.554
NO_x	0.409	0.552
SO_x	0.233	0.2395
VOC	0.074	0.017

CHP Generator Emissions

Pollutant	Current Permit	Renewal
	tons/yr	tons/yr
PM	0.44	0.44
PM_{10}	0.44	0.44
$PM_{2.5}$	0.44	0.44
CO	51.61	30.77
NO_x	22.72	30.66
SO_x	12.94	13.30
VOC	4.11	0.94

Updated Emission Factors for CO, NO_x and VOC

Parameter	Source Test Results				
Year	2014	2016	2017	2018[(1)]	**Average**
Gas Flow (m^3/hr)	563.0[(2)]	631.8	570.8	*495.2*	**565.2**
Gas Flow (cf/hr)	19882	22312	20158	*17489*	**19960**
Heat Input (MMBtu/hr)	11.19	12.56	11.35	9.85	**11.24**
CO (lb/hr)	6.54	6.54	5.90	5.81	**6.20**
CO (lb/MMBtu)	0.584	0.521	0.520	0.590	**0.554**
NO_x (lb/hr)	7.48	5.42	5.66	6.00	**6.14**
NO_x (lb/MMBtu)	0.668	0.431	0.499	0.609	**0.552**
VOC (lb/hr)	0.50	0.14	0.07	0.05	**0.19**
VOC (lb/MMBtu)	0.045	0.011	0.006	0.005	**0.017**

(1)NOTE: The 2018 Source Test Report neglected to include the biogas flow rate data during the test, so an estimated flow rate was calculated using a conversion factor developed using the power output per cubic foot of gas from the average of the three previous source tests (0.067 KW/cf).
(2)NOTE: The 2014 Source Test Report listed the gas flow rate in cubic feet per hour, but communication with the facility confirmed that the biogas totalizer for the generator measures in the units of cubic meter per hour.

EU-2 & EU-10 Waste Biogas Flare Emissions

Higher Heating Values (HHV)

Combined Biogas[(1)]	563	btu/cf
Methane	1010	btu/cf
Other Biomass Gases[(2)]	655	btu/cf

[(1)]NOTE: HHV reported is the projected HHV of the combined raw biogas from Type 1, 2, & 3 feedstocks. Use of this value results in a higher EF for SO_x emissions and is therefore more conservative for that use.
[(2)]NOTE: This is the default HHV for biomass fuels (other than landfill gas) as reported in 40 CFR Part 98 subpart C. Use of this value results in a higher EF for criteria pollutants (other than SO_x) and is therefore more conservative for that use.

Flare Emission Factors

Pollutant	EF	Units
PM	17	lb/10^6 dscf Methane
PM_{10}	17	lb/10^6 dscf Methane
$PM_{2.5}$	17	lb/10^6 dscf Methane
CO	750	lb/10^6 dscf Methane
NO_x	40	lb/10^6 dscf Methane
SO_x	0.2395	lb/MMbtu
VOC	5.5	lb/10^6 dscf NG

Flare Biogas Throughput

	Operating Hours	Gas Flow Rate	Gas Flow Rate	Heat Input
	hours	m^3/hr	cf/hr	MMbtu/hr
Existing Flare	200	850	30,018	19.66
Enclosed Flare	876	6,000	211,889	138.8
Open Flares	40	1,000	35,315	23.13

Flare Emission Factors Based on Biogas Throughput

Pollutant	Existing Flare Factor	Enclosed Flare Factor	Open Flare Factor	Units
PM	0.33	2.34	0.39	lb/hr Biogas
PM_{10}	0.33	2.34	0.39	lb/hr Biogas
$PM_{2.5}$	0.33	2.34	0.39	lb/hr Biogas
CO	14.6	103.1	17.18	lb/hr Biogas
NO_x	0.78	5.5	0.92	lb/hr Biogas
SO_x	0.2395	0.2395	0.2395	lb/MMbtu Biogas
VOC	0.0084	0.0084	0.0084	lb/MMbtu Biogas

