Source Reference 18

Emissions Estimate Organics Management AD and BG Treatment for Fuel and Electricity Production, Edgar & Associates, Feb. 9, 2015

February 9, 2015

Emissions Estimate
Organics Management
Anaerobic Digestion and Biogas Treatment for Transportation Fuel or Electricity Production
12,500 TPY Unit

Proposed Operations

The Anaerobic Digestion (AD) Facility will receive an average of 48 tons per day (TPD), up to 12,500 tons per year (TPY), of organic material, consisting of food and green waste from residential and commercial sources. The proposed activities consist of processing organics consisting of about 67% food and 33% green waste, which would be anaerobically digested. The resulting biogas may either be used to produce compressed natural gas (CNG) for vehicle fuel or to generate electricity.

The anaerobic digestion (AD) process results in a by-product called digestate, which is the organic material remaining after anaerobic digestion is complete. This material requires further aerobic composting to produce an organic soil amendment. The digestate will be removed from the AD vessels and transported to an off-site permitted compost facility for further processing.

Proposed Project Emissions

The proposed project would generate emissions from the following sources:

- Short-term storage in the aeration bay.
- Anaerobic digestion and biogas purification.

<u>In the case of CNG production</u>:

- Flaring of waste gas of low Btu content from the biogas purification process and the startup and shutdown of anaerobic digestion bunkers.

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- Combustion of natural gas in a boiler for heating percolate for the anaerobic digestion process.

In the case of electricity production:
- Flaring of waste gas of low Btu content from the startup and shutdown of anaerobic digestion bunkers.
- Emissions from the genset for electricity generation.
- Note that thermal energy to heat the percolate would be provided by the combined heat and power system (CHP) unit.

Only anthropogenic greenhouse gas (GHG) emissions are estimated in this report; biogenic GHG emissions are not included.

Some emissions may be generated that would be included in a CEQA analysis but are not estimated in this report; for instance:

- Mobile emissions associated with transport of feedstock to the facility and hauling away finished product.
- Stationary equipment emissions such as grinders and screens.
- Mobile equipment such as front-end loaders.

Emission Factors for Organic Decomposition
Volatile Organic Compounds: VOCs are generated during the decomposition of organic waste. The South Coast Air Quality Management District (SCAQMD) has adopted emission factors for VOC's for aerobic composting.

The SCAQMD has proposed an emission factor of 4.25 lbs.-VOCs/wet ton during active composting, which includes curing (62 days total). The SCAQMD assumes that 90% of compost VOC emissions occur during the 22-day active composting phase and 10% during curing, which is discussed in the SCAQMD Staff Report for the compost emission rule (Rule 1133). Therefore, emission factors used for VOCs are:

- 3.83 lbs.-VOCs/wet ton for composting
- 0.425 lbs.-VOCs/wet ton for compost curing

Methane and Nitrous Oxide: Methane and nitrous oxide are generated during composting from anaerobic pockets in the waste. The California Air Resources Board (CARB) conducted an extensive literature review and published the results in a document entitled "Method for Estimating Greenhouse Gas Emission Reductions from Compost from Commercial Waste". The emission factors for methane and nitrous oxide generation from compost are 0.078 $MTCO_2e$/ton for methane and 0.025 $MTCO_2e$/ton for nitrous oxide.

Emissions Capture and Biofiltration

Receiving Building and Aeration Bay

Organic material used for anaerobic digestion would be off-loaded in the receiving building and placed in an aeration bay for mixing prior to being loaded into an enclosed anaerobic digestion bunker within 72 hours of receipt. The aeration bay will be enclosed, subject to negative aeration pressure and designed to capture all emissions generated during short-term storage of the organic feedstock. The ventilation system would then discharge the air to a biofilter for cleaning prior to being emitted to the atmosphere.

Biofiltration is a well known treatment technology that has consistently documented destruction efficiencies of over 90% for VOCs. A pilot-scale experiment done at California State University, Fresno, demonstrated a 99% destruction efficiency for VOCs. Tests conducted at the Inland Empire Regional Compost Facility resulted in a measured VOC destruction efficiency of 94%. Additionally, the South Coast Air Quality Management District (SCAQMD) published a list of operational biofilters and estimated destruction efficiencies that can be found at: http://www.aqmd.gov/rules/doc/r1133/app_c_biofilter.pdf.

Likusta, a manufacturer of odor control/biofilter systems, provides guaranteed control efficiencies of 90% for VOCs.

