ONEOK
HYDROCARBON
A SUBSIDIARY OF ONEOK PARTNERS

January 5, 2016

Ms. Melanie Magee
Environmental Engineer
Air Permits Section (6PD-R)
United States Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, TX 75202

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AIR PERMITS SECTION
6PD-R

Re: ONEOK Hydrocarbon, L.P.
Mont Belvieu NGL Fractionation Plant, Frac-2 Unit
Chambers County, Texas
Rescission Request for Permit PSD-TX-106921-GHG

Dear Ms. Magee:

ONEOK Hydrocarbon, L.P. ("ONEOK") respectfully submits this request to rescind the above-referenced Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") permit. This permit was issued by the U.S. Environmental Protection Agency ("EPA") solely because project GHG emissions were above the PSD major source threshold. The project did not result in a PSD-significant increase of any other criteria pollutant. Per the U.S. Supreme Court decision in *UARG v. EPA*, 134 S.Ct. 2427 (2014), the U.S. Environmental Protection Agency's ("EPA") regulatory program to require a PSD or Title V Permit for sources considered major sources only for their potential to emit GHGs alone violated the Clean Air Act. In response, and following remand proceedings at the U.S. Circuit Court of Appeals for the District of Columbia, EPA issued its May 7, 2015 direct final rule which modified 40 CFR §52.21(w)(2)(iii) to read:

> *(w)(2) Any owner or operator of a stationary source or modification who holds a permit for the source or modification may request that the Administrator rescind the permit or a particular portion of the permit if the permit for the source or modification was issued: (iii) Under § 52.21 between July 1, 2011 and July 6, 2015 for a modification that was classified as a major modification under paragraph (b)(2) solely on the basis of an increase in emissions of greenhouse gases, which were defined as a regulated NSR pollutant through the application of paragraph (b)(49)(v)(b) of this section as in effect during this time period.*

Permit No. PSD-TX-106921-GHG was issued on July 23, 2013. Project emissions of non-GHG criteria pollutants were authorized under TCEQ Permit No. 106921, issued on July 25, 2013.

pollutants for the new unit being authorized (the Frac-2 Unit). Attachment B includes a copy of TCEQ's technical review for Permit No. 106921 which summarizes the total project emissions increase and documents that the project was not a major modification for any non-criteria pollutants. Attachment C includes EPA's Statement of Basis for Permit No. PSD-TX-106921-GHG, dated May, 2013.

I hereby assert to EPA that the EPA Region 6-issued GHG PSD permit is not used, or planned to be used, for any other regulatory or compliance and enforcement purposes and that the information contained in this rescission submittal is factual and correct.

If you have any questions or need any additional information during the course of your review please do not hesitate to contact Ms. Terrie Blackburn at (918) 561-8052 or by email at Terrie.Blackburn@oneok.com.

Sincerely,

Scott Schingen
Vice President – NGL Fractionation and Storage

Attachments

ATTACHMENT A

ISSUED TCEQ PERMIT NO. 106921

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

July 25, 2013

MR SCOTT SCHINGEN
VICE PRESIDENT NGL FRACTIONATION AND STORAGE
ONEOK HYDROCARBON LP
100 W 5TH ST
TULSA OK 74103-4279

Re: Permit Application
Permit Number: 106921
Mont Belvieu NGL Fractionation Unit
Mont Belvieu, Chambers County
Regulated Entity Number: RN106123714
Customer Reference Number: CN603674086

Dear Mr. Schingen:

This is in response to your Form PI-1 (General Application for Air Preconstruction Permits and Amendments) concerning the above-referenced facility. Also, this will acknowledge that your application for the above-referenced permit is technically complete as of June 12, 2013.

A permit for your new facility is enclosed. The permit contains several general and special conditions that define the level of operation, a maximum allowable emission rates table (MAERT), and a permit face. We appreciate your careful review of the special conditions of the permit and assuring that all requirements are consistently met. In addition, the construction and operation of the facilities must be as represented in the application.

Planned maintenance, startup, and shutdown for the sources identified on the MAERT have been reviewed and included in the MAERT and specific maintenance activities are identified in the permit special conditions. Any other maintenance activities are not authorized by this permit and will need to obtain separate authorization.

This permit will be automatically void upon the occurrence of any of the following, as indicated in Title 30 Texas Administrative Code § 116.120(a) [30 TAC § 116.120(a)]:

1. Failure to begin construction within 18 months of the date of issuance,

2. Discontinuance of construction for more than 18 months prior to completion, or

3. Failure to complete construction within a reasonable time.

Upon request, the executive director may grant extensions as allowed in 30 TAC § 116.120(b).

Re: Permit Number: 106921

This permit is effective as of the date of this letter and will be in effect for ten years from the date of approval.

You may file a **motion to overturn** with the Chief Clerk. A motion to overturn is a request for the commission to review the executive director's decision. Any motion must explain why the commission should review the executive director's decision. According to 30 TAC § 50.139, an action by the executive director is not affected by a motion to overturn filed under this section unless expressly ordered by the commission.

A motion to overturn must be received by the Chief Clerk within 23 days after the date of this letter. An original and 11 copies of a motion must be filed with the Chief Clerk in person, or by mail to the Chief Clerk's address on the attached mailing list. On the same day the motion is transmitted to the Chief Clerk, please provide copies to the applicant, the executive director's attorney, and the Public Interest Counsel at the addresses listed on the attached mailing list. If a motion to overturn is not acted on by the commission within 45 days after the date of this letter, then the motion shall be deemed overruled.

You may also request **judicial review** of the executive director's approval. According to Texas Health and Safety Code § 382.032, a person affected by the executive director's approval must file a petition appealing the executive director's approval in Travis County district court within 30 days after the **effective date of the approval**. Even if you request judicial review, you still must exhaust your administrative remedies, which includes filing a motion to overturn in accordance with the previous paragraphs.

Thank you for your cooperation and interest in air pollution control. If you need further information or have any questions, please contact Mr. Rick Goertz, P.E. at (512) 239-5606 or write to the Texas Commission on Environmental Quality, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

Re: Permit Number: 106921

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/rg

Enclosure

cc: Mr. Jason Graves, P.E., Waid Environmental, League City
Air Section Manager, Region 12 - Houston

Project Number: 185336

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
ONEOK Hydrocarbon, L.P.
Authorizing the Construction and Operation of
Mont Belvieu NGL Fractionation Unit
Located at **Mont Belvieu, Chambers County, Texas**
Latitude 29° 51′ 30″ Longitude 94° 53′ 24″

Permit: 106921

Issuance Date : July 25, 2013

Renewal Date: July 25, 2023

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates**. The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)]
9. **Maintenance of Emission Control**. The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules**. Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.

Special Conditions

Permit Number 106921

1. This permit authorizes natural gas fractionation operations for a facility located at 1802 N Loop 207, Mont Belvieu, Chambers County, Texas.

   This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits and other conditions specified in that table.

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions.

<u>Federal Applicability</u>

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A, General Provisions.

   B. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   D. Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

4. These facilities shall comply with all applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

   A. Subpart A, General Provisions.

   B. Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

5. If any condition of this permit is more stringent than the applicable regulations in Special Condition Nos. 3 and 4, then for the purposes of complying with this

permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Emission Standards and Operational Specifications

6. A. Unless otherwise stated, all process vent streams shall be routed to one of the Hot Oil Heaters (EPNs H-04, H-05, and H-06) for control of emissions. The hot oil heaters shall achieve a minimum destruction efficiency of 99% for Volatile Organic Compounds (VOC) and Hydrogen Sulfide (H_2S).

B. Heaters shall be fired with natural gas or a combination of natural gas and vent stream waste gas.

C. Natural gas shall contain no more than 0.25 grains of total sulfur per 100 dry standard cubic feet (dscf). The natural gas shall be sampled every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

D. Except as specified in Special Condition 28, the hot oil heaters (EPNs H-04, H-05, and H-06) shall be controlled using Selective Catalytic Reduction.

E. Except as specified in Special Condition 28, Nitrogen Oxides (NO_x), Carbon Monoxide (CO), and ammonia (NH_3) concentrations from the hot oil heaters (EPNs H-04, H-05, and H-06) shall not exceed the following emission limits. The following emission limits shall apply during normal operation and during periods of standby or turndown:

0.01 lb NOx/MMBtu on an hourly average
50 ppmvd CO corrected to 3 percent oxygen on an hourly average
10 ppmvd NH_3 corrected to 3 percent oxygen on an hourly average

F. Each Hot Oil Heater is limited to a maximum firing rate of 154 MMBtu/hr and an annual firing rate of 1,350,000 MMBtu/yr.

7. A. The owner or operator shall determine the total reduced sulfur concentration from the gas streams combusted in the hot oil heater as follows:

1. Samples shall be collected weekly and analyzed as described in paragraph B below for each vent gas stream routed to a process heater for combustion. Vent streams that are mixed prior to combustion may be sampled after mixing. A sample point that is representative of the composition being combusted in more than one heater may be used for each heater to which that stream is vented.

2. Sample and analysis shall be completed using one of the following reference methods:

a. ASTM D1072 -06 (2012) Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration

b. ASTM D7551 – 10 Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases and Natural Gas by Ultraviolet Fluorescence.

c. ASTM D5504 – 12 Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence.

d. ASTM D6667 –Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence.

e. ASTM D3246 – 11 Standard Test Method for Sulfur Compounds in Petroleum Gas by Oxidative Microcoulometry.

f. Any other method approved by the TCEQ Executive Director or the TCEQ Regional Director. The method must be approved by the TCEQ Executive Director or TCEQ Regional Director prior to use.

3. Samples shall be taken as follows:

a. Weekly. After three consecutive months of samples have been collected, the sampling frequency may be reduced to monthly if all results are within 25% of the mean.

b. If at any time the total reduced sulfur concentration sampled indicates SO_2 emissions within 20% of the hourly MAERT limit, sampling for total reduced sulfur shall be repeated every 24 hours until the measured concentration results in

SO_2 emissions below 80% of the maximum hourly MAERT limit.

c. Upon notification of an increase of more than 25 ppm in total sulfur in the feed stream (above levels previously demonstrated to show compliance with MAERT limits) from the supplier, daily samples shall be taken for the first 7 days the stream is received after notification.

B. Results from the monitoring of total reduced sulfur shall be used to determine compliance with the emission rates specified in the MAERT.

C. Records shall include the date of the sample, sampling results, calculated SO_2 emissions, and notifications of change in feed stream sulfur content received from the supplier. Records shall be kept for a period of 5 years.

8. Storage tank throughput and service shall be limited to the following:

Tank	Service	Maximum Fill Rate (gallons/hour)	Rolling 12 Month Throughput (gallons)
T-410-2	Spent Caustic	6,637	433,128
T-630-2	Wastewater	7,000	126,936

9. Storage tanks are subject to the following requirements:

A. Uninsulated tank exterior surfaces exposed to the sun shall be white or aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

B. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for each tank.

10. Emissions from storage tanks storing spent caustic or process wastewater shall be minimized by one of the following methods.

   A. Emissions shall be vented to a Carbon Adsorption System meeting the requirements of Special Condition 15.

   B. Minimize the VOC partial pressure.

      (1) Low partial pressure liquid that is soluble with the VOC liquid previously stored may be added to lower the VOC partial pressure of the hydrocarbon mixture remaining in the tank to less than or equal to 0.02 psia. This liquid shall be added prior to initial fill and to reduce the vapor pressure of the liquid mixture as needed.

      (2) The hydrocarbon layer shall be sampled once per month to determine the VOC partial pressure of the hydrocarbon mixture.

      (3) The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12 month period. The record shall include tank identification number, tank capacity in gallons, name of the material stored, the estimated volume of VOC liquid in the tank and the volume and type of VOC liquid added to reduce vapor pressure, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, results of sampling per Special Condition 10.B(2) and all calculations used to determine VOC vapor pressure at the monthly average material temperature, VOC throughput for the previous month and year-to-date.

      (4) Compliance with short term VOC emission rates shall be demonstrated each month using the VOC partial pressure as specified in paragraph (2) of this condition.

11. Pressure tanks shall be maintained such that there are no emissions of VOC to the atmosphere during normal operating conditions (including filling operations).

12. The permit holder shall maintain prevention and protection measures for the NH_3 storage system which includes the following:

   A. The NH_3 storage tank area will be marked and secured so as to protect the NH_3 storage tank from accidents that could cause a rupture.

B. The permit holder shall maintain the piping and valves in NH_3 service as follows:

(1) Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made once per day.

(2) As soon as practicable, following the detection of a leak, plant personnel shall take one or more of the following actions:

(a) Locate and isolate the leak, if necessary.

(b) Commence repair or replacement of the leaking component.

(c) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

13. A. Loading operations are limited to the liquids identified below at the rates indicated.

Liquid	Maximum Loading Rate (gallons per Hour)	Annual Loading Rate (gallons per year)
Spent Caustic	7,560	433,128
Wastewater	7,560	126,936

B. All loading shall be submerged and rolling 12 month rack throughput records shall be updated on a monthly basis for each product loaded.

C. All lines and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.

14. Flares shall be designed and operated in accordance with the following requirements:

A. The flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions.

The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements.

B. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Infrared monitors shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. This shall be ensured by the use of air assist to the flare.

D. The permit holder shall install a continuous flow monitor and composition analyzer that provide a record of the vent stream flow and composition (total VOC or Btu content) to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour.

The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg;

If VOC monitored, calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000 (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR §60.18(f)(3) as amended through October 17, 2000 (65 FR 61744).

If a calorimeter used, the calorimeter shall be calibrated, installed, operated, and maintained, in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare, in British thermal units/standard cubic foot of the gas.

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12 month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §60.18(f)(4) shall be recorded at least once every 15 minutes. If a VOC monitor is used, hourly mass emission rates shall be determined and recorded using the above readings and the emission factors used in the permit application PI-1 dated November 15, 2012.

E. Pilot and sweep gas shall be sweet natural gas containing no more than 0.25 grains of total sulfur per 100 dry standard cubic feet.

15. When using a carbon system as a control option, the spent caustic and wastewater tanks (EPNs T-410-2 and T-630-2) shall vent through a carbon adsorption system (CAS) consisting of at least two activated carbon canisters that are connected in series.

A. The CAS shall be sampled weekly to determine breakthrough of volatile organic compounds (VOC). The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sampling shall be performed while the tank is being filled with spent caustic or wastewater.

B. The VOC sampling and analysis shall be performed using an instrument with a flame ionization detector (FID), or a TCEQ-approved alternative detector. The instrument/FID must meet all requirements specified in Section 8.1 of EPA Method 21 (40 CFR 60, Appendix A). Sampling and analysis for VOC breakthrough shall be performed as follows:

(1) Immediately prior to performing sampling, the instrument/FID shall be calibrated with zero and span calibration gas mixtures. Zero gas shall be certified to contain less than 0.1 ppmv total hydrocarbons. Span calibration gas shall be methane at a concentration within ± 10 percent of 100 ppmv, and certified by the manufacturer to be ± 2 percent accurate. Calibration error for the zero and span calibration gas checks must be less than ± 5 percent of the span calibration gas value before sampling may be conducted.

(2) The sampling point shall be at the outlet of the initial canister but before the inlet to the second or final polishing canister. Sample ports

or connections must be designed such that air leakage into the sample port does not occur during sampling.

(3) During sampling, data recording shall not begin until after two times the instrument response time. The VOC concentration shall be monitored for at least 5 minutes, recording 1-minute averages, during tank filling.

C. Breakthrough shall be defined as the highest 1 minute average measured VOC concentration at or exceeding 100 ppmv. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within 24 hours. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

D. Records of the CAