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ENGINEERING EVALUATION / FACT SHEET

BACKGROUND INFORMATION

Application No.:	R13-3435
Plant ID No.:	053-00080
Applicant:	Domestic Synthetic Fuels I, LLC
Facility Name:	Mason County Facility
Location:	Near Point Pleasant, Mason County
SIC/NAISC Code:	2911/324110
Application Type:	Construction
Received Date:	January 15, 2019 (Original); May 10, 2019 (Resubmitted)
Engineer Assigned:	Joe R. Kessler
Fee Amount:	$4,500
Date Received:	February 4, 2019
Complete Date:	June 5, 2019
Due Date:	September 3, 2019
Applicant Ad Date:	January 31, 2019
Newspaper:	*Point Pleasant Register*
UTM's:	403.948 km Easting • 4,309.098 km Northing • Zone 17
Latitude/Longitude:	38.92554/-82.10807
Description:	Construction of a Direct Coal Liquefaction Facility that will convert coal into ultra-low sulfur diesel fuel, gasoline, liquefied petroleum gases (LPGs), elemental sulfur, and flake product for sale to market.

DESCRIPTION OF FACILITY/PROCESS

On January 15, 2019, Domestic Synthetic Fuels I, LLC, a subsidiary of America First, Inc., submitted a permit application to construct a direct coal liquefaction plant proposed to be located approximately 5.80 miles north of downtown Point Pleasant, Mason County, WV. Direct coal liquefaction is a process of contacting coal directly with a catalyst at elevated temperatures and pressures with added hydrogen, in the presence of a solvent, to form a raw liquid product. The raw liquid product is then further refined into high quality liquid fuels. In the direct coal liquefaction process, coal is transformed into liquid without first being gasified to form syngas. The coal-to-syngas-to-liquids process is termed "indirect" coal liquefaction, which is the more common coal-to-liquids process.

At the proposed DSF facility, a maximum of 912,000 tons/year (TPY) of coal will be converted into ultra-low sulfur diesel fuel, gasoline, liquefied petroleum gases (LPGs), elemental sulfur, and flaked residue product for sale to market. The process is generally broken down into seven (7) different processing units: Units 100 through 700, each of which will be summarized below. A complete and detailed description of the complex process is given under Section 2 of the permit application. The proposed maximum design production capacity of the plant per material is given in the following table:

Table 1: Production Capacities

Product	Annual Production Capacity	Units
Diesel	100,426,830	gallons/year
Raw Gasoline	52,137,330	gallons/year
LPG	22,903,020	gallons/year
Flake Residue	223,599	tons/year
Elemental Sulfur	19,995	tons/year

Unit 100: Coal Preparation

Unit 100 is the area of the facility where 912,500 TPY coal will be delivered, milled, and dried to proper specifications for introduction into the liquefaction process. Coal will be delivered to the facility by both barge and trucks and conveyed (100-TC-1 and 100-TC-2) to one of two (2) open coal storage piles: the 26,136 ft^2 active pile (100-CSP-1) or a larger 87,991 ft^2 backup pile (100-CSP-2). Wind guards will be used on the open storage piles to mitigate fugitive entrainment of particulate matter. From the storage piles, coal is transferred by a front-end loader to the Coal Mill (100-CM-1) and then to the 13.45 mmBtu/hr Coal Milling Dryer (100-CMD-1). The coal milling circuit is limited to 2,500 tons/day as this is the maximum capacity of the downstream H-Coal unit. Air emissions from the Coal Mill are controlled by a baghouse (100-BH-1). Most other coal transfer points are controlled by fabric filters. After milling and drying, the sized and dried coal is stored in one of two coal storage silos (100-CS-1, 100-CS-2) prior to introduction into Unit 200 for liquefaction.

Unit 200: H-Coal

Unit 200 is the area of the facility where the sized and dried coal is mixed with process-derived recycle oil and then pumped and contacted with hydrogen and a catalyst at high temperature/pressure for conversion to liquid fuels. This is accomplished through the use of a series of reactors, separators, and heaters. First, the sized and dried coal is mixed with slurry oils, or process-derived recycle oils, (hot solvent, cold solvent, and bottoms recycle) in the Coal Slurry Mixing Drum (200-D-111) to form a coal slurry. This coal slurry is then heated in the 74.02 mmBtu/hr Slurry Feed Heater (200-H-102), mixed with hydrogen from the Hydrogen Reformer and heated in the 15.34 mmBtu/hr Hydrogen Heater (200-H-101), and sent to the 1st Stage Reactor (200-R-101). In the first reactor, reactions occur to improve the recycle solvent quality and coal liquids are formed, hydrogenated, and stabilized. After the first reactor, the mix is sent to the 2nd Stage Reactor (200-R-102) where the conversion of coal and residuum to distillate liquids is completed.

From the reactors, through the use of separators, strippers, and vacuum towers, the distillate liquids and the off gas streams are further separated, recycled, and refined into raw liquid naphtha, diesel, and vacuum gas oil products. The 24.79 mmBtu/hr Vacuum Tower Feed Heater is used in this process. During the Unit 200 operations, fresh catalyst is added daily to the Reactors and an equivalent amount of spent catalyst is withdrawn to maintain constant catalyst activity. The spent catalyst is transferred into drums (200-D-209) for eventual delivery off-site. Air emissions from Unit 200 are limited to combustion exhaust from the heaters and to particulate matter from spent catalyst handling. The multiple effluent and off gas streams are processed and recycled back into the process and not emitted into the air during normal operations.

Unit 300: Product Upgrading

Unit 300 is the area of the facility where the crude liquid naphtha, diesel, and vacuum gas oil products produced in Unit 200 are processed via a hydrotreater, hydrocracker, and fractionator to form stabilized naphtha and diesel fuel product streams. Unit 300 is broken down into the further sub-units of Unit 310: Hydrocracker and Unit 320: Catalytic Reformer.

In Unit 310, the crude liquid product stream from Unit 200 containing the crude gas oil, diesel, and naphtha is mixed with a hydrogen gas feed and is preheated in the 8.37 mmBtu/hr Reaction Heater (310-H-101) before entering the Hydrotreater/Hydrocracker Reactor (310-R-101). The hydrocracker "cracks" the heavy long-chain molecules of the crude liquids into shorter chain molecules in the presence of hydrogen and catalyst that then allows for further refinement and fractionation. Therefore, after hydrocracking, the reacted stream is again processed through a series of separators, fractionators, and strippers to form the stabilized naphtha and diesel fuel product streams. After the stream is processed in the Fractionator (310-C-201), which is heated by a 10.78 mmBtu/hr Fractionation Reboiler (310-H-103), the diesel product is sent to the appropriate storage tank (630-TK-8, 630-TK-9).

The heavy naphtha stream from the Fractionator is further processed in Unit 320, where the stream is routed through four (4) Catalytic Reactors (320-R-201, 320-R-202, 320-R-203, 320-R-204). Each Reactor is heated by a 11.89 mmBtu/hr Catalytic Reaction Heater (320-H-201, 320-H-202, 320-H-203, and 320-H-204). After the Reactors and further separation, LPG (630-TK-1A, 630-TK-1B) and Heavy Naphtha (630-TK-4, 630-TK-5) are sent to the appropriate product storage tanks.

Air emissions from Unit 300 are limited to combustion exhaust from the heaters. The multiple effluent and off gas streams are processed and recycled back into the process and not emitted into the air during normal operations.

Unit 400: Product Treating

Unit 400 has multiple process sections that treat gas, water, and amine streams from Unit 200 and Unit 300. The subunits in Unit 400 include Unit 410: Gas Recovery Unit, Unit 420: Amine Regeneration, Unit 430: Sour Water Stripping, and Unit 440: Sulfur Recovery.

In the Unit 410: Gas Recovery Unit, gas streams from the other process units are processed in a conventional saturated gas plant that recovers light naphtha for blending to gasoline, LPG (mixed C_3/C_4), and fuel gas that is used in all process heaters and other combustion devices at the plant. This is accomplished through the use of various strippers, knockout drums, absorbers, and the debutanizer. Produced LPG (630-TK-1A, 630-TK-1B) and light naphtha (630-TK-2, 630-TK-3) are then sent to he appropriate storage tanks.

In Unit 420: Amine Regeneration, the rich amine streams from Unit 200 and the Sulfur Recovery Unit (SRU) are regenerated and the produced lean amine streams are then routed back to these units for reuse. This is accomplished primarily in the Amine Regenerator (420-R-101), where acid gases are stripped off the rich amine stream. The Amine Regenerator is re-boiled with steam in the Amine Regenerator Reboiler (420-H-101). The Amine Regenerator overhead stream is partially condensed by the Amine Regenerator Overhead Air Cooler (420-A-101) before being routed to the Amine Regenerator Reflux Drum (420-D-102) where the vapor and liquid phases are separated. Waste acid gases are sent to the (SRU) for processing.

In Unit 430: Sour Water Stripping, sour water streams (containing H_2S) from other process units are stripped of sulfur compounds and sent either back to other units as recycled/process water or discharged offsite. This is accomplished primary in the H_2S Stripper (430-C-101) and the H_2S-NH_3 Stripper (430-C-102). The H_2S Stripper is a trayed column where H_2S is separated from the sour water utilizing the H_2S Stripper Reboiler (430-H-101), which is provided with steam. The H_2S Stripper bottom stream is sent to the top tray of the H_2S-NH_3 Stripper, which is also a trayed column where ammonia and any remaining H_2S are removed from the sour water. The H_2S-NH_3 Stripper is reboiled with steam via the H_2S-NH_3 Stripper Reboiler (430-H-102). Acid gases collected during the process are sent to SRU, and recovered ammonia is compressed and condensed by cooling water before entering the Ammonia Product Drum (430-D-106) from which it is pumped to storage.