Additionally, very high destruction efficiencies for methane and nitrous oxide have also been demonstrated. A pilot-scale experiment done at California State University, Fresno, demonstrated a 99.7% destruction efficiency for methane and 97.1% for nitrous oxide.

For this analysis, the following biofilter destruction efficiencies are used:

VOCs:	90%
Methane:	90%
Nitrous Oxide:	90%

Short-term Storage

The organic material may be stored in an aeration bay for up to 72 hours where food and yard waste are blended together using a front end loader. Based on the background information from CARB (2011) and the SCAQMD (Rule 1133), the following assumptions are made:

- 90% of emissions occur during the phase of active composting, consisting of 22-days. Therefore, emissions generated during a 72-hour storage time in the aeration bay are estimated as:

  (3 days/22 days)(0.90 fraction of emissions generated) = 12% of total emissions

- The biofilter will destroy 90% of the emissions:

  (12% of total emissions)(1 – 0.9) = 0.012 of total emissions

VOC Emissions: (0.012)(4.25 lbs./ton)(12,500 tons)/2000 = 0.33 TPY

Methane: (0.012)(0.078 MTCO2/ton)(12,500 tons) = 12.0 MTCO2e

Nitrous Oxide: (0.012)(0.025 MTCO2/ton)(12,500 tons) = 3.8 MTCO2e

Anaerobic Digestion

Biogas Generation

Organic waste will be delivered to the AD system, consisting of approximately 33% green waste and 67% food waste. The following parameters are used in the analysis:

- Organic waste digested = 12,500 tons per year
- Biogas recovery for purification or electricity generation (net of flared lean gas) = 3,352 ft^3/ton
- Biogas methane content = 60%
- Methane energy content (low heating value) = 930 btu/ft^3
- Biogas energy content = 558 btu/ft^3

The total amount of biogas generation anticipated is 41,900,000 ft^3 per year, which has an energy content of 23,380 MMBtu.

The biogas flows from the anaerobic digester under positive pressure. If the end use is CNG for vehicle fuel, then the biogas is further pressurized for purification to pipeline quality natural gas and then the purified, fuel quality BioCNG fuel is pressurized for vehicle fueling. If the end use is electricity, the biogas is fed into an engine/generator system (genset). The anaerobic digestion process itself occurs in an enclosed, sealed vessel to prevent any air intrusion or leakage over a period of 21 to 28 days.

Digestate Management

Following anaerobic digestion, the digestate is removed from the anaerobic digestion vessel and transported to an off-site, permitted compost facility. Therefore, digestate management will generate no significant on-site emissions.

Biogas Processing for Vehicle Fuel

A BioCNG biogas conditioning system will be installed to process biogas, produced by the anaerobic digesters, into bio-methane to power CNG vehicles. When the biogas is directed to the BioCNG system it will first pass through a condensate sump for initial dewatering. From the sump the biogas goes into the H_2S treatment tank with granular Sulfatreat media. The H_2S treatment system will reduce the inlet H_2S concentration to less than 50 parts per million by volume (ppmv). The biogas is then compressed to approximately 100 pounds per square inch (psi) and then it passes through the inlet moisture removal process where the gas is chilled to 35°F.

The gas then is routed through activated carbon filled vessels where siloxanes and VOCs are removed to non-detect levels. The final gas treatment process includes routing the biogas through membranes where the CO_2 is separated from the product BioCNG fuel gas. The membranes produce a BioCNG product gas with a composition of approximately 95 percent methane (CH_4), 2.5 percent CO_2, and a trace of oxygen (O_2) and nitrogen (N_2). Waste gas leaving the membranes consists of approximately 11 percent CH_4, 89 percent CO_2, O_2 and N_2 and moisture. The BioCNG is a closed system which has no outlets of exhaust into the ambient air. The waste gas produced from the process is routed to an enclosed flare for abatement. The purification system recovers about 90% of the biomethane for fuel, while the remaining 10% is included in the "waste gas" flow from the purification system, consisting mostly of carbon dioxide.

Flare Emissions

Anaerobic Digestion – Lean Gas Flaring GHG Emissions

The biogas system is a sealed vessel designed to capture all emissions. No emissions are anticipated from the anaerobic digestion vessel, with the exception of "lean gas" that is drawn from the digesters and flared. During start up and shutdown of the digesters there is a period during which the gas generated is of low methane content and can't be routed to the purification system. This lean gas flow is instead sent to a flare where it is destroyed. Anthropogenic emissions from the flare consist of the methane pass through emissions from methane that isn't combusted by the flare, which are estimated at about 2% of total methane, i.e. 98% destruction efficiency, a conservative assumption.

