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ENGINEERING EVALUATION / FACT SHEET

BACKGROUND INFORMATION

Application No.:	R13-3708
Plant ID No.:	053-00134
Applicant:	MGS CNP 1, LLC
Facility Name:	BECCS Plant
Location:	Point Pleasant
NAICS Code:	221117 - Biomass Electric Power Generation
Application Type:	Construction
Received Date:	February 24, 2025
Engineer Assigned:	Edward Andrews
Fee Amount:	$4500.00
Date Received:	March 13, 2025
Complete Date:	June 23, 2025
Due Date:	September 21, 2025
Applicant Ad Date:	March 13, 2025
Newspaper:	*The River Cities Tribune*
UTMs:	Easting: 403.93 km Northing: 4,308.98 km Zone: 17N
Latitude/Longitude:	38.9245069°N/-82.1082251°W

ACTION SUMMARY

MGS CNP 1, LLC (MSG) filed a permit application for the construction of 940 million (MM) Btu per hour, biomass fired boiler for the purpose of generating electricity not for sale. The application includes other emission units to support the operation of the biomass fired boiler (e.g. fuel handling, cooling tower, emergency generator). As part of this application, MGS proposed to control the emission from the biomass boiler using dry sorbent injection (DSI) coupled with fabric filter baghouse, selective catalytic reduction (SCR), oxidation catalyst, wet scrubber, and amine absorber for carbon dioxide capture (CCS). These control measures will limit the potential to emit from the facility to the following, which are below the major source threshold level in the Title V Operating Permit and Prevention of Significant Deterioration Permitting Programs:

Table 1 - Summary of Facility-Wide Emissions in TPY

Pollutants							
NO_x	CO	SO_2	VOC	PM	PM_{10}	$PM_{2.5}$	Total HAPs
90.90	46.48	50.79	55.78	59.09	83.95	75.65	24.01

The biomass boiler is subject to provision and emission standards in State Rules 2 and 10; and Federal Rules Subpart Db of Part 60, Subpart JJJJJJ of Part 60.

The administrative support at the facility (offices) will rely on electricity supplied by the local electricity retailer/provide. The emission units proposed in the application will be supplied by the facility either generated by the biomass boiler or the NG Startup Generator and not connected to the gird. Therefore, the biomass boiler is not subject to EPA emissions trading program which are: Title IV Acid Deposition Control (AKA: Acid Rain Program); and Section 126 of Clean Air Act (AKA: Cross-State Air Pollution Rule – CSAPR). The electricity generated by the biomass boiler will not be sold.

DESCRIPTION OF PROCESS

The fluidized bed boiler at the BECCS facility will use clean woodchips as fuel during normal operation and burn natural gas during start up process. MGS CNP1 intends to commence construction of the BECCS facility in 2026 with startup operations in 2029. The proposed plant will include the following major processes:

- Receiving, storing, and handling raw materials such as wood chips, sand and sodium bicarbonate
- Biomass boiler and environmental train
- Post-combustion carbon capture unit (PCCU)
- Power generation
- Storage and handling of fly ash and bottom ash
- Balance of Plant (BoP) facilities including, but not limited to:
    - Raw Water / Utility Water
    - NG Startup Generator
    - Electric and Diesel Driven Fire Water Pumps
    - Cooling Tower
    - Storage Tanks
    - Wastewater Treatment

The main emission sources that are being proposed to be at the facility include:

- Hoppers, Bins and Conveyors in Material Handling
- One Wood Chip Fired Bubbling Fluidized Bed (BFB) Boiler
- One Mechanical Draft Evaporative Cooling Tower
- Trucks Traveling on Paved In-plant Road
- Storage Silos for Fly Ash and Bottom Ash
- Equipment Leaks
- One NG Startup Generator with an engine output rating no greater than 3,000 hp.
- One Fire Water Diesel Engine Pump with an engine output rating no greater than 600 hp.

Two Storage Tanks – an amine makeup tank, and a lean amine tank. The facility will also have two additional tanks, a diesel tank and a biodegraded amine tank, but according to Table 45-13B in 45CSR13, these two tanks are de minimis sources and do not need to be included in this permit application.

Raw Material Receiving and Transfer

Truck Traffic

Raw material used as fuel will be clean wood chips. The wood chips will be delivered to the site by trucks. The wood chips will be stored outdoor in piles until burned as fuel in the fluidized bed boiler. Other materials trucked to the facility include sand, sodium bicarbonate ($NaHCO_3$), ammonia and amine solutions. The substances trucked out of the facility include fly ash, bottom ash, and degraded amine.

Raw Material Receiving and Handling

Biomass will be unloaded from the trucks by truck tippers which dump the biomass into two receiving hoppers. Dust is controlled by slight negative pressure in the receiving hoppers. The extracted dust laden air will be directed through a baghouse before discharge to the atmosphere.

Conveying and Processing

From the hoppers, biomass is conveyed via covered conveyors to an uncovered chip pile, which is large enough for at least 14 days of storage. From the storage pile, front end loaders will be used to load the biomass into a biomass receiving hopper and the subsequent conveyors will transport the material to the day bins at the biomass boiler for feed loading.

The chip pile will be surrounded by a drainage trench to catch storm water runoff for treatment and disposal.

Combustion Process

MGSCNP1 will construct one bubbling fluidized bed (BFB) boiler. BFB boiler has been proven to efficiently combust wood biomass. MGSCNP1 proposes to fuel the new boiler with woody biomass under normal operation. Natural gas will be used for startup operation of the boiler only.

As discussed in this section, the boiler will be capable of accommodating the following:

1) Natural gas for boiler startup; and

2) Wood (biomass) for normal operation.

The boiler is not being designed to combust natural gas as a secondary fuel for power generation. The boiler heat input capacity for natural gas will be rated at 180 million British thermal units per hour (MMBtu/hr). The anticipated maximum design heat input of the boiler while combusting woody biomass will be 944 MMBtu/hr.

BFB boilers are capable of efficiently combusting woody biomass. A fluid-like mixture of solid fuel and other solids (such as sand) is suspended in the BFB boiler's combustion chamber by a turbulent upward air flow. The turbulent mixing provides for greater combustion efficiency in the BFB boiler.

Combustion of woody biomass (in normal operation) and natural gas (at startup only) in the proposed BFB boiler accounts for most of the potential to emit regulated air pollutants from the proposed facility. A discussion of the control technology and methods to be used and the associated estimates of air pollutant emission rates are discussed below.

Attachment F in Appendix B of the application shows a detailed process flow diagram of the major equipment, control technologies, and material flows for the BFB boiler system. As depicted in the figures, natural gas will be provided via pipeline, woody biomass will be provided by wood suppliers via incoming trucks and stored on-site. Also, as part of the process, MGS CNP 1 will be installing silos to store materials required to support the proposed woody biomass boilers. The silos anticipated to be installed are as follows:

- Sand storage silo with breather vent to support boiler operation; and
- Sorbent (Sodium Bicarbonate ($NaHCO_3$)) storage silo to support as needed dry in-duct sorbent injection.

Both silos will be vented to the boiler with particulate emissions controlled by the boiler PJFF.

Fly ash silos with filters for storing the fly ash and economizer ash from biomass combustion.

Proposed Air Pollution Control Technologies / Techniques

The proposed boiler will utilize a combination of state-of-the-art control devices/techniques to minimize potential emissions of regulated air pollutants. A discussion of these devices/techniques, along with the air pollutant being controlled is provided below.