In Unit 440: Sulfur Recovery, the "Claus Process" is utilized to recover elemental sulfur from the various waste acid gas streams sent to the unit from other areas of the plant. In this process, the H_2S is partially combusted with air to make SO_2, which reacts with the H_2S in the furnace and catalytic stages to form elemental sulfur. To accomplish this, the main combustion reaction is carried out in the 4.40 mmBtu/hr gas-fired SRU Claus Furnace (440-CF-1). The products of the reactor are then sent through the Waste Heat Boiler (440-H-102) for cooling and then through a series of converters and condensers. Condensed sulfur from each stage is sent to the sulfur pit, where the elemental sulfur is then sent to Unit 610: Solid Products Handling. The tail gas from the process is sent first through the hydrogenation section, where the sulfur compounds are catalytically converted to back to H_2S prior to removal in the amine treating section (sour amine is then sent back to Unit 420: Amine Regeneration). Remaining waste gases are then combusted in the 10.60 mmBtu/hr Sulfur Recovery Incinerator (440-SRI-1), which converts the residue H_2S in the tail gas into SO_2 emissions.

Unit 500: Utilities

In Unit 500: Utilities, the plant includes non-process or reactive equipment necessary to operate the facility. These include the 24.3 mmBtu/hr Steam Boiler (500-SB-1) to generate steam. During normal steady-state operations, using heat-recovery equipment, other areas of the plant will produce excess steam, which will allow the Steam Boiler to be operated at partial load (approximately 4.9 mmBtu/hr). It will, however, be required to be operated at full load during startup operations (estimated to be a maximum of 60 hours/year). Additionally, the plant will include a 671 horsepower (hp) diesel-fired Generac Model SD500 Emergency Generator (500-EG-1) to supply power to critical equipment in the vent of a power failure. The facility will also operate an induced-flow Cooling Tower (500-CT-1) with an estimated maximum flow rate of 5,565 gallons per minute.

Unit 600: Product Storage and Loading

Unit 600 has multiple process sections that store and load-out solid and liquid products. The subunits in Unit 600 include: Unit 610: Solid Product Handling, Unit 620: Emergency Flare System, Unit 630: Liquid Product Storage, and Unit 640: Liquid Product Load-out.

In Unit 610: Solid Product Handling, elemental sulfur and flaked produce (slurry residue from the bottom of the Unit 200 vacuum fractionator that is flaked and transferred off-site as a saleable product) is conveyed, stored, and trucked offsite for sale. For the flaked product, the slurry residue is pumped from the Unit 200 onto a flake transfer conveyor system (610-TC-1) that allows the material to cool and solidify as a flake product. From the conveyor system, flake product is stored in the surge flake storage silo (610-SS-1) before transfer via a pipe conveyor (610-TC-2) to product storage domes (610-DS-1, 610-DS-2). Each of the flake product storage domes is controlled with a fan filter. Within the storage domes, stack conveyors (6100-TC-4, 610-TC-5) are used to create storage piles (610-SP-1, 610-SP-2). From the storage piles, flake is gravity fed to loading hoppers (610- TH-1, 610-TH-2) before conveyance along two conveyors (610-TC-6, 610-TC-7) prior to loading into the truck loading hopper (610-TH-3). A maximum of 223,599 TPY of flaked product is loaded from the loading hopper into trucks (610-TR-1) for delivery off-site.

The elemental sulfur is recovered from Unit 440 and is stockpiled for eventual transport via truck off-site. From Unit 440, sulfur enters via a hopper (610-TH-4) and transported along a conveyor (610-TC-8) for deposition on the sulfur storage pile (610-SP-3). From the storage sulfur storage pile, sulfur product is transferred from a front-end load into the Sulfur Loading Hopper (610-TH-5). From the hopper, a maximum of 19,995 TPY of sulfur product is conveyed (610-TC-9) to the Truck Loading Hopper (610-TH-6) for loading into trucks (610-TR-2) for delivery off-site.

In Unit 630: Liquid Product Storage, various liquid products are stored prior to loading and shipping for delivery off-site. In addition to the final product storage tanks, there are four process vessels that can be used to hold in-process materials during maintenance outages, unexpected process interruptions, off-spec material to be reworked in the process, etc. The 126,000 gallon HYK Heavy Feed Tank (630-TK-12) and 672,000 gallon HYK Light Feed Tank (630-TK-13) can be used to handle in-process materials from Unit 200. The 672,000 gallon Heavy Slop Oil Tank (630-TK-14) and 672,000 gallon Light Slop Oil Tank (630-TK-15) can be used to handle in-process materials from Unit 430. The HYK Light Feed Tank and the Light Slop Oil Tank utilize internal floating roofs to which limit working/breathing losses. The following storage tanks (and information related to each tank) will be located at the proposed facility:

Table 2: Storage Tanks Information

Tank ID	Material Stored	Tank Size (gallons)	Throughput (gallons)	Pressurized (Y/N?)	Internal Floating Roof (Y/N?)	Control Device	Subpart Kb (Y/N?)
630-TK-1A through 63-TK-1I	LPG	60,000 (each)	22,903,020 (total)	Y	N	n/a	N
				Y	N	n/a	N
630-TK-2	Light Naphtha	126,000	21,691,950	N	Y	Flare(1)	N
630-TK-3		126,000		N	Y	Flare(1)	N
630-TK-4	Reformate (Heavy Naphtha)	168,000	30,445,380	N	Y	None	N
630-TK-5		168,000		N	Y	None	N
630-TK-6	Gasoline	840,000	52,137,330	N	Y	Flare(1)	Y
630-TK-7		840,000		N	Y	Flare(1)	Y
630-TK-8	Diesel	1,197,000	100,426,830	N	N	None	N
630-TK-9		1,197,000		N	N	None	N
630-TK-10	Ethanol	168,000	9,200,704	N	Y	Flare(1)	Y
630-TK-11		168,000		N	Y	Flare(1)	Y
630-TK-12	HYK Heavy Feed(3)	126,000	209,454	N	N	None(3)	N
630-TK-13	HYK Light Feed(3)	672,000	1,316,572	N	Y	None(3)	N
630-TK-14	Heavy Slop Oil	672,000	1,316,572	N	N	None	N
630-TK-15	Light Slop Oil	672,000	1,316,572	N	Y	None	N
430-TK-1	Sour Water	210,000	165,179,261	N	Y	SRI(2)	N

(1) Vapors are captured from the storage tank and routed through a **closed vent system** to the Liquid Product Loadout Flare (640-FL-1).
(2) Vapors are captured from the storage tank and routed through a **closed vent system** to the Sulfur Recovery Unit Incinerator (440-SRI-1).
(3) These tanks are under normal operating conditions process vessels that do not store these materials and when operating in that scenario displaced vapors are routed through a **closed vent system** to the Emergency Flare (620-FL-1). However, during a plant shutdown, they will serve as storage tanks for up to one month/year and during those times are uncontrolled.

In Unit 640: Liquid Product Loadout, the liquid products stored in the storage tanks listed under Table 3 will be loaded into trucks, railcars, or barges for delivery off-site. The following table details the material unloading operations:

Table 3: Material Loading/Unloading Operations

Emission Unit ID	Material Loaded/Unloaded	Truck (gpm)	Rail (gpm)	Barge (gpm)
640-TR-1 640-RR-1 640-BR-1	Gasoline(1)	2,400(2)	800(2)	1,800(2)
640-TR-2 640-RR-2 640-BR-2	Diesel	3,600	800	1,800
640-TR-3	LPG	600	n/a	n/a

(1) Gasoline from the two (2) storage tanks is blended with ethanol from the two (2) storage tanks to fill transports with finished gasoline (15% ethanol blend). The maximum design and annual throughput limits are applicable to this blended gasoline.
(2) Vapors captured (minimum of 99.2%) and sent to Flare 640-FL-1 for destruction.

Unit 700: Hydrogen Plant

In Unit 700: Hydrogen Plant, hydrogen (H_2) is produced in the 537 mmBtu/hr Hydrogen Reformer (700-HR-1) to supply H_2 to various processes within the production process. This unit will utilize Selective Catalytic Reduction (SCR) to reduce NO_x in the exhaust gas stream. An SCR selectively reduces NO_x emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. The compounds NO_x, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. The temperature of the exhaust stream is critical to promote the reaction of NO_x with the catalyst material. During facility startup (estimated to be a maximum of 60 hours/year), minimum temperatures to promote NO_x reduction are not expected until proper heating from the exhaust gases has occurred.

In the Hydrogen Reformer, 28 mmscf/day of natural gas reacts with steam under pressure and in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide. Subsequently, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen. In a final process step called "pressure-swing adsorption," carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen. Steam reforming is endothermic, that is, heat must be supplied to the process for the reaction to proceed and therefore, natural gas is also combusted in the unit to produce heat for the process. A maximum of 75 mmscf/day of hydrogen is produced in the plant.

