MEMORANDUM

TO: Amy S. Mann, P.E. ASM

FROM: Jordan G. Matthews, P.E. JGM

SUBJECT: **BioEnergy Development Group, LLC**
BioEnergy Innovation Center
Draft Permits: APC-2022/0048- CONSTRUCTION & APC-2022/0049-CONSTRUCTION
1,451 HP (1,082 kW) Natural Gas-Fired Cummins Emergency Generator
Anaerobic Digesters with Associated Flare, RTO, & Biogas Upgrade Equipment

DATE: August 21, 2022

BACKGROUND

On January 13, 2022, the Department received an air permit application from Verdantas LLC on behalf of BioEnergy Devco requesting permission to construct an anaerobic digestion (AD) process at the BioEnergy Innovation Center (BIC) in Seaford. The process would be equipped with a flare, regenerative thermal oxidizer (RTO), and other filtration equipment, which would be used to upgrade and control the biogas generated from the AD's operation. The application also requested permission to construct one (1) 1,451 HP (1,082 kW) natural gas-fired Cummins Model C1000N6 Generator, which would be used in emergency situations. This memorandum will discuss the review of both applications, and the drafting of the permits for the respective equipment.

This was the second submission of the applications for the AD process and emergency generator. During the first attempt at obtaining an air permit, applications for the emergency generator and AD process were submitted separately. The initial application for the emergency generator was submitted on July 24, 2020 by Duffield Associates, LLC (the consulting company which would later merge with two other national consulting firms to form Verdantas LLC) on behalf of BioEnergy Devco. Following a review of its contents, the application was advertised on August 30, 2020.

During the 15-day public comment period provided through the application advertisement process, the Department received comments from a concerned citizen about issuing a permit for an emergency generator intended to power equipment which would also require an air permit before the permit applications for that equipment were submitted. In response to these concerns, the Department and representatives of BioEnergy Devco agreed to postpone issuance of the construction permit for the generator until the applications for the other equipment were received and processed.

On December 18, 2020, the Department received a permit application for the proposed construction of an anaerobic digestion process and associated RTO and flare control equipment at the same location. This application had also been prepared and submitted by Duffield Associates, LLC on behalf of the applicants – BioEnergy Devco and the Chesapeake Utilities Corporation. In this case, the permit would be shared by BioEnergy Devco, who would act as the owner of the land and owner/operator of the anaerobic digester, and the Chesapeake Utilities Corporation, who would act as the owner/operator of the biogas cleaning portion of the process as well as the flare and RTO air pollution control equipment.

Upon reviewing the permit application for the digester and its associated control equipment, it was discovered that zoning approval for the proposed project had not yet been obtained. While I initially began to process the permit application on the condition that no permit would be advertised or issued until zoning approval had been obtained, I was later advised to stop processing the application until zoning approval had been obtained and provided.

Zoning approval was later obtained and provided via email on April 23, 2021, but the documentation I received required additional review by the Department and I did not receive approval to return to work on the application until May 17, 2021.

While the process of obtaining zoning approval proved to be an obstacle towards drafting a permit for the proposed equipment, it was not the only problem encountered. The following bulleted list summarizes some of the other issues identified while reviewing the initial permit application:

- The emissions estimates provided in the permit application were not adequately explained.
    - There were outstanding questions on how the emissions were calculated, and how the control equipment would be used to handle emissions.
    - There was no explanation on how the volume or composition of material digested may impact the emissions generated.
    - A detailed and current process flow diagram should have been provided along with the explanation of the generation, flow, and control of emissions.
- Of the pollutants modeled for their potential downwind impact, the downwind concentration of silica (generated through the combustion of siloxanes in the gas stream) from the flare and RTO was above the Department's modeling criteria.
    - More information was requested to understand how these emissions would be generated and to determine whether they should be considered a likely pollutant emitted by the process.
    - And, if deemed a potential pollutant, what steps would be taken to ensure downwind concentrations of the pollutant do not pose a threat to the health and safety of the surrounding community.
- There was evidence to suggest that additional air pollution control equipment (removal of CO_2, H_2S, siloxanes) would be part of the planned biogas cleaning process but had not been included in the permit application.
- Potential emissions, and control of emissions, from the receipt and storage of raw material were not addressed. Brian Lyncha, P.E., Sr. Project Manager with Duffield Associates (now Verdantas), indicated that the existing scrubbing equipment located at the site could be used, but no final decision had been communicated.
- On May 21, 2021 I was informed that the flare proposed for construction in the original permit application would be replaced by a flare from a different vendor. An application for the proposed replacement was not submitted in a timely fashion.
- A phone conversation with Peter Ettinger, Chief Development Officer for BioEnergy Devco, on July 15, 2021 revealed, among other things, that Chesapeake Utilities Company would be removed from the permit application as the owner and operator of the biogas cleaning equipment and associated control equipment. Instructions on how to request this change were provided via email on July 20, 2021, but the Department did not receive a modification to the application prior to deciding to return the application.

As the list above suggests, many details surrounding this project and application were either unknown or in flux. Because of these issues, many of which had not been addressed over the course of several months, the Department made the decision to return both applications until the applicant's plans were finalized and administratively and technically complete applications could be prepared and submitted. A letter discussing these issues and informing representatives of BioEnergy Devco of the returned applications was sent on August 5, 2021.

Between the time the initial permit applications were returned and the date on which the new applications were received, I maintained regular communication with, and provided feedback to, Brian Lyncha on draft documents to help ensure that the next set of applications submitted would contain the information needed for the Department to determine whether the proposed equipment met the applicable regulatory requirements.

At the time of writing this memorandum, the BioEnergy Innovation Center is home to a composting operation, which is permitted to compost up to 30,000 tons per consecutive twelve (12) month period of the following feedstocks:

- Poultry Litter;
- Hatchery Waste; and
- Dissolved Air Flotation (DAF) Cake and Sludge.

Not listed in the bullets above, but also permitted for use in the composting process, is wood, which is used as a bulking agent in the compost process and not included in the 30,000 ton per year (TPY) limitation. Based on current emission estimation methods, the composting process is expected to have the potential to emit (PTE) and emission limitations specified in Table 1.

Pollutant	PTE	Emission Limitation
	TPY	TPY
VOCs	26.7	2.67
NH_3	43.95	9.67

Table 1: Potential and Limited Emissions from BIC Composting Operations

In addition to the composting plant, the facility is also home to an existing 166 horsepower, diesel-fired emergency generator. This generator was used to provide emergency power for the former Perdue AgriRecycle, LLC pellet plant's fire pumps, plant lighting, and drain water sump pumps. I reviewed the memorandum from when the emergency generator was permitted, but no tier or emissions information was provided for the generator's engine. Instead, emissions were calculated using AP-42 emission factors. Table 2 summarizes the emissions estimated from the generator based on a 500 hour per year limitation and using emission factors from AP-42 Chapter 3.3.

Pollutant	Emission Rate	
	#/hr	TPY
NO_X	5.146	1.287
SO_X	0.340	0.085
VOCs	0.410	0.103
PM	0.365	0.091
CO	1.109	0.277

Table 2: Potential Emissions from Existing Emergency Generator Based on 500 hr/yr Limitation

It should be noted that this emergency generator no longer requires a permit because of Item 32.0 of Appendix A to 7 **DE Admin. Code** 1102 which provides an exemption from the requirement to obtain a permit for "Any internal combustion engine associated with a stationary electrical generator that…has a standby power rating of 450 kilowatts or less that is used only during times of emergency…as these terms are defined in 7 **DE Admin. Code** 1144."

According to the "Engineering Report", which was attached to the application, the "existing composting facility will be expanded in two phases to include four anaerobic digesters (two in each phase) and total

capacity of up to an additional 250,000 tons per year of recycling capability." Item 27 of the AQM-1 forms for the AD process equipment and emergency generator indicate that the proposed construction of the project's first phase would begin on April 1, 2022. While the Division of Air Quality's permitting process would not be completed in time to approve construction by the proposed date, representatives of BioEnergy Devco are aware that construction is not permitted to commence until the necessary permits are obtained. The "Engineering Report" indicated that construction of the second phase will start concurrently with the commissioning of the phase 1 digesters.

As mentioned in the previous paragraph, the application requests permission to digest up to 250,000 tons per year in the AD. The feedstock material would be comprised of "poultry litter and DAF (liquid and solid cake; fats, oils & grease; and waste activated sludge). The following paragraphs from the "Engineering Report" describe the plan for the end products of the AD process:

> *The AD process will generate a solid digestate and biogas that can be further processed to produce marketable end-products as well as liquid digestate that will require pre-treatment on-site and final treatment off-site. The solid digestate will either be transported to the adjacent compost facility or marketed as a soil amendment/conditioner. The biogas will be upgraded and conditioned to pipeline grade renewable natural gas (RNG). The RNG will be pressurized and transported as Compressed Natural Gas (CNG) by an energy services provider for injection into the natural gas pipeline grid.*

It should be noted that this application does not include a request to allow the use of the solid digestate in the adjacent compost facility, nor does it request permission to increase the compost facility's throughput capacity. With that said, the proposed AD system would digest nearly the same feedstocks that are currently composted, so the potential future use of this material in the composting operations would not be expected to significantly alter the emissions profile of that process. Additionally, much of the potential air pollutants from the material would be expected to have been released during the AD process, suggesting that the material to potentially be composted would be relatively inert from an air pollution perspective.

Having said that, the permit for the composting plant will require modification before an increase in capacity or addition of digestate is allowable for use. Representatives of BioEnergy Devco are aware that permit modification would necessary prior to using the solid digestate material in the composting process.

While the upgrading and conditioning of the biogas generated in the AD process is briefly touched upon in the quoted text above, Section 3.3.4 of the "Engineering Report" provides more information on the conditioning and upgrading of biogas as well as how the flare, RTO, and other filtration media will be used:

> *BioEnergy DevCo will be responsible for treating the biogas to generate Renewable Natural Gas (RNG) and sell the RNG to an energy services provider who will pressurize and transport it as Compressed Natural Gas (CNG) for injection into the natural gas pipeline grid. A utility flare will be available to combust the gas in the event of equipment maintenance or excess RNG.*
>
> *The project basis of design and mass balance shows that the BIC will generate up to approximately 1,600 scfm of biogas with approximately 62% methane when fully built-out and at full production. The raw biogas from the digesters will be boosted in pressure by a blower and pass through a biogas conditioning system. The conditioned biogas will then be upgraded to RNG. The preliminary design data for the filtration component of the biogas conditioning system is presented in Table 8.*

Table 8 – Biogas Conditioning System Design Data

Equipment	Quantity (Number)	Manufacturer	Bed Cross-Sectional Area	Bed Depth	Pressure Drop Across Bed
H2S removal vessels	2	Biospark	63.6 sq. ft.	36.5 ft.	33-63 in. WC
Siloxane removal vessels	2	-	59 sq. ft.	12 ft.	40-60 in. WC
PSA vessels	3	Global Welding Services	1,520 sq. in.	78 in.	28 in. WC
Polishing filters	2	Global Welding Services	38.5 sq. ft.	19.4 ft.	16-30 in. WC

The conditioning and polishing skid will include a biogas booster to increase the raw biogas pressure followed by pre-conditioner to remove hydrogen sulfide (H2S) and moisture from the gas. A polishing step using carbon filter skids with a catalytic high capacity media removes siloxanes and VOCs.

Each system is designed with lead-lag vessels with each vessel capable of processing the full production of biogas. This allows for changeout of media while continuing to operate at full production. The media is periodically replaced and removed for landfill disposal. The design of the media vessels is such that this should only be necessary two times a year.

A feed gas compressor will be used to increase the biogas temperature and pressure followed by a series of disposable particulate filters to remove moisture and bacteria from the gas prior to treatment with the membrane separation system.

The membrane separation system will be the final step of the biogas upgrade system and will separate the carbon dioxide (CO2) and other gases from the biogas using a membrane filtration system resulting in a near pure (97 to 98.5%) methane (CH4) stream of renewable natural gas (RNG). The tailgas, or waste gas stream, will be routed to a thermal oxidizer. The membrane filters are disposable and will need to be changed once every 3 years. The filters will be disposed of at an appropriately permitted landfill.

While there are several proposed components that would impact the gas stream composition, the AD process is only proposed to have two (2) potential emission points – the flare and the RTO. As discussed previously, the flare would be used in the event of equipment maintenance or excessive gas production to combust biogas that does not go through the entire conditioning and upgrade system. Clarification on the instances in which the flare would be operated is provided later in this document. The RTO would operate consistently to control the waste gas stream from the biogas conditioning and upgrade system.

According to emission estimates provided in the application, the gas stream headed to the flare is expected to have the potential to emit pollutants at the rates specified in Table 3.

Pollutant	Uncontrolled Emissions		Controlled Emissions		Controlled Emissions w/ Operating Limitations
	#/hr	TPY	#/hr	TPY	TPY
CH_4	4,043	17,708	81	354	99
CO_2	3,260	14,280	9,489	41,562	11,638
N_2	65	286	-	-	-
O_2	65	1,565	-	-	-
PM	-	-	0.00038	0.0017	0.00047

Pollutant	Uncontrolled Emissions		Controlled Emissions		Controlled Emissions w/ Operating Limitations
	#/hr	TPY	#/hr	TPY	TPY
SO_X	-	-	0.00003	0.0001	0.00004
NO_X	-	-	3.7	16	4.5
CO	-	-	16.8	74	20.6
VOCs	2.8	12	0.00028	0.0012	0.00034
Siloxanes	1.1	5	0.000	0.00	0.00

Table 3: Estimated Uncontrolled, Controlled, & Controlled + Limited Emissions from AD Process & Flare

The "Uncontrolled Emissions" columns includes an estimate of the biogas that was initially generated by the AD and subsequently filtered through the activated carbon hydrogen sulfide (H_2S) removal media. For the purpose of estimating the process's PTE, the activated carbon VOC/siloxane removal vessels, which are downstream of the H_2S removal vessels in this gas flow configuration prior to combustion by the flare, are considered air pollution control equipment and are not credited for pollution reduction. While nitrogen (N_2) and oxygen (O_2) are components of this gas stream and included in the "Uncontrolled Emissions" columns of Table 2, they were not included in the "Controlled Emissions" columns because they are not considered pollutants for the purpose of permitting.

For other pollutants such as particulate matter (PM), sulfur oxides (SO_X), nitrogen oxides (NO_X), and carbon monoxide (CO), no "Uncontrolled Emissions" were estimated because they are not expected to be generated from the digestion activity, but were included in the "Controlled Emissions" columns because they are byproducts of combustion. For clarification, methane (CH_4) is not considered a VOC as the term is defined in 7 **DE Admin. Code** 1101, but is still an air pollutant. The "Controlled Emissions w/ Operating Limitations" column estimates emissions from the flare if the volume of gas combusted during a twelve (12) month period is restricted to 840.96 million standard cubic feet (MMSCF), as proposed in the application.

Table 4 summarizes the uncontrolled and controlled emission estimates for the RTO as they were submitted in the permit application.

Pollutant	Uncontrolled Emissions		Controlled Emissions	
	#/hr	TPY	#/hr	TPY
CH_4	38	166	0.76	3.3
CO_2	2,615	11,455	2,696	11,808
N_2	2	9	-	-
O_2	16	68	-	-
PM	-	-	0.0051	0.022
SO_X	-	-	0.0004	0.002
NO_X	-	-	0.252	1.10
CO	-	-	0.056	0.25
VOCs	1.2	5	0.0037	0.016
Siloxanes	0.5	2	0.000	0.00

Table 4: Estimated Uncontrolled & Controlled Emissions from AD Process & RTO

Almost all of the comments included in the paragraph describing the information in Table 3 also apply to the information included in Table 4. Like the gas stream headed to the flare, the "Uncontrolled Emissions" columns represent gas that was originally generated in the AD and filtered by the activated carbon H_2S

removal vessels. Again, the activated carbon VOC/siloxane removal vessels are considered air pollution control equipment and are not credited for pollution reduction when calculating PTE.

Based on the information shown in Tables 3 & 4 the proposed AD project would have the annual emissions summarized in Table 5.

Pollutant	Maximum Uncontrolled Emissions	Maximum Controlled Emissions	Controlled Emissions w/ Operating Limitations
	TPY	TPY	TPY
CH_4	17,708	354	99
CO_2	14,280	41,562	11,808
N_2	286	-	-
O_2	1,565	-	-
PM	0	0.022	0.022
SO_X	0	0.002	0.002
NO_X	0	16	4.5
CO	0	74	20.6
VOCs	12	0.016	0.016

Table 5: Maximum Uncontrolled, Controlled, & Controlled w/ Operating Limitations Emissions from AD, RTO, & Flare Processes

Not included in the estimate in Table 5 are the potential emissions resulting from operation of the proposed, natural gas-fired emergency generator. The engine associated with this generator has a rated mechanical power of 1,451 HP (1,082 kW). Table 6 summarizes the potential emissions estimated from the operation of this generator with 500 hours limiting the emissions on an annual basis.

Pollutant	PTE	
	#/hr	TPY
NO_X	2.624	0.656
SO_X	0.006	0.001
VOCs	0.239	0.060
PM	0.098	0.025
CO	6.441	1.610

Table 6: Potential Emissions from New Emergency Generator Based on 500 hr/yr Limitation

Table 7 summarizes the potential annual emissions from the proposed anaerobic digestion operation and emergency generator along with emissions from the existing composting facility and emergency generator for comparison against the major source threshold for each pollutant in Sussex County.

Pollutant	Facility Wide PTE (TPY)	Major Source Threshold (TPY)	Major Source?
Nitrogen Oxides (NO_X)	17.943	100	No
Volatile Organic Compounds (VOCs)	26.879	50	No
Carbon Monoxide (CO)	75.887	100	No
Particulate Matter (PM)	0.138	100	No
Sulfur Dioxide (SO_2)	0.088	100	No
Carbon Dioxide (CO_2)	41,562	-	No
Methane (CH_4)	17,708	-	No
Carbon Dioxide Equivalent (CO_2e)	484,262	100,000	No

Table 7: Facilitywide PTE (Emergency Generators, Composting & AD/Flare/RTO Operations)

It should be noted that while potential emissions of CO_2 and CH_4 are above the 100 ton per year major source threshold for "Other" pollutants (not including VOCs, NO_X, CO, SO_X, PM_{10}, & HAPs), these pollutants are considered to be greenhouse gases (GHGs). According to a June 2014 Supreme Court ruling, a source is only considered to be a major source for equivalent CO_2 (CO_2e) if it has the potential to emit above 100,000 TPY of CO_2e and has the potential to emit above the major source threshold for another regulated pollutant. Because this source is considered minor for all other pollutants, the facility is considered a minor source even though potential CO_2e emissions are above 100,000 TPY.

With regards to the contents of the application, confidentiality was not requested. As a result, only one set of documents were drafted for the review of this application, all of which are publicly available upon request.

Chapter 70 of Title 7 ("Conservation") of Delaware Code focuses on the "Coastal Zone Act". The following purpose of this act is specified in §7001:

> *It is hereby determined that the coastal areas of Delaware are the most critical areas for the future of the State in terms of the quality of life in the State. It is, therefore, the declared public policy of the State to control the location, extent and type of industrial development in Delaware's coastal areas. In so doing, the State can better protect the natural environment of its bay and coastal areas and safeguard their use primarily for recreation and tourism. Specifically, this chapter seeks to prohibit the construction of new heavy industry in its coastal areas beyond the heavy industry use sites defined in this chapter. The expansion of heavy industry beyond those sites is determined to be incompatible with the protection of that natural environment in those areas. While it is the declared public policy of the State to encourage the introduction of new industry into Delaware, the protection of the environment, natural beauty and recreation potential of the State is also of great concern. In order to strike the correct balance between these 2 policies, careful planning based on a thorough understanding of Delaware's potential and the State's needs is required. Therefore, control of industrial development in the coastal zone of Delaware through a permit system at the state level is called for. It is further determined that offshore bulk product transfer facilities represent a significant danger of pollution to the coastal zone, therefore bulk product transfer facilities are prohibited in the coastal zone, unless approved through a conversion permit at a heavy industry use site that had a docking facility or pier for a single industrial or manufacturing facility on or before June 28, 1971.*

Paragraph (i) of §7002 defines the "coastal zone" as "all that area of the State, whether land, water or subaqueous land between the territorial limits of Delaware in the Delaware River, Delaware Bay and Atlantic Ocean, and a line formed by certain Delaware highways and roads as follows". Rather than including the lengthy geographical description that followed, I have included a screenshot of the interactive map used to determine whether a parcel proposed for development falls within the Coastal Zone. Figure 1 shows the location of the BioEnergy Innovation Center (blue icon in southwest corner of state) relative to the Coastal Zone (pink highlighted portion along Delaware's eastern coastline).

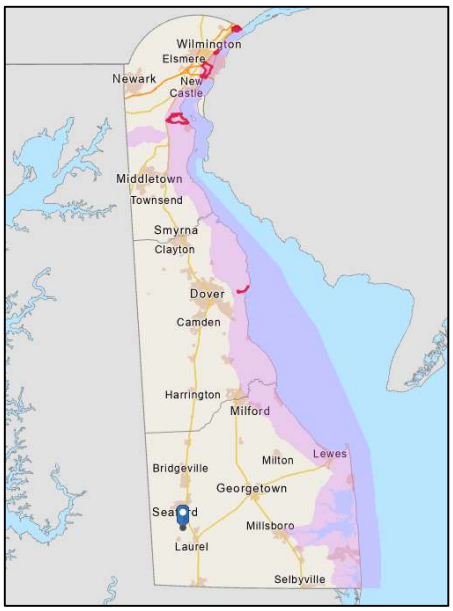


Figure 1: Location of BioEnergy Innovation Center with Respect to Coastal Zone

As Figure 1 illustrates, the proposed project would not be located within the Coastal Zone.

In terms of fees, BioEnergy Devco is current with their annual operating fees for the composting operations. Records show that invoices for $125 were sent to the company on August 7, 2020, and August 13, 2021, for the 2021 and 2022 billing cycles, respectively. For reference, billing for natural minor sources is based on fiscal year (October 1-September 30) rather than calendar year. $125 payments for the 2021 and 2022 billing cycles were submitted on May 7, 2021, and September 28, 2021, respectively.

For the equipment proposed for this project, separate checks for $540 were submitted along with the initial applications for the emergency generator and anaerobic digestion process. These $540 checks covered the advertisement ($325) and process equipment construction application ($215) fees associated with the proposed equipment. While permits for the proposed equipment were not issued during the initial application process, and only the application for the emergency generator was advertised, the checks were deposited by the Department. With that said, the letter sent to Peter Ettinger on August 5, 2021, in which he was informed that the initial applications were being returned, included the following statement with respect to fees in the event that applications for the equipment were resubmitted in the future:

> *Please note, permit and advertising fees are not required if the fees were provided with the initial application.*

As a result, no additional fees were charged during the review of the subsequently submitted applications.

As previously touched upon, obtaining zoning approval for this project was an obstacle in the permit application process. To provide some background, the land on which the proposed project would occur is zoned AR-1, which is an "Agricultural Residential District". The purpose of this district, per §115-19 of Sussex County Code, is as follows:

> *The purpose of these districts is to provide for a full range of agricultural activities and to protect agricultural lands, as one of the county's most valuable natural resources, from the depreciating effect of objectional, hazardous and unsightly uses. They should also protect established agricultural operations and activities. These districts are also intended for protection of watersheds, water resources, forest areas and scenic values and, at the same time, to provide for low-density single-family residential development, together with such churches, recreational facilities and accessory uses as may be necessary or are normally compatible with residential surroundings. The AR regulations seek to prevent untimely scattering of more-dense urban uses, which should be confined to areas planned for efficient extension of public services.*

With this in mind, the permitted uses of §115-20 and accessory uses listed in paragraphs A and B of §115-21 of Sussex County Code were reviewed, but none of the uses appeared to apply. Once I determined that the permitted and accessory uses were inapplicable, the conditional uses of §115-22 were reviewed.

While I will not go into detail on each of the conditional uses listed in §115-22, I will note that Ordinance No. 2311 was adopted by the Sussex County Council and signed by Robin A. Griffith, Clerk of the Council, on June 25, 2013. This ordinance was issued "to grant a conditional use of land in an AR-1 Agricultural Residential District for a Composting Facility as an extension to Conditional Use No. 1691 (a micronutrient plant with related truck entrance and rail spur for the processing and handling of poultry litter) to be located on a certain parcel of land lying and being in Broad Creek Hundred, Sussex County, containing 228.88 acres, more or less." Conditional Use No. 1691, referenced in this ordinance, was related to the poultry litter pellet and prill micronutrient plant which was owned and operated by Perdue AgriBusiness LLC until the plant's closure in 2017.

Ordinance No. 2311 was adopted subject to the following conditions:

1. *The conditions of previously approved Conditional Use No. 1314 and No. 1691 are unchanged by this approval, unless specifically modified herein.*
2. *The use shall be strictly limited to the improvements shown on the April 11, 2013 Site Plan proposed by Axiom Engineering, LLC. Any future additions, alterations or improvements to the Site Plan shall be subject to an application and public hearing to amend this Conditional Use.*
3. *Any rail cars accessing the site shall be cleaned at an off-site location.*
4. *The noise and odor emissions from the operations of the composting facility shall not exceed minimum standards established by DNREC or any other agency having jurisdiction over the project. The odors shall be controlled by negative air pressure in the receiving building, a bio-filter, and by the Gore Cover System.*
5. *The lands on the Site Plan surrounding the composting facility shall remain wooded north of the truck entrance. The location of all wooded, vegetative and buffer areas shall be shown on the Final Site Plan.*
6. *As proposed by the Applicant, all wooded areas outside of the approximately 20 acre project area shall remain as woodlands. Cut-over woodlands shall be allowed to mature.*
7. *Any lighting on the site shall be downward screened so that it does not illuminate neighboring properties or roadways.*
8. *All trucks entering the site must be covered.*
9. *The Final Site Plan shall be subject to the review and approval of the Sussex County Planning and Zoning Commission.*

As stated in Item 2 in the quoted text, any "future additions, alterations or improvements to the Site Plan shall be subject to an application and public hearing to amend this Condition Use." Item 36 on AQM-1 of the application submitted on December 18, 2020, indicated that "Proof of Local Zoning" had been attached. The following paragraphs are from the October 20, 2020, letter from Jamie Whitehouse, Sussex County's Director of Planning & Zoning, to Stephen Gorski, P.E., Senior Project Manager for Duffield

Associates, Inc. regarding the zoning and use of the parcels of land located at 28192 Enviro Way in Seaford:

> *Thank you for your zoning verification request regarding Tax Parcels 132-11.00-41.00, 132-6.00-88.01, 132-6.00-95.00, and 132-11.00-41.02. The tax parcels are located on the north side of Oneals Road (S.C.R. 485) and the west side of Seaford Road (Route 13A) with access off of Enviro Way.*
>
> *The above-mentioned parcels consist of a total of 223.26 acres and are zoned Agricultural Residential (AR-1). The subject properties are not located within a Flood Zone. There are two tax ditches present on parcel 132-11.00-41.00. The northern tax ditch contains a R.O.W. that is measured 30-ft from the top of bank of the ditch, and the southern tax ditch contains a R.O.W. is measured 80-ft from the centerline of the ditech.*
>
> *The use of the site as a composting facility as an addition/extension to the previously approved micro-nutrient plant for the processing and handling of poultry litter was approved by the Sussex County Council on Tuesday, June 25, 2013 under Conditional Use No. 1962. This change was adopted through Ordinance No. 2311 and is subject to nine (9) conditions. The conditions previously approved for the site under Condition Use No. 1314 and 1691 were unchanged by this approval.*
>
> *A Preliminary Site Plan for the addition of seven (7) storage tanks and other associated site improvements to be located between Buildings 1 and 3 was received by the Department of Planning and Zoning on April 16, 20202. The site plan includes a proposed 2,000 square foot security and reception office, new landscaping and fencing near the site entrance.*
>
> *At their meeting of Thursday, April 23, 2020, the Planning and Zoning Commission approved the Preliminary Site Plan with the request that the Final Site Plan also require Commission approval.*
>
> *A search was conducted regarding the parcel's history which concluded that there are no open violations on the property. Placement of any additional structures on the property which are not reflected on the current site plan will require site plan review and a separate permit from the County.*

While this letter provided information about the property and its history, it stopped short of stating that zoning approval had been approved and included no mention of a change to the conditional use adopted through Ordinance No. 2311. Paragraph (c)(1) of §6003 to 7 DE Admin. Code Chapter 60 states the following with regards to zoning and permit issuance:

> *(c) The Secretary shall grant or deny a permit required by subsection (a) or (b) of this section in accordance with duly promulgated regulations provided all of the following:*
>
> *(1) No permit may be granted unless the county or municipality having jurisdiction has first approved the activity by zoning procedures provided by law*

As a result, I was informed that I could continue reviewing and processing the permit application for this project as my workload permitted, but could not advertise or issue a permit until zoning approval was obtained. I relayed this stance to Brian Lyncha during a meeting and subsequent email on January 27, 2021.

On February 11th, 2021, Sussex County's Planning & Zoning Commission held a public hearing regarding Conditional Use 2258 which was summarized as follows:

> *An Ordinance to grant a Conditional Use of land in an AR-1 Agricultural Residential District to amend Conditional Use No. 1314 (Ordinance No. 1354) (as amended by Conditional Use No. 1691 (Ordinance No. 1865) and Conditional Use No. 1962 (Ordinance No. 2311)) to permit the processing and handling of poultry litter to include nutrient recovery for natural gas and electrical generation, to be located on a certain parcel of land lying and being in Broad Creek hundred, Sussex County, containing 228.88 acres, more or less. The property is lying on the west side of Seaford Rd. (Rt. 13A) approximately 0.2 mile north of Oneals Rd. (S.C.R. 485). 911 Address: 28338 Enviro Way, Seaford. Tax Parcels: 132-6.00-88.01 & 95.00, 132-11.00-41.00 & 41.02.*

After hearing the case from those for and against the project, the council deferred to make a decision until the next meeting on February 18th, 2021. On February 18th, 2021, inclement weather forced cancellation of the meeting. The BioEnergy project was again on the agenda for the February 25th, 2021 meeting, but council members decided to defer again because at least one council member was absent. Finally, during a meeting on March 11, 2021, the Planning & Zoning Commission unanimously recommended approval of Conditional Use 2258 to permit the processing and handling of poultry litter to include nutrient recovery for natural gas and electrical generation based upon the record made during the public hearing and for the following reasons:

1. *The property is a large parcel consisting of approximately 228.88 acres more or less and is located in the AR-1 Agricultural Residential District, which allows for a full range of agricultural activities, and is designated in the County's Comprehensive Land Use Plan as an Industrial Area, allowing land to be devoted to concentrations of larger industrial uses including heavier industrial, light industry, warehousing, and flex space.*
2. *The site was originally approved in 1999 for a conditional use and has been in operation since then for the receipt of poultry waste to be converted to fertilizers. The site is currently operated by the Applicant as a micro-nutrient plant with related truck entrance and rail spur for the processing and handling of poultry waste and litter. These historic uses have been approved by regulatory agencies, including DNREC air and water quality agencies.*
3. *The present use was originally granted by Conditional Use No. 1314 and has been amended by Conditional Use Nos. 1691 and 1962. These conditions, as amended, will continue to apply to the site.*
4. *This proposed extension to the existing conditional use enlarges the use to include nutrient recovery and conversion for natural gas and electrical generation. As part of this expansion, the Applicant intends to construct a facility with tanks and anerobic digesters which will recycle poultry byproducts and create renewable natural gas. The Applicant intends to use dissolved air flotation sludge ("DAF") which is derived from the poultry industry in this process. Microorganisms within contained tanks will be used to extract energy from poultry residuals. The other structures currently existing on the site will remain.*
5. *The proposed change is consistent with and is a reasonable expansion of the current use and is essential and desirable for the general convenience and welfare of Sussex County residents and the agribusiness community*
6. *The proposed use will require regulatory review by State agencies, including DNREC, relating to air and water quality controls, the State Fire Marshal, and DelDOT. New approvals for the proposed use will be required.*
7. *The granting of this application benefits the environment by providing a clean and efficient method for the conversion of poultry litter and DAF to renewable energy and by serving the community with natural gas and electricity.*
8. *As proposed by the Applicant, the total area of disturbance from the proposed use will be 11.22 acres, more or less, and there will be no change to the wooded cover on the property.*
9. *The proposed facility will be located adjacent to the existing compost facility and behind the pelletizing facility and will be designed to blend into the site.*

10. *The Applicant will accept poultry litter and DAF from area poultry producers and the proposed use will reduce the amount of DAF land application on area farms which would benefit area soils and waterways.*
11. *The anerobic digester system proposed by the Applicant will utilize existing stormwater and the Applicant intends to recycle treated wastewater as well to minimize the need for other water sources in this process. The Applicant also aims to have a 0% discharge of surface water from the site.*
12. *There were concerns raised through written comments and at the public hearing about the environmental effect of the project but the Applicant will be subject to regular permitting requirements imposed by DNREC and will have to comply with DNREC's requirements.*
13. *The use, if in compliance with DNREC regulations, will not likely have any adverse impact upon the area or neighboring or adjacent properties.*
14. *The use, as amended, will not generate a significant amount of traffic, or otherwise have an adverse effect on traffic or area roadways. DelDOT has submitted a letter that DelDOT considers the traffic impacts from the proposed use to be diminutive.*
15. *The use is of a public or semi-public character that will be a benefit to Sussex County and will promote the health, safety, and welfare of the inhabitants of Sussex County.*
16. *This use is subject to the following conditions:*
    a. *Except as otherwise amended by this grant of conditional use, the conditions imposed by Conditional Use No. 1314 as amended by Conditional Use Nos. 1691 and 1962 shall remain in effect.*
    b. *The proposed facility shall be subject to DNREC and other state and federal regulatory approvals.*
    c. *The proposed facility shall only accept, process, and handle poultry litter and DAF.*
    d. *There shall not be any stockpiling of DAF, poultry litter, or wastewater on site*
    e. *This conditional use shall be valid concurrent with DNREC's permits for this use. If the DNREC permits shall be terminated or expire, this conditional use shall also terminate and expire.*
    f. *The proposed facility, anaerobic digesters, pretanks, and other equipment and structures related to this use shall be located behind the site of the existing pelletizing facility and the area of disturbance related to this new use shall be no greater than 11.3 acres.*
    g. *As proposed by the Applicant, there will be no change to the wooded coverage on the property.*
    h. *All stormwater management facilities shall be subject to the review and approval of the Sussex Conservation District. The Final Site Plan shall include the approval of the Sussex Conservation District for the design and location of the stormwater management areas.*
    i. *Prior to the submission of the Final Site Plan, the Applicant must provide copies of all active permits from DNREC demonstrating that the Applicant has received all necessary approvals and permits from DNREC to operate the proposed facility.*
    j. *As proffered by the Applicant, a landscape buffer shall be installed at the front of the site. A landscape buffer plan shall be included as part of the Final Site Plan for the project.*
    k. *The failure to abide by these conditions shall result in the termination of the conditional use approval.*
    l. *The Applicant shall submit a Final Site Plan, which shall be subject to the review and approval of the Sussex County Planning and Zoning Commission.*

Following the March 11, 2021 meeting of the Planning & Zoning Commission, the Conditional Use was elevated to the Sussex County Council where another public hearing was held during a March 16, 2021 meeting. Again, individuals made their cases for and against the proposed project, but the council deferred on making a decision.

On April 20, 2021, during a regularly scheduled Sussex County Council meeting, the council unanimously adopted a motion to adopt Ordinance No. 2769, which would grant the requested Conditional Use approval for the proposed project. The Ordinance included the conditions listed in subconditions "a." through "l." of Item 16 from the March 11, 2021 Planning & Zoning Commission meeting.

Once the council's approval had been obtained, I received a copy of the Notice of Decision Letter for Conditional Use 2258 which was sent from Christin Scott, Planner I with Sussex County' Planning and Zoning Department, to a Dennis Schrader, Esq., of Morris James LLP, and dated March 19, 2021. The letter was provided to me via email from Brian Lyncha on April 23, 2021, and the following paragraph was excerpted from the letter:

> *At their meeting of April 20, 2021, the Sussex County Council approved the Conditional Use application to amend CU 1314 (as amended by CU's 1691 and 1962) to permit the processing and handling of poultry litter to include nutrient recovery for natural gas and electrical generation at 28338 Enviro Way in Seaford subject to twelve (12) conditions. The Conditional Use shall be substantially underway within three (3) years of the County Council approval otherwise the Conditional Use shall expire. A Site Plan showing the conditions of approval shall be reviewed and approved by the Planning Commission prior to commencement of the use on the parcel. The following are the conditions:*
>
> A. *Except as otherwise amended by this grant of conditional use, the conditions imposed by Conditional Use No. 1314 as amended by Conditional Use Nos. 1691 and 1962 shall remain in effect.*
> B. *The proposed facility shall be subject to DNREC and other state and federal regulatory approvals.*
> C. *The proposed facility shall only accept, process and handle poultry litter and DAF.*
> D. *There shall not be any stockpiling of DAF, poultry litter, or wastewater on site.*
> E. *This conditional use shall be valid concurrent with DNREC's permits for this use. If the DNREC permits shall be terminated or expire, this conditional use shall also terminate and expire.*
> F. *The proposed facility, anaerobic digesters, pretanks, and other equipment and structure related to this use shall be located behind the site of the existing pelletizing facility and the area of disturbance related to this new use shall be no greater than 11.3 acres.*
> G. *As proposed by the Applicant, there will be no change to the wooded coverage on the property.*
> H. *All stormwater management facilities shall be subject to the review and approval of the Sussex Conservation District. The Final Site Plan shall include the approval of the Sussex Conservation District for the design and locations of the stormwater management areas.*
> I. *Prior to the submission of the Final Site Plan, the Applicant must provide copies of all active permits from DNREC demonstrating that the Applicant has received all necessary approvals and permits from DNREC to operate the proposed facility.*
> J. *As proffered by the Applicant, the landscape buffer shall be installed at the front of the site. A landscape buffer plan shall be included as part of the Final Site Plan for the project.*
> K. *The failure to abide by these conditions shall result in the termination of the conditional use approval.*
> L. *The Applicant shall submit a Final Site Plan, which shall be subject to the review and approval of the Sussex County Planning and Zoning Commission.*

After receiving this letter, I was instructed on April 28, 2021, to wait until its contents were reviewed and approved by the Department's Office of the Secretary and their legal experts before I should continue to process the permit application. I received approval to proceed with the permit application process from Angela Marconi via email on May 14, 2021. The application received on January 13, 2022, included a copy of the same "Notice of Decision Letter for Condition Use (CU 2258)" letter that was previously provided.

To date, the BioEnergy Development Group, LLC has no history of violations with respect to the air permit they hold at the neighboring compost facility.

TECHNICAL INFORMATION

As the "Background" section already discussed, the application included a request for the construction of an AD system, with associated process and air pollution control equipment, as well as a generator which would provide electrical power to components of the AD system during emergency situations. This section will discuss the technical aspects of the proposed equipment, starting with the emergency generator.

1,451 HP (1,082 kW) Natural Gas-Fired Cummins Model C1000N6 Generator

The proposed generator is a natural gas-fired Cummins Model C1000N6 generator, which is part of the QSK60G generator series, and would be operated solely in emergency situations. The associated lean burn engine would have a gross engine power output of 1,451 HP (1,082 KW). The following description of lean burn engines was published on Caterpillar's website:

> ***Lean burn*** *gas engines are characterized by lower fuel consumption and lower emissions than rich burn engines operating at a balanced stoichiometric ratio (air-fuel ratio or Lambda is unity). The higher efficiency of lean burn engines is primarily due to their ability to achieve a higher power for a given displacement. Comparing two similar sized rich burn and lean burn engines producing similar power at similar efficiencies, the temperatures produced by a rich burn engine don't make achieving the power density of lean burn practical. A* ***rich burn*** *engine is characterized by excess fuel in the combustion chamber during combustion (oxygen in exhaust typically ranges from 0.5%-0.6%), while a lean burn engine is characterized by excess air in the combustion chamber (oxygen in exhaust is typically >6%).*
>
> *Characteristics of lean burn and rich burn*
> ***Lean Burn***
> - *Lower exhaust temperature*
> - *Lower exhaust NOx and CO emissions*
> - *Higher power density*
> - *Better fuel efficiency*
>
> ***Rich Burn***
> - *Higher exhaust temperatures*
> - *Higher NOx emissions (due to higher exhaust temperatures)*
> - *More complete fuel consumption*
> - *Lower power density*

Some additional engine information, as provided by the manufacturer-published "Generator Set Data Sheet", is shown in Tables 8 & 9.

Fuel Consumption (ISO3046/1)	% of Rated Load			
	100	90	75	50
Fuel Consumption (LHV) ISO3046/1, kW (MMBTU/hr)	2885 (9.85)	2630 (8.98)	2248 (7.68)	Below Minimum
Electrical Efficiency ISO3046/1, percent	36.4%	35.9%	35.0%	Tested
Thermal Efficiency ISO3046/1, percent	52.4%	52.6%	53.0%	Power

Table 8: Generator Fuel Consumption Data

Engine Manufacturer	Cummins
Engine Model	QSK60G
Configuration	V16
Displacement, L (cu. in)	60 (3672)

Aspiration	Turbocharged and Charge Air Aftercooled
Gross Engine Power Output, kWm (ho)	1082 (1451)
BMEP, bar (psi)	12.3 (178)
Bore, mm (in)	159 (6.25)
Stroke, mm (in)	190 (7.48)
Rated Speed, rpm	1800
Piston Speed, m/s (ft/min)	11.4 (2244)
Compression Ratio	11.4:1
Lube Oi Capacity, L (qt)	379 (400)
Full Load Lubricating oil consumption, b/kWe-hr (g/hp-hr)	0.15 (0.11)

Table 9: Generator Engine Specifications

According to Section 3.3.7 of the Engineering Report attached to the application, the generator is "sufficient to support critical loads during a grid power outage." In an email correspondence between myself and Brian Lyncha on August 6, 2020, Brian elaborated a bit further on the proposed generator's purpose.

> *"[The generator] will support critical process loads related to the anaerobic digester, wastewater treatment system and the biogas conditioning and upgrading equipment. The generator will be connected behind to transformers servicing the facility and will be able to be connected to all the electrical systems through the existing facility panel boards. The generator capacity will required that some of the non-critical loads be shed during a power outage but BDC would be able to manage loads as necessary with the 1.0MW of generation available."*

The generator has no associated air pollution control equipment, but is certified to meet the emission standards from Table 1 of Subpart JJJJ (4J) to 40 CFR Part 60 (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines) for "Non-Emergency SI Lean Burn Natural Gas and LPG" engines. While the generator is proposed for emergency use, it is expected to meet the federal standards for non-emergency use, which are more stringent than those for emergency use. Table 10 compares the Subpart 4J emission standards for engines used in emergency applications against the non-emergency engine standards, which the proposed generator is certified to meet:

Engine Type & Fuel	Maximum Engine Power	Manufacture date	Emission Standards (g/HP-hr)		
			NO_X	CO	VOC
Non-Emergency SI Lean Burn Natural Gas and LPG		7/1/2010	1.0	2.0	0.7
Emergency	HP ≥ 130		2.0	4.0	1.0

Table 10: Comparison of Emission Standards from Table 1 of Subpart 4J to 40 CFR Part 60

The emission standards the proposed generator is certified to meet are 50% of the emission standards for both NO_X and CO, and 0.3 g/HP-hr less for VOC emissions, compared to an engine intended for emergency use. Furthermore, testing results for the engine revealed that actual emissions were safely below both standards. Table 11 contains data pulled from the Cummins 2020 EPA Exhaust Emission Compliance Statement included in the permit application and compares the generator's emissions to the non-emergency and emergency standards from Table 1 of Subpart 4J to 40 CFR Part 60.

	Grams per BHP-hr			Grams per kWm-hr		
	NO_X	CO	VOC	NO_X	CO	VOC
Test Results:	0.8	2.0	0.1	1.1	2.7	0.1
Emission Standard:	1.0	2.0	0.7	1.3	2.7	0.9

Table 11: Comparison of Engine Emission Test Results to Subpart 4J Non-Emergency Emission Standards

The permit application included a "Certificate of Conformity with the Clean Air Act" for the generator engine which stated that the engine was certified to meet the Subpart 4J emission standards as well as the emission standards from 40 CFR Part 1048 (Control of Emissions from New, Large Nonroad Spark-Ignition Engines). A comparison of the engine's test results to the Tier 2 emission standards of 40 CFR Part 1048 is shown in Table 12.

	Grams per BHP-hr		Grams per kWm-hr	
	NO_X + NMHC	CO	NO_X + NMHC	CO
Test Results:	0.8	2.0	1.1	2.7
Emission Standard:	2.0	3.3	2.7	4.4

Table 12: Comparison of Engine Emission Test Results to 40 CFR Part 1048 Emission Standards

While the generator engine is certified to meet the Part 1048 emission standards, these standards are not believed to be applicable to the engine in this instance. In §1048.1 it states that the regulations in the part apply to all new, spark-ignition nonroad engines (as defined in §1048.801) with a maximum engine power above 19 kW, except as provided in §1048.5. While this engine has a maximum power rating above 19 kW, I reviewed the definition mentioned in §1048.801. §1048.801 defines a "nonroad engine" as follows:

> *Nonroad engine means:*
> *(1) Except as discussed in paragraph (2) of this definition, a nonroad engine is an internal combustion engine that meets any of the following criteria:*
> *(i) It is (or will be) used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers).*
> *(ii) It is (or will be) used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers).*
> *(iii) By itself or in or on a piece of equipment, it is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.*
> *(2) An internal combustion engine is not a nonroad engine if it meets any of the following criteria:*
> *(i) The engine is used to propel a motor vehicle, an aircraft, or equipment used solely for competition.*
> *(ii) The engine is regulated under 40 CFR part 60, (or otherwise regulated by a federal New Source Performance Standard promulgated under section 111 of the Clean Air Act (42 U.S.C. 7411)). Note that this criterion does not apply for engines meeting any of the criteria of paragraph (1) of this definition that are voluntarily certified under 40 CFR part 60.*
> *(iii) The engine otherwise included in paragraph (1)(iii) of this definition remains or will remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A location is any single site at a building, structure, facility, or installation. For any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine*

> *replaced, include the time period of both engines in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at that single location approximately three months (or more) each year. See §1068.31 for provisions that apply if the engine is removed from the location.*

Because this engine is regulated under 40 CFR Part 60 (Subpart JJJJ, specifically), it is not considered a nonroad engine under Part 1048. Figures 2 & 3 show the proposed location of the emergency generator relative to the other proposed equipment.

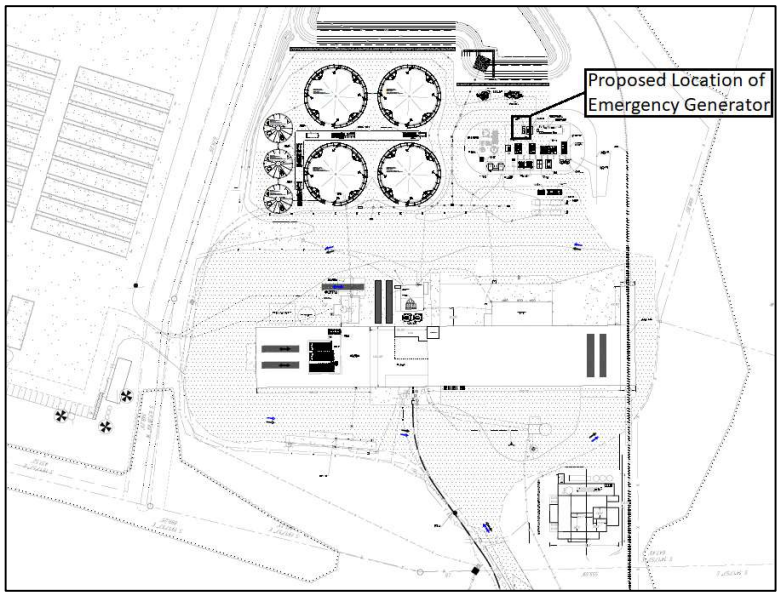


Figure 2: Proposed Location of Emergency Generator

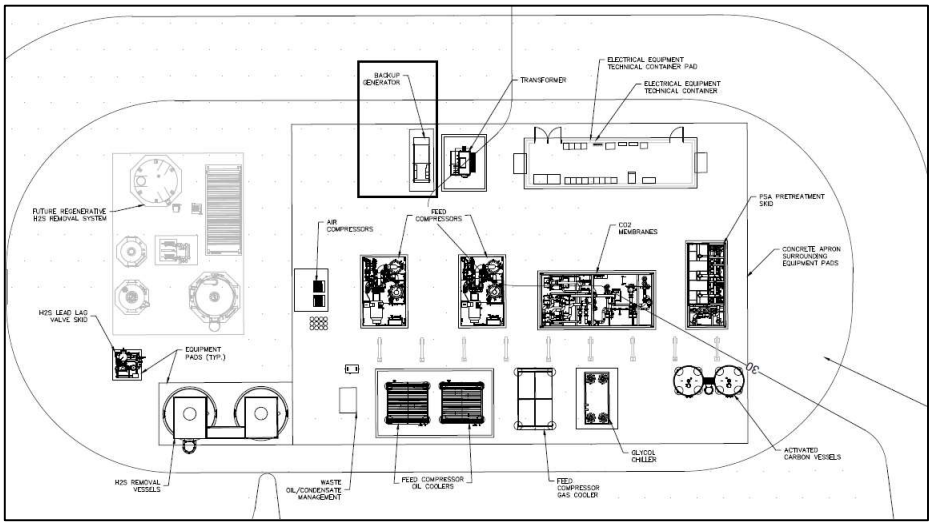


Figure 3: Proposed Location of Emergency Generator Relative to Biogas Process Equipment

Figure 4 provides an image of the proposed generator, which was obtained from the manufacturer's website.

Figure 4: QSK60G Cummins Generator Set

Anaerobic Digesters (ADs) with Associated Process & Control Equipment

The proposed AD project will involve receiving raw solid and liquid feedstock, combining that feedstock into a slurry, digesting the slurry in large reactors, and capturing and refining the gas produced during the process to meet standards for use in the natural gas pipeline system. The solid portion of the digestate resulting from the digestion process is proposed for use as a soil amendment/conditioner or as an additional feedstock in the compost process currently located at the facility. The components of the gas stream that are unwanted will be filtered out by various equipment prior to combustion in either the flare or RTO. According to Section 3.3 of the Engineering Report submitted along with the application, the facility's AD system will include the following major components:

- Feedstock Receiving
  - Solids Feedstock Tipping Floor in an enclosed building
  - Solids Feedstock Receiving Feeders
  - Biomix Feed Pump
  - Liquids Feedstock Receiving Pad and Pump House
- Anaerobic Digestion System
  - Pretank/slurry tank
  - Digester Tanks
- Digestate Handling System
  - Polyelectrolyte Preparator (polymer feed system)
  - Centrifuge Solids Separation
  - Screw Press (as part of Phase 2 to be inserted upstream of centrifuge)
- Wastewater Pretreatment System
  - Solids Removal
  - Bioreactor
  - Ultrafiltration System
  - Reverse Osmosis

  - Nanofiltration
  - Superconcentration Reverse Osmosis
- Biogas Upgrading, Conditioning, and Control Equipment
  - Biogas Conditioning (H2S Scrubber and moisture removal)
  - Compression System
  - Flare and Thermal Oxidizer
- Odor Control Equipment
  - Building Air Dilution Air Exhaust Fan System
- Truck Scales
  - Inbound truck scale, 70-ft
  - Outbound truck scale, 70-ft

The following sections will discuss these components and the process's impact as it relates to air quality as I understand it through information provided in the application and other correspondence supplementing the application.

Incoming Feedstock

According to Section 3.3.2.1 of the Engineering Report, all incoming feedstock will be transported to the facility in various sized transfer trailers up to a maximum of 53' in length. There is no indication that material will be delivered to the site via any other transportation method.

All trucks delivering feedstock material will enter the facility on Enviro Way after turning off of Seaford Road. Prior to offloading, trucks will weigh in on the 70' inbound truck scale. In the event that there is a backup of truck traffic, the Engineering Report indicated that there will be a "Queue Area" where trucks can wait during high delivery periods. Before departing, trucks will again weigh in on a 70' outbound truck scale. The scales are intended to monitor and track incoming waste receipts and outbound shipments from the facility. Incoming liquid wastes received at the facility will be metered.

Upon entering the site, all vehicle flow will proceed in a counter-clockwise direction around the facility after progressing over the inbound scale. Figure 5 includes the proposed facility layout drawing that was included in the application:

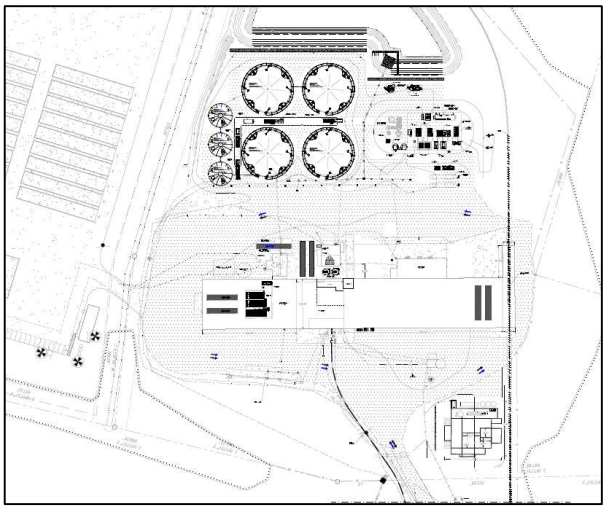


Figure 5: Proposed Facility Layout Drawing

While it's difficult to see in Figure 5, there are blue and black arrows showing the proposed traffic flow for trucks carrying solid and liquid feedstock. Since all traffic is being directed in a counterclockwise direction around the existing building, the blue and black arrows are identical for trucks delivering solid and liquid feedstocks. Figure 6 shows the same traffic flow imposed over the screenshot of an aerial view of the existing facility on Google Maps.

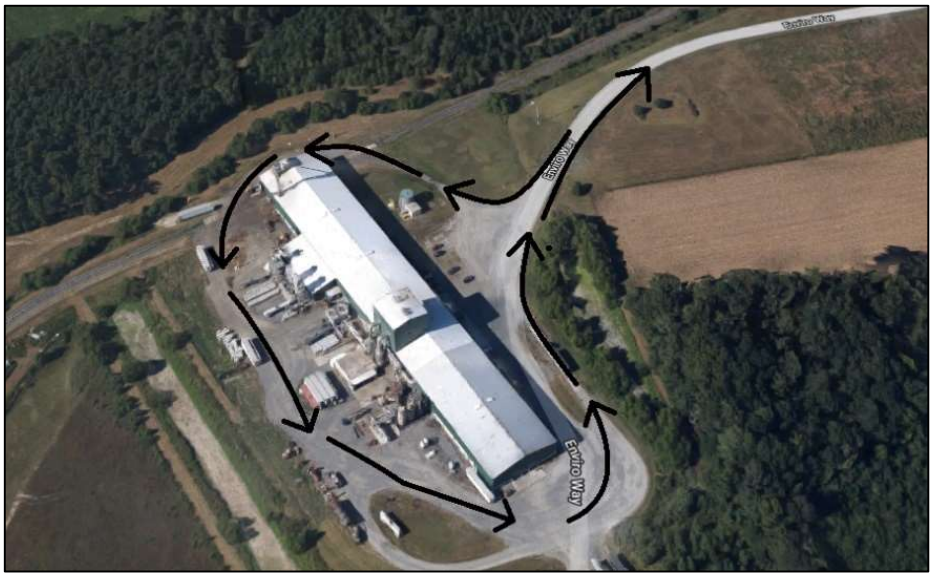


Figure 6: Proposed Traffic Flow

What isn't identical, however, is the area in which solid and liquid feedstock material is received. Of the two locations, trucks will reach the liquid feedstock area first during their counterclockwise path around the existing building. The liquid unloading area will be located along the back (southwest side) of the existing building and is designed to accommodate only one truck unloading at a time. Liquid DAF and other similar liquid organic materials will be transported to the facility by large tanker trailer trucks. The driver would park the truck on a spill pad, which is expected to be designed to contain any spillage that may occur during the unloading process.

The spill pad is expected to have the capacity to contain up to 2,304 gallons and would connect to a trench drain that will route back to a sump that will be connected to the wastewater treatment system in order to handle potential maximum spill volumes. The driver will unload the contents of their truck by connecting a vacuum line via a quick connect fitting on the tanker vessel and pump the liquid to one of three (3) pre-tanks. Preliminary design data for the liquids receiving area is presented in Table 13.

Equipment	Quantity	Size/Rating	Capacity
Sump Pump	1	-	170 gpm
Flow Meter	1	-	-
Liquid Unloading Station Pump	1	20 KW/460 V	300 gpm

Table 13: Liquids Receiving Area Design Data

Figures 7 and 8 highlight the location of the liquid feedstock receiving area, as shown on the Proposed Facility Layout Drawing that was included in the application.

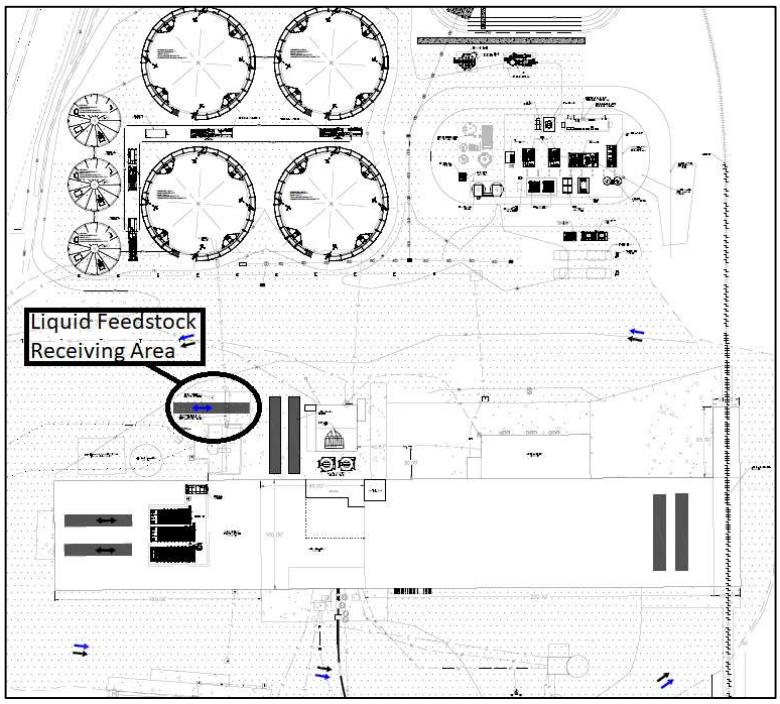


Figure 7: Location of Liquid Feedstock Receiving Area

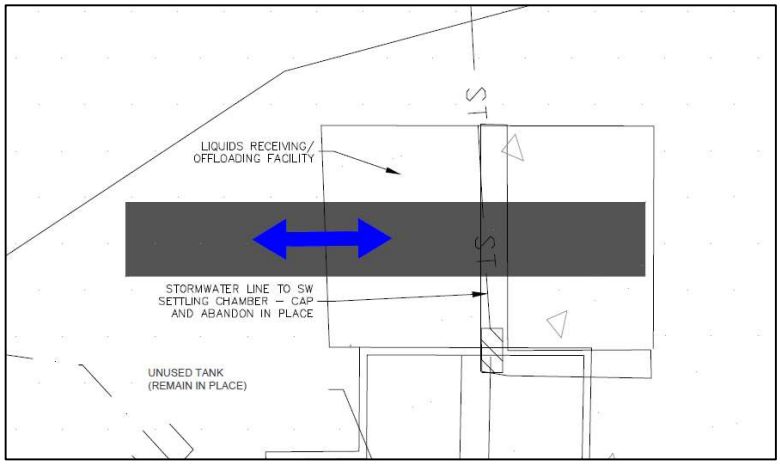


Figure 8: Liquid Feedstock Receiving Area

As trucks continue around the corner of the building, they will reach the entrance to the solid feedstock receiving area. The solid feedstock receiving area is shown in Figures 9 & 10.

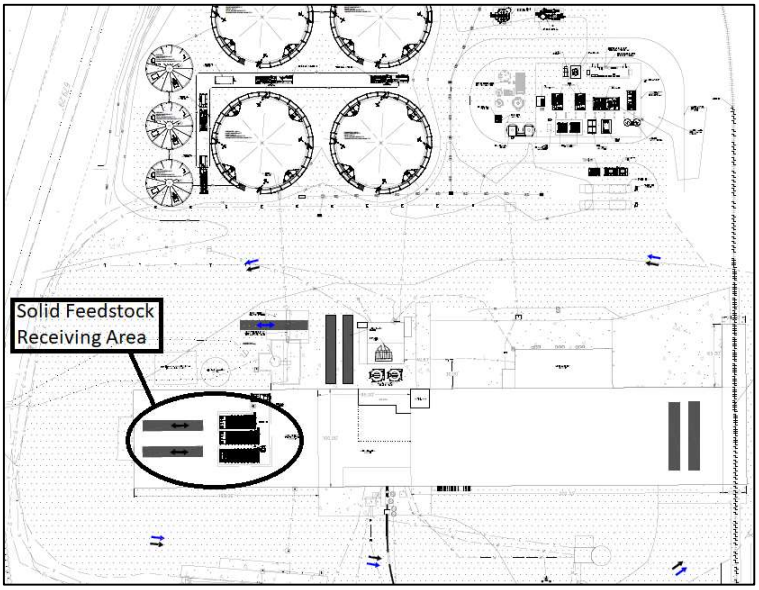


Figure 9: Location of Solid Feedstock Receiving Area

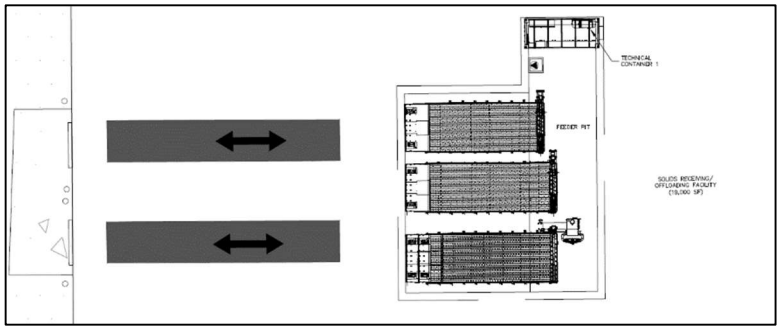


Figure 10: Solid Feedstock Receiving Area

The Engineering Report included the following summary of the Solids Receiving Area:

> *The solid DAF, chicken litter, or other similar solid organic materials will be transported to the facility in various sized transfer trailers up to a maximum of 53' in length. These trucks will enter through one of two roll up doors and tip in the Solids Receiving Area located on the south end of the building, which will accommodate a minimum of four (4) transfer trailers per hour. The trucks will tip and unload material into a receiving pit with a feeder. A screw auger conveyor will be located at the bottom of the feeder to transport the material to be pumped to the Pre-tanks. The screw auger will be sized to remove material quickly enough to avoid backups or overflow of the feeder. In the event some material does end up on the floor, a hose station will be located nearby to wash the material into the feeder.*

The preliminary design data for the solids receiving area from the Engineering Report is shown in Table 14.

Equipment	Quantity	Size/Rating	Capacity
Feeder 1 and 2 (DAF Waste)	2	2,472 ft^3	30 ton/hr
Feeder 3	1	2,825 ft^3	30 ton/hr
Bio-Mix Feeder Pumps	3	30 KW/460 V	300 gpm

Table 14: Solids Receiving Area Design Data

Based on the proposed facility layout drawing provided in the application, Figure 11 shows the locations of the liquid and solid receiving areas relative to the existing building.

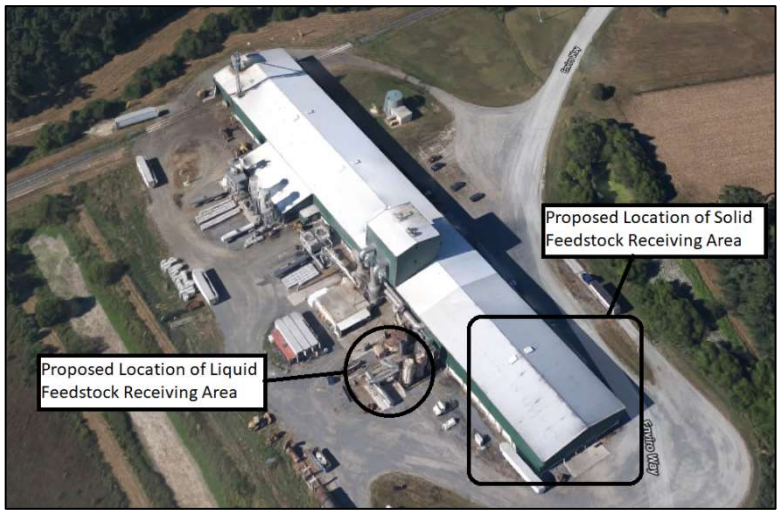


Figure 11: Proposed Feedstock Receiving Areas Relative to Existing Building

One item I had some concern about leading into this project was the potential storage of raw feedstock material and the odors that could be generated as a result. Based on the description of the liquid and solid receiving systems, it appears that material should be quickly transferred from the receiving areas to one of three (3) pre-tanks. Beyond quick material transfer, the Engineering Report provided the following information related to "Odor Control Equipment":

> *All the solid feedstock will be received in an enclosed process building with an air ventilation system that will provide and maintain a negative air pressure inside the building at all times, especially in and around the Solids Receiving Area (i.e., the tipping floor for solid organic waste). The air ventilation system will prevent odors from escaping outside the process building. As the solid feedstock will be received by trucks, quick acting rollup doors will be utilized to minimize the amount of time these areas of the building are open when trucks are being received, unloading, or when they are exiting the process building. The rollup doors will remain in the closed position at all other times.*
>
> *The air ventilation system design has accounted for the removal of odors from the building and elimination through the sufficient dilution of odors prior to being released into the surrounding environment. Design requirements for equipment include a proven history of eliminating odors with examples of similar applications along with other attributes such as reliability, operational and maintenance requirements, critical spare parts, required space, and both CapEx and OpEx costs. Filters and dilution exhaust fans are proven technologies that are currently being considered for use. The facility equipment that will have process odor control is mainly the feedtank separators prior to the solid separation of digestate downstream of the digesters. This equipment will have process filters to eliminate odors. Filters will be changed according to the maintenance requirements for correct functioning of the system. Changes will be done with the use of all required Personal Protective Equipment. Used filters will be disposed of at an appropriately permitted facility. Based on experience with other facilities, emissions from the Solids Receiving area are not expected to trigger regulatory thresholds for control equipment. If, during commissioning, it is determined that emissions require controls, BDC will seek permitting for appropriate equipment.*

Based on this description, it is my understanding that the solid feedstock receiving building's odor control system is essentially control through dilution. In a March 30, 2022 letter to BioEnergy representatives I asked for, among other things, additional information related to the solid feedstock receiving operations. The questions initially asked (italicized) and answers provided (bold italicized) in BioEnergy's April 7, 2022, response letter are summarized below:

> *For the solid feedstock receiving area, it is the Department's understanding that it is the intention to maintain the area at a negative air pressure, but that this negative pressure will be achieved through the operation of a dilution exhaust fan which will vent the air through the roof/exterior of the building to the environment. The Department understands that quantification of emissions from this process may be difficult due to the nature of the activity, but requests submission of the following information:*
>
> *The sequence of events involved in the unloading and transfer of solid feedstock and an estimated residence time of material in the area prior to transfer into the pre-tanks.*
>
> > ***Solid deliveries will enter the building, back in, and offload onto the walking floor area. The feedstock is then immediately conveyed and mixed with liquid feedstocks before being pumps to pre-tanks. The unloading and processing of a single load is approximately 30 minutes.***
>
> *A plan of action in the event that equipment malfunction, for example, prevents the unloading and transfer of solid feedstock from occurring in the manner in which it was designed.*
>
> > ***The design of the plant includes preventative measures to ensure that, in the event of an equipment malfunctions, the solid feedstock will be handled as designed:***
> >
> > ***There are three walking floor feeders. Typically, only one walking floor is required, or two may be required for maximum conditions. In the event one feeder malfunctions, there will be either one or two others available for use.***
> >
> > ***There will be an inventory of spare parts. In the event of an equipment malfunction, the other feeders will be used while maintenance is being done on the malfunctioning part.***

In a May 5, 2022 letter sent to BioEnergy representatives I indicated that I felt these responses were adequate, but included the following language to commemorate discussions held during an April 25, 2022 meeting:

> *I am proposing that requirements to prohibit the stockpiling of feedstock and requiring the stoppage of feedstock receipt and/or shutdown of receiving area ventilation system in the event that there is an unplanned malfunction of the feedstock transfer system that prevents feedstock from being transferred to the pre-tanks.*
>
> *In lieu of an estimate of emissions from this and other processes, I am also proposing requirements to conduct daily qualitative odor surveys at areas of the site where odors could be generated. This shall include, but is not necessarily limited to, the solid feedstock receiving area, feedtank separator, and any other locations where feedstock or digestate could reasonably be vented to the atmosphere. In the event that excessive odors are observed, corrective action and fenceline odor surveys would be triggered.*
>
> *As discussed during the April 25, 2022, meeting, the frequency of the odor surveys may be reduced in response to the findings of emissions testing or due to the lack of odors identified over an extended period of conducting the surveys. No additional response to this item is required unless there are any proposed alternatives to conducting these surveys, or additional comments to add on the matter.*

As stated above, no additional response was required, and none was provided. It is my understanding that, based on the discussions held during in-person meetings and the lack of response to this issue in BioEnergy's May 12, 2022 response to the Department's May 5, 2022 letter, there is no objection to these proposals.

The March 30, 2022 letter also included some questions about the feedtank separators. The following italicized statement was posed by me, and the bolded italicized statement was the response provided by BioEnergy in their April 7, 2022, letter:

> *For the feedtank separators portion of the process, it is the Department's understanding that filters will be implemented to control odors. Please quantify and submit the pre- and postcontrol emissions anticipated to be generated in this area along with the specifications of the filters proposed for use.*
>
> ***In lieu of use of a filter(s) to control potential VOC emissions (odors), Bioenergy Devco proposes to sample/monitor potential VOC/odor emission sources within 6 months of achieving steady-state operations after plant startup. Once data is obtained, the data will be evaluated and controls will be added, if necessary to comply with applicable regulations.***

In the May 5, 2022 letter sent from the Department to BioEnergy representatives I summarized my understanding of the situation, which had also been discussed during a meeting on April 25, 2022:

> *This issue was discussed during the April 25, 2022, meeting and it was my understanding that filters are no longer being considered for use in this area of the process. Please provide written confirmation that this is the case and any additional information you feel is necessary.*
>
> *I also agree that sampling emissions from this location in the process is the best method of understanding the air quality impact. Requirements to conduct testing of emissions following startup of the proposed equipment will be included in the draft permit. In the event that testing reveals emissions above the permitting threshold, an application for this emission source shall be submitted to the Department within thirty (30) days of receiving the test report, and additional controls may be required.*

BioEnergy responded to the statements made in the May 5, 2022 letter with the following statements in their May 12, 2022 letter to the Department:

> ***The solids separation equipment is located in the building, which will have an overall exhaust system for odor control. The exhaust system will be sized appropriately for air flow in both the receiving area and the solid separation area. In the solid separation area liquid from the digesters flows to the solid separation feed tank which in turn feeds the disc press for the dewatering process. The disc press produces liquid and solid fractions. At this time, we do not plan to install filters on the solid separation tanks.***

As their response indicates, sampling of emissions from the building's exhaust system should ensure that cumulative emissions from the solid feedstock receiving operations and solids separation equipment are captured.

From the liquid and solid feedstock receiving areas, the material is transferred into one of three (3) pre-tanks. The pre-tanks were described as follows in the Engineering Report:

The project will include pre-tanks to provide mixing and stirring with mechanical agitators and provide for equalization allowing a constant flow rate and consistent quality of substrate to be fed to the digesters. The liquid DAF material will be pumped directly to the Pre-tanks.

The Solid DAF and processed poultry litter will be combined with liquid substrate that can be pumped from the pre-tanks to create a pumpable slurry with a desired percentage of solids. The slurry will then be pumped to the digesters.

The pre-tanks are constructed using post-tensioned, pre-cast concrete panels which are sealed to prevent reactions with potential corrosives.

The pre-tanks are designed with almost 3 days of hydraulic retention time. The reduced retention time is kept short so as not to produce biogas. Any biogas produced is collected at the top of the tank with a line that connects to the common biogas lines from the anaerobic digesters and pulled to the biogas treatment system by way of a blower.

The pre-tanks preheat the substrate and provide some initial breakdown of complex organic molecules into sugars, amino acids, and fatty acids to aid the AD process within the digesters.

As stated above, the liquid and solid feedstocks are mixed and heated in the pre-tanks to form a slurry before being sent to the digesters.

Anaerobic Digesters

Prior to discussing the operation of the digester, it is important to understand the feedstock that will be digested. As previously stated, the application has requested permission to process up to 250,000 tons of feedstock through the digesters on a rolling twelve (12) month basis. According to the Engineering Report, this feedstock will include poultry litter, dissolved air flotation (or DAF, which includes liquid and solid cake; fats, oils & grease; and waste activated sludge), and the bioreactor sludge from the on-site wastewater treatment plant. Table 15 provides the breakdown of the expected quantities of each feedstock source, type, and amount as it was originally provided in Table 1 of Section 3.3.2 of the Engineering Report:

Feedstock		Tonnage (tpy)	
Source	**Type**	**Annual (TPY)**	**Daily[3] (Tons)**
Facility 1	Cake	11,542.44	31.71
	DAF Sludge Primary	38,176.32	104.88
Facility 2	DAF Sludge	22,196.72	60.98
Facility 3	DAF Cake	79,908.92	219.53
Facility 4	Cake	17,755.92	48.78
	Poultry Litter	29,924.44	82.21
	Subtotal[1]:	199,504.76	548.09
BIC	Bioreactor Sludge	45,478.16	124.94
	Total:	244,982.92	673.03

Table 15: Feedstock Tonnage Estimates

[1]Accounts for all of the feedstock being delivered to the facility
[2]Accounts for total amount of material processed by the AD equipment. This total is greater than the tonnage of feedstock delivered to the facility because the bioreactor sludge is recycled through the process.

[3]Assumes 7 days per week/52 weeks per year operation. Actual daily values will be slightly higher per feedstock receiving operations

While Table 15 includes an estimate of the types of feedstocks and tonnages, the air permit would not restrict the ability to increase or decrease these individual values so long as the tonnage of feedstock digested does not exceed 250,000 tons per year.

To provide some context in terms of each of the proposed feedstocks, I did some research into the components of each. According to the "Poultry Litter Sampling" document published by the University of Georgia, "poultry litter is a mixture of poultry manure, feathers, wasted feed, and bedding material that contains nitrogen, phosphate, potash and other nutrients essential for plant growth." The document continues to explain that "poultry litter can vary considerably in nutrient content due to bird type, feed composition, bedding materials used, clean-out frequency, storage and handling practices, use of litter amendments, and other factors."

In addition to poultry litter, the proposed project would also be digesting DAF. As previously stated, DAF stands for "Dissolved Air Flotation". For an explanation of DAF, I turned to information published on the website for Ecologix Environmental Systems, a manufacturer and integrator of wastewater treatment equipment:

> *Dissolved air flotation (DAF) is a clarification process that utilizes air to remove suspended matter from the surface of treated water. DAF works by dissolving air under pressure and then releasing millions of tiny air bubbles into the water at atmospheric pressure. This process allows the dissolved air bubbles to adhere to a suspended matter within the water, causing it to come to the surface to be skimmed away. The process is also often assisted by the addition of a coagulant or a flocculant to the flow water, which encourages clustering of colloidal particles. Typically, DAF is used to clarify wastewater from food processing plants, oil refineries, oil fracking operation, chemical plants, and paper mills, among others. A strong DAF system is efficient and can clarify high volumes of wastewater in one session.*

As another website summarized it, DAF is essentially the "small bits of proteins, fats, and fibrous materials [in the poultry processing facility's wastewater stream] that could not be removed by simple mechanical means". As the italicized text above suggests, the suspended solids removed from the wastewater stream form a sludge that is skimmed and collected. This sludge, or cake when the sludge is dewatered, from poultry processing plant wastewater streams is what is proposed for use in the AD at the BIC.

