NORTH CAROLINA
DIVISION OF AIR QUALITY
Application Review / Preliminary Determination

Issue Date: xx

Region: Wilmington Regional Office
County: Duplin
NC Facility ID: 3100029
Inspector's Name: Russell Morgan III
Date of Last Inspection: 09/18/2017
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Valley Proteins, Inc. - Rose Hill Division

Facility Address:
Valley Proteins, Inc. - Rose Hill Division
469 Yellow Cut Road
Rose Hill, NC 28458

SIC: 2077 / Animal And Marine Fats And Oil
NAICS: 311613 / Rendering and Meat Byproduct Processing

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02D .0503, .0515, .0516, .0521, .0530, and .1112
NSPS: Subpart Dc
NESHAP: Subpart DDDDD
PSD: VOC
PSD Avoidance: N/A
NC Toxics: Yes
112(r): No
Other: 02D .0539, and 02Q .0504, 0702(a)(27), and .0528

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Steve Lester General Manager (540) 877-2590 P. O. Box 1026 Rose Hill, NC 28458	Steve Lester General Manager (540) 877-2590 P. O. Box 1026 Rose Hill, NC 28458	Robert Vogler Director of Environmental Affairs (540) 877-2590 P. O. Box 3588 Winchester, VA 22604-3588

Application Data

Application Number: 3100029.17C
Date Received: 10/18/2017
Application Type: Modification
Application Schedule: PSD

Existing Permit Data
Existing Permit Number: 05127/T24
Existing Permit Issue Date: 04/16/2018
Existing Permit Expiration Date: 08/31/2019

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2016	0.6000	36.44	18.10	25.13	1.34	0.5534	0.5296 [Hexane, n-]
2015	15.73	35.06	16.16	23.71	3.68	0.5170	0.4835 [Hexane, n-]
2014	17.62	28.63	15.20	19.96	2.91	0.4479	0.4182 [Hexane, n-]
2013	144.79	55.34	14.91	17.41	10.85	0.4181	0.2987 [Hexane, n-]
2012	223.62	75.11	15.45	12.49	16.09	0.3274	0.1410 [Hexane, n-]

Review Engineer: Rahul Thaker

Review Engineer's Signature: **Date:** May 4, 2018

Comments / Recommendations:
Issue 05127/T25
Permit Issue Date: xx
Permit Expiration Date: xx

1.0 Purpose of Application

Valley Proteins, Inc. - Rose Hill Division, Rose Hill, NC (hereinafter "VP"), submitted a Prevention of Significant Deterioration (PSD) application to obtain pre-construction approval for a project consisting of a new fat extraction process and two natural gas-fired boilers under §165 of the Clean Air Act (CAA). The process will utilize hexane extraction to remove residual fat from solid and liquid material.

This application also includes a request for pre-construction approval under Section §§112(g) and (d) of CAA for the above fat extraction process and two natural gas-fired boilers, respectively.

The application has been deemed "complete" for PSD as of 11/16/2017.

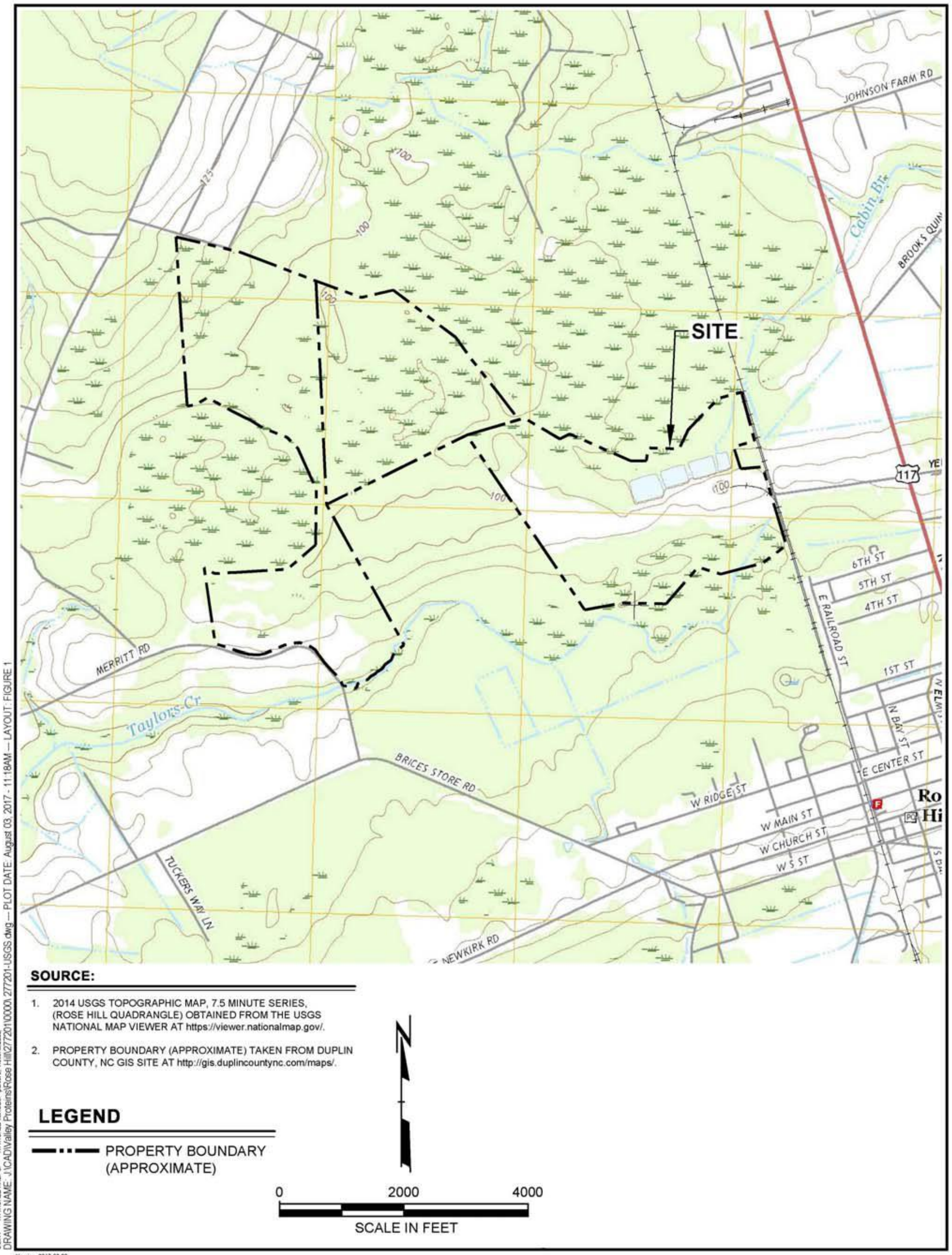
As requested by the applicant, North Carolina Division of Air Quality ("DAQ") will process the application using the procedure in 15A NCAC 02Q .0501(c)(2) and .0504, satisfying the permitting requirements in .02Q .0300, and 02D .0530 (PSD), .1111 (Maximum Achievable Control Technology) and .1112 (112(g) Case-by-Case Maximum Achievable Control Technology). The applicant will be required to submit another application within 12 months of commencement of operation of the above equipment, in accordance with 02Q .0500 "Title V Procedures".

2.0 Facility Information and Existing Operations

2.1 Site Description

The VP facility located in Rose Hill, Duplin County, North Carolina (NC), is approximately 50 miles northwest of Wilmington, NC. The town of Wallace is approximately 2 miles southeast of the facility. The coordinates of the facility are 34° 82" 62" N latitude, 78º 02' 01" W longitude. The topography of the site and the surrounding area are exhibited in Figure 2-1, as below:

Figure 2-1: Site Topography



Current air quality designations for Duplin County with respect to promulgated National Ambient Air Quality Standards (NAAQSs) are described below in Table 2-1, in accordance with 40 CFR 81.334 "North Carolina":

Table 2-1: Attainment Status Designations

Pollutant	Designations
PM_{10}	Attainment (Both 1987 (annual)[1] and 2012 (24-hour) NAAQSs)[2]
$PM_{2.5}$	Unclassifiable/Attainment (Both 2006 (24-hr) and 2012 (annual) NAAQSs)
Sulfur Dioxide	Attainment (1971 (annual) NAAQS), Attainment/Unclassifiable (2010 (1-hr) NAAQS)
Nitrogen Dioxide	Attainment (1971 (annual) NAAQS)[3], Unclassifiable/Attainment (2010 (1-hr) NAAQS)
Carbon Monoxide	Unclassifiable/Attainment (1971 (1-hr and 8-hr) NAAQS)[4]
Ozone	Unclassifiable/Attainment (2008 (8-hr) NAAQS), Attainment/Unclassifiable (2015 (8-hr) NAAQS)
Lead	Unclassifiable/Attainment (2008 (3-month) NAAQS)

In summary, Duplin County is either in attainment or attainment/unclassifiable of all promulgated NAAQS. Further, this County is considered a Class II area with ambient air increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_2. For Class I area standpoint, the closest (Class I) area from this facility is Swanquarter National Wilderness Area, which is located approximately 99 miles (160 kilometers) northeast of the facility.

2.2 Existing Operations

VP owns and operates a rendering facility in Rose Hill, Duplin County, North Carolina, that processes animal by-products (inedible chicken, turkey and hog parts (mostly offal, feathers and chicken blood)) into animal feeds and feed ingredients. The facility also processes used cooking oils. The finished products are protein meal, fats, and oils.

The existing operations comprise of six natural gas/saleable fats/fuel oils-fired boilers, two Supercookers, one feather hydrolyzer and dryer, one waste heat evaporator, one vapor collection system, and a live steam evaporator system.

The facility's primary business activity is classified under the Standard Industrial Classification (SIC) code 2048 "Prepared Feed and Feed Ingredients for Animals and Fowls, Except Dogs and Cats." Under North American Industrial Classification System (NAICS), it is classified under code 311613 "Rendering and Meat Byproduct Processing".

3.0 Proposed Modification

3.1 Project Sources / Description

The proposed system uses hexane to extract residual fats from the solid fraction of the rendering process of used cooking oil, animal byproducts, and associated sludges. The hexane solvent is mixed with the material to remove the fats and then reclaimed for reuse.

The raw material is fed at a maximum rate of 180 tons per day into one of the three extractors where the solids are submerged in a bath of hexane solvent, then drained and discharged.

The liquid phase, or miscella, which is a combination of solvent and oil, is then processed in an evaporator where the solvent vapors are evaporated under a negative pressure and sent to a condenser. The resulting solids are conveyed to the solids discharge.

---

[1] The same 1987 PM_{10} annual NAAQS was retained in 1997.

[2] Assumed. Duplin County has been designated unclassifiable / attainment for more stringent PM2.5 NAAQSs for both 24-hr and annual averaging periods.

[3] The same 1971 NO_2 NAAQSs (primary and secondary) for annual averaging period were retained in 1985, 1996, 2010 and 2012.

[4] The same 1971 CO NAAQSs (primary) for both 1-hr and 8-hr averaging periods were retained in 1985, 1994 and 2011.

An oil stripper operates under partial vacuum to remove the remaining solvent from the oil using sparge steam. The vapors are drawn off to a condenser. Any remaining water is removed by flash drying in the oil dryer.

After exiting the extractor, the solid material, or meal, is conveyed by means of a vapor-tight conveyor to the desolventizer. The desolventizer uses steam to flash remaining vapor hexane from the material. From the desolventizer, the hexane vapors are sent to the vapor scrubber, where fines are knocked down with hexane sprayed from nozzles. Remaining vapors from the desolventizer go to a condenser. The resulting liquid hexane goes to the solvent work tank where it is recycled back into the process.

Non-condensible vapors from the extractors and desolventizer, as well as vapors from the rest of the plant, are sent to a condenser where they are cooled before they enter the solvent air absorption system.

The solvent air separation system is a mineral oil absorption system that removes solvent from vent gasses before discharging to atmosphere by spraying cold mineral oil across the gases as the gases flow though the packing material. The solvent is absorbed by the mineral oil and the desolventized gasses are drawn off through a demister at the top. The solvent-laden mineral oil is sent to the oil stripper.

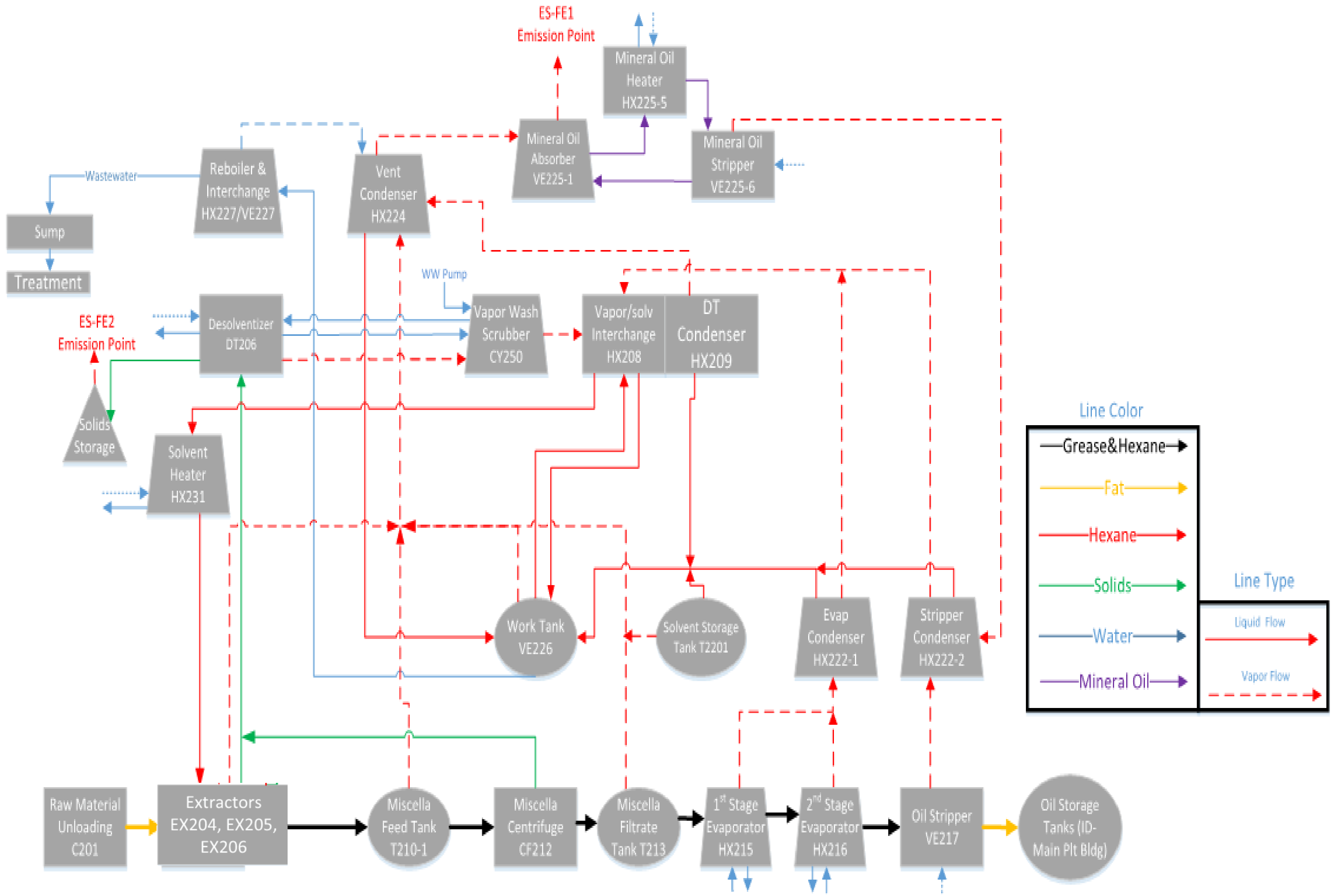
Solvent-free mineral oil collected from the mineral oil stripper is recycled for re-use in the solvent air separation system.

The reclaimed solvent from all condensers is collected in the solvent work tank. This tank is designed for separating the water from the solvent. Part of the tank is also used for working storage of solvent before it goes to the extractor. Wastewater from the solvent/water separator is heated with live steam to above the boiling point of solvent to ensure that all traces of solvent have been removed.

It needs to be noted that from desolventizer, meal is sent to the meal room for storage in two bins. The vents for the bins are open and exhaust into the room where they are located. The emissions (hexane vapors) are then picked up by the storage room mechanical vent for eventual release into the atmosphere.

A detailed process flow diagram is included in Figure 3-1 below:

Figure 3-1: Process Flow Diagram



As per the engineering drawings provided by the Permittee, the following are the inputs and outputs values for the fat extraction process equipment per extractor. These values reflect the expected actual conditions under which the extraction process will operate.

Extractors (ID Nos. EX204, EX205, and EX206)

Inputs
Solids flow rate: 3,375 lbs/hr
Water flow rate: 375 lbs/hr
Brown grease flow rate: 3,750 lbs/hr
Fresh solvent flow rate: 22,100 lbs/hr

Outputs
Solids flow rate: 3,375 lbs/hr
Water flow rate: 375 lbs/hr
Brown grease flow rate: 19 lbs/hr
Spent solvent flow rate to desolventizer: 2,513 lbs/hr
Spent solvent flow rate to miscella feed tank: 19,588 lbs/hr

Miscella Feed Tank (ID No. T210-1), Miscella Centrifuge (ID No. CF212)

Inputs and Outputs
Miscella flow rate: 19,588 lbs/hr
Brown grease flow rate: 3,731 lbs/hr

Oil Storage tanks (ID No. Main Plt Bldg.)