SITE INSPECTION

On March 19, 2019, the writer conducted an inspection of the proposed location of DSF's Mason County Facility. The proposed site is located on a 221 acre plot within the boundary of the Mason County Industrial Park approximately 5.80 miles north of downtown Point Pleasant, Mason County, WV. Prior to the inspection, a discussion about the site and the facility boundaries was had with Mr. Kelvin Whited, President of DSF. Observations from the inspection include:

- The proposed location of the facility is within the boundary of the Mason County Industrial Park and on land that lies between WV State Route (SR) 62 to the East and the Ohio River to the west. Directly south of the site is an industrial facility known as Steel Specialties (which is part of the Mason County Industrial Park), and north of the facility lies scattered farms and homes. Wedged between part of the facility and the SR 62 eastern boundary of the plot are three (3) buildings: an industrial facility called Precision Fabricators, the Grace Baptist Church, and what appears to be a currently empty former industrial facility;

- The topography of the proposed location is dominated by the flood plain of the Ohio River, with hills increasing both to the west on the other side of the valley and to the east. The local area includes scattered farms, homes, and more settled communities. The city of Point Pleasant is approximately 5.80 miles to the south;

- Several large coal-fired power plants lie very close to the proposed location: the 2,600 mW Gavin Power Plant just across the Ohio River to the west-northwest and the 1,000 mW Kyger Power Plant just across the Ohio River to the southwest;

- The McClintic Wildlife Management Area (~1.5 miles) and the Mason County Fair Grounds (~1.1 miles) lie to the east. Neither of these areas are given special status under 45CSR13 for permitting purposes (such as a Class I area would under 45CSR14). The Mason County Airport lies approximately 0.65 miles to the south-southeast. Point Pleasant High School lies approximately 3.0 miles to the south;

- At the time of the inspection, no construction of any kind was seen with the exception of some survey stakes. The proposed site was heavily wooded with signs, however, of some former industrial activity; and

- The occupied residences located nearest to the proposed site are approximately 0.2 miles to the east of the proposed site on the far side of SR 62.

The following picture was taken looking northwest from near the southern boundary of the proposed site, near the Mason County Industrial Park access road. Steel Specialties is behind and to the left, and the Gavin Power Plant can be seen across the Ohio River.

Proposed DSF Site within Mason County Industrial Park

Directions: [Latitude/Longitude: 38.92554/-82.10807] At the time of writing, it is expected that the main entrance to the facility will be by the Mason County Industrial Park access road which is located to the left along SR 62 approximately 5.70 miles north of the SR 62/SR 2 junction in Point Pleasant.

AIR EMISSIONS AND CALCULATION METHODOLOGIES

DSF, in Attachment N of the permit application, provided a facility-wide potential-to-emit (PTE) for the proposed Mason County Facility and calculations for all equipment and processes at the facility. The following section will summarize the air emissions and emissions calculation methodologies used by DSF to calculate the PTE. For a detailed review of the emissions calculations, see Attachment N of the permit application.

Coal Handling

Emissions of particulate matter (PM, PM_{10}, and $PM_{2.5}$) may occur from the unloading, transporting, conveying, crushing, and storing of coal. Where emission sources (silos, enclosed conveyer transfer points, crushing, etc.) are controlled by fabric filters/baghouses, the filterable particulate matter emission estimate for the controlled source was based on the maximum outlet concentration of the filter (0.010 gr/dscf) and the maximum expected airflow of the associated fan. For uncontrolled emission sources, or where controlled through the use of enclosures, emissions were calculated using the appropriate section of AP-42 (AP-42 is a database of emission factors maintained by USEPA). Controlled emissions were then calculated using a reasonable control efficiency based on the type of enclosure or other mitigating factor. See the following table for the source of various material handling emission factors used by DSF:

Table 4: Coal Handling PM Emission Factor Sources

Emission Source	Emission Factor Source	Notes
End-loader/Truck/Other Drops	AP-42, Section 13.2.4 (11/06)	Emission factor calculation includes material moisture content and average wind speed.
Conveyer Transfer Points		
Open Storage	WV G-10D General Permit Guidance	G-10D Guidance based on emission factor given in Air Pollution Engineering Manual © 1992 pp. 136 & References.
Paved Haulroads & Mobile Work Areas	AP-42 Section 13.2.1 (1/11)	Based on average truck weights, surface material silt content, and number of precipitation days. A control percentage of 75% was used for vacuum sweeping.
Sources Controlled by Fabric Filters	Maximum Outlet Loading Concentration(1)	Calculated with maximum outward airflow.

(1) As based on vendor information or vendor guarantees.

If based on AP-42 emission factors, all hourly emissions were based on the worst-case hourly throughput (either as limited by the bottlenecked process or by the capacity of the unit) and, unless otherwise noted, annual emissions were based on 8,760 hours a year of operation. Hourly emissions from the fabric filters/baghouses were based on the maximum expected airflow through the units and, unless otherwise noted, annual emissions were based on 8,760 hours a year of operation. Where appropriate, DSF adjusted the emission rates of PM_{10} and $PM_{2.5}$ as based on appropriate particle size distribution.

Other Solid Material Handling

Other material handling operations besides coal will occur at the proposed facility and are a potential source of particulate matter emissions. These are the handling, processing, and storage of flaked sulfur product and both feed and spent catalyst. As with the coal handling sources, where emission sources are controlled by fabric filters/baghouses, the filterable particulate matter emission estimate for the controlled source was based on the maximum outlet concentration of the filter (0.010 gr/dscf) and the maximum associated airflow. For uncontrolled emission sources, where applicable, emissions were calculated using the same methodology as given in Table 3 above. Hourly and annual emissions were calculated using the same methodology as the coal handling emissions as described above.

Coal Milling Dryer, Process Heaters, Steam Boiler

Potential emissions from the proposed 13.45 mmBtu/hr Coal Milling Dryer (100-CMD-1), 74.02 mmBtu/hr Slurry Feed Heater (200-H-102), 15.34 mmBtu/hr Hydrogen Heater (200-H-1), 10.78 mmBtu/hr Fractionation Reboiler (310-H-101), 24.79 mmBtu/hr Vacuum Tower Feed Heater (200-H-301), 8.37 mmBtu/hr Hydrocracker Reaction Heater (310-H-101), 11.89 mmBtu/hr Catalyst Reaction Heaters (320-H-201 through 204), and the 24.3 mmBtu/hr Steam Boiler (500-SB-1) - each of which is fired by natural gas, fuel gas, or a combination thereof - were based on emission factors provided by the particular unit's vendor (where applicable) and as given in AP-42, Section 1.4 - "Natural Gas Combustion." Hourly emissions were based on the maximum design heat input (MDHI) of each unit. With the exception of the Steam Boiler, individual unit annual emissions were based on 8,760 hours of operation per year. To be conservative, a fuel gas lower heat content of 712 Btu/scf was used in the calculations. Where applicable, emission factors appropriate for use of low-NO_x burners and flue gas recirculation were used. For the Steam Boiler, annual emissions were based on the unit operating at MDHI for 60 hours/year, and at 4.9 mmBtu/hr the other 8,700 hours/yr.

Hydrogen Reformer

Potential emissions from the proposed 537 mmBtu/hr gas-fired (both natural gas and fuel gas with up to a 90/10 ration of PNG/fuel gas) Hydrogen Reformer (700-HR-1) were based on emission factors provided by the unit's vendor (CO, NO_x, and VOCs) and as given in AP-42, Section 1.4 - "Natural Gas Combustion." As the Hydrogen Reformer utilizes an SCR to control NO_x emissions and the SCR does not become effective until the exhaust reaches the proper temperature, DSF also included an estimate for NO_x emissions without the SCR during times of unit startup (basing the uncontrolled NO_x emission rate on an effective SCR control efficiency of 87%). Maximum hourly emissions were based on the MDHI of the unit. Maximum annual emissions were based on 8,760 hours of operation per year (8,700 hours with the SCR operating and 60 hours of startup operations). A lower heat content of the fuel gas mixture of 918 Btu/scf was used in the calculations.

Storage Tanks

DSF provided an estimate of the uncontrolled and controlled VOC/HAP emissions produced from each of the storage tanks using the TANKS 4.09d program as provided under AP-42, Section

7. The total emissions from each fixed roof storage tank are the combination of the calculated "breathing loss" and "working loss." The breathing loss refers to the loss of vapors as a result of tank vapor space breathing (resulting from temperature and pressure differences) that occurs continuously when the tank is storing liquid. The working loss refers to the loss of vapors as a result of tank filling or emptying operations. Breathing losses are independent of storage tank throughput while working losses are dependent on throughput. The total emissions from each storage tank utilizing an internal floating roof are the combination of the calculated "rim seal," "withdrawal," "deck fitting," and "deck seam" losses.

Maximum annual emissions from the storage tanks were as calculated by the TANKS program and based on specific maximum throughputs of each tank. As vapors from the Light Naphtha (630-TK-2, 630-TK-3), Gasoline (630-TK-6, 630-TK-7), and Ethanol (630-TK-10, 630-TK-11) storage tanks are captured and sent to the Liquid Product Loadout Flare (640-FL-1) for control, the controlled emissions from these storage tanks were based on the flare's DRE of 98%. The remaining storage tanks vent directly to the atmosphere.

Truck/Railcar/Barge Loadouts

With the exception of LPG loading, uncontrolled VOC/HAP emissions from the truck, railcar, and barge loading of liquids occur as emissions generated by displacement of VOC-laden vapors from the loaded containers. The emission factors used to generate the VOC/HAP emissions are based on equations given in AP-42, Section 5.2-4. In this equation, DSF used variables specific to liquids being loaded and to the method of loading. Maximum hourly emissions were based on the maximum design loading rates for each liquid and container loaded in gallons/minute (see Table 3 above). Additionally, worst-case annual emissions were based on the maximum annual loading rates for each liquid and container loaded in gallons/year. Gasoline loading operations are conducted with a vapor capture system installed, maintained, and operated so as to achieve a minimum capture efficiency of displaced tank vapors of 99.2% (which the AP-42 states is appropriate for racks subject to a "MACT-level" annual leak test which is required by Subpart BBBBBB). All vapors captured during loading operations will then be sent, via a closed vent system, back to the Gasoline Storage Tanks (630-TK-6, 630-TK-7) which are then controlled by the Liquid Product Loadout Flare with a minimum DRE of 98%.

Uncontrolled VOC emissions from the pressurized truck loading of LPG occur as emissions generated when LPG is released when the hose is disconnected. DSF based the calculations on a 5-feet long section of 3-inch inner diameter hose located between the LPG Loading Rack disconnection valves. This volume of LPG is calculated to be released after each loading event (a maximum of 3,371 events/year). A maximum of 2 events/hour were used to calculate the maximum hourly emissions.

Waste Gas Venting

Waste gas vented from various areas of the plant due to regular operations or during planned and unplanned events (not malfunctions, however, that would qualify as an "Act of God" under Section 3.3 of the draft permit) are collected and sent to the Emergency Flare (620-FL-1) for destruction. The waste gas vented from the following scenarios were quantified (using engineering estimation and modeling software) to calculate the potential uncontrolled VOC/HAP emissions from these events: Unit 200 Depressurization, Unit 310 Depressurization, Unit 320 Stabilizer Feed Loss, and Unit 420 Control Valve Failure. The maximum annual emissions were based on each unit sending waste gas streams to the flare for a maximum of four (4) 30 minute emergency events per year. The controlled emissions of these sources were then calculated using the minimum Emergency Flare DRE of 98%.

Sulfur Gas Venting

Sulfur containing gases (in the form of H_2S and COS) from Unit 440: Amine Treating Tail Gas and Unit 430: Sour Water Storage Tank are collected and sent to the SRU Incinerator for control. The amount of VOCs, HAPS, CO, and the sulfur species produced from each source were estimated by DSF (in lbs/hr) and then a 98% DRE was applied to estimate the controlled emissions of each. Maximum annual emissions were based on the sulfur gas venting occurring 8,760 hours/year.

Emergency & Liquid Loadout Flares' Combustion Exhaust

Three (3) sources of air emissions occur at the Emergency and Liquid Loadout Flares: VOC/HAP emissions that pass-through the units uncombusted, the products of combusting the organic vapors sent to the units for destruction, and the products of combustion of each flare's natural gas-fired pilot lights. This section details the products of combustion generated at the units from both the combustion of the waste gases and at the pilot light (the pass-through emissions are discussed under the Waste Gas Venting, Storage Tanks, and Truck/Railcar/Barge Loadouts). Uncontrolled combustion exhaust emissions from both sources are based on emission factors (CO and NO_x) as given in AP-42, Section 13.5 and on AP-42, Section 1.4 (particulate matter, SO_2, formaldehyde, and total HAPs). Based on the maximum amount of waste gases sent to the flare as described in the Waste Gas Venting, Storage Tanks, and Truck/Railcar/Barge Loadouts and the gas characteristics, DSF calculated the maximum hourly and annual waste gas heat content sent to the Emergency and Liquid Loadout Flares (7,928 and 7,546 mmBtu, respectively) and used this data to calculate the combustion exhaust emissions.

SRU Incinerator & Claus Furnace Combustion Exhaust

Three sources of emissions will be vented from the SRU Incinerator (440-SRI-1) emission point: (1) productions of waste gas combustion from the 10.60 mmBtu/hr SRU Incinerator, (2) productions of fuel gas combustion from the 4.40 mmBtu/hr Claus Furnace (440-CF-1), and primarily uncombusted sulfur-containing waste gases. Potential emissions from the products of combustion were based on emission factors provided by the units' vendor (CO, NO_x) and as given in AP-42, Section 1.4 - "Natural Gas Combustion." Maximum hourly emissions were based on the combined MDHI of the units and annual emissions were based on 8,760 hours of operation per year. To be conservative, a fuel gas lower heat content of 712 Btu/scf was used in the calculations. The emissions of uncombusted sulfur-containing waste gases were discussed above under Sulfur Gas Venting.

Cooling Tower

Particulate matter emissions from the Cooling Tower (500-CT-1) occur because the wet-type cooling towers provide direct contact between the cooling water and the air passing through the tower. Some of the liquid water may be entrained within the air stream and carried out of the tower as "drift" droplets. Therefore, the particulate constituent (suspended and dissolved solids) of the drift droplets may be classified as particulate matter. The potential particulate matter emissions from the cooling tower were calculated using a conservative emission factor (0.019 lb-PM_{10}/gal of cooling water) provided in AP-42 Section 13.4 (1/95). A maximum water flow rate of 5,565 gpm was used to determine hourly emissions and annual emissions were based on 8,760 hours of operation per year. While a drift eliminator will most likely be used, no credit was taken for this control strategy in the calculations.

Equipment Leaks

DSF based their VOC/HAP fugitive equipment leak calculations on emission factors taken from the document EPA-453/R-95-017 - "Protocol for Equipment Leak Emission Estimates" Table 2-2. Aggregate component counts were based on engineering estimates for the specific sections of the proposed plant. Control efficiencies on valves in gas and light liquid service were based on a HON MACT 500 ppm_v leak detection monitoring program (as also required under the applicable Subpart GGGa - see below) and using the associated control percentages as given under USEPA's "Leak Detection and Repair (LDAR) Compliance Assistance Guidance -A Best Practices Guide" Table 4-1 (which are based on control percentages taken from the document EPA-453/R-95-017 - "Protocol for Equipment Leak Emission Estimates" Table 5-2). Leakless compressor seals and capped and sealed open-ended lines are assumed to have 100% control. VOC by-weight percentages were considered at 100% for all gas/liquid streams. HAP streams were present only in Units 320, 630, and 640 and the subsequent HAP by-weight percentages were based on worst-case speciated molar percentages.

Emergency Generator

Potential emissions from the 671 hp diesel-fired Generac Model SD500 Emergency Generator (500-EG-1) were based on emission factors obtained from AP-42, Section 3.3. Maximum hourly emissions based on the calculated MDHI usage of the unit (based on a vendor given fuel usage rate of 31.20 gal/hr and a diesel heat content of 0.14 mmBtu/gal) and maximum annual emissions were based on 100 hours per year of non-emergency operation.

Emissions Summary

Based on the above estimation methodology as submitted in Attachment N of the permit application, the facility-wide PTE of DSF's proposed Mason County Facility is given in the following table (a detailed by-unit breakdown of the facility-wide PTE is given in Attachment N):

Table 5: Facility-Wide Annual PTE

Pollutant	PTE (TPY)
CO	71.32
NO_x	80.91
$PM_{2.5(1)}$	54.66
$PM_{10(1)}$	78.12
PM(1)	83.49
SO_2	27.19
VOCs	86.10
Total HAPs	16.96(2)

(1) Including condensables where applicable.

(2) As no individual HAP has a PTE over 10 TPY (n-Hexane is the largest contributor - see Table N-2 of the permit application - at 6.37 TPY) and emissions of total HAPs is less than 25 TPY, the proposed Mason County Facility is defined as a minor (area) source for purposes of 40 CFR 61 and 40CFR63.

REGULATORY APPLICABILITY

The proposed DSF Mason County Facility is subject to a variety of substantive state and federal air quality rules and regulations. Each applicable rule, and DSF's proposed compliance thereto, will be discussed below. Additionally, those rules that have questionable applicability but have been determined to not apply will also be discussed. DSF included a Regulatory Applicability the permit application under section 4.0.

45CSR2: To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers

45CSR2 "establishes emission limitations for smoke and particulate matter which are discharged from fuel burning units." A fuel burning unit is defined under 45CSR2 as any "*furnace, boiler apparatus, device, mechanism, stack or structure used in the process of burning fuel or other combustible material for the primary purpose of producing heat or power by indirect heat transfer*." Additionally, the definition of "indirect heat exchanger" specifically excludes process heaters, which are defined as "*a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.*" Based on these definitions, the proposed 24.3 mmBtu/hr Steam Boiler (500-SB-1) and the 13.45 mmBtu/hr Coal Milling Dryer (100-CMD-1) are each defined as a fuel burning unit and are subject to 45CSR2. Other proposed combustion devices are either defined as process heaters or do not meet the definition of an indirect heat exchanger. Each substantive 45CSR2 requirement is discussed below.

<u>45CSR2 Opacity Standard - Section 3.1</u>

Pursuant to 45CSR2, Section 3.1, each of the applicable fuel burning units noted above are subject to an opacity limit of 10%. Proper maintenance and operation of the units (and use of gaseous fuel) should keep the opacity of the units well below 10% during normal operations.

45CSR2 Weight Emission Standard - Section 4.1.b

The facility-wide allowable particulate matter (PM) emission rate for the applicable fuel burning units noted above, identified as Type "b" fuel burning units, per 45CSR2, Section 4.1(b), is the product of 0.09 and the total aggregate design heat input of all the applicable units in million Btu per hour. As shown in Table 6 below, the maximum aggregate design heat input (short-term) of all of the applicable units (500-SB-1 and 100-CMD-1) will be 37.75 mmBtu/Hr. Using the above equation, the 45CSR2 aggregate PM emission limit of the units will be 3.40 lb/hr. This limit represents filterable PM only and does not include condensable PM. The exemption of condensable PM is located within the 45CSR2 Appendix - which establishes compliance test procedures - by not requiring measurement of the condensable PM. The maximum potential hourly PM emissions during normal operations from the units (*including* condensables) is estimated to be 0.31 lb/hr. This conservative emission rate is 9.12% of the 45CSR2 limit.

Table 6: 45CSR2 Compliance Demonstration

Emission Unit ID	Fuel Burning Unit Description	Design Capacity (mmBtu/hr)	Fuel Burning Unit PTE (lb-PM/hr)
500-SB-1	Steam Boiler	24.30	0.20
100-CMD-1	Coal Milling Dryer	13.45	0.11
	Totals ➜	***37.75***	***0.31***

45CSR2 Testing, Monitoring, Record-keeping, & Reporting (TMR&R) - Section 8

Section 8 of 45CSR2 requires testing for initial compliance with the limits under Section 3 and 4, monitoring for continued compliance, and record-keeping of that compliance. The TMR&R requirements are clarified under 45CSR2A and discussed below.

45CSR2A Applicability - Section 3

Pursuant to 45CSR2, Section 3.1(b), the owner or operator of a "*fuel burning unit(s) which combusts only natural gas shall be exempt from sections 5 and 6.*" Therefore, there is no substantive performance testing or monitoring requirements under 45CSR2 for the proposed fuel burning units. Pursuant to DAQ precedent, the use of a fuel gas mixed with natural gas would still qualify for this exemption.

45CSR2A Record-keeping and Reporting Requirements - Section 7

Section 7 sets out the record-keeping requirements that DSF will have to meet under 45CSR2A for the fuel burning units. For units that combust only pipeline natural gas (and as noted above, natural gas mixed with fuel gas), the record-keeping requirements are limited to the date and time of start-up and shutdown, and the quantity of fuel consumed on a monthly basis.

45CSR5: To Prevent and Control Air Pollution from Coal Preparation Plants, Coal Handling Operations, and Coal Refuse Disposal Operations

45CSR5 was established "*to prevent and control air pollution from the operation of coal preparation plants, coal handling operations and coal refuse disposal areas.*" A "coal preparation plant" is defined under 45CSR5 as "*any facility (excluding underground mining operations) that prepares coal by one or more of the following processes: screening, breaking, crushing, wet or dry cleaning and thermal drying, and further such definition of a coal preparation plant shall include all coal handling operations associated with the processes described above. . .*" As the Unit 100 operations at the proposed facility will be involved in the milling (breaking) of coal and coal handling, the Unit 100 operations will be subject to 45CSR5. The substantive requirements applicable are discussed below.

45CSR5 Emission of Particulate Matter - Section 3

Section 3 of 45CSR5 sets a twenty percent (20%) opacity limit on all stack and fugitive dust control systems. This opacity limit will apply on all coal handling emission points. DSF's proposed use of enclosures, stackers, and filters should allow them to meet this requirement.

45CSR5 Thermal Dryer - Section 4

Pursuant to §45-5-2.4(b), as the Coal Milling Dryer is subject to 45CSR2 as an "indirect heat exchanger," it is not subject to the thermal dryer requirements under 45CSR5.

45CSR5 Fugitive Emissions - Section 6

Section 6 of 45CSR5 requires all facilities subject to the rule to minimize emissions through the use of a fugitive dust control system. DSF has proposed a fugitive dust control system of stackers, wind shields, hoppers and bins and use of paving and dust suppression on haulroads. These methods are considered appropriate fugitive emissions minimization.

45CSR6: To Prevent and Control Particulate Air Pollution from Combustion of Refuse

45CSR6 "*establishes emission standards for particulate matter and requirements for activities involving incineration of refuse which are not subject to, or are exempted from regulation under a federal counterpart for specific combustion sources.*" 45CSR6 defines "incineration" as the "*the destruction of combustible refuse by burning in a furnace designed for that purpose. For the purposes of this rule, the destruction of any combustible liquid or gaseous material by burning in a flare or flare stack, thermal oxidizer or thermal catalytic oxidizer stack shall be considered incineration.*" Based on this definition, the proposed Emergency Flare (620-FL-1), the Liquid Product Loadout Flare (640-FL-1), and the SRU Incinerator (440-SRI-1) each meet the definition of an "incinerator" under 45CSR6 and are, therefore, subject to the requirements therein.

Emission Standards for Incinerators - Section 4.1

Section 4.1 of 45CSR6 limits PM emissions from incinerators to a value determined by the following formula:

Emissions (lb/hr) = F x Incinerator Capacity (tons/hr)

Where, the factor, F, is as indicated in Table I below:

Table I: Factor, F, for Determining Maximum Allowable Particulate Emissions

Incinerator Capacity	Factor F
A. Less than 15,000 lbs/hr	5.43
B. 15,000 lbs/hr or greater	2.72

Based on information taken from Attachments M and N of the permit application, the following table shows the compliance determination for each flare:

Table 7: 45CSR6 PM Limitation Determination

Flare	Capacity (tons/hr)	45CSR6 Emission Limit (lb-PM/hr)	PTE (lb-PM/hr)
620-FL-1	69.5	189.04	10.57
640-FL-1	0.67	3.64	0.03
440-SRI-1	4.68	25.41	0.16

Opacity Limits for Incinerators - Section 4.3, 4.4

Pursuant to Section 4.3, and subject to the exemptions under 4.4, each incinerator has a 20% limit on opacity during operation. Proper design and operation of the units should prevent any significant opacity.

45CSR7: To Prevent and Control Particulate Air Pollution from Manufacturing Process Operations

45CSR7 has requirements to prevent and control particulate matter air pollution from manufacturing processes and associated operations. Pursuant to §45-7-2.20, a "manufacturing process" means "*any action, operation or treatment, embracing chemical, industrial or manufacturing efforts . . . that may emit smoke, particulate matter or gaseous matter.*" 45CSR7 has three substantive requirements potentially applicable to the particulate matter-emitting "source operations" at the proposed DSF Facility (excluding the coal handling operations regulated under 45CSR5 as discussed above). These are the opacity requirements under Section 3, the mass emission standards under Section 4, and the fugitive emission standards under Section 5.

Pursuant to §45-7-10, 45CSR7 does not apply to particulate matter emissions regulated under 45CSR2 or 45CSR5, excluding therefore the "fuel burning units" (Steam Boiler and the Coal Milling Dryer) and the coal handling equipment. Additionally, the combustion exhaust from the incinerators (flares) are properly regulated under 45CSR6 (see above). As the process heaters, Hydrogen Reformer and combustion devices only result in relatively small amounts of particulate matter emissions from the combustion of low particulate matter-emitting fuel gas, these units are also excluded from 45CSR7 applicability. Therefore, 45CSR7 will be applied to the feed/spent catalyst handling operations, the solid product handling operations, and the product haulroads.

45CSR7 Opacity Standards - Section 3

§45-7-3.1 sets an opacity limit of 20% on all "process source operations." Pursuant to §45-6-2.38, a "source operation" means the "*last operation in a manufacturing process preceding the* *emission of air contaminants [in] which [the] operation results in the separation of air contaminants from the process materials or in the conversion of the process materials into air contaminants and is not an air pollution abatement operation.*" With the exception of the haulroads, each of the manufacturing processes outlined above are subject to Section 3. Use of fabric filters, enclosures, and the inherent moisture content of certain materials should allow the catalyst and product handling emission sources to operate in compliance with the 20% opacity limit.

45CSR7 Weight Emission Standards - Section 4

Section 4.1 of 45CSR7 requires that each manufacturing process source operation or duplicate source operation meet a maximum allowable "stack" particulate matter limit based on the weight of material processed through the source operation. As the limit is defined as a "stack" limit (under Table 45-7A), the only applicable emission units (defined as a type 'a' sources) are those that the emissions are captured and directed through a stack prior to be emitted. The following table details the pertinent data for the compliance demonstration of each of these source operations.

Table 8: 45CSR7 Section 4.1 Compliance

Source Operation	EP ID	Source Type	Process Weight Rate (lb/hr)	Table 45-7A Limit (lb/hr)	PTE (lb/hr)	% of Limit
Feed Catalyst Bins	200-D-206	A	4,400	4.52	0.10	2.21%
Spent Catalyst Drums(1)	Various	A	7,040	7.04	0.01	0.14%
Flaked Residue Product Handling(1)	Various	A	51,060	31.04	3.77	12.15%
Sulfur Product Handling(1)	Various	A	95,860	32.83	3.17	9.66%

(1) To be conservative, these source operations are aggregations of all the individual emissions points within the grouping.

45CSR7 Fugitive Emissions - Section 5

Pursuant to §45-7-5.1 and 5.2, each manufacturing process or storage structure generating fugitive particulate matter must include a system to minimize the emissions of fugitive particulate matter. Specific to the feed/spent catalyst handling operations, the solid product handling operations, and the product haulroads, where there is a potential for substantive particulate matter emissions DSF has proposed the utilization of fabric filters. Other emission sources either have the potential for minimal particulate matter emissions or have a high moisture content. All haul roads will be paved and maintained using a vacuum sweeper to minimize fugitive particulate matter emissions.

45CSR10: To Prevent and Control Air Pollution from the Emission of Sulfur Oxides

The purpose of 45CSR10 is to "prevent and control air pollution from the emission of sulfur oxides." 45CSR10 has requirements limiting SO_2 emissions from "fuel burning units," limiting in-stack SO_2 concentrations of "manufacturing process source operations," and limiting H_2S concentrations in "process gas" streams that are combusted. Each substantive 45CSR10 requirement is discussed below.

45CSR10 Fuel Burning Units - Section 3

As noted under the discussion of 45CSR2 applicability, based on the same definitions therein, the proposed 24.3 mmBtu/hr Steam Boiler (500-SB-1) and the 13.45 mmBtu/hr Coal Milling Dryer (100-CMD-1) are each defined as a "fuel burning unit" and are subject to 45CSR10.

The allowable sulfur dioxide (SO_2) emissions from applicable fuel burning units noted above, each identified as a Type "b" fuel burning unit in a Priority III Region (which includes Mason County), per 45CSR10, Section 3.3(f), is the product of 3.2 and the total design heat input of each applicable unit in million Btu per hour. As shown in Table 8 below, the maximum aggregate design heat input (short-term) of all of the applicable units (500-SB-1 and 100-CMD-1) will be 37.75 mmBtu/Hr. Using the above equation results in a SO_2 limit of 120.80 pounds per hour. As all the applicable fuel burning units are fueled by PNG or desulfurized fuel gas, the aggregate PTE of these fuel burning units will be nominal.

Table 9: 45CSR10 Section 3 Compliance Demonstration

Emission Unit ID	Fuel Burning Unit Description	Design Capacity (mmBtu/hr)	Fuel Burning Unit PTE (lb-SO_2/hr)
500-SB-1	Steam Boiler	24.30	0.02
100-CMD-1	Coal Milling Dryer	13.45	0.01
	Totals ➜	***37.75***	***0.03***

45CSR10 Manufacturing Process Source Operations - Section 4.1

Section 4.1 of Rule 10 requires that no in-stack SO_2 concentration exceed 2,000 parts per million by volume (ppm_v) from any manufacturing process source operation except as provided in subdivisions 4.1(a) through 4.1(e). The process heaters, under 45CSR10, are nominally considered manufacturing process source operations. However, as each unit will be fueled by PNG or desulfurized fuel gas, only small amounts of SO_2 will be emitted from each unit. The units are also subject to more stringent SO_2 exhaust limits under 40 CFR 60, Subpart Ja (20 ppm_v), and compliance with those limits will determine compliance with the 45CSR10 limit.

Additionally, as part of a "sulfur recovery plant," the (SRU) Incinerator (440-SRI-1) will be subject to Section 4.1(b), which states that "*[n]o person shall cause, suffer, allow or permit the emission of sulfur oxides, calculated as sulfur dioxide, from a sulfur recovery plant to exceed 0.06 pounds per pound of sulfur processed.*" Based on information included in the permit application, the (SRU) will process 4,565 pounds per hour of sulfur and will emit, from the incinerator stack, a maximum of 5.64 lbs-SO_2/hour. This equates to a performance based emission rate of 1.24 x 10^{-3} lbs-SO_2/hour, far below the 45CSR10 limit.

45CSR10 Combustion of Refinery Gas Streams - Section 5

Section 5.1 of Rule 10 prohibits the combustion of any "refinery process gas stream" that contains H_2S in excess of 50 grains for every 100 cubic feet of gas consumed. The fuel gas routed from Unit 410 is considered a "refinery process gas stream" under 45CSR10 and is combusted in all the combustion devices at the facility. Based on information in the permit application, this gas contains a maximum of 10 ppm_v of H_2S or 0.04 grains/H_2S per 100 cubic feet of gas. Compliance with the 45CSR10 H_2S limit will based on the more stringent continuous H_2S fuel gas monitoring requirements applicable under 40 CFR 60, Subpart Ja.

45CSR13: Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation

The proposed construction of the DSF Facility has the potential to emit a regulated pollutant in excess of six (6) lbs/hour and ten (10) TPY and, therefore, pursuant to §45-13-2.24, the proposed facility is defined as a "stationary source" under 45CSR13. Pursuant to §45-13-5.1, "[n]o person shall cause, suffer, allow or permit the construction . . . and operation of any stationary source to be commenced without . . . obtaining a permit to construct." Therefore, DSF is required to obtain a permit under 45CSR13 for the construction and operation of the proposed facility.

As required under §45-13-8.3 ("Notice Level A"), DSF placed a Class I legal advertisement in a "newspaper of *general circulation* in the area where the source is . . . located." The ad ran in the January 31, 2019 (a first ad ran on January 18, 2019 but had an incorrectly listed latitude/longitude and a new advertisement was required) edition of the *Point Pleasant Register* and the affidavit of publication for this legal advertisement was submitted on February 8, 2019.

45CSR14: Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration - (Not Applicable)

45CSR14 establishes and adopts a preconstruction permit program for the construction and major modification of major stationary sources in areas of attainment with the National Ambient Air Quality Standards (NAAQS). Mason County is currently classified as in attainment with the NAAQS and, therefore, a proposed new "major stationary source" in Mason County would be subject to the provisions of 45CSR14. The proposed DSF Direct Coal Liquefaction Facility is defined as a source listed under §45-14-2.43.a ("Fuel Conversion Plants") and, therefore, pursuant to 2.43.b., would be defined as a "major stationary source" if any regulated pollutant has a PTE in excess of 100 TPY. The proposed facility, however, does not have a potential-to-emit of any regulated pollutant in excess of 100 TPY (see Table 5 above) and is, therefore, not defined as a major stationary source and is not subject to the provisions of 45CSR14.

45CSR27: To Prevent and Control the Emissions of Toxic Air Pollutants (Not Applicable)

45CSR27 was established to "*prevent and control the discharge of toxic air pollutants requiring the application of best available technology.*" A toxic air pollutant (TAP) is defined as one of the compounds listed under Table A of 45CSR27. Pursuant to §45-27-3.1, the "*owner or operator of a plant that discharges or may discharge a toxic air pollutant into the open air in excess of the amount shown in the Table A [of 45CSR27] shall employ [Best Available Technology] at all chemical processing units emitting the toxic air pollutant.*" Formaldehyde and Benzene, compounds that are listed in Table A, shall be emitted by the proposed DSF facility. However, the annual PTE of each (600 and 320 lbs/yr, respectively) is below the threshold (1,000 lbs/yr) under Table A of 45CSR27 that would trigger applicability of the rule.

45CSR30: Requirements for Operating Permits

45CSR30 provides for the establishment of a comprehensive air quality permitting system consistent with the requirements of Title V of the Clean Air Act. The proposed DSF Direct Coal Liquefaction Facility does not meet the definition of a "major source under §112 of the Clean Air Act" as outlined under §45-30-2.26 and clarified (fugitive policy) under 45CSR30b. The proposed facility-wide PTE (see Table 5 above) of any regulated pollutant does not exceed 100 TPY. Additionally, the facility-wide PTE does not exceed 10 TPY of any individual HAP or 25 TPY of aggregate HAPs.

However, as the facility is subject to various New Source Performance Standards (NSPS) - e.g., 40 CFR 60, Subpart Dc - that do not contain a Title V permitting exemption, the proposed facility is subject to Title V as a non-major source. Non-major sources subject to Title V, pursuant to DAQ policy, are deferred from having to submit a Title V application but still pay annual fees pursuant to submission of a Certified Emissions Sheet (CES).

40 CFR 60, Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc of 40 CFR 60 is the federal NSPS for "steam generating units" that have a MDHI of less than 100 mmBtu/hr and greater than 10 mmBtu/hr and that were constructed, modified, or reconstructed after June 9, 1989. Subpart Dc contains within it emission standards, compliance methods, monitoring requirements, and reporting and record-keeping procedures for affected facilities applicable to the rule.

Pursuant to §60.40c(a), Subpart Dc applies to "*each steam generating unit that commences construction . . . after June 9, 1989, and that has a maximum design heat input capacity of. . . 100 mmBtu/hr or less, but greater than or equal to 10 mmBtu/hr.*" Subpart Dc defines a "Steam Generating Unit" as "a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium." The definition also states that "*[t]his term does not include process heaters as they are defined in this subpart.*" A "process heater" is defined as "*a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.*" Based on these definitions, the proposed 24.3 mmBtu/hr Steam Boiler (500-SB-1) and the 13.45 mmBtu/hr Coal Milling Dryer (100-CMD-1) are each defined as a steam generating unit and are subject to Subpart Dc. Subpart Dc does not, however, have any emission standards for gas fired units. Therefore, the applicable heaters are only subject to the record-keeping and reporting requirements given under §60.48c.

Note that Subpart Dc states that "*[a]ffected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and* NO_X *standards* [there are no NO_x standards under Subpart Dc] *under this subpart and the* SO_2 *standards under subpart J or subpart Ja of this part, as applicable.*" However, as the Steam Boiler and the Coal Milling Dryer are not otherwise applicable to the PM standards under Subpart Dc, they will not apply even with the units' applicability to Subpart Ja.

40 CFR60, Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

Subpart Ja of 40 CFR 60 is the NSPS for Petroleum Refineries for which construction, reconstruction, or modification commenced After May 14, 2007. The subpart applies to "*the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants.*" The subpart defines "Petroleum Refinery" as "*any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives.*" And finally, "Petroleum" is defined as "the crude oil removed from the earth and the oils derived from tar sands, shale, and coal." Based on the above definitions and the processes located at the plant, the various fuel gas combustion devices (including process heaters), the flare, and the sulfur recovery plant.

Fuel Gas Combustion Units

The Slurry Feed Heater (200-H-102), Hydrogen Heater (200-H-101), Vacuum Tower Feed Heater (200-H-301), Hydrocracker Reaction Heater (310-H-101), Fractionation Reboiler (310-H-101), Catalytic Reaction Heaters 1 through 4 (320-H-201 through 204), Steam Boiler (500-SB-1), and Coal Milling Dryer (100-CMD-1) are subject to NSPS Subpart Ja because they meet the definition a "fuel gas combustion unit." Pursuant to §60.102a(g), DSF can choose to comply with either §60.102a(g)(1)(i) or §60.102a(g)(1)(ii) for each of the units identified above - an SO_2 emission standard or a sulfur fuel gas limit. Pursuant to §60.102a(g)(1)(i), the above identified heaters "*shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppm_v (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppm_v (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis.*" Pursuant to §60.102a(g)(1)(ii), the above identified heaters "s*hall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppm_v determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppm_v determined daily on a 365 successive calendar day rolling average basis.*"

The application states that while the units will burn some fuel gas provided by the liquefaction process, this gas will not have total sulfur content greater than 0.04 lb-H_2S/100 ft^3 - easily in compliance with §60.102a(g)(1)(ii) limit. The small amount of total sulfur in the desulfurized fuel gas or natural gas will allow the heaters to easily meet the SO_2 stack emissions limits under §60.102a(g)(1)(i) if compliance with that standard is chosen. Compliance under Subpart Ja with the SO_2 stack limit will be determined through the use of a Continuous Emissions Monitoring System (CEMS) as given under §60.107a(a)(1). Compliance under Subpart Ja with the H_2S fuel limit will be determined through the use of a instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device as given under §60.107a(a)(2).