The final proposed feedstock is the bioreactor sludge from the on-site wastewater treatment plant. The following bullets summarize the flow of the process wastewater, according to information provided in the Engineering Report, and the underlined portions highlight the areas where solids removed from the wastewater for use in the AD or compost systems are mentioned:

- *Preliminary Treatment, Filtration, and Screening*
  - *AD discharge is directed into an equalization tank prior to coarse solids removal step using disc press equipment.*
  - *Separated solids are sent to the compost operation.*
  - *Disc pressate will be pumped sequentially through Drum Filters and Microscreens located near the MBR tanks.*
    - *The Drum Filters protect the Microscreens which protect the downstream membrane systems.*

        - *Solids captured by the Drum Filters and Microscreens will be collected in portable containers and will be recycled to the AD system.*
- *Bioreactor*
    - *Screened wastewater will flow by gravity to the Bioreactor Anoxic Zones.*
        - *The anoxic environment functions as a zone with depleted oxygen levels to allow for denitrification of effluent recycled from the Aeration Zones*
        - *The Anoxic Zones are complete mix reactors with no supplemental oxygen provided.*
        - *Anoxic Zone effluent will flow by gravity to the Aerobic Zones where diffused air and supplemental carbon (depicted as "nutrient" on the PFD) will be added to provide nitrification of ammonia nitrogen first to nitrites and then to nitrates.*
        - *The diffused air system will provide oxygen and mixing energy needed for the Aeration Zones to function as completely mixed reactors.*
        - *Waste solids from the bioreactor will be routed back to the AD system.*
    - *A UF Feed Tank will be provided to collect and mix effluent from both Aeration Zones prior to pumping to the UF systems.*
        - *Recirculation Pumps will recycle fully nitrified wastewater from the UF Feed Tank back to the Anoxic Zones for denitrification.*
        - *In addition, heat exchangers will be provided to cool recycled wastewater during warm months to optimize the denitrification process.*
- *Membrane Treatment*
    - *The UF systems provide membrane filtration of Bioreactor effluent to remove additional contaminants.*
        - *UF system is a physical filtration system and will remove suspended solids.*
        - *The UF membranes have a mean pore size of 30 nanometers, therefore any constituent with a size greater than 30 nm will be removed.*
        - *UF effluent will be pumped to the UF Permeate tank and from there into the RO Systems.*
        - *The RO system is a multi-concentration, triple pass system that will remove dissolved solids including metal ions and aqueous salts.*
        - *The RO system includes a 5 nanometer filter as well as semipermeable membranes.*
        - *The RO systems will remove any remaining contaminants and provide effluent quality designed to meet Seaford treatment permit requirements.*
        - *RO permeate will be pumped to a holding tank prior to being loaded on trucks and eventually allowed to be discharged to the new pumping station.*
    - *Some RO permeate will be pumped back into the plant to be used as service water for clean-in-place systems of other equipment.*
        - *The RO systems will also produce a concentrated effluent stream (RO concentrate) containing all the contaminants removed from UF Permeate.*
        - *This waste stream is directed into the NF system which uses membranes having pore sizes of 0.002 to 0.005 microns to remove smaller contaminants.*
        - *NF permeate is fed to an additional RO super concentration process.*
        - *NF concentrate (approximately 3,200 gallons per day) will be sent to the composting system to be used moisture control and because it contains concentrated minerals.*
        - *RO super concentrate (approximately 5,800 gallons per day) will be trucked off site to a facility that accepts industrial wastewater.*
- *Supplemental Chemical Additions*
    - *An antifoaming agent will be injected into the Anoxic Zone recirculation lines to combat foaming within the Bioreactor.*
    - *The UF, NF and RO systems all include a clean-in-place capabilities to allow periodic cleaning with an acid, a base, sodium hypochlorite (UF), and an antiscalant (RO).*

- *Biocide and an anticorrosive will be injected into wastewater recycled through the heat exchanger systems.*

Table 16 summarizes the proposed feedstocks along with a description of each.

Feedstock	Description
Poultry Litter	Mixture of poultry manure, feathers, wasted feed, and bedding material that contains nitrogen, phosphate, potash and other nutrients
DAF	Suspended matter (proteins, fats, and fibrous materials) that is removed by aerating the wastewater stream at poultry processing plants
Bioreactor sludge	Filtered solids from AD wastewater stream that are recycled back into AD process.

Table 16: Proposed Feedstocks & Corresponding Descriptions

With a better understanding of these feedstock materials, the quoted sections below, which describe the anaerobic digesters, were pulled from the Engineering Report:

> *The project includes four digesters that will operate in parallel to provide anaerobic digestion of the slurry and produce biogas. The digester tanks will be heated and mixed to facilitate the biological process. The digesters are expected to produce 2,304,000 SCF of biogas per day (1600 SCFM) which is expected to equate to 1,428,480 SCF of methane produced per day based on continuous 24-hour operation, seven days per week. Biogas will be collected from the digesters and treated at the biogas conditioning system. Digestate from the digesters will be pumped to a Feed Tank for solids separation.*

Table 17 summarizes the digester design data as it was originally provided in Table 5 of Section 3.3.3.2 of the Engineering Report:

Quantity	Material	Foundation	Operating Temperature		Inside Diameter	Height	Volume Fermentation	Total Volume
	Type	Type	°F	°C	ft.	ft.	ft^3	ft^3
4	Pre-Cast Post-Tension Concrete	Concrete Geo-Piers and Slab	108	42	92	39.5	244,096	265,919

Table 17: Digester Design Data

The following paragraph, which discusses the flow of the digestate, is a continuation of the information provided in the "Digester Tanks" section of the Engineering Report:

> *The digestate is then pumped to centrifuges to provide solids separation prior to further treatment. A polyelectrolyte preparator will feed and blend polymer with the digestate upstream of the Centrifuges to facilitate solids separation. Solids from the centrifuges will be conveyed and discharged into a storage bunker and either marketed as a soil amendment product or transported to the adjacent compost facility for further processing.*

As stated above, storage of the solid digestate was planned to be done through the use of a "storage bunker". In a March 30, 2022 letter to BioEnergy representatives I asked for, among other things, additional information related to the proposed storage bunkers. The questions initially asked (italicized) and answers provided (bold italicized) in BioEnergy's April 7, 2022, response letter are summarized below:

The Engineering Report attached to the application indicates that the separated solid digestate "will be conveyed and discharged into a storage bunker and either marketed as a soil amendment product or transported to the adjacent compost facility for further processing."

Will this storage bunker be vented to the atmosphere?

Yes.

And if so, have potential emissions from the storage of solid digestate been quantified?

No potential emissions from the storage bunker have been quantified; however, based on operating experience at other similar facilities, no emissions are expected to exceed applicable regulatory thresholds.

I was unsatisfied with this response and raised questions regarding the storage bunker again during a meeting on April 25, 2022. The following italicized statement, which was sent as part of another letter to BioEnergy representatives on May 5, 2022, summarized my understanding of the response provided during the April 25, 2022 meeting. The bold italicized statement below my understanding was provided as part of BioEnergy's response letter dated May 12, 2022.

It is my understanding that the solid digestate storage bunker and the previously addressed feedtank separators section of the process are the same potential source of emissions. Please provide written confirmation that this is the case and any additional information you feel is necessary.

There is no separated solids storage bunker. There is a receiving trailer on site that collects dewatered solids from the disc press that are transported to compost daily.

As BioEnergy's response indicates, solid digestate material will not be stored on site, but instead is planned to be transferred on a daily basis to the neighboring compost facility. As previously discussed, an amendment to the air permit for the compost facility will be required prior to allowing this activity.

Table 18 summarizes the solid digestate handling design data as it was originally provided in Table 5 of Section 3.3.3.2 of the Engineering Report:

Dewatering System Component	Units	Unit Capacity	Type	Material	Performance	Motor HP
Feed Tank Separation	1					
Sludge Feed Pump	1	150 gpm @ 30' TDH	Progressing Cavity	Cast Iron		10
Solids Macerator	1	150 gpm	Inline	Mild Steel		3
Decanter Centrifuge	3	110 gpm/4,018 lbs/hr	Hydraulic Backdrive	Stainless Steel	3,000 G	60 HP scroll; 15 HP backdrive
Flat Collector Conveyor	1	2,275 dry lbs/hr	Screw Conveyor	Stainless Steel		15

Dewatering System Component	Units	Unit Capacity	Type	Material	Performance	Motor HP
Inclined Discharge Conveyor	2	2,275 dry lbs/hr	Screw Conveyor	Stainless Steel		15
Polymer Dosing System	1	1-10 gph	Neat Blending/Dosing Skid	Stainless Steel Skid/PVC Pipe	0.25-1% Solution	Fractional
Sludge Flow Meter	1	4-20 mA	Magnetic	Stainless Steel with EPDM Liner	n/a	n/a
Storage Bunker	1					

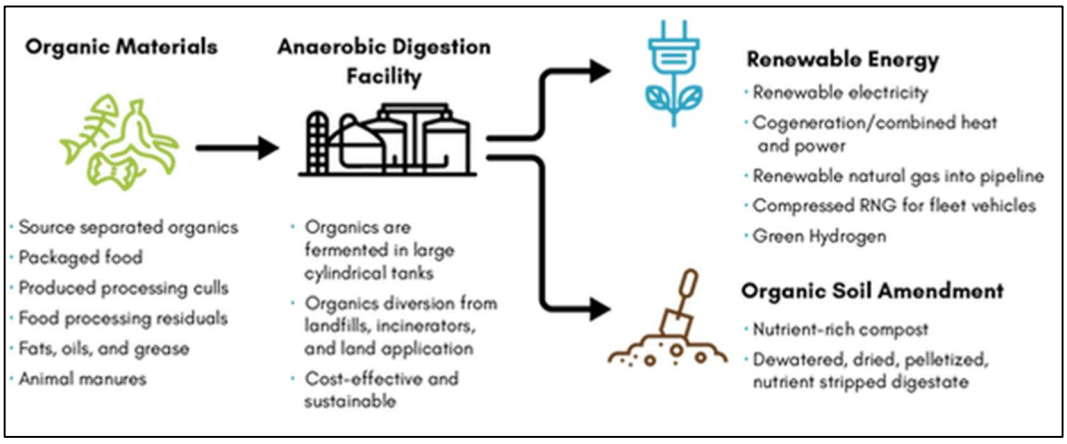
Table 18: Solid Digestate Handling Design Data

The following paragraph discussing the flow of the liquid digestate is the final portion of the information provided in the "Digester Tanks" section of the Engineering Report

> *The liquid fraction (centrate) exiting the centrifuges will be sent to a buffering or equalization tank to ensure constant feed to the wastewater pretreatment system. From there most of the liquid will be pumped to the wastewater treatment equipment and a portion of the liquid will be pumped back to the digesters.*

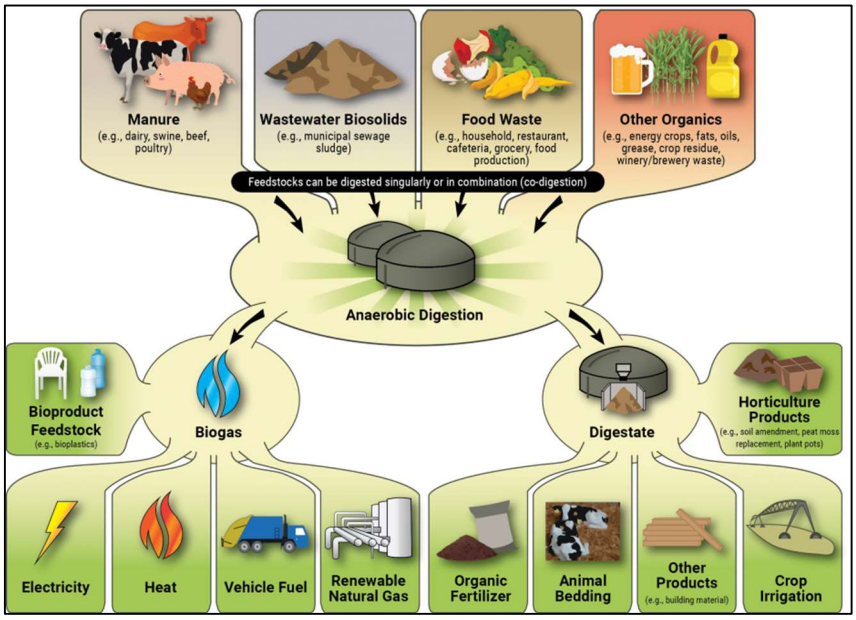
The Engineering Report didn't provide much detail on the proposed digestion process, so I decided to research elsewhere. At the time of writing this document, the website for the BioEnergy Innovation Center provided the following description of anaerobic digestion:

> *Anaerobic digestion (AD) is a safe and common process that uses microbes to break down organic materials into important and valuable end-products – renewable energy and an organic soil amendment. This widely adopted technology is used worldwide, with approximately 50 million ADs in operation across the globe, ranging from small backyard digesters to large digesters common at wastewater treatment sites, farms, and food processing facilities. The AD facility being developed at BIC, while innovative, is hardly a new or untested technology.*
>
> *Here is how the process works:*



I felt this explanation, while a nice overview, lacked the detail I wanted to better understand the process so I consulted the EPA's website which included a number of resources available through AgSTAR. AgSTAR was described as "a collaborative program sponsored by EPA and USDA that promotes the use of biogas recovery systems to reduce methane emissions from livestock waste." The following paragraphs were copied from the "How Does Anaerobic Digestion Work?" page of the AgSTAR section.

> *Anaerobic digestion is a process through which bacteria break down organic matter—such as animal manure, wastewater biosolids, and food wastes—in the absence of oxygen. Anaerobic digestion for biogas production takes place in a sealed vessel called a reactor, which is designed and constructed in various shapes and sizes specific to the site and feedstock conditions. These reactors contain complex microbial communities that break down (or digest) the waste and produce resultant biogas and digestate (the solid and liquid material end-products of the AD process) which is discharged from the digester.*
>
> *Multiple organic materials can be combined in one digester, a practice called co-digestion. Co-digested materials include manure; food waste (i.e., processing, distribution and consumer generated materials); energy crops; crop residues; and fats, oils, and greases (FOG) from restaurant grease traps, and many other sources. Co-digestion can increase biogas production from low-yielding or difficult-to-digest organic waste.*
>
> *The following figure illustrates the flow of feedstocks through the AD system to produce biogas and digestate.*



For this facility, co-digestion would occur with poultry litter and DAF sludge/cake feedstocks which will come from poultry-related facilities in Delaware and potentially others in surrounding states. The outputs of this process are biogas and digestate. The AgSTAR site summarized these outputs as follows:

> ***Biogas***
> *Biogas is composed of methane (CH4), which is the primary component of natural gas, at a relatively high percentage (50 to 75 percent), carbon dioxide (CO2), hydrogen sulfide (H2S), water vapor, and trace*

amounts of other gases. The energy in biogas can be used like natural gas to provide heat, generate electricity, and power cooling systems, among other uses. Biogas can also be purified by removing the inert or low-value constituents (CO2, water, H2S, etc.) to generate renewable natural gas (RNG). This can be sold and injected into the natural gas distribution system, compressed and used as vehicle fuel, or processed further to generate alternative transportation fuel, energy products, or other advanced biochemicals and bioproducts.

Digestate
Digestate is the residual material left after the digestion process. It is composed of liquid and solid portions. These are often separated and handled independently, as each have value that can be realized with varying degrees of post processing.

With appropriate treatment, both the solid and liquid portions of digestate can be used in many beneficial applications, such as animal bedding (solids), nutrient-rich fertilizer (liquids and solids), a foundation material for bio-based products (e.g., bioplastics), organic-rich compost (solids), and/or simply as soil amendment (solids), the latter of which may include the farm spreading the digestate on the field as fertilizer. Digestate products can be a source of revenue or cost savings, and are often pursued to increase the financial and net-environmental benefit of an AD/biogas project.

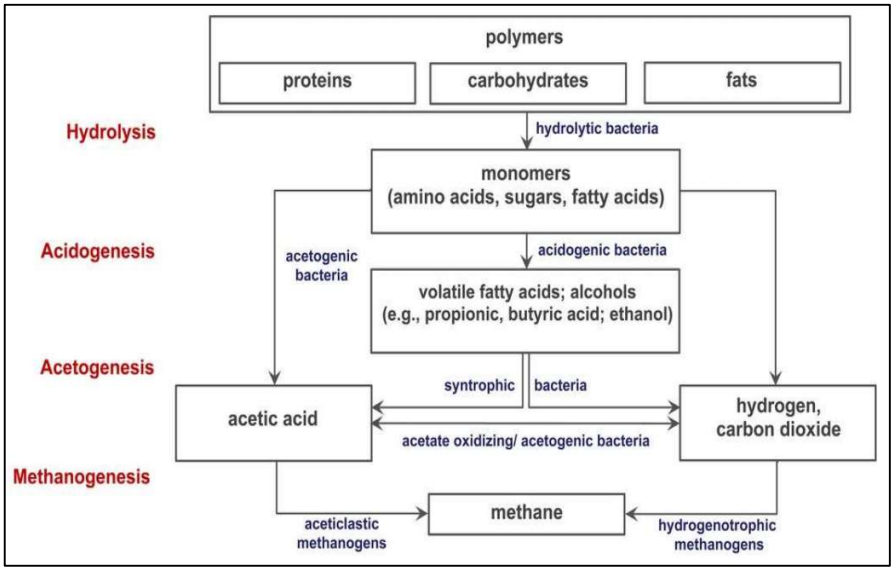
In terms of how the AD is expected to function, I again consulted the AgSTAR page of the EPA's website and found the AgSTAR Operator Guidebook, which was written with the intent of helping "on-farm AD and biogas (AD/biogas) system operators improve performance and efficiency." Section 2.2 of the guidebook includes a Section titled "How Does an Anaerobic Digester Work?" and includes the following information:

This section describes the underlying biochemical principles of AD. The biochemical conversions in an anaerobic digester are quite complex; in simple terms, a variety of microorganisms break down the readily biodegradable organic matter to form biogas. Organic matter anaerobically decomposes naturally under wet conditions where dissolved oxygen (O_2) is absent. This most commonly occurs in the bottom sediments of lakes and ponds, swamps, peat bogs, animal intestines, and the interiors of solid waste landfills.

The AD process involves the following four steps:

- *Hydrolysis — Complex organics are broken down into simple organics. Specifically, hydrolytic microorganisms break down complex organic compounds such as proteins, carbohydrates, and fats.*
- *Acidogenesis—Acidogenic microorganisms ferment the simple organics into short-chain fatty acids (also called volatile fatty acids [VFAs]), CO_2, and hydrogen gases.*
- *Acetogenesis—Acetogenic microorganisms convert the mixture of short-chain fatty acids to acetic acid, with the release of more CO_2 and hydrogen gases.*
- *Methanogenesis—CH_4-producing microorganisms called methanogens convert acetic acid and hydrogen to biogas. The biogas is a mixture of CH_4, CO_2, other compounds of lesser proportion such as H_2S, and numerous trace elements. There are two classes of methanogens: one class primarily converts the acetic acid to CH_4, while the other class combines the hydrogen and CO_2 into CH_4; some unique methanogens can do both.*

The four steps of anaerobic biodegradation are shown in [the following Figure]. One key to successful AD operation is maintaining a balance between the populations of the methanogenic microorganisms and the hydrolytic, acidogenic, and acetogenic microorganisms—which are heterotrophs, meaning that they consume complex organic substances. It is important to ensure an adequate population of methanogens because methanogens reproduce at a slower rate than heterotrophs. With insufficient methanogens, VFAs will accumulate, and these acids are toxic to methanogens at higher concentrations.



To maintain methanogens, the rate of methanogen loss in the digester effluent should not be greater than the rate of methanogen growth. This can be managed by controlling the amount of time that waste is in the digester, called the residence or retention time. To achieve the desired conversion of any specific organic waste, including livestock manure, operators must maintain the digester-specific design values for residence times (discussed in Section 3.1).

Most AD/biogas systems employ a single reactor, where the production of acetic acid, hydrogen, CO_2, and CH_4 occur concurrently. Theoretically, separating the various populations of microorganisms should provide for more precise process control. Two-stage digesters target microorganisms for the first three phases of digestion (hydrolysis, acidogenesis, and acetogenesis) in the first vessel and the CH_4-forming microorganisms in a second, downstream vessel. However, separating phases of AD has not been shown to offer any significant advantage over single-stage digestion.

In all cases, given the range of process options, the art of deploying a successful digester lies in selecting the best engineering solution for the specific feedstock (i.e., material being converted in the anaerobic digester) being treated. There are numerous design, operational, and cost reasons for choosing a specific type of digester. Each type should be considered carefully for its suitability to treat the specific feedstock. There is not any one AD/biogas system design or technology that works the best for all feedstocks. This Operator Guidebook does not endorse any specific brand or process.

As described in the preceding paragraphs, the proposed AD system is a biological process. Creating and maintaining a successful AD system is complex and involves balancing a number of variables. To gain a better understanding of the parameters that will be monitored, the Department requested that a list of operating parameters and ranges considered to be indicative of good operation be provided in the application. Table 19 summarizes the list provided:

Parameter	Units	Standard Operating Practice Values
Total Solids	% FM	6-14
Volatile Solids	% DM	65-95

Parameter	Units	Standard Operating Practice Values
Ash	% DM	35-5
Fat	% DM	>25
Starch	% DM	>40
Sugar	% DM	No limit
NFC	% DM	>40
NDF	% DM	>50
ADF	% DM	>50
ADL	% DM	>25
pH		7.2-8.5
Total nitrogen	mg/l	2000-9000
Ammonium	mg/l	1500-6000
Acetic acid/propionic acid	Ratio	>1/2
Propionic acid		>300
Sulfur as H2S	mg/l	50
Sulfur as S2-	mg/l	100
Sulfur as Na2S	mg/l	160
Sodium	g/l	>30
Calcium	g/l	>2.8 CaCl2
Potassium	g/l	>3
Phosphor	g/l	n.a.
Magnesium	g/l	>2.4 MgCl2
Ni (free ions)	mg/	>10
Cu (free ions)	mg/l	>40
Cr (free ions)	mg/l	>130
Pb (free ions)	mg/l	>340
Zn (free ions)	mg/l	>400

Table 19: Typical Digester Operating Parameters

In addition to these parameters, the information provided in the AgSTAR Operator Guidebook indicated that reactor residence time was important to ensuring an adequate population of methanogens in the AD. While not specified in the application, information provided during a tour of BioEnergy's facility in Jessup, MD on March 1, 2022, indicated that the residence time would normally be 28-35 days. This number is inexact because the digesters will be operated as a continuous process rather than a batch process.

Based on the information provided, it appears that the proposed AD would be considered a "complete mix digester". According to information provided by the EPA, "Complete mix digesters are designed with an enclosed, heated tank with a mechanical, hydraulic or gas mixing system. Complete mix digesters work best when there is some dilution of the excreted manure with water (e.g., milking center wastewater)." Figure 12 is a diagram of a complete mix digester.

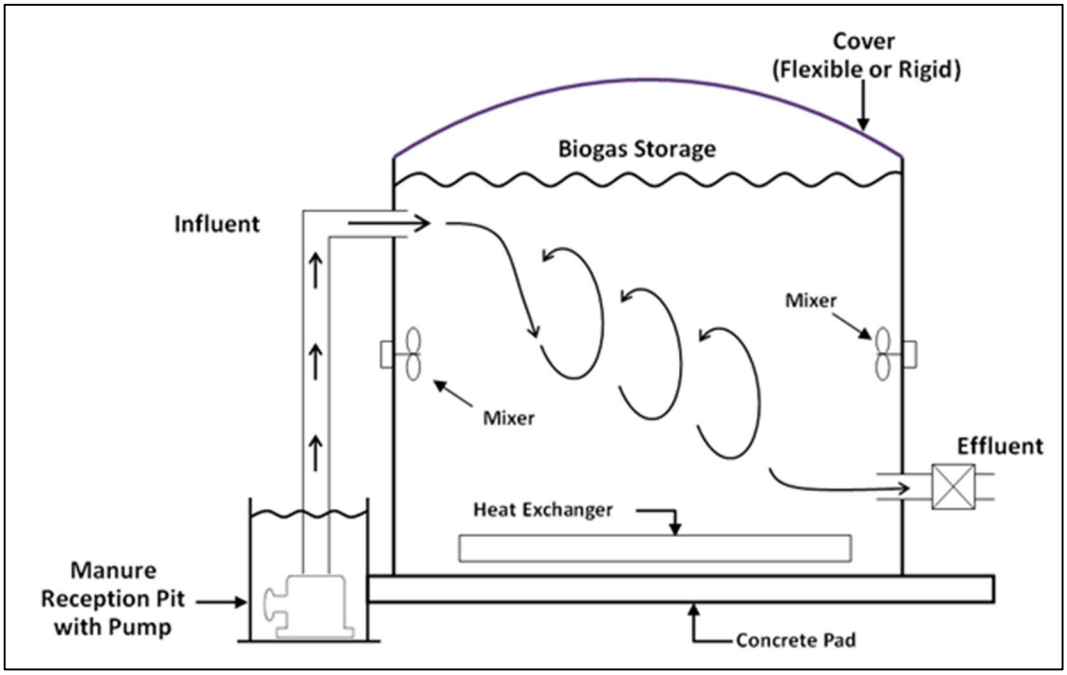


Figure 12: Complete Mix Flow Digester Diagram

Figures 13-18 show the digesters observed at BioEnergy Devco's Jessup, MD facility during the March 1, 2022, site visit.

Figure 13: Digester at BioEnergy Jessup, MD Facility

Figure 14: Digester at BioEnergy Jessup, MD Facility

Figure 15: Digester at BioEnergy Jessup, MD Facility with CHP in Background

Figure 16: Digester at BioEnergy Jessup, MD Facility

Figure 17: Digester at BioEnergy Jessup, MD Facility

Figure 18: Digester at BioEnergy Jessup, MD Facility

It was indicated that the Jessup, MD facility digesters are identical to those which are proposed for the BIC facility in Seaford. The only significant differences are the following:

- Two (2) digesters are planned for the Jessup, MD facility and four (4) digesters are proposed in Seaford.
- The Jessup, MD facility digests food waste and the Seaford facility is proposed to digest poultry litter, DAF sludge/cake, and bioreactor sludge.

Ultimately, the biogas is generated as a result of microorganisms breaking down organic material in the absence of air. The biogas generated from the ADs, and pre-tanks to the ADs, is collected and routed through an upgrade system before it is compressed and trucked offsite for injection into the natural gas pipeline system. A process flow diagram (PFD) from the application is shown in Figure 19.

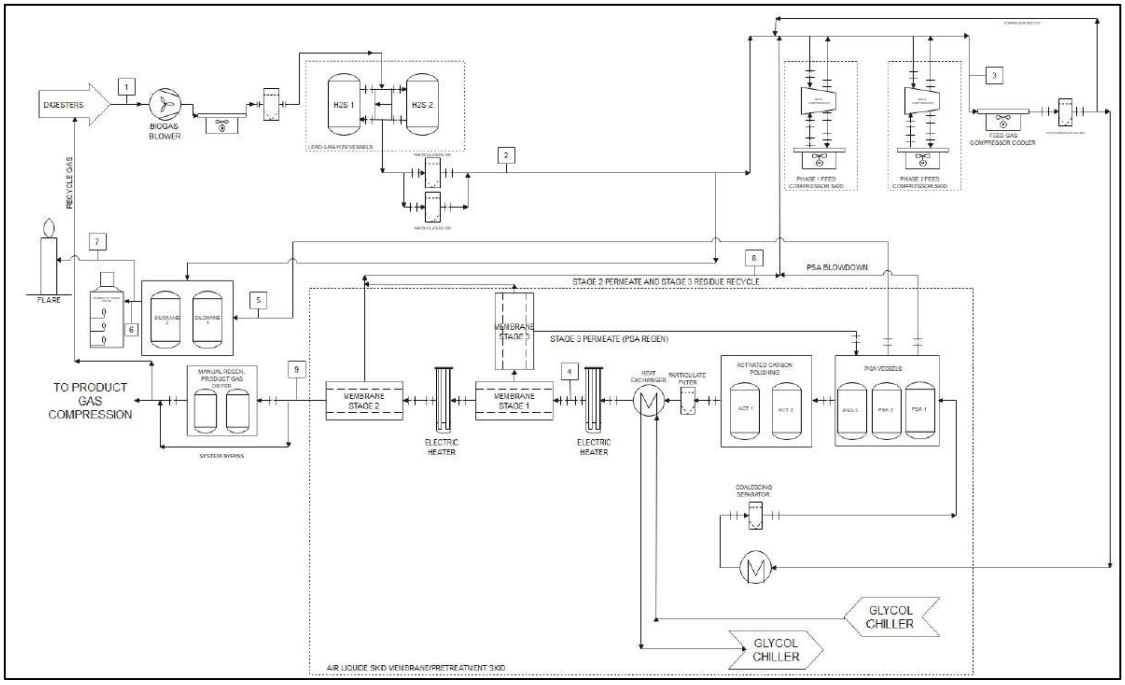


Figure 19: Process Flow Diagram

While the detail in Figure 19 is useful, a simplified PFD – shown in Figure 20 – was also provided.

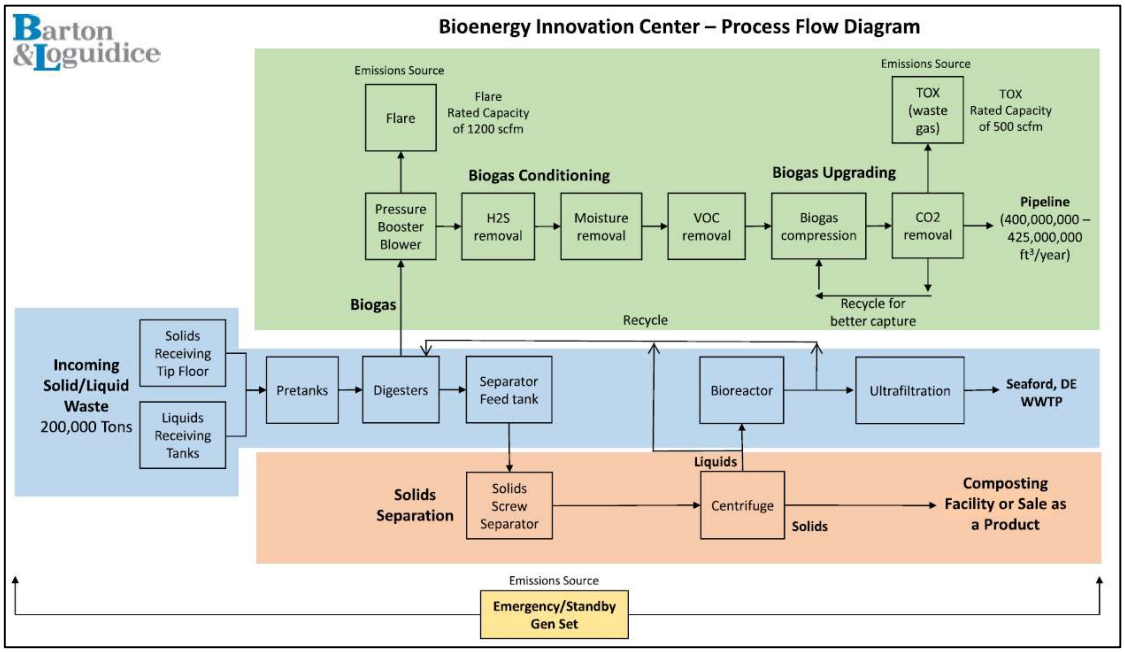


Figure 20: Simplified PFD

While the PFDs were helpful in understanding the flow, I wanted greater clarification on the potential paths through which the biogas would flow. In order to obtain that understanding, I requested "a narrative

describing the potential pathways through which biogas may travel, beginning with generation in the anaerobic digesters and concluding with the final RTO and flare emission points" in a March 30, 2022 letter in which additional information was requested. In response to this request, the following description was provided:

> *The biogas flow path has two potential routes:*
>
> *Route 1 - normal operations: biogas generated in the anaerobic digesters flow to the biogas blower to boost the pressure of the biogas to ~5psig. The biogas will then flow to activated carbon vessels to remove the H2S in the raw biogas. The biogas will be fed to a feed gas compressor, where the pressure will be boosted to ~150psig. A coalescing filter is installed after the feed gas compressor to remove any carryover of oil in the gas. The next step is PSA vessels, where the VOCs and siloxanes are removed from the biogas. The polishing vessels will remove any trace VOCs or H2S. The 3-stage membrane system will separate the CO2 from the CH4, which will be the product gas. The CO2 from this stream will contain a small amount of methane and will be sent to the regenerative thermal oxidizer (RTO). Before reaching the RTO, the tailgas stream will be scrubbed of siloxanes prior to oxidation.*
>
> *Route 2 - emergency operations to the flare: biogas generated in the anaerobic digesters flow to the biogas blower to boost the pressure of the biogas to ~5psig. The biogas will then flow to activated carbon vessels to remove the H2S in the raw biogas. After being scrubbed of H2S, the biogas will be routed to two lead-lag siloxane/VOC removal vessels to remove any contaminants before being flared.*

In addition to understanding the potential pathways through which the generated biogas could flow, I also asked whether simultaneous operation of the proposed RTO and flare was possible. In response to that question, I received the following statement:

> *The RTO and the flare would not operate simultaneously. The flare will only operate when the gas upgrading system is not receiving biogas, as explained in Question 1. The RTO is a component of normal operations, oxidizing the methane in the tailgas (waste gas) of the gas upgrading system.*

Figure 21 shows the location of the proposed equipment (see area with black border) used to filter and upgrade the biogas relative to the proposed digesters.

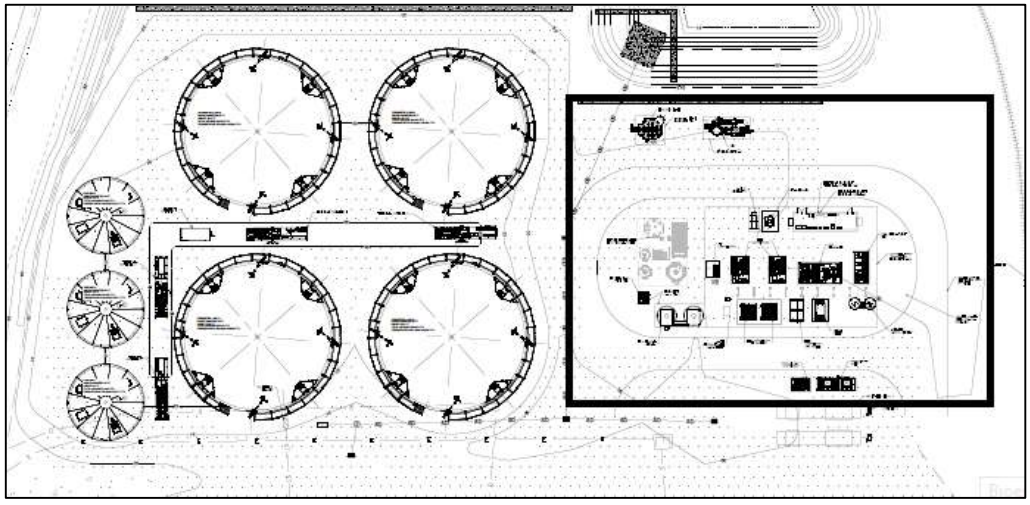


Figure 21: Location of Biogas Upgrade & Air Pollution Control Equipment Relative to Anaerobic Digesters

The following sections discuss the various aspects of the biogas conditioning and upgrade system and air pollution control equipment in greater detail.

H_2S Removal Equipment

Following the generation of biogas in the pre-tanks or digester reactors and the subsequent boosting of biogas pressure, the biogas would be designed to enter the H_2S removal vessels. The Engineering Report included in the application identified this as a pre-conditioning step. Figures 22-24 show the location of this equipment in the PFD and as shown on site drawings.

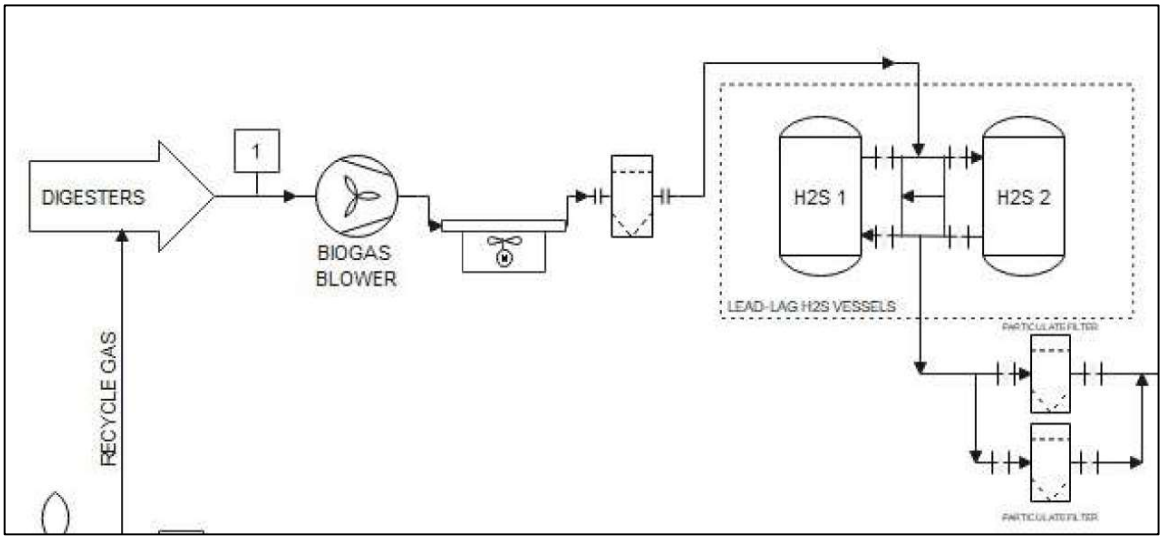


Figure 22: H_2S Removal Vessels in PFD

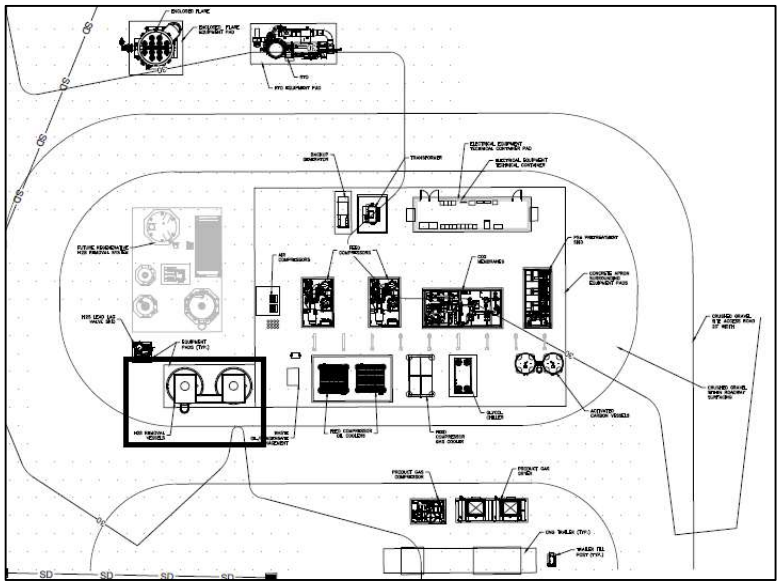


Figure 23: Location of H_2S Removal Vessels Relative to Biogas Upgrade & Air Pollution Control Equipment

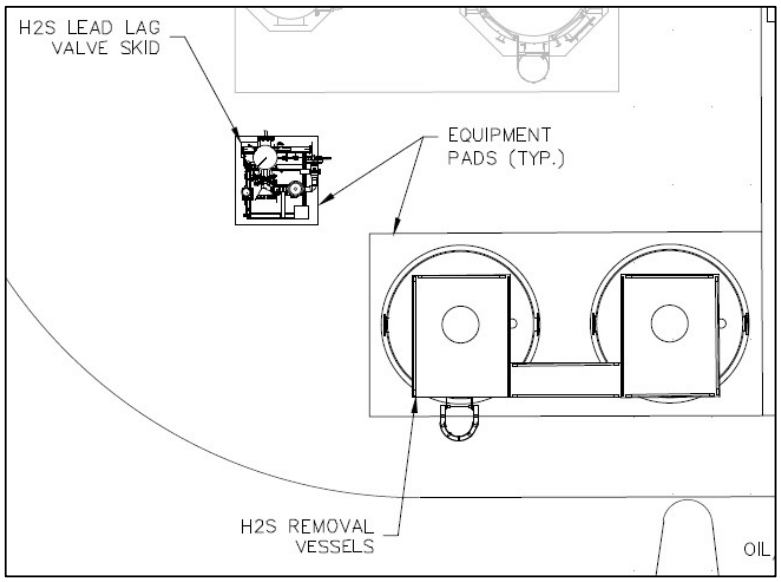


Figure 24: H_2S Removal Vessels

The following text from the "Filter Operations" section of the application describes the H_2S removal vessels proposed for use:

> *The H2S removal vessels are filled with an activated carbon. The adsorption is based on a conversion reaction that requires the presence of O2 in the gas. The vessels are designed in a lead-lag configuration to maximize carbon utilization, and can be operated in parallel or as single vessels (one online, one offline – i.e. in the event of a changeout). The first vessel in the series is used as bulk removal, and the second vessel acts as a polishing vessel to remove any trace amounts of H2S from the gas. The H2S concentration of the gas is monitored between the vessels, either by a permanent gas analyzer, or by an operator using a draeger tube. The concentration of H2S between the vessels should be 0 ppm, so any value above this would indicate that the media is saturated. Increased pressure drop across the vessels can also be an indication that the media needs to be changed. The maximum pressure drop is 63 in. water column. Operators will record the pressure drop daily, and closely monitor as the value increases toward the maximum. When a changeout is required, the vessels will switch which is lead and which is lag, so that the process does not require a shutdown, and the gas can flow through the unused media in the second bed. The estimated bed lifetime is 6 months.*

While the quoted text above includes a statement that the vessels "can be operated in parallel or as single vessels (one online, one offline – i.e. in the event of a changeout)", the subsequent sentence about using the first vessel for bulk removal and the second vessel as a "polishing vessel" suggests that this equipment will be used in series. This is supported by Item 13 on AQM-4.2 where it indicates the adsorber vessels will be operated in series.