Flare Emissions

Pollutant	EU-2		EU-10	Total Flare Emissions
	Existing Flare	Enclosed Flare	Open Flares	
	tons/yr	tons/yr	tons/yr	tons/yr
PM	0.033	1.02	0.008	1.06
PM_{10}	0.033	1.02	0.008	1.06
$PM_{2.5}$	0.033	1.02	0.008	1.06
CO	1.46	45.2	0.34	46.85
NO_x	0.078	2.4	0.02	2.50
SO_x	0.40	14.6	0.11	15.14
VOC	0.017	0.51	0.004	0.52

EU-3 Natural Gas Boilers Emissions

Boiler Operating Information

Hours of operation	8760	hours
Input Capacity	10	MMbtu/hr
Natural Gas HHV	1026	btu/cf

Boiler Emission Factors

Pollutant	EF	Units	EF	Units
PM	7.6	lb/10^6 dscf	0.0074	lb/MMbtu
PM_{10}	7.6	lb/10^6 dscf	0.0074	lb/MMbtu
$PM_{2.5}$	7.6	lb/10^6 dscf	0.0074	lb/MMbtu
CO	84	lb/10^6 dscf	0.0819	lb/MMbtu
NO_x	50	lb/10^6 dscf	0.0487	lb/MMbtu
SO_x	0.6	lb/10^6 dscf	0.0006	lb/MMbtu
VOC	5.5	lb/10^6 dscf	0.0054	lb/MMbtu

Boiler Emissions

Pollutant	Boiler 1	Boiler 2	Total
	tons/yr	tons/yr	tons/yr
PM	0.33	0.33	0.65
PM_{10}	0.33	0.33	0.65
$PM_{2.5}$	0.33	0.33	0.65
CO	3.61	3.61	7.17
NO_x	2.15	2.15	4.27
SO_x	0.03	0.03	0.05
VOC	0.24	0.24	0.47

EU-9 Propane Boiler (Stand-by) Emissions

Boiler Operating Information

Hours of operation	1000	hours
Input Capacity	2.07	MMbtu/hr
Natural Gas HHV	91,000	btu/gal

Propane Boiler Emission Factors

Pollutant	EF	Units	EF	Units
PM	0.7	lb/10^3 gal	0.0077	lb/MMbtu
PM_{10}	0.7	lb/10^3 gal	0.0077	lb/MMbtu
$PM_{2.5}$	0.7	lb/10^3 gal	0.0077	lb/MMbtu
CO	7.5	lb/10^3 gal	0.082	lb/MMbtu
NO_x	13	lb/10^3 gal	0.14	lb/MMbtu
SO_x	0.6	lb/10^3 gal	0.00059	lb/MMbtu
VOC	1.0	lb/10^3 gal	0.011	lb/MMbtu

Propane Boiler Emissions

Pollutant	Boiler #3
	tons/yr
PM	0.008
PM_{10}	0.008
$PM_{2.5}$	0.008
CO	0.083
NO_x	0.143
SO_x	0.00061
VOC	0.011

<u>Fugitive Emissions – Paved Road Dust</u>

Equation 2 with precipitation correction utilized from AP-42 13.2.1 Paved Roads:

$$E_{ext} = [\ k\ (sL)^{0.91} \times (W)^{1.02}\ ]\ (1 - P/4N)$$

Particle Size Multipliers[(1)]

PM_{30}	k=	0.011	lb/VMT (Vehicle Miles Traveled)
PM_{10}	k=	0.0022	lb/VMT
$PM_{2.5}$	k=	0.00054	lb/VMT

[(1)]NOTE: Values obtained from AP-42 Table 13.2.1-1.

Emission Factor Equation Variable Definition

Variable	Definition	Value Used	Units	Reference
sL	Silt loading	7.4	g/m^2	AP-42 Table 13.2.1-3
W	Vehicle weight	25	tons (Type 1 and Type 2 feedstock)	Facility estimate
P	Number of wet days	140	rain days (at least 0.01" rainfall)	NOAA
N	Days in averaging period	365	days per year	Facility election

Particle Size Emission Factors[(2)]

PM_{30}	EF=	1.6388	lb/VMT
PM_{10}	EF=	0.3278	lb/VMT
$PM_{2.5}$	EF=	0.0804	lb/VMT

[(2)]NOTE: Emission factors only developed for the Type 1 feedstock, Type 2 feedstock and associated loads, which are the highest contributors to fugitive particulate emissions.

Total Vehicle Miles Traveled

Load Type	Loads[(3)]	Trip Distance	Total Miles
	trips/year	VMT/trip	VMT/yr
Type 1 Feedstock Trucks	4732	0.45	2151
Type 2 feedstock Trucks	2184	0.45	993
Facility Trucks	21840	0.45	9927
		Total	**13071**

[(3)]NOTE: The number of loads is based on estimates provided by the facility.

Fugitive Particulate Emissions for Paved Roads

PM_{30}	10.7	tons/year
PM_{10}	2.1	tons/year
$PM_{2.5}$	0.5	tons/year

HAP Emissions Estimations for Fuel Burning Emission Units

Biogas-Fired Generator (EU-1)

HAP	Emission Factor[(1)]	Annual Emissions	Annual Emissions
	lb/MMBTU	lbs/yr	tons/yr
1,1,2,2-Tetrachloroethane	4.00E-05	4.44	2.22E-03
1,1,2-Trichloroethane	3.18E-05	3.53	1.77E-03
1,3 -Butadiene	2.67E-04	29.66	1.48E-02
1,3-Dichloropropene	2.64E-05	2.93	1.47E-03
2,2,4 -Trimethylpentane	2.50E-04	27.78	1.39E-02
2-Methylnapthalene	3.32E-05	3.69	1.84E-03
Acenaphthene	1.33E-06	0.15	7.39E-05
Acenaphthylene	5.53E-06	0.61	3.07E-04
Acetaldehyde	8.36E-03	928.80	4.64E-01
Acrolein	5.14E-06	0.57	2.86E-04
Benzene	4.40E-04	48.88	2.44E-02
Benzo(b)fluoranthene	1.66E-07	0.02	9.22E-06
Benzo(e)pyrene	4.15E-07	0.05	2.31E-05
Benzo(g,h,i)perylene	4.14E-07	0.05	2.30E-05
Biphenyl	2.12E-04	23.55	1.18E-02
Carbon Tetrachloride	3.67E-05	4.08	2.04E-03
Chlorobenzene	3.04E-05	3.38	1.69E-03
Chloroform	2.85E-05	3.17	1.58E-03
Chrysene	6.93E-07	0.08	3.85E-05
Ethyl benzene	3.97E-05	4.41	2.21E-03
Ethylene Dibromide	4.43E-05	4.92	2.46E-03
Fluoranthene	1.11E-06	0.12	6.17E-05
Fluorene	5.67E-06	0.63	3.15E-04
Formaldehyde	5.28E-02	5866	2.93E+00
Methanol	2.50E-03	277.75	1.39E-01
Methylene Chloride	2.00E-05	2.22	1.11E-03
n-hexane	1.11E-03	123.32	6.17E-02
Naphthalene	7.44E-05	8.27	4.13E-03
PAH	2.69E-05	2.99	1.49E-03
Phenanthrene	1.04E-05	1.16	5.78E-04
Phenol	2.40E-05	2.67	1.33E-03
Pyrene	1.36E-06	0.15	7.55E-05
Styrene	2.36E-05	2.62	1.31E-03
Tetrachloroethane	2.48E-06	0.28	1.38E-04
Toluene	4.08E-04	45.33	2.27E-02
Vinyl Chloride	1.49E-05	1.66	8.28E-04
Xylene	1.84E-04	20.44	1.02E-02
[(1)]NOTE: Reference AP-42 Table 3.2-2, calculated at 111,100 MMBtu/yr.		**Total**	**3.73**

Biogas Waste Flares (EU-2 and EU-10)