Total lean gas methane flows are estimated at 1,059,152 ft^3 CH_4 per year, of which 10% is estimated to be methane and the remainder principally biogenic CO_2.

Methane pass-through emissions from the flare:

$(1{,}059{,}152\ ft^3\ CH_4)(10/100)(m^3/35.3\ ft^3)(0.000674\ MTCH4/m^3)(21\ MTCO_2e/MTCH4)(1\text{-}98/100)$ = 0.96 MTCO2e

Biogas Upgrading – Waste Gas Flaring GHG Emissions

The biogas treatment system that removes carbon dioxide from the biogas does not capture all of the methane in the biogas; about 10% of the methane in the biogas is present in the waste gas stream, which is flared to destroy the methane. The waste gas stream methane flow is about 4.8 ft^3/min. The non-combusted pass-through methane emitted from the flare is:

$(4.8\ ft^3/min)(525{,}600\ min/yr)(m^3/35.3\ ft^3)(0.000674\ MTCH4/m^3)(21\ MTCO_2e/MTCH4)(1\text{-}98/100)$ = 20.2 MTCO2e

Flare Emissions with Supplemental Natural Gas

The minimum Btu value for the flare to operate is 220 Btu/ft^3. Because the combination of lean gas and waste gas is less than the minimum Btu value, natural gas must be used to supplement the flare.

BIOGAS PURIFICATION - FLARING

The enclosed flare will generate other emissions, as well, which are estimated using emission factors from US EPA AP-42, Section 13.5 – Industrial Flares. The combination of lean and waste gas has an energy content of 129 Btu/ft^3 at a flow rate of 35.9 cfm. Another 4.9 cfm of pipeline natural gas must be blended with this flow to achieve the minimum energy content for the flare, assuming the low heat value of methane of 930 Btu/ft^3.

Greenhouse Gases

The Climate Registry publishes emission factors to estimate greenhouse gas emissions and provides a value of 53.02 kg CO_2/MMBtu for natural gas, and 0.001 kg CH4 and 0.0001 kg N2O per MMBtu. Applying the global warming potentials of 21 for CH_4 and 310 for N_2O results in an overall emission factor of 53..07 kg CO_2e/MMBtu.

(4.9 ft^3/min)(525,600 min/year)(930 Btu/ft^3)/(1,000,000)(53.07 kg/MMBtu)/(1,000) =

127 $MTCO_2e$

Flare Emissions - Criteria Pollutant Emissions

In the scenario where vehicle fuel is the product, the overall flow rate to the enclosed flare will be 40.8 cfm, of which 4.9 cfm are pipeline natural gas to achieve the minimum energy content of 220 Btu/ft^3. The blend of lean gas, waste gas and natural gas provides 4,832 MMBtu per year. Emissions of criteria pollutants are estimated using emission factors from US EPA AP-42, Section 13.5 – Industrial Flares. The methane present in the waste gas will have undergone VOC and H_2S removal prior to discharge to the flare. The lean gas will be raw biogas of low methane content (about 10%) and constitutes less than 5% of the flow to the flare at a flow rate of 2 ft^3/min.

Based on project experience, lean gas is expected to have a peak concentration of 100 ppmv of H_2S that would be converted to SO_2 during combustion. The amount of SO_2 generated is calculated using the equation below (SCS Engineers, 2007):

Mass flow rate (lbs./hour) =

((CS/1,000,000)((1,000 L/m^3)(34 g/mol)(60 min/hour)(VS)/((35.3 ft^3/m^3)(24.45 L/mol)(453.59 g/lb.) =

= 0.00521*(CS)(VS)

Where CS = concentration in ppmv and VS = flow rate in scfm

Lean Gas SO_2 Emissions:

Using CS = 1,00 ppmv H_2S and a flow rate of 2 cfm, the H_2S emissions are 0.005 tons per year. Converting to SO_2 using the stoichiometric of SO_2/H_2S of 64/34 yields SO_2 emissions of 0.009 TPY.

Waste Gas SO_2 Emissions:
Using CS = 50 ppmv H_2S and a flow rate of 33.9 cfm, the H_2S emissions are 0.04 tons per year. Converting to SO_2 using the stoichiometric of SO_2/H_2S of 64/34 yields SO_2 emissions of 0.07 TPY.