Additionally, pursuant to §60.102a(g)(2)(i), each natural-draft process heater with an MDHI over 40 mmBtu/hr is subject to an emission limit of NO_x in excess of the applicable limits in paragraphs (g)(2)(i)(A) or (B). The 74.02 mmBtu/hr Slurry Feed Heater (200-H-102) and the 537.00 mmBtu/hr Hydrogen Reformer (700-HR-1) are each defined as a natural-draft process heater and are, therefore, subject to §60.102a(g)(2)(i). DSF has stated they will comply with §60.102a(g)(2)(i)(B), which gives a NO_x limit of 0.040 lbs/mmBtu (higher heating value basis) as determined daily on a 30-day rolling average basis. Use of natural gas and low nitrogen-containing fuel gas (and the use of the SCR on the Hydrogen Reformer) should allow each unit to meet this limit. In the calculations, DSF used the Subpart Ja limit to estimate the maximum NO_x emissions from the Slurry Feed Heater and used the vendor guaranteed NO_x emission rate (with the SCR in operation) of 0.008 lbs/mmBtu to for the Hydrogen Reformer. While the startup NO_x emission rate is estimated to be 0.064 lbs/mmBtu, the minimal startup time of the unit should easily allow the average rolling 30-day average to easily meet the Subpart Ja limit.

Flare

The Emergency Flare (620-FL-1) is subject to the design, equipment, work practice or operational standards as given under §60.103a. This includes a requirement to develop and implement a written flare management plan.

Sulfur Recovery Plant

The SRU will have a design production capacity greater than 20 long tons per day and will be designed with a reduction control system followed by incineration. Therefore, pursuant to §60.102a(f)(1)(i), the applicable Claus unit shall not exceed an SO_2 emission limit of 250 ppm_v (dry basis) at zero percent excess air.

All affected facilities discussed above are subject to the applicable monitoring, record-keeping, reporting, and testing requirements given under Subpart Ja.

40 CFR 60, Subpart Kb: 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

Subpart Kb of 40 CFR 60 is the NSPS for storage tanks containing Volatile Organic Liquids (VOLs) which construction commenced after July 23, 1984. The Subpart applies to storage vessels used to store volatile organic liquids with a capacity greater than or equal to 75 m^3 (19,813 gallons). However, storage tanks with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa are exempt from Subpart Kb.

Pursuant §60.110b(b)(2), "[p]ressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere" are exempt from Subpart Kb. Additionally, the definition of "storage vessels" excludes "process tanks." Process Tanks are defined as those tanks that are "*used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is* *transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.*"

Therefore, based on the above, the following storage tanks are exempt from Subpart Kb:

- The two (2) pressurized LPG Storage Tanks (630-TK-1A, 630-TK-1A);

- The Light and Heavy Naphtha Storage Tanks (630-TK-2, 630-TK-3, 630-TK-4, 630-TK-5), the HYK Light and Heavy feed Storage Tanks (630-TK-12, 630-TK-13), the Light and Heavy Slop Oil Storage Tanks (630-TK-14, 630-TK-15), and the Sour Water Storage Tank (430-TK-1) as they are defined as process tanks; and

- The 1,197,000 gallon (4,531 m^3) Diesel Storage Tanks (630-TK-8, 630-TK-9) as the vapor pressure of diesel is less than 3.5 kPa.

The proposed two (2) 840,000 gallon (3,179.75 m^3) Gasoline Storage Tanks (630-TK-6, 630-TK-7) and the two (2) 168,000 gallon (635.95 m^3) Ethanol Storage Tanks (630-TK-10, 630-TK-11), are, however, subject to the applicable provisions of Subpart Kb.

Pursuant to §60.112b(a), the Ethanol Storage Tanks, based on the tank capacities (>75m^3) and the vapor pressure of gasoline (5.2 kPa < capacity < 76.6 kPa), are required to meet one of the control options under §60.112b(a)(1) through (3). While the Ethanol Tanks will have a fixed roof with an internal floating roof as given under §60.112b(a)(1), DSF has chosen to also meet the requirement under §60.112b(a)(3): a closed vent system and control device meeting the requirements under §60.112b(a)(3)(i) and (ii). DSF's proposed use of a closed vent system evacuating to a flare (with a minimum DRE of 98%) meets the requirements of §60.112b(a)(3).

Pursuant to §60.112b(b)(1), the Gasoline Storage Tanks, based on the tank capacities (>75m^3) and the vapor pressure of gasoline (>76.6 kPa), are required to be equipped with a "*closed vent system and control device as specified in §60.112b(a)(3).*" DSF's proposed use of a closed vent system evacuating to a flare (with a minimum DRE of 98%) meets the requirements of §60.112b(a)(3).

Additionally, DSF will be required to meet all applicable monitoring, recordkeeping, and reporting requirements in Subpart Kb. DSF provided a Subpart Kb applicability table as Table 4-1 in Attachment N.

40 CFR 60, Subpart Y: Standards Of Performance For Coal Preparation And Processing Plants

40 CFR 60, Subpart Y is the federal NSPS for coal preparation and processing plants that process more than 200 tons of coal per day. Pursuant to §60.250, affected facilities under Subpart Y are defined as "coal conveying and processing equipment (including breakers and crushers), coal storage systems, coal transfer and loading systems, and coal storage piles" located at "coal preparation and processing plants" that process greater than 200 tons per day. "Coal preparation and

processing plants" is defined as "any facility (excluding underground mining operations) which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying." DSF has proposed to mill (crush) coal at their facility and, therefore, all coal conveying and processing equipment (including, potentially, the coal milling dryer) is subject to the applicable sections of Subpart Y.

The substantive standards under Subpart Y applicable to the proposed DSF facility are given in §60.254(b) and (c):

! A 10% opacity limit on all emission points excluding equipment used in the loading, unloading, and conveying operations of open storage piles;

! A particulate matter limit on any "mechanical vent" of 0.023 g/dscm (0.010 gr/dscf);

! Operation of all coal open storage piles in accordance with a fugitive coal dust emissions control plan as outlined under §60.254(c)(1) through (6).

It is important to note that, pursuant to §60.252(c), as the Coal Milling Dryer receives all of its thermal input from an affected facility covered under 40 CFR 60, Subpart Dc, it is not subject to the requirements of Subpart Y.

DSF's proposed use of fabric filters (with an outlet grain loading limit of 0.010 gr/dscf or less) on most coal conveying and processing equipment (including the Coal Mill) should allow them to meet the 10% opacity limit. DSF has further proposed the use of a wind barrier on both the open and backup coal storage piles.

DSF will be required to comply with all other applicable monitoring, testing, reporting, and record-keeping requirements given under §60.255 through §60.258.

40 CFR 60, Subpart XX: Standards of Performance for Bulk Gasoline Terminals

Subpart XX applies to "all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks" constructed after December 17, 1980. A "bulk gasoline terminal" is defined as "any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters [~20,000 gallons] per day." The DSF facility meets the definition of a bulk gasoline terminal as it will have the capacity to load in excess of 75,700 liters of gasoline per day.

The substantive control and emission standards in Subpart XX are listed in the following:

! §60.502(a) requires the use of a "vapor collection system" installed on the loading racks. “Vapor collection system” means “any equipment used for containing total organic compounds vapors displaced during the loading of gasoline tank trucks;”

! §60.502(b) sets an emissions limit from the vapor collection system of 35 mg-TOC/L gasoline loaded (29 x 10^{-5} lb-TOC/gal gasoline loaded); and

! §60.502(e) requires that gasoline shall only be loaded into vapor-tight gasoline tanks trucks (as defined under §60.501).

DSF has proposed that all the gasoline loading racks will be connected to a vapor collection system and that collected vapors will be balanced with the gasoline storage tanks which are in turn controlled by the Liquid Product Loadout Flare (640-FL-1) with a minimum DRE of 98%. This configuration will meet the above requirements. DSF will be required to load gasoline only into vapor-tight tanks trucks. DSF has stated that the gasoline loading requirements under 40 CFR 63, Subpart BBBBBB are more stringent than those under Subpart XX. See below for the discussion on Subpart BBBBBB.

40 CFR 60, Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

Subpart GGGa of 40 CFR 60 is the NSPS for equipment leaks of VOCs in petroleum refineries for which construction commenced after November 7, 2006. The Mason County Facility is subject to the requirements under Subpart GGGa. Subpart GGGa incorporates by reference the fugitive requirements under 40 CFR 60, Subpart VVa. Subpart VVa contains Leak Detection and Repair (LDAR) requirements for all affected facilities at the proposed facility; these affected facilities are defined under Subpart VVa as "*the components assembled and connected by pipes or ducts to process raw materials and . . . includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping.*" Most substantively, Subpart VVa defines a leak (and triggers repair procedures) when pollutant concentrations are detected in excess of 500 ppm_v for valves in gas and light liquid service and connectors in gas service. DSF shall be required to meet these requirements of Subpart GGGa and therefore by reference Subpart VVa.