Input and Output
Yellow grease flow rate for storage: 3,731 lbs/hr

Desolventizer (ID No. DT206)

Inputs
Solids flow rate: 3,375 lbs/hr
Brown grease flow rate: 19 lbs/hr
Spent solvent flow rate: 2,513 lbs/hr

Outputs
Solids flow rate: 3,375 lbs/hr
Brown grease flow rate: 19 lbs/hr
Spent solvent flow rate (in meal product): 2 lbs/hr
Desolventized hexane vapors rate: 2,511 lbs/hr

Meal Storage (ID ES-FE2)

Inputs and Outputs
Solids flow rate: 3,375 lbs/hr
Brown grease flow rate: 19 lbs/hr
Hexane emission (in meal product) rate: 2 lbs/hr

Evap Condenser (ID No. HX222-1)

Input
Spent solvent flow rate: 19,473 lbs/hr (18,769 + 704)

Output

Evap condenser condensate (recovered hexane) flow rate: 19,473 lbs/hr

Stripper condenser (ID No. HX222-2)

Input
Spent solvent flow rate: 115 lbs/hr

Output
Stripper condenser condensate (recovered hexane): 115 lbs/hr

Vapor/Solvent Interchange (ID No. HX208) and DT Condenser (ID No. HX209)

Input
Spent solvent flow rate: 2,511 lbs/hr

Outputs
Recovered solvent flow rate: 2,511 lbs/hr
Vapors flow rate from DT Condenser: 5 lbs/hr

Vent Condenser (ID No. HX224)

Inputs
Spent solvent vapor flow rate (reboiler): 1 lbs/hr
Spent solvent vapor flow rate (work tank): 5 lbs/hr
Spent solvent vapor flow rate (DT condenser): 5 lbs/hr
Spent solvent vapor flow rate (solvent storage tank): 5 lbs/hr
Spent solvent vapor flow rate (extractor and miscella): 0 lbs/hr
Spent solvent vapor flow rate (miscella filtrate tank): 5 lbs/hr

Outputs
Vent condenser condensate (recovered hexane) flow rate: 100 lbs/hr
Vapors to mineral oil absorber: 5 lbs/hr

Mineral Oil Absorber (ID No. VE225-1)

Inputs
Vapors (hexane) flow rate: 5 lbs/hr
Mineral oil scrubbing rate: 8 gallons/minute

Output
Vapors (hexane) to atmosphere: 1 lb/hr

In addition, the following are coolant (cooling water) flow rate for condensers and mineral oil flow rate for mineral oil absorber:

Evap Condenser (ID No. HX222-1): 2,900 gallons per minute cooling water flow rate
Stripper Condenser (ID No. HX222-2): 400 gallons per minute cooling water flow rate
DT Condenser (ID No. HX209): 3,600 gallons per minute cooling water flow rate
Vent Condenser (ID No. HX224): 300 gallons per minute cooling water flow rate
Mineral Oil Absorber (ID No. VE225-1): 8 gallons per minute mineral oil flow rate

As shown in the process flow diagram (Figure 3-1) above, the fat extraction process will have 3 pieces of equipment (or 3 stages of vapor recovery) in which the hexane solvent is recovered. The first and second pieces are included in the evaporator process which includes two evaporators (ID Nos. HX-215 and HX-216), which feed to the evaporator condenser (ID No. HX-222-1). An ancillary piece of the evaporators is the vapor solvent interchanger (ID No. HX-208) with associated condenser (ID No. HX-209). The final stage is the mineral oil absorber (ID No. VE-225-1), which feeds to the stripper condenser (ID No. HX-222-2). In these staged vapor recovery processes, the vent condenser ID No. HX-224 is a miscellaneous condenser which captures any vent vapors released from some of the process equipment (extractors ID No. EX204, EX205, EX206, miscella feed tank ID No. T210-1), in addition to any venting from the major condensers (ID Nos. HX222-1 and HX222-2).

Finally, two natural gas-fired boilers (10.04 million Btu per hour each, ID Nos. ES-B8 and ES-B9) will be installed to provide the required steam to the fat extraction equipment.

3.2 Project Schedule

Construction on the fat extraction process at VP facility is proposed to begin in October 2018. The testing (half operation) of the process is planned to begin in December 2018 and the start of the full operation is planned to begin in January 2019.

3.3 Project Emissions

Emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, lead, GHG, hazardous air pollutant (HAP) and some NC-regulated air toxics are expected due to fat extraction process and burning of natural gas in the new boilers. The change in emissions, discussed in detail in Section 4.0 below, are as follows:

- Particulate Matter (PM filterable only): 0.66 ton/year (TPY) [increase]
- PM_{10}: 0.49 TPY [increase]
- $PM_{2.5}$: 0.08 TPY [increase]
- SO_2: 0.05 TPY [increase]
- NOx: 8.62 TPY [increase]
- CO: 7.24 TPY [increase]
- VOC: 51.81 TPY [increase]
- Lead: 0.00 TPY [increase]
- GHG (as CO_2e): 10,364 TPY [increase]
- Single HAP (n-hexane): 30.81 [increase]
- Total HAP: 30.81 [increase]

4.0 Regulatory Applicability

The applicable regulations for the proposed project equipment are as follows:

15A NCAC 2D .0503 "Particulates from Fuel Burning Indirect Heat Exchangers"

This regulation applies to particulate matter (PM) emissions from indirect heat exchangers, except that the PM emissions from electric steam generating units are subject to 2D .0536.

Emissions of PM from combustion of natural gas that are discharged from the proposed boilers into the atmosphere, shall not exceed PM emission rate as derived using 2D .0503(c).

Accordingly, allowable emissions of particulate matter (PM) from burning of natural gas shall be calculated as follows.

$E = 1.090 \times Q^{-0.2594}$ Where: E = allowable PM emission rate in lbs/million Btu heat input Btu
Q = maximum heat input rate in million Btu/hour at the plant site

The maximum heat input rates of all permitted boilers (in operation, being constructed, etc.), all shut-downed sources, and all unpermitted boilers included in this application have been considered for estimating the allowable PM emission rate for each of these unpermitted sources, as per 2D .0503(e).

Q	=	[264.2 million Btu/hr] (combined heat input rate for all permitted boilers included in air permit 05127T24)
	+	[20.08 million Btu/hr] (combined heat input rate for unpermitted boilers; ES-B8 and ES-B9)
	=	284.28 million Btu/hr

Therefore, $E = 1.090 \times 284.28^{-0.2594}$
$= 0.252$ million Btu/hr

The appropriate emission factor (rate) for natural gas firing in the indirect heat exchanger is 0.00745 lb/million Btu[5]. Hence, compliance with the above allowable emission standard is expected for each of these boilers. No monitoring / record keeping / reporting is required for PM emissions from natural gas firing.

15A NCAC 02D .0515 "Particulates from Miscellaneous Industrial Processes"

This rule sets emissions limits for particulate matter (PM) resulting from any industrial process for which no other emission control standards are applicable according to the following formula for sources with production rates less than or equal to 30 tons per hour (tph):

$E = 4.1 \times (P^{0.67})$

Where:
E = the allowable emission rate in lb/hr
P = process weight rate in tph

For process weight rates greater than 30 tph, the following equation is used:

$E = 55.0 \times (P^{0.11} - 40)$

Where:
E = allowable emission rate in lbs/hr
P = process weight rate in tph

Based on a production rate of 7.5 tph (corresponding to 180 tons per day), the allowable particulate emissions from the extraction process cannot exceed 15.82 lbs/hr. As per the applicant, no PM emissions are expected from the process. No monitoring / record keeping / reporting is required for PM emissions from natural gas firing.

However, the applicant will be required to monitor the process rate of fat extraction process and submit the reports on a semi-annual basis.

15A NCAC 02D .0516 Sulfur Dioxide Emissions from Combustion Sources

Two new natural gas-fired boilers (each 10.04 million Btu heat input rate, ID No. ES-B8 and ES-B9) are subject to this requirement.

Emission of sulfur dioxide from any source of combustion that is discharged from any vent, stack, or chimney shall not exceed 2.3 pounds of sulfur dioxide per million BTU input. Sulfur dioxide formed by the combustion of sulfur in fuels, wastes, ores, and other substances shall be included when determining compliance with this standard. Sulfur dioxide formed or reduced as a result of treating flue gases with sulfur trioxide or other materials shall also be accounted for when determining compliance with this standard.

A source subject to an emission standard for sulfur dioxide in Rules .0524, .0527, .1110, .1111, .1205, .1206, .1210, or .1211 of 15A NCAC shall meet the standard in that particular rule instead of the 2.3 lb/million Btu emission standard under 2D .0516.

[5] Section 1.4 "Natural Gas Combustion", July 1998, AP-42, Fifth Edition.

Although the proposed boilers are subject to NSPS Subpart Dc (02D .0524), the NSPS does not include any SO_2 emission standards for natural gas fired boilers; thus, they are subject to the requirements in 02D .0516.

Natural gas has very negligible sulfur content. As per the above referenced AP-42 emission factors (footnote 5) for natural gas combustion, based upon sulfur content of 2000 grains/million cubic feet (pipeline quality gas), the SO_2 emissions are estimated to be 0.0006 lb/million Btu. Hence, compliance with the SO_2 standard in 02D .0516 is expected. Because, the potential emission rate is significantly lower than the emission standard, no monitoring / record keeping / reporting will be required for SO_2 emissions from new, natural gas-fired boilers.

15A NCAC 02D .0521 "Control of Visible Emissions"

This Rule shall apply to all fuel burning sources and to other processes that may have a visible emission. However, sources subject to a visible emission standard in Rules .0506, .0508, .0524, .0543, .0544, .1110, .1111, .1205, .1206, .1210, .1211, or .1212 of this Subchapter shall meet that standard instead of the standard contained in this Rule.

The intent of this Rule is to prevent, abate and control emissions generated from fuel burning operations and industrial processes where visible emissions can be reasonably expected to occur, except during startup, shutdowns, and malfunctions, approved as such, according to the procedures approved under 15A NCAC 02D .0535.

For sources manufactured after July 1, 1971, visible emissions shall not be more than 20 percent opacity when averaged over a six-minute period. However, except for sources required to install, operate, and maintain continuous opacity monitoring systems (COMS), compliance with the 20 percent opacity limit shall be determined as follows:

i. No six-minute period exceeds 87 percent opacity;
ii. No more than one six-minute period exceeds 20 percent opacity in any hour; and
iii. No more than four six-minute periods exceed 20 percent opacity in any 24-hour period.

Excess emissions during startup and shutdown shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(g). Excess emissions during malfunctions shall be excluded from the determinations in paragraphs i. and ii. above, if the excess emissions are exempted according to the procedures set out in 2D .0535(c).

All periods of excess emissions shall be included in the determinations in paragraphs i. and ii. above, until such time that the excess emissions are exempted according to the procedures in 2D .0535.

The proposed extraction process is not expected to generate visible emissions as per the applicant. Moreover, visible emissions from burning of natural gas in the new boilers are expected to be low to non-existent due to inherently clean fuel. Compliance with this applicable requirement is expected. No monitoring including any record keeping is justified for both fat extraction process and the boilers.

It needs to be noted that although the boilers are subject to NSPS Subpart Dc (02D .0524), as below, there are no visible emissions limits for natural gas-fired boilers in this NSPS.

15A NCAC 02D .0524 "New Source Performance Standards"

The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h). These "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units" [NSPS Subpart Dc] were revised last time on February 16, 2012 (77 FR 9461).

The proposed natural gas fired boilers is subject to this NSPS, as each has a maximum heat input rate of 10.04 lb/million Btu.

The NSPS does not include any emissions standards (PM, SO_2) for natural gas fired boilers.

As per §60.48c(a), the Permittee will be required to submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

As per 60.48c(g) and (g)(2), for affected facilities burning only natural gas, the Permittee can elect to record and maintain records of the amount of each fuel combusted during each calendar month, instead of each operating day.

15A NCAC 02D .0530 "Prevention of Significant Deterioration"
15A NCAC 02D .0544 "Prevention of Significant Deterioration for Greenhouse Gases"

United States (US) Congress first established the New Source Review (NSR) program as a part of the 1977 Clean Air Act Amendments and modified the program in the 1990 amendments. The NSR program includes requirements for obtaining a pre-construction permit and satisfying all other preconstruction review requirements for major stationary sources and major modifications, before beginning actual construction for both attainment areas and non-attainment areas. The NSR program for attainment and non-attainment areas are called "Prevention of Significant Deterioration" (PSD) and "Non-attainment New Source Review" (NAA NSR), respectively. The NSR focuses on industrial facilities, both new and modified, that create large increases in the emissions of specific pollutants.

The basic goal for PSD is to ensure that the air quality in attainment areas (e.g., Duplin County NC for PM_{10}, $PM_{2.5}$, NO_2, SO_2, CO, ozone, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth.

Under PSD, all new major stationary sources and all major modifications to existing major stationary sources of air pollutants, as defined in §169 of the CAA, must be reviewed and permitted, prior to construction, by EPA and/or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28+ named source categories (e.g., "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input"), which emits or has a potential to emit (PTE) of 100 tons per year of any "regulated NSR pollutant", or any other stationary source (i.e., other than 28 named source categories), which emits or has the potential to emit 250 tons per year of any "regulated NSR pollutant".

Pursuant to the Federal Register (FR) notice on February 23, 1982 (47 FR 7836), North Carolina (NC) has a full authority from the US Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. NC's State Implementation Plan (SIP) - approved PSD regulation has been codified in 15A NCAC 02D .0530, which implements the requirements of 40 CFR 51.166 "Prevention of Significant Deterioration of Air Quality" with a few exceptions as included in the approved regulation. The version of the CFR incorporated in the NC's PSD regulation is that of July 1, 2014 and it does not include any subsequent amendments or editions to the referenced material. Refer to Table 1 to §52.1770.

The VP facility is not one of the listed 28+ source categories source. Therefore, the 250 tons/yr major stationary source classification applies. The facility is an existing PSD major stationary source; because, it emits or has a potential to emit 250 tons per year or more for one or more of regulated NSR pollutants: $PM_{10,}$ $PM_{2.5}$, SO_2, NO_x (as NO_2), CO, and VOC.

Because the existing facility is considered a major stationary source, any modification to an existing major source resulting in both significant emission increase and significant net emissions increase for a regulated NSR pollutant, is subject to PSD review and must meet appropriate review requirements.

The Permittee performed a PSD applicability analysis, as follows, for the modification (project) for determining whether the project results in an emission increase of any regulated NSR pollutant above the applicable significance thresholds. Using the "actual-to-potential test for projects that only involve construction of new emissions unit(s)" (such as fat extraction process vent, two meal storage bins, fat extraction process fugitives, and two natural gas fired boilers) in §51.166(a)(7)(iv)(d) (as implemented through 02D .0530), the Permittee has performed calculations for potential to emit [PTE] (post-change) for each regulated NSR pollutant expected to be emitted from each new unit. The baseline actual emissions [BAE] (pre-change), resulting from initial construction for each new unit is zero by definition in §51.166(b)(47).

The PTE of fat extraction process vent (emissions unit) is based upon the following:
- a maximum amount of air exiting the process (31.6 ft^3/min),
- lower explosive limit of hexane (1.1 percent by volume),
- molecular weight of hexane (86.18 lb/lb-mole),
- molecular weight of air (29 lb/lb-mole),
- assumed concentration of hexane as percent of LEL in exhaust (25),
- safety factor (1.72), and
- operating hours (8760).

The combined PTE of storage bins (two emissions units) is based upon the following:
- a maximum process rate (180 tons per day),
- percent of solids in product (50),
- assumed maximum solvent concentration in product (600 ppmw),
- safety factor (1.33), and
- operating hours (8760).

The PTE of fugitive VOC emissions (emissions unit) due to equipment leaks losses are based upon emissions factors included in “Protocol for Equipment Leak Emissions Estimates” document (EPA-453/R-95-017, 1995), leak definitions in NESHAP Subpart UU “National Emission Standards for Equipment Leaks—Control Level 2 Standards”, and operating hours (8760). The number of equipment leaks include the worst-case maximum numbers of pumps (25), valves (600), flanges (510), and sight-glasses (140), as included in the project design.

Finally, PTE of each natural gas-fired boiler (emission unit) is based upon 10.4 million Btu per hour maximum heat input rate and applicable EPA emissions factors for natural gas combustion, as referenced previously, and operating hours (8760).

Table 4-1: Change in Emissions Due to Proposed Project

<table>
<tr><th>Regulated NSR Pollutant</th><th>Baseline Actual Emissions Tons Per Year</th><th colspan="4">Potential to Emit Emissions Tons Per Year</th><th>Emissions Change (Increase/Decrease) Tons Per Year</th><th>Significant Emission Rate Tons Per Year</th><th>Major Modification Review Required?</th></tr>
<tr><td>PM[6]</td><td>0</td><td colspan="4">0.66</td><td>0.66</td><td>25</td><td>No</td></tr>
<tr><td>PM_{10}</td><td>0</td><td colspan="4">0.49</td><td>0.49</td><td>15</td><td>No</td></tr>
<tr><td>$PM_{2.5}$</td><td>0</td><td colspan="4">0.08</td><td>0.08</td><td>10</td><td>No</td></tr>
<tr><td>SO_2</td><td>0</td><td colspan="4">0.05</td><td>0.05</td><td>40</td><td>No</td></tr>
<tr><td>NOx (as NO_2)</td><td>0</td><td colspan="4">8.62</td><td>8.62</td><td>40</td><td>No</td></tr>
<tr><td>CO</td><td>0</td><td colspan="4">7.24</td><td>7.24</td><td>100</td><td>No</td></tr>
<tr><td rowspan="3">VOC</td><td rowspan="3">0</td><td colspan="4">51.81</td><td rowspan="3">51.81</td><td rowspan="3">40</td><td rowspan="3">Yes</td></tr>
<tr><td>Process Vent</td><td>Meal Storage Vent</td><td>Equipment Losses</td><td>Boilers</td></tr>
<tr><td>8.76</td><td>26.21</td><td>16.36</td><td>0.47</td></tr>
<tr><td>Lead</td><td>0</td><td colspan="4">0.00004</td><td>0.00004</td><td>0.6</td><td>No</td></tr>
</table>

[6] Filterable only.

Regulated NSR Pollutant	Baseline Actual Emissions Tons Per Year	Potential to Emit Emissions Tons Per Year	Emissions Change (Increase/Decrease) Tons Per Year	Significant Emission Rate Tons Per Year	Major Modification Review Required?
GHG as CO_{2e}	0	10363.66	10363.66	75000	No

It should be noted that PTE for both PM-10 and PM2.5 include filterable and condensable portions, but for PM, it includes only the filterable portion, pursuant to §51.166(b)(49)(i)(a).