Pulse Jet Fabric Filter (Baghouse): Particulate Matter Control

Emissions of particulate matter (PM) will be controlled by a Pulse Jet Fabric Filter (PJFF) commonly referred to as a baghouse. Modern baghouses can provide a high level of control efficiency, more than 99% reduction of particulate emissions.

The fabric filter proposed for this project is a self-cleaning dry filtration system. Dust is collected on the external surface of the filter, where it commonly forms into a cake. When the dust cake is at an appropriate thickness (based on time) a pulse of compressed air is pushed through the interior of the filter, knocking the dust cake free to fall into the hopper below for removal. The dust from the pulse jet fabric filter is combined with the economizer ash for removal.

Dry In-Duct Sorbent Injection (DSI): Hydrogen Chloride and Acid Gas Control

HCl is formed from the presence of chlorine in the wood. MGSCNP1 will be installing a dry induct sorbent injection system, which will utilize NaHCO3 as the injection sorbent material. The dry sorbent is typically injected as a powder into the flue between the furnace of the boiler and baghouse. The dry sorbent reacts with the targeted air pollutants (i.e., hydrogen chloride (HCl) and other acid gases) and removes them from the flue gas before such pollutants are subsequently being filtered from the flue gas by the baghouse. The system is designed to reduce acid gases such as HCl and is also effective at reducing sulfur dioxide and sulfuric acid mist. Initial engineering estimates indicate that the incorporation of the BFB boiler design, baghouse, and the dry induct sorbent injection is sufficient to maintain HCl and other acid gases to minor source levels.

Selective Catalytic Reduction (SCR): Nitrogen Oxides (NO_X) Control

An SCR system will be utilized for controlling NO_X emissions. The SCR process chemically reduces the NO_X molecule into molecular nitrogen and water vapor. A nitrogen-based reactant such as ammonia is injected into the ductwork, downstream of the combust unit. The waste gas mixes with the reagent and enters a reactor module containing a catalyst. The hot flue gas reagent diffuses through the catalyst. The reagent reacts selectively with the NO_X within a specific temperature range and in the presence of the catalyst and oxygen.

A small amount of the ammonia will “slip” through the process without reacting and be emitted in the boiler’s exhaust. This emission of ammonia is termed “ammonia slip.”

Oxidation Catalyst: Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs) Control A properly designed firebox and burner coupled with effective operating controls will minimize CO and VOC generation by providing the proper residence time, temperature and combustion zone turbulence, as well as the proper air-to-fuel ratio. In addition to combustion controls such as proper boiler design and operation, CO oxidation catalysts will be applied to the BFB to control the CO and VOC emissions. The oxidation catalyst is typically a precious metal catalyst (e.g. platinum), which has been applied over a metal or ceramic substrate. The catalyst lowers the activation energy required for the oxidation of CO to temperatures between 400 and 1100 °F. No chemical reagent addition is required.

Injection of Caustic (Wet Flue Gas Desulfurization): Sulfur Oxides (SO_X) Control

Caustic will be injected into the boiler flue gas to remove SO_X in a process known as wet flue gas desulfurization. The aqueous caustic solution is sprayed from the top of the polishing scrubber column. Blowdown from the wash water / caustic solution is sent to the wastewater treatment plant.

Ash Handling, Storage and Shipment Process

The combustion of biomass in the proposed boiler will result in the formation of bottom ash and fly ash. The resultant amount of ash is reflection of the ash in the fuel.

The fly ash is the particulates captured by the high efficiency baghouse. The generated fly ash will be transferred to two ash storage silos via two PJFF Ash Collection Drag Chain Conveyors, two PJFF Ash Collection Surge Bins, two PJFF Ash Transport Drag Chain Conveyors, an Ash Bucket Elevator, and an Ash Distribution Drag Chain Conveyor. Each fly ash storage silo will be equipped with a pulse jet filter to minimize any PM from the storage silo. When a sufficient volume has been collected, the fly ash will be mixed with utility water and then trucked off site. The fly ash will have a minimum moisture content of 10% by weight when loaded into trucks. The chute used to dispense fly ash into the truck will be designed to minimize PM emissions.

Bottom ash along with heavy non-combustible material will be collected in two metering conveyors and transferred to two vibrating conveyors. The bottom ash is separated from sand on the vibrating conveyor, after which it is moved outside of the boiler island and cooled. This material will be delivered to enclosed bins for storage and to be trucked away and disposed of.

Post-Combustion Carbon Capture

The Post-Combustion Carbon Capture Unit (PCCU) is designed to remove greater than 95% of the CO_2 in the combustion flue gas from the biomass boiler. For this emission unit (biomass boiler), the applicant is not required to control CO_2 emissions (the facility is minor source, and the unit is not triggering federal emission standard to control CO_2 emissions). This process description is for a generic amine carbon capture unit. Depending on the carbon capture licensor that is selected to move forward in the project, there may be slight modifications in the operation. The CO_2 that is captured is dehydrated and compressed to pipeline specifications prior to being permanently sequestered offsite of the BECCS facility.

Absorber

In the absorber, flue gas from the direct contact cooler containing CO_2 is fed to an absorption column where it’s contacted with a downflowing amine-based solvent. The amine removes the CO_2 from the flue gas. The amine which contains the captured CO_2 exits the absorption column as rich amine bottoms liquid. The produced flue gas free of CO_2 is vented from the top of the absorber column to atmosphere.

Amine Regenerator

The rich amine stream leaving the amine absorber is routed to the regenerator column to regenerate amine. This is achieved by the regenerator column being operated at conditions that separate the CO_2 vapor from the liquid amine.

The amine feed flows to the top of the regenerator column. Separation of the CO_2 and amine occurs by a stripping effect created as amine comes in contact with the up-flowing CO_2 vapor. The heat required for regeneration will be supplied by low pressure (LP) Steam to a reboiler. The LP steam is provided from the biomass boiler steam system. The regenerated lean amine from the regenerator is pumped to the absorber column as feed to complete the cycle of CO_2 removal from the flue gas.

CO_2 vapors rise to the top of the column, where they are passed through a condenser. A reflux drum after the condenser separates the liquid amine from the CO_2 vapor. The liquid amine from the condenser is sent back to the regenerator column as reflux while the CO_2 vapor is sent to compression.

Reclaimed Amine

Degradation of amine solvents occurs over time due to the presence of oxygen and other impurities in the flue gas, resulting in deterioration of long-term performance. Purification of the amine solvent is therefore required to maintain operating efficiency. Reclamation includes both neutralization and regeneration steps. The contaminated amine solution is first mixed with a strong base, such as caustic, to reform the amine and separate it from degradation products. Heat is then applied to boil off the free amine and water and leaving behind sludge of degradation products. The degradation products are removed periodically from site by trucks. Reclaimed amine is sent to the lean amine tank for recirculation. Makeup amine will be brought to site using trucks, stored in the Amine Makeup Tank and then supplied to the amine absorber system to account for losses to the degradation products.

CO_2 Compression

CO_2 product from the reflux drum of amine stripper is dehydrated and compressed to 1,850 psig and 100°F for sequestration via an external pipeline.

Amine Storage

One Lean Amine Tank and one Amine Makeup Tank will be installed to store lean amine and makeup amine, respectively. Makeup amine will be delivered to the makeup amine tank by truck, while makeup demineralized water is provided from the demineralized water system for diluting the solvent.

Power Generation

Steam Turbine Generator

The steam turbine generator (STG) extracts the thermal energy from the superheated, pressurized steam produced by the biomass boiler and uses it to perform mechanical work. The mechanical work is then converted to electrical power by the generator. The resulting steam exhaust from the STG is then cooled in a surface condenser with cooling water. The steam condensate from the surface condenser is recirculated back to the deaerator.

Auxiliary Processes and Balance of the Plant (BoP) Facilities

Emergency Engine

The proposed plant will require an emergency fire water pump. This piece of emergency equipment will be fueled with ultra-low sulfur distillate fuel oil (diesel) and operate only a limited number of hours (100 hours per year or less) for testing purposes under normal conditions. To support this emergency equipment, an above-ground tank with a maximum capacity of 1,292 gallons (gal) will be installed. This tank will be designed to store the ultra-low sulfur distillate fuel oil. According to Table 45-13B in 45CSR13, the diesel tank is a de minimis source and does not need to be included in this permit application.

Cooling Tower

A dedicated cooling tower will be installed to supply cooling water to all plant users. The Cooling Tower makeup is supplied using Utility Water (Raw water that has been treated).

Storage Tanks

Two storage tanks will be installed to support the operation of the facility which are a lean amine tank and an amine makeup tank.

Wastewater Treatment Plant

The wastewater treatment plant will receive water from the direct contact cooler/polishing scrubber system. The scrubbing liquid will have direct contact with the flue gas exhaust from the boiler. The scrubber solution will absorb ammonia, sulfuric acid and hydrochloric acid that could be present in the flue gas. The scrubbing solution will be sent to the Wastewater Treatment Plant for further processing before it is discharged to the outfall. It is conservatively assumed that 10% of the ammonia, sulfuric acid and hydrochloric acid in the flue gas could be emitted from the Wastewater Treatment plant. The wastewater treatment plant will also receive water from the demineralized water system, raw water treatment, flush pond water, cooling tower water and boiler blowdown water. These streams are not expected to contribute emissions from the wastewater treatment plant.

Others

To support the operation of the facility, other facilities will also be installed such as raw water/utility water, fire water, demineralized water generation, natural gas system, storm water pond, first flush pond, buildings, etc. These facilities are not expected to generate any air emissions.

SITE INSPECTION

On March 25, 2025, the writer conducted a site inspection of the proposed site. Mr. William Calhoun, Vice-President for MGS, Mr. Micheal Dearing, Principal Consultant for ERM accompanied the DAQ personnel during this inspection.

The turn off from Ohio River Road (West Virginia Route 62) to the access road for the facility is approximately 3 miles north of Point Pleasant High School. Once on the access road, one would travel approximately 950 feet in a north-by-north westly direction to the proposed site. There is one existing business (Steel Specialties) that is due south of the proposed by 450 feet away.

The notable landmarks are the smokestacks from the Gavin Power Station, near Cheshire, Ohio are northwest of the site, and the Mason County Airport is southeast as well.

Observed activities that have occurred at the is the maintenance of an unimproved access road to several existing oil wells located on the property. These oil wells are operated by Pillar Energy LLC. The actual location of the proposed equipment at the site is covered by vegetation (e.g., kudzu).

Figure 1 - Photographic of Site on March 25, 2025.

There are no residences within sight of the proposed facility. Using geographic information systems (e.g., google earth, ArcMap), there is a cluster of residual homes approximately 1,300 feet away in a south easterly direction from the site. This writer deems that the proposed site is appropriate for the proposed emission units.

ESTIMATE OF EMISSIONS BY REVIEWING ENGINEER

The applicant used a variety of different approaches to determine the potential emissions from the emission units proposed in this application. The sources or approaches include equipment manufacturer's specifications, manufacturer’s emissions data, AP-42, and other available information (e.g., test data). The startup emissions were based on average heat input during the startup event of 414.3 MMBtu/hr from both fuels with an average of 131.1 MMBtu/hr from natural gas and a duration of 10 hours per startup event.

Table 2Hourly Emissions from the Biomass Boiler

Pollutant	Startup (lb/hr)	Normal Ops w/o Carbon Capture (lb/hr)	Normal Ops w/Carbon Capture (lb/hr)
Oxides of Nitrogen (NOx)	90.90	20.20	20.20
Carbon Monoxide (CO)	45.45	10.20	10.20
Sulfur Dioxide (SO_2)	13.82	11.58	11.58
PM	3.64	7.99	7.99
PM_{10}	6.91	15.54	15.54
$PM_{2.5}$	6.91	15.54	15.54
Volatile Organic Compounds (VOCs)	0.73	1.89	4.43
Sulfuric Acid (H_2SO_4)	7.64	6.35	6.35
Hazardous Air Pollutants (HAPs)			
Lead (Pd)	0.05	0.05	0.05
Hydrochloric Acid HCl	18.55	1.18	1.18
Mercury (Hg)	0.11	3.30E-3	3.30E-3

Total Organic HAPs	0.73	1.91	3.97
Total Metallic HAPs	0.11	0.27	0.27
Total HAPs*	19.39	3.36	5.42

* Total HAPs include HCl, Total Organic HAPs, and Total Metallic HAPs.

For metallic HAPs, the applicant used the AP-42 emissions factors in Table 1.6-4 for trace elements from wood residue combustion. AP-42 noted these specific emission factors for trace elements were based on boilers with no controls or particulate matter control. The emission factor for these individual elements was not noted if a factor was or was not based on a particulate matter control device being used. Thus, the applicant used these factors without applying any removal efficiency for the proposed controls.

From the actual Biomass Boiler, most of the hazardous air pollutants (HAPs) emissions are in the form of HCl emissions. The controlled HCl emissions were based solely on application based that using the dry sorbent injection. The wet scrubber will also remove HCl from the exhaust stream. There might be an additional reduction in HCl emissions due to the amine's absorbing HCl and other acid gases (e.g., H_2SO_4 and SO_2). In the proposed emission rates for these acid gases, the applicant did not apply or account for any additional reduction due to the carbon capture unit.

SO_2 and H_2SO_4 emissions will be controlled primarily using the wet desulfurization scrubber (wet scrubber).

The carbon capture unit has the potential to emit VOC and volatile organic HAPs due to the degradation of the amine (MDEA and MEA) in the carbon capture unit. Degradation, particularly thermal degradation, can become significant at higher temperature, especially when combined with factors like the presence of contaminates (e.g., nitrite). These HAPs emissions are in the form of nitrosamines, acetaldehyde, and formaldehyde.

Table 3 Annual Emissions from the Biomass Boiler

Pollutant	Startup (tpy)	Normal Ops w/o Carbon Capture (tpy)	Normal Ops w/Carbon Capture[1] (tpy)
Oxides of Nitrogen (NOx)	2.5	87.92	90.42
Carbon Monoxide (CO)	1.25	44.40	45.65
Sulfur Dioxide (SO_2)	0.38	50.40	50.78

Pollutant	Startup (tpy)	Normal Ops w/o Carbon Capture (tpy)	Normal Ops w/Carbon Capture[1] (tpy)
PM	0.10	34.78	34.88
PM_{10}	0.19	67.65	67.84
$PM_{2.5}$	0.19	67.65	67.84
Volatile Organic Compounds (VOCs)	0.73	8.24	19.04
Sulfuric Acid (H_2SO_4)	0.21	27.66	27.87
Hazardous Air Pollutants (HAPs)			
Lead (Pd)	0.02	0.20	0.22
Hydrochloric Acid (HCl)	0.51	5.14	5.65
Mercury (Hg)	0.00	0.01	0.01
Total Organic HAPs	0.02	8.32	16.49
Total Metallic HAPs	0.003	1.20	1.20
Total HAPs*	0.53	14.66	23.36

[1] Startup emission are included.

The annual startup emission was based on 55 hours per year. During these startups, the unit would be initial fired using natural gas (up to 180 MMBtu/hr) with the wood chip being introduced during the startup event. Most of the controls require the exhaust temperature to be elevated to function (e.g., SCR, Oxidation Catalyst, DSI, etc.). These startup emissions were either based on firing natural gas with average heat input 131 MMBtu with total average heat input of 414 MMBtu/hr.

The annual emissions are based on 768 hours of normal operations without the carbon capture unit operating, 7,937 hours of normal operations with the carbon capture unit online, and 55 hours for startup operations.

To support the operation of the biomass boiler, 929,147 tons of wood chips (biomass fuel) will need to be received, stored, and fed to the boiler. These activities have the potential to generate dust in the form of fugitive particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions. The applicant used a combination of vender provided data, and approaches outline in AP-42 for wind erosion from open stockpile and transfer points (material drop operations) to estimate these emissions. Hourly potential is based on annual reduced to hours, which equates to 106.07 tons of wood chip per hour. Some of the equipment is duplicate sources (e.g., Receiving Hopper 1 and Receiving Hopper 2) and

Table 4 Emissions from the Wood Chip (Fuel) Handling

Source Name	**Transfer Rate**		**Short-term Emissions (lb/hr)**			**Annual Emissions (tpy)**		
	(tons/hr)	**(tons/yr)**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**PM**	**PM_{10}**	**$PM_{2.5}$**
Receiving Hoppers	106.07	929,146.92	1.08	1.08	1.08	4.72	4.72	4.72
Conveyor 1 for Receiving Hopper 1	106.07	929,146.92	0.06	0.03	0.004	0.19	0.09	0.01
Conveyor 2 for Receiving Hopper 2	106.07		0.06	0.03	0.004			
Stockpile Loading Fugitives	106.07	929,146.92	0.11	0.05	0.01	0.37	0.18	0.03
Feed Hopper	106.07	929,146.92	0.112	0.053	0.008	0.37	0.177	0.03
Conveyor from Feed Hopper to SC A/B	106.07	929,146.92	0.06	0.027	0.004	0.19	0.09	0.01
SC A to Fuel Metering Bin A	106.07	929,146.92	0.06	0.027	0.004	0.19	0.09	0.013
SC A to Fuel Metering Bin B	106.07		0.06	0.027	0.004			

Source Name	Transfer Rate		Short-term Emissions (lb/hr)			Annual Emissions (tpy)		
	(tons/hr)	(tons/yr)	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Fuel Metering Bin A	106.07	929,146.92	0.06	0.03	0.004	0.19	0.09	0.01
Fuel Metering Bin B	106.07		0.06	0.03	0.01			
Wood Chip Stockpile		929,146.92				0.21	0.11	0.01
Totals			1.72	1.38	1.13	6.43	5.55	4.83

To aid in suspending the wood chips (fuel) in the boiler, sand is added to the boiler help suspend the wood chips above the bed in the furnace section of the boiler. There is a recoverable amount of sand that is entrained in the bed ash (bottom ash) from the boiler. The mixture of bed ash and sand is conveyed from the boiler to one of two vibrating screens to separate the recoverable sand from the ash. Presented in the following table are the hourly and annual particulate matter emissions associated with the sand handling at the facility.

Table 5 Emissions from the Ash & Sand Handling

Source Name	Transfer Rate		Hourly Emissions (lb/hr)			Annual Emissions (tpy)		
	tons/hr	tons/yr	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Ash Collection Drag Conveyor A to Surge Bin 1	4.5	39,420	0.54	0.25	0.04	1.79	0.85	0.13
Ash Collection Drag Conveyor B to Surge Bin 2	4.5		0.54	0.25	0.04			
Ash Surge Bin A & B	4.5	39,420	0.54	0.25	0.04	1.79	0.85	0.13
Drag Chain Conveyor from Surge Bin to ash transfer conveyor	4.5	39,420	0.54	0.25	0.04	1.79	0.85	0.13
Bucket Elevator (BE)	4.5	39,420	0.54	0.25	0.04	1.79	0.85	0.13
Ash Drag Chain from BE to Ash Silos	4.5	39,420	0.54	0.25	0.04	1.79	0.85	0.13
Ash Drag Chain A from Econ Hopper to Econ Ash Surge Bin	3.3	28,908	0.39	0.19	0.03	1.31	0.62	0.09

Source Name	Transfer Rate		Hourly Emissions (lb/hr)			Annual Emissions (tpy)		
	tons/hr	tons/yr	PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$
Ash Drag Chain B from Econ Hopper to Econ Ash Surge Bin	3.3	28,908	0.39	0.19	0.03	1.31	0.62	0.09
Econ Ash Conveyor A	3.3	28,908	0.39	0.19	0.03			
Econ Ash Conveyor B	3.3		0.39	0.19	0.03			
Fly Ash Silo A	7.8	68,328	0.02	<0.01	<0.01	0.06	0.03	<0.01
Fly Ash Silo B	7.8		0.02	<0.01	<0.01			
Fly Ash Truck Loading	8.6	75,336	<0.01	<0.01	<0.01	0.01	<0.01	<0.01
Bed Ash Screw Conveyor A	1.125	9,855	0.004	0.002	0.002	0.02	0.008	0.008
Bed Ash Screw Conveyor A	1.125		0.004	0.002	0.002			
Vibrating Screener A	1.125	9,855	0.004	0.002	0.002	0.02	0.008	0.008
Vibrating Screener B	1.125		0.004	0.002	0.002			
Sand Receiving Hopper	50	1,752	0.345	0.165	0.165	0.01	0.003	0.003
Inclined Sand Conveyor	50	1,752	0.173	0.083	0.083	0.01	0.001	0.001
Transfer Conveyor A	0.125	1,095	0.000	0.000	0.000	0.01	<0.01	<0.01
Transfer Conveyor B	0.125		0.000	0.000	0.000			
Bucket Elevator A	0.325	2,847	<0.01	<0.01	<0.01	0.01	0.002	0.002
Bucket Elevator B	0.325		<0.01	<0.01	<0.01			
NaCOH3 Vent Hoppers	0.05	438	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
		Totals	5.40	0.258	0.258	11.72	5.54	0.87

The is a makeup sand silo associated with the sand handling system. This silo is vent directly to the boiler and the PM emissions associated from the silo are accounted/included with the PM emissions from the boiler, which is why the makeup sand silo emission is not presented in the above table.

The applicant used engine performance and emissions data from the engine manufacturer data and appropriate emission factors from AP-42 to determine the potential emission from the engine for the NG Startup generator and the diesel-fired engine for the fire water pump.

Table 6Potential Emissions from the Engines (NG Startup Generator & Firewater pump)

Source Name	NG Startup Generator	Firewater Pump
Engine Type	Spark Ignition	Compression Ignition
Model	TBD	C18H0-UFAD42
Model Year	2025 or newer	2025 or newer

Source Name		NG Startup Generator	Firewater Pump
EPA Family No.		TBD	TBD
Manufactured Date		TBD	TDB
Power Output		3,000 hp	614 hp
Fuel Type		Natural Gas	Ultra Low Sulfur Diesel (ULSD)
Fuel Consumption Rate		18,808 ft^3/hr	35.90 gph
PM	Emission Factor	7.71 E-5 lb/MMBtu	0.20 g/kW-hr
	Hourly Emissions Rate	<0.01 lb/hr	<0.01
	Annual Rate	<0.01 TPY	<0.01
$PM_{10}/PM_{2.5}$	Emission Factor	0.0099871 lb/MMBtu*	0.2 g/kW-hr
	Hourly Emissions Rate	0.20 lb/hr	0.20
	Annual Rate	0.01 TPY	0.01 TPY
NO_x	Emission Factor	1.0 g/hp-hr	3.04 g/kW-hr
	Hourly Emissions Rate	6.61 lb/hr	3.07 lb/hr

Source Name		NG Startup Generator	Firewater Pump
	Annual Rate	0.33 TPY	0.15 TPY
SO_2	Emission Factor	1.06E-5 lb/MMBtu	1.26E-5 lb/hp-hr
	Hourly Emissions Rate	0.03 lb/hr	0.01 lb/hr
	Annual Rate	<0.01 TPY	<0.01 TPY
CO	Emission Factor	2.0 g/hp-hr	3.30 g/kW-hr
	Hourly Emissions Rate	13.23 lb/hr	3.33 lb/hr
	Annual Rate	0.66 TPY	0.17 TPY
HC (VOCs)	Emission Factor	0.7 g/hp-hr + 5.28E-2 lb/MMBtu[1]	0.11 g/kW-hr + 1.18E-3 lb/MMBtu
	Hourly Emissions Rate	5.67 lb/hr	0.11 lb/hr
	Annual Rate	0.28 TPY	<0.01 TPY
Total HAPs	Emission Factor	7.22E-02 lb/MMBtu	3.87E-03 lb/MMBtu

Source Name		NG Startup Generator	Firewater Pump
	Hourly Emissions Rate	1.43 lb/hr	1.88E-02 lb/hr
	Annual Rate	0.07 TPY	<0.01 TPY

* This emission factor includes condensable and filter portion of particulate matter.
[1] This emission factor includes VOCs plus formaldehyde emissions.

Emissions from the fluid cooler are due to the solids in the cooling water for the cooler. The applicant determined the $PM/PM_{10}/PM_{2.5}$ emissions from the coolers based on the mass of the solids in the water droplet from data collected by the Electric Power Research Institute (EPRI). The applicant based these emissions on a maximum total dissolved solid (TDS) content of 5000 ppmw and average TDS concentration of 1700 ppmw of the circulated cooling water. These values were developed from a maximum TDS concentration of 1,000 ppmw in the make-up water with an average TDS of 340 ppmw. These emission rates are presented in the following table.

Table 7 Potential Emission from the Cooling Tower (129-CT-9391)

Pollutant	Hourly Rate (lb/hr) Max TDS 5000 ppm	Hourly Rate (lb/hr) Avg TDS 1700 ppm	Annual Rate (TPY)
PM	2.02	0.69	3.02
PM_{10}	1.48	0.57	2.50
$PM_{2.5}$	0.67	0.29	1.27

The facility will have a variety of storage vessels (tanks) that will be used to store volatile organic liquids (VOLs). The tanks of any size are lean amine and amine makeup tanks, which are 376,986 gallons and 8,812 gallons respectively. Amines have low vapor pressures for volatile organic liquids. Also, the VOL in the lean amine tank will be a solution of 47% amines in water. The VOCs potential from these two tanks are significantly less than 0.01 tons per year.

To accommodate the proposed emission units associated with this project, additional components will be required to be put into VOC service (e.g., piping for the fuel gas system). These additional components have the potential to emit 36.46 tons of VOCs per year. Of these fugitive VOCs, less than 0.01 ton per year would be in the form of HAP emissions.

Other sources of fugitive emissions are from the vehicle traffic on plant control roadways. The applicant determined the PM emissions from roadways on 107 vehicles per day to support operating the facility with an average vehicle weight of 32.7 tons. The roadway distance is approximately 0.68 miles on paved surface. Accounting for the average number of days of 0.01 inches of rain or greater per year, the PM emissions from roadways are 9.38 tons per year. The PM_{10} and $PM_{2.5}$ are 1.88 tons per year and 0.46 tons per year respectively.

There were several instances that the writer did not agree with the applicant's determination of annual emissions, which were limited to the engines. The application is based on 50 hours per year for these two engines. The writer believes that this operation limitation is not realistic and increased operating hours to 100 hours per year for each engine, which is consistent with the Federal limit for emergency engines. The applicant planned to only use the NG Startup Engine to support 5 startup events per year for the Biomass Boiler with each was estimated to take up to 10 hours per event. Changing the operational limitation for NG Startup Generation to 100 hours does not change the status of the operation of this engine under the federal rule. The operation of the engine for the NG Startup Generator is for non-emergency purposes.

Also, the applicant applied the condensable fraction to the total PM. PM emission and only PM emission only includes the filterable portion. The issue only affects PM emissions from the Biomass Boiler. The condensable fraction was omitted from the PM emission rates from the boiler.

Table 8 Summary of Annual Emissions at the Facility (in TPY)

Pollutant	Biomass Boiler	Material Handling	Engines	Cooling Tower	Fugitive Sources	New Potential for the Facility (TPY)
NO_x	90.42	N/A	0.48	N/A	N/A	90.90
CO	45.65	N/A	0.83	N/A	N/A	46.48
SO_2	50.78	N/A	0.01	N/A	N/A	50.79
PM	34.88	18.15	0.02	3.02	3.02	59.09
PM_{10}	67.84	11.09	0.02	2.50	2.50	83.95
$PM_{2.5}$	67.84	5.25	0.02	1.27	1.27	75.65
VOCs	19.04	N/A	0.28	N/A	36.46	55.78

H_2SO_4	27.87	N/A	N/A	N/A	N/A	27.87
Total HAPs	23.36	N/A	0.07	N/A	0.58	24.01

REGULATORY APPLICABILITY

NEW SOURCE REVIEW APPLICABILITY ANALYSIS

Major Source Status

Section 52.21(b)(1)(i)(a) of 40 CFR, and 45 CSR 14-2.43a, lists the NSR source categories with a 100 ton per year (tpy) "major" source threshold. Fossil Fuel-fired Steam Electric Plants of More than 250 million (MM)Btu/hr Heat Input and Fossil Fuel Boilers (or combinations thereof) Totaling More than 250 MM Btu/hour Heat are two of the 28 source categories that are identified as possible applicable categories regarding applicant's proposed biomass boiler. The applicant's proposed biomass is going to be capable of only utilizing 180 MMBtu/hr of natural gas, which is a classified as a fossil fuel but less than 250 MMBtu/hr size criteria in these categories. The proposed unit will be capable utilizing 944 MMBtu/hr of biomass (wood) fuel, which is not classified as a fossil fuel. Therefore, none of applicant's proposed units meets any of the 28 source categories list and therefore "major source" applicability for this applicant is set at the default threshold of 250 tpy of any criteria pollutants.

The proposed facility will not have potential to emit any criteria pollutant about 250 tpy and therefore, the proposed facility is classified as a "not major" and not subject to requirements covered under the major source permitting rule (45CSR14).

Bubbling Fluidize Bed Boiler (Biomass Boiler)

The biomass boiler will be used to generate steam which will be used to generate electric for not sale. However (as noted in the above section), the boiler will only be capable of utilizing 180 MMBtu/hr of natural gas, which is a fossil fuel and less than 250 MMBtu/hr applicability threshold of Subpart Da of 40CFR60. Thus, the biomass boiler is subject to Subpart Db of 40CFR60 because the unit will be capable of utilizing over 100 MMBtu/hr of heat input from any fuel.

Subpart Db establishes emission standards for three criteria pollutants, which are sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxides (NO_2).

SO_2 Standard – No greater than 0.32 lb of SO_2 per MMBtu on a potential basis.

PM Standard – No greater than 0.030 lb of PM per MMBtu.

NO_2 Standard – No greater than 0.20 lb of NO_2 per MMBtu or 2.1 lb of NO_2 per MWh on gross output basis.

The unit will not produce steam or electric for sale. Therefore, the boiler is also subject to West Virginia State Rule 45CSR2 (Rule 2) for PM and visible emissions, which are 81 lb/hr of PM and 10% opacity. Also, the unit is subject to 45CSR10 for sulfur dioxide at a type “c” fuel burning unit is a Priority III region. The allowable sulfur dioxide standard for the boiler is 3.2 lb of SO_2 per MMBtu.

The applicant provided additional information about the proposed biomass fuel, which indicates that biomass fuel would contain 0.01% sulfur by weight. At a maximum firing rate of 106.07 tons per hour of biomass with a heat input of 944 MMBtu, this fuel would have the SO_2 potential of 0.045 lb of SO_2 per MMBtu, which is less than the standard under Subpart Db.

Again, because no electric is being sold and the unit will have a heat input of greater than 250 MMBtu/hr, the boiler is subject to West Virginia’s Ozone Rule (45CSR40 or Rule 40). This state rule does not establish an allowable or standard for units to meet per say. However, the rule requires the permit to establish a NO_x limit for the unit to limit the mass amount of NO_x to be emitted from the affected unit during the ozone Season, which begins on May 1st and ends on September 30th of the same. The ozone season is 5 months out of the year. The writer recommends multiplying the annual potential NOx rate (90.42 tons per year) by 5/12, which equates to 37.68 tons/ ozone season), round up to whole number (38 tons) in establishing a NOx limit for the unit as required by Rule 40.

The application indicates that this proposed facility will meet the criteria of a “area source” of HAPs, which means that the facility will not have the potential to emit any single HAP equal to or greater than 10 tons per year and/or total HAP equal to or greater than 25 tons per year. Since the facility will be an area source of HAPs with a solid fuel fired boiler, the biomass boiler is subject to Subpart JJJJJJ of 40CFR63 as a new unit with a heat input greater than 30 MMBtu/hr. Thus, the boiler is subject to the PM and work practice standards of this regulation, which is a 0.030 lb of PM per MMBtu of heat input and conduct tune-ups on the boiler on a biennially basis.

The following is summary of the more stringent standard of the applicable standard of PM, NO_x, SO_2, and visible emissions.

Table 9 Summary of the Most Stringent Standard for the Biomass Boiler

Pollutant	Most Stringent Standard	Averaging Period	Citation
PM	0.030 lb/MMBtu	30 days rolling avg.	40CFR60.43b(h)(1) & 40CFR63.11201(a)
NOx	0.20 lb/MMBtu or	30 days rolling avg.	40CFR60.44b(l)(1)
SO_2	0.32 lb/MMBtu		40CFR60.42b(k)(2)

Visible Emissions	10% opacity	6-mintue Avg.	45CSR2-3.1.

The fuel (biomass) and material handling (e.g., flyash, sand, bicarbonate, etc.) systems to support the Biomass Boiler is subject to the fugitive emissions requirements of Section 5 of Rule 2 and the milling of sodium bicarbonate and equipment used to handling of processed sodium bicarbonate is subject to Subpart OOO of 40CFR60.

For Rule 2 fugitive emissions, the permittee must minimize fugitive emissions from equipment used to transport fuel/ash or other material associated with the support of fuel burning unit(s). The applicant proposed a collection of measures to minimize fugitive cover conveyors, paved roads, storage silo with controls, and covered hopper where there are feasible.

Sodium bicarbonate is not specifically listed as nonmetallic mineral. This regulation defines nonmetallic to include sodium compounds. In 2017, EPA Region 5 determine that sodium gluconate meets the definition of nonmetallic mineral and therefore the process equipment processing sodium gluconate was affected units under Subpart OOO. Based on EPA's past determination that equipment used to process sodium bicarbonate would be affected sources under Subpart OOO.

The applicant noted that the facility was an affected facility subject to Subpart OOO. The writer disagrees with the application because the applicant did not disclose any sodium bicarbonate processing equipment (crusher/grinding mill) in the application. Equipment used to handle or store sodium bicarbonate does not constitute "processing" under this subpart. Therefore, the proposed facility is not subject to any requirements from Subpart OOO due to this permitting action. alone does not make a facility an affected source believes, which in

The writer reviewed other federal regulations for applicability for the biomass boiler, which were Subparts Da and TTTTa from Part 60, Subpart UUUUU. The unit is not subject to Subpart Da because the unit will only have the capacity to combust 180 MMBtu/hr of natural gas (fossil fuel) which is less than the trigger level of 250 MMBtu/hr. Wood or clean cellulosic biomass is not listed in the definition of "fossil fuel" under 40CFR60.41Da.

Subpart TTTTa regulates new coal fired stream electric generating units and integrated gasification combined cycle facility. The proposed biomass boiler is neither and therefore not subject to Subpart TTTTa.

Subpart UUUUU regulates HAPs from coal-fired or oil-fired electric generating units (EGUs). Again, the proposed boiler will not be fueled with coal or oil and therefore is not subject to this subpart.

Because the electricity generated by the Biomass Boiler will not be sold, the Biomass Boiler is not an Acid Rain Unit under Title IV of the Clean Air Act and not subject to emission trading programs such the Acid Rain Program and Cross-State Air Pollution Rule. The permit will prohibit the source from selling electricity generated.

ENGINES for the STARTUP GENERATOR & FIREWATER PUMP

The applicant proposed installing and operating a non-emergency engine for the NG startup generator which utilizes a spark-ignition (SI) engine. This engine will be fuel with natural gas to generate a maximum power out of 3,000 horsepower. This engine is subject to Subpart JJJJ of 40CFR60. Even though the applicant proposed to limit operation of this engine to 50 hours per year, this engine is proposed to be operated as a non-emergency engine under this regulation and therefore, the engine will be required to meet the emission standards for a non-emergency, SI, natural gas engine with a maximum engine power rating greater than 500 hp. To meet the emissions standards of this subpart, the applicant chose to purchase a manufacturer “certified engine” in accordance with the regulation.

The engine for the firewater pump is a new compression ignition that is subject to Subpart IIII of 40CFR60. The applicant proposed to operate this engine as an emergency engine as an outline in the regulation, which is operating the engine for no more than 50 hours per year for maintenance and readiness with total non-emergency utilization of the engine of no more than 100 hours per calendar year.

This subpart requires the engine to utilize “ultra-low sulfur diesel” and an hour-meter be installed and maintained, which will be required in the permit.

As noted earlier, the facility is an area source of HAPs and both engines are subject of these two subparts (IIII & JJJJ) under 40CFR60, therefore applicant meets the requirements of Subpart ZZZZ (RICE MACT) of 40CFR63 by satisfying the requirements of Subparts IIII and JJJJ of 40CFR60.

COOLING TOWER

The proposed fluid cooler is not subject to any state rule or federal regulation that establishes emission standards for cooling towers.

STORAGE VESSELS

Most of the proposed storage vessels will have a design capacity of less than 20,000 gallons and do not meet the size capacity of 40 CFR 60 Subpart Kc of 20,000 gallons or greater. However, the lean amine storage tank will have the capacity to store over 375,986 gallons, which is greater than the initial size capacity trigger threshold value of 20,000 gallons. To trigger the control requirements of Subpart Kc, the volatile organic liquid (VOL) being stored in the vessel with a capacity of 40,000 gallons or greater, and has a maximum true vapor pressure of 0.5 psia (3.4 kPa) is subject to the control requirements of Subpart Kc.

The applicant proposed to store lean amine at 50°F. The amine to be stored is a mixture of 25% methyl diethanolamine (MDEA), 23% monoethanolamine (MEA) and 53% water on a mass basis. At 50°F, the applicant noted the maximum true vapor pressure is 0.15 psia. The writer verified this provided maximum true vapor using a process simulator (ProMax 6.0) using ASTM D6377 Vapor Pressure of Crude Oil (VPCRx) method at a temperature of 50°F with a volume to liquid ratio of 4, which is stated in the Subpart Kc. The simulation predicted the vapor pressure of 0.149 psia.

The lean amine tank is not subject to the control requirements of this subpart but is required to maintain records of the following:

- Dimensions of the vessel to indicate the storage capacity of the vessel.
- Information to indicate the maximum true vapor pressure of the VOL being stored in using a method accepted by the subpart.

The permit will limit the maximum temperature of the stored VOL to 50 °F and require continuous monitoring of the temperature.

MINOR SOURCE PERMITTING RULE

To make the proposed controls federally enforceable limit practically enforceable, which is necessary to limit criteria pollutant and HAP emissions below major source threshold levels, the applicant prepared and submitted a complete application, paid the appropriate application fee, and published a Class I legal Advertisement in *The River Cities Tribune* on February 22, 2025.

CONFIDENTIAL BUSINESS INFORMATION (CBI)

The applicant provided information about the components in the biomass fuel. Other than the sulfur content, which was used to prove that the fuel would have a SO_2 potential at or less than the Subpart Db exclusion. The remaining information in this information was claim confidential and the applicant filed a proper claim in accordance with 45 CSR 31 to protect the information.

TITLE V OPERATING PERMIT

Given that the biomass boiler will not be generating electric for sale, the biomass boiler is not subject to Title IV – Acid Deposition Control of the Clean Air Act. The boiler is not an affected source under the Title V – Operating Permit Program.

As listed the Table 8 of this evaluation, the facility total potential to emit after controls will be less than the major source threshold levels defined under Title V (45CSR30), which is 100 tons per year or greater of any criteria pollutant (e.g., CO, NO_x, PM); 10 tons per year or greater of any single HAP (e.g., HCl, formaldehyde); or 25 tons per year or greater of total HAPs.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

There are several hazardous air pollutants (HAPs) that are released into the open air from the facility with the main source of HAPs is from the Biomass Boiler. The applicant identified 69 volatile organic HAPs, 13 metal HAPs, and one non-volatile organic HAP. This discussion will focus on HAPs with a potential to emit greater than 1 ton per year, which are acetaldehyde, acrolein, benzene, formaldehyde, and hydrogen chloride. The potential of these five HAPs from the Biomass Boiler accounts for 85% of the total HAP potential or 19.94 tons per year of HAPs from these five HAPs.

Acrolein
The carcinogenicity of acrolein is undetermined currently.
Additional information on the potential health effects can be found at:
https://iris.epa.gov/ChemicalLanding/&substance_nmbr=364

Acetaldehyde:
The carcinogenicity of acetaldehyde is listed as probable human carcinogen.
Additional information on the potential health effects can be found at:
https://iris.epa.gov/ChemicalLanding/&substance_nmbr=290

Benzene
The carcinogenicity of benzene is listed as human carcinogen.
Additional information on the potential health effects can be found at:
https://iris.epa.gov/ChemicalLanding/&substance_nmbr=276
Formaldehyde
The carcinogenicity of acrolein is listed as human carcinogen.
Additional information on the potential health effects can be found at:
https://iris.epa.gov/ChemicalLanding/&substance_nmbr=419

Hydrogen Chloride
The carcinogenicity of hydrogen chloride has not been assessed under EPA's Integrated Risk Information System (IRIS) program.
Additional information on the potential health effects can be found at:
https://iris.epa.gov/ChemicalLanding/&substance_nmbr=396

Other sources of HAPs at the facility will be limited to the internal combustion engines for the NG Startup Generator and Firewater Pump and the wastewater treatment plant. These engines will be limited to 100 hours per year of operation, which significantly limits the potential to emit HAPs.

Many non-criteria regulated pollutants fall under the definition of HAPs which are compounds identified under Section 112(b) of the Clean Air Act (CAA) as pollutants or groups of pollutants that EPA knows or suspects may cause cancer or other serious human health effects. These adverse health effects may be associated with a wide range of ambient concentrations and exposure times and are influenced by source-specific characteristics such as emission rates and local meteorological conditions. Health impacts are also dependent on multiple factors that affect variability in humans such as genetics, age, health status (e.g., the presence of pre-existing disease), and lifestyle. As stated previously, there are no applicable federal or state ambient air quality standards for these specific chemicals. It is also important to note that the USEPA does not divide the various HAPs into further classifications based on toxicity or if the compound is a suspected carcinogen.

MONITORING

Biomass Boiler includes the support equipment for the carbon capture unit.

The applicant proposed to monitor actual NO_x emissions from the Biomass Boiler, which satisfies monitoring requirements under Subpart Db and 45CSR40, and the fabric filter baghouse with a bag leak detector system, which avoids monitoring visible emissions with a continuous opacity monitoring system (COMs) requirement under Subpart Db and is required under the Boiler GACT.

Rule 2 excuses the boilers using wet scrubbers from requiring COMs to monitor visible emissions, which applies for this case. Rule 2 requires a monitoring plan, which the applicant does not cover.

Subpart Db only relieve sources from the requirement to use COMs for using a bag leak detector. Subpart Db requires sources without COMs to monitor visible emission using one of three compliance options which are:

1. Conduct Subsequent visible emission test with the frequency based on result of the most recent test. The frequent can vary from 12 months, 6 months, or 3 months;

2. Monitor visible emissions using Method 22 for each operating day with an option to reduce the frequency to once a week if no visible emissions are observed for 10 operating days: or

3. Use a digital opacity compliance system in accordance with a site-specific monitoring plan approved by the Administrator.

Options 2 and 3 are only available for sources that the results of most recent the Method 9 test show the maximum 6-minute average is less than 10% opacity. Under Rule 2, the visible emission standard is 10% opacity is less. Thus, a source meeting Rule 2 standard would most likely qualify for options 2 and 3. This applicant must meet the Rule 2 standard.

Option 3 is not truly because available to this applicant at this time because a site-specific monitoring plan must be developed and approved. It will not be discussed any further in this evaluation. The permit will require option 1 (subsequent testing) and include option 2 if the most recent test results show the maximum 6-minute average is less than 10% opacity.

Rule 2 requires a monitoring plan and under Rule 2A this plan for sources without non-COMs must include Method 9 observation at least once per month. Neither of these two rules recognized the specific use of other continuous monitoring systems such as PM Continuous Emission Monitoring (PMCEMs) or Bag Leak Detection Systems with regards as part of monitoring plan. This writer views the PMCEMs to continuously monitor compliance directly with the PM emission standard and therefore, a more stringent monitoring system than COMs.

This writer views the Bag Leak Detection Systems as an instrument that continuously measures the amount of filterability particulate matter to determining if the measured amount is or is not above a specific set point (e.g. qualitative measurement). The instrument used in these Bag Leak Detection System is counting the number of particles downstream of the baghouse (PM control device).