According to Chapter 1 (Carbon Adsorbers) of an October 2018 document published by John L. Sorrels, of the Air Economics Group in the Health and Environmental Impacts Division of the EPA's Office of Air Quality Planning and Standards, and Amanda Baynham, David D. Randall, and Karen S. Schaffner, of RTI International, adsorption "is the term used for the phenomenon where gas molecules passing through a bed of solid particles are selectively held on the surface of the solid by attractive forces which are weaker and less specific than those of chemical bonds."

While the proposed equipment is advertised to adsorb the H_2S, the correct term for this is chemisorption, which is described as follows in the October 2018 document cited in the preceding paragraph:

> *"The term chemisorption is used where the gas molecules form actual chemical bonds with the adsorbent surface groups. Energy is released when a molecule from the gas stream adheres to the surface of the solid. This energy is known as the "heat of adsorption" and it typically equals or exceeds the heat of condensation. Adsorptive capacity of the solid for the gas tends to increase with the gas phase concentration, molecular weight, diffusivity, polarity, and boiling point."*

The carbon adsorption beds, which are expected to be custom manufactured by Biospark, are fixed bed and non-regenerative. As such, they will need to be replaced when they become saturated with contaminants. The application suggested that the estimated life expectancy will be 6 months, but that measurements such as the H_2S concentration (anything above 0 ppm would indicate saturated media) between vessels (as measured by either a permanent gas analyzer, or by an operator using a draeger tube) or the pressure drop (estimated range is 33-63" water column) across the bed will be used to make this determination. As previously stated, the "Filter Operations" document proposed that the pressure drop across the media would be monitored and recorded daily. The Engineering Report attached to the application stated that this media would be removed and disposed of in a landfill.

In a March 30, 2022, letter requesting additional information related to the project, I asked which method (monitoring pressure drop across media or sampling of gas between vessels) would be used to determine the point at which the media is saturated. In the response letter, dated April 7, 2022, the following answer was provided:

> *Use of both methods provides redundancy in monitoring breakthrough in the H2S and VOC/siloxane removal vessels. The pressure drop can be monitored remotely via the HMI, while the sampling between vessels will be part of the operator's daily checklist.*

In a follow-up to the initial question, I asked for information from the manufacturer of the equipment indicating the acceptable range of pressure drop across the media that would represent effective operation of the equipment. The following response was provided:

> *H2S Removal Vessels:*
> *Min: 33" WC*
> *Max: 63" WC*

In addition to this statement, the information summarized in Table 20 was provided in the response:

Make	Air Liquide
Manufacturer	Biospark
Model	Custom
Adsorber Type	Fixed Non-regenerative
Description (If the above is "Other")	Not Applicable (NA)
Maximum Gas Flow Rate to Adsorber (acfm)	1200
Maximum Temperature of Vapor Stream to Adsorber (°F)	120 (Gas Cooled by air fan)

Minimum Temperature of Vapor Stream to Adsorber (°F)	100 (Gas Cooled by air fan)
Minimum Moisture Content of Vapor Stream to Adsorber (%)	70%
Type of Adsorbent:	Cabot DARCO BG1 H2S Activated Carbon or equal + Support media (bottom layer of vessel)
Bed Height	26.5 Activated Carbon
Bed Length	36.5 Vessel with Heads and feet
Bed Width	N/A
Units (for above three dimensions)	Feet
Other Bed Dimension (optional)	Diameter
Value (for above optional dimension)	9
Units (for above optional dimension)	Feet
Minimum Pressure Drop Across Adsorbent (in. H2O)	33
Maximum Pressure Drop Across Adsorbent (in. H2O)	63
Total Weight of Adsorbent (lbs)	88000
Total Weight of Adsorbent When Saturated (lbs)	127600
Maximum adsorbent Capacity (lbs Adsorbate/lbs Adsorbent)	45%
Set-up Type	Series (Lead-Lag)
Method of Determining Breakthrough (check all that apply)	
Continuous Emissions Monitor (CEM)	No
Replacement By Weight	Yes
Periodic Testing	Yes (main)
Sampling Frequency (if periodic testing)	Continuous
Sampling Device (if periodic testing)	Online H2S analyzer
Other	No
Description (if other)	N/A
Minimum Concentration at Breakthrough (ppmvd)	8 H2S
Handling Method of Saturated Adsorbent	Disposed of off-site (Vac-truck)
Method of Regeneration (if regenerated on-site)	N/A
Alternative Method to Demonstrate Control Apparatus is Operating Properly	Monitor Pressure Drop
Comments	Two configured as Lead – Lag each 9 diameter by 36.5 feet tall

Table 20: Specifications for H_2S Removal Vessels

Below the information included in the response letter and summarized in Table 20, the following note was also provided:

> *H2S removal expected to be 100% removal efficiency assuming proper monitoring (including calibration of online H2S analyzer) of breakthrough and change out frequency of media if and when H2S breakthrough is seen.*

Since calibration and maintenance of the H_2S analyzer is an integral part in ensuring that 100% removal efficiency is achieved, I asked that BioEnergy provide the "H2S analyzer manufacturer's recommended calibration and maintenance requirements" in a May 5, 2022 letter. In BioEnergy's May 12, 2022 response, they provided a data sheet and Operator Manual for the AMI Model 3010BR Trace Hydrogen Sulfide (H_2S) analyzer. The Operator Manual included sections on "Sensor Installation/Replacement", "Calibration", "Analyzer Operation", and "Troubleshooting, Maintenance & Repairs". Reference to this document and its requirements will be included in the permit.

Item 23 of AQM-4.2 indicated that the heat of adsorption would potentially lead to temperature excursions. To understand the implications of these excursions, the following questions were asked in a March 30, 2022 letter to BioEnergy. The italicized questions were asked in the Department's March 30, 2022 letter, and the bolded italicized statements in the corresponding sub-bullets were the answers provided by BioEnergy in their April 7, 2022 response letter:

- *What causes the excursions?*
  - ***The media reacting with O2/H2O in the micropores.***
- *Is the temperature of the H2S and VOC/siloxane adsorption beds continuously monitored and recorded?*
  - ***The temperature can be seen in upstream and downstream transmitters.***
- *How long are the excursions expected to last?*
  - ***A few hours at most. The manufacturer has a method of "treating" and inerting the media prior to putting it online that has drastically reduced the temperature excursions that are typically seen. This includes introducing biogas after inerting and letting the gas assimilate with the vessel and media prior to introduction of live process gas. In the manufacturer's experience, this has reduced the length, as well as the temperature range of the excursion.***
- *What is the expected impact of the excursion on the composition of the gas stream that is eventually emitted to the atmosphere?*
  - ***Little to none, as the temperature is not changing the CH4/CO2 mixture.***
- *Are there any other expected instances where excursions are expected to occur?*
  - ***No, assuming proper procedures are followed regarding inerting.***

These responses left me with additional questions, which I addressed during a meeting with BioEnergy representatives on April 25, 2022. My understanding of their response was communicated in the May 5, 2022 letter sent to BioEnergy.

> *It is my understanding, based on responses provided during the meeting, that the excursion events are not expected to have an impact on the adsorption media's ability to fully remove the intended contaminants from the biogas stream. Please provide written confirmation that this is the case and any additional information you feel is necessary.*

BioEnergy provided the following response in a letter sent to the Department on May 12, 2022:

> ***There is no expected impact to the adsorption media due to temperature excursions.***

Similar vessels were installed at BioEnergy's facility in Jessup, MD. Figure 25 shows the vessels as they were observed during the Department's visit on March 1, 2022.

Figure 25: H_2S and VOC/Siloxane Removal Vessels at Jessup, MD Facility

Figure 25 includes both the H_2S and VOC/siloxane vessels. At the time of the inspection, BioEnergy representatives could not confidently identify which was which. As the picture suggests, the housing for the media was nearly identical.

Pressure Swing Adsorption

During normal operating conditions, biogas would enter the pressure swing adsorption (PSA) system after it has undergone filtration through the activated carbon H_2S removal vessels and another filtration system to remove moisture from the gas. The PSA works to break the biogas into two (2) portions:

- The product gas, which will later be compressed, transported by truck, and injected into the natural gas pipeline system; and
- The tailgas, which is the waste gas stream that will undergo further filtration to remove siloxanes and VOCs before it is combusted in the RTO.

In instances where the flare would be operated, the PSA system would not be involved. Instead the biogas would go from the H_2S and moisture removal systems directly to the siloxane/VOC removal vessels. Figures 26 and 27 show the location of the PSA vessels from the proposed site drawings:

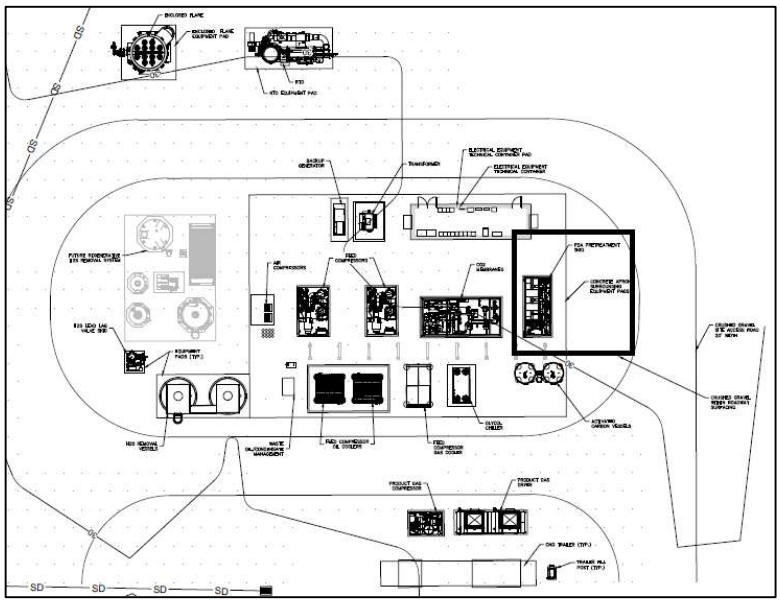


Figure 26: Location of PSA Vessels Relative to Biogas Upgrade & Air Pollution Control Equipment

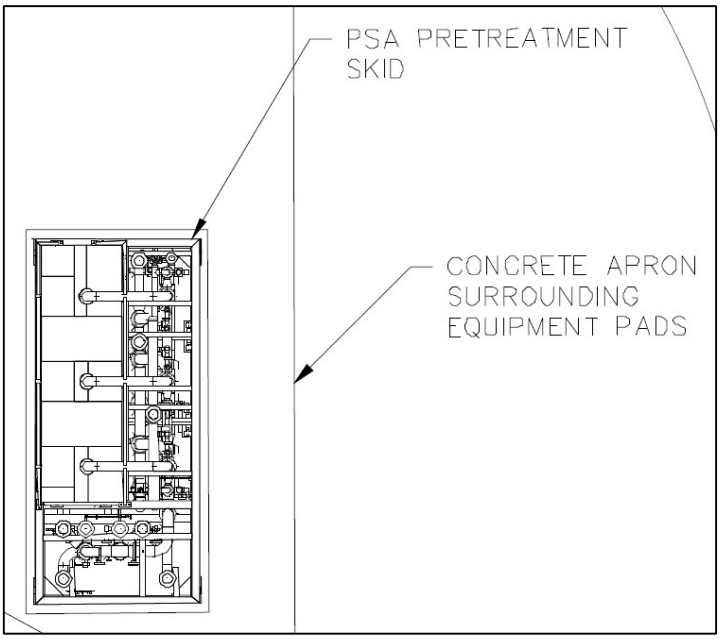


Figure 27: PSA Removal Vessels

The following text from the "Filter Operations" section of the application describes the PSA and subsequent VOC/siloxane removal vessels proposed for use:

> *VOCs and siloxanes are removed via Pressure Swing Adsorption (PSA). The VOCs are adsorbed in these vessels, and then the media is regenerated by the tailgas from the membrane system. During regeneration, the contaminants desorb from the media and the stream of gas with the contaminants goes to two lead-lag vessels through a layer of activated carbon, where physical (not chemical) removal occurs. The concentration of siloxanes is measured daily via a VOC analyzer or from a draeger tube sample between the*

> *vessels, and should be 0 ppm when the system is functioning properly. Increased pressure drop across the carbon vessels can also be an indication that the media needs to be changed. The maximum pressure drop is 60 in. water column. Operators will record the pressure drop daily, and closely monitor as the value increases toward the maximum. When breakthrough is detected, the media will be changed. Since the PSA media is regenerated, the lifetime of the media is anywhere from 3-5 years. The concentration of VOCs can be monitored quarterly (due to the extended lifetime of this media) at the outlet of the PSA vessels by the operators to determine if the media in the PSAs needs to be replaced.*

To break this down, PSA operates under the understanding that, under high pressure, gases become trapped onto solid surfaces, or adsorbed. More gas is adsorbed as the pressure is increased. When the pressure is dropped, the gas is released, or desorbed. PSA is used to separate gases in a mixture because different components of gas stream become adsorbed under different pressures.

In the case of the PSA proposed for use at BIC, the pressure will be adjusted to attract the components of the gas stream that are unwanted (namely VOCs and siloxanes). This unwanted portion of the gas stream will remain adsorbed in the bed, and the portion of the gas desired for use in the natural gas pipeline system will continue to be filtered for any remaining pollutants. Downstream of the PSA is a membrane system, which is used to separate CO_2 and other gases from the product biogas. Tailgas from the membrane system is returned to the PSA to help desorb the pollutants that were initially adsorbed.

The PSA will be manufactured by Global Welding Services. According to AQM-4.2, the operating temperature of the adsorbent will range from 40°F to 110°F. The adsorbent is expected to last 3 to 5 years and remove VOCs with 90% efficiency. The PSA would be designed to have three (3) adsorbers working in parallel so that the media is regenerated by a "CO_2-rich gas stream" every 10 minutes to its full capacity. The pollutants desorbed from the PSA and the tailgas separated by the membrane system are then filtered through two (2) VOC/siloxane removal vessels, which are discussed in the following section.

VOC/Siloxane Removal Vessels

The VOC/siloxane removal vessels will use activated carbon to remove the pollutants. A description of these vessels from the Engineering Report attached to the application is included in the preceding "Pressure Swing Adsorption" section.

Like the H_2S removal vessels, the activated carbon within the vessels is non-regenerative and will occasionally require replacement with an estimated life expectancy of 6 months. Measurements such as the concentration of siloxanes between vessels or the pressure drop across the bed will be used to make this determination. The application suggests that the siloxane concentration between vessels should be 0 ppm when the system is functioning properly, and proposes that measurements be taken daily by either a VOC analyzer, or by an operator using a draeger tube. As for the pressure drop across the media, the application indicated that a range of 40-60" H_2O would be representative of proper operation. Like the siloxane concentration, the "Filter Operations" document proposed that operators will monitor and record the pressure drop on a daily basis. The Engineering Report attached to the application stated that this media would be removed and disposed of in a landfill.

In a March 30, 2022, letter requesting additional information related to the project, I asked which method – monitoring pressure drop across media or sampling of gas between vessels – would be used to determine if the media is saturated. The following answer was provided in an April 7, 2022 response letter:

> *Use of both methods provides redundancy in monitoring breakthrough in the H2S and VOC/siloxane removal vessels. The pressure drop can be monitored remotely via the HMI, while the sampling between vessels will be part of the operator's daily checklist.*

In a follow-up to the initial question, I asked for information from the manufacturer of the equipment indicating the acceptable range of pressure drop across the media that would represent effective operation of the equipment. The following response was provided:

> *Siloxane Removal Vessels:*
> *Min: 40" WC*
> *Max: 60" WC*

According to AQM-4.2, the vessels will each have the capacity to adsorb up to 40 lbs of VOCs or siloxanes per 100 lbs of adsorbent. The vessels are expected to have the capacity to control up to 1,500 acfm of gas at 115°F with a residence time of 0.2 minutes, or 12 seconds. Item 24.1 of AQM-4.2 indicates that the estimated siloxane removal efficiency is 100%. In addition to the statement on the acceptable range of pressure drop across the siloxane removal vessels, an April 4, 2022 proposal from Greg Myrick of Air Liquide to Tressa Bathke of BioEnergy for "two (2) Activated Carbon Towers (ACTs) and associated media, valving and safeties" was provided in response to the Department's March 30, 2022 letter and included a statement that the "efficiency of VOC/Siloxane removal expected to be 100% assuming proper monitoring and change out frequency of media if and when breakthrough of contaminants are seen."

Item 23 of AQM-4.2 indicated that the heat of adsorption would potentially lead to temperature excursions. As previously discussed, this issue was discussed in letters sent on March 30th and May 5th, 2022 as well as in an April 25, 2022 meeting. BioEnergy's responses provided in letters sent on April 7th and May 12th, 2022, as well as during the April 25, 2022 meeting, indicated that the excursions would not have an impact on the emission rate of anticipated pollutants.

Similar vessels were installed at BioEnergy's facility in Jessup, MD, and were previously pictured in Figure 25. The location of these proposed vessels was not observed on site drawings.

Activated Carbon Polishing Vessels

The portion of the gas that isn't adsorbed by the PSA will undergo polishing through another set of activated carbon vessels. The following text from the "Filter Operations" section of the application describes the activated carbon polishing vessels proposed for use:

> *The polishing vessels contain a mixture of H2S and VOC removal media. The vessels are designed in a lead-lag configuration. The first vessel in the series is used as bulk removal, and the second vessel acts as a polishing vessel to remove any trace amounts of H2S or VOCs from the gas. The concentration of contaminants between vessels can be determined using a draeger tube. The concentration of contaminants between the polishing vessels should be 0 ppm, so any value above this would indicate that the media needs to be changed out. Increased pressure drop across the vessels can also be an indication that the media needs to be replaced. The maximum pressure drop is 30 in. water column. Operators will record the pressure drop daily, and closely monitor as the value increases toward the maximum. The estimated bed lifetime is 6 months.*

The activated carbon polishing vessels will be located downstream of the PSA vessels, and their proposed location on the site is shown in Figures 28 & 29.

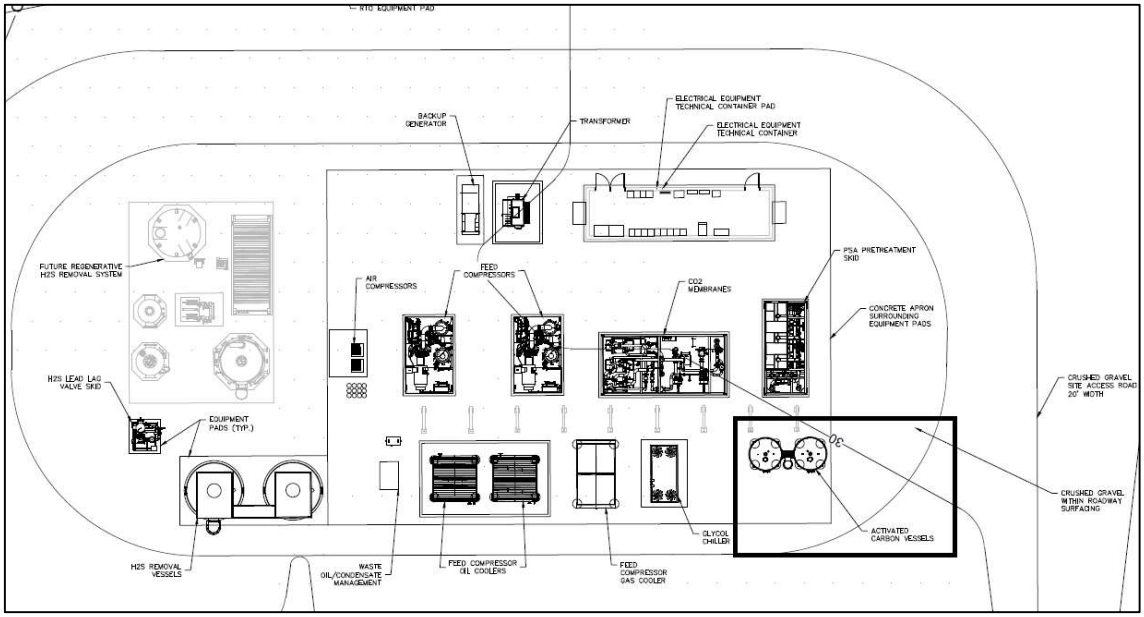


Figure 28: Location of Activated Carbon Polishing Vessels Relative to Biogas Upgrade & Air Pollution Control Equipment

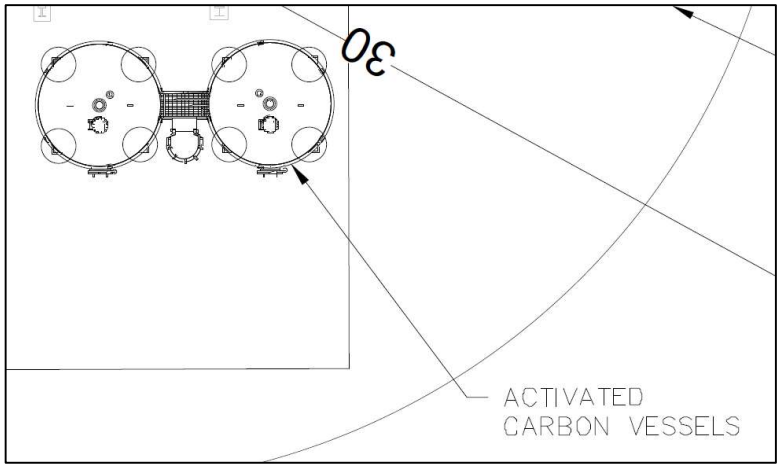


Figure 29: Activated Carbon Polishing Vessels

The polishing filters will be custom manufactured by Global Welding Services and have the capacity to adsorb up to 40 lbs of VOCs or siloxanes per 100 lbs of adsorbent. The life expectancy is about 6 months but will be monitored by monitoring and recording the pressure drop across the media. The air application indicates that the range of pressure drop which represents proper operation of the vessels is 16-30" of water column. In an April 7, 2022-dated letter response to a March 30, 2022, letter requesting additional information, the specifications in Table 21 were provided.

Make	Air Liquide
Manufacturer	Global Welding Services (GWS)
Model	Custom
Adsorber Type	Fixed Non-regenerative
Description (If the above is "Other")	Not Applicable (NA)

Maximum Gas Flow Rate to Adsorber (acfm)	200
Maximum Temperature of Vapor Stream to Adsorber (°F)	50 (Gas Cooled by Chiller)
Minimum Temperature of Vapor Stream to Adsorber (°F)	60 (Gas Cooled by air fan)
Minimum Moisture Content of Vapor Stream to Adsorber (%)	5%
Type of Adsorbent:	Calgon WS-480 + Support media (bottom layer of vessel)
Bed Height	12 Activated Carbon
Bed Length	19.4 Vessel with Heads and feet
Bed Width	N/A
Units (for above three dimensions)	Feet
Other Bed Dimension (optional)	Diameter
Value (for above optional dimension)	7
Units (for above optional dimension)	Feet
Minimum Pressure Drop Across Adsorbent (in. H2O)	16
Maximum Pressure Drop Across Adsorbent (in. H2O)	30
Total Weight of Adsorbent (lbs)	22730
Total Weight of Adsorbent When Saturated (lbs)	28400
Maximum adsorbent Capacity (lbs Adsorbate/lbs Adsorbent)	25%
Set-up Type	Series (Lead-Lag)
Method of Determining Breakthrough (check all that apply)	
Continuous Emissions Monitor (CEM)	No
Replacement By Weight	Yes
Periodic Testing	Yes (main)
Sampling Frequency (if periodic testing)	Weekly
Sampling Device (if periodic testing)	Draeger Tube or Portable Gas Analyzer
Other	No
Description (if other)	N/A
Minimum Concentration at Breakthrough (ppmvd)	10 ppm Xylene
Handling Method of Saturated Adsorbent	Disposed of off-site (Vac-truck)
Method of Regeneration (if regenerated on-site)	N/A
Alternative Method to Demonstrate Control Apparatus is Operating Properly	Monitor Pressure Drop
Comments	Two configured as Lead – Lag each 7 diameter by 19.4 feet tall

Table 21: Specifications for Activated Carbon Polishing Vessels

According to the Engineering Report, the activated carbon vessels will be followed by a feed gas compressor, which "will be used to increase the biogas temperature and pressure followed by a series of disposable particulate filters to remove moisture and bacteria from the gas prior to treatment with the membrane separation system." From there, the Engineering Report provides the following summary:

> *"The membrane separation system will be the final step of the biogas upgrade system and will separate the carbon dioxide (CO_2) and other gases from the biogas using a membrane filtration system resulting in a near*

> *pure (97 to 98.5%) methane (CH_4) stream of renewable natural gas (RNG). The tailgas, or waste gas stream will be routed to a thermal oxidizer. The membrane filters are disposable and will need to be changed once every 3 years. The filters will be disposed of at an appropriately permitted landfill."*

Additional information on the handling of biogas following this point in the process was not specified. The following question (italicized) and response (bold italicized) were asked and provided in May 5th and 12th, 2022 letters to and from representatives of BioEnergy, respectively:

> *Unrelated to questions previously asked in the March 30, 2022, request for additional information letter, it was noticed that no information regarding the on-site storage of finished biogas was provided in the application. This issue was discussed at the April 25, 2022, meeting between representatives of the Department and BioEnergy Devco. During this meeting it was indicated that no on-site biogas storage would occur downstream of the biogas upgrade system, and that all biogas produced would either be loaded onto trucks for off-site transfer or injected directly into a natural gas transmission pipeline, upon completion. Please provide written confirmation that this is the case and any additional information you feel is necessary.*
>
> ***There is no onsite biogas storage. The renewable natural gas from the biogas upgrading system will either be injected directly into a natural gas pipeline or compressed and offloaded into tube trailers for daily off-site transfer.***

For the record, at the commencement of operation of the proposed project, injection into an onsite natural gas pipeline is not expected to be available.

Regenerative Thermal Oxidizer (RTO)

The proposed RTO will be the model 5 manufactured by Griffith Consulting, LLC (GCL), and will be used to combust tailgas removed during the process of conditioning and upgrading the biogas produced in the pre-tanks and AD digesters. The following general description was provided in the October 28, 2021, Proposal for the RTO prepared by GCL:

> *Regenerative Thermal Oxidizer (RTO) with 5000 scfm capacity to be designed by GCL to reduce emissions. The 2-bed RTO is designed to provide high methane destruction.*

Following that statement, the following "Application Description" was provided in the same document:

> *Chesapeake Utilities captures biogas from a digester and then purifies it using a proprietary process. The process generates a tail gas stream that contains compounds that cannot be exhausted to atmosphere without further treatment. A regenerative thermal oxidizer is proposed that will take the tail gas and destroy the methane to a level of 98% or greater.*

Permeate/Tail Gas Definition (from Customer)

Component	***%***	***PPM***	
Methane	*1.41-5*		*Design for 0.5-6% Methane*
Carbon Dioxide	*Balance*		
Nitrogen	*0.08*		
Oxygen	*0.60*		
Water	*0.4*		
Hydrogen Sulfide		*0*	*To be removed by others prior to RTO*
VOC		*0*	*To be removed by others prior to RTO*
Siloxanes		*0*	*To be removed by others prior to RTO*

Regen/permeate gas flow is 127-720 scfm
Estimated Pressure 1 PSIG
Temperature 70°F

While Chesapeake Utilities is no longer involved in the project in the same capacity, the remainder of the information is expected to be accurate. In addition to this information, the following text was pulled from the same proposal and describes the equipment:

Thermal Oxidation
Subjecting hydrocarbon compounds to an environment of high temperature and adequate oxygen causes the hydrocarbon molecules to breakdown and their component atoms to combine with oxygen. The hydrocarbons in the process stream are converted to carbon dioxide and water with the release of additional thermal energy inside the combustion chamber. The process of regenerative thermal oxidation operates with minimal auxiliary fuel, due to the high heat transfer efficiency of the system.

This section will describe the RTO system in general. More specific information of each of the described sub-systems is included below. The RTO consists of five main parts: a valve and manifold system, a two-chamber energy recovery system and one combustion chamber with a burner system.

Valve and Manifold System
The inlet and outlet manifold system consists of the ducting at the RTO which direct processed air in and out of the energy recovery chambers through the valve system.

The RTO system includes a valve system that switches flow from one direction to the other on a timed basis.

Energy Recovery System
The energy recovery chambers are the housing for the ceramic heat recovery media and serve as a heat exchanger for the system. The two ceramic beds operate under a swing bed direct heat exchange principle. By switching towers between inlet and outlet, the flow reversal preheats the air coming into the RTO and alternately cools the air leaving the RTO by direct heat exchange with the ceramic media. The process of heat recovery using direct heat exchange combined with flow reversal is called regeneration.

As the fume stream travels through the heated bed of ceramic media, it absorbs the heat energy stored in the ceramic media mass which pre-heats the stream. The fume stream then enters the combustion chamber, where heat energy is added from the burner to reach the system operating temperature. Once the fume stream temperature has been elevated to the operating set point, the hydrocarbons in the stream are destroyed. The clean exhaust stream then passes through a cooler energy recovery chamber. As the clean exhaust stream passes through the tower, the relatively cooler ceramic media mass absorbs and stores the heat energy of the exhaust stream. This tower then becomes a relatively hotter energy recovery tower. Once the heat energy transfer is completed, the flow through the chamber is reversed, so the incoming concentrated hydrocarbon process stream is then directed through the hotter energy recovery tower and absorbs the heat from the ceramic media. By using the reversal of exhaust flow through the ceramic beds, a minimal amount of thermal energy needs to be added to the incoming process stream to maintain the system's minimum operating temperature.

RTO Heat Generation System Burner
The burner is spark ignited and is utilized to maintain the operational temperature of the combustion chamber above the minimal required control temperature to ensure adequate thermal oxidation. The burner is sized to maintain the oxidizer operational temperature at the full air volume during a zero-hydrocarbon loading condition and allow the expected system startup time from an ambient start to be no more than 60

minutes. The burner produces a reliable combustion flame with a controllable size, geometry, and heating characteristics. The burner combines the fuel and air in a manner to create a flammable stream of the gas with the proper velocity to create a steady combustion flame. The fuel and air pressures supplied to the burner allow a flame of variable size and heat input. The burner flame is continuously monitored to guarantee proper combustion when fuel is being supplied to the burner. The burner has an automatic ignition source to initiate the combustion process as required. The burner is designed to allow a large enough heating capacity to bring the combustion chamber up to operating temperature during startup. During normal operation, the burner is able to maintain a controllable flame with minimum fuel flow to provide only the minimum energy required to maintain combustion chamber temperature and minimize the potential for NOx generation.

Hot-side Bypass
This option is for solvent loading that is greater than what is required for self-sustained operation of the oxidizer to increase solvent throughput. This option consists of a high temperature valve with refractory lining, high temperature alloy metal parts, 4-20 MA pneumatic actuator with heat shield, and internally insulated bypass duct.

Fuel Train
The fuel train provides a controllable supply of natural gas to the burner and ensures proper safety and redundant isolation of the fuel supply as required. The fuel train is piped and wired with the requisite components to ensure that it complies with NFPA codes and insurance approval requirements. The fuel train uses the signal it obtains from the control system to increase or decrease the gas pressure to the burner to control the heat input. The fuel train will completely isolate the RTO system from the fuel supply using redundant and proven isolations when required.

Combustion Air System
The combustion air system provides the requisite pressure to ensure the proper air flow through the burner and provides a controllable supply of oxygen to the burner. The combustion air blower provides the motive force needed to supply the required flow of air to the burner. The control system signals for the combustion air and fuel train are dependent signals in order to provide the proper ratio of fuel and air to the burner.

RTO Fan and Motor
The RTO fan assembly provides the motive force to control the flow through the RTO system over the full range of designed volumetric flow. The RTO fan and motor can operate at variable speed using a variable frequency drive that controls the AC frequency of the power supplied to the motor. When the system is not processing a hydrocarbon exhaust stream, the RTO fan may operate at minimum flow to lower the amount of electricity required to operate the system. When the system is processing hydrocarbons, the RTO fan will automatically adjust from anywhere between the minimum and maximum flow rate based upon the amount of the inlet process stream flow. This is accomplished by monitoring and controlling the pressure of the system inlet ductwork. When the system detects a change in process exhaust flow by means of the ductwork pressure change, the RTO fan automatically compensates to change the flow through the system. The inlet pressure remains constant for minimal impact on the operation of the upstream process and the flow through the RTO system adjusts to ensure the minimum amount of energy required is used to clean the process stream.

Clean Air Stack
The clean air stack receives system exhaust from the RTO and directs it to atmosphere.

Control Panel
The control panel provides the primary user interface, monitors and records system parameters, processes the logic software and sequences, and supplies the safety and control signals to system components and interfacing systems.

The system instrumentation inputs, user inputs, and interfacing system inputs are passed to a Programmable Logic Controller (PLC) which automatically processes the information and efficiently controls the detailed operation of the RTO system. The PLC receives analog & discrete inputs from the various system devices and outputs analog & discrete signals to controlled devices. The program logic controls the overall system operation. All timing and alarm detection and annunciation controls reside in the PLC.

Alarms are generated by the PLC if any part of the system is found to not be operating properly. The PLC will automatically take the required level of initial control actions if a fault is detected to prevent the equipment from damage and to prevent inadvertent release of process contaminants if not properly processed through the abatement system. A separate, dedicated flame safety logic controller is used to control the safety features of the heat generation system to reinforce the protection from risks associated with the natural gas fuel source.

Instrumentation
The instrumentation includes the necessary pressure switches, thermocouples, solenoid valves and transmitters to control and safeguard the system.

RTO Details:
- *Maximum design air plus tail gas flow- 5000 scfm*
- *Process gas turndown: 6:1*
- *Valve for flow direction changes through media*
- *Main process fan with 25 hp TEFC motor (480 volt/3 phase/60 Hz)*
- *Combustion air blower, 1.5 hp TEFC motor (480 volt/3 phase/60 Hz)*
- *Variable frequency drives, ABB*
- *Operating Temperatures RTO chamber 1500-1600°F*
- *Thermal Efficiency 93±2%*
- *Destruction Efficiency 98%*
- *Preliminary dimensions of RTO system: 8'W x 16'L x 25'H*
- *Preliminary weight of T.O. system: 45,000 lbs.*
- *Stack*
    - *Height: 25 feet*
    - *Diameter: 24"*
    - *CS/SS*
    - *Guyed*
- *Heat recovery media chambers*
    - *Two (2) heat recovery media chambers*
    - *3/16" (4.8mm) thick CS plate, stiffened with angle iron*
    - *Refractory lining – 6" thick ceramic fiber modules*
    - *Heat recovery media bed supports*
- *Oxidation chamber*
    - *Sufficient residence time for methane destruction*
    - *Refractory lining – 6" thick ceramic fiber modules*
- *Specialty natural gas burner for incineration/thermal oxidation*
    - *Direct spark ignited*
    - *UV scanner for flame confirmation*
    - *Fully modulating firing to control RTO temperature*
- *Natural gas control train*
    - *Manual valves*
    - *Pressure regulator*

  - *Pressure gauges*
  - *Safety shutoff valves*
  - *Natural gas control valve*
- *Pre-wired control panel*
  - *PLC – Allen-Bradley*
  - *Flame Safeguard with Indicating Lights*
  - *Ignition transformer*
  - *On-Off switch*
  - *High temperature shutdown switch*
  - *Temperature controller*
- *Type K thermocouples*
- *Flame arrestor on Permeate waste gas stream*
  - *Carbon steel body*
  - *Stainless steel center section*
- *Waste gas flow meter*
  - *To be shipped loose and installed in customer's Permeate gas line from the plant to the T.O.*

As described above, the RTO would be operated with the intention of thermally destroying hydrocarbons in the gas stream, which is expected to consist primarily of CH_4. The text below explains the "Theory of Operation" for RTOs as described by the EPA's "Air Pollution Control Technology Fact Sheet" associated with the technology:

> *"RTOs use a high-density media such as a ceramic-packed bed still hot from a previous cycle to preheat an incoming VOC-laden waste gas stream. The preheated, partially oxidized gases then enter a combustion chamber where they are heated by auxiliary fuel (natural gas) combustion to a final oxidation temperature typically between 760°C to 820°C (1400 to 1500°F) and maintained at this temperature to achieve maximum VOC destruction, however, temperatures of up to 1100°C (2000°F) may be achieved, if required, for very high control efficiencies of certain toxic VOC. The purified, hot gases exit this chamber and are directed to one or more different ceramic-packed beds cooled by an earlier cycle. Heat from the purified gases is absorbed by these beds before the gases are exhausted to the atmosphere. The reheated packed bed then begins a new cycle by heating a new incoming waste gas stream."*

The following advantages and disadvantages of the technology were also listed:

> *Advantages of RTOs:*
>
> a. *Lower fuel requirements because of high energy recovery (85 to 95 percent);*
> b. *High temperature capability (up to 1100°C (2000°F)) provides better destruction efficiency over recuperative incinerators, which are generally limited to 820°C (1500°F) due to heat exchanger limitations, and catalytic incinerators, which are generally limited to 600°C (1100°F) due to catalyst limitations;*
> c. *Less susceptible to problems with chlorinated compounds; and*
> d. *Generally lower NO_X emissions than thermal oxidation (except when operating temperatures are above approximately 760°C (1400°F).*
>
> *Disadvantages of RTOs:*
>
> a. *High initial cost;*
> b. *Difficult and expensive installation;*
> c. *Large size and weight; and*
> d. *High maintenance demand for moving parts.*

From my vantage point, the advantages outweigh the disadvantages. The cost, size, and installation concerns are not disadvantages when it comes from the perspective of limiting air pollution. As indicated, the maintenance requirements will be critical to ensuring proper operation of the equipment. One item to point out is the concern for NO_X emissions. Item "d" in the list of advantages suggests that NO_X emissions may increase once operating temperatures surpass 1400°F, and the minimum combustion chamber operating temperature was listed at 1450°F in the permit application. Estimated NO_X emissions from the RTO have been modeled to ensure compliance with the Department's modeling criteria and the NAAQS, and stack testing of emissions from the RTO will also be required.

The RTO's proposed location is shown in Figures 30 and 31.