HAP	Emission Factor[(2)]	Annual Emissions	Annual Emissions
	lb/MMBtu	lb/yr	tons/yr
PAH	6.98E-09	8.83E-04	4.41E-07
Napthalene	7.68E-06	9.71E-01	4.86E-04
Acenaphthene	9.30E-08	1.18E-02	5.88E-06
Acenaphthylene	6.98E-09	8.83E-04	4.41E-07
Anthracene	9.30E-09	1.18E-03	5.88E-07
Benz(a)anthracene	9.30E-10	1.18E-04	5.88E-08
Benzo(a)pyrene	2.33E-09	2.95E-04	1.47E-07
Benzo(b)fluoranthene	2.33E-09	2.95E-04	1.47E-07
Benzo(g,h,i)perylene	2.56E-09	3.24E-04	1.62E-07
Benzo(k)fluoranthene	9.30E-10	1.18E-04	5.88E-08
Chrysene	2.33E-09	2.95E-04	1.47E-07
Dibenzo(a,h)anthracene	2.56E-09	3.24E-04	1.62E-07
Fluoranthene	1.40E-09	1.77E-04	8.85E-08
Fluorene	2.56E-08	3.24E-03	1.62E-06
Indeno(1,2,3-cd)pyrene	2.56E-09	3.24E-04	1.62E-07
Phenanathrene	1.67E-07	2.11E-02	1.06E-05
Pyrene	4.65E-09	5.88E-04	2.94E-07
Formaldehyde	4.92E-02	6.22E+03	3.11E+00
Acetaldehyde	2.56E-04	3.24E+01	1.62E-02
Acrolein	2.33E-05	2.95E+00	1.47E-03
1,3-butadiene	4.70E-05	5.88E+00	2.94E-03
Metals	$lb/10^6$ scf	lb/yr	tons/yr
Arsenic	2.0E-04	3.86E-02	1.93E-05
Beryllium	1.2E-05	2.32E-03	1.16E-06
Cadmium	1.1E-03	2.12E-01	1.06E-04
Chromium	1.4E-03	2.70E-01	1.35E-04

Biogas Waste Flares (EU-2 and EU-10)

HAP	Emission Factor(2)	Annual Emissions	Annual Emissions
	lb/MMBtu	lb/yr	tons/yr
Cobalt	8.4E-05	1.62E-02	8.11E-06
Manganese	3.8E-04	7.34E-02	3.67E-05
Mercury	2.6E-04	5.02E-02	2.51E-05
Nickel	2.1E-03	4.05E-01	2.03E-04
Selenium	2.4E-05	4.63E-03	2.32E-06
		Total	**3.13**

(2)NOTE: Organics – Reference *Emission Factors for Gas Fired CHP Units <25MW*. Metals – Reference AP-42 Table 1.4-3, calculated at max 193 MMscf/yr.

Two Natural Gas Boilers (EU-3)