As shown in the Table 4-1 above,

- The change in emissions for PM, PM_{10}, $PM_{2.5,}$ SO_2, NOx, CO, lead, and GHG, do not exceed the applicable significance thresholds. Therefore, the proposed project is not a major modification for these pollutants.

- For VOC, based on applicant's analysis, the change in emissions (51.81 tons per year) exceeds the respective significance threshold. Thus, the Permittee has determined that the major modification review is required for this pollutant, with the presumption that the project also causes significant net emissions increase. Note that the applicant has not provided any net emission increase analysis for this pollutant.

  However, closer examination of potential to emit for equipment losses (16.36 tons per year) reveal that these emissions can possibly be deemed fugitive emissions, as defined in §51.166(b)(20); however, no evaluation was performed / submitted by the applicant to characterize these losses as fugitive emissions pursuant to DAQ guidance[7]. Based on NC's SIP-approved PSD regulation, if the modification at any non-listed industrial source category source (i.e., other than 28+ listed source categories in PSD) is deemed a major modification only if the fugitive emissions are counted, those (fugitive) emissions need not be considered in PSD applicability in §51.1666(b)(i)(1)(ii) as below:

  > The plan may provide that requirements equivalent to those contained in paragraphs (j) through (r) of this section do not apply to a particular major stationary source or major modification if:
  >
  > > …
  > > The source or modification would be a major stationary source or major modification only if fugitive emissions, to the extent quantifiable, are considered in calculating the potential to emit of the stationary source or modification and such source does not belong to any of the following categories:

  As stated above, VP's Rose Hill facility is not one of the 28+ listed source categories. Thus, the potential to emit emissions for PSD applicability for the proposed project have been calculated to be 35.45 tons per year (after removing the exempt fugitive emissions total of 16.36 tons per year). This is less than the significance threshold of 40 tons per year for VOC. Accordingly, a PSD permit is not required for the project pursuant to §51.166(a)(7)(iii). However, regardless of the above calculation and conclusions, the applicant has requested that the proposed project be evaluated pursuant to the PSD requirements in 15A NCAC 02D .0530 and that an air permit be issued meeting the requirements therein.

  It should also be noted that the meal storage room vent emissions (26.21 tons per year) are bound in the product and some of them, but not all, are released at the facility, as per the applicant. Some of them will remain entrained in the product permanently and some of them will be released into the atmosphere after meal is shipped off-site. The emissions which are released off-site are considered "secondary emissions" in accordance with

---

[7] Memorandum on "Fugitive Emissions", from John C. Evans, Supervisor, NSR Branch, to Central Office Engineers, NC Division of Air Quality, January 10, 2013, available at https://files.nc.gov/ncdeq/Air%20Quality/permits/psd/docs/fugitives_defined_2013.pdf.

§51.166(b)(18); thus, again, they are not required to be included in the determination of "potential to emit" for the proposed project per §51.166(b)(4).

The applicant has performed the following reviews and analyses for emissions of VOCs, to be emitted from the new fat extraction process and natural gas-fired boilers. These reviews and analyses are required for each affected new or modified emission unit causing or contributing to an emission increase of any regulated NSR pollutant equaling to or exceeding its significance threshold, as per 15A NCAC 02D .0530.

- BACT analysis
- Source impact analysis
- Additional impact analysis

Refer to Sections 5.0 through 7.0 below for discussions on these requirements.

Finally, it needs to be noted that the project does not cause significant emissions of any pollutant with an established Class I Area Increment or Deposition Analysis Threshold. The project also does not result in significant emissions of any visibility-impairing pollutant such as NO_X, SO_2, $PM_{2.5}$, or PM_{10}. Therefore, analysis of project impacts on Class I Area Increments, deposition, or visibility is not required.

15A NCAC 02D .0539 "Odor Control of Feed Ingredient Manufacturing Plants"

This rule applies to any facility that produces feed grade animal proteins. Given the fact that the proposed process will be processing feed grade animal proteins and fats, emissions resulting from this process may be required to be passed through condensers and incinerated (or treated in an equally effective manner) prior to emitting to the atmosphere. The vent from this process passes through a series of condensers and scrubbers prior to discharge to the atmosphere. As per the Permittee, these devices are for recovery of hexane; however, they will also control odors from this process. Therefore, this project is not expected to cause an odor nuisance to the surrounding community.

The Permittee shall be required to install, operate, and maintain in good working order and calibration continuous measuring and recording devices for equipment operational parameters to document equipment operation in accordance with this Rule. In addition, the owner or operator of the facility shall:

(1) demonstrate that the measuring and recording devices are capable of verifying the compliance status of the equipment on a continuous basis;

(2) describe the parameters to be used to determine the compliance status and how these parameters:

(A) are to be measured;
(B) are to be used to determine compliance status; and

(3) provide a quality assurance program approved by the Director for all monitoring devices and systems that includes:

(A) procedures and frequencies for calibration;
(B) standards traceability;
(C) operational checks,
(D) maintenance schedules and procedures;
(E) auditing schedules and procedures;
(F) data validation; and
(G) schedule for implementing the quality assurance program. These data shall be available to the Director upon request.

The Permittee shall not cause or permit any raw material to be handled, transported, or stored, or to undertake the preparation of any raw material without taking reasonable precautions to prevent odors from being discharged. For the purpose of this Rule, such raw material is in "storage" after it has been unloaded at a facility or after it has been located at the facility for at least 24 hours. Reasonable precautions shall include the following:

(1) storage of all raw material before or in the process of preparation, in properly enclosed and vented equipment or areas, together with the use of effective devices and methods to prevent the discharge of odor bearing gases;
(2) use of covered vehicles or containers of watertight construction for the handling and transporting of any raw material; and
(3) use of hoods and fans to enclose and vent the storage, handling, preparation, and conveying of any odorous materials together with effective devices or methods, or both, to prevent emissions of odors or odor bearing gases.

Finally, the Permittee shall notify the Wilmington Regional Office Air Quality Supervisor within two business days after conditions are encountered that cause or may cause release of excessive and malodorous gases or vapors.

15A NCAC 02Q .0700 "Toxic Air Pollutant Procedures"
15A NCAC 02D .1100 "Control of Toxic Air Pollutants"

The facility has not been triggered into the NC's air toxics permitting program. As per the current air permit 05127T23 (September 18, 2014), the facility has avoided the applicability of the requirements in 02D .1100 by accepting a limitation per 02Q .0317. Refer to Section 2.2 B.2. of the current permit.

With this application, there are increases in emissions of n-hexane (168.72 lbs/day), causing the exceedance of its toxic air pollutant emission rate (TPER of 46.3 lbs/day for unobstructed and vertical stacks) in 15A 02Q .0711. Thus, per 02Q .0706(c), toxic air pollutant (TAP) compliance demonstration is required for new or modified sources to ensure TAPs from the facility will not cause any acceptable ambient level (AAL) listed in 15A NCAC 02D.1104 to be exceeded beyond the property line. In brief, the Permittee is required to demonstrate compliance with the AAL of n-hexane.

Accordingly, the Permittee has performed the modeling analysis for this pollutant including emissions rates of the proposed hexane extraction process equipment (ID Nos. ES-FE1, ES-FE2, and ES-FG1) only and disregarding the new (unpermitted) boilers (ID Nos. ES-B8 and ES-B9) and all existing (permitted) boilers. With this approach, the predicted concentration for n-hexane is estimated to be 244 ug/m^3, approximately 22 percent of its AAL of 1100 ug/m^3.

It should be noted that the air toxics protection program, however, exempts sources subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) in Parts 61 and 63 of 40 CFR, and Case-by-Case MACT in §112(j) of CAA, pursuant to 02Q .0702(a)(27).

All existing boilers, except boiler ID No. ES-B7 (i.e., ID Nos. ES-B2 through ES-B6) are currently subject to Part 63 NESHAP Subpart 6J. Moreover, all existing boilers (ID Nos. ES-B2 through ES-B7) will be subject to 5D NESHAP after permit issuance as discussed previously, along with the proposed boilers (ID Nos. ES-B8 and ES-B9). Thus, toxics emissions for all boilers are not required to be regulated, pursuant to 02Q .0702(a)(27). However, the DAQ is still required to assure that no unacceptable risk to human health exists for n-hexane, based on the AAL in 02D .1104, by incorporating emissions of exempt sources (i.e. boilers ID Nos. ES-B2 through ES-B9) in the modeling analysis.

The DAQ has conducted a qualitative evaluation of the change in predicted concentration for n-hexane after including emissions rates of all existing and new boilers regardless of the exemption for MACT-subject boilers (total of 0.47 lb/hr from 8 boilers). This evaluation indicates a negligible change to the previous estimate of 22 percent of AAL, may be expected. Because the analysis did demonstrate compliance on a source-by-source basis including emissions of exempt sources with the applicable AAL, the DAQ has concluded that the emissions from the exempt Part 63 affected boilers (ID Nos. ES-B2 through ES-B9), will not present an unacceptable risk to human health. Thus, the revised permit will include approved limits for non-exempt sources only (ID Nos. ES-FE1, ES-FE2, and ES-FG1).

15A NCAC 02D .1111 "Maximum Achievable Control Technology"

With the permit approval for the proposed fat extraction process, the Rose Hill facility's status with respect to hazardous air pollutants (HAPs) changes from a minor to major stationary source. Thus, the two, new natural gas fired boilers (ID Nos. ES-B8 and ES-B9) become subject to the requirements of “National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters” in 40 CFR 63, Subpart DDDDD. Refer to 76 FR 15664, March 21, 2011. This NESHAP was lastly revised at 80 FR 72806, November 20, 2015. Compliance with the NESHAP will be required upon start-up for new boilers such as the proposed natural gas-fired boilers.

In addition, five existing permitted boilers (ID Nos. ES-B2, ES-B3, ES-B4, ES-B5, and ES-B7), which are currently subject to the requirements of “National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources” in Subpart JJJJJJ of 40 CFR 63, will instead become subject to the requirements of Subpart DDDDD NESHAP. These existing boilers will be required to be in compliance with the this NESHAP within 3 years of issuance of a permit for the proposed fat extraction process (i.e., 3 years from facility reclassification to a major stationary source based on HAPs emissions).

The NESAHP requirements for the boilers are categorized and discussed below:

Type 1 - New natural gas fired boilers (ES-B8 and ES-B9)
- Assumed construction 2018
- Deemed “new” under this Subpart
- Subcategory - Unit designed to burn gas 1 subcategory

Type 2 - Permitted Natural gas/No. 2, 4 and 6/saleable fat-fired boilers (ES-B2, ES-B3, ES-B4, ES-B5, and ES-B7)
- Construction on or before June 4, 2010
- Deemed “existing” under this Subpart
- Subcategories - Unit designed to burn heavy liquid subcategory, Unit designed to burn liquid fuel

Type 3 - Permitted Natural gas/No. 2 fuel oil/saleable fat-fired boiler (ES-B6)
- Construction after June 4, 2010
- Deemed “existing” under this Subpart (because at the time of construction of the boiler, the facility was not a major source)
- Subcategories - Unit designed to burn light liquid subcategory, Unit designed to burn liquid fuel

<u>Emissions Standards</u> [§63.7500(a)(1)]

- Type 1 (ES-B8 and ES-B9)

  There are no emissions standards or operating limits, applicable to Category 1 boiler. [§63.7500(e)]

- Type 2 Boilers (ES-B2, ES-B3, ES-B4, ES-B5, and ES-B7)

  HCl - 0.0011 lb/million Btu heat input
  Hg - 0.000002 lb/million Btu heat input
  CO - 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average
  Filterable PM (or TSM) - 0.062 lb/million Btu heat input (or 0.0002 lb/million Btu heat input)

  [§63.7500(a)(1), Table 2 to the Subpart]

- Type 3 Boiler (ES-B6)

  HCl - 0.0011 lb/million Btu heat input
  Hg - 0.000002 lb/million Btu heat input
  CO - 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average
  Filterable PM (or TSM) - 0.0079 lb/million Btu heat input (or 0.000062 lb/million Btu heat input)

  [§63.7500(a)(1), Table 2 to the Subpart]

<u>Work Practice Standards</u> [§63.7500(a)(1) and Table 3 to the Subpart]

The following work practice standards shall apply:

- A new or existing boiler without a continuous oxygen trim system and a heat input capacity of 10 million Btu/hr or greater, conduct a tune-up of the boiler annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this Subpart. Units in all other subcategories (except Gas 1 or Metal Process Furnace subcategories) will conduct this tune-up as a work practice for dioxins/furans.

  Based, on the above, all above boilers (ES-B2 through ES-B9) are required to perform tune-ups annually.

- An existing boiler, must have a one-time energy assessment performed by the compliance date by a qualified energy assessor for each existing boiler. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575:

  a. A visual inspection of the boiler or process heater system.
  b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
  c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
  d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
  e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified.
  f. A list of cost-effective energy conservation measures that are within the facility's control.
  g. A list of the energy savings potential of the energy conservation measures identified.
  h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

  Accordingly, boilers (ES-B2 through B-7) are required to perform this one-time energy assessment, meeting the above requirements.

- An existing or new boiler subject to emissions standards in Tables 1 or 2, or 11 through 13, adhere to all applicable startup procedures.

  a. You must operate all continuous monitoring systems (CMS) during startup.
  b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis.
  c. You have the option of complying using either of the following work practice standards:
     (1) If you choose to comply using definition (1) of "startup" in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR
     (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels.

You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this Subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e).

d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.

Accordingly, boilers (ES-B2 through B-7) are subject to the above startup procedures.

- An existing or new boiler subject to emissions standards in Tables 1 or 2, or 11 through 13, adhere to all applicable shutdown procedures.

  a. You must operate all CMS during shutdown.
  While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

  Accordingly, boilers (ES-B2 through B-7) are subject to the above shutdown procedures.

Operating Limits [§63.7500(a)(2) and Table 4 to the Subpart]

The Permittee shall comply with the following operation limits:

Performance testing

- For boilers and process heaters that demonstrate compliance using a performance test, maintain the 30-day rolling average operating load[8] of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.

  Accordingly, boilers (ES-B2 through B-7) are subject to the above operating limit.

Oxygen analyzer system

- For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).

Miscellaneous

- If the Permittee wishes to establish and monitor an alternative operating limit or an alternative monitoring parameter, the Permittee shall apply to the EPA Administrator for approval of alternative monitoring under §63.8(f). [§63.7500(a)(2)]

[8] Actual heat input.

- At all times, the Permittee shall operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [§63.7500(a)(3)]

- As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this Section. [§63.7500(b)]

<u>General Compliance Requirements</u> [§63.7505]

- The Permittee shall be in compliance with the emission limits, work practice standards, and operating limits in this Subpart. These emission and operating limits apply to you at all times the affected unit is operating, except for the periods noted in §63.7500(f). During periods of startup and shutdown, the Permittee shall comply only with items 5 and 6 of Table 3 to this Subpart.

- The Permittee shall demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. The Permittee may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis, if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. Otherwise, the Permittee shall demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Table 2 to this Subpart.

- If the Permittee demonstrates (initial) compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, the Permittee shall develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this Section for the use of any CEMS, COMS, or CPMS. This requirement also applies if the Permittee petitions the EPA Administrator for alternative monitoring parameters under §63.8(f).

- If the Permittee has an applicable emission limit, and he/she chooses to comply using definition (2) of "startup" in §63.7575, the Permittee shall develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this Subpart. The SSP must be maintained onsite and available upon request for public inspection.

<u>Initial Compliance Requirements</u> [§63.7510]

- For each boiler that is required or that the Permittee elects to demonstrate compliance with any of the applicable emission limit in Table 2 of this Subpart through performance (stack) testing, initial compliance requirements shall include all the following:

    - Conduct performance tests according to §63.7520 and Table 5 to this Subpart.
    - Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this Subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this Section.
    - Establish operating limits according to §63.7530 and Table 7 to this Subpart.
    - Conduct CMS performance evaluations according to §63.7525.

- For each boiler or process heater that the Permittee elects to demonstrate compliance with the applicable emission limits in Table 2 to this Subpart for HCl, mercury, or TSM through fuel analysis, the Permittee's initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in a boiler or process heater according to §63.7521 and Table 6 to this Subpart and establish operating limits according to §63.7530 and Table 8 to this Subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this Section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this Section are exempt from the chloride fuel analysis and operating limit requirements. Boilers that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this Section for the HAP for which CEMS are used.

- If the boiler or process heater is subject to a carbon monoxide (CO) limit, the Permittee's initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this Subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table to this Subpart, as specified in §63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this Section.

- If the boiler or process heater is subject to a PM limit, initial compliance demonstration for PM shall include a performance test in accordance with §63.7520 and Table 5 to this Subpart.

- For existing affected sources (as defined in §63.7490), the Permittee shall complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this Section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this Subpart, except as specified in paragraph (j) of this Section. The Permittee shall complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this Section. The Permittee shall complete the one-time energy assessment specified in Table 3 to this Subpart no later than the compliance date specified in §63.7495.

  Based on the above, all existing boilers (ES-B2 through ES-B7) are required to (i) conduct stack tests within 180 days after the compliance date (which is 3 years from permit issuance) and (ii) perform both initial tune up and one-time energy assessment by the compliance date (which is 3 years from permit issuance).

- For new or reconstructed affected sources (as defined in §63.7490), the Permittee shall complete the initial compliance demonstration with the emission limits in Table 1 no later than 180 days after startup of the source.

- For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Accordingly, the new boilers (ES-B8 and ES-B9) are required to complete the applicable annual tune-ups as specified in §63.7515(d).

- For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, the Permittee shall demonstrate compliance within 60 days of the effective date of the switch, unless the Permittee had previously conducted his/her compliance demonstration for this subcategory within the previous 12 months.

  <u>Subsequent Compliance Requirements</u> [§63.7515]

- The Permittee shall conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this Section. Annual performance tests shall be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this Section.