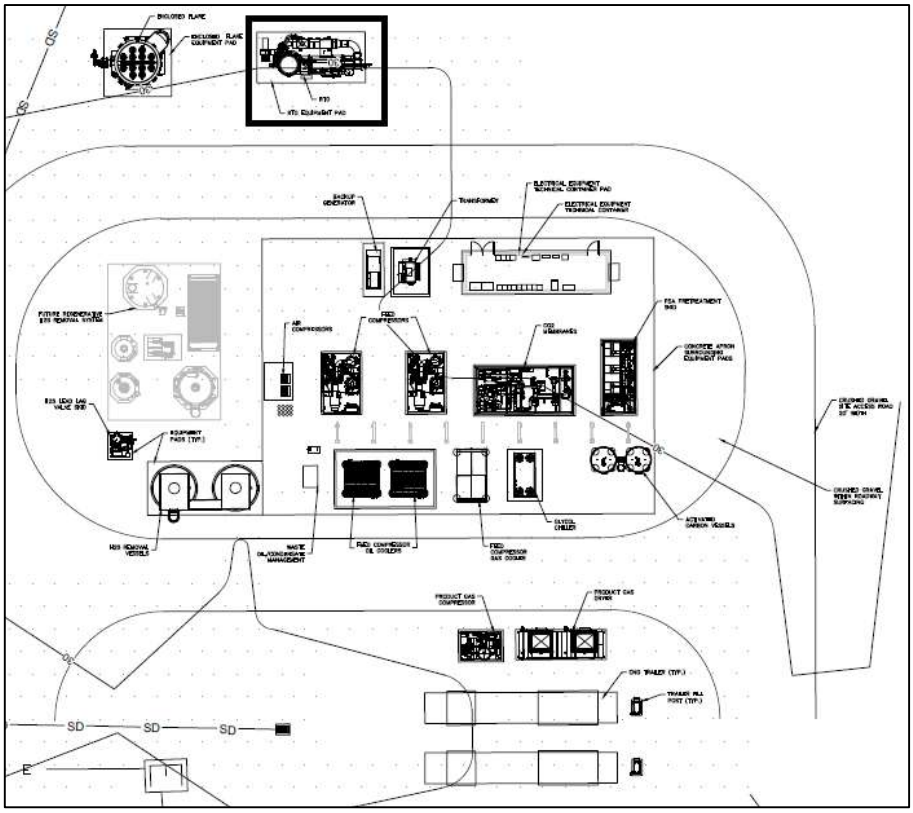


Figure 30: Location of RTO Relative to Biogas Upgrade & Air Pollution Control Equipment

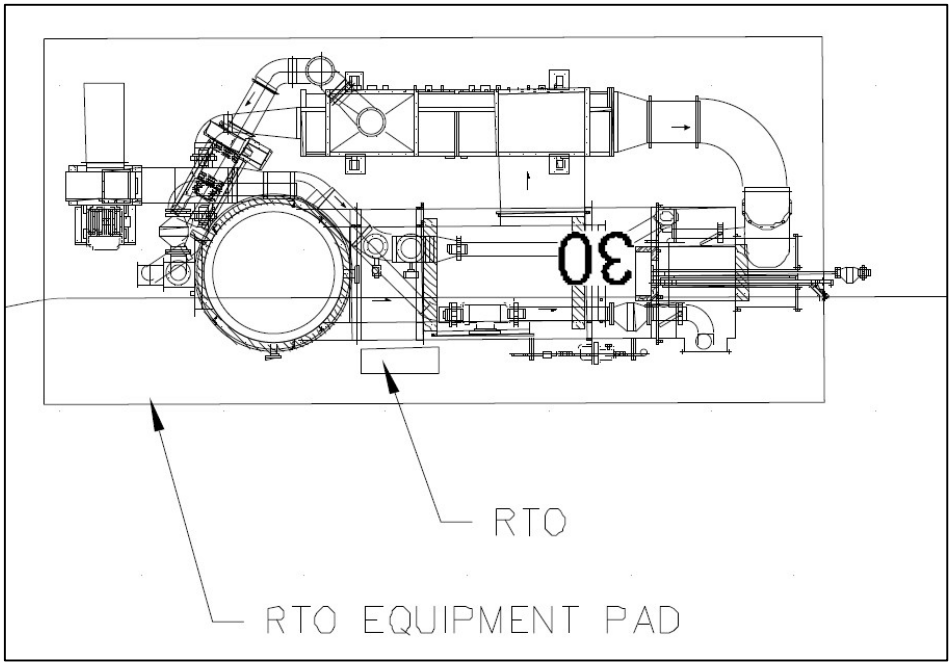


Figure 31: RTO

The image shown in Figure 32 was included on the cover of the proposal prepared by Griffith Consulting, LLC for BioEnergy Devco. While it may not be the exact model proposed for use, it is likely similar.

Figure 32: RTO Pictured on Griffith Consulting, LLC Proposal Document

While pictures of the carbon adsorption vessels at BioEnergy's Jessup, MD facility were included in preceding sections, the RTO proposed for use was not yet installed.

Flare

The flare proposed for use is a John Zink Model ZEF 10x30 elevated, non-assisted flare with natural gas as an auxiliary fuel, which will be operated to combust biogas that does not go through the process of conditioning and upgrading process due to equipment malfunction or excessive biogas production. In a March 30, 2022, letter from the Department to representatives of BioEnergy, additional information was requested on what types of "equipment malfunction" and what instances of "excessive gas production" would require the flare's operation. The following responses were provided in an April 7, 2022, letter:

> *"An equipment malfunction that would require flare operation would include any equipment downstream of the digesters, including the biogas blowers or the membrane purification system. If the equipment downstream of the digesters is not operational, the biogas will be routed to flare.*
>
> *[Excessive gas production] refers to the overproduction of biogas in the digesters. The biogas upgrading equipment is designed to treat 800 scfm of biogas for phase 1 and 1600 scfm of biogas for phase 2. If biogas production exceeds these flow rates, it will exceed the capacity of the gas upgrading system. While excessive gas production isn't expected to happen often, occasional fluctuations in feedstock could generate minor increases in biogas flow."*

The following "Process Description" was provided in the "ZEF™ Elevated Flare System Budgetary Technical and Commercial Proposal" attached to the application:

> *"Operation begins when power is applied to the system. First, gas flows to the pilot and a spark is generated to ignite the pilot flame. The automatic mode attempts to light the pilot three times. At the end of these three attempts "Pilot Flame Failure" will be illuminated and the operator will have to press the reset push-button to restart the unit. Upon proving the pilot flame with the thermocouple, the automatic block valve is opened and the gas blower is started, allowing gas flow to the flare. A thermocouple at the flare tip proves the main flame is lit.*
>
> *After the automatic block valve is opened, the pilot gas is discontinued after a timed delay to limit utility gas usage. If the main flame is detected at the flare tip, the system continues operation otherwise it is shut down by flame failure. To prevent the potential of flashback beyond the flare system, a high temperature detected by the temperature switch located at the flare inlet also discontinues system operation.*
>
> *Due to the presence of an open flame, the flare system typically is located in an electrical area classified "nonhazardous".*"

The flare's proposed location is shown in Figures 33 and 34.

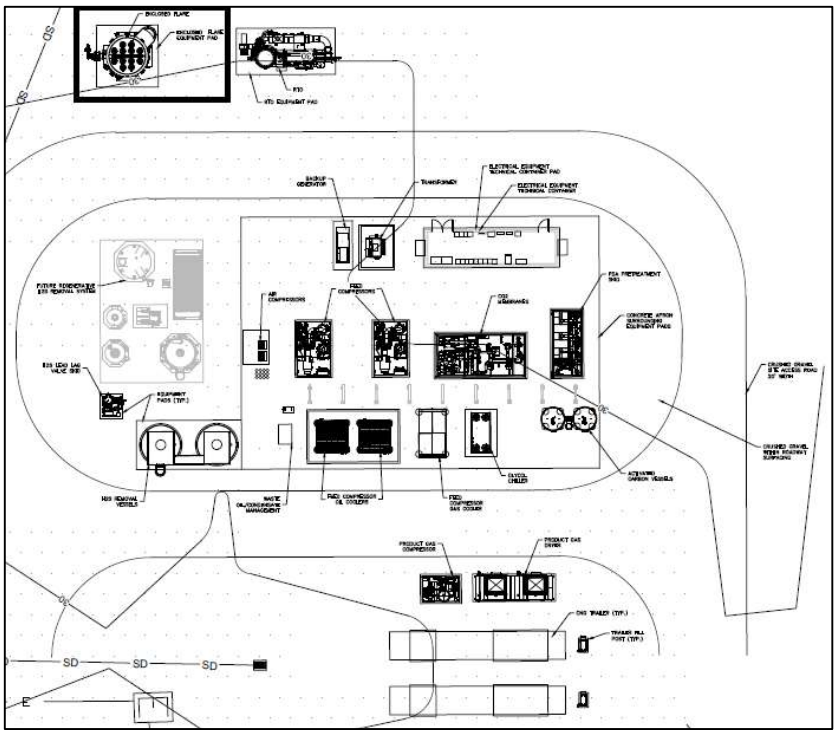


Figure 33: Location of RTO Relative to Biogas Upgrade & Air Pollution Control Equipment

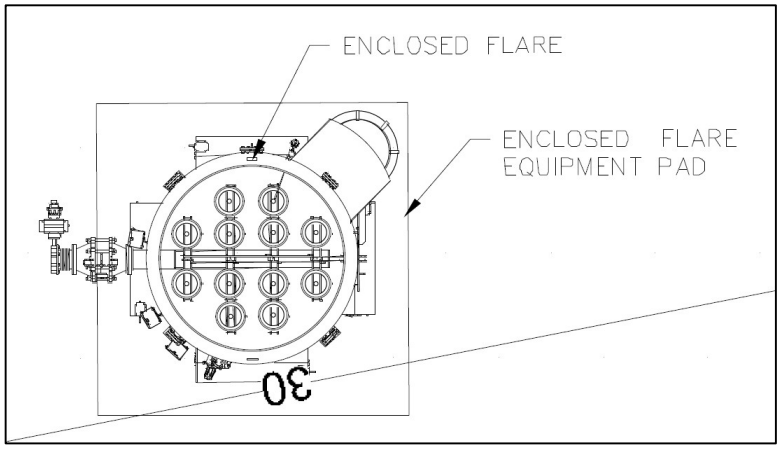


Figure 34: Flare

Attached to the application was a copy of the "ZEF™ Elevated Flare System Budgetary Technical and Commercial Proposal". Within that document were the images shown in Figures 35 & 36.

Figure 35: Image of Flare in Manufacturer's Proposal Document

Figure 36: Image of Flare in Manufacturer's Proposal Document

The proposal document included the following information:

> **Design Criteria**
> *Flare Gas Stream*
> *Type: Digester Gas*
> *Composition: 58% CH_4 (design); 50 to 62% CH_4 (range) balance CO_2, air, inerts, less than 5% O_2*
> *Lower Heating Value: 528 BTU/SCF (design), 455 BTU/SCF to 564 BTU/SCF (range)*

Temperature: 100°F
Flow Rate: 1,601 SCFM (design normalized at 58% CH_4), 310 SCFM (minimum without continuous pilot)
Heat Release: 50.7 MMBTU/hr (design at 58% CH_4)

Mechanical
Design Wind Speed (ASCE 7-95; EXP C): 120 mph
Design Seismic (UBC-1994): Zone 4
Ambient Temperature: 0°F to 100°F
Ambient Pressure: 14.7 psia
Elevation: Approx 20 feet above sea level
Electrical Area Classification: Class 1 Div 3 Group D (flare and skid)

Process
Smokeless Capacity: 100%
Required Flame Arrester Inlet Pressure: 5 inches of H_2O (design)

Utilities
Pilot Gas (intermittent): 22 SCFH of propane at 7-10 psig (or) 50 SCFH of natural gas at 10-15 psig
Compressed Air (or Nitrogen): 100 PSIG (regulated, clean and dry)
Electricity: 480 V, 3 phase, 60 Hz for motor control; transformer provided for 120 V, single phase for control system components
Auxiliary Fuel: none (pilot only)

Equipment Details
Flare
Quantity: one (1)
Material:
- *Riser: carbon steel*
- *Flare Tip: 304 stainless steel (top 5 feet)*
- *Windshield: 310 stainless steel*

Nominal Diameter: 10 in.
Nominal Stack Height: 30 ft.
Inlet Diameter: 10 in.
EEP Pilot Ignition: 6000 V electronic spark ignitor; NEMA 7 ignition panel
Pilot Confirmation: one (1) type K thermocouple
Main Flame Confirmation: two (2) type K thermocouples
Structural Anchoring: AISC continuous base plate
Lifting Lugs: two (2)

Skid Mounted Equipment
Moisture Separator:
Quantity: one (1)
Orientation: vertical
Diameter: 2 ft.
Height: 8 ft.
Separator Material: HDPE
Element Material: 304 stainless steel
Design Pressure: ±5 psig
Inlet/Outlet Diameter: 10 in.
Monitoring Equipment:
- *Sight Glass: one (1)*

Differential pressure gauge: one (1)

Blowers:
Quantity: one (1)
Manufacturer: New York Blower (or equal)
Flow at design pressure: 1,601 SCFM each
Inlet Suction: -3 inches of H_2O
Outlet Pressure: 10 inches of H_2O
Motor Power: 7.5 HP
Motor Enclosure: TEFC (NEMA)
Motor Control: variable frequency drive
Inlet Attachments:
Manual butterfly valve:
Quantity: one (1) per blower inlet
Diameter: 10 in.
Style: wafer
Body material: ductile iron
Disk: 316 stainless steel
Seat: nitrile
Manufacturer: Bray (or equal)
Flexible expansion joint: one (1) per blower inlet
Bearing Thermocouple: one (1) per blower inlet
Outlet attachments:
Manual butterfly valve:
Quantity: one (1) per blower inlet
Diameter: 10 in.
Style: wafer
Body material: ductile iron
Disk: 316 stainless steel
Seat: nitrile
Manufacturer: Bray (or equal)
Flexible Expansion joint: one (1) per blower inlet
Bearing Thermocouple: one (1) per blower inlet

Automatic Block Valve:
Quantity: one (1)
Diameter: 10 in.
Style: wafer
Actuator: pneumatic, fail closed
Body material: carbon steel
Disk: 316 stainless steel
Seat: PTFE
Manufacturer: Xomox (or equal)

Automatic Ignition and Control Station:
Panel Rack: one (1); including the following:
Power Disconnect: one (1) [480 V]
Power transformer: one (1) [480 V]
Control Panel:
Quantity: one (1)
Enclosure: weatherproof

Classified Area Operation: Z-purge panel
Certification: Underwriters Laboratory
PLC: Allen Bradly Micrologix 1400
Operator Touchscreen: 8" C-More (or equal) Color Operator Interface Panel
Data Recorder: Yokogawa 6 channel recorder
Emergency Stop Button: one (1)

Variable Frequency Drive:
Quantity: one (1) per blower
Enclosure: NEMA 3R
VFD Power: 7.5 HP
Drive Manufacturer: FUJI (or equal)

Skid Piping:
Material: 304 stainless steel
Skid Inlet Pipe Diameter: 10 in.
Skid Outlet Pipe Diameter: 10 in.
Note: Piping provided on blower skid only. Field piping is provided by others.

Shipped Loose Equipment
Flame Arrester:
Quantity: one (1)
Manufacturer: Enardo (or equal)
Diameter: 10 in.
Style: eccentric
Housing material: 304 stainless steel
Internals material: 304 stainless steel
Internal monitoring:
Thermocouple: one (1) type K thermocouple for high temperature shutdown

Flow Meter:
Quantity: one (1)
Type: thermal mass
Probe material: 304 stainless steel, Teflon coated
Manufacturer: Thermal Instruments (or equal)

Ancillary Equipment:
Vacuum Transmitter: one (1), for VFD control
Pilot Gas Spool: one (1) including, ½" piping, solenoid valve, pressure regulator, manual valve, pressure gauge
Thermocouple Wire: 400 ft.
Ignition Wire: 25 ft.

Included Field Service:
Technicians: one (1)
Trips: three (3), totaling four (4) 10-hr days onsite
Note: Days onsite are assumed to be normal business days
Note: Additional days if required are per attached technical service contract rate sheet.

The text below explains the "Theory of Operation" for flares as described by the EPA's "Air Pollution Control Technology Fact Sheet" associated with the technology:

Flaring is a VOC combustion control process in which the VOC are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote the mixing for nearly complete (>98%) VOC destruction. Completeness of combustion in a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the gas stream components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all VOC are converted to carbon dioxide and water. Incomplete combustion results in some of the VOC being unaltered or converted to other organic compounds such as aldehydes or acids.

Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Elevating the flare can prevent potentially dangerous conditions at ground level where the open flame (i.e., an ignition source) is located near a process unit. Elevating the flare also allows the products of combustion to be dispersed above working areas to reduce the effects of noise, heat, smoke, and objectionable odors.

In most flares, combustion occurs by means of a diffusion flame. A diffusion flame is one in which air diffuses across the boundary of the fuel/combustion product steam toward the center of the fuel flow, forming the envelope of a combustible gas mixture around a core of fuel gas. This mixture, on ignition, establishes a stable flame zone around the gas core above the burner tip. This inner gas core is heated by diffusion of hot combustion products from the flame zone.

Cracking can occur with the formation of small hot particles of carbon that give the flame its characteristic luminosity. If there is an oxygen deficiency and if the carbon particles are cooled to below their ignition temperature, smoking occurs. In large diffusion flames, combustion product vortices can form around burning portions of the gas and shut off the supply of oxygen. This localized instability causes flame flickering which can be accompanied by soot formation. As in all combustion processes, an adequate air supply and good mixing are required to complete combustion and minimize smoke. The various flare designs differ primarily in their accomplishment of mixing.

…

The non-assisted flare consists of a flare tip without any auxiliary provision for enhancing the mixing of air into its flame. Its use is limited to gas streams that hove a low heat content and a low carbon/hydrogen ratio that burn readily without producing smoke. These streams require less air for complete combustion, have lower combustion temperatures that minimize cracking reactions, and are more resistant to cracking.

The following advantages and disadvantages of the technology were also listed:

Advantages:

a. *Can be an economical way to dispose of sudden releases of large amounts of gas;*
b. *In many cases do not require auxiliary fuel to support combustion; and*
c. *Can be used to control intermittent or fluctuating waste streams.*

Disadvantages:

a. *Can produce undesirable noise, smoke, heat radiation, and light;*
b. *Can be a source of SO_X, NO_X, and CO;*
c. *Cannot be used to treat waste streams with halogenated compounds; and*
d. *Released heat from combustion is lost.*

With respect to the information listed above, the flare is intended to be used intermittently in cases where equipment downstream of the digesters malfunctions or there is excessive biogas production. In the case of the proposed flare, an auxiliary fuel would be used, but only to initiate combustion of the biogas stream. Once the biogas stream has ignited, the auxiliary fuel flow would cease.

While noise, smoke, heat radiation, and light are valid concerns, there is some reason for optimism that these may not be problematic at this facility. For one, the flare should only be operated intermittently during events where the biogas upgrade system has experienced a malfunction or where biogas production is excessive. The permit shall restrict flare operation to those specific instances and to a fixed volume on a rolling twelve (12) month period.

Second, the proposed location of the flare should help minimize impact to the surrounding community. As shown in Figure 37, the flare (gray bubble on map) is located more than half a mile off of Seaford Road and from the nearby Sussex Manor Mobile Home Park, with the existing building and groves of trees blocking it from sight and potentially shielding neighbors from noise impacts.

Figure 37: Proposed Flare Location Relative to Surrounding Community

Finally, Delaware regulations, which are discussed in greater detail later in this document, prevent the emission of exhaust containing an opacity of 20% or more for more than three (3) minutes during any hour. Requirements will be written into the permit requiring daily opacity observations of the equipment, when they are operated, and specifying that immediate corrective action be taken in the case where opacity is observed. It should also be noted that the flare manufacturer advertises a 100% smokeless capacity.

While it is unclear whether the flare installed at BioEnergy's Jessup, MD facility was the same as the one proposed for installation at the Seaford location, a photo of the flare from my March 1, 2022 visit to the Jessup, MD facility is shown circled in Figure 38.

Figure 38: Flare at BioEnergy's Jessup, MD Facility

EMISSION CALCULATIONS

The following sections discuss the estimation of emissions from the proposed equipment. I start by going through the methods and emission factors used to estimate emissions from the emergency generator before going into a review of how potential emissions from the anaerobic digestion system were calculated.

Emergency Generator Emissions

Of the proposed equipment, emissions from the emergency generator are the simplest to understand. The generator's engine combusts fuel, which provides mechanical power that works in conjunction with an alternator to produce electrical power. Simply, all emissions from the generator come from the combustion of fuel – in this case, natural gas. The proposed generator engine has the specifications shown in Table 22, which were used in calculating its potential to emit.

Gross Engine Power Output		Max. Heat Input Rate
kWm	Hp	MMBTU/hr
1,082	1,451	9.85

Table 22: Proposed Generator Engine Specifications

These specifications, along with the emission factors outlined in Table 23, were used to estimate hourly and annual potential emissions.

Pollutant	Emission Factor		
	Value	Units	Source
PM_{10} (Filterable)	7.71E-05	#/MMBTU	Table 3.2-2 of AP-42 Chapter 3.2
$PM_{2.5}$ (Filterable)	7.71E-05	#/MMBTU	Table 3.2-2 of AP-42 Chapter 3.2
PM Condensable	9.91E-03	#/MMBTU	Table 3.2-2 of AP-42 Chapter 3.2
Total PM	9.9871E-03	#/MMBTU	Sum of AP-42 PM Filterable & Condensable Emission Factors
SO_X	5.88E-04	#/MMBTU	Table 3.2-2 of AP-42 Chapter 3.2

Pollutant	Emission Factor		
	Value	Units	Source
NO_X	1.1	g/kWh	Manufacturer
CO	2.7	g/kWh	Manufacturer
VOCs	0.1	g/kWh	Manufacturer
CO_2	110	#/MMBTU	Table 3.2-2 of AP-42 Chapter 3.2

Table 23: Emission Factors Used to Estimate Emissions from Proposed Generator

Using the information in Tables 22 & 23, the potential emissions shown in Table 24 were calculated.

Pollutant	Potential Emissions	
	#/hr	TPY
PM_{10} (Filterable)	0.0008	0.0002
$PM_{2.5}$ (Filterable)	0.0008	0.0002
PM Condensable	0.098	0.0244
Total PM	0.098	0.0246
SO_X	0.006	0.0014
NO_X	2.624	0.6560
CO	6.441	1.6101
VOCs	0.239	0.0596
CO_2	1,083.5	270.8750

Table 24: Estimated Emissions from Operation of Proposed Emergency Generator

Unlike other sources, the annual potential to emit for emergency generators is estimated under the assumption that the generator operates 500 hours per year. This estimation method is conducted pursuant to the September 6, 1995 memorandum from John Seitz, then-Director of the Office of Air Quality Planning and Standards, titled "Calculating Potential to Emit (PTE) for Emergency Generators". The following statement is an excerpt from the memorandum:

> *"The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions."*

Anaerobic Digestion System Emissions

The process of estimating potential emissions from the operation of the AD and its associated biogas upgrade and air pollution control equipment is somewhat complicated. In discussing these emissions, I will start by focusing on the status of the various proposed equipment with respect to EPA's memorandum on determining process and control equipment before discussing the AD's potential to emit (PTE) and the emission limitations to which the proposed equipment will be held.

Process vs. Control Equipment

Because the proposed equipment involves a mix of components that will be used to clean the biogas to meet standards for its injection into the natural gas pipeline system as well as those that are strictly for reducing the pollutants released into the air, I consulted the EPA's November 27, 1995 memorandum discussing the "Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment" in order to ensure the potential to emit from the equipment was calculated appropriately. This document provides the following guidance:

> *For purposes of determining a source's potential to emit, it is necessary to calculate the effect of air pollution control equipment. Current Environmental Protection Agency (EPA) regulations and policy allow air*

> *pollution control equipment to be taken into account if federally enforceable requirements are in place requiring the use of such air pollution control equipment. There are, however, situations for which case-by-case judgements are needed regarding whether a given device or strategy should be considered as air pollution control equipment, or as an inherent part of the process. The EPA believes that the following list of questions should be considered in making such case-by-case judgements as to whether certain devices or practices should be treated as pollution controls or an inherent to the process:*
>
> 1. *Is the primary purpose of the equipment to control air pollution?*
> 2. *Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?*
> 3. *Would the equipment be installed if no air quality regulations are in place?*
>
> *If the answers to these questions suggest that equipment should be considered as an inherent part of the process, then the effect of the equipment or practices can be taken into account in calculating potential emissions regardless of whether enforceable limitations are in effect.*

During the process of preparing the application, Brian Lyncha provided the following response to these questions via email on September 24, 2021:

1. *The sole purpose of the H2S removal equipment and siloxane removal equipment is to condition the gas to meet product specifications. The purpose is not to control air pollution.*
2. *There are no product recovery elements associated with the H2S removal equipment and siloxane removal equipment.*
3. *The equipment would be installed if no air quality regulations were in place since the equipment is necessary to produce a final gas product within acceptable specifications.*

Upon reviewing these statements and additional information provided by Brian via email on October 29, 2021, I agreed with these assertions in an email sent to Brian on November 23, 2021. As I will discuss in the following subsection, my opinion changed after reviewing the information provided within the permit application and gaining a better understanding of the process.

<u>H_2S Removal Vessels</u>
Going in order of the systems in place that have an impact on the composition of the gas stream, the H_2S removal vessels come first. During my review of the permit application, I reviewed these questions in relation to the H_2S removal vessels, and drew the following conclusions:

1. Is the primary purpose of the H_2S removal vessels to control air pollution?
    a. No
2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?
    a. There is no product recovery involved.
3. Would the H_2S removal vessels be installed if no air quality regulations are in place?
    a. Yes

With regards to these vessels, I believe that their primary purpose is <u>not</u> to control air pollution. While the vessels have this added benefit, their primary purpose appears to be the removal of H_2S in order to meet standards for the gas's eventual injection into the natural gas pipeline system. This determination was supported by an October 16, 2019 letter from Cheryl Martin, VP, Rates & Regulatory Affairs of the Eastern Shore Natural Gas Company, to Ms. Kimberly D. Bose, Secretary of the Federal Energy Regulatory

Commission (FERC), which was included as an attachment in an email sent to me by Brian Lyncha on October 29, 2021. This letter included the standards for various properties of natural gas for Eastern Shore Natural Gas as well as several other upstream pipelines. Table 25 summarizes the standards included in this document:

Containment/Property	Unit	Eastern Shore Proposal	Transco	TETCO	Columbia
Heating Value	BTU/SCF	967-1100	980-1100	967-1110	967-1130
Wobbe Number	BTU/SCF	1250-1400	-	1314-1400	1350-1400
Carbon Dioxide	CO_2, % vol	≤2	-	≤2	≤1.25
Oxygen	O_2, % vol	≤0.1	-	≤0.1	≤0.02
Nitrogen	N_2, % vol	≤3	-	-	-
Total inerts	% vol	≤4	-	≤4	≤4
Hydrogen Sulfide	PPM	≤4	≤4.71	≤7.85	≤4
Siloxanes	PPM	≤1	-	-	-
Total Sulfur	PPM	≤78.5	≤314	≤78.5	≤31.4
Water	lbs/MMSCF	≤7	≤7	≤7	≤7

Table 25: Natural Gas Quality Specifications Identified in October 16, 2019 letter to Ms. Kimberly D. Bose, Secretary of the FERC

According to a spreadsheet included as an attachment in the October 29, 2021 email from Brian, the biogas is expected to have a H_2S concentration of up to 3300 ppm following its exit from the AD reactor. In my opinion, the primary purpose of the H_2S removal vessels is to reduce the concentration of H_2S in the biogas in order to meet the standard in Table 15. As such, I believe these vessels should be considered process equipment.

Pressure Swing Adsorption (PSA) System

Following the H_2S removal vessels, the next system reviewed was the pressure swing adsorption (PSA) system. I reviewed the questions outlined in the EPA memorandum with respect to the PSA system and drew the following conclusions:

1. Is the primary purpose of the PSA system to control air pollution?
    a. No
2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?
    a. There is no product recovery involved.
3. Would the PSA system be installed if no air quality regulations are in place?
    a. Yes

In my opinion, the PSA system is more of a system designed to separate components of an air stream than it is a piece of air pollution control equipment. As I will later discuss, it is also the point in the process flow where process and control equipment diverge from one another.

Similar to the H_2S removal vessels, the PSA serves to eliminate components of the biogas stream which do not meet the specifications for use in the natural gas pipeline. In this case the pollutants are VOCs and siloxanes. Prior to the PSA, the spreadsheet attached to the October 29, 2021 email from Brian Lyncha indicated that gas entering the PSA contained up to 500 mg/nm^3 of VOCs and 200 mg/nm^3 of siloxanes. While comparison against the standards in Table 15 is difficult, because these are groups of compounds rather than specific compounds, 500 mg/nm^3 of any VOC and 200 mg/nm^3 of any siloxane would translate into extremely large concentrations of the pollutants in terms of ppm.

The pollutants that are removed from the product gas stream within the PSA system are only adsorbed temporarily. Following adsorption, the pollutants are desorbed and rerouted to equipment for removal of those VOCs and siloxanes. At this point in the process, the removal of these pollutants is done in order to meet the previously referenced pipeline gas specifications. As such, I believe the PSA vessels, along with the activated carbon polishing vessels and membranes downstream of the PSA vessels, should be considered process equipment.

VOC/Siloxane Removal Vessels

Downstream of the PSA system, the vessels responsible for the removal of VOCs and siloxanes from the waste gas stream were reviewed. As shown below, I asked and answered the same three (3) questions from the November 27, 1995 EPA memorandum with respect to the VOC/siloxane removal vessels:

1. Is the primary purpose of the VOC/siloxane removal vessels to control air pollution?
    a. Yes
2. Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?
    a. There is no product recovery involved.
3. Would the VOC/siloxane removal vessels be installed if no air quality regulations are in place?
    a. No

The answers to the questions differed from those in the previous sections because the gas at this point in the process flow no longer has any value to the company. It has been separated from the components of the biogas intended for injection in the natural gas pipeline system, and is headed for the RTO. Because of this, there is no obvious purpose for the VOC/siloxane removal system at this point in the process other than to reduce the concentration of contaminants prior to combustion in the RTO. Similarly, the vessels would not likely be installed if air quality regulations were not in place. Because these questions were answered in this manner, it is my opinion that the VOC/siloxane removal vessels should be treated as air pollution control equipment.

Flare & RTO

The flare and RTO are both considered to be control equipment. Their primary purpose is to control air pollution and they would not likely be installed if it weren't for air quality regulations. As such, I believe they both meet the definition of control equipment.

Potential to Emit

Based on the determinations discussed above, the proposed equipment's potential to emit for each pollutant was calculated for each of the two (2) potential paths through which the biogas would travel:

- Normal operations (Path 1) where biogas travels through the H_2S removal vessels, PSA vessels, VOC/siloxane removal vessels, and is ultimately combusted by the RTO.
- Emergency operations (Path 2)

The following paragraphs discuss the potential emissions from each path.

Path 1

For Path 1, the PTE for each pollutant was determined to be the higher of the following scenarios:

- The potential emission rate immediately downstream of the PSA vessels, ignoring the removal efficiencies of the VOC/siloxane removal vessels and RTO control equipment; or
- The potential emission rate of the gas stream post-combustion in the RTO.

In the first scenario, the biogas has passed through the initial H_2S removal vessels and we are looking at the tailgas stream immediately downstream of the PSA vessels. At this point, VOCs and siloxanes have been stripped from the product gas stream by the PSA vessels and rerouted towards the VOC and siloxane removal vessels and RTO. In addition to VOCs and siloxanes, the gas is primarily composed of CO_2, which is removed from the product gas stream by the membrane separation system and recirculated into the remainder of the tailgas stream. The gas is expected to have the characteristics shown in Table 26:

Flowrate (SCFM)		658
Gas Composition (%)	**CH_4**	1.41
	CO_2	97.53
	N_2	0.08
	O_2	0.58
Gas Composition (mg/m³)	**VOCs**	500
	Siloxanes	200

Table 26: Composition of Waste/Tail Gas Downstream of PSA Vessels

If this gas stream were to be emitted to the atmosphere at this point in the process, Table 27 shows the potential to emit on an hourly and rolling twelve (12) month basis (assuming 8,760 hours of operation/yr).

Pollutant	Emission Rate	
	#/hr	TPY
CH_4	38	166.44
CO_2	2,615	11,453.7
N_2	2	8.76
O_2	16	70.08
VOC	1.2	5.256
Siloxanes	0.5	2.19

Table 27: PTE of Stream 1 Downstream of PSA Vessels

While the gas stream will not be emitted at this point, the equipment downstream of the PSA vessels is considered air pollution control equipment. As such, this is where we begin analyzing the proposed source's potential to emit.

In the second scenario, the gas stream reviewed in scenario 1 is subsequently filtered through the VOC/siloxane removal vessels and combusted in the RTO. Emissions from the RTO are a combination of those generated through the combustion of natural gas (the RTO's fuel source) and the combustion of the tailgas that is sent to the RTO for destruction. The emission factors outlined in Table 28 were used to estimate hourly and annual potential emissions from the combustion of natural gas.

Pollutant	Emission Factor		
	Value	Units	Source
PM_{Total}	7.6	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
$PM_{Condensable}$	5.7	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
$PM_{Filterable}$	1.9	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
SO_X	0.6	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
NO_X	100	#/MMSCF	Table 1.4-1 of AP-42 Chapter 1.4
CO	84	#/MMSCF	Table 1.4-1 of AP-42 Chapter 1.4

Pollutant	Emission Factor		
	Value	Units	Source
VOCs	5.5	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
CO_2	120,000	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
CH_4	2.3	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4

Table 28: Emission Factors Used to Estimate Emissions from Combustion of Natural Gas in Proposed RTO

Using the factors in Table 28 and the RTO's estimated hourly fuel consumption rate of 0.0007 MMSCF/yr (which translates to roughly 6.132 MMSCF/yr), the potential hourly and rolling twelve (12) month emissions in Table 29 were calculated.

Pollutant	Potential Emissions	
	#/hr	TPY
PM_{Total}	0.005	0.023
$PM_{Condensable}$	0.004	0.017
$PM_{Filterable}$	0.001	0.006
SO_X	0.001	0.002
NO_X	0.070	0.307
CO	0.056	0.258
VOCs	0.004	0.017
CO_2	84.000	367.920
CH_4	0.002	0.007

Table 29: Estimated Emissions from Combustion of Natural Gas in Proposed RTO

In addition to the natural gas combusted, emissions from the combustion of tailgas in the RTO are also expected. According to information provided in the April 7, 2022, response to the Department's March 30, 2022, request for additional information letter, the biogas directly upstream of the RTO is anticipated to contain the mass rate of pollutants summarized in Table 30.

Pollutant	Biogas Loading Rate Immediately Upstream of RTO		
	#/hr	#/day	TPY
CH_4	38	907	166
CO_2	2,615	62,770	11,455
N_2	65	51	9
O_2	65	373	68
VOC	0	0	0
Siloxanes	0	0	0

Table 30: Biogas Pollutant Loading Rate Directly Upstream of RTO (Post-VOC/Siloxane Removal Vessels)

According to estimates provided in the permit application, the pollutants and emission rates in Table 31 are expected from the combustion of the tailgas in the RTO.

Pollutant	Potential Emissions	
	#/hr	TPY
CH_4	0.76	3.329
CO_2 (pass through)	2,615	11,453.7
CO_2 (from combustion)	81	354.78
$CO_{2,\ total}$	2,696	11,808.48

Table 31: Estimated Emissions from Combustion of Tailgas in Proposed RTO

These estimates are based on the expected composition of biogas generated in the AD, the impact of the process and control equipment upstream of the RTO, and the impact of the RTO, itself. The CH_4 in the biogas stream headed to the RTO is largely expected to be converted into CO_2 and H_2O. The CO_2 present in the tailgas stream, being an inert gas, is expected to remain unchanged.

According to initial estimates, no emissions of pollutants such as NO_X, CO, VOCs, or PM were expected to be generated from the combustion of biogas in the RTO. After some additional discussion, BioEnergy later amended their emission estimates for NO_X in the event that those emissions were higher than initially anticipated. Between the combustion of natural gas by the RTO and the tailgas in the RTO, the combined, expected emissions are those summarized in Table 32.

Pollutant	Potential Emissions	
	#/hr	TPY
PM_{Total}	0.005	0.023
$PM_{Condensable}$	0.004	0.017
$PM_{Filterable}$	0.001	0.006
SO_X	0.001	0.002
NO_X	0.252	0.307
CO	0.056	0.258
VOCs	0.004	0.017
CO_2	2,780.000	12,176.400
CH_4	0.762	3.336

Table 32: Estimated Emissions from Combustion of Natural Gas & Tailgas in Proposed RTO

As previously discussed, the PTE for each pollutant is based on the higher emitting scenario (immediately downstream of PSA vessels or post-combustion in RTO). Table 33 summarizes the maximum emissions for each pollutant and the scenario in which they are expected to occur.

Pollutant	PTE		Controlling Scenario
	#/hr	TPY	
PM_{Total}	0.005	0.023	Combustion in RTO
$PM_{Condensable}$	0.004	0.017	Combustion in RTO
$PM_{Filterable}$	0.001	0.006	Combustion in RTO
SO_X	0.000	0.002	Combustion in RTO
NO_X	0.070	0.307	Combustion in RTO
CO	0.059	0.258	Combustion in RTO
VOCs	1.2	5.256	Downstream of PSA Vessels
CO_2	2,780.000	12,176.400	Combustion in RTO
CH_4	38	166.44	Downstream of PSA Vessels
Siloxanes	0.5	2.19	Downstream of PSA Vessels

Table 33: PTE of Biogas Path 1

With the exception of VOCs, CH_4, and siloxanes, the PTE for all anticipated pollutants results from combustion in the RTO. This same exercise was next conducted for Path 2.

Path 2

For Path 2, the PTE for each pollutant was determined to be the higher of the following scenarios:

- The potential emission rate immediately downstream of the H_2S removal vessels, ignoring the removal efficiencies of the VOC/siloxane removal vessels and flare control equipment; or
- The potential emission rate of the gas stream post-combustion in the flare.

In the first scenario, the biogas stream has passed through the initial H_2S removal vessels, but, due to equipment malfunction or excessive gas production, has been rerouted directly to the VOC/siloxane removal vessels and flare. In this path, the PSA vessels and other biogas upgrade equipment are bypassed. At this point in the flow, the gas is expected to have the characteristics shown in Table 34:

Flowrate (SCFM)		1,600
Gas Composition (%)	**CH_4**	62
	CO_2	50
	N_2	1
	O_2	1
Gas Composition (mg/m³)	**VOCs**	500
	Siloxanes	200

Table 34: Composition of Waste/Tail Gas Downstream of H_2S Removal Vessels

If this gas stream were to be emitted to the atmosphere at this point in the process, Table 35 summarizes the potential to emit on an hourly and rolling twelve (12) month basis (assuming 8,760 hours of operation per year).

Pollutant	Emission Rate	
	#/hr	TPY
CH_4	4,034	17,668.92
CO_2	3,260	14,280
N_2	65	286
O_2	65	286
VOC	2.8	12.264
Siloxanes	1.1	5

Table 35: PTE of Stream 2 Downstream of H_2S Removal Vessels

While the gas stream will not be emitted at this point, the VOC/siloxane and flare downstream of the H_2S removal vessels in this path are considered air pollution control equipment. As such, this is where we begin analyzing the proposed source's potential to emit.