Natural Gas SO_2 Emissions:
Natural gas SO_2 emissions are estimated using the emission factor provided in AP-42, Chapter 1.4, Natural Gas Combustion, of 0.6 lb./10^6 ft^3.

$(0.6)/(1{,}020\ Btu/ft^3)(4.9\ ft^3/min)(525{,}600\ min/year)(930\ Btu/ft^3)/(1{,}000{,}000)/(2{,}000) = 0.0007$ TPY

Flare emissions under the vehicle fuel production scenario are shown in Table 1.

Table 1. Flare Emissions Under the Vehicle Fuel Production Scenario

Constituent	Lbs./MMBtu	Tons per Year
NOx	0.068	0.16
CO	0.37	0.89
THC[1]	0.14	0.34
VOCs[1]	0.055	0.13
SO_2	0.00059 (natural gas)	0.08

1. Total hydrocarbons is used as a conservative proxy for NMOCs. Per AP-42, VOCs = 0.39*NMOCs.
2. TPY of SO_2 is based on ppm H_2S in waste and lean gas.

ELECTRICITY PRODUCTION
In the case of electricity production, there is no waste gas generated from a biogas purification process; the lean gas that is flared must be supplemented by natural gas. In this case, the lean gas flow rate is about 2 cfm at 93 Btu/ft^3. This must be supplemented by a flow of natural gas of 0.40 cfm, assuming an energy content of 930 Btu/ft^3 (low heat value for methane).

This results in the following GHG emissions:

$(0.40\ ft^3/min)(525{,}600\ min/year)(930\ Btu/ft^3)/(1{,}000{,}000)(53.02\ kg/MMBtu)/(1{,}000) = 10.4\ MTCO_2e$

Criteria Pollutant Emissions
In this scenario, the overall flow rate to the enclosed flare will be 2.4 cfm, of which 0.40 cfm are pipeline natural gas to achieve the minimum energy content of 220 Btu/ft^3. The blend of lean gas and natural gas provides 294 MMBtu per year. Emissions of criteria pollutants are estimated using emission factors from US EPA AP-42, Section 13.5 – Industrial Flares. Flare criteria pollutant emissions under the electricity production scenario are shown in Table 2.

Table 2. Flare Criteria Pollutant Emissions Under the Electricity Production Scenario

Constituent	Lbs./MMBtu	Tons per Year
NOx	0.068	0.01
CO	0.37	0.05
THC[1]	0.14	0.02
VOCs	0.055	0.01
SO_2		0.009

1. Total hydrocarbons is used as a conservative proxy for NMOCs. Per AP-42, VOCs = 0.39*NMOCs.
2. The SO2 emissions from 0.40 ft^3/min of natural gas are negligible given the number of significant figures.

<u>Methane Pass-Through Emissions</u>
The AD system will recover about 62,749,440 ft^3 of methane (methane produced less lean gas), that would go to the genset for power production. The destruction efficiency of the engine is assumed to be 98.34% (SCS Engineers, 2007).

(25,140,000 ft^3 CH_4/year)(1-98.34)(m^3/35.3 ft^3)(0.000674 $MTCO_2e/m^3$)(21) = 167 $MTCO_2e$

Percolate Heating – Natural Gas Combustion: Fuel Production Scenario
The methane present in the lean gas and waste gas is too low in energy content to combust in a standard boiler for heating liquid percolate. In the case of electricity production, the heat would be provided by the CHP system. However, in the case of fuel production, the heat is provided by an industrial boiler. Therefore, the lean gas and waste gas are combusted with a flare and pipeline natural gas is used in an industrial boiler to provide thermal energy to heat the percolate liquid. It is estimated that 4,000 MMBtu/year of natural gas are needed to meet the thermal requirements. The Climate Registry publishes emission factors to estimate greenhouse gas emissions and provides a value of 53.02 kg CO_2e/MMBtu for natural gas.

(4,000 MMBtu)(53.07 kg CO_2e/MMBtu)($MTCO_2e$/1,000 kg) = 212 $MTCO_2e$

<u>Criteria Pollutant Emissions</u>
Emissions of criteria pollutants are estimated using emission factors from US EPA AP-42, Section 1.4 – Natural Gas Combustion, Table 1,4 – 1 for Small Boilers. Criteria pollutant emissions from the industrial boiler are shown in Table 3.

Table 3. Criteria Pollutant Emissions from the Industrial Boiler – Vehicle Fuel Production

Constituent	lb/10^6 ft^3	Lbs./MMBtu	Tons Per Year
NOx	100	0.09804	0.20
CO	84	0.08235	0.16
PM	7.6	0.00745	0.01
SO_2	0.6	0.00059	0.00
VOC	5.5	0.00539	0.01
CH_4[1]	2.3	0.00225	0.005 = 0.10 $MTCO_2e$

1. Methane is included as a pass-through emission

Electricity Generation

To estimate emissions from the generation of electricity, a 2G Cenergy engine lean-burn technology engine without after treatment is used as a model for potential to emit. However, for VOCs, the emission factor from USEPA AP-42, Chapter 3.2 is used, as it is more conservative. The amount of biogas to be produced is sufficient to generate about 297 kW of electric power, and provide the thermal energy to heat the liquid percolate for the AD system. Emission factors for the 2G Cenergy engine, which assume biogas as the feedstock and generating capacity of up to 370 kW, and VOCs using the AP-42 emission factor, are provided in Table 4.

Table 4. Engine/Generator System Emission Factors – Electricity Production Scenario

Constituent	Emission Factor No After Treatment
CO	3.353 g/kW-hr
NOx	1.475 g/kW-hr
VOCs	0.118 lb./MMBtu
HCOH (formaldehyde)	0.094 g/kW-hr
SO_2	0.805 g/kW-hr

Overall annual emissions from the engine are shown in Table 5, conservatively assuming no down time for engine maintenance and repair (i.e. 8,760 hours of operation per year) and using the "no treatment" emission factors. Emissions calculations are as shown below.

NOx: (1.48 g/kW-hr)(8,760 hours/year)(297 kW-hr)(1 lb./453.6 g)/(2,000 lbs./ton) = 4.2 TPY

CO: (3.35 g/kW-hr)(8,760 hours)(297 kW-hr)(1 lb./453.6 g)/(2,000 lbs./ton) = 9.6 TPY

VOC: (0.12 lb./MMBtu)(23,380 MMBtu)/(2,000 lbs./ton) = 1.4 TPY

HCHO: (0.094 g/kW-hr)(8,760 hours/year)(297 kW-hr)(1 lb./453.6 g)/(2,000 lbs./ton) = 0.3 TPY

SO_2: (0.81 g/kW-hr)(8,760 hours)(297 kW-hr)(1 lb./453.6 g)/(2,000 lbs./ton) = 2.3 TPY

Table 5. Engine/Generator System Pollutant Emissions – Electricity Production Scenario

Constituent	No After Treatment Tons per Year
CO	9.6
NOx	4.2
VOCs	1.4
HCOH (formaldehyde)	0.3
SO_2	2.3

Overall Project Emissions

A summary of project emissions for the production of vehicle fuel is provided in Table 6.

Table 6. Project Emission Summary – Vehicle Fuel Scenario

VOCs (TPY)	Methane $MTCO_2e$	Nitrous Oxide $MTCO_2e$	NOx (TPY)	CO (TPY)	PM (TPY)	SO_2 (TPY)	HCOH (TPY)
0.47	372	3.8	0.36	1.05	0.01	0.08	0.3

A summary of project emissions for the production of electricity is provided in Table 7.

Table 7. Project Emission Summary – Electricity Production Scenario

VOCs (TPY)	Methane $MTCO_2e$	Nitrous Oxide $MTCO_2e$	NOx (TPY)	CO (TPY)	PM (TPY)	SO_2 (TPY)	HCOH (TPY)
1.74	189	3.8	4.2	9.7	0	2.3	0.3

Note: Assumes the "no treatment" genset emission factors.

Information Sources

Edgar & Associates, Inc., relied on information and data provided by the client, equipment vendors and other sources for the preparation of this report.

This report was reviewed by Evan W.R. Edgar, who has more twenty-seven years of experience in all aspects of solid waste management as a registered civil engineer since 1987. Mr. Edgar is the Principal of Total Compliance Management (TCM), an environmental engineering firm based in Sacramento and established in 1996, specializing in solid waste management, recycling, composting, renewable energy, and greenhouse gas reduction issues. Mr. Edgar has a B.S., in Civil Engineering, from California State University, Chico.

This report was prepared by Rick Moore, P.E., Principal Civil Engineer at Edgar and Associates. Mr. Moore has more than 20 years experience in solid waste management and public works engineering and received his M.S. in Civil Engineering from University of California, Davis.

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