- If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Table 2 to this Subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or air pollution control equipment that could increase emissions, the Permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If the Permittee elects to demonstrate compliance using emission averaging under §63.7522, the Permittee shall continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

- If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Table 2 to this Subpart) for a pollutant, the Permittee shall conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Table 2 to this Subpart).

- If the Permittee is required to meet an applicable tune-up work practice standard, the Permittee shall conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12). Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

- If the Permittee demonstrates compliance with the mercury, HCl, or TSM based on fuel analysis, the Permittee shall conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Table 2 to this Subpart. The Permittee may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If the Permittee burns a new type of fuel, the Permittee shall conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. The Permittee shall still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the Permittee may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or the Permittee begins burning a new type of fuel, the Permittee shall return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

- The Permittee shall report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report shall also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this Subpart, as applicable. The reports for all subsequent performance tests shall include all applicable information required in §63.7550.

- For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the Permittee shall complete the subsequent compliance demonstration, if subject to the emission limit in Table 2 to this Subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this Subpart. The Permittee shall complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

- If the Permittee operates a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this Subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 2 to this Subpart, the Permittee is not required to conduct subsequent CO performance tests and is not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).

<u>Stack Tests Procedures</u> [§63.7520]

- The Permittee shall conduct all performance tests according to §63.7(c), (d), (f), and (h). The Permittee shall also develop a site-specific stack test plan according to the requirements in §63.7(c). The Permittee shall conduct all performance tests under such conditions as the Administrator specifies to the Permittee, based on the representative performance of each boiler or process heater for the period being tested. Upon request, the Permittee shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

- The Permittee shall conduct each performance test according to the requirements in Table 5 to this Subpart.

- The Permittee shall conduct each performance test under the specific conditions listed in Tables 5 and 7 to this Subpart. The Permittee shall conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if the Permittee is opting to comply with the TSM alternative standard and the Permittee is required to demonstrate initial compliance and establish operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, the Permittee shall comply with the operating limit for operating load conditions specified in Table 4 to this Subpart.

Fuel Analysis [§63.7521]

- The Permittee shall conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this Section and Table 6 to this Subpart, as applicable. The Permittee shall also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. The Permittee is not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. The Permittee is required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Table 2 to this Subpart.

- The Permittee shall develop a site-specific fuel monitoring plan according to the procedures and requirements in paragraphs (b)(1) and (2) of this Section, if the Permittee is required to conduct fuel analyses as specified in §63.7510.

Emissions Averaging [§63.7522]

- As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler-specific basis, if the Permittee has more than one existing boiler or process heater in any subcategories located at the facility, the Permittee may be able to demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this Section. The Permittee may not include new boilers in an emissions average.

- For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, the Permittee may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this Section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

- For a group of two or more existing units in the same subcategory, each of which vents through a single common stack, the Permittee may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this Subpart if you satisfy the requirements in paragraph (i) or (j) of this Section.

  For a group of two or more existing units in the same subcategory, where exhaust of affected units are each individually controlled and then sent to a common stack, the Permittee may elect to conduct performance tests according to procedures in §63.7520 in the common stack. In addition, the Permittee can meet the applicable operating limits specified in §63.7540 and Table 8 to the Subpart for each emission control system except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack.

Monitoring, Installation, Operation, and Maintenance Requirements [§63.7525]

- If the boiler is subject to a CO emission limit in Table 2 to this Subpart, the Permittee shall install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this Section.

- If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

<u>Continuous Compliance</u> [§63.7540]

- The Permittee shall demonstrate continuous compliance with each emission limit in Table 2 to this Subpart, the work practice standards in Table 3 to this Subpart, and the operating limits in Table 4 to this Subpart that applies to the affected boilers, according to the methods specified in Table 8 to this Subpart and paragraphs (a)(1) through (19) of this Section.

- Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this Subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits shall be confirmed or reestablished during performance tests.

- As specified in §63.7555(d), the Permittee shall keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

  Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

  Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

- To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Table 2 to this Subpart, the Permittee shall meet the requirements in paragraphs (a)(8)(i) through (iv) of this Section, as follows.

  Continuously monitor CO according to §§63.7525(a) and 63.7535.
  Maintain a CO emission level below or at applicable alternative CO CEMS-based standard in Table 2 to this Subpart at all times the affected unit is subject to numeric emission limits.
  Keep records of CO levels according to §63.7555(b).

- For gas 1, light liquid fuel, and heavy liquid fuel-fired boilers with heat input capacity of 10 million Btu per hour or greater, the Permittee shall conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs §63.7540(a)(10). The Permittee shall conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

- If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

- You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this Subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this Subpart. These deviations must be reported according to the requirements in §63.7550.

- For startup and shutdown, the Permittee shall meet the work practice standards according to items 5 and 6 of Table 3 of this Subpart.

Notifications [§63.7545]

- The Permittee shall submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to the affected boilers by the dates specified.

- As specified in §63.9(b)(2), if the startup of the affected source is before January 31, 2013, the Permittee shall submit an Initial Notification not later than 120 days after January 31, 2013.

- As specified in §63.9(b)(4) and (5), if the startup of the new or reconstructed affected source is on or after January 31, 2013, the Permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

- If the Permittee is required to conduct a performance test, he/she shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

- If the Permittee is required to conduct an initial compliance demonstration as specified in §63.7530, the Permittee shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler, the Permittee shall submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boilers at the facility according to §63.10(d)(2). The Notification of Compliance Status report shall contain all the information specified in paragraphs (e)(1) through (8) of this Section, as applicable.

- If the Permittee has switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, the Permittee shall provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

  The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.
  The currently applicable subcategory under this Subpart.
  The date upon which the fuel switch or physical change occurred.

Reporting [§63.7550]

- The Permittee shall submit each report in Table 9 to the Subpart that applies to the affected boilers.

- Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), the Permittee shall submit each report, according to paragraph (h) of this Section, by the date in Table 9 to this Subpart and according to the requirements in paragraphs (b)(1) through (4) of this §63.7550.

- A compliance report shall contain the information as applicable in paragraph (c) of this Section depending on how the facility chooses to comply with the limits set in this rule.

- For each deviation from an emission limit or operating limit in this Subpart that occurs at an individual boiler where the Permittee is not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report shall additionally contain the information required in paragraphs (d)(1) through (3) of §63.7550.

- For each deviation from an emission limit, operating limit, and monitoring requirement in this Subpart occurring at an individual boiler or process heater where the Permittee is not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of §63.7550. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

- The Permittee shall submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of §63.7550.

Record keeping [§§63.7555 and 63.7560]

- The Permittee shall keep a copy of each notification and report that he/she submitted to comply with this Subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that he/she submitted, according to the requirements in §63.10(b)(2)(xiv).

- The Permittee shall keep records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

- For each CEMS, COMS, and continuous monitoring system, the Permittee shall keep records according to paragraphs (b)(1) through (5) of this Section.

- The Permittee shall keep the records required in Table 8 to this Subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to the affected boiler.

- For each boiler subject to an emission limit in Table 2 to this Subpart, the Permittee shall also keep the applicable records in paragraphs (d)(1) through (11) of 63.7555.

- If the Permittee elects to average emissions consistent with §63.7522, the Permittee shall additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

- The records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

- As specified in §63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

- The Permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Permittee can keep the records off site for the remaining 3 years.

15A NCAC 02D .1112 "112(g) Case by Case Maximum Achievable Control Technology"
15A NCAC 02Q .0528 "112(g) Case-by-Case MACT Procedures"

These Rules apply to the construction or reconstruction of major sources of hazardous air pollutants unless: (1) the major source has been specifically regulated or exempted from regulation under: (A) Rule .1109 (Case-by-Case MACT under §112(j) or .1111 (§112(d) MACT) of this Section; or (B) a standard issued pursuant to Section 112(d), 112(h), or 112(j) of the federal Clean Air Act and incorporated in another Subpart of 40 CFR Part 63.

The new fat extraction process is not regulated under any §112(d) MACT standards nor has it been categorically exempted by EPA. Moreover, this proposed source (fat extraction process) is not regulated under §112(j) of CAA.

The HAP emissions from the fat extraction process itself (without two new natural gas fired boilers) are approximately 30.8 tons per year on a PTE basis, whether for a single HAP (hexane) or aggregate HAP emissions. Thus, the requirements of these regulations apply as follows:

- Per 02Q .0528(c), the applicant is required to submit a permit application and the DAQ is required to process the application using the procedures in 02Q .0501(c).

  The Permittee has submitted the application to obtain a case-by-case MACT determination for the proposed fat extraction process. The DAQ is processing the application as a first-step of 02Q .0501(c)(2) (using the 02Q .0300 construction and operating permit procedures), as stated by the applicant. The applicant will be required to submit another application conforming to the requirements of Title V program within 1 year of start-up of the proposed project, which will send the permit through a 30-day public notice and a 45-day EPA review.

- Per 02Q .0528(e), the Permittee, required to apply to apply MACT, shall submit a permit application that contains all information required in 40 CFR 63.43(e), as follows:

(1) Specify the control technology selected to meet MACT emission limitation or standard.

The Permittee proposes the following control technology:

Emission Unit	Control Technology
Fat extraction process vent	Good design and operating practices: Use of closed loop vent system, multiple stages of process condensers, and absorber
Dry meal storage room exhaust vent (Two storage bins)	Good design and operating practices: Proper operation of desolventizer, efficient transfer of meal, and use of equipment maintenance program and housekeeping
Fat extraction process equipment fugitive emissions	Leak detection and repair program

(2)(i) Provide name and address of the major source to be constructed.

Valley Proteins, Inc. – Rose Hill Division
469 Yellow Cut Road
Rose Hill, Duplin County, North Carolina 28458

(2)(ii) Brief description of the major source to be constructed.

Refer to Section 3.1 above.

(2)(iii) Expected commencement date of construction.

Refer to Section 3.2 above.

(2)(iv) Expected completion date of construction.

Refer to Section 3.2 above.

(2)(v) Anticipated date of start-up.

Refer to Section 3.2 above.

(2)(vi) HAP emitted by the constructed major source and the estimated emission rate.

Pollutant	Emission Unit	Emission Rate Before Control Tons/yr	Emission Rate After Control Tons/yr
n-Hexane	Fat extraction process vent	5.26	5.26
n-Hexane	Dry meal storage room exhaust vent (Two storage bins)	15.73	15.73
n-Hexane	Fat extraction process equipment fugitive emissions	18.44	9.82

(2)(vii) Provide any federally enforceable limitation applicable to the constructed source.

All applicable regulations included in this application review are federally enforceable, unless noted otherwise.

(2)(viii) Provide the maximum and expected utilization of capacity of the constructed major source, and the associated uncontrolled emission rate for the source.

The emissions rates for each of the emission units are based upon the maximum utilization rate of 8760 hours (24 hours/day, 7 days/week, 52 weeks/yr). The expected utilization rate is the same as the maximum utilization rate. The uncontrolled emission rates for each unit are included in the above Table.

(2)(ix) Provide the controlled emissions for the constructed major source in tons/yr at expected and maximum utilization of capacity.

The controlled emissions rates at maximum and expected utilization rates are the same for each of the units. They are included in engineering unit of tons per year in paragraph (2)(vi) above.

(2)(x) Provide a recommended emission limitation for the constructed major source consistent with the principles in §63.43(d).

Pollutant	Emission Unit	Recommended Emission Limitation Tons/yr	Recommended / Selected Control Technology
n-Hexane	Fat extraction process vent	5.26	Good design and operating practices: Use of closed loop vent system, multiple stages of process condensers, and absorber
n-Hexane	Dry meal storage room exhaust vent (Two storage bins)	15.73	Good design and operating practices: Proper operation of desolventizer, efficient transfer of meal, and use of equipment maintenance program and general housekeeping
n-Hexane	Fat extraction process equipment fugitive emissions	9.82	Leak detection and repair program

(2)(xi) Specify the selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology.

The selected control technology for each of the emission units is included in the Table in paragraph (2)(x) above. Specifically, "good design and operating practices" include use of condensers and mineral oil absorber; both have been deemed "integral" to the fat extraction process and not air pollution control devices. The design parameters of each the condensers and mineral oil absorber are included in Section 3.1 above.

For meal storage room vent, the recommended technologies include good design and operating practices which are proper operation of desolventizer, efficient transfer of meal, and use of equipment maintenance program and general housekeeping.

For extraction process equipment losses, the recommended technology is leak detection and repair program using EPA protocols.

(2)(xii) Provide the supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology;

The supporting information for the selected technology is included in the following Section.

- Per 02D .1112(d), the following general principles shall be used to make a case-by-case MACT determination concerning construction or reconstruction of a major source by the permitting authority such as DAQ.

  (1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the Division shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Division. This minimum requirement for the new sources is termed the "MACT floor".

  (2) Based upon available information, the MACT emission limitation and control technology (including any requirements under Subparagraph (3) of this Paragraph) recommended by the applicant and approved by the Division shall achieve the maximum degree of reduction in emissions of HAP that can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

  (3) The owner or operator may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the Director may approve such a standard if the Division specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in Section 112(h)(2) of the federal Clean Air Act.

  (4) If the EPA has either proposed a relevant emission standard pursuant to Section 112(d) or 112(h) of the federal Clean Air Act or adopted a presumptive MACT determination for the source category that includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

  The applicant has prepared a case-by-case MACT analysis, meeting the above general principles. The analysis is prepared using seven basic steps as outlined in EPA's "Guidelines for MACT Determinations under Section 112(j) Requirements".[9] They are:

  Step 1 Identify the MACT-affected emission unit(s).
  Step 2 Make a MACT floor finding.
  Step 3 List all available control technologies.
  Step 4 Eliminate technically infeasible control technologies.
  Step 5 Rank technically feasible control technologies.
  Step 6 Conduct a non-air quality health, environmental, economic, and energy impacts analysis.
  Step 7 Establish MACT.

  Step 1 Identify the MACT-affected emission unit(s).

[9] EPA 453/R-02-001, February 2002.

The fat extraction process has several sources of hexane emissions: process exhaust vent, meal storage (two storage bins) room exhaust vent, and fugitive equipment losses. The estimated hexane emissions from each of these units are as follows:

Emission Unit	Stack ID	Exhaust Flow Rate (scfm)	Exhaust Temperature (°F)	Hexane Emissions	
				lb/hr	TPY
Process Exhaust Vent	ES-FE1	50	80	1.2	5.26
Dry Meal Storage Room Exhaust Vent (Two storage bins)	ES-FE2	7,000	80	3.6	15.7
Fugitive Losses	ES-FG1	Variable	80	2.24	9.81

Step 2 Make a MACT floor finding.

In general, for new sources, the MACT floor must equal the level of emissions control currently achieved by the best-controlled similar source. The key in meeting the MACT requirement is defining the "best controlled similar source". The obvious first step is to define "similar source". The EPA includes a definition of similar source in §63.41 as below:

> "a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology."

VP has stated that it is not aware of any other permitted facility in USA, similar to the proposed facility (project), consisting of use of hexane to extract fat and oil from animal by-products (meat products). Accordingly, no air permits are available for any similar facility to determine emissions reductions currently being achieved for the proposed project. Therefore, the MACT floor cannot be determined for the proposed facility. Thus, a "more detailed analysis is required in order to determine the appropriate level of control".[10]

As per the applicant, vegetable oil production is similar to the proposed fat (brown grease) extraction process. Since fat extraction process and vegetable oil production process have similar emission types and emissions can be controlled at approximately similar extent with the same technologies, they can be considered similar emission units for purposes of case-by-case MACT determinations.[11]

The applicant queried EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for control technologies used by various types of emissions units in vegetable oil production industry. The database was searched for the following process types for the last 10 years (from September 2017):

70.350 Soybean Oil Manufacturing
70.310 Corn and Sunflower Seed Oil Manufacturing
70.320 Corn Oil Manufacturing
70.330 Cotton Seed Oil Manufacturing
70.390 Other Vegetable Oil Manufacturing
70.600 Meat Processing
70.900 Other Food and Agricultural Products and Processes

This search showed control methods including condensers, mineral oil absorption scrubbers, hexane storage tanks with internal floating roofs, LDAR, and good operating practices, for process vents. No control methods were identified specifically for the meal room exhaust and/or exhaust associated with dry meal storage (two storage bins). There were no facilities or sources listed in the RBLC for process categories types 70.600 and 70.900.

[10] Page 3-3 in Ibid. at 9.
[11] Page 3-18 in Ibid. at 9.

The DAQ has performed its own search of the RBLC data (1/1/2018 through 3/6/2018) for the above process types. The search results exhibit no determinations for process types 70.330 and 70.600. It should be noted that process type 70.900 is not for vegetable oilseed processing industry. So, DAQ has excluded search for any state/local/EPA determinations in RBLC database for this process type. The DAQ RBLC summary match the applicant summary and has been included in Appendix xx of this application review.

Step 3 List all available control technologies.

The facility has identified following control technologies:

- Oxidation Systems (i.e., thermal or catalytic, regenerative or recuperative)
- Flares
- Adsorption Systems
- Absorption Systems
- Biofiltration Systems
- Condensation Systems
- Internal/External Floating Roofs (for storage tanks)
- LDAR Program (for fugitives)
- Good design and operating practices

Oxidation Systems

Oxidation refers to the combustion of organic compounds at a sufficiently high temperature and adequate residence time. These oxidation technologies can be categorized based on the type of heat recovery used, if any, and if a catalyst is used. If a shell-and-tube or plate-type heat exchange is used, the system is generally classified as recuperative. If a high-efficiency bed of ceramic material is used, the system is generally classified as regenerative. A unit that does not utilize heat recovery is referred to as a direct-fired thermal oxidizer, or afterburner. These oxidation technologies can also be further categorized based on whether or not a catalyst is used to facilitate the oxidation reaction. Catalytic oxidation allows operation at lower temperatures, meaning less fuel consumption and associated costs and additional emissions. Thermal oxidation occurs at higher temperatures, but generally has a lower capital cost because an expensive catalyst is not required for it to work. For these analyses, the following oxidation systems were considered: direct-fired thermal oxidizer (afterburner), catalytic direct-fired thermal oxidizer, regenerative thermal oxidizer, regenerative catalytic oxidizer, and recuperative thermal oxidizer.