In the second scenario, the gas stream reviewed in scenario 1 is subsequently filtered through the VOC/siloxane removal vessels and combusted by the flare. The emissions from the flare are a combination of those generated through the combustion of natural gas (the flare's pilot fuel, which is only combusted long enough to ignite the biogas stream) and the combustion of the tailgas that is sent to the flare for destruction. The emission factors outlined in Table 36 were used to estimate hourly and annual potential emissions from the combustion of natural gas.

Pollutant	Emission Factor		
	Value	Units	Source
PM_{Total}	7.6	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
$PM_{Condensable}$	5.7	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
$PM_{Filterable}$	1.9	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4

Pollutant	Emission Factor		
	Value	Units	Source
SO_X	0.6	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
NO_X	100	#/MMSCF	Table 1.4-1 of AP-42 Chapter 1.4
CO	84	#/MMSCF	Table 1.4-1 of AP-42 Chapter 1.4
VOCs	5.5	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
CO_2	120,000	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4
CH_4	2.3	#/MMSCF	Table 1.4-2 of AP-42 Chapter 1.4

Table 36: Emission Factors Used to Estimate Emissions from Combustion of Natural Gas in Proposed Flare

Using the factors in Table 36 and the flare's estimated hourly fuel consumption rate of 50 ft^3/hr (which translates to a maximum usage of 0.438 MMSCF/yr), the potential hourly and rolling twelve (12) month emissions in Table 37 were calculated.

Pollutant	Potential Emissions	
	#/hr	TPY
PM_{Total}	0.0004	0.0017
$PM_{Condensable}$	0.0003	0.0012
$PM_{Filterable}$	0.0001	0.0004
SO_X	0.00003	0.0001
NO_X	0.0050	0.0219
CO	0.0042	0.0184
VOCs	0.0003	0.0012
CO_2	6.0000	26.280
CH_4	0.0001	0.0005

Table 37: Estimated Emissions from Combustion of Natural Gas (Pilot gas) in Proposed Flare

It should be noted that these numbers, as low as they are, are likely far higher than will be achieved since natural gas is only expected to be combusted for the period of time required to ignite the biogas stream, at which point the natural gas flow will cease.

In addition to the natural gas combusted, emissions from the combustion of tailgas in the flare are also expected. According to information provided in the April 7, 2022, response to the Department's March 30, 2022, request for additional information letter, the biogas directly upstream of the flare is anticipated to contain the mass rate of pollutants summarized in Table 38.

Pollutant	Biogas Loading Rate Immediately Upstream of RTO		
	#/hr	#/day	TPY
CH_4	4,034	97,028	17,708
CO_2	3,260	78,248	14,280
N_2	65	1,565	286
O_2	65	1,565	286
VOC	0	0	0
Siloxanes	0	0	0

Table 38: Biogas Pollutant Loading Rate Directly Upstream of Flare (Post-VOC/Siloxane Removal Vessels)

Like the biogas stream combusted in the RTO, the CH_4 in the biogas stream headed to the flare is largely expected to be converted into CO_2 and H_2O. The permit application estimated a 98% CH_4 destruction

efficiency. The CO_2 in the tailgas stream, being an inert gas, is expected to remain unchanged. The permit application also provided the emission factors summarized in Table 39.

Pollutant	Emission Factor		
	Value	Units	Source
CO_2	115	#/MMBTU	Engineering Standard
NO_X	0.068	#/MMBTU	Manufacturer
CO	0.31	#/MMBTU	Manufacturer

Table 39: Emission Factors Used to Estimate Emissions from Combustion of Tailgas by Proposed Flare

It should be noted that the tailgas is expected to possess a heat content of 564 BTU/SCF and flow at a rate up to 1,600 SCFM. Using the 98% CH_4 destruction efficiency, the emission factors in Table 39, and the biogas flow specifications in the previous sentence, the pollutants and emission rates in Table 40 were estimated from the combustion of the tailgas by the flare.

Pollutant	Potential Emissions	
	#/hr	TPY
CH_4	81.000	354.780
CO_2 (pass through)	3,260.000	14,278.800
CO_2 (from combustion)	6,229.000	27,283.020
$CO_{2,\ total}$	9,489.000	41,561.820
NO_X	3.700	16.206
CO	16.800	73.584

Table 40: Estimated Emissions from Combustion of Tailgas by Proposed Flare

These estimates are based on the expected composition of biogas generated in the AD, the impact of the process and control equipment upstream of the flare, and the impact of the flare, itself. The cumulative emissions from the combustion of natural gas and tailgas by the flare are those summarized in Table 41.

Pollutant	Potential Emissions	
	#/hr	TPY
PM_{Total}	0.0004	0.002
$PM_{Condensable}$	0.0003	0.001
$PM_{Filterable}$	0.0001	0.0004
SO_X	0.0000	0.0001
NO_X	3.7	4.5
CO	16.8	20.6
VOCs	0.000	0.001
CO_2	9,495.000	41,588.100
CH_4	81.000	354.781

Table 41: Estimated Emissions from Combustion of Natural Gas & Tailgas by Proposed flare

The PTE for each pollutant is based on the higher emitting scenario (immediately downstream of PSA vessels or post-combustion by flare). It should be noted that while the potential emissions of SO_X from the flare are only expected at levels in the hundred-thousandths of a pound on an hourly basis and ten-thousandths of a ton on an annual basis, the permit includes limits on hourly emissions of the pollutant at the thousandths of a pound level. Similarly, the permit establishes limits on annual emissions of the pollutant at the thousandths of a ton level. This was done to ensure consistency with the other emission limitations and to ensure that calculations are aligned with detection capabilities. Please note that all

screening modeling was conducted at the higher limits to ensure that Department criteria to protect public health and welfare were met. Table 42 summarizes the maximum emissions for each pollutant and the scenario in which they are expected to occur.

Pollutant	PTE		Controlling Scenario
	#/hr	TPY	
PM_{Total}	0.0004	0.002	Combustion by flare
$PM_{Condensable}$	0.0003	0.001	Combustion by flare
$PM_{Filterable}$	0.0001	0.0004	Combustion by flare
SO_X	0.0000	0.0001	Combustion by flare
NO_X	3.7	4.5	Combustion by flare
CO	16.8	20.6	Combustion by flare
VOCs	2.8	12.264	Downstream of H_2S Removal Vessels
CO_2	9,495.000	41,588.100	Combustion by flare
CH_4	4,034	17,668.92	Downstream of H_2S Removal Vessels
Siloxanes	1.1	5	Downstream of H_2S Removal Vessels

Table 42: PTE of Biogas Path 2

With the exception of VOCs, CH_4, and siloxanes, all of the anticipated pollutants in Path 2 are expected to have their maximum PTE in the scenario in which biogas is combusted by the flare.

Summary

The PTE for each pollutant is the highest potential emission rate of the paths and scenarios described in the preceding sections. Table 43 summarizes the maximum emissions for each pollutant and the scenario in which they are expected to occur.

Pollutant	PTE		Path	Controlling Scenario
	#/hr	TPY		
PM_{Total}	0.0053	0.0233	1	Combustion in RTO
$PM_{Condensable}$	0.0040	0.0175	1	Combustion in RTO
$PM_{Filterable}$	0.0013	0.0058	1	Combustion in RTO
SO_X	0.0004	0.0018	1	Combustion in RTO
NO_X	3.7	4.5	2	Combustion by flare
CO	16.8	20.6	2	Combustion by flare
VOCs	2.800	12.264	2	Downstream of H_2S Removal Vessels
CO_2	9,495.000	41,588.100	2	Combustion by flare
CH_4	4,034	17,668.92	2	Downstream of H_2S Removal Vessels
Siloxanes	1.1	4.818	2	Downstream of H_2S Removal Vessels

Table 43: Final PTE of Proposed Process

It should be noted that while potential emissions of CO_2 and CH_4 are above the 100 ton per year major source threshold for "Other" pollutants (not including VOCs, NO_X, CO, SO_X, PM_{10}, & HAPs), these pollutants are considered to be greenhouse gases (GHGs). As discussed earlier in this document, a June 2014 Supreme Court ruling established that a source is only considered to be a major source for equivalent CO_2 (CO_2e) if it has the potential to emit above 100,000 TPY of CO_2e and has the potential to emit above the major source threshold for another regulated pollutant. Because this source is considered minor for all other pollutants, the proposed AD system is considered a minor source despite the elevated potential emission levels of these greenhouse gases.

Emission Limitations

The permits associated with this memorandum contain limits on the pollutants that can be emitted from the emergency generator, flare, and RTO. The following subsections discuss those emission limitations.

Emergency Generator

The permit for the proposed emergency generator contains reference to federal emission standards for NO_X, CO, and VOCs, which are required by Subpart JJJJ (4J) to 40 CFR Part 60, as well as hourly emission limits for other anticipated pollutants. Table 44 summarizes the applicable emission standards from Subpart 4J for the proposed generator engine.

Engine Type & Fuel	Maximum Engine Power	Manufacture date	Emission Standards (g/HP-hr)		
			NO_X	CO	VOC
Emergency	HP ≥ 130		2.0	4.0	1.0

Table 44: Applicable Emission Standards from Table 1 of Subpart 4J to 40 CFR Part 60

In addition to the pollutants regulated under Subpart 4J, emissions of filterable particulate matter (PM_{Filt}) will be limited to the standard specified in 7 DE Admin. Code 1104.

While the generator's PTE was calculated using 500 hours per year as a limiting factor, no such annual limits will be included in the permit. As will be discussed later in this memorandum, 7 DE Admin. Code 1144 allows unlimited operation of the generator so long as it is operated in the event of an emergency, as the term is defined by the regulation. Because of this language, I believe that limiting only the short-term emission rates is the best policy when regulating emissions from emergency generators.

RTO

Emissions from the RTO will be restricted to the rates summarized in Table 32. With that said, emissions of each type of PM will not be included. Instead, only an emission limit for PM_{Total} will be included. Hourly emissions of CO_2 and CH_4 will not be restricted. The proposed hourly and annual emission limitations are listed below:

- 0.005 lbs/hr and 0.023 TPY of PM_{Total};
- 0.001 lbs/hr and 0.002 TPY of SO_X;
- 0.252 lbs/hr and 0.307 TPY of NO_X;
- 0.056 lbs/hr and 0.258 TPY of CO; and
- 0.004 lbs/hr and 0.017 TPY of VOCs.

Flare

The application proposed limiting the flare's operations to 840.96 MMSCF/yr (representing the possible flow of gas over 2,453 hours/yr). Table 45 summarizes the emission limits that are proposed for the flare based on this usage.

Pollutant	Emission Limitations	
	#/hr	TPY
PM_{Total}	0.001	0.002
SO_X	0.001	0.001
NO_X	3.7	4.5
CO	16.8	20.6

Pollutant	Emission Limitations	
	#/hr	TPY
VOCs	0.001	0.001

Table 45: Proposed Emission Limitations for Proposed Flare

Like the RTO, emission limitations on CH_4, CO_2, and the various subtypes of PM are not proposed to be included in the permit.

AERSCREEN DISPERSION MODELING

The effects of air contaminant emissions on the public health, safety, and welfare were assessed using the Department's criteria. The criteria assume no adverse effect when the Maximum Downwind Concentration (MDC) is less than the significant impact level (SIL) for each air contaminant emitted and over each applicable averaging period. For reference a SIL is "the level of ambient impact below which the EPA considers a source to have an insignificant effect on ambient air quality." The current pollutant-specific SILs along with their respective averaging periods are summarized in Table 46.

Pollutant	Averaging Time	Significant Impact Level (µg/m^3)
CO	1-hour	2,000
	8-hour	500
NO_2	1-hour	7.5
	Annual	1.0
SO_2	1-hour	7.9
	3-hour	25
	24-hour	5
	Annual	1.0
PM_{10}	24-hour	5.0
	Annual	1.0
$PM_{2.5}$	24-hour	1.2
	Annual	0.3
Air Toxics	8-hour	TLV/100

Table 46: Significant Impact Levels (SILs) used during Modeling Exercise

According to the EPA's 2018 Guidance on SILs, the EPA believes there is a valid analytical and legal basis in most cases for the permitting authority to conclude that the proposed source will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) only after a permit applicant has shown through air quality modeling that the projected air quality impact from a proposed source for a particular pollutant is not significant or meaningful. In order to show that the proposed source will not have a significant or meaningful impact on air quality, the Department has elected to compare the AERSCREEN results against these SIL values as a compliance demonstration tool.

In the case where a pollutant-specific SIL was not available, Threshold Limit Values (TLVs) for pollutants were obtained from the *2020 TLVs and BEIs* publication from the American Conference of Governmental Industrial Hygienists (ACGIH). TLVs refer to airborne concentrations of chemical substances and represent conditions under which it is believed that nearly all workers may be repeatedly exposed, day after day, over a working lifetime, without adverse effects. The Department requires that when compared against one another, the MDC of a pollutant must be at a level no greater than 100 times less than its associated TLV in order to demonstrate that public health and safety is protected.

In utilizing AERSCREEN, emissions from the RTO and emergency generator were analyzed as point sources, while the flare was modeled as a flare. Open flares, like the one proposed at BIC are unique point sources because they do not have a defined exit diameter. For modeling it is necessary to compute equivalent emission parameters, i.e., adjusted values of temperature, stack height and "stack" inside diameter. AERSCREEN has a source category for flares and makes these adjustments internally.

The potential impact from the proposed sources was reviewed at the same time in order to ensure that cumulative impacts from the new emission sources were reviewed as a whole. As stated in the May 1999 document "Consideration of Cumulative Impacts in EPA Review of NEPA Documents", individual sources "may be insignificant by themselves, [but] cumulative impacts accumulate over time, from one or more sources, and can result in the degradation of important resources."

When assessing the cumulative impact of these sources, each source was modeled individually and the resulting MDCs within the respective averaging periods were summed and compared against the SILs for each pollutant. One important point to note is that emissions from the flare and RTO were not reviewed together because they will not operate simultaneously. In order to be conservative, the worst-case MDC between the flare and RTO was summed with the corresponding MDC for the emergency generator for comparison against the associated SIL. The individual source impacts are analyzed in the following paragraphs.

Point source variables in AERSCREEN are:

- Air contaminant emission rate (lbs/hr);
- Stack height (ft.);
- Stack inside diameter (ft.);
- Stack gas exit velocity (ft./sec) or air flow (ACFM);
- Stack gas exit temperature (°F); and
- Source location (urban or rural)

For a flare, the variables entered into AERSCREEN are:

- Air contaminant emission rate (lbs/hr);
- Stack height (feet)
- Total heat release rate (cal/sec)
- Radiative heat loss fraction

Values input for the stack parameters for the emergency generator, RTO, and flare were obtained from the permit application forms associated with each emission source. These inputs are summarized in Table 47.

Parameter	Units	Value		
		Flare	RTO	Emergency Generator
Stack Height	ft.	30	25	21
Stack Exit Diameter	ft.	0.83	2	1.33
Stack Cap Present?	N/A	No	No	Yes
Stack Configuration	N/A	Vertical	Vertical	Vertical
Stack Gas Exit Temperature	°F	500+	500	932
Stack Exit Gas Flowrate	ACFM	1,600	9,000	8,790
Total Heat Release Rate	Calories/sec	3,551,315	-	-

Table 47: AERSCREEN Inputs for Flare, RTO, & Emergency Generator

To clarify some of the information listed for the flare:

- The exhaust gas temperature was stated to be "500+ °F" in the permit application.
  - The actual temperature will depend upon the volume and composition of gas being combusted.
  - To be conservative, a value of 500°F was used.
  - The application specified that at 500°F the exhaust flowrate would be 1,600 ACFM.
- The radiative heat loss fraction was not specified. Instead the AERSCREEN default value of 0.55 was used.

Since AERSCREEN is limited to assessing impacts from a single source, each of these sources was modeled individually using the "cultivated land" surface characteristic option and assuming "Wet Conditions" as the dominant surface profile. Table 48 summarizes the distance from the stack where AERSCREEN predicted the MDC of each air contaminant would occur for each emission source as well as the distance from each source to the closest property line.

Source	Distance to MDC		Distance to Closest Property Line
	Meters	Feet	Feet
Emergency Generator	44	144	330
RTO	64	210	337
Flare	135	443	388

Table 48: Distances from Exhaust Stack to MDC & Exhaust Stack to Closest Property Line

With the exception of the flare, the MDC for each pollutant emitted by each source is expected to fall within the property lines. This suggests that the pollutant concentrations for the emergency generator and RTO should decrease as they approach and cross the property line. As the next step, the MDC for the emergency generator and the higher MDC between the RTO and flare was summed for each pollutant and compared against the SIL for the corresponding pollutant. The MDC results from AERSCREEN for each averaging period and emission source are shown in Table 49.

Pollutant	Averaging Period	Emergency Generator		RTO		Flare	
		Emission Rate (#/hr)	MDC (µg/m³)	Emission Rate (#/hr)	MDC (µg/m³)	Emission Rate (#/hr)	MDC (µg/m³)
$PM_{2.5}$	24-hour	0.098	1.625	0.005	0.04643	0.001	0.001409
	Annual		0.2708		0.007739		0.0002348
SO_X	1-hour	0.006	0.1658	0.001	0.01548	0.001	0.002348
	3-hour		0.1658		0.01548		0.002348
	24-hour		0.09947		0.009286		0.001409
	Annual		0.01658		0.001548		0.0002348
NO_2	1-hour	2.624	72.49	0.252	3.951	3.7	8.686
	Annual		7.249		0.3951		0.8686
CO	1-hour	6.441	178.0	0.056	0.9132	16.8	39.44
	8-hour		160.2		0.8218		35.50

Table 49: AERSCREEN MDCs for Each Averaging Period with an Associated SIL

For the purposes of modeling, all PM emissions were assumed to be $PM_{2.5}$. The emission factors used to estimate PM emissions from the emergency generator and RTO each came from sections of AP-42 with notes indicating that the PM was considered be less than 1.0 micrometer in diameter. PM_{10} emissions were not included because the emission rates are expected to be identical, and the SILs for the pollutant are less stringent than those for $PM_{2.5}$. It should also be noted that, in the interest of efficiency, emissions of NO_X were assumed to consist entirely of NO_2, for this run of modeling.

Between the RTO and the flare, the MDC associated for each relevant averaging period for $PM_{2.5}$ and SO_X was higher from the RTO. For NO_X and CO, however, the MDC associated with each relevant averaging period was higher from the flare. With that in mind, Table 50 summarizes the combined MDCs for the emergency generator and RTO for each averaging period and compares them to the corresponding SIL value.

Pollutant	Averaging Period	MDC (µg/m³)				SIL	MDC<SIL?
		Emergency Generator	RTO	Flare	Total	µg/m³	
$PM_{2.5}$	24-hour	1.625	0.04643	-	1.67143	1.2	No
	Annual	0.2708	0.007739	-	0.278539	0.3	Yes
SO_X	1-hour	0.1658	0.01548	-	0.18128	7.9	Yes
	3-hour	0.1658	0.01548	-	0.18128	25	Yes
	24-hour	0.09947	0.009286	-	0.108756	5	Yes
	Annual	0.01658	0.001548	-	0.018128	1.0	Yes
NO_2	1-hour	72.49	-	8.686	81.176	7.5	No
	Annual	7.249	-	0.8686	7.6441	1.0	No
CO	1-hour	178.0	-	39.44	217.44	2,000	Yes
	8-hour	160.2	-	35.50	195.7	500	Yes

Table 50: Preliminary AERSCREEN Modeling Results & Comparison to SILs

As shown above, the preliminary AERSCREEN results indicate that SO_X and CO meet the Department's modeling criteria because the combined MDC from these sources is below each of the applicable SILs. The criteria was also met for the annual SIL associated with $PM_{2.5}$, but not for the 24-hour $PM_{2.5}$ SIL or either of the NO_X SILs. As a result, $PM_{2.5}$ and both NO_2 required further review.

As previously stated, the preliminary analysis assumed that the NO_X emitted from each source consisted entirely of NO_2. This is a conservative assumption when in reality NO_X consists of other compounds, namely NO. As a secondary option, the Division has adopted use of the Ambient Ratio Method (ARM), which assumes that only 80% of NO_x emitted consists of NO_2. This method simply requires that the preliminary results for NO_2 be multiplied by a factor of 0.8; however, this method is only recommended for the 1-hr NO_2 standard. Table 51 summarizes the results when accounting for the ARM.

Pollutant	Averaging Period	MDC (µg/m³)			SIL	MDC<SIL?
		Emergency Generator	Flare	Total	µg/m³	
NO_2	1-hour	57.992	6.9488	64.9408	7.5	No

Table 51: AERSCREEN 1-hr NO_2 Analysis Using Ambient Ratio Method

While the ARM decreased the cumulative impact from the sources by 20% with regards to the 1-hr SIL, the pollutant still exceeds the NO_X SIL on a 1-hr and annual basis. Additional options for modeling this pollutant exist and were explored. For intermittent sources, such as the emergency generator, the EPA published a memo dated March 1st, 2011, and titled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour National Ambient Air Quality Standard".

In this memo, under the "Treatment of Intermittent Emissions" section, it states that "[m]odeling of intermittent emission units, such as emergency generators, and/or intermittent emission scenarios, such as startup/shutdown operations, has proven to be one of the main challenges for permit applicants." The memo continues to state that some sources will take annual limits on operation, but "actually operate far fewer hours than the permitted limit in many cases". "For example", says the memo, "an intermittent

source that is permitted to operate up to 500 hours per year, but typically operates much less than 500 hours per year and on a random schedule that cannot be controlled would be appropriate to consider under this guidance."

The memo continues to advise that "a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760." Essentially, this memo allows the reduction of hourly emissions by a factor of 0.057 (500/8,760) for the purposes of modeling emissions from the emergency generator. Multiplying this factor by the emergency generator emission rates for $PM_{2.5}$ and NO_X results in average hourly emission rates of 0.0056 and 0.15 pounds per hour, respectively.

It is my opinion that the flare also fits the description of an intermittent emission source. While it is proposed to combust up to 840,960,000 SCF/yr of biogas, which is equivalent to 2,453 hours of operation, it is not expected to operate to that extent. BioEnergy's intended product from this system is a source of pipeline quality biogas, and it is easy to understand why flaring the biogas is not a desired outcome. The flare will only operate during instances in which there is excessive gas production or the biogas upgrade system is unable to operate, and the operating schedule is expected to be sporadic. In the case of the flare, a factor of 0.28 (2,453/8,760) was applied to calculate a reduced emission factor of 1.036 pounds per hour. Table 52 provides the adjusted AERSCREEN analysis based off the reduced emission rates.

Pollutant	Averaging Period	Emergency Generator		RTO	Flare		Total	SIL	MDC<SIL?
		Emission Rate (#/hr)	MDC (µg/m³)	MDC (µg/m³)	Emission Rate (#/hr)	MDC (µg/m³)		µg/m³	
$PM_{2.5}$	24-hour	0.0056	0.0926	0.04643		-	0.1390	1.2	Yes
NO_2	1-hour	0.150	4.144	-	1.036	2.432	6.576	7.5	Yes
	Annual		0.4144	-		0.2432	0.6576	1.0	Yes

Table 52: AERSCREEN NO_2 Analysis Using ARM & Appendix W Emission Reduction for Emergency Generator

As shown in Table 52, the adjusted MDCs for each pollutant and averaging period that failed the initial analysis were below the corresponding SILs for each pollutant.

Missing from the preceding tables are emissions of VOCs. The VOC pollutant group does not have an assigned TLV, nor is there a single compound which was identified as a primary concern. In this case, the Department has historically used a value of 29 mg/m³ for analyzing modeling results for the VOC pollutant group. Like the previous modeling conducted, the 8-hr averaging period MDCs for VOCs were summed and compared against the associated TLV. The results of this analysis are summarized in Table 53.

Pollutant	Averaging Period	MDC (mg/m³)			TLV	TLV:MDC	TLV:MDC > 100?
		EG	RTO	Total	mg/m³		
VOCs	8-hour	0.239	0.000056	0.239	29	121.3	Yes

Table 53: AERSCREEN Analysis for VOCs

As shown above, the cumulative impact from VOC emissions is not expected to pose a threat to public health or safety. As such, public health and safety is presumed to be protected.

REGULATORY REVIEW

In order to determine which requirements apply to the proposed emergency generator (EG) and AD system, I completed a review of various state and federal regulations. Table 54 summarizes the state regulations reviewed and whether they were deemed applicable.

Regulation #	Regulation Name	Applicable?	
		EG	AD
1101	Definitions and Administrative Principles	Yes	Yes
1102	Permits	Yes	Yes
1103	Ambient Air Quality Standards	Yes	Yes
1104	Particulate Emissions from Fuel Burning Equipment	Yes	No
1105	Particulate Emissions from Industrial Process Operations	No	Yes
1106	Particulate Emissions From Construction And Materials Handling	No	Yes
1107	Emissions From Incineration of Noninfectious Waste	No	No
1108	Sulfur Dioxide Emissions from Fuel Burning Equipment	Yes	Yes
1109	Emissions of Sulfur Compounds From Industrial Operations	No	Yes
1110	Control of Sulfur Dioxide Emissions – Kent and Sussex Counties	No	No
1111	Carbon Monoxide Emissions From Industrial Process Operations New Castle County	No	No
1112	Control of Nitrogen Oxide Emissions	No	No
1113	Open Burning	No	No
1114	Visible Emissions	Yes	Yes
1115	Air Pollution Alert and Emergency Plan	No	No
1116	Sources Having an Interstate Air Pollution Potential	No	No
1117	Source Monitoring, Record Keeping, and Reporting	Yes	Yes
1118	Particulate Emissions from Grain Handling Operations	No	No
1119	Control of Odorous Air Contaminants	Yes	Yes
1120	New Source Performance Standards	No	No
1121	Emission Standards for Hazardous Air Pollutants	No	No
1122	Restriction on Quality of Fuel in Fuel Burning Equipment	No	No
1123	Standards of Performance for Steel Plants: Electric Arc Furnaces	No	No
1124	Control of Volatile Organic Compound Emissions	No	No
1125	Requirements for Preconstruction Review	No	No
1126	Motor Vehicle Emissions Inspection Program	No	No
1127	Stack Heights	No	No
1128	Control of Toxic Air Contaminants	No	No
1129	Emissions from Incineration of Infectious Waste	No	No
1130	Title V State Operating Permit Program	No	No
1131	Low Enhanced Inspection and Maintenance Program	No	No
1132	Transportation Conformity	No	No
1133	Motor Vehicle Pressure Test and Emission Control Device Inspection Program	No	No
1134	Emission Banking and Trading Program	No	No
1135	Conformity of General Federal Actions to the State Implementation Plans	No	No
1136	Acid Rain Program	No	No
1137		No	No
1138	Emission Standards for Hazardous Air Pollutants for Source Categories	No	No
1139	Nitrogen Oxides (NOx) Budget Trading Program	No	No
1140	Delaware Low Emission Vehicle Program	No	No
1141	Limiting Emissions of Volatile Organic Compounds from Consumer and Commercial Products	No	No
1142	Specific Emission Control Requirements	No	No
1143	Heavy Duty Diesel Engine Standards	No	No
1144	Control of Stationary Generator Emissions	Yes	No
1145	Excessive Idling of Heavy Duty Vehicles	No	Yes
1146	Electric Generating Unit (EGU) Multi-Pollutant Regulation	No	No
1147	CO_2 Budget Trading Program	No	No
1148	Control of Stationary Combustion Turbine Electric Generating Unit Emissions	No	No

Regulation #	Regulation Name	Applicable?	
		EG	AD
1149	Regulations Governing the Control of Noise	Yes	Yes
1150	Outer Continental Shelf Air Regulations	No	No
1151	Prohibitions on Use of Certain Hydrofluorocarbons in Specific End-Uses	No	No

Table 54: Applicability of State Air Quality Regulations

The following paragraphs discuss the specific applicability of each state regulation reviewed.

7 **DE Admin. Code** 1101, *Definitions and Administrative Principles* was reviewed while writing this permit. This regulation includes definitions of words and phrases as well as administrative principles which apply to all regulations, unless the specific regulation indicates otherwise. This regulation was deemed applicable to the proposed emergency generator and AD system.

7 **DE Admin. Code** 1102, *Permits*, was reviewed and deemed applicable. Section 2.1 states that *"Except as exempted in 2.2 of this regulation, no person shall initiate construction, install, alter, or initiate operation of any equipment or facility or air contaminant control device which will emit or prevent the emission of an air contaminant prior to receiving approval of his application from the Department".* Section 2.2 states that *"a permit for installation, alteration, or operation pursuant to this regulation shall not be required for the following equipment or air contaminant control device"* provided that 7 **DE Admin. Code** 1125 does not apply:

> *2.2.1. Equipment without an air contaminant control device that has actual emissions to the atmosphere of any air contaminant or contaminants, in the aggregate, during each and every day that are less than 0.2 pound per day, provided that:*
>
> *2.2.1.1. The actual emissions are quantified and documented; and*
> *2.2.1.2. Records are maintained at the facility and are made available to the Department upon request which document that the equipment qualifies for this exemption.*
>
> *2.2.2. Equipment with an air contaminant control device that has actual emissions to the inlet of the air contaminant control device of any air contaminant or contaminants, in the aggregate, during each and every day that are less than 0.2 pound per day, provided that:*
>
> *2.2.2.1. The actual emissions are quantified and documented; and*
> *2.2.2.2. Records are maintained at the facility and are made available to the Department upon request which document that the equipment qualifies for this exemption.*
>
> *2.2.3. The equipment listed in **Appendix A** of this regulation.*
>
> *2.2.4. For operation, any equipment or air contaminant control device that is specifically identified in an operation permit issued pursuant to 7 **DE Admin. Code** 1130.*
>
> *2.2.5. Equipment that is registered pursuant to 9.0 of this regulation.*

The proposed emergency generator does not have any associated air pollution control equipment and has the potential to emit aggregate emissions above 0.2 pounds per day. As for the proposed AD, the process includes air pollution control equipment, so Section 2.2.1 does not apply. With regards to Section 2.2.2, the proposed AD process would generate a gas stream that would contain actual emissions to the inlet of the

air pollution control devices of air contaminants, in the aggregate, during each and every day that are greater than 0.2 pound per day.

In relation to Section 2.2.3, Appendix A of this regulation includes a list of equipment exempt from the requirement to obtain a permit, but no exemptions exist for any of the components of the proposed project. Item 32 of Appendix A states that emergency generators are exempt from permitting requirements if they have a standby power rating of 450 kW or less, but the proposed generator is rated just above 1,000 kW.

With regards to Section 2.2.4, none of the equipment or air contaminant control devices are identified in an operation permit issued pursuant to 7 **DE Admin. Code** 1130. Finally, with regards to Section 2.2.5, none of the equipment is eligible to be registered pursuant to Section 9.0 of the regulation.

Section 2.1.3 states that "for equipment, a facility or an air contaminant control device that is not subject to 2.1.1 [equipment for which a registration must be obtained] or 2.1.2 [equipment for which a source category permit must be obtained] of this regulation, the person shall submit to the Department an application for a permit pursuant to 11.0 of this regulation." The application submitted on January 13, 2022 satisfies this requirement. Obtaining an air permit is necessary for the construction of the proposed emergency generator and AD, along with the associated equipment that have an impact on the generation, formation, or reduction of air pollutants.

Upon completion of construction, representatives of BioEnergy Devco shall contact the Department to schedule a "construction-to-operation" inspection of the generator and AD process. Assuming this inspection is successful (equipment constructed matches application, equipment is operating properly, procedures are in place to comply with permit requirements, etc.), the construction permit would then be converted to an operating permit. This project may require more than one construction-to-operation inspection, as the AD reactors are expected to be built in phases.

7 **DE Admin. Code** 1103, *Ambient Air Quality Standards*, is applicable. Emissions from the proposed flare, RTO, and emergency generator were modeled using AERSCREEN, and the results were compared against the NAAQS and other Department criteria to ensure protection of the health and safety of surrounding communities. Additional information is available in the "AERSCREEN Dispersion Modeling" section of this memorandum.

7 **DE Admin. Code** 1104, *Particulate Emissions from Fuel Burning Equipment*, was reviewed to determine applicability. Section 1.1 states that the "emission of particulate matter from fuel burning equipment shall be controlled to a limit that shall meet the ambient air quality requirements." As previously discussed, the downwind concentration of each anticipated air pollutant – including particulate matter – was modeled and compared against Department criteria and the NAAQS to ensure protection of the health and safety of the surrounding community.

Section 1.2 states that the provisions of the regulation do not apply to equipment with a heat input capacity of less than 1,000,000 BTU/hr (1 MMBTU/hr). According to information provided in the application, the emergency generator has a maximum heat input capacity of 8.95 MMBTU/hr.

Section 2.1 of this regulation limits emissions of particulate matter from equipment like the proposed emergency generator to less than or equal to 0.3 pounds per million BTU (lb/MMBTU) heat input on a maximum two-hour average. Section 2.2 of this regulation includes the same numerical limitation (0.3

lb/MMBTU), but states that it cannot be exceeded on a maximum 30-day rolling average. No reference to the standard set in Section 2.2 will be included in the permit because the 2-hour average set in Section 2.1 is more restrictive.

Based on the definition of particulate matter provided in 7 **DE Admin. Code** 1101 ("Particulate matter" means material, other than uncombined water, which is suspended in or discharged into the atmosphere as a liquid or solid), my interpretation is that this standard only applies to emissions of filterable particulate matter (PM_{Filt}). The emission factor for PM_{Filt} obtained from AP-42 suggests that the generator would emit far below this standard (0.0000771 lbs PM_{Filt}/MMBTU). Compliance with this standard will be demonstrated by combusting only natural gas and maintaining records showing the type and volume of fuel combusted.

As for the AD system, the RTO and flare are considered air pollution control equipment which are responsible for controlling emissions generated by the AD system. Section 1.3 states that the "provisions of this regulation shall not apply to equipment or operations whose emissions are controlled by 7 DE Admin. Code 1105 [Particulate Emissions from Industrial Process Operations] or 7 DE Admin. Code 1107 [Emissions From Incineration of Noninfectious Waste] or 7 DE Admin. Code 1129 [Emissions from Incineration of Infectious Waste]." It is my opinion that the flare and RTO are subject to the requirements of 7 DE Admin. Code 1105, as will be discussed in the next section.

7 **DE Admin. Code** 1105, *Particulate Emissions from Industrial Process Operations*, was also reviewed for applicability. According to the definition listed in 7 DE Admin. Code 1101, the term "Process operation" means "any chemical, industrial, or manufacturing operation including, but not limited to, heat transfer, fluid flow, evaporation, humidification, absorption, extraction, distillation, drying, mixing, classification, sedimentation, decantation, filtration, crystallization, centrifugation, disintegration and material handling." Based on this definition it is my opinion that this regulation does not apply to the proposed emergency generator, but that PM emissions released from the AD system (through the RTO or flare emission points) are subject to the requirements of this regulation.

Section 1.1 requires that "emission of particulate matter from industrial process equipment shall be controlled to a limit that shall meet the ambient air quality requirements." As discussed in the section summarizing the applicability of 7 DE Admin. Code 1103, the maximum downwind concentration of each pollutant from the RTO and flare was modeled and compared against the Department's criteria to ensure the protection of public health.

To help enforce this requirement, Section 2.1 prohibits "particulate emissions into the atmosphere from any source not provided for in subsequent sections of this Regulation in excess of 0.2 grains per standard cubic foot." Based on the definition of particulate matter provided in 7 **DE Admin. Code** 1101, my interpretation is that this limit only applies to emissions of filterable particulate matter (PM_{Filt}). PM_{Filt} emissions from the RTO are expected to be released at a rate of 0.001 lbs/hr with an estimated exhaust flowrate of up to 9,000 acfm. The following shows the anticipated PM_{Filt} emission rate based on these assumptions.

$$\frac{0.001\ lbs\ PM_{Filt}}{hr} \times \frac{1\ hr}{60\ minutes} \times \frac{7{,}000\ grains}{1\ lb} \times \frac{minute}{9000\ ft^3} = \frac{0.000013\ grains}{ft^3}$$

Assuming a consistent emission rate of 0.001 lbs PM_{Filt}/hr, the exhaust flowrate from the RTO would only have to exceed 0.583 ft^3/minute in order to meet this standard.

The same analysis was performed on the flare with a PM_{Filt} emission rate of 0.0001 lbs/hr and an exhaust flowrate of up to 1,600 acfm.

$$\frac{0.0001\ lbs\ PM_{Filt}}{hr} \times \frac{1\ hr}{60\ minutes} \times \frac{7{,}000\ grains}{1\ lb} \times \frac{minute}{1{,}600\ ft^3} = \frac{0.0000073\ grains}{ft^3}$$

In either case, the emissions of PM from the RTO and flare are expected to meet this emission standard.

7 **DE Admin. Code** 1106, *Particulate Emissions From Construction And Materials Handling*, was reviewed for applicability. According to Section 1.0, the "purpose of this Regulation is to control particulate emissions from construction and materials handling operations to a limit so as not to cause a condition of air pollution." I reviewed the requirements while considering the construction of the proposed equipment as well as the subsequent operation.

Sections 2.0 and 3.0 focus on "Demolition" and "Grading, Land Clearing, Excavation and Use of Non-Paved Roads", respectively. While the activities associated with the proposed project do not appear to involve demolition, the following requirements shall apply in any instances where demolition may be required:

2.1. No person shall cause or allow the demolition of existing structures, buildings, or parts of buildings, in New Castle County or in incorporated areas of Kent County and Sussex County unless methods are employed to control dust emissions.
2.2. Such methods may include the application of water or the use of other techniques approved by the Department.
2.3. The restriction in 2.1 of this regulation may be extended to unincorporated areas of Kent County and Sussex County in situations where the Department determines that demolition activities could emit dust in quantities sufficient to cause air pollution.

The access road to the site is currently a non-paved gravel road. The lone requirement from Section 3.0 is as follows:

> *"No person shall cause or allow land clearing, land grading (including grading for roads), excavation, or the use of non-paved roads on private property unless methods, as indicated in 2.2 of this regulation, are employed to control dust emissions, when the Department determines that such activities could emit dust in quantities sufficient to cause air pollution."*

In summary, any demolition or use of the non-paved road as part of the construction of this project (or as part of normal site operations in the case of the non-paved road) shall be performed in a manner that employs dust control measures to minimize the generation of PM emissions.

While the transport and handling of the solid and liquid feedstocks proposed for use as part of this project are not expected to generate emissions of PM, the following language from Sections 4 and 6, respectively, will be included in the permit.

> *"No person shall cause or allow visible particulate emissions of any material being transported by a motor vehicle."*

> *"No person shall cause or allow stockpiling or other storage of material or transport to or from a storage facility in such a manner as may cause a condition of air pollution."*

These requirements are covered in Conditions 2.2 (under "other activities") and Condition 3.1.7 of the permit, respectively.

7 **DE Admin. Code** 1107, *Emissions From Incineration of Noninfectious Waste*, was reviewed and deemed inapplicable. The incineration of waste (noninfectious or otherwise) is not a component of the proposed project.