HAP	Emission Factor(3)	Annual Emissions	Annual Emissions
	lb/10^6 scf	lb/yr	tons/yr
2-Methylnaphthalene	2.4E-05	4.12E-03	2.06E-06
3-Methylchloranthrene	1.8E-06	3.09E-04	1.55E-07
7,12-Dimethylbenz(a)anthracene	1.6E-05	2.75E-03	1.37E-06
Acenaphthene	1.8E-06	3.09E-04	1.55E-07
Acenaphthylene	1.8E-06	3.09E-04	1.55E-07
Anthracene	2.4E-06	4.12E-04	2.06E-07
Benz(a)anthracene	1.8E-06	3.09E-04	1.55E-07
Benzene	2.1E-03	3.61E-01	1.80E-04
Benzo(a)pyrene	1.2E-06	2.06E-04	1.03E-07
Benzo(b)fluoranthene	1.8E-06	3.09E-04	1.55E-07
Benzo(g,h,i)perylene	1.2E-06	2.06E-04	1.03E-07
Benzo(k)fluoranthene	1.8E-06	3.09E-04	1.55E-07
Chrysene	1.8E-06	3.09E-04	1.55E-07
Dibenzo(a,h)anthracene	1.2E-06	2.06E-04	1.03E-07
Dichlorobenzene	1.2E-03	2.06E-01	1.03E-04
Fluoranthene	3.0E-06	5.15E-04	2.58E-07
Fluorene	2.8E-06	4.81E-04	2.40E-07
Formaldehyde	7.5E-02	1.29E+01	6.44E-03
Hexane	1.8E+00	3.09E+02	1.55E-01
Ideno(1,2,3-cd)pyrene	1.8E-06	3.09E-04	1.55E-07
Naphthalene	6.1E-04	1.05E-01	5.24E-05
Phenanthrene	1.7E-05	2.92E-03	1.46E-06
Pyrene	5.0E-06	8.59E-04	4.29E-07
Toluene	3.4E-03	5.84E-01	2.92E-04
Arsenic	2.0E-04	3.44E-02	1.72E-05
Beryllium	1.2E-05	2.06E-03	1.03E-06
Cadmium	1.1E-03	1.89E-01	9.45E-05
Chromium	1.4E-03	2.40E-01	1.20E-04
Cobalt	8.4E-05	1.44E-02	7.21E-06
Manganese	3.8E-04	6.53E-02	3.26E-05
Mercury	2.6E-04	4.47E-02	2.23E-05
Nickel	2.1E-03	3.61E-01	1.80E-04
Selenium	2.4E-05	4.12E-03	2.06E-06
		Total	**0.162**

(3)NOTE: Reference AP-42 Table 1.4-3, calculated at 172 MMscf/yr.

Propane Boilers (EU-9)

HAP	Emission Factor(4)	Annual Emissions	Annual Emissions
	lb/10^3 gal	lb/yr	tons/yr
2-Methylnaphthalene	2.15E-06	4.87E-05	2.44E-08
3-Methylchloranthrene	1.61E-07	3.65E-06	1.83E-09
7,12-Dimethylbenz(a)anthracene	1.44E-06	3.25E-05	1.62E-08
Acenaphthene	1.61E-07	3.65E-06	1.83E-09
Acenaphthylene	1.61E-07	3.65E-06	1.83E-09
Anthracene	2.15E-07	4.87E-06	2.44E-09
Benz(a)anthracene	1.61E-07	3.65E-06	1.83E-09
Benzene	1.88E-04	4.26E-03	2.13E-06
Benzo(a)pyrene	1.08E-07	2.44E-06	1.22E-09
Benzo(b)fluoranthene	1.61E-07	3.65E-06	1.83E-09
Benzo(g,h,i)perylene	1.08E-07	2.44E-06	1.22E-09
Benzo(k)fluoranthene	1.61E-07	3.65E-06	1.83E-09
Chrysene	1.61E-07	3.65E-06	1.83E-09
Dibenzo(a,h)anthracene	1.08E-07	2.44E-06	1.22E-09
Dichlorobenzene	1.08E-04	2.44E-03	1.22E-06
Fluoranthene	2.69E-07	6.09E-06	3.04E-09
Fluorene	2.51E-07	5.68E-06	2.84E-09
Formaldehyde	6.73E-03	1.52E-01	7.61E-05
Hexane	1.61E-01	3.65E+00	1.83E-03
Ideno(1,2,3-cd)pyrene	1.61E-07	3.65E-06	1.83E-09

Propane Boilers (EU-9)

HAP	Emission Factor[4]	Annual Emissions	Annual Emissions
	$lb/10^3$ gal	lb/yr	tons/yr
Naphthalene	5.47E-05	1.24E-03	6.19E-07
Phenanthrene	1.53E-06	3.45E-05	1.73E-08
Pyrene	4.49E-07	1.01E-05	5.07E-09
Toluene	3.05E-04	6.90E-03	3.45E-06
Arsenic	4.49E-05	1.01E-03	5.07E-07
Beryllium	1.79E-05	4.06E-04	2.03E-07
Cadmium	1.08E-06	2.44E-05	1.22E-08
Chromium	9.87E-05	2.23E-03	1.12E-06
Cobalt	1.26E-04	2.84E-03	1.42E-06
Manganese	7.54E-06	1.70E-04	8.52E-08
Mercury	3.41E-05	7.71E-04	3.86E-07
Nickel	2.33E-05	5.28E-04	2.64E-07
Selenium	1.88E-04	4.26E-03	2.13E-06
		Total	0.00192