Flares

Flaring is an oxidation process that does not include any heat recovery. Flares can be classified as either open or enclosed and are used to combust components, mostly hydrocarbons, of gases from industrial operations. The gases are mixed with oxygen; oxidation takes place at the tip of open flares or in the stack of enclosed flares. Waste gases provide the fuel necessary for combustion. The concentration of the waste gas must be greater than the lower flammability limit of the gas. If the concentration of the waste gas is greater than the upper flammability limit, the waste gas needs to be diluted with air prior to reaching the combustion zone for combustion to occur. Flares are primarily used at refineries, blast furnaces, coke ovens, and chemical manufacturing process equipment. Natural gas, propane, ethylene, propylene, butadiene, and butane constitute over 95 percent of the waste gases flared. Flares can only be used for waste gas streams with relatively high concentrations of organics. EPA reference[12] indicates that critical considerations of combustion in flares is the net heating value of the waste gas along with the combustible concentration in the flare gas. Specifically, a heat content of at least 300 British thermal units per standard cubic feet (Btu/scf) of waste gas is needed for well operated flares. If flares are used for compliance with either an NSPS or a MACT, the steam-assisted or air-assisted flare should only be used with gases with a net heating value of 300 Btu/scf and 200 Btu/scf for non-assisted flares. Refer to §60.18(c)(3)(ii) and §63.11(b)(6)(ii).

[12] Page 13.5-2, AP-42, 02/18.

Adsorption Systems

Adsorption is the process by which molecules collect on and adhere to the surface of an adsorbent solid. The adsorption is due to physical and/or chemical forces. Activated carbon is typically used as an adsorbent because of its large surface area, which is a critical factor in the adsorption process. The adsorption capacity of a material is proportional to surface area; activated carbon has significant surface area due to its internal pore structure. Adsorption systems can control VOCs in the range of 200 ppm to 10,000 ppm. However, at the low end of that range, the small concentrations may be difficult or uneconomical to control.[13] Carbon adsorption systems are ideally used for recoverable VOC materials. Adsorption is also not a reliable control technology for highly volatile materials. Highly volatile materials; *e.g.*, molecular weights less than 45 pounds per mole (lb/mol), do not readily adsorb onto carbon; therefore, adsorption is not typically used for exhaust streams containing these materials.

Absorption (Scrubber) Systems

In absorption systems, certain constituents of a gas stream are selectively removed by a liquid solvent. The control of gas-phase VOCs using an absorption scrubber system relies on contact between the gas and a liquid in which the pollutants are soluble or with which it will chemically react. The degree of control depends on the following: solubility of the gas, gas and liquid throughput rates, contact time, mechanism of contact, and type of scrubber.

Gas absorption is commonly used to recover products or to purify gas streams with high concentrations of water soluble compounds. Per EPA Air Pollution Control Cost Manual[14], gas absorbers are most effective for gas streams with pollutant concentrations between 250 and 10,000 ppmv. Low concentrations of organics in an exhaust stream require long contact times and large quantities of absorbent for effective removal. Absorptions are generally more practical for processes in which the absorbent is easily regenerated or the resulting solution can be used as a make-up stream.

Biofiltration Systems

Biofiltration is based on the biodegradation of exhaust stream constituents as the exhaust passes through a biologically active filter material. Naturally occurring microorganisms are used to treat air containing odorous substances such as reduced sulfur compounds and VOCs. The microorganisms consume the contaminants in the air stream for energy, thus cleaning the air. Biofiltration is most successful when treating low molecular weight and highly soluble organic compounds with simple structures. Compounds with complex bond structures generally require more energy to break down than the microorganisms have available to them[15]. Biofiltration has been applied on a limited basis with typical control efficiencies of 50 to 90 percent. Pre-conditioning of the gas stream is often required to control temperatures, moisture content, and particulate matter. Gas streams with high levels of particulate matter or sticky substances may also cause the biofilter media to clog, thus reducing the efficiency of the system. The bacteria commonly used in biofiltration are highly temperature sensitive and are susceptible to damage by broadly varying process conditions. High exhaust temperatures may kill the microorganisms and low temperatures may slow or stop degradation. Biofiltration systems may also require the addition of nutrients to support microbial growth. Furthermore, biofiltration systems require substantial operating space and system monitoring.

Condensation Systems

Condensation systems utilize a refrigeration source to cool the exhaust stream to convert the VOC from a gaseous phase to a liquid phase. Condensation is used for VOC reduction in applications where there is a concentrated VOC stream. Condensation systems are most efficient at removing VOC emissions from exhaust streams with

[13] Technical Bulletin, Choosing an Adsorption System for VOC: Carbon, Zeolite, or Polymers? May 1999, EPA 456/F-99-004.
[14] EPA/452/B-02-001, January 2002.
[15] Kumar, T.P., Rahul, Kumar, M.A., and Chandrajit, B., *Biofiltration of Volatile Organic Compounds (VOCs) – An Overview*, Research Journal of Chemical Sciences, Vol. 1(8), 83-92, November 2011.

concentrations above 5,000 ppmv[16,17] and can achieve high-recovery efficiencies (greater than 95 percent) when VOC concentrations are greater than 10,000 ppmv.

Internal/External Floating Roofs

Fixed roof tanks are common because they are inexpensive to construct and are often the minimum acceptable equipment for storing organic liquids. Emissions from fixed roof tanks come from evaporation during storage (i.e., breathing losses) and evaporation during filling and emptying (i.e., working losses). A way to reduce VOC emissions is with the use of internal floating roof tanks (IFRT) and to a lesser extent external floating roof tanks (EFRT). IFRT have both a permanent fixed roof and a floating roof inside. The floating roof, which rises and falls with the liquid level in the tank, consists of a deck, fitting, and rim seal system. Depending on the type of roof and seals used and the type of organic liquid stored, IFRT can have a VOC control efficiency that ranges from 60 to 99 percent.

LDAR Program

LDAR programs are work practices that can be used for reducing the fugitive VOC emissions. Process equipment applicable to an LDAR program, such as pumps, valves, flanges, and pressure relief devices are periodically monitored using sensory inspection techniques (*e.g.*, visual, olfactory, or audible) or with a portable hydrocarbon detector to detect leaks. The LDAR program will define a concentration or action level at which an affected component is considered to be leaking and also specify a time period during which the leak must be repaired. Due to the ongoing monitoring and repairs of "leaks", fugitive emissions are reduced. The level of reduction is based on the monitoring frequency, threshold triggering repair, and number of components monitored. This can be considered a part of good operating practices.

Good Design and Operating Practices

Good design includes process and mechanical equipment designs that are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods and procedures, housekeeping, and preventive maintenance programs.

Step 4 Eliminate technically infeasible control technologies.

The technical feasibility of each of the control techniques discussed in Step 3 above is addressed below:

<u>Process Exhaust Vent</u>

Oxidation

Oxidation systems are technologically feasible for control of the HAP emissions from the process exhaust vent (mineral oil absorber). The applicant has indicated an oxidation control efficiency of 99 percent for 50 scfm exhaust flow for the process exhaust vent.

Flares

As noted above, flares can be used for waste gas streams with a heat content of at least 300 Btu/scf (lower/net heating value). The heating value of the exhaust stream for hexane lower/net heating value of 19,403 Btu/lb[18], 1.2 lb/hr hexane emission rate, and 50 scfm exhaust stream, is estimated as follows:

[16] Schnelle, K. and Brown, C. *Air Pollution Control Technology Handbook*. CRC Press (October 1, 2001).
[17] Page 2-3, Refrigerated Condensers, EPA Air Pollution Control Cost Manual, Ibid. at 14.

[18] Combustion Flame and Explosions of Gases, American Gas Association, 1951.

$$\left(\frac{1.2\ lb\ hexane}{hr}\right) \times \left(\frac{hr}{60\ min}\right) \times \left(\frac{19{,}403\ Btu}{lb\ hexane}\right) \times \left(\frac{min}{50\ scf}\right) = 8\ Btu/scf$$

Therefore, flares are deemed a technically infeasible option for the process exhaust vent.

Adsorption Systems

As per the applicant, the estimated VOC concentration in the process vent for the proposed extraction process is 2,978 ppm and is outside the typical range of 400 ppm to 2000 ppm for inlet loading. However, adsorption is still considered a technically feasible option for the process vent.

Absorption (Scrubber) Systems

The design of the fat extraction process does include a mineral oil absorber to recover hexane solvent. The review of the RBLC shows that mineral oil absorption is considered BACT for vegetable oilseed extraction systems, which as stated above, are similar to the proposed fat extraction process. As per EPA, unrealistic options such as placing in series the same or similar control technology need not be to be considered.[19] Therefore, the Permittee has not considered this control technology option for the process vent.

Biofiltration Systems

Biofiltration systems are not a previously demonstrated control method or a method currently used in practice by other facilities on vegetable oilseed extraction systems. In addition, because hexane is not water soluble, it is not suitable for control by biofiltration. Therefore, as per Permittee, biofiltration has been deemed a technically infeasible option for the process exhaust vent.

Condensation Systems

As noted previously, the fat extraction process vent includes numerous condensers for recovering hexane for re-use. They are to be located upstream of the mineral oil absorber. As mentioned earlier, control technologies in series do not need to be considered. Therefore, additional condensers are not considered for the process vent.

Internal/External Floating Roofs

Internal and external floating roofs are emission control technologies that are applied to storage tanks that are not otherwise controlled. The hexane storage tanks to be used as part of the fat extraction system are not vented separately but are vented to the process vent system which is vented through 3-stages of condensation and the mineral oil absorber and accounted for as part of the steady-state process vents. Therefore, as per the Permittee, internal and external floating roofs are not required to be evaluated further for the proposed process vent sources.

Good Design and Operating Practices

Good design and operating practices include a nearly closed loop vent system from all of the process sources where hexane is present to multiple stages of condensers and a mineral oil scrubber to recover hexane. This is considered a technically feasible option.

<u>Dry Meal Storage Room Exhaust Vent</u>

A 7,000 scfm room exhaust fan is the emission point for the dry meal storage area. The technological feasibility of each control system is addressed below.

Oxidation

[19] Page 6, *Guidance for Determining BACT Under PSD,* David G. Hawkins, Assictant Administrator for Air, Noise, and Radiation, EPA, January 4, 1979.

Exhaust from the dry meal storage area can be ducted and routed to an oxidizer system. As per the Permittee, VOCs concentrations in the room will be diluted with air to an estimated 63 ppmv, well below the concentration needed to sustain the incineration temperature without auxiliary fuel[20]. Additionally, the products of combustion from the auxiliary fuel can contribute to the VOC emissions from the oxidizer and negatively bias the control efficiency results. Regardless, the Permittee has deemed oxidation technology as a technically feasible option, with an assumed reduction efficiency of 90 percent as the VOC concentrations for destruction would be less than desirable as stated above.

Flares

Flares can be used for waste gas streams with a heat content of at least 300 Btu/scf (lower/net heating value).[21] The heating value of the exhaust stream for hexane, using 19,403 Btu/lb[22] lower/net heating value, 3.6 lb/hr hexane emission rate, and 7,000 scfm exhaust stream, is estimated as follows:

$$\left(\frac{3.6\ lb\ hexane}{hr}\right) \times \left(\frac{hr}{60\ min}\right) \times \left(\frac{19{,}403\ Btu}{lb\ hexane}\right) \times \left(\frac{min}{7{,}000\ scf}\right) = 0.2\ Btu/scf$$

Therefore, flares are not a technically feasible option for the meal storage area exhaust.

Adsorption Systems

The concentration of VOC in the exhaust from the dry meal storage area is estimated to be 63 ppmv, which is outside the typical range of 400 ppm to 2000 ppm for inlet loading. Nonetheless, the Permittee has considered this option technically feasible.

Absorption Systems

An absorption system will be considered technologically feasible for the dry meal storage area exhaust, because, it does not vent to the mineral oil absorber.

Biofiltration Systems

Biofiltration systems are not a demonstrated control technology or a method currently used in practice by other facilities on vegetable oilseed extraction systems. In addition, because hexane is not water soluble, it is not suitable for control by biofiltration. Therefore, biofiltration has been a technically infeasible for the meal area exhaust vent.

Condensation Systems

Condensers are not considered technologically feasible for the dry meal storage exhaust because the VOC concentration is too low to have any practical effect[23].

Internal/External Floating Roofs

Internal and external floating roofs do not apply to the meal storage vent. Therefore, it will not be evaluated further.

---

[20] United States EPA. (n.d.). *Air Pollution Control Technology Fact Sheet, Thermal Incinerator, page 3,* Retrieved from https://www3.epa.gov/ttncatc1/dir1/fthermal.pdf.
[21] (OAQPS), U. E. (2012, April). *Parameters for Properly Designed and Operated Flares, Page 3-31.* Retrieved from https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf.
[22] Ibid at 18.
[23] United States EPA. (1995, December). *EPA Air Pollution Control Cost Manual, Refrigerated Condensers, page 2-3.* Retrieved from https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

Good Design and Operating Practices

Good design and operating practices will ensure that the hexane is properly stripped from the meal and the meal efficiently transferred to storage. Other good work practices include an equipment maintenance program and housekeeping. Therefore, good design and operating practices have been deemed technically feasible.

<u>Fugitive Losses</u>

The fugitive losses are estimated based upon EPA equipment leak factors. Because these leaks occur at many points throughout the process, it would be impractical to capture the VOC emissions without enclosing all hexane piping within a permanent total enclosure. Therefore, the following control options have been deemed technically infeasible for fugitive losses because the emissions cannot be captured: Oxidation, Flares, Adsorption Systems, Absorption Systems, Biofiltration Systems, and Condensation Systems.

Thus, only technically feasible option available is Good Design and Operating Practices. An LDAR program, equipment maintenance program, and housekeeping, are good design and operating practices.

Step 5 Rank technically feasible control technologies.

The following Tables provide ranking of technical feasible options for each emission units:

Process Exhaust Vent

Control Option	Emission Reduction Efficiency	Ranking
Catalytic Regenerative Oxidation	99 percent	1
Catalytic Recuperative Oxidation	99 percent	1
Thermal Regenerative Oxidation	99 percent	1
Thermal Recuperative Oxidation	99 percent	1
Direct Thermal Oxidation	99 percent	1
Adsorption	70 percent	2
Good Design and Operating Practices	Not applicable	3

Dry Meal Storage Room Exhaust Vent

Control Option	Emission Reduction Efficiency	Ranking
Oxidation	90 percent	1
Adsorption	70 percent	2
Absorption	60 percent	3
Good Design and Operating Practices	Not Applicable	4

Fugitive Losses

Control Option	Emission Reduction Efficiency	Ranking
LDAR Program	51 percent	1
Good Design and Operating Practices	Not Applicable	2

Step 6 Conduct a non-air quality health, environmental, economic, and energy impacts analysis.

The following Table provides an impact analysis for each emission unit for each identified technically feasible option in Step 5 above. It needs to be noted that economic impact for each feasible option is based upon detailed engineering information for developing capital and operation and maintenance costs, as provided in the EPA Air Pollution Control Cost Manual, as referenced previously.

Process Exhaust Vent

Control Option	Cost Impacts	Environmental Impacts	Energy Impacts
Catalytic Regenerative Oxidation	$32,100 per ton of pollutant	No adverse impact	No adverse impact
Catalytic Recuperative Oxidation	$17,900 per ton of pollutant	No adverse impact	No adverse impact
Thermal Regenerative Oxidation	$32,000 per ton of pollutant	No adverse impact	No adverse impact
Thermal Recuperative Oxidation	$17,500 per ton of pollutant	No adverse impact	No adverse impact
Direct Thermal Oxidation	$15,500 per ton of pollutant	No adverse impact	No adverse impact
Adsorption	$265,800 per ton of pollutant	No adverse impact	No adverse impact
Good Design and Operating Practices	$0 per ton of pollutant	No adverse impact	No adverse impact

Dry Meal Storage Room Exhaust Vent

Control Option	Cost Impacts	Environmental Impacts	Energy Impacts
Catalytic Regenerative Oxidation	$21,000 per ton of pollutant	No adverse impact	No adverse impact
Catalytic Recuperative Oxidation	$20,900 per ton of pollutant	No adverse impact	No adverse impact
Thermal Regenerative Oxidation	$22,800 per ton of pollutant	No adverse impact	No adverse impact
Thermal Recuperative Oxidation	$27,100 per ton of pollutant	No adverse impact	No adverse impact
Direct Thermal Oxidation	$50,000 per ton of pollutant	No adverse impact	No adverse impact
Adsorption	$588,300 per ton of pollutant	No adverse impact	No adverse impact
Absorption	$69,000 per ton of pollutant	No adverse impact	No adverse impact
Good Design and Operating Practices	$0 per ton of pollutant to negligible	No adverse impact	No adverse impact

Fugitive Losses

Control Option	Cost Impacts	Environmental Impacts	Energy Impacts
LDAR Program	$11,500 per ton of pollutant[24]	No adverse impact	No adverse impact

Step 7 Establish MACT

The Permittee has proposed the following MACT after evaluating each technically feasible option in Step 6 and considering economic, environment, and energy impacts. Specifically, the Permittee has determined that economic impacts unreasonable for each of the technically feasible options in Step 6 above, except the option proposed for MACT for each emissions unit in Step 7.

[24] Assumes that the facility currently has leak detection instruments for existing sources. Thus, no capital investment is required and only operating cost will be part of cost effectiveness.

MACT Emission Unit	MACT Control Technology	MACT Emission Limit
Process Exhaust Vent	Good design and operating practices	1.2 lb/hr
Dry Meal Storage Room Exhaust Vent	Good design and operating practices	3.6 lb/hr
Fugitive Losses	LDAR program and good design and operating practices	2.24 lb/hr

After carefully evaluating the information in Step 1 through 7 above, including consideration of economic, environmental and energy impacts, the DAQ agrees with the applicant that all options included in Step 6 are unreasonable, except the option included in the Table in Step 7, with respect to economic impact, even though their other impacts (environmental and energy) may be reasonable. Thus, the DAQ proposes to approve the above MACT under the §112(g) of CAA for the proposed fat extraction process.

It needs to be noted that these case-by-case MACT apply during all periods of operations including start-up, shut-down, and malfunction, for process exhaust vent, meal storage room vent, and equipment fugitive losses.

Compliance with the MACT limits for process vent and meal vent will be determined by EPA's Reference Test Method(s), using average of 3-run stack tests. For fugitive equipment losses, employing LDAR would be the mechanism to demonstrate compliance with the proposed MACT. The applicant has proposed to use a leak rate of 5,000 ppmv, as an indicator to determine a need for repair or replacement of equipment.

- Per 02Q .0528(f), within 60 days of issuance of a permit under 02Q .0500 or .0300, incorporating a MACT determination, the DAQ shall provide a copy of such permit to EPA, and shall provide a summary in a compatible format for inclusion in the MACT database.

  The DAQ will provide a copy of both the draft and final permit to EPA, containing a MACT determination, within the stipulated timeframe.

- Per 02D .1112(e), the effective date of a MACT determination shall be the date of issuance of a permit under procedures in either 02Q .0300 or .0500 incorporating a MACT determination.

  The air permit incorporating the MACT determination for the proposed project at the VP facility will be issued pursuant to 02Q .0300. The issuance date of the permit will be the effective date of the MACT determination.

- Per 02D .1112(f), on and after the date of start-up, a constructed or reconstructed major source shall be in compliance with all applicable requirements specified in the MACT determination.

  The Permittee shall be in compliance with the requirements of a MACT determination for the proposed fat extraction process, upon its start-up.

- Per 02D .1112(g), the Permittee shall comply with the requirements set forth in a 02Q .0300 (or 02Q .0500) permit for a MACT determination, including any MACT emission limitation or MACT work practice standard, and any notification, operation and maintenance, performance testing, monitoring, reporting, and recordkeeping requirements.

5.0 BACT Analysis

<u>Background</u>

The CAA §169(3) defines:

> "The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis,

taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to enactment of the federal Clean Air Act Amendments of 1990."

Given the variation between emission sources, facility configuration, local air-sheds, and other case-by-case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economic, energy, and environmental impacts are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impracticable, BACT can be defined using a particular type of control device, work practice, or fuel type. In no event, can a technology be recommended which would not comply with any applicable standard of performance under CAA §§111 (NSPS) or 112 (NESHAP).

The EPA developed a guidance, commonly referred to as "Top-Down" BACT[25], for PSD applicants for determining BACT. This guidance is a non-binding reference material for permitting agencies, which process PSD applications pursuant to their SIP-approved regulations. As stated in Section 4.0 above, NCDAQ issues PSD permits in accordance with its SIP-approved regulation in 15A NCAC .02D .0530. Therefore, the DAQ does not strictly adhere to EPA's "top-down" guidance. Rather, it implements BACT in accordance with the statutory and regulatory language. As such, NCDAQ's BACT conclusions may differ from those of the EPA.

As stated above, a major modification is triggered for the project due to increases in emissions of VOC. Thus, each emissions unit undergoing physical or operation change, where the net emissions increase is projected to occur, is required to apply BACT for VOC, as per §51.166(j)(3).

The emissions unit must be defined so that the BACT analysis can be performed. In this case, the Permittee has proposed to add a fat extraction process consisting of a process exhaust vent, dry meal storage room vent and process equipment fugitive losses, along with two new boilers. Thus, the emissions units are:

(i) Process exhaust vent
(ii) Meal storage room vent
(iii) Process equipment fugitive losses
(iv) Two natural gas-fired boilers

The DAQ will determine and propose the BACT for each of the above emissions units for emissions of VOC.

BACT Analysis for VOC for Fat Extraction Process Emissions Units
Process exhaust vent
Meal storage room vent
Process equipment fugitive losses

As discussed in detail in Section 3.1 above, the fat extraction process uses a solvent (hexane) and mechanical pressure to extract the proteins and oils using equipment similar to a vegetable oilseed extraction processes. The hexane is then stripped from the product, condensed, recovered, and recycled back into the extraction process. Several stages of chilled water condensers and a mineral oil absorber are used to control hexane emissions from the final process vent.

---

[25] "Improving New Source Review (NSR) Implementation", J. Craig Potter, Assistant Administrator for Air and Radiation US EPA, Washington D.C., December 1, 1987, and "Transmittal of Background Statement on "Top-Down" Best Available Control Technology", John Calcagni, Director, Air Quality Management Division, US EPA, OAQPS, RTP, NC, June 13, 1989.

The fat extraction process has several sources of VOC emissions (100 percent by weight hexane), including a final process gas vent, meal storage room exhaust vent, and steady state fugitive losses from equipment leaks.

As stated above, vegetable oil production is similar to the proposed fat (brown grease) extraction process. Since fat extraction process and vegetable oils production process have similar emission types and emissions can be controlled at approximately similar extent with the same technologies, the RBLC information for vegetable oilseed processing systems can be instructive in determining case-by-case BACT for the proposed fat extraction process.

RBLC

The applicant queried EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for control technologies used by various types of emissions units in vegetable oil production industry. The database was searched for the following process types for the last 10 years (from September 2017):

70.350 Soybean Oil Manufacturing
70.310 Corn and Sunflower Seed Oil Manufacturing
70.320 Corn Oil Manufacturing
70.330 Cotton Seed Oil Manufacturing
70.390 Other Vegetable Oil Manufacturing
70.600 Meat Processing
70.900 Other Food and Agricultural Products and Processes

This search showed control methods including condensers, mineral oil absorption scrubbers, hexane storage tanks with internal floating roofs, LDAR, and good operating practices, for process vents. No control methods were identified specifically for the meal room exhaust and/or exhaust associated with dry meal storage (two storage bins). There were no facilities or sources listed in the RBLC for process categories types 70.600 and 70.900.

The DAQ has performed its own search of the RBLC data (1/1/2018 through 3/6/2018) for the above process types. The search results exhibit no determinations for process types 70.330 and 70.600. It should be noted that process type 70.900 does not represent vegetable oilseed processing industry. So, DAQ has excluded search for any state/local/EPA determinations in RBLC database for this process type. The DAQ RBLC search summary match the applicant summary and has been included in Appendix 1 of this application review.

Control Options

Potential VOC control alternatives include the following options:

- Oxidation Systems (*i.e.*, thermal or catalytic, regenerative or recuperative)
- Flares
- Adsorption Systems
- Absorption Systems
- Biofiltration Systems
- Condensation Systems
- Internal/External Floating Roofs (for storage tanks)
- LDAR Program (for fugitives)
- Good design and operating practices

Oxidation Systems

Oxidation refers to the combustion of organic compounds at a sufficiently high temperature and adequate residence time. These oxidation technologies can be categorized based on the type of heat recovery used, if any, and if a catalyst is used. If a shell-and-tube or plate-type heat exchange is used, the system is generally classified as recuperative. If a high-efficiency bed of ceramic material is used, the system is generally classified as regenerative. A unit that does not utilize heat recovery is referred to as a direct-fired thermal oxidizer, or afterburner. These oxidation technologies can also be further categorized based on whether or not a catalyst is used to facilitate the oxidation reaction. Catalytic oxidation allows operation at lower temperatures, meaning less fuel consumption and associated costs and additional emissions. Thermal oxidation occurs at higher temperatures, but generally has a lower capital cost because an expensive catalyst is not required for it to work. For these analyses, the following oxidation systems were considered: direct-fired thermal oxidizer (afterburner), catalytic direct-fired thermal oxidizer, regenerative thermal oxidizer, regenerative catalytic oxidizer, and recuperative thermal oxidizer.

Flares

Flaring is an oxidation process that does not include any heat recovery. Flares can be classified as either open or enclosed and are used to combust components, mostly hydrocarbons, of gases from industrial operations. The gases are mixed with oxygen; oxidation takes place at the tip of open flares or in the stack of enclosed flares. Waste gases provide the fuel necessary for combustion. The concentration of the waste gas must be greater than the lower flammability limit of the gas. If the concentration of the waste gas is greater than the upper flammability limit, the waste gas needs to be diluted with air prior to reaching the combustion zone for combustion to occur. Flares are primarily used at refineries, blast furnaces, coke ovens, and chemical manufacturing process equipment. Natural gas, propane, ethylene, propylene, butadiene, and butane constitute over 95 percent of the waste gases flared. Flares can only be used for waste gas streams with relatively high concentrations of organics. EPA reference[26] indicates that critical considerations of combustion in flares is the net heating value of the waste gas along with the combustible concentration in the flare gas. Specifically, a heat content of at least 300 British thermal units per standard cubic feet (Btu/scf) of waste gas is needed for well operated flares. If flares are used for compliance with either an NSPS or a MACT, the steam-assisted or air-assisted flare should only be used with gases with a net heating value of 300 Btu/scf and 200 Btu/scf for non-assisted flares. Refer to §60.18(c)(3)(ii) and §63.11(b)(6)(ii).

Adsorption Systems

Adsorption is the process by which molecules collect on and adhere to the surface of an adsorbent solid. The adsorption is due to physical and/or chemical forces. Activated carbon is typically used as an adsorbent because of its large surface area, which is a critical factor in the adsorption process. The adsorption capacity of a material is proportional to surface area; activated carbon has significant surface area due to its internal pore structure. Adsorption systems can control VOCs in the range of 200 ppm to 10,000 ppm. However, at the low end of that range, the small concentrations may be difficult or uneconomical to control.[27] Carbon adsorption systems are ideally used for recoverable VOC materials. Adsorption is also not a reliable control technology for highly volatile materials. Highly volatile materials; *e.g.*, molecular weights less than 45 pounds per mole (lb/mol), do not readily adsorb onto carbon; therefore, adsorption is not typically used for exhaust streams containing these materials.

Absorption (Scrubber) Systems

In absorption systems, certain constituents of a gas stream are selectively removed by a liquid solvent. The control of gas-phase VOCs using an absorption scrubber system relies on contact between the gas and a liquid in which the pollutants are soluble or with which it will chemically react. The degree of control depends on the following: solubility of the gas, gas and liquid throughput rates, contact time, mechanism of contact, and type of scrubber.

Gas absorption is commonly used to recover products or to purify gas streams with high concentrations of water soluble compounds. Per EPA Cost Control Manual[28], gas absorbers are most effective for gas streams with pollutant concentrations between 250 and 10,000 ppmv. Low concentrations of organics in an exhaust stream require long contact times and large quantities of absorbent for effective removal. Absorptions are generally more practical for processes in which the absorbent is easily regenerated or the resulting solution can be used as a make-up stream.

Biofiltration Systems

Biofiltration is based on the biodegradation of exhaust stream constituents as the exhaust passes through a biologically active filter material. Naturally occurring microorganisms are used to treat air containing odorous substances such as reduced sulfur compounds and VOCs. The microorganisms consume the contaminants in the air stream for energy,

[26] Ibid. at 12.
[27] Ibid. at 13.
[28] Ibid. at 14.

thus cleaning the air. Biofiltration is most successful when treating low molecular weight and highly soluble organic compounds with simple structures. Compounds with complex bond structures generally require more energy to break down than the microorganisms have available to them[29]. Biofiltration has been applied on a limited basis with typical control efficiencies of 50 to 90 percent. Pre-conditioning of the gas stream is often required to control temperatures, moisture content, and particulate matter. Gas streams with high levels of particulate matter or sticky substances may also cause the biofilter media to clog, thus reducing the efficiency of the system. The bacteria commonly used in biofiltration are highly temperature sensitive and are susceptible to damage by broadly varying process conditions. High exhaust temperatures may kill the microorganisms and low temperatures may slow or stop degradation. Biofiltration systems may also require the addition of nutrients to support microbial growth. Furthermore, biofiltration systems require substantial operating space and system monitoring.

Condensation Systems

Condensation systems utilize a refrigeration source to cool the exhaust stream to convert the VOC from a gaseous phase to a liquid phase. Condensation is used for VOC reduction in applications where there is a concentrated VOC stream. Condensation systems are most efficient at removing VOC emissions from exhaust streams with concentrations above 5,000 ppmv[30,31] and can achieve high-recovery efficiencies (greater than 95 percent) when VOC concentrations are greater than 10,000 ppmv.

Internal/External Floating Roofs

Fixed roof tanks are common because they are inexpensive to construct and are often the minimum acceptable equipment for storing organic liquids. Emissions from fixed roof tanks come from evaporation during storage (i.e., breathing losses) and evaporation during filling and emptying (i.e., working losses). A way to reduce VOC emissions is with the use of IFRT and to a lesser extent EFRT. IFRT have both a permanent fixed roof and a floating roof inside. The floating roof, which rises and falls with the liquid level in the tank, consists of a deck, fitting, and rim seal system. Depending on the type of roof and seals used and the type of organic liquid stored, IFRT can have a VOC control efficiency that ranges from 60 to 99 percent.

LDAR Program

LDAR programs are work practices that can be used for reducing the fugitive VOC emissions. Process equipment applicable to an LDAR program, such as pumps, valves, flanges, and pressure relief devices are periodically monitored using sensory inspection techniques (*e.g.*, visual, olfactory, or audible) or with a portable hydrocarbon detector to detect leaks. The LDAR program will define a concentration or action level at which an affected component is considered to be leaking and specify a time period during which the leak must be repaired. Due to the ongoing monitoring and repairs of “leaks”, fugitive emissions are reduced. The level of reduction is based on the monitoring frequency, threshold triggering repair, and number of components monitored. This can be considered a part of good operating practices.

Good Design and Operating Practices

Good design includes process and mechanical equipment designs that are either inherently lower polluting or are designed to minimize emissions. Good operating practices include operating methods and procedures, housekeeping, and preventive maintenance programs.

<u>Technical Feasibility</u>

The technical feasibility of each of the control techniques discussed is addressed below:

Process Exhaust Vent

---

[29] Ibid. at 15.
[30] Ibid. at 16.
[31] Ibid. at 17.

Oxidation

Oxidation systems are technologically feasible for control of the HAP emissions from the process exhaust vent (mineral oil absorber). The applicant has indicated an oxidation control efficiency of 99 percent for 50 scfm exhaust flow for the process exhaust vent.

Flares

As noted above, flares can be used for waste gas streams with a heat content of at least 300 Btu/scf (lower/net heating value). The heating value of the exhaust stream for hexane lower/net heating value of 19,403 Btu/lb[32], 2 lb/hr VOC emission rate, and 50 scfm exhaust stream, is estimated as follows:

$$\left(\frac{2.0\ lb\ hexane}{hr}\right)\times\left(\frac{hr}{60\ min}\right)\times\left(\frac{19{,}403\ Btu}{lb\ hexane}\right)\times\left(\frac{min}{50\ scf}\right)=13\ Btu/scf$$

Therefore, flares are deemed a technically infeasible option for the process exhaust vent.

Adsorption Systems

As per the applicant, the estimated VOC concentration in the process vent is 2,978 ppm and is outside the typical range of 400 ppm to 2000 ppm for inlet loading. However, adsorption has been considered technically feasible option for the process vent.

Absorption (Scrubber) Systems

The design of the fat extraction process does include a mineral oil absorber to recover hexane solvent. The review of the RBLC data shows that mineral oil absorption is considered BACT for vegetable oilseed extraction systems, which as stated above, are similar to the proposed fat extraction process. As per EPA, unrealistic options such as placing in series the same or similar control technology need not be to be considered.[33] Therefore, additional absorption system has not been considered for the process vent.

Biofiltration Systems

Biofiltration systems are not a previously demonstrated control method or a method currently used in practice by other facilities on vegetable oilseed extraction systems. In addition, because hexane is not water soluble, it is not suitable for control by biofiltration. Therefore, as per Permittee, biofiltration has been deemed a technically infeasible option for the process exhaust vent.

Condensation Systems

As noted previously, the fat extraction process vent includes numerous condensers for recovering hexane for reuse. They are to be located upstream of the mineral oil absorber. As mentioned earlier, control technologies in series do not need to be considered. Therefore, additional condensers are not considered for the process vent.

Internal/External Floating Roofs

Internal and external floating roofs are emission control technologies that are applied to storage tanks that are not otherwise controlled. The hexane storage tanks to be used as part of the fat extraction system are not vented separately but are vented to the process vent system which is vented through 3-stages of condensation and the mineral oil absorber and accounted for as part of the steady-state process vents. Therefore, as per the Permittee, internal and external floating roofs are not required to be evaluated further for the proposed process vent sources.

---

[32] Ibid. at 18.
[33] Ibid. at 19.

Good Design and Operating Practices

Good design and operating practices include a nearly closed loop vent system from all of the process sources where hexane is present to multiple stages of condensers and a mineral oil scrubber to recover hexane. This is considered a technically feasible option.

Dry Meal Storage Room Exhaust Vent

A 7,000 scfm room exhaust fan is the emission point for the dry meal storage room. The technical feasibility of each control system is addressed below.

Oxidation

Exhaust from the dry meal storage area can be ducted and routed to an oxidizer system. As per the Permittee, VOCs concentrations in the room will be diluted with air to an estimated 63 ppmv, well below the concentration needed to sustain the incineration temperature without auxiliary fuel[34]. Additionally, the products of combustion from the auxiliary fuel can contribute to the VOC emissions from the oxidizer and negatively bias the control efficiency results. Regardless, the Permittee has deemed oxidation technology as a technically feasible option, with an assumed reduction efficiency of 90 percent as the VOC concentrations for destruction would be less than desirable as stated above.

Flares

Flares can be used for waste gas streams with a heat content of at least 300 Btu/scf (lower/net heating value).[35] The heating value of the exhaust stream for hexane, using 19,403 Btu/lb[36] lower/net heating value, 6 lb/hr VOC emission rate, and 7,000 scfm exhaust stream, is estimated as follows:

$$\left(\frac{6.0\ lb\ hexane}{hr}\right) \times \left(\frac{hr}{60\ min}\right) \times \left(\frac{19{,}403\ Btu}{lb\ hexane}\right) \times \left(\frac{min}{7{,}000\ scf}\right) = 0.3\ Btu/scf$$

Therefore, flares are not a technically feasible option for the meal storage area exhaust.

Adsorption Systems

The concentration of VOC in the exhaust from the dry meal storage area is estimated to be 63 ppmv, which is outside the typical range of 400 ppm to 2000 ppm for inlet loading. Nonetheless, the Permittee has considered this option technically feasible.

Absorption Systems

An absorption system will be considered technologically feasible for the dry meal storage area exhaust, because, it does not vent to the mineral oil absorber.

Biofiltration Systems

Biofiltration systems are not a demonstrated control technology or a method currently used in practice by other facilities on vegetable oilseed extraction systems. In addition, because hexane is not water soluble, it is not suitable for control by biofiltration. Therefore, biofiltration has been a technically infeasible for the meal area exhaust vent.

Condensation Systems

Condensers are not considered technologically feasible for the dry meal storage exhaust because the VOC concentration is too low to have any practical effect[37].

---

[34] Ibid. at 20.
[35] Ibid. at 21.
[36] Ibid. at 18.
[37] Ibid. at 23.

Internal/External Floating Roofs

Internal and external floating roofs do not apply to the meal storage vent. Therefore, it will not be evaluated further.

Good Design and Operating Practices

Good design and operating practices will ensure that the hexane is properly stripped from the meal and the meal efficiently transferred to storage. Other good work practices include an equipment maintenance program and housekeeping. Therefore, good design and operating practices have been deemed technically feasible.

Fugitive Losses

The fugitive losses are estimated based upon EPA equipment leak factors. Because these leaks occur at many points throughout the process, it would be impractical to capture the VOC emissions without enclosing all hexane piping within a permanent total enclosure. Therefore, the following control options have been deemed technically infeasible for fugitive losses because the emissions cannot be captured: Oxidation, Flares, Adsorption Systems, Absorption Systems, Biofiltration Systems, and Condensation Systems.

Thus, only technically feasible option available is Good Design and Operating Practices. An LDAR program, equipment maintenance program, and housekeeping, are good design and operating practices.

<u>Ranking of Technically Feasible Control Options</u>

The following Tables provide ranking of technical feasible options for each emissions unit:

Process Exhaust Vent

Control Option	Emission Reduction Efficiency	Ranking
Catalytic Regenerative Oxidation	99 percent	1
Catalytic Recuperative Oxidation	99 percent	1
Thermal Regenerative Oxidation	99 percent	1
Thermal Recuperative Oxidation	99 percent	1
Direct Thermal Oxidation	99 percent	1
Adsorption	70 percent	2
Good Design and Operating Practices	Not applicable	3

Dry Meal Storage Room Exhaust Vent

Control Option	Emission Reduction Efficiency	Ranking
Oxidation	90 percent	1
Adsorption	70 percent	2
Absorption	60 percent	3
Good Design and Operating Practices	Not Applicable	4

Fugitive Losses

Control Option	Emission Reduction Efficiency	Ranking
LDAR Program	51 percent	1
Good Design and Operating Practices	Not Applicable	2

Energy, Environmental, and Economic Impacts Analysis

The following Table provides impacts analysis with respect to energy, environmental, and economic factors, for each technically feasible option, as included in the permit application. It needs to be noted that economic impact for each feasible option is based upon detailed engineering information for developing capital and operation and maintenance costs, as provided in the EPA Air Pollution Control Cost Manual, as referenced earlier. With respect to Good Design and Operating Practices option, the applicant contends that it is difficult to estimate resulting reductions in VOC emissions; hence it has made no attempt to determine cost impacts for such option for process vent and meal room vent.

Process Exhaust Vent

Control Option	Cost Impact	Environmental Impact	Energy Impact
Catalytic Regenerative Oxidation	$19,200 per ton of pollutant	No adverse impact	No adverse impact
Catalytic Recuperative Oxidation	$10,700 per ton of pollutant	No adverse impact	No adverse impact
Thermal Regenerative Oxidation	$19,200 per ton of pollutant	No adverse impact	No adverse impact
Thermal Recuperative Oxidation	$10,500 per ton of pollutant	No adverse impact	No adverse impact
Direct Thermal Oxidation	$9,200 per ton of pollutant	No adverse impact	No adverse impact
Adsorption	$11,000 per ton of pollutant	No adverse impact	No adverse impact
Good Design and Operating Practices	$0 per ton of pollutant	No adverse impact	No adverse impact

Dry Meal Storage Room Exhaust Vent

Control Option	Cost Impact	Environmental Impact	Energy Impact
Catalytic Regenerative Oxidation	$12,500 per ton of pollutant	No adverse impact	No adverse impact
Catalytic Recuperative Oxidation	$12,400 per ton of pollutant	No adverse impact	No adverse impact
Thermal Regenerative Oxidation	$13,600 per ton of pollutant	No adverse impact	No adverse impact
Thermal Recuperative Oxidation	$16,100 per ton of pollutant	No adverse impact	No adverse impact
Direct Thermal Oxidation	$29,900 per ton of pollutant	No adverse impact	No adverse impact
Adsorption	$353,900 per ton of pollutant	No adverse impact	No adverse impact
Absorption	$41,400 per ton of pollutant	No adverse impact	No adverse impact
Good Design and Operating Practices	$0 per ton of pollutant to negligible	No adverse impact	No adverse impact

Fugitive Losses

Control Option	Cost Impacts	Environmental Impacts	Energy Impacts

LDAR Program	$5,800 per ton of pollutant[38]	No adverse impact	No adverse impact

<u>BACT Determination</u>

The Permittee has proposed the following BACT, after evaluating each of the technically feasible options, included above, considering economic, environment, and energy impacts. Specifically, the Permittee has determined the economic impacts unreasonable, and environmental and energy impacts reasonable, for each of the technically feasible options listed above. The following option is proposed below as BACT:

Emissions Unit	BACT	Control Method(s)
Process Exhaust Vent	2.0 lb/hr	Good design and operating practices
Dry Meal Storage Room Vent	6.0 lb/hr	Good design and operating practices
Fugitive Losses	3.7 lb/hr	LDAR program and good design and operating practices

As discussed earlier the RBLC search summary, condensers and mineral oil absorption units have been determined to be control methods for VOC emissions from vegetable oilseed processing industry. These same types of control methods are to be used for Valley Proteins' process exhaust vent. Specifically, all process sources vent to multiple stage condensers and a mineral oil scrubber, which results in a proposed BACT of 2.0 lbs/hr.

With respect to VOC emissions of meal storage room exhaust, no determinations are available in RBLC database for similar vegetable oilseed processing industry, as stated above; thus, the applicant proposed good design and operating practices as control methods that will ensure hexane is stripped properly from the meal and the meal is efficiently transferred to storage. In addition, preventative maintenance of the equipment and good housekeeping practices are also to be employed as good design and operating practices. The associated BACT for meal storage room vent is 6.0 lbs/hr.

For equipment losses, an LDAR program has been identified as a control method in various determinations included in the RBLC. Thus, the applicant has proposed an LDAR along with equipment maintenance program and general housekeeping practices as good design and operating practices as control methods for the proposed BACT of 3.7 lbs/hr.

After carefully evaluating the information presented above in the BACT analysis, including consideration of economic, environmental and energy impacts, the DAQ proposes to approve the applicant-proposed BACT, as included in the above Table. The DAQ finds all other options unreasonable (except the option proposed as BACT), based on excessive economic impacts, even though their other impacts (environmental and energy) may be reasonable.

It needs to be noted that these BACT applies for all periods of operations including start-up, shut-down, and malfunction, for process exhaust vent, meal storage room exhaust vent, and equipment fugitive losses.

The compliance with BACT for process vent and meal vent will be determined by EPA's Reference Test Method(s), using average of 3-run stack tests. For fugitive equipment losses, employing LDAR would be the mechanism to demonstrate compliance with the proposed BACT. The applicant has proposed to use a leak rate of 5,000 ppmv, as an indicator to determine a need for repair or replacement of equipment.

Finally, it should be emphasized that the biogenic (produced or brought about by living organisms) sector is the most abundant source of VOCs in North Carolina and accounts for approximately 90% of the total VOC emissions

[38] Assumes that the facility currently has leak detection instruments for existing sources. Thus, no capital investment is required and only operating cost will be part of cost effectiveness.

statewide[39]. The overwhelming abundance of biogenic VOCs makes the majority of North Carolina a NOx-limited environment for the formation of ozone. Therefore, the increase in emissions of VOCs or the reductions of VOCs from the proposed fat extraction process are not as critical to attainment of ambient ozone standard in Duplin County air-shed; thus, this air-shed is expected to continue attaining the most recent ozone NAAQS (2015) with the proposed approval of fat extraction process at Valley Proteins' Rose Hill facility.

BACT Analysis for VOC for Natural Gas-fired Boilers

Two natural gas-fired boilers are also sources of VOC emissions. VOC emissions are generated from boilers because of incomplete fuel combustion. Operating conditions such as lower than optimal temperatures, insufficient residence time, and lower than optimal oxygen levels due to inadequate mixing and/or a low air-to-fuel ratio in the combustion zone can increase VOC emissions. Trace amounts of VOC species in natural gas fuel (e.g., formaldehyde and benzene) can also contribute to VOC emissions if they are not completely combusted in boiler.

The applicant has performed a RBLC database search for natural gas fired boilers (less than 100 million Btu per hour heat input) in industrial/commercial/institutional categories, for determinations issued for VOC for period 01/01/2007 to 09/12/2017. Most of determinations include no control techniques at all or were combinations of good practices (good combustion practices, good design practices, good operating practices). Catalytic oxidation, thermal oxidation, and flue gas recirculation (FGR) were also resulted from the search. As per the applicant, while FGR may have some coincidental reduction of VOCs, it would not be effective at the low levels of VOC from the natural gas boilers and it is a control technology designed for NO_X emissions control. Therefore, it has deemed it not applicable for the proposed boilers.

VOCs in the exhaust of the proposed boilers are expected to be at a level of 2 ppmv, well below the concentration needed to sustain incineration temperature. While not practical, the applicant has deemed the oxidation technology technically feasible assuming a control efficiency of 80 percent due to very low concentrations of VOCs in the exhaust. The cost impacts for oxidation technologies range between $797,000 per ton of VOC (catalytic recuperative oxidation) and $1.375 million per ton of VOC (direct fired thermal oxidizer), using the EPA Air Pollution Control Cost Manual, as previously referenced. No adverse environmental and energy impacts are expected from employing oxidation technologies.

The DAQ finds the cost impacts associated with various types of oxidation technologies excessive; thus, DAQ proposes to approve the BACT of 0.054 lb/hr (3 run stack test average) for each new boiler, based upon good combustion control and use of clean fuels such as natural gas. The BACT applies to all periods of boilers operations including start-up, shut-down, and malfunction. The BACT is based upon AP-42 emissions factors.[40]

The DAQ believes that for these relatively small-sized boilers (approximately 10 million Btu per hour heat input rate) and negligible emissions, good combustion control is an appropriate method to reduce emissions, in addition to use of clean fuels (such as natural gas) for reduction of VOC emissions.

The applicant proposes to conduct frequent tune-ups and inspections as part of the proposed good combustion control method. No compliance demonstration is required to ensure compliance with the above BACT due to negligible emissions from each of the natural gas fired boilers.

6.0 Source Impact Analysis

The DAQ has determined that no ozone impact analysis will be needed for the project VOC emissions of 51 tons per year. The DAQ has further determined that North Carolina is a NOx-limited region and the above small increase in VOC emissions would not have any impact on ozone concentrations in the Duplin county air-shed.

---

[39] Clean Air Act Section 110(l) Non-Interference Demonstration to Support the Gasoline Reid Vapor Pressure (RVP) Standard Relaxation in Gaston and Mecklenburg Counties for The Charlotte-Gastonia-Salisbury, NC, 2008 8-Hour Ozone Maintenance Area, North Carolina Department of Environment and Natural Resources Division of Air Quality, April 16, 2015.

[40] Ibid. at 5.

Regardless of the above, the applicant has prepared an ozone impact analysis using the EPA *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*, issued on In a December 2, 2016. The EPA has laid out a framework to evaluate the impact of point sources on regional pollutants such as ozone and $PM_{2.5.}$

In this case, VOC emissions such as n-hexane are precursors to the formation of ozone at downwind locations. To begin the assessment, it is necessary to determine the background concentration for the Rose Hill area. The North Carolina DEQ operates an ozone monitor in Lenoir County, which is adjacent to Duplin County (in which the facility is located). Ozone data in Lenoir County for the previous 3 years are summarized below.

Year	Annual 4th highest, daily maximum 8-hour Ozone (ppm)
2016	0.06
2015	0.062
2014	0.06
Average	0.063

These observations define a design concentration of 0.063 ppm versus the National Ambient Air Quality Standard (NAAQS) of 0.070 ppm (current 2015 NAAQS). That leaves a margin of 0.007 ppm or 7 ppb between current air quality and the NAAQS.

The document referenced above provides a list of the expected impact of VOC emissions on area ozone concentrations for different locations across the country and for various levels of emissions on an annual basis. The closest station listed to Rose Hill in the EPA document is Horry, South Carolina. The document lists an expected ozone impact of 0.03 ppb for emissions of 500 tpy of VOCs from a “low” stack source at the Horry, SC location.

Extrapolated to 40 tons per year, the expected impact would be 40/500 x 0.03 ppb or 0.002 ppb. Given that the margin of compliance for ozone NAAQS in the air-shed is 7 ppb, this project would have only a negligible impact on local ozone concentrations and the impact would not threaten the attainment of ozone NAAQS.

7.0 Additional Impact Analysis

Visibility Impact

This visibility impact is generally called Class II Area Visibility Impact. The proposed fat extraction is a major modification due to VOCs emissions only. Because of that, the project is not projected to have any impact on regional visibility or haze as VOCs are not a variable that is input in models to determine visibility impacts (such as in the VISCREEN algorithm).

Impacts on Soil and Vegetation

According to data presented in Table 3-1 of EPA' s final report on "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA 450/2-81-078), vegetation effects for sensitive plants are possible for ozone concentrations above 200 ppb. From the evaluation for project effects on ozone concentrations, the incremental effect of this project was estimated to be 0.002 ppb as discussed in Section 6 above. There are no known effects of ozone on soils for incremental increases in ozone concentrations of 0.002 ppb. It is concluded that there would be no effects on soils or vegetation expected from the project.

Associated Growth Impacts

The proposed modification is not anticipated to result in any significant increase in full-time employment (and associated increase in traffic flow) at the facility. The construction activity related to the project is not expected to result in any sustained increase in local traffic due to construction related jobs and associated traffic. Therefore, no additional growth impacts are expected.

Air Quality Impact due to Associated Growth

A screening level assessment presented in Section 6 above for the direct emissions of VOCs (and possible conversion to ozone) from the project showed no predicted effect from the proposed project on the ozone attainment status for the area. Because there is no anticipated increase in traffic associated with this project, there is not expected to be any secondary project impact effects on ozone formation as well.

8.0 Facility-wide Emissions

The following is a facility-wide emissions summary. The actual emissions are for calendar year 2016, as reported by the Permittee to DAQ via submittal of emission inventories. The potential emissions (with control) are copied from the application.

Pollutant	Actual Emissions tons/yr	Potential Emissions (with control) tons/yr
PM	1.34	76.06
PM-10	1.34	52.79
PM-2.5	1.31	28.28
SO_2	0.60	580.05
NOx	36.44	271.42
CO	25.13	48.14
VOC	18.10	118.81
Lead	0.000060	0
GHG as CO_2e	Not Reported	186301
Single HAP	0.53 (n-hexane)	30.81 (n-hexane)
Aggregate HAP	1.49	> 30.81

9.0 Public Participation

This permit application's processing is conforming to the public participation requirements pursuant to 15A NCAC 0530 "Prevention of Significant Deterioration", and 15A NCAC 02Q .0300 "construction and operation permits" and 02Q .0528 "112(g) Case-by-Case MACT Procedures".

A public notice (Appendix 2 below) for the availability of application review including pre-construction reviews under both §§112(g) and 165 of CAA and the draft Title V, will be published in a local newspaper of general circulation for 30 days for review and comments. A copy of the public notice will be provided to the EPA, and all local and state authorities having authority over the location at which the proposed modification is to be constructed. Draft permit documents will also be provided to EPA, affected states, and all interested persons in mailing list, maintained by the DAQ. All documents will be placed on the DEQ's website and a complete administrative record for the draft permit will be kept for public review at the DEQ's Wilmington Regional Office for the entire public notice period (30 days). Appendix 3 below, provides a list of entities and associated documents required to be sent for the proposed PSD major modification, satisfying the requirements in §51.166(q) "public participation". This listing also satisfies the requirements for preconstruction approval for a case-by-case MACT.

It needs to be noted that as this application is not processed pursuant to 15A NCAC 02Q .0500 "Title V procedures", none of the public participation requirements contained therein apply to the application.

A final notice of the issuance of case-by-case MACT approval will be sent to EPA and all other State and local control agencies having jurisdiction in affected States.

A notice will also be sent to the applicant for the issuance of final determination. It will also be made available for public inspection at the DEQ's Wilmington Regional Office and on DEQ's website.

10.0 Stipulation Review

The following changes were made to the Valley Proteins, Rose Hill's Air Quality Permit No. 05127T24:

Old Page No. [Air Permit No. 05127T24]	**New Page No.** [Air Permit No. 05127T25]	**Condition No.**	**Changes**
3	3	Section 1 Table	Include the following sources: (i) Fat extraction process equipment (ID No. ES-FE1) consisting of: Raw material unloading C201 Extractor EX204 Extractor EX205 Extractor EX206 Miscella feed tank T210-1 Miscella centrifuge CF212 Miscella filtrate tank T213 1st stage evaporator HX215 2nd stage evaporator HX216 Oil stripper VE217 Oil storage tanks (Main plt Bldg.) Work tank VE226 Solvent storage tank T2201 Solvent heater HX231 Desolventizer DT206 Vapor wash scrubber CY250 Vapor/solvent interchange HX208 Reboiler and Interchange HX227/VE227 Mineral oil heater HX225-5 Mineral oil stripper VE225-6 Evaporator condenser HX222-1 (2,900 gal/min cooling water flow rate) Stripper condenser HX222-2 (400 gal/min cooling water flow rate) DT condenser HX209 (3,600 gal/min cooling water flow rate) Vent condenser HX224 (300 gal/min cooling water flow rate) Mineral oil absorber VE225-1 (8 gal/min mineral oil flow rate) (ii) Fat extraction process meal storage room equipment (ID No. ES-FE2) consisting of: Two storage bins (each 20 feet (l) x 7 feet (w) x 17.25 ft (h)

			(iii) Fat extraction process equipment fugitive losses (ID No. FG1) (iv) Two natural gas-fired boilers (each 10.04 million Btu per hour heat input, ID No. ES-B8 ES-B9)
6	7	Section 2.1 A. Table	Include applicable requirement under 5D NESHAP.
10	-	Section 2.1 A. 6.	Remove non-applicable requirement under 6J NESHAP.
14	13	Section 2.1 C. Table	Include applicable requirement under 5D NESHAP. Remove non-applicable requirement under 6J NESHAP.
18	-	Section 2.1 C. 7.	Remove non-applicable requirement under 6J NESHAP.
-	19	Section 2.1 E.	Include this Section for all fat extraction process equipment included in the first row of this table.
-	22	Section 2.1 F.	Include this Section for two natural gas fired boilers (included in the first row of this table).
23	24	Section 2.2. A.	Include new emission sources ES-FE1, ES-FE2, ES-FG1, ES-B8, and ES-B9.
-	29	Section 2.2 C.	Include this Section for multiple source requirements (PSD and 2nd step application submittal) for all fat extraction process equipment and two natural gas fired boilers.
-	31	Section 2.2 D.	Include this Section for NESHAP 5D requirements for two natural gas fired boilers.

11.0 Conclusions, Comments, and Recommendations

- The application includes four new condensers and one new mineral oil absorber. The DAQ has deemed each of the condensers and mineral oil absorber inherent process equipment (i.e., integral part of) for hexane extraction process. Thus, professional engineer seal is not required for each of these equipment per 02Q .0112(c)(1). Although, the applicant consultant (James F. Graves III, PE No. 042774) provided a professional engineer seal without indicating which pages he is certifying.

- Duplin County Planning Director (Elizabeth Stalls) has provided a zoning consistency determination, which is dated October 25, 2017. It states, "I have received a copy of the air permit application (draft or final) and there are no applicable zoning ordinances for this facility at this time".

- The draft permit (pre-public notice version) was sent to Wilmington Regional Office (WiRO) on April 17, 2018 for review. Dean Carroll emailed on April 24th indicating no comments on the draft permit.

- The draft permit (pre-public notice version) was sent to Valley Proteins, Inc. - Rose Hill Division, on April 17, 2018. The applicant (Steve Lester, General Manager, Valley Proteins, Inc. - Rose Hill Division) emailed on August 20th including comments on the draft permit and the application review. It needs to be noted that the comments on application review are the same as those on the draft permit. Therefore, there is no need to repeat any comment on the application review as responding to the comments on the draft permit will adequately take care of comments on the application review.

  Company Comment 1:

Revise the applicability label from “GACT Subpart JJJJJJ” to “MACT Subpart DDDDD” for boilers (ES-B2 through ES-B6) in Section 1 Table.

DAQ Response:

Agreed. This was an error and it will be corrected. These boilers (ES-B2 through ES-B6) are subject to major source boiler MACT Subpart DDDDD upon issuance of the final permit, approving the proposed fat extraction process. In addition, the remaining existing boiler (ES-B7) will be subject to this MACT; thus, it will also be accordingly labeled.

Company Comment 2:

The manufacturer of the equipment for the fat extraction process has determined that there will be a total of three extractors (ES204 through EX206). The draft permit states only one extractor EX204. Thus, the Permittee is asking the DAQ to revise the descriptor for extractor EX204 to indicate extractors in plural as EX204 through EX206.

DAQ Response:

Agreed. The DAQ will make this change and specify three extractors EX204 through EX206, wherever it currently indicates only one extractor EX204 in the permit.

Company Comment 3:

Include prefix “process” for condensers and delete prefix “mineral oil” for mineral oil absorber, both in Section 2.1 E. 4. b. Table and Section 2.2 C.1. b. Table.

DAQ Response:

Agreed. This change will be made.

Company Comment 4:

Clarify in Section 2.1 E. 4.c. iv. that the Permittee intends to confirm the manufacturer-recommended values for maximum coolant temperature exiting each condenser and minimum scrubbant flow pressure for mineral oil absorber, both during the stack test, required to be performed to demonstrate compliance with the case-by-case MACT.

DAQ Response:

Agreed. This change will be made.

Company Comment 5:

Remove wordings “and ensure that maximum control efficiency is” in Section 2.1 E. 4.d.i.

DAQ Response:

The DAQ believes that the first part of this stipulation includes that “to comply with the provisions of this Permit”, the Permittee shall perform inspections and maintenance (O&M) on condensers and absorber, etc. That is the intent of the O&M requirement. The additional wordings on “and ensure that maximum control efficiency is” after “to comply with the provisions of this Permit”, are redundant. The DAQ will remove the above redundant wordings.

Comment 6:

In Section 2.2 C.1 b. Table, remove the wordings "3 run stack test average" associated with the proposed VOC BACT of 0.054 lb/million Btu, for each new boiler (ES-B8 and ES-B9).

DAQ Response:

Each established BACT needs to be practically enforceable. That means the agency needs to include the averaging period for the limitation and the method of compliance, among others. The DAQ is not requiring any stack testing to demonstrate compliance with the above VOC BACT for the boilers. It is simply specifying the reasonable averaging period for the limit and the method of compliance to make the BACT practically enforceable.

Comment 7:

Include clarifying changes in Sections 2.2 D.2. m. and n., and Sections 2.2 D.3. m. and n., to state that the operation of oxygen trim system only applies when liquid fuels are fired.

DAQ Response:

Agreed. This change will be made in these sections.

- This engineer recommends issuing the revised permit.

Appendix 1
RBLC Data Summary for Vegetable Oilseed Process
VOC Emissions (01/01/2008-Present)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
VA-0327	PERDUE GRAIN AND OILSEED, LLC	7/12/2017	(2) Grain Dryers	0	-	-	0.21	LB/HR	BACT-PSD	U
VA-0327	PERDUE GRAIN AND OILSEED, LLC	7/12/2017	Soybean Oil Extraction Plant	0	-	-	0.152	GAL	BACT-PSD	U
VA-0327	PERDUE GRAIN AND OILSEED, LLC	7/12/2017	(4) 27 MMBtu/hr boilers, Natural gas and No. 2 fuel oi	0	-	-	0.1	LB/HR	BACT-PSD	U
VA-0327	PERDUE GRAIN AND OILSEED, LLC	7/12/2017	Emerge ncy Generat or	0	-	-	0.49	LB/HR	BACT-PSD	U
*IL-0125	ADM QUINCY	6/30/2017	Vegetable Oil Production Process	47500000	bushels/year	Mineral oil scrubber for extractor, desolventizer-toaster and hexane tanks. LDAR for components.	0.175	POUNDS/GALLON	BACT-PSD	U
PA-0308	PERDUE AGRIBUSINESS LLC/MARIETT A	5/5/2016	Extraction process	0	-	Good work practices and LDAR	0.028	LBS/TON SOYBEAN	LAER	U
PA-0308	PERDUE AGRIBUSINESS LLC/MARIETT A	5/5/2016	Meal dryer	1750	Tons per day	LDAR	0.023	LB/TONS OF SOYBEAN	LAER	U
PA-0308	PERDUE AGRIBUSINESS LLC/MARIETT A	5/5/2016	Meal cooler	0	-	LDAR	0.102	LB/TON OF SOYBEAN	LAER	U
MN-0092	CHS HALLOCK	9/23/2015	CANOLA OILSEED PROCESSING	1750	T/D	GOOD SOLVENT RECOVERY PRACTICES, LEAK DETECTION AND REPAIR PROGRAM	0.29	GAL/TON	BACT-PSD	

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
IA-0111	DES MOINES SOYBEAN PROCESSING PLANT	9/22/2015	Extractor and Desolventizer Toaster Dryer Cooler	215	tons/hr	Mineral Oil Absorption System and Good Operating Practices	0.14	GAL/TON	BACT-PSD	U
IA-0111	DES MOINES SOYBEAN PROCESSING PLANT	9/22/2015	Equipment Leaks	0	-	Leak Detection and Repair (LDAR) Monitoring System	788	TONS/YR	BACT-PSD	U
IA-0110	CARGILL EDDYVILLE	8/14/2015	Corn germ expeller 1	660	T/D	-	6	POUNDS/HOUR	BACT-PSD	U
IA-0110	CARGILL EDDYVILLE	8/14/2015	corn germ expeller 2	660	T/D	-	6	POUNDS/HOUR	BACT-PSD	U
*NE-0059	AGP SOY	3/25/2015	Soybean Extraction Process	85000	bushel/day	Mineral Oil Absorber. During SSM the source must comply with 40 CFR 63.2852 as amended April 20, 2006	381.26	TON/YR	BACT-PSD	U
*NE-0059	AGP SOY	3/25/2015	Boiler #1	200	MMBTU/H	-	0.0054	LB/MMBTU	BACT-PSD	U
*NE-0059	AGP SOY	3/25/2015	Boiler #2	200	MMBTU/H	-	0.0054	LB/MMBTU	BACT-PSD	U
IN-0209	CONSOLIDATED GRAIN AND BARGE CO.	11/10/2014	EXTRACTION SYSTEM	0	-	MINERAL OIL ABSORBER	0.048	LB/TON	OTHER CASE-BY-CASE	U
IN-0209	CONSOLIDATED GRAIN AND BARGE CO.	11/10/2014	OVERALL SOLVENT LOSS RATIO	0	-	-	0.19	GAL/TON	OTHER CASE-BY-CASE	U
IN-0209	CONSOLIDATED GRAIN AND BARGE CO.	11/10/2014	DTDC DRYERS	87	TON/HR	-	0.152	LB/TON	OTHER CASE-BY-CASE	U
IN-0209	CONSOLIDATED GRAIN AND BARGE CO.	11/10/2014	DTDC COOLER	87	TON/HR	-	0.152	LB/TON	OTHER CASE-BY-CASE	U
IN-0209	CONSOLIDATED GRAIN AND BARGE CO.	11/10/2014	SOYBEANS PROCESSED	0	-	-	1095000	TON/YR	OTHER CASE-	U

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
									BY-CASE	
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Extraction	2500	TONS PER DAY	Mineral Oil Scrubber	0.29	LB/GAL	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Dryer/Cooler	2500	Tons per day	Desolventizer	157	DEGREES F	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Crude Meal Emissions	2500	Tons per day	Desolventizer/Toaster Operation	157	DEGREES F	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	VOC Storage (Hexane)	0	-	Vapor Collection and Control (Mineral Oil Scrubber)	0	-	N/A	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Equipment Leaks	0	-	Leak Detection and Repair (LDAR)	0	-	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Wastewater Evaporator	0	-	Evaporator routed to Mineral Oil Scrubber	0	-	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Gas-fired Boiler	95	MMBTUH	Good Combustion	0.006	LB/MMBTU	BACT-PSD	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Refinery Boiler	5	MMBTUH	Good Combustion	0.0054	LB/MMBTU	N/A	U
*OK-0156	NORTHSTAR AGRI IND ENID	7/31/2013	Fire Pump Engine	550	hp	Good Combustion	0.35	LB/MMBTU	BACT-PSD	U
MN-0086	NORTHSTAR AGRI INDUSTRIES - HALLOCK	7/23/2013	Canola Oilseed Processing	2000	T/D	Solvent Loss Factor less than or equal to 0.25 gal/ton of canola oilseed processed on a 12-month rolling sum.	0.25	GAL/TON	BACT-PSD	U
IN-0150	LOUIS DREYFUS AGRICULTURAL INDUSTRIES LLC	9/21/2012	SOYBEAN OIL EXTRACTION PLANT AND MEAL DRYER AND COOLER	2251836	T/YR	COMBINED CONDENSER AND MINERAL OIL SCRUBBER SYSTEM, LDAR PROGRAM	0	-	OTHER CASE-BY-CASE	U
IA-0103	AG PROCESSING SERGEANT BLUFF	7/24/2012	Soybean oil extraction	133333	bushels/day	mineral oil scrubber	0.145	GALLONS/TON	BACT-PSD	N

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
ND-0027	WEST FARGO OILSEEDS PROCESSING PLANT	1/4/2012	Extraction and refining	1500	metric tons/day	Condensers and mineral oil scrubber are considered to be inherent process equipment.	0.23	GAL/TON OF SEEDS	BACT-PSD	U
MO-0082	ARCHER DANIELS MIDLAND-MEXICO	10/5/2010	SOYBEAN OIL EXTRACTION	2100	T/D	USE OF CONDENSATION FOR SOLVENT RECOVERY AND UNCONDENSED VAPORS ROUTED TO A MINERAL OIL ABSORBER. SOLVENT STORAGE - BREATHING AND WORKING LOSSES ROUTED TO SOLVENT RECOVERY SYSTEM. PROCESS, FUGITIVE - LDAR PROGRAM	0.15	GALLONS/TON	BACT-PSD	U
MO-0082	ARCHER DANIELS MIDLAND-MEXICO	10/5/2010	DUAL-FIRED 85.6 MMBTU/HR WATER-TUBE BOILER	85.6	MMBTU/H	GOOD COMBUSTION PRACTICES	0.0055	LB/MMBTU	BACT-PSD	U
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Biodiesel Plant	60	MMGal/yr	Leak Detection and Repair (LDAR) for the biodiesel production processes that meet the requirements of 40 CFR Part 60, Subpart VV	0	-	BACT-PSD	U
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Methanol Storage Tanks	0	-	Breathing losses from storage tanks controlled by nitrogen blanketing. Working losses controlled during truck or railcar unloading by use of	0	-	BACT-PSD	U

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
						a vapor balance system.				
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Two 95 MMBtu/hr boilers	95	MMBTU/H	-	0.0164	LB/MMBTU	BACT-PSD	U
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Extractor and Desolventizing-Toasting	0	-	The extraction system is controlled by condenser(s) and a mineral oil absorber with chiller system. The desolventizer-toaster is controlled by evaporator(s), conderser(s) and then to the mineral oil absorber system.	0.056	LB/TON OF SOYBEANS	BACT-PSD	U
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Soybean Processing Operations	3000	T/D	LDAR program for the soybean processing operations.	0.145	GAL/TON OF OILSEED	BACT-PSD	U
MO-0081	AMERICAN ENERGY PRODUCERS, INC.	1/22/2009	Condensation/Scrubbing System for Biodiesel Production Processes	0	-	The vapor outlet of the rectification vent condenser shall be routed to the soy oil scrubber and water scrubber. The vapor outlets of the glycerine methanol stripper and biodiesel methanol stripper shall be ducted to the condensation/scrubber system.	70	DEG F	BACT-PSD	U
IA-0096	VERASUN CHARLES CITY, LLC	11/18/2008	DTDC STACK, DESOLVENTIZER TOASTER, DRYER/COOLER	1300	T/D	MOS SYSTEM	0.7	GAL SOLVENT/T/DDGS	BACT-PSD	U

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
IA-0096	VERASUN CHARLES CITY, LLC	11/18/2008	COE VENT SYSTEM	1300	T/D	MOS SYSTEM (MINERAL OIL ABSORBER SYSTEM)	0.7	GAL SOLVENT/T DDGS	BACT-PSD	U
IA-0096	VERASUN CHARLES CITY, LLC	11/18/2008	COE BOILER	50	MMBTU/H	-	0.27	LB/H	BACT-PSD	U
NE-0048	ARCHER DANIELS MIDLAND - FREMONT	10/29/2008	SOYBEAN OIL EXTRACTION	-	-	USE OF MINERAL OIL SCRUBBER, LEAK DETECTION AND REPAIR PROGRAM	0.165	LB/T	Other Case-by-Case	U
IA-0094	ARCHER DANIELS MIDLAND	4/7/2008	DESOLVENTIZER/TOASTER	250	T/YR	MINERAL OIL ABSORBER	0.1712	GAL/T	BACT-PSD	N
AR-0097	RICELAND FOODS, INC - SOY DIVISION	3/12/2008	RICE BRAN OIL EXTRACTION	-	-	MINERAL OIL SEPERATOR	1.98	LB/T SEED	BACT-PSD	U

Appendix 2
Public Notice

Appendix 3
Listing of Entities and Documents To be Sent

NEWSPAPER	Mr. Alan Wells Duplin Times/Progress Sentinel 102 Front Street Kenansville, NC 28349 (910) 296-0239 awells@ncweeklies.com	Public Notice
OFFICIALS	Mr. Mike Aldridge Manager, Duplin County Duplin County Administration Office 224 Seminary Street P. O. Box 910 Kenansville, NC 28349 (910) 296-2100	Public Notice
SOURCE	Steve Lester General Manager Valley Proteins, Inc. – Rose Hill Division P. O. Box 1026 Rose Hill, NC 28458 (540) 877-2590	Application Review, Draft Permit & Public Notice
EPA	Ms. Heather Ceron Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, Georgia 30303-3104 (404) 562-9185	Application Review, Draft Permit & Public Notice
	Application Review, Draft Permit, and Public Notice, via electronic mail to: ceron.heather@epa.gov with cc to: shepherd.lorinda@epa.gov	
FLM	Ms. Jill Webster Branch of Air and Water Resources US Fish and Wildlife Service 7333 W. Jefferson Avenue, Suite 375 Lakewood, CO 80235-2017 (303) 914-3804	None
WILMINGTON REGIONAL OFFICE	Mr. Brad Newland NC DAQ Air Quality Regional Supervisor 127 Cardinal Drive Extension Wilmington, NC 28405 (910) 796-7215	Application Review, Draft Permit & Public Notice