7 **DE Admin. Code** 1108, *Sulfur Dioxide Emissions from Fuel Burning Equipment*, was reviewed while writing this document. This regulation requires that emissions of SO_2 from fuel burning equipment be controlled to a limit that meets ambient air quality requirements. As discussed in the "AERSCREEN Dispersion Modeling" section of this memorandum, downwind concentrations of SO_2 from the proposed equipment are not expected to contribute to an exceedance of the SO_2 NAAQS or the Department's modeling criteria.

This regulation also focuses on the sulfur content of fuels, with a specific focus on liquid distillate or residual fuels. Aside from distillate and residual fuels, Section 2.3.3 of this regulation requires that "any other fuel" shall possess a sulfur content no greater than 1.0% by weight. The tailgas combusted by the flare and RTO is not considered a fuel but will first be pre-conditioned to remove H_2S from the gas. It is not expected to contain an appreciable amount of sulfurous compounds. The emergency generator, RTO, and flare will combust natural gas, which is expected to contain a sulfur content well below this standard.

Compliance with the requirements of this regulation shall be demonstrated by combusting natural gas, through proper operation and maintenance of the H_2S removal vessels, and by generating and maintaining corresponding records. For reference, proper operation and maintenance of the H_2S removal vessels shall involve monitoring and recording the pressure drop across the media on a daily basis, and sampling of the biogas between vessels via a continuous H_2S analyzer to ensure breakthrough has not occurred.

7 **DE Admin. Code** 1109, *Emissions of Sulfur Compounds From Industrial Operations*, was reviewed for applicability. Section 1.1 states that the "emission of sulfur dioxide from process operations shall be controlled to a limit that shall meet the ambient air quality requirements." According to the definition listed in 7 DE Admin. Code 1101, the term "Process operation" means "any chemical, industrial, or manufacturing operation including, but not limited to, heat transfer, fluid flow, evaporation, humidification, absorption, extraction, distillation, drying, mixing, classification, sedimentation, decantation, filtration, crystallization, centrifugation, disintegration and material handling."

Based on this definition it is my opinion that this regulation does not apply to the proposed emergency generator, but that SO_2 emissions released from the AD system (through the RTO or flare emission points) are subject to the requirements of this regulation. As discussed in the "AERSCREEN Dispersion Modeling" section of this memorandum, the downwind concentrations of SO_2 from the RTO and flare are not expected to contribute to an exceedance of the SO_2 NAAQS or other Department criteria. No other requirements from this regulation were deemed applicable.

7 **DE Admin. Code** 1110, *Control of Sulfur Dioxide Emissions – Kent and Sussex Counties*, was reviewed for applicability because the proposed equipment would be located in Sussex County. Section 2.0 of this regulation focuses on "Requirements for New Sources of Sulfur Dioxide". Section 2.3 states that "[e]missions of sulfur dioxide from watercraft and from sources where less than 3.0 pounds per hour of sulfur dioxide are discharged, are excluded from the provisions of this regulation." The estimated hourly

emissions of SO_2 from the emergency generator, flare, and RTO are each expected to be well below the applicability threshold. The proposed equipment is considered exempt from the regulation's requirements.

7 **DE Admin. Code** 1111, *Carbon Monoxide Emissions From Industrial Process Operations New Castle County*, was reviewed and deemed inapplicable. The proposed project is located in Sussex County.

7 **DE Admin. Code** 1112, *Control of Nitrogen Oxides Emissions*, does not apply because the facility is not expected to be a "Major nitrogen oxides (NO_X) emitting source", as the term is defined in Section 2.0. This regulation defines a "major nitrogen oxides (NO_X) emitting source" as a stationary source which emits or has the potential to emit at a rate greater than 100 tons per year in Sussex County. The proposed equipment, along with the existing compost process and emergency generator engine, are expected to emit well below the regulation's applicability threshold.

7 **DE Admin. Code** 1113, *Open Burning*, was reviewed and deemed inapplicable. According to Section 3.0 of the regulation open burning means "any outdoor fire or outdoor smoke-producing process from which the products of combustion are emitted directly into the ambient air", but "does not include incinerators, boilers, or heaters used in process operations." No open burning is expected to occur as part of the construction or subsequent operation of the proposed equipment.

7 **DE Admin. Code** 1114, *Visible Emissions*, was reviewed and deemed applicable to the proposed equipment. This regulation prohibits the emission of visible air contaminants or smoke with opacity greater than 20% for more than 3 minutes in any 1-hour, or more than 15 minutes in any 24-hour period. No method of demonstrating compliance with this standard was proposed in the permit application. After discussing with Joanna French, we agreed that requiring daily qualitative visible emission observations of the RTO and, when applicable, flare and emergency generator, would be better than less frequent standard visible emission observations. Those observations shall be conducted as follows:

- The observations shall be conducted over a period of time sufficient to determine whether the emission points are emitting visible air contaminants.
    - For the emergency generator, operation simply means combusting natural gas.
    - In the case of the RTO and flare, operation means the combustion of the tailgas generated by the AD system.
- Observations shall not be required on days in which the applicable equipment does not operate or in certain other instances in which an observation is not possible.
- This procedure does not require that the opacity of the emissions be determined.
    - Since this procedure requires only the determination of whether a visible emission occurs and does not require the determination of opacity levels, observer certification according to the procedures of EPA Reference Method 9 (40 CFR 60, Appendix A) is not required.
    - It is necessary that the observer is educated on the general procedures for determining the presence of visible emissions.
    - At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions.
- If visible emissions are observed:
    - The owner or operator shall take corrective action(s) to eliminate the cause of the opacity and repeat the qualitative observation to determine if the actions were effective.

  - For the emergency generator, if corrective action does not eliminate the excess opacity observed during the qualitative visible emission observation, the generator shall be shut down until the cause of the opacity has been determined and corrected.
  - For the RTO and flare, the owner or operator shall continue taking corrective action until the opacity has been eliminated.
- If no visible emissions are observed, no further action is required.
- Each observation, and any associated actions taken to address observed opacity, shall be recorded and maintained in a manner suitable for review.

7 **DE Admin. Code** 1115, *Air Pollution Alert and Emergency Plan*, and was deemed inapplicable. This regulation outlines the Department's plans to ensure that air contaminants in the atmosphere do not increase in concentration to a degree that would be detrimental to the health, welfare and safety of the population during adverse weather conditions.

7 **DE Admin. Code** 1116, *Sources Having an Interstate Air Pollution Potential*, was reviewed and deemed inapplicable. According to Section 3.2, "All new sources of air contaminants, whose emissions are carried into a neighboring state, shall control their emissions to such an extent as to not substantially affect the ambient air quality of the receptor state." Based on the measurement tool available through Google Maps, the proposed equipment will be located nearly 5.5 miles away from the closest border of Delaware and Maryland. Emissions from the proposed equipment are not anticipated to travel that distance in a concentration that would substantially affect the ambient air quality of Maryland.

7 **DE Admin. Code** 1117, *Source Monitoring, Record Keeping, and Reporting*, applies for Section 2.0, but not for 3.0, 4.0, 5.0, 6.0, or 7.0. Section 2.0 pertains to general "Sampling and Monitoring" requirements the owner or operator may be subject to upon request from the Department.

Section 3.0 deals with minimum emission monitoring requirements for existing sources. While "existing sources" is not defined by this regulation, the following language comes from 7 **DE Admin. Code** 1101:

> *"Existing installation, equipment, source or operation" means any air contaminant source the construction or modification of which was commenced before the date of adoption of any applicable regulation or standard. As this definition applies to 7 **DE Admin. Code** 1120, New Source Performance Standards, it means any air contaminant source the construction or modification of which was commenced before August 17, 1971. As this definition applies to 7 **DE Admin. Code** 1121. Emission Standards for Hazardous Air Pollutants, it means any air contaminant source the construction or modification of which was commenced before March 31, 1971."*

While the second and third sentences of the regulation apply to other regulations, it is my interpretation that the first sentence applies to this regulation. As such, Section 3.0 does not apply to this project because all proposed equipment would be new sources.

Section 4.0 is applicable to those who install monitoring equipment to comply with the regulation, and no such monitoring equipment is required for the proposed equipment. Section 5.0 applies to owners or operators of facilities required to install continuous monitoring systems, but no CMS is required. Section 6.0 deals with data reduction requirements for the previously mentioned monitoring systems.

Section 7.0 states that "emission statement requirements apply to all stationary sources located in an ozone nonattainment area that emit nitrogen oxides (NO_X) or volatile organic compounds (VOCs) to the

atmosphere." Sussex County, where the BIC is located, is considered in attainment with the 2015 8-hour standard for ozone. Therefore, the emission statement requirements of Section 7.0 do not apply.

7 **DE Admin. Code** 1118, *Particulate Emissions from Grain Handling Operations*, was reviewed and deemed inapplicable. Grain handling is not expected to be a component of this project.

7 **DE Admin. Code** 1119, *Control of Odorous Air Contaminants* prohibits the emission of odorous air contaminants such as to cause a condition of air pollution. At the neighboring compost facility, compliance with this requirement is demonstrated by conducting and recording the results of odor surveys of the entire property boundary at least once per calendar quarter.

In the event that odors from the compost plant at BIC are observed, the owner or operator is required to take immediate action to locate and address the source of the odor. Additional odor surveys are required at least once per week until the odor is no longer detectable. Any such odors or actions are required to be documented.

The feedstocks proposed for receipt and digestion in the AD have the potential to generate odorous conditions if not managed correctly. I am proposing that the owner or operator of the proposed equipment perform daily qualitative odor surveys and document the results. The owner or operator shall identify areas where odors could be generated, including but not limited to areas where solid and liquid feedstocks are received, transferred, and stored, and focus the surveys on these areas to ensure odorous conditions are not created. In the case that odorous conditions are detected, immediate action shall be taken until the odorous conditions no longer exist. Any associated actions shall be documented.

7 **DE Admin. Code** 1120, *New Source Performance Standards*, was reviewed for applicability. According to Section 1.1, "The provisions of this regulation apply to any person responsible for any stationary sources specified herein the construction, reconstruction or modification of which was commenced after August 17, 1971." Table 55 summarizes the standards reviewed and whether they were deemed applicable:

Section	Title	Applicable?
2.0	Standards of Performance for Fuel Burning Equipment	No
3.0	Standards of Performance for Nitric Acid Plants	No
4.0	Standards of Performance for Storage Vessels for Petroleum Liquid for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 18, 1978	No
5.0	Standards of Performance for Asphalt Concrete Plants	No
6.0	Standards of Performance for Incinerators	No
7.0	Standards of Performance for Sewage Treatment Plants	No
8.0	Standards of Performance for Sulfuric Acid Plants	No
9.0	Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978	No
10.0	Standards of Performance for Stationary Gas Turbines	No
11.0	Standards of Performance for Petroleum Refineries	No
12.0	Standards of Performance for Steel Plants: Electric Arc Furnaces	No
13.0	Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	No
14.0	Standards of Performance for Lead -Acid Battery Manufacturing Plants	No

Section	Title	Applicable?
15.0	Standards of Performance for Automobile and Light Duty Truck Surface Coating Operations	No
16.0	Standards of Performance for the Graphic Arts Industry: Publication Rotogravure Printing	No
17.0	Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	No
18.0	Standards of Performance for Pressure Sensitive Tape and Label Surface Coating Operations	No
19.0	Standards of Performance for Equipment Leaks of VOC in SOCMI [Synthetic Organic Chemicals Manufacturing Industry]	No
20.0	Standards of Performance for Bulk Gasoline Terminals	No
21.0	Standards of Performance for Surface Coating of Metal Furniture	No
22.0	Standards of Performance for Equipment Leaks at Petroleum Refineries	No
23.0	Standards of Performance for Flexible Vinyl and Urethane Coating and Printing	No
24.0	Standards of Performance for Secondary Brass and Bronze Ingot Production Plants	No
25.0	Standards of Performance for Steel Plants: Electric Arc Furnaces and Argon Decarburization Vessels Constructed After August 7, 1983	No
26.0	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	No
27.0	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984	No
28.0	Standards of Performance for Municipal Solid Waste Landfills	No
29.0	Reserved	No
30.0	Standards of Performance for Municipal Solid Waste Landfills After July 11, 2017	No

*Table 55: Subsections of 7 **DE Admin. Code** 1120 Reviewed & Applicability Status*

In summary, this regulation does not apply to the proposed equipment because there are no adopted standards of performance that apply to the activities conducted at the facility.

7 **DE Admin. Code** 1121, *Emission Standards for Hazardous Air Pollutants*, was reviewed for applicability. Section 1.0 states that the "provisions of this regulation apply to the owner or operator of any stationary source for which a standard is prescribed under this regulation." The prescribed standards of the regulation begin in Section 10.0.

Section 10.0 focuses on emissions standards for asbestos, and subsection 10.1 states that the "provisions of 40 CFR, Part 61, Subpart M (1992) are hereby incorporated into this Regulation by reference." I reviewed Subpart M of Part 61 and found that the "provisions of this subpart are applicable to those sources specified in §§61.142 through 61.151, 61.154, and 61.155." Table 56 summarizes the sources corresponding to each of the sections listed.

Section #	Section Title
§61.142	Standard for asbestos mills.
§61.143	Standard for roadways.

Section #	Section Title
§61.144	Standard for manufacturing.
§61.145	Standard for demolition and renovation.
§61.146	Standard for spraying.
§61.147	Standard for fabricating.
§61.148	Standard for insulating materials.
§61.149	Standard for waste disposal for asbestos mills.
§61.150	Standard for waste disposal for manufacturing, fabricating, demolition, renovation, and spraying operations.
§61.151	Standard for inactive waste disposal sites for asbestos mills and manufacturing and fabricating operations.
§61.154	Standard for active waste disposal sites.
§61.155	Standard for operations that convert asbestos-containing waste material into nonasbestos (asbestos-free) material.

Table 56: Sections & Titles for Sources Subject to Subpart M of 40 CFR Part 61 & Section 10 of 7 DE Admin. Code 1121

As evidenced by the section titles, the proposed equipment at the BIC is not subject to the requirements of Subpart M to 40 CFR Part 61.

Section 11 of 7 **DE Admin. Code** 1121 focuses on emission standards for beryllium. According to Section 11.1, the provisions of this section of the regulation apply to the following stationary sources:

- Extraction plants, ceramic plants, foundries, incinerators, and propellant plants which process beryllium ore, beryllium, beryllium oxide, beryllium alloys, or beryllium-containing waste.
- Machine shops which process beryllium, beryllium oxides, or any alloy when such alloy contains more than 5% beryllium by weight.

The sources subject to Section 11 of this regulation are unrelated to the proposed equipment at the BIC.

Section 12 of 7 **DE Admin. Code** 1121 focuses on emission standards for mercury, and states that the "provisions of Subpart E, National Emission Standards for Mercury of Part 61, Title 40 of the Code of Federal Regulations July 1, 1986, and amended in the Federal Register on March 19, 1987, are hereby adopted by reference." I reviewed Subpart E of Part 61 and found that the "provisions of this subpart are applicable to those stationary sources which process mercury ore to recover mercury, use mercury chlor-alkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge." The proposed equipment at the BIC are not among the sources listed and are not expected to process mercury-containing materials.

Section 13 of 7 **DE Admin. Code** 1121 focuses on emission standards for vinyl chloride which applies to plants which produce the following:

- Ethylene dichloride by reaction of oxygen and hydrogen chloride with ethylene,
- Vinyl chloride by any process, and/or
- One or more polymers containing any fraction of polymerized vinyl chloride.

None of the bulleted sources apply to the proposed equipment at the BIC.

Section 14 of 7 **DE Admin. Code** 1121 focuses on emission standards for equipment leaks (fugitive emission sources) and adopts the provisions of Subpart V of 40 CFR Part 61 by reference. According to paragraph (a) of §61.240, the requirements of Subpart V "apply to each of the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart." I explored the applicability of this section by reviewing the definitions within of §61.241. The following terms were deemed relevant:

> ***Volatile hazardous air pollutant* or *VHAP*** means a substance regulated under this part for which a standard for equipment leaks of the substance has been proposed and promulgated. Benzene is a VHAP. Vinyl chloride is a VHAP.
>
> ***In VHAP service*** means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of § 61.245(d). The provisions of § 61.245(d) also specify how to determine that a piece of equipment is not in VHAP service.

Based on these definitions, the only VHAPs appear to be benzene and vinyl chloride. I also consulted §61.245(d), as instructed in the "In VHAP service" definition, and found the following guidance:

> *(d)*
>
> *(1) Each piece of equipment within a process unit that can conceivably contain equipment in VHAP service is presumed to be in VHAP service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service. For a piece of equipment to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10 percent by weight. For purposes of determining the percent VHAP content of the process fluid that is contained in or contacts equipment, procedures that conform to the methods described in ASTM Method D-2267 (incorporated by the reference as specified in § 61.18) shall be used.*
>
> *(2)*
>
> *(i) An owner or operator may use engineering judgment rather than the procedures in paragraph (d)(1) of this section to demonstrate that the percent VHAP content does not exceed 10 percent by weight, provided that the engineering judgment demonstrates that the VHAP content clearly does not exceed 10 percent by weight. When an owner or operator and the Administrator do not agree on whether a piece of equipment is not in VHAP service, however, the procedures in paragraph (d)(1) of this section shall be used to resolve the disagreement.*
>
> *(ii) If an owner or operator determines that a piece of equipment is in VHAP service, the determination can be revised only after following the procedures in paragraph (d)(1) of this section.*
>
> *(3) Samples used in determining the percent VHAP content shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.*

The biogas produced in this process is expected to consist primarily of CH_4 and CO_2. The VHAPs listed are not expected to exist in any appreciable amount. As such, Section 14 of 7 **DE Admin. Code** 1121 was determined not to apply.

Finally, Section 15 of 7 **DE Admin. Code** 1121 focuses on emission standards for equipment leaks (fugitive emission sources of benzene) and adopts the provisions of Subpart J of 40 CFR Part 61 by reference. According to paragraph (a) of §61.110, the provisions of Subpart J apply to each of the

following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by the subpart.

According to §61.111, "***In benzene service*** means that a piece of equipment either contains or contacts a fluid (Liquid or gas) that is at least 10 percent benzene by weight as determined according to the provisions of § 61.245(d). The provisions of § 61.245(d) also specify how to determine that a piece of equipment is not in benzene service." The benzene composition of biogas produced is not expected to exceed 10% by weight. As such, the requirements of 7 DE Admin. Code 1121 are not believed to apply.

7 **DE Admin. Code** 1122, *Restriction on Quality of Fuel in Fuel Burning Equipment*, was reviewed and deemed inapplicable. This regulation restricts the burning of waste oil in fuel burning equipment or incinerators without receiving the Department's permission. The proposed equipment would not combust waste oil ("spent oil or solvents or other volatile hydrocarbons, including but not limited to crankcase oil").

7 **DE Admin. Code** 1123, *Standards of Performance for Steel Plants: Electric Arc Furnaces*, was reviewed and was found to have been repealed as of March 11, 2018. The proposed facility is not a steel plant, nor would it include the construction or operation of an electric arc furnace.

7 **DE Admin. Code** 1124, *Control of Volatile Organic Compound Emissions*, was reviewed and deemed inapplicable due to the following language from Section 1.2.1.

> *Sources, other than solvent metal-cleaning sources, whose emissions of Volatile Organic Compounds (VOCs) are not more than fifteen (15) pounds per day, unless other limits are specified herein, provided the emission rates are determined and certified in a manner acceptable to the Department.*

The proposed emergency generator, flare, and RTO are individually expected to emit VOCs at a rate no greater than 10 pounds per day, which would exempt them from this regulation's requirements.

7 **DE Admin. Code** 1125, *Requirements for Preconstruction Review*, regulates the preconstruction review requirements. The requirements for Emission Offset Provisions (EOP), Prevention of Significant Deterioration of Air Quality (PSD), and Minor New Source Review (MNSR) are defined, respectively in 7 **DE Admin. Code** 1125.2, 1125.3, and 1125.4.

Section 2.0 of this regulation applies to any person responsible for any proposed new major stationary source or any proposed major modification. For the purposes of Section 2.0 of the regulation, "major stationary source" means:

- *Any stationary source of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act, except for either volatile organic compound or nitrogen oxides, or*
- *Any stationary source of air pollutants which emits, or has the potential to emit, either volatile organic compounds, or nitrogen oxides, in the following amounts:*
    - *For areas in ozone attainment, ozone marginal, or ozone moderate nonattainment areas and located in the ozone transport region - 50 tons per year volatile organic compounds or 100 tons per year of oxides of nitrogen, or*
    - *For serious ozone nonattainment areas - 50 tons per year of either volatile organic compounds or oxides of nitrogen, or*

  - *For severe ozone nonattainment areas - 25 tons per year of either volatile organic compounds or oxides of nitrogen, or*
  - *For extreme ozone nonattainment areas - 10 tons per year of either volatile organic compounds or oxides of nitrogen.*
- *Any physical change that would occur at a stationary source not qualifying under subsection 2.2.1 or subsection 2.2.2 of this regulation as a major stationary source, if the change would constitute a major stationary source by itself, or*
- *A major stationary source that is major for either volatile organic compounds or nitrogen oxides shall be considered major for ozone, and "installation" means an identifiable piece of process, combustion or incineration equipment.*
- *Nitrogen oxides and SO_2 shall be considered as precursors, and are considered nonattainment pollutants in any $PM_{2.5}$ nonattainment area.*

The BIC is located in an ozone attainment area within the ozone transport region. Sussex County is also considered in attainment with the current (2012) $PM_{2.5}$ standard. The facility does not have the potential to emit over the threshold of any of the pollutants specified in the bullets above and does not qualify as a major stationary source per this definition.

The other way that Section 2.0 can be triggered is if the installation of the proposed equipment meets the definition of a "major modification" as the term is defined in Section 1.9 of the regulation. According to Section 1.9, "major modification" is defined as follows:

- *Major modification means any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the CAA.*
- *Any net emissions increase that is significant for either volatile organic compounds or nitrogen oxides shall be considered significant for ozone.*
- *A physical change or change in the method of operation shall not include:*
  - *Routine maintenance, repair and replacement;*
  - *Use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;*
  - *Use of an alternative fuel by reason of an order or rule under Section 125 of the CAA;*
  - *Use of an alternative fuel at a steam-generating unit to the extent that the fuel is generated from municipal solid waste;*
  - *Use of an alternative fuel or raw material by a stationary source which:*
    - *The source was capable of accommodating before January 6, 1975; unless such change would be prohibited under any previously issued permit condition which was established after January 6, 1975;*
    - *The source is approved to use under any previously issued PSD permit or under Section 3.0 of this regulation;*
  - *An increase in the hours of operation or in the production rate, unless such change would be prohibited under any previously issued permit condition which was established after January 6, 1975;*
  - *Any change in ownership at a stationary source.*

For reference, the terms "Net Emissions Increase" and "Significant" are defined as follows in Section 1.0 of the regulation:

"Net Emissions Increase"

- *Net emissions increase means the amount by which the sum of the following exceeds zero:*
  - *Any increase in actual emissions from a particular physical change or change in method of operation at a stationary source; and*
  - *Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.*
- *An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:*
  - *The date five years before construction on the particular change commences; and*
  - *The date that the increase from the particular change occurs.*
- *An increase or decrease in actual emissions is creditable only if the Department has not relied on it in issuing a permit for the source under this regulation, which permit is in effect when the increase in actual emissions from the particular change occurs.*
- *An increase or decrease in actual emissions of sulfur dioxide or particulate matter which occurs before the applicable baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.*
- *An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.*
- *A decrease in actual emissions is creditable only to the extent that:*
  - *The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;*
  - *It is enforceable at and after the time that actual construction on the particular change begins; and*
  - *It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.*
  - *It has not been adopted by the Department as a required reduction to be made part of the SIP or it is not required by the Department pursuant to an existing requirement of the SIP.*
- *An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.*

"Significant"

(a) "Significant" means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant and Emissions Rate
Carbon monoxide: 100 tons per year (TPY)
Nitrogen oxides: 40 TPY
Sulfur dioxide: 40 TPY
Particulate matter: 25 TPY
Ozone:
*New Castle and Kent Counties - 25 TPY of either volatile organic compounds or nitrogen oxides **
*Sussex County - 40 TPY of either volatile organic compounds or nitrogen oxides **
Lead: 0.6 TPY
Asbestos: 0.007 TPY
Beryllium: 0.0004 TPY
Mercury: 0.1 TPY
Vinyl chloride: 1 TPY

Fluorides: 3 TPY
Sulfuric acid mist: 7 TPY
Hydrogen sulfide (H_2S): 10 TPY
Total reduced sulfur (including H_2S): 10 TPY
Reduced sulfur compounds (including H_2S): 10 TPY
PM_{10} particulate: 15 TPY
$PM_{2.5}$: 10 TPY of direct PM2.5 emissions; 40 TPY of sulfur dioxide emissions; 40 TPY nitrogen oxide emissions.

**Note: Increases in net emissions shall not exceed 25 tons per year in New Castle and Kent Counties, or 40 tons per year in Sussex, when aggregated with all other net increases in emissions from the source over any period of five consecutive calendar years which includes the calendar year in which such increases occur. No part of the five consecutive years shall extend before January 1, 1991.*

(b) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the CAA that (a) does not list, any emissions rate.
(c) Notwithstanding (a), "significant" means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within ten kilometers of a Class I area, and have an impact on such area equal to or greater than one μg/m3, (24-hour average).

Based on the emission estimates provided as part of the application, the proposed project is not expected to be a major modification. As a result, Section 2.0 was deemed not to apply.

Next, I reviewed Section 3.0 – Prevention of Significant Deterioration (PSD) of Air Quality. Section 3.7.1 states that "[n]o stationary source or modification to which the requirements of subsection 3.8 through subsection 3.15 apply, shall begin actual construction without a permit which states that the stationary source or modification would meet those requirements." Section 3.7.2 continues to state that "[t]he requirements of subsection 3.8 through subsection 3.15 of this regulation shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the CAA that it would emit, except as Section 3.0 of this regulation otherwise provides." And Section 3.7.3 adds that "[t]he requirements of subsection 3.8 through subsection 3.15 of this regulation apply only to any major stationary source or major modification that would be constructed in an area designated as attainment or unclassifiable." Sussex County, where the proposed equipment would be located, is considered to be in attainment with all current NAAQS with the exception of the 2008 8-hour ozone standard, for which it is classified as "marginal" nonattainment.

Section 3.1 includes the definitions for PSD, and contains the following definition for "Major Stationary Source":

- 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 pollutant subject to regulation under the CAA:
    - 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,
- 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,
- 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

- Notwithstanding the stationary source size specified in the above paragraph, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the CAA; or
- Any physical change that would occur at a stationary source not otherwise qualifying under the preceding paragraph as a major stationary source, if the change would constitute a major stationary source by itself.
- A major stationary source that is major for volatile organic compounds or nitrogen oxides shall be considered major for ozone.

After reviewing this list of major stationary sources, I determined that the proposed equipment and their associated potential emissions would not trigger this section.

Finally, the requirements of Section 4.3, within Section 4.0 – Minor New Source Review (MSNR), apply to any proposed new stationary source, the construction of which:

- Was applied for, pursuant to Section 11.10 of 7 **DE Admin. Code** 1102 after August 11, 2005, and
- Is subject to the construction, installation, or alteration requirements of subsection 2.1.3 of 7 **DE Admin. Code** 1102, and
- Is not subject to the requirements of Section 2.0 or Section 3.0 of this regulation, and
- Has a potential to emit of equal to or greater than five tons per year of volatile organic compounds (VOCs), nitrogen oxides (NO_X), sulfur oxides (SO_X), fine particulate matter ($PM_{2.5}$), or the aggregate of any of the hazardous air pollutants (HAPs) listed in Section 112(b) of the federal Clean Air Act.

Construction of the proposed equipment meets the first two (2) bullet points and is not subject to Sections 2.0 or 3.0 of this regulation. While the source technically was determined to have a PTE above 5 TPY of VOCs, that estimate was calculated prior to the VOC/siloxane removal vessels and subsequent RTO or flare control equipment. After taking those control technologies into account, the expected VOC emissions from the proposed equipment is well below the 5 TPY applicability threshold. Operation of these control technologies shall be considered essential to avoiding the requirements of Section 4.0. No requirements of Section 4.0 were deemed to be applicable.

7 **DE Admin. Code** 1126, *Motor Vehicle Emissions Inspection Program*, was reviewed and deemed not to apply. This regulation focuses on the standards, requirements and procedures applicable to all motor vehicles, model years 1968 and newer with the exception of the five newest model years, titled and registered within Sussex County and as specified by the Department, including any motor vehicles owned or operated by the federal, state and local governments and their agencies. This regulation is not relevant to the proposed equipment.

7 **DE Admin. Code** 1127, *Stack Heights*, was reviewed and found to be inapplicable. This regulation is intended to "assure that the degree of emission limitation required for the control of any air pollutant is not affected by that portion of any stack height which exceeds good engineering practice (GEP) or by any dispersion technique." Section 1.2 states that the regulation "does not restrict the physical heights of stacks but does restrict the credit for that portion of any stack height which may be used for dispersion techniques." Section 3.1 states that, for new and existing sources, "the degree of limitation required of any source for control of any air contaminant shall not be affected by so much of any source's stack height that exceeds good engineering practice or by any other dispersion technique except as provided in 3.2.3 of this regulation."

Good Engineering Practice (GEP) is defined in Section 3.2 as the greater of the following:

3.2.1. A height of 65 meters, measured from the ground-level elevation at the base of the stack;
3.2.2.
3.2.2.1. For stacks in existence on January 12, 1979, and for which the owner had obtained all applicable permits or approvals in accordance with these regulations, Hg = 2.5 H (see 3.2.2.2 for terms Hg and H), provided the owner or operator produces evidence that this equation was actually relied on in establishing an emission limitation;
3.2.2.2. For all other stacks, Hg = H + 1.5 L, where
Hg = good engineering practice stack height, measured from the ground-level elevation at the base of the stack;

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

L = lesser dimension (height or projected width) of nearby structure or structures,

provided that the Secretary may require the use of a field study or fluid model to verify GEP stack height for the source; or

3.2.3. The height demonstrated by a fluid model or a field study approved by the Secretary, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, plume impactions or eddy effects created by the source itself, structures or terrain obstacles. "Guideline for Use of Fluid Modeling to Determine Good Engineering

> *Practice Stack Height", July, 1981, EPA 450/4-81-003, and "Guideline for Fluid Modeling of Atmospheric Diffusion", April, 1981, EPA 600/8-81-009, shall be the basis for approval of fluid modeling demonstrations.*

The stacks associated with the proposed equipment are proposed to be shorter than the heights that would exceed GEP, per this regulation. As such, I do not believe that this regulation applies.

7 **DE Admin. Code** 1128, *Control of Toxic Air Contaminants*, was reviewed and found that it is currently designated as "Reserved". There are no requirements, applicable or otherwise, specified in the regulation at the time of writing this document.

7 **DE Admin. Code** 1129, *Emissions from Incineration of Infectious Waste*, was reviewed and deemed in applicable. The incineration of waste (infectious or otherwise) is not a component of the proposed project.

7 **DE Admin. Code** 1130, *Title V State Operating Permit Program*, covers the sources required to obtain a Title V permit. According to Section 3.1, these sources include:

- Any major source;
- Any source, including an area source, subject to a standard, limitation, or other requirement under Section 111 (Standards of Performance for New Stationary Sources) of the Act;
- Any source, including an area source, subject to a standard or other requirement under section 112 (National Emissions Standards for Hazardous Air Pollutants) of the Act, except that a source is not required to obtain a permit solely because it is subject to regulations or requirements under section 112(r) of the Act;
- Any affected source; and
- Any source that is subject to applicable requirements.

I also reviewed the contents of Section 3.2, which includes source category exemptions. The source category exemptions from Section 3.2 are shown below:

- All sources listed in 3.1 of this regulation that are not (i) major sources, (ii) affected sources, or (iii) solid waste incineration units required to obtain a permit pursuant to section 129(e) (Solid Waste Combustion - Permits) of the Act, are exempt from the obligation to obtain a Part 70 permit. Any such exempt source may opt to apply for a permit under this regulation and shall be issued a permit if the applicant otherwise satisfies all of the requirements of this regulation.
- Sources in the following source categories are exempted from the obligation to obtain a permit under this regulation:
    - All sources in source categories that would be required to obtain a permit solely because they are subject to 40 CFR Part 60, Subpart AAA, "Standards of Performance for New Residential Wood Heaters"; and
    - All sources in source categories that would be required to obtain a permit solely because they are subject to 40 CFR Part 61, Subpart M, "National Emission Standards for Hazardous Air Pollutants" for Asbestos, section 61.145, "Standard for Demolition and Renovation".

To determine if the proposed equipment was exempt from the requirements to obtain a Part 70 permit, I reviewed the source category exemptions individually. First of all, the proposed equipment is not subject to the Subpart AAA to 40 CFR Part 60 (Standards of Performance for New Residential Wood Heaters) or to

Subpart M to 40 CFR Part 61 (National Emission Standard for Asbestos). As such, it is not exempt from the permitting requirements of Part 70 for those reasons.

Next, I reviewed whether the proposed equipment to be located at the BIC would be considered a major source, affected source, or solid incineration unit required to obtain a permit pursuant to section 129(e). To make that determination, I reviewed the definition of each term as they are defined in 7 DE Admin. Code 1130. The definition of a major source from 7 DE Admin. Code 1130 is shown below:

"Major source" means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (i.e., all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987.

(1) A major source under section 112 (Hazardous Air Pollutants) of the Act, defined as:
- *(i) For pollutants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, 10 tons per year ("tpy") or more of any hazardous air pollutant which has been listed pursuant to section 112(b) (Hazardous Air Pollutants - List of Pollutants) of the Act, 25 tpy or more of any combination of such hazardous air pollutants, or such lesser quantity as the Administrator may establish by rule. Notwithstanding the preceding sentence, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources; or*
- *(ii) For radionuclides, "major source" shall have the meaning specified by the Administrator by rule.*

(2) A major stationary source of air pollutants, as defined in section 302 (Title III - General Definitions) of the Act, that directly emits or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation (including any major source of fugitive emissions of any such pollutant, as determined by rule by the Administrator). The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source for the purposes of section 302(j) (Title III - General Definitions) of the Act, unless the source belongs to one of the following categories of stationary sources:
- *(i) Coal cleaning plants (with thermal dryers);*
- *(ii) Kraft pulp mills;*
- *(iii) Portland cement plants;*
- *(iv) Primary zinc smelters;*
- *(v) Iron and steel mills;*
- *(vi) Primary aluminum ore reduction plants;*
- *(vii) Primary copper smelters;*
- *(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;*
- *(ix) Hydrofluoric, sulfuric, or nitric acid plants;*
- *(x) Petroleum refineries;*
- *(xi) Lime plants;*
- *(xii) Phosphate rock processing plants;*
- *(xiii) Coke oven batteries;*
- *(xiv) Sulfur recovery plants;*
- *(xv) Carbon black plants (furnace process);*
- *(xvi) Primary lead smelters;*

(xvii) Fuel conversion plants;
(xviii) Sintering plants;
(xix) Secondary metal production plants;
(xx) Chemical process plants;
(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(xxiii) Taconite ore processing plants;
(xxiv) Glass fiber processing plants;
(xxv) Charcoal production plants;
(xxvi) Fossil-fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; or
(xxvii) All other stationary source categories regulated by a standard promulgated under section 111 (Standards of Performance for New Stationary Sources) or section 112 (Hazardous Air Pollutants) of the Act, but only with respect to those air pollutants that have been regulated for that category.

(3) A major stationary source as defined in Part D (Plan Requirements for Nonattainment Areas) of Title I (Air Pollution Prevention and Control) of the Act, including:
(i) For ozone nonattainment areas, sources with the potential to emit 100 tpy or more of volatile organic compounds or oxides of nitrogen in areas classified as "marginal" or "moderate," 50 tpy or more in areas classified as "serious," 25 tpy or more in areas classified as "severe," and 10 tpy or more in areas classified as "extreme"; except that the references in this paragraph to 100, 50, 25, and 10 tpy of nitrogen oxides shall not apply with respect to any source for which the Administrator has made a finding, under section 182(f) (1) (2) (Plan Submissions and Requirements – NO_x Requirements) of the Act, that requirements under section 182(f) of the Act do not apply;
(ii) For ozone transport regions established pursuant to section 184 (Control of Interstate Ozone Air Pollution) of the Act, sources with the potential to emit 50 tpy or more of volatile organic compounds;
(iii) For carbon monoxide nonattainment areas:
(A) that are classified as "serious", and
(B) in which stationary sources contribute significantly to carbon monoxide levels as determined under rules issued by the Administrator, sources with the potential to emit 50 tpy or more of carbon monoxide; and
(iv) For particulate matter (PM_{10}) nonattainment areas classified as "serious", sources with the potential to emit 70 tpy or more of PM_{10}.

(4) For purposes of this regulation, a research and development operation may be treated as a separate source from other stationary sources that are located on a contiguous or adjacent property and under common control only if that operation belongs to a different major group as described in the Standard Industrial Classification Manual, 1987.

Looking at paragraph one of this definition, related to section 112 of the CAA, the PTE for the proposed equipment is expected to be well below the 10 ton per year (TPY) threshold for a single HAP, or 25 TPY threshold for any combination of HAPs. It is also not expected to be a source of radionuclides.

Paragraph two of the definition states that a major source is any stationary source with the potential to emit above 100 tons per year, and then proceeds to list a variety of sources for which fugitive emissions should be considered. The combined PTE for all existing and proposed equipment at the BIC is below the 100 TPY threshold for all pollutants calculated.

Paragraph three of the definition focuses on sources located in areas where there is an existing level of air pollution contributing to some level of nonattainment with the NAAQS. Sussex County is classified as being

in marginal nonattainment with the 2008 8-hour ozone standard but is also located within an ozone transport region. The PTE for VOCs from proposed equipment is well below the 50 TPY threshold.

Finally, paragraph four of the definition focuses on research and development operations. This facility is not considered a research and development facility.

As a result, the BIC is not currently considered a major source. Next, I reviewed whether the proposed equipment would be considered an "affected source". According to 7 DE Admin. Code 1130, an "affected source" is a source that includes one or more affected units. An affected unit is defined below:

> *"Affected unit" means a unit that is subject to emission reduction requirements or limitations under Title IV (Acid Disposition Control) of the Act, as defined.*

Title IV of the Clean Air Act is called "Acid Deposition Control" but includes the Acid Rain Program under 40 CFR Parts 72 through 78. The proposed equipment is not subject to requirements under the Acid Rain Program, nor is it considered a solid waste incineration unit required to obtain a permit pursuant to section 129(e).

Since the proposed equipment at the BIC is not considered to be a "major source", "affected source", or solid waste incineration unit, as these terms are defined in 7 **DE Admin. Code** 1130, they are exempt from the requirements of this regulation.

7 **DE Admin. Code** 1131, *Low Enhanced Inspection and Maintenance Program*, was reviewed and deemed inapplicable. This regulation's stated purpose is to "ensure that emissions of hydrocarbons (HC), and carbon monoxide (CO) from light-duty vehicles in the State of Delaware do not adversely impact public health, safety, and welfare." As such, it was determined not to be relevant to the proposed equipment.

7 **DE Admin. Code** 1132, *Transportation Conformity*, was reviewed and deemed inapplicable. This regulation's purpose is to "implement section 176(c) of the Clean Air Act (CAA), as amended (42 U.S.C. 7401 et seq.), and the related requirements of 23 U.S.C. 109(j), with respect to the interagency consultation process and commitments to transportation control and mitigation measures." As such, it was determined not to be relevant to the proposed equipment.