[4]NOTE: Reference AP-42 Table 1.4-3, using HHV of 91,000 btu/10^3 gal propane per 40 CFR Part 98 Table C-1. Calculated at 22,747.3 gal

Emissions Summary	**Emissions**	
Total HAP – Combined Fuel Burning Emission Units	7.02	tons/year
Highest Single HAP – Formaldehyde	6.05	tons/year

Projected Greenhouse Gas Emissions from Fuel Combustion Emission Units and non de minimis sources (in Metric Tons)

Emission Unit Information				Emissions (kg/MMBtu)[1]			Anthropogenic ($mtCO_2e$)[2][3]				Bio-Comb CO_2[4]	Biomass CO_2[3]
Emissions unit	Fuel Type	Quantity	Fuel units	CH_4	CO_2	N_2O	CH_4	CO_2	N_2O	Total Anthropogenic	($mtCO_2$)	($mtCO_2$)
EU-1	Other Biomass Gases	169,618,321	Cubic ft	0.0032	0	0.00063	8.9	N/A	20.9	29.7	5,785	4,831
EU-2[5]	Other Biomass Gases	191,617,697	Cubic ft	0.0032	0	0.00063	10.0	N/A	23.6	33.6	6,535	4,693
EU-3	Natural gas	170,760,234	Cubic ft	0.001	53.06	0.0001	4.4	9,296	5.2	9,305.7	N/A	N/A
	Natural gas	1,146,784	Cubic ft	0.001	53.06	0.0001	0.029	62.4	0.035	62.5	N/A	N/A
EU-11	Propane	22,747	Gallons	0.003	62.87	0.0006	0.155	130.1	0.370	130.7	N/A	N/A
EU-12	Other Biomass Gases	1,412,589	Cubic ft	0.0032	0	0.00063	0.090	N/A	0.211	0.3	48	35
EU-10	Other Biomass Gases	1,071,452,457	Cubic ft		mass balance		235.9	N/A	0.0	235.9	N/A	28,921
	Digestate (liquid)	63,817,669	Gallons		mass balance		420.5	N/A	2265.7	2,686.2	N/A	37
Total combustion emissions ($mtCO_2e$):										12,485	12,368	38,517
Total combustion emissions converted to US Short tons (TPY CO_2e):										13,762	13,634	42,457

[1] NOTE: The higher heating value used for "Other Biomass Gases" was the default value in the Oregon DEQ Combustion calculator of 655 Btu/cf. The higher heating value used for "Natural Gas" was also the calculator default value of 1026 Btu/cf.

[2]NOTE: The carbon dioxide equivalent (CO_2e) values were calculated using the global warming potentials for CH_4 at 25 and N_2O at 298.

[3]NOTE: Green House Gasses (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. The definition of greenhouse gases in this section does not include, for purposes of LRAPA title 37, OAR 340 division 218, and LRAPA title 38, carbon dioxide emissions from the combustion or decomposition of biomass except to the extent required by federal law." The definition of biomass includes biogas from the decomposition of non-fossilized and biodegradable organic matter. From 40 CFR Part 98, anthropogenic emissions have reporting requirements for natural gas combustion and is to include methane and nitrogen oxide emissions from all processes. For the purposes of this table, Biomass CO_2 represents the CO_2 generated by the decomposition or anaerobic digestion of organic matter.

[4]NOTE: Bio-Comb CO_2 is short for biogas combustion CO_2 and is the carbon dioxide generated from the combustion of biogas. This does not include methane or nitrogen oxide.

[5]NOTE: Emissions from natural gas pilot lights are not included in the projection.