40 CFR 60, Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

Subpart QQQ of 40 CFR 60 is the NSPS for Petroleum Refinery Wastewater Systems for which construction, modification, or reconstruction is commenced after May 4, 1987. NSPS Subpart QQQ sets standards to reduce VOC emissions from individual drain systems, oil-water separators, and aggregate facilities. The DSF facility will not operate a wastewater treatment facility that will discharge to the Ohio River. Instead, wastewater generated at the facility will be discharged to the Publically Owned Treatment Works (POTW). Prior to this discharge, however, process waters will contain oily waters subject to the provisions of this rule.

Drains, junction boxes, sewer lines, and other conveyance systems for oily water will be constructed, operated, and maintained in accordance with the Subpart QQQ. The oil-water separator in Unit 430: Sour Water Stripping, in this case, the Sour Water Storage Tank (430-T-101) as it contains therein an oil skimmer, will qualify as an affected unit under Subpart QQQ. The Sour Water Storage Tank will be equipped and operated with a closed vent system that routes the vapors to the Sulfur Recovery Incinerator (440-SRI-1). The slop oil tanks (440-LSO-1, 440-HSO-1) will operate in an enclosed system and oils will be recycled to the process.

40 CFR 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII of 40 CFR 60 is the NSPS for stationary compression ignition internal combustion engines (diesel fired engines). Section §60.4200 states that "*provisions of [Subpart IIII] are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE).*" Specifically, §60.4200(a)(1) states that Subpart IIII applies to "*[o]wners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:*

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines."

DSF has proposed the use of a new 671 hp Generac Model SD500 emergency generator (with a displacement of less than 30 liters per cylinder). Based on the §80.112/§80.113 standards for owner/operators of emergency generator CI ICE referenced under §60.4202(a)(2), the following table details the emission standards for the engine:

Table 10: Subpart IIII Standards

Duty	Size (kW_m)	Displacement (L/cyl)	Source	Emission Standards - g/kW-hr (g/hp-hr)				
				NO_x	HC	NMHC + NO_x	CO	PM
Emergency	450<kW>560	<10	§80.112, Table 1[(1)]	9.2 (6.90)	1.3 (0.98)	4.0 (3.07)	3.5 (2.6)	0.20 (0.15)

(1) Logic train is as follows: §60.4205(b) ➜ §60.4202(a)(2) ➜ §89.112/§89.113.

DSF included in the application a specification sheet for the specific engine that states that the unit is an "EPA Certified Stationary Emergency [Generator]."

40 CFR 63 Subpart ZZZZ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

On June 1, 2013 the DAQ took delegation of the area source provisions of 40 CFR 63, Subpart ZZZZ. As the Mason County Facility is defined as an area source of HAPs (see Table 5), the facility is subject to applicable requirements of Subpart ZZZZ. Pursuant to §63.6590(c):

> An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

§63.6590(c)(1) includes "[a] new or reconstructed stationary RICE located at an area source." Pursuant to §63.6590(a)(2)(iii), a "*stationary RICE located at an area source of HAP emissions is* *new if* [the applicant] *commenced construction of the stationary RICE on or after June 12, 2006.*" The new emergency generator proposed for the Mason County Facility is defined as a new stationary RICE (manufacture date shall be after June 12, 2006) and, therefore, DSF will show compliance with Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII. Compliance with that rule is discussed above.

40 CFR 63, Subpart BBBBBB: National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities - (No Determination Made)

Pursuant to §45-34-4.1(c), the DAQ has not taken delegation of 40 CFR 63, Subpart BBBBBB and, therefore, has not determined whether the permittee is subject to this area source air toxics standard requiring Generally Achievable Control Technology (GACT) that was promulgated on January 24, 2011. If subject, however, DSF is required to comply with this federal rule independent of the proposed permit. DSF stated in the permit application that the gasoline storage and loading operations are subject to Subpart BBBBBB.

40 CFR 63 Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Hazardous Air Pollutants Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters - (Not Applicable)

Subpart DDDDD of 40 CFR 63 establishes national emission limitations and work practice standards for HAPs emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. Pursuant to §63.7485, a boiler or process heater is applicable to Subpart DDDDD "that is located at, or is part of, a major source of HAP[s]." A major source of HAPs is defined under §63.2 as a source that "*has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.*" The proposed Mason County Facility will not have a potential to emit of HAPs at or above this threshold and is, therefore, not subject to Subpart DDDDD (see Table 5).

40 CFR 63 Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources - (Not Applicable)

Subpart JJJJJJ of 40 CFR 63 establishes national emission limitations and work practice standards for HAPs emitted from industrial, commercial, and institutional boilers located at area sources of HAPs. An area sources of HAPs is defined as a facility that has a PTE, considering controls, in the aggregate, of less than 10 tons per year any single HAP or less than 25 tons per year or more of any combination of HAPs. The proposed Mason County Facility meets the definition of an area source of HAPs.

Pursuant to §63.11237, the definition of "boiler" covered under Subpart JJJJJJ is limited to "*an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water.*" This would include only the proposed 24.3 mmBtu/hr Steam Boiler (500-SB-1). However, pursuant to §63.11195(e), as this unit is exclusively "gas-fired," it is exempt from Subpart JJJJJJ.

NON-CRITERIA REGULATED POLLUTANTS

This section provides information on those regulated pollutants that may be emitted from the proposed Mason County Facility and that are not classified as "criteria pollutants." Criteria pollutants are defined as Carbon Monoxide (CO), Lead (Pb), Oxides of Nitrogen (NO_x), Ozone, Particulate Matter (PM_{10} and $PM_{2.5}$), and Sulfur Dioxide (SO_2). These pollutants have National Ambient Air Quality Standards (NAAQS) set for each that are designed to protect the public health and welfare. Other pollutants of concern, although designated as non-criteria *and without national air quality standards*, are regulated through various state and federal programs designed to limit their emissions and public exposure. These programs include federal source-specific HAP regulations promulgated under 40 CFR 61 and 40 CFR 63 (NESHAPS/MACT), and WV Legislative Rule 45CSR27 that regulates certain HAPs defined as Toxic Air Pollutants (TAPs). Any potential applicability to these programs were discussed above under REGULATORY APPLICABILITY.

The majority of 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 affects 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.

The following table lists each specific HAP currently identified by DSF as potentially emitted in an amount greater than 20 lbs/year from the Mason County Facility. Additionally, information concerning the pollutant, the associated carcinogenic risk (as based on analysis provided in IRIS), and any potentially applicable MACT is provided. For a complete discussion of the suspected health effects of each compound listed in the table, refer to the Integrated Risk Information System (IRIS) database located at www.epa.gov/iris.

Table 11: Non-Criteria Regulated Pollutant Information

Pollutant	CAS #	Type	PTE(1) (tons/yr)	Known/Suspected Carcinogen	Classification	MACT(2)
Formaldehyde	50-00-0	VOC	0.29	Yes	B1 - Probable Human Carcinogen(3)	None
n-Hexane	110-54-3	VOC	6.37	No	Inadequate Data(4)	BBBBBB
Benzene	71-43-2	VOC	0.16	Yes	A - Known Human Carcinogen	BBBBBB
Toluene	108-88-3	VOC	2.60	No	Inadequate Data(4)	BBBBBB

Pollutant	CAS #	Type	PTE[1] (tons/yr)	Known/Suspected Carcinogen	Classification	MACT[2]
Ethylbenzene	100-41-4	VOC	3.27	No	D - Non Classifiable[5]	BBBBBB
Xylenes	1330-20-7	VOC	3.95	No	Inadequate Data[4]	BBBBBB
Carbonyl Sulfide	463-58-1	n/a	0.09	No	Not Assessed	None

(1) From a table in Attachment N of Permit Application R13-3435, pp. 374.

(2) Does a MACT apply to this specific HAP for any emission unit at the facility? See "Regulatory Applicability" section for discussion. Subpart BBBBBB is listed here as applicable based on the determination made in the permit application only. See Subpart BBBBBB discussion for more information.

(3) From IRIS: "*Based on limited evidence in humans, and sufficient evidence in animals. Human data include nine studies that show statistically significant associations between site-specific respiratory neoplasms and exposure to formaldehyde or formaldehyde-containing products. An increased incidence of nasal squamous cell carcinomas was observed in long-term inhalation studies in rats and in mice. The classification is supported by in vitro genotoxicity data and formaldehyde's structural relationships to other carcinogenic aldehydes such as acetaldehyde.*"

(4) From IRIS: "*Under the Draft Revised Guidelines for Carcinogen Risk Assessment (U.S. EPA, 1999), data are inadequate for an assessment of the carcinogenic potential of xylenes. Adequate human data on the carcinogenicity of xylenes are not available, and the available animal data are inconclusive as to the ability of xylenes to cause a carcinogenic response. Evaluations of the genotoxic effects of xylenes have consistently given negative results.*"

(5) From IRIS: "Nonclassifiable due to lack of animal bioassays and human studies."

AIR QUALITY IMPACT ANALYSIS

The estimated maximum emissions of the proposed facility are less than applicability thresholds that would define the facility as "major" under 45CSR14 and, therefore, no air quality impacts modeling analysis was required pursuant to that rule.

MONITORING, COMPLIANCE DEMONSTRATIONS, REPORTING, AND RECORDING OF OPERATIONS

Refer to Section 4.2 of the draft permit for the unit-specific monitoring, compliance demonstration, reporting, and record-keeping requirements (MRR).

PERFORMANCE TESTING OF OPERATIONS

Refer to Section 4.3 of the draft permit for the unit-specific performance testing requirements.

RECOMMENDATION TO DIRECTOR

The information provided in Permit Application R13-3435, and all attachments and revisions thereto, indicates that compliance with all applicable federal and state 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 R13-3435 to Domestic Synthetic Fuels I, LLC for the construction of their proposed Mason County Facility located near Point Pleasant, Mason County, WV.

____
Joe Kessler, PE
Engineer

____
Date