7 **DE Admin. Code** 1133, *Motor Vehicle Pressure Test and Emission Control Device Inspection Program*, was reviewed and found to have been replaced by 7 DE Admin. Code 1131. As such, this regulation was not deemed applicable.

7 **DE Admin. Code** 1134, *Emission Banking and Trading Program*, was reviewed and deemed inapplicable. This regulation establishes a "voluntary banking and trading program" for "any person who desires to have an emission reduction or reductions certified as an ERC or ERCs, any person who desires to trade an ERC or ERCs with another person, and any person who desires to use an ERC or ERCs." This project does not include the trading or use of emission reduction credits (ERCs).

7 **DE Admin. Code** 1135, *Conformity of General Federal Actions to the State Implementation Plans*, was reviewed and deemed inapplicable. The stated purpose of this regulation is to "implement §176(c) of the Clean Air Act (CAA), as amended (42 U.S.C. 7401 et seq.) and regulations under 40 CFR Part 51 Subpart W (July 1, 1994), with respect to the conformity of general federal actions to the applicable implementation plan." It is not considered relevant to the proposed project.

7 **DE Admin. Code** 1136, *Acid Rain Program*, was reviewed and deemed inapplicable. This regulation incorporates the "provisions of Parts 72 through 78, of Title 40 of the Code of Federal Regulations, dated July 1, 2016". The Acid Rain Program's (ARP) requirements focus on emissions from sources in the power sector. As such, the requirements of the ARP's were not considered relevant to the proposed equipment.

7 **DE Admin. Code** 1138, *Emission Standards for Hazardous Air Pollutants for Source Categories*, was reviewed for applicability. According to Section 3.1.2.1, the "provisions of this regulation apply to the owner or operator of any stationary source that [e]mits or has the potential to emit any hazardous air pollutant listed in or pursuant to Section 112(b) of the Act and…Is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to 40 CFR Part 63 or this regulation." The emission standards summarized in Table 57 are contained within this regulation:

Section	Title
5.0	Perchloroethylene Air Emission Standards for Dry Cleaning Facilities
6.0	Emission Standards for Chromium Emissions from Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks
7.0	Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers
8.0	Emission Standards for Halogenated HAP Solvent Cleaning
9.0	Emission Standards for Hospital Ethylene Oxide Sterilizers
10.0	Emission Standards for Hazardous Air Pollutants for Area Source Plating and Polishing Operations
11.0	Emission Standards for Hazardous Air Pollutants for Area Source Lead Acid Battery Manufacturing Plants
12.0	Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production
13.0	Emission Standards for Hazardous Air Pollutants for Area Source Paint Stripping Operations
14.0	Emission Standards for Hazardous Air Pollutants for Area Source Miscellaneous Parts or Products Surface Coating Operations
15.0	Emission Standards for Hazardous Air Pollutants for Area Source Motor Vehicle or Mobile Equipment Surface Coating Operations
16.0	Emission Standards for Hazardous Air Pollutants for Area Source Asphalt Processing and Asphalt Roofing Products Manufacturing Operations
17.0	Emission Standards for Hazardous Air Pollutants for Area Source Prepared Feeds Manufacturing Facilities

Table 57: 7 DE Admin. Code 1138 Sections Reviewed

Upon review of the sections listed in Table 57, I determined that none applied to the construction of the proposed emergency generator, AD system, flare, or RTO as they do not fall subject to any of the source categories currently regulated.

7 **DE Admin. Code** 1139, *Nitrogen Oxides (NO_X) Budget Trading Program*, was reviewed and deemed inapplicable. This regulation was repealed on November 1, 2013.

7 **DE Admin. Code** 1140, *Delaware Low Emission Vehicle Program*, was reviewed and deemed inapplicable. This regulation establishes a Low Emission Vehicle (LEV) program, which incorporates the requirements of the California LEV program and applies to all new model year 2014 and subsequent model year motor vehicles that are passenger cars, light-duty trucks, medium-duty passenger vehicles, and

medium-duty vehicles subject to the California LEV program and delivered for sale in Delaware. It is not relevant to the proposed equipment at the BIC.

7 **DE Admin. Code** 1141, *Limiting Emissions of Volatile Organic Compounds from Consumer and Commercial Products*, was reviewed and deemed inapplicable. This regulation applies to any person who supplies, sells, offers for sale, blends, repackages for sale, or manufactures any architectural coating for use in the State of Delaware, as well as any person who applies or solicits the application of any architectural coating in the State of Delaware on or after the applicable compliance dates. The proposed project is unrelated to the manufacture or sale of architectural coatings.

7 **DE Admin. Code** 1142, *Specific Emission Control Requirements*, was reviewed and deemed inapplicable. This regulation includes sections on the "Control of NO_X Emissions from Industrial Boilers" and "Control of NO_X Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries". Neither of the sections apply to the proposed equipment.

7 **DE Admin. Code** 1143, *Heavy Duty Diesel Engine Standards*, was reviewed and deemed inapplicable. This regulation was repealed on November 1, 2013.

7 **DE Admin. Code** 1144, *Control of Stationary Generator Emissions*, was reviewed and deemed applicable to the proposed emergency generator. With some exception, this regulation applies to new and existing emergency and distributed, stationary generators. Going chronologically through the regulation, the following sections were deemed relevant.

Section 1.3.1 requires that the "owner of a new stationary generator shall submit the information required in 1.4 of this regulation and comply with the requirements of this regulation by the date of installation." Section 1.4 includes the requirements related to the submission of an "Initial Notification". An "Initial Notification" for the proposed emergency generator was received electronically by the department on July 23, 2020, when the first application for its construction was submitted. Table 58 summarizes the requirements of Section 1.4 and the information provided in the Initial Notification.

Section	Language	Response
1.4.1	The owner of a stationary generator shall submit to the Department the following information:	
1.4.1.1	The generator owner's name and telephone number;	First Name: Vinnie Last Name: Bevivino Company Name: BioEnergy Devco Telephone Number: (202) 360-1805
1.4.1.2	The physical address where the generator is installed, or will be installed;	Address: 28338 Enviro Way, Seaford, DE 19973 Coordinates: Latitude: 38.603889 Longitude: -75.605000
1.4.1.3	A description of the generator including the make, model number, and serial number;	Make: Cummins Model: C1000N6 Serial Number: TBD
1.4.1.4	The year of manufacture for the generator;	Year of Manufacture: 2020

Section	Language	Response
1.4.1.5	The standby power rating or the prime power rating for the generator, or both power ratings if both are known; and	Standby Power Rating (kW): Not Listed on manufacturer's data Prime Power Rating (kW): 1082 Engine Horsepower: 1,451
1.4.1.6	The date of installation for existing generators, or the expected date of installation for new generators.	Planned for December 2020
1.4.2	The owner of a stationary generator shall submit to the Department a letter stating whether the generator is to be classified as an emergency generator or a distributed generator.	Emergency Generator

Table 58: Responses to Initial Notification Requirements

Section 2.0 of the regulation includes the definitions of various words and terms used in the regulation. Section 3.0 of the regulation specifies the "Emissions" requirements for subject generators and states that a "generator shall not exceed the following standards (in pounds per megawatt-hour (lbs/MWh) of electricity output) under full load design conditions or at the load conditions specified by the applicable testing methods." Section 3.1 specifies the requirements applicable to emergency generators. According to Section 3.1.2, a "new emergency generator shall meet the applicable emissions standards set by the US EPA for non-road engines (40 CFR 89, 90, 91, 92, 94, 1039, or 1048 July 1, 2004 Edition)." The following bullets discuss the relevancy of each of these federal regulations:

- 40 CFR Part 89 focuses on the "Control of Emissions New and In-Use Nonroad Compression-Ignition Engines".
    - The proposed emergency generator engine is not subject to this regulation because it is a spark-ignition engine.
- 40 CFR Part 90 focuses on the "Control of Emissions from Nonroad Spark-Ignition Engines at or Below 19 Kilowatts".
    - While the proposed emergency generator engine is a spark-ignition engine, it has a rated capacity above 19 kilowatts. As such, this regulation was not considered to be applicable.
- 40 CFR Part 91 focuses on the "Control of Emissions from Marine Spark-Ignition Engines".
    - While the proposed emergency generator engine is a spark-ignition engine, it is not a marine engine. As such, this regulation was not considered to be applicable.
- 40 CFR Part 92 focuses on the "Control of Air Pollution from Locomotives and Locomotive Engines".
    - The proposed emergency generator engine is not subject to this regulation because it is not a locomotive engine.
- 40 CFR Part 94 focuses on the "Control of Emissions from Marine Compression-Ignition Engines".
    - The proposed emergency generator engine is not subject to this regulation because it is neither a compression-ignition engine nor a marine engine.
- 40 CFR Part 1039 focuses on the "Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines".
    - The proposed emergency generator engine is not subject to this regulation because it is a spark-ignition engine.
- 40 CFR Part 1048 focuses on the "Control of Emissions from New, Large Nonroad Spark-Ignition Engines".
    - This regulation applies to:

        - All new, spark-ignition nonroad engines (defined in § 1048.801) with maximum engine power above 19 kW, except as provided in § 1048.5.
        - Engines built on or after January 1, 2004
    - The proposed emergency generator engine is a spark-ignition engine that meets the criteria to be subject to this regulation, but §1048.1(c) states the following:
        - The definition of nonroad engine in 40 CFR 1068.30 excludes certain engines used in stationary applications. These engines may be required by 40 CFR part 60, subpart JJJJ, to comply with some of the provisions of this part 1048; otherwise, these engines are only required to comply with the requirements in § 1048.20. In addition, the prohibitions in 40 CFR 1068.101 restrict the use of stationary engines for nonstationary purposes unless they are certified under this part 1048 to the same standards that would apply to nonroad engines for the same model year.
    - Because the proposed emergency generator engine is subject to the requirements of Subpart JJJJ (4) to 40 CFR Part 60, it is my interpretation that the emission standards of 40 CFR 1048 do not apply.

Section 4.0 focuses on the "Operating Requirements" to which subject units would be held. The relevant requirements from this section are shown below:

4.1. An emergency generator may operate for an unlimited number of hours during an emergency.
4.2. An emergency generator may operate for an unlimited number of hours during testing or for maintenance purposes, pursuant to the definition of an emergency generator, except as restricted by 4.4 of this regulation.
4.4. No emergency or distributed generator shall be used during testing or for maintenance purposes before 5 p.m. on a day which has a Ground Level Ozone Pollution Forecast or Particle Pollution Forecast of "Code Red" or "Code Orange" as announced by the Department.
4.5. Despite of this regulation, an emergency generator may be tested on any day that such testing is required to meet National Fire Protection Association (NFPA) or Joint Commission on Accreditation of Healthcare Organizations (JCAHO) standards.

These requirements will be included in the permit. Section 5.0 specifies the "Fuel Requirements" and contains the following relevant requirement:

5.2. Gaseous fuels, except for waste, landfill, or digester gases, combusted in a generator on or after April 11, 2006 shall contain no more than ten grains total sulfur per 100 dry standard cubic feet (170 ppmv total sulfur) on a daily average.

The EPA's criteria for pipeline quality natural gas from 40 CFR Part 72.2 states that "pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet." As such, it is expected that the natural gas combusted will safely meet this requirement.

Section 6.0 includes the "Record Keeping and Reporting" requirements and states that the owner or operator must maintain the following relevant records on the property where the generator is installed, or other Department-approved location which is readily accessible.

6.1.1. An owner shall monitor the monthly and yearly amounts of fuel, or fuels, consumed by their generators. Yearly fuel consumption shall be calculated and recorded each calendar month by recording (for each fuel) the current calendar month's fuel consumption and adding it to those of the previous eleven consecutive months.

6.1.2. A non-resettable hour metering device shall be used by an owner to continuously monitor the monthly and yearly operating hours for each of their generators. Yearly operating hours shall be calculated and recorded each calendar month by recording the current calendar month's operating hours and adding them to those of the previous eleven consecutive months.

6.1.3. Monthly and yearly operating hours for an emergency generator. Yearly operating hours during which testing or maintenance occurred shall be calculated and recorded each calendar month by recording the current calendar month's testing or maintenance hours and adding them to those of the previous eleven consecutive months. A brief description of each testing or maintenance performed shall also be recorded.

These requirements will also be included in the permit associated with the proposed emergency generator. The owner may retain hard copies (e.g. paper) or electronic copies (e.g. compact discs, computer disks, magnetic tape, etc.) of the records, and shall promptly provide the original or a copy of a record or records to the Department upon request. The owner or operator will be required to maintain the records for a minimum of five (5) years after the date the record is made.

Section 7.0 details the "Emissions Certification, Compliance, and Enforcement Requirements". Section 7.2 covers the "Emissions Certification of New Emergency Generators by a Supplier" and states that "an engine that has been certified to meet the currently applicable US EPA non-road emissions standards shall be deemed to be certified for use in new emergency generators." Section 7.3 includes the following relevant language for new emergency generators:

7.3. Emissions Verification by an Owner. An owner shall verify, by each generator's respective compliance date as detailed in 1.3 of this regulation, that a generator complies with its respective emission requirements of 3.0 of this regulation by submitting any or all of the following types of data to the Department for review:

7.3.2. any emissions certification of a new emergency generator as detailed in 7.2 of this regulation;

7.3.3. any maintenance or operating requirements/instructions provided by the generator manufacturer;

7.3.4. emissions test data for the generator (such as a manufacturer's technical data sheet), any supporting documentation for any emission control equipment used, any supporting calculations, any quality control or assurance information, and any other information needed to demonstrate compliance with the requirements.

As will be discussed later the proposed emergency generator engine is certified to meet the applicable emission standards of Subpart JJJJ (4J) of 40 CFR Part 60. Documents associated with the certification and supporting test data were provided in the initial permit application. Documents related to the operation and maintenance of the generator were not provided as part of the application, but will be required to be provided prior to the issuance of an operating permit for the equipment.

Sections 8.0 (Credit for Concurrent Emissions Reductions) and 9.0 (DVFA Member Companies) were deemed inapplicable.

7 **DE Admin. Code** 1145, *Excessive Idling of Heavy Duty Vehicles*, applies to all on-road heavy-duty motor vehicles with a gross vehicle weight rating (GVWR) of greater than 8,500 pounds operating in the State of Delaware. For reference, "On-road heavy-duty motor vehicle" is defined as "any vehicle with a gross vehicle weight rating (GVWR) of greater than 8,500 pounds which is self- propelled and designed for transporting persons or property, including but not limited to trucks, buses, and farm vehicles." Section 4.0 states that, unless specifically exempted under Section 5.0 of the regulation, the owner or operator of

an on-road heavy-duty motor vehicle shall not allow the vehicle to operate for more than three (3) consecutive minutes when the vehicle is not in motion.

For the purposes of this project, the trucks responsible for delivering feedstock materials to the facility are likely subject to this requirement. The most likely exemptions from this requirement, in my opinion, are those specified in Section 5.10, which states the following:

> *5.10. Any vehicle when providing heat to the occupant and when the temperature is between -23 and 0°C, or -10 and 32°F, an engine shall not idle for more than 15 consecutive minutes; or when the temperature is below -23°C or -10°F, and where no nuisance is created, an engine shall not be subject to idling restrictions.*

A condition limiting the idling of on-road heavy-duty motor vehicle at the facility to three (3) minutes has been included in the permit.

7 **DE Admin. Code** 1146, *Electric Generating Unit (EGU) Multi-Pollutant Regulation*, was reviewed and deemed inapplicable. This regulation "establishes Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), and mercury emissions limits to achieve reductions of those pollutants from Delaware's large electric generation units." The requirements of the regulation were not considered relevant to the proposed equipment.

7 **DE Admin. Code** 1147, *CO_2 Budget Trading Program*, was reviewed and deemed inapplicable. This regulation applies to "any unit that, at any time on or after January 1, 2005, serves an electricity generator with a nameplate capacity equal to or greater than 25 MWe". The requirements of the regulation are not relevant to the proposed equipment.

7 **DE Admin. Code** 1148, *Control of Stationary Combustion Turbine Electric Generating Unit Emissions*, was reviewed and deemed inapplicable. This regulation's purpose is to "control the emissions of nitrogen oxides (NOx) from stationary combustion turbine electric generating units in the State of Delaware to reduce the impact on public health, safety, and welfare." The requirements of the regulation are not relevant to the proposed equipment.

7 **DE Admin. Code** 1149, *Regulations Governing the Control of Noise*, was reviewed and is considered applicable. This regulation's intent is to "prevent, prohibit and provide for the abatement of excess and unnecessary noise and/or vibration which may endanger the health, safety and welfare, jeopardize the value of property and erode the integrity of the environment of the people of this state." While the regulation applies, there are no specific requirements that will be included in the permit. Should activity at the facility generate noise that becomes a nuisance to the surrounding community, the Department will investigate the source and potential solutions at that time.

7 **DE Admin. Code** 1150, *Outer Continental Shelf Air Regulations*, was reviewed and deemed inapplicable. This regulation applies to "the owner or operator of any OCS source for which Delaware is the corresponding onshore area (COA) as authorized under Section 328 of the federal Clean Air Act Amendments (42 U.S.C. 7627), Outer Continental Shelf technical changes of 84 Fed. Reg. 13132 (April 4, 2019), and 40 CFR Part 55 (July 1, 2018 ed.)." The requirements of the regulation are not relevant to the proposed equipment.

7 **DE Admin. Code** 1151, *Prohibitions on Use of Certain Hydrofluorocarbons in Specific End-Uses*, was reviewed and deemed inapplicable. This regulation "establishes the prohibitions and requirements for the use and manufacture of hydrofluorocarbons in the State of Delaware according to their specific end usage

(including air conditioning and refrigeration equipment, aerosol propellants, and foam end-uses) and adopts specific United States Environmental Protection Agency Significant New Alternatives Policy Program prohibitions." The proposed equipment is unrelated to the use and manufacture of hydrofluorocarbons.

Following my review of regulations established under 7 **DE Admin. Code** 1100, I reviewed federal regulations to determine which applied. Table 59 summarizes the federal regulations reviewed and whether they were deemed applicable.

Regulation #	Regulation Name	Applicable?
40 CFR Part 60	Standards of Performance for New Stationary Sources	
Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Yes
40 CFR Part 63	National Emission Standards for Hazardous Air Pollutants for Source Categories	
Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Yes

Table 59: Federal Regulations Reviewed & Applicability Status

40 CFR Part 60, Subpart JJJJ (4J), *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines*, was reviewed for applicability. The engine associated with the proposed emergency generator was deemed subject to this subpart based on the following language from §60.4230(a)(4)(iv):

> *(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.*
> *(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:*
> *(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).*

For reference, "emergency stationary internal combustion engine" is defined as follows in §60.4248:

> *Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.*
> *(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.*
> *(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4243(d).*
> (3) *The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4243(d)(2)(ii) or (iii) and § 60.4243(d)(3)(i).*

The engine associated with the proposed emergency generator is a lean burn engine and has gross engine power output of 1,451 HP (1,082 KW). Going chronologically through the regulation §60.4233 discuss the emission standards applicable to owners and operators of an engine subject to the subpart. §60.4233(e) includes the following relevant language:

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

Since the first sentence of §60.4233(e) applied to the proposed emergency generator engine, I reviewed Table 1 of the subpart, as referenced in the quoted text above. The applicable portion of Table 1 is shown below in Table 60.

Engine type and fuel	Max. Engine power	Manufacture Date	Emission Standards					
			g/hp-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC	NO_X	CO	VOC
Emergency	HP ≥ 130		2.0	4.0	1.0	160	540	86

Table 60: Applicable Emission Standards from Table 1 to Subpart JJJJ of Part 60

It should be noted that the following notes apply to the standards in Table 1 to Subpart JJJJ of 40 CFR Part 60 as they are shown in Table 60:

- Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.
- For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

Table 61 compares the proposed emergency generator engine's anticipated emissions of the pollutants regulated under this subpart against the subpart's emission standards.

Pollutant	NSPS JJJJ Emission Standard	Proposed EG Engine
	g/hp-hr	g/hp-hr
NO_X	2.0	1.0
CO	4.0	2.0
VOC	1.0	0.7

Table 61: Comparison of Proposed Emergency Generator Engine Emissions to Subpart 4J Emission Standards

As shown in Table 61, the proposed emergency generator engine is expected to meet each of the relevant emission standards. I continued to §60.4234 which includes the following language regarding the engine's lifelong obligation to meet these standards:

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

§60.4236 discussed the deadlines for importing or installing stationary SI ICE produced in previous model years. §60.4236(c) includes the following relevant language.

> *For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in § 60.4233 after January 1, 2011.*

The proposed emergency generator engine is expected to meet the applicable emission standards specified in §60.4233. §60.4237 includes the monitoring requirements for owners and operators of emergency stationary SI internal combustion engines, and paragraph (a) includes the following relevant language:

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

In the case of the engine associated with the proposed emergency generator, it is certified to meet the emission standards shown in Table 62 which are applicable to equivalent non-emergency engines.

Engine Type & Fuel	Maximum Engine Power	Manufacture date	Emission Standards (g/HP-hr)		
			NO_X	CO	VOC
Non-Emergency SI Lean Burn Natural Gas and LPG		7/1/2010	1.0	2.0	0.7

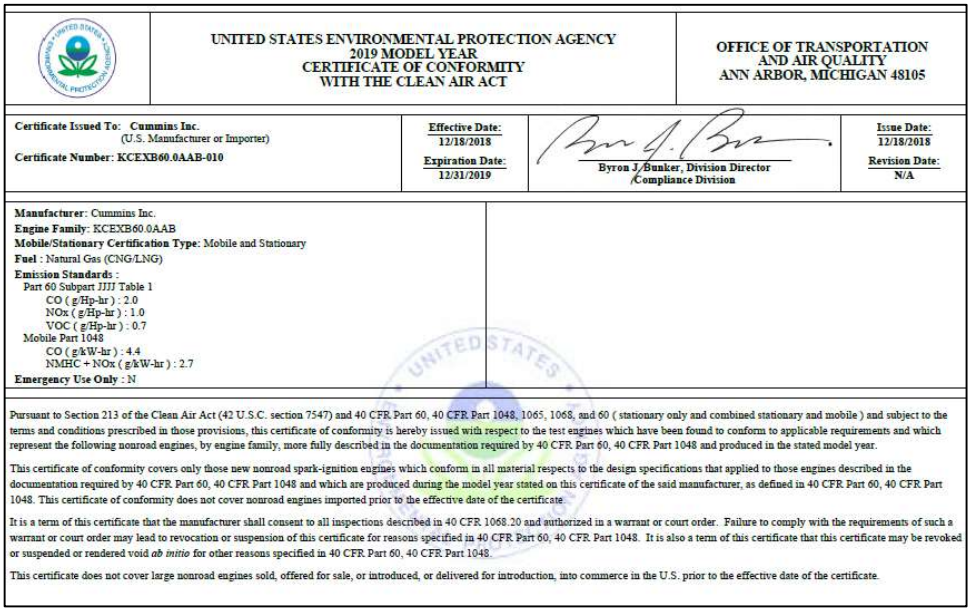
Table 62: Subpart 4J Emission Standards Applicable to Equivalent Non-Emergency Engines

Because the proposed emergency generator engine meets the relevant emission standards, it is my understanding that installation of a non-resettable hour meter is not required by this regulation.

The next section reviewed, §60.4243, provides the compliance requirements for owners and operators of stationary SI internal combustion engines. Paragraph (b) of this section includes the following relevant language:

> *(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.*
> *(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.*

As Figure 39 shows, the engine associated with the proposed emergency generator is certified to meet the emission standards required by §60.4233(e).



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
2019 MODEL YEAR
CERTIFICATE OF CONFORMITY
WITH THE CLEAN AIR ACT

OFFICE OF TRANSPORTATION
AND AIR QUALITY
ANN ARBOR, MICHIGAN 48105

Certificate Issued To: Cummins Inc.
(U.S. Manufacturer or Importer)
Certificate Number: KCEXB60.0AAB-010

Effective Date: 12/18/2018
Expiration Date: 12/31/2019

Byron J. Bunker, Division Director
Compliance Division

Issue Date: 12/18/2018
Revision Date: N/A

Manufacturer: Cummins Inc.
Engine Family: KCEXB60.0AAB
Mobile/Stationary Certification Type: Mobile and Stationary
Fuel : Natural Gas (CNG/LNG)
Emission Standards :
Part 60 Subpart JJJJ Table 1
CO (g/Hp-hr) : 2.0
NOx (g/Hp-hr) : 1.0
VOC (g/Hp-hr) : 0.7
Mobile Part 1048
CO (g/kW-hr) : 4.4
NMHC + NOx (g/kW-hr) : 2.7
Emergency Use Only : N

Pursuant to Section 213 of the Clean Air Act (42 U.S.C. section 7547) and 40 CFR Part 60, 40 CFR Part 1048, 1065, 1068, and 60 (stationary only and combined stationary and mobile) and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following nonroad engines, by engine family, more fully described in the documentation required by 40 CFR Part 60, 40 CFR Part 1048 and produced in the stated model year.

This certificate of conformity covers only those new nonroad spark-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 60, 40 CFR Part 1048 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 60, 40 CFR Part 1048. This certificate of conformity does not cover nonroad engines imported prior to the effective date of the certificate.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR 1068.20 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to revocation or suspension of this certificate for reasons specified in 40 CFR Part 60, 40 CFR Part 1048. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void *ab initio* for other reasons specified in 40 CFR Part 60, 40 CFR Part 1048.

This certificate does not cover large nonroad engines sold, offered for sale, or introduced, or delivered for introduction, into commerce in the U.S. prior to the effective date of the certificate.

Figure 39: Certificate of Conformity for Proposed Emergency Generator Engine Included in Permit Application

As §60.4243(b)(1) states, the owner or operator must demonstrate compliance according to one of the methods specified in paragraph (a) of the section. The relevant language from §60.4243(a) is shown below:

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in § 60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in § 60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

Paragraph (d) of §60.4243 includes the following additional language for owners and operators of emergency stationary RICE:

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

While this language is included in the federal regulation, some of it conflicts with requirements from Delaware's 7 DE Admin. Code 1144. 7 DE Admin. Code 1144 and Subpart 4J agree that there is no time limit on the use of an emergency engine in emergency situations, but disagreement between the regulations occurs in paragraphs (d)(2) and (d)(3).

Paragraph (d)(2) allows for operation of the engine for up to 100 hours per calendar year for any of the purposes specified in paragraphs (d)(2)(i) through (iii). These instances include:

- Maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine;
- Emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3; and
- Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

Section 4.2 of Delaware's 7 DE Admin. Code 1144 allows an emergency generator engine to "operate for an unlimited number of hours during testing or for maintenance purposes, pursuant to the definition of an emergency generator, except as restricted by 4.4 of [the] regulation." The terms "testing" and "maintenance" are defined as follows:

> ***"Testing"*** *means determining the capability of a generator to meet the specified requirements of this regulation or determining if the generator and any ancillary equipment associated with its use are functioning correctly.*
>
> ***"Maintenance"*** *means the recurrent, periodic, or scheduled work necessary to repair, prevent damage, or sustain existing components of a generator or any ancillary equipment associated with its use.*

It is my interpretation that the maintenance described in paragraph (d)(2) of the federal regulation generally aligns with the definition of "maintenance" from 7 DE Admin. Code 1144. As such, operation of the proposed emergency generator for maintenance purposes would be capped at 100 hours in accordance with the federal requirement.

As for the instances of operation for purposes of "emergency demand response", this type of operation would not be permissible by 7 DE Admin. Code 1144. Emergency demand response would require the emergency generator to provide power to the electrical grid when the supply of power is unable to meet the demand. Participating in an emergency demand response event would require the emergency

generator to operate outside of the definition of "emergency" as the term is defined by 7 DE Admin. Code 1144. The 7 DE Admin. Code 1144 definitions for the terms "emergency generator" and "emergency" are copied below:

> ***"Emergency generator"*** *means a stationary generator used only during an emergency, during testing, and for maintenance purposes. An emergency generator may not be operated in conjunction with a voluntary demand-reduction program or any other interruptible power supply arrangement with a utility, other market participant, or system operator (e.g., Delmarva Power, Delaware Electric Cooperative, PJM, etc.).*
>
> ***"Emergency"*** *means:*
> - *an electric power outage due to: a failure of the electrical grid; on-site disaster; local equipment failure; or public service emergencies such as flood, fire, natural disaster, or severe weather conditions (e.g., hurricane, tornado, blizzard, etc.); or*
> - *when there is a deviation of voltage or frequency from the electrical provider to the premises of 3% or greater above, or 5% or greater below, standard voltage or frequency.*

Furthermore, paragraph (d)(3) opens the door for operation of the emergency generator engine for the purposes of supplying power as part of a financial arrangement with another entity. This too would qualify as operation outside of the "emergency generator" and "emergency" definitions of 7 DE Admin. Code 1144.

§60.4244 details the test methods and other procedures required for owners and operators of stationary SI ICE who are required to conduct performance tests. There are no performance tests required for the proposed emergency generator engine.

§60.4245 includes the notification, reporting, and recordkeeping requirements for owners and operators of stationary SI internal combustion engines. The following paragraphs were deemed applicable:

> *(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.*
> *(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.*
> *(2) Maintenance conducted on the engine.*
> *(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.*

It should be noted that paragraph (a)(4) specifies requirements for engines that are either not certified or are certified engines operating in a non-certified manner. Neither of these applies to the engine associated with the proposed emergency generator. Paragraph (c) includes the following language regarding initial notifications:

> *(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in § 60.4231 must submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.*
>
> *(1) Name and address of the owner or operator;*
> *(2) The address of the affected source;*

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
(4) Emission control equipment; and
(5) *Fuel used.*

§60.4231 was reviewed, but none of the paragraphs were deemed applicable. As such, the initial notification requirement specified in paragraph (c) of §60.4245 was not considered applicable.

The final section of the regulation that was deemed relevant, §60.4246 focuses on the "General Provisions" of the subpart and provides instruction to refer to Table 3 of the subpart. Table 63 includes the information provided in Table 3 of the subpart.

General provisions citation	Subject of Citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in § 60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4245.
§60.8	Performance tests	Yes	Except that § 60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Table 63: Table 3 to Subpart JJJJ of Part 60

To summarize these requirements as expeditiously as possible, §60.1 includes the following relevant language:

(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

§60.2 and §60.3 include "Definitions" and "Units and abbreviations" used within the subpart, respectively. §60.4 specifies addresses to use, and includes the following language, which was edited to focus on the applicable portions:

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air Protection Division, Mail Code 3AP00, 1650 Arch Street, Philadelphia, PA 19103-2029.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(9) State of Delaware, Department of Natural Resources & Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19903.

§60.5 discusses the determination on whether a proposed action constitutes construction (including reconstruction) or modification. In this case, the installation of the proposed emergency generator is clearly an example of construction. §60.6 includes the following language regarding the "review of plans".

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.
(b)
(1) A separate request shall be submitted for each construction or modification project.
(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.
(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall

(1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or
(2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

The language contained within §60.6 has been satisfied through the submission of the permit application for the proposed emergency generator.

§60.7 includes the notification and record keeping requirements for the subpart. The following sections were deemed relevant:

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:
(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
(2) [Reserved]
(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:
(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.
(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.
(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

Requirements related to this language from §60.7 will be included in the permit. The following applicable language was taken from the next section of the subpart, §60.8.

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator

(1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology,

(2) approves the use of an equivalent method,

(3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance,

(4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or

(5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

(1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or

conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the

sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, www.epa.gov/ttn/emc, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

(i) Preparing the sample;
(ii) Confirming the true concentration of the sample;
(iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at http://standards.gov/standards_gov/a119.cfm. The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4)of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, http://www.epa.gov/ttn/emc.

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the

appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations," may be used.

While the requirements of §60.8 apply, I am only including certain paragraphs of the section in the permit.

§60.9 states that "[t]he availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter." §60.10 includes language which essentially allows states to adopt and enforce emission standards or limitations "provided that such emission standard or limitation is not less stringent than the standard applicable to such facility" and requires "the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility."

As mentioned in Table 63, the requirements from §60.11 are specified in subpart JJJJ. The following language from §60.12 deals with requirements related to circumvention:

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

The next several sections did not possess language deemed necessary to include in the permit. While it currently does not apply, the requirements of §60.14 focus on modifications to equipment, which include "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies". Similarly, §60.15 contains requirements related to reconstruction of an existing facility. §60.16 contained a table of the "Prioritized Major Source Categories" and §60.17 included a list of incorporations by reference. §60.18 contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61; since no control devices are required to comply with any applicable subparts, this section was not considered relevant.

The final section reviewed, §60.19, specified the general notification and reporting requirements of the part. The language below was determined to be relevant:

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)

(1)

(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

This concludes the summary of requirements under Subpart JJJJ to 40 CFR Part 60 which were determined to be applicable to the engine associated with the proposed emergency generator.

40 CFR Part 63 Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*, was determined to be applicable because the proposed emergency generator would include a stationary reciprocating internal combustion engine (RICE) and would be considered an area source of HAP emissions. An area source is any source of HAP emissions less than a major source of HAPs (≥10 TPY of any single HAP or ≥25 TPY of any combination of HAPs). Using the EPA's recommendation to assume worst case operation of an emergency generator is 500 hours per year, the generator engine is estimated to emit no more than 0.18 tons of HAPs during any given twelve (12) month period.

According to §63.6590(a)(2)(iii), the new emergency generator engine is considered an affected source as a new stationary RICE because it is located at an area source of HAP emissions and construction occurs after June 12, 2006. However, §63.6590(c)(1) states that the emergency generator meets the requirements of this part by meeting the requirements of 40 CFR part 60 Subpart JJJJ as a new stationary RICE located at an area source. As a result, no further requirements apply for such engines under this part.

PRE-NOTIFICATION DRAFTS & ASSOCIATED COMMENTS

On June 24, 2022, I sent draft copies of **Permits: APC-2022/0048-CONSTRUCTION** & **APC-2022/0049-CONSTRUCTION** to Peter Ettinger, Chief Strategy Officer for BioEnergy Devco, as well as other representatives of BioEnergy Devco and Verdantas, LLC via email. The intention of sending draft copies of the permits to these individuals was to provide them with the opportunity to provide feedback and to identify any errors, omissions, unclear or confusing provisions or conditions, or any other conditions which could be considered infeasible prior to the commencement of the public advertisement period for these permits.

This practice of providing and allowing comment on "pre-notification" draft permits to the applicant is standard practice for facilities within the Title V permitting universe, but was deemed appropriate due to the high profile nature of the process for which the permit applications and corresponding draft permits had been prepared. The email to which these draft documents had been attached included instruction to review the documents and provide any comments in writing no later than close of business on July 8, 2022.

In response to the draft permit documents, comments were provided verbally on two (2) instances prior to receiving them in writing on July 8, 2022. The first of those verbal communications occurred on June 28, 2022 when Brian Lyncha, a Project Manager representing Verdantas, LLC, gave me a call to discuss a few items he had personally identified as potential issues. The second instance in which comments and questions on the pre-notification draft permits were fielded and answered occurred on July 5, 2022. This meeting occurred over Microsoft Teams and again included only myself and Brian Lyncha. While Brian and I were the only participants in the meeting, he was there relaying comments provided by representatives of BioEnergy Devco.

Formal, written comments on the draft permit documents were later received via email on July 8, 2022. Of the three (3) comments provided, the first two (2) were discussed during the June 28th phone conversation and the third was discussed during the July 5th meeting. Each of the three (3) comments provided were in relation to the permit associated with the proposed anaerobic digesters with the associated flare, RTO, and other air pollution control & biogas upgrade equipment. No comments related to the permit associated with the proposed emergency generator were received.

The first two (2) comments included in the July 8, 2022, letter to the Department were provided as follows:

1. *Condition 2.1.2.2:*
   The permit indicates Nitrogen Oxide (NOx) Emission limits of 0.005 lbs/hr and 0.022 tons per rolling twelve (12) month period from the flare. The calculated emissions for this source as stated in the submitted permit application are 3.7 lbs/hr and 16 tons/year, respectively.

2. *Condition 2.1.5.2:*
   The permit indicates Carbon Monoxide (CO) Emission limits of 0.004 lbs/hr and 0.018 tons per rolling twelve (12) month period from the flare. The calculated emissions for this source as stated in the submitted permit application are 16.8 lbs/hr and 74 tons/year, respectively.

As Brian pointed out during our June 28th phone conversation, these limits had correctly included emissions from the combustion of natural gas (the flare's pilot burner fuel), but had incorrectly omitted emissions resulting from the combustion of process gas. I reviewed the permit application and the internal memorandum on the permits and verified that Brian was correct. These emission rates had been accounted for during the process of completing the regulatory review and dispersion modeling exercises, but the wrong values had mistakenly been copied and pasted into the permit.

The permit was amended to reflect the emission rates that had been requested in the permit application. While not included in the July 8, 2022, letter, Brian also verbally identified instances where the source of emission factors had been referenced incorrectly. These issues were also corrected.

The third comment provided in the July 8, 2022, letter was submitted as follows:

3. *Section 3 Operational Limitations and Appendix A:*
   The permit includes conditions on operations that are specific to control and process equipment produced by certain manufacturers. It's Bioenergy's intention to construct, if permitted, the proposed facility with the equipment for which specifications were provided to DNREC in the permit application. But we are concerned about the limitations imposed in the draft permit should identified equipment is not available due to unforeseen circumstances such as supply chain issues or that technology improvements can be made to further reduce emissions beyond what's stated in the current application without alteration of construction standards.

   Bioenergy Devco understands, supports and is committed to the purpose of the permit to identify and quantify potential emissions to the atmosphere from the facility. And to assure that said emissions do not exceed standards designed to be protective of human health and the environment. The permit is a mechanism to assure that the facility is operated in accordance with this purpose.

   With respect to Section 3 and Appendix A, Bioenergy Devco is seeking flexibility through less specific operational and manufacturer detail in the permit such that should operational or manufacturer changes become necessary, due to supply chain issues or improvements in emissions reductions in given technologies during or after construction, and said changes provide functional equivalency and do not increase permitted emissions, that said changes could be made without having to significantly modify the permit.

While BioEnergy's concern that "unforeseen circumstances such as supply chain issues" could prevent equipment from being readily available is a valid concern, it does not change the Department's requirement that the equipment applied for be the equipment that is ultimately installed. The operating

specifications of equipment varies to some degree from manufacturer to manufacturer. In the case of equipment which has the potential to emit directly to the atmosphere, a change in specifications from one manufacturer to another may have an impact on the dispersion of pollutants in the atmosphere. The Department specifies the manufacturer and model of all relevant equipment in construction and operating permits issued, and there is no reason for there to be an exception in this case.

This same rationale applies to the concern that the specification of equipment in the permit could prevent improvements in emissions reductions. Should the applicant desire to install equipment that is more efficient at removing pollutants from the waste stream, it still needs to be requested and approved by the Department. These types of changes would likely trigger the need for a fifteen (15) day public advertisement period.

RECOMMENDATIONS

The proposed project and attached draft permits comply with all applicable zoning requirements and federal and state air pollution control laws and regulations. I recommend that the attached **Draft Permits: APC-2022/0048-CONSTRUCTION** & **APC-2022/0049-CONSTRUCTION** be included for review during the public review process.

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pc: Dover File