The requirements for bag leak detection system in Subpart Db refers requirements in Subpart Da which are summarized in the following:

- Instruments must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter or less.
- Sensor/instrument must provide output of relative PM loadings.
- Alarm system to alert operators that concentrations are above the alarm setpoint.
- Establish a minimum baseline output and averaging period.
- Senor/instrument must be located downstream of the fabric filter and upstream of any wet scrubber.
- Development and submit a site-specific monitoring plan.
- Must initiate procedures to casus of every alarm event with one hour of the alarm.
- If the alarm rate exceeds 5 percent of any 30 operating days, the source must conduct a PM test within 60 calendar days.

These requirements will be established in the permit.

The permit will require subsequent PM testing according to the schedule established in 45CSR2A. Based on the proposed PM_{10}/$PM_{2.5}$ emissions, which included both forms of PM, the unit following Cycle 3 of 45CSR2A for actual PM emissions less than 50% of the PM standard of 45CSR2, which would be conducting a performance test once every 36 months.

The application only contained very few details (specifications/operating parameters) for the proposed controls. The writer developed a few initial operating parameters for these controls until initial testing can be conducted to demonstrate compliance with the emission limits and establish the actual operating parameter limits.

- SCR
    - Minimum exhaust temperature of 200^{o}F to begin injecting ammonia.[1]
- Oxidization Catalyst
    - Minimum catalyst bed temperature of 500 ^{o}F.
    - Maximum pressure drop of 2 inches of water column across the catalyst.
    - Minimum Oxygen content of 4% at the inlet of the catalyst.
- Dry Sorbent Injection
    - Maximum exhaust temperature of 500^{o}F with a daily average temperature of no greater than 400 ^{o}F.[2]
    - Minimum exhaust temperature of 250^{o}F during startup to begin injection of the sorbent. [1]
    - Minimum injection rate of sorbent based on manufacturer minimum rate.
- Wet Scrubber
    - Minimum circulation rate of 16.85 gpm of solution.
    - Minimum Daily average pH of 12.2.
    - Manufacturers' minimum pressure drop across the scrubber.
- Carbon Capture Unit (Amine Unit)

- Establish maximum lean amine circulation rate.
- Maximum amine solvent loss rate of 0.48 lb per hour.
- Maximum stripper column temperature of 120°F.[3]

[1] These parameter limits are a startup setpoint at which the permittee must begin operating the control device.
[2] This limitation is in place to prevent sintering of the sodium bicarbonate.
[3] This limit is in place to minimize thermal degradation of the amine.

Most of these initial operating limits were established on basic knowledge of these control or principles of these control devices or physical property of proposed sorbent. The minimum circulation rate was based on results of simulation a caustic scrubber in process simulation with uncontrolled SO_2, H_2SO_4, and HCl loading from the application to predict a circulation rate of 10% caustic solution to achieve a SO_2 control outlet rate of 11.53 pounds per hour, which is less than the permitted limit of 11.58 pounds per hour. The selected solvent rate was from the application.

The applicant has proposed a bypass vent for the divert the exhaust from Biomass Boiler from passing through the carbon capture unit (amine's unit absorber column). This divert valve will be locate downstream of the wet scrubber and the amine's unit absorber column. There is no regulatory mechanism that requires the applicant to control carbon dioxide emissions (CO_2). The amine's unit generates additional VOCs and volatile HAPs from the amine process. The permit will require monitoring the position of this divert value to know when the emissions from the boiler are bypassing the carbon capture unit.

The permit will require initial performance testing for CO, SO_2, H_2SO_4, HCl, and 21 individual volatile HAPs which were selected based on the have the potential to emit 0.01 tons per year. These 21 individual volatile HAPs make up 99.5% of the total volatile HAPs on a mass annual basis. The applicant will be required to measure the emission rate of several other pollutants which are carbon dioxide (CO_2), methane, and ethane. To get the total VOC rate, a method 25A test will be required to be conducted concurrently with the Method 320 (FTIR Method) test. The applicant will use methane and ethane rates measured with the FTIR Method, which are hydrocarbons but are not classified as VOCs, to be deducted out of the total VOC rate measured using Method 25A, which will yield just VOCs as defined in 40CFR51. Method 25A detects and measures total VOCs to include non-VOCs (e.g., methane and ethane).

During this initial testing, the applicant will be required to establish operating parameter limits that can be directly linked to the results of the testing that demonstrated compliance with the permitted limits.

The amine unit for the carbon capture unit will capture significant portions of the acid gas (SO2, H_2SO_4, HCl) that are not captured by the dry sorbent injection system or the caustic soda scrubber. A portion of these acid gases will be emitted to the atmosphere from the CO_2 dehydration unit (flash tank and/or regenerator still vent), or compressor blow down. The writer suspects a good portion of these acid gases will be entrained the collected water as result of in the dewatering operations/activities associated with the draining of knock-out vessels and 2-phase separators. The collected water will be routed to the wastewater treatment unit at the facility. The writer recommends that the applicant utilize a process simulator to determine the actual emissions from the CO_2 dehydration units and compressor blow down emissions of SO_2, HCl, and H_2SO_4.

Other parameters to be monitored for the Biomass Boilers are the following:

- Exhaust flow rate on a continuous basis to determine the actual heat input.
- Natural gas usage rate.
- Electric output of the generator on a continuous basis.
- Steam production to include pressure and temperature of the stream.
- Amount of ammonia injected into the SCR.
- Fuel analysis to determine dry F factor of combustion (scf of exhaust flow per MMBtu of fuel combusted).

Material Handling Activities

The writer recommends the following monitoring activities for fuel handling, sand, ash, and other consumable material (e.g., caustic soda, sodium bicarbonate):

- Record the amount of material delivered to the facility.
- Conduct monthly visible emission observation of point sources (e.g., outlet of fabric filter duct collector).
- Conduct monthly visual inspection of equipment and associated control device (e.g., covers, enclosers, fabric filters).
- Conduct monthly inspection of the paved haul road for defects or excessive silt.

Engines – NG Startup Generator and Firewater Pump

The permit will require the applicant to track hours of operation of both engines though a non-resettable hour meter and the purpose of the operation; and keep records indicating the diesel used/delivered for the Firewater Pump engine meets the standard as “ultra-low sulfur diesel”.

Also, the permittee will be required to perform maintenance on each engine in accordance with the respective manufacturer and maintained documentation that each engine is certified to comply with the appropriate emission standard under 40CFR60.

Cooling Tower

For the cooling tower, the applicant will need to monitor the cooling water flow rate and either the concentration of the total dissolved solids in the make-up water or the specific conductivity daily. Also, the permittee will be required to determine the actual PM emissions monthly.

Storage Tanks/Loadout/Wastewater Treatment

The permit will require monitoring the temperature in the lean amine storage tank and the permittee will have to determine the maximum true vapor pressure of the VOL stored in the vessel. On a semiannual (once every six months) basis, the permittee will be required to conduct a leak survey of all process piping in VOC.

<u>RECOMMENDATION TO DIRECTOR</u>

The information provided in Permit Application R13-3708 indicates that compliance with all applicable state and federal air quality regulations will be achieved. Therefore, I recommend to the Director that the DAQ go to public notice with a preliminary determination to issue Permit Number R13-3708 to MGS CNP 1, LLC for the proposed construction of a biomass fired boiler with a carbon capture unit and associated equipment to be located near Point Pleasant, Mason County, WV.

Edward S. Andrews

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Edward Andrews, P.E.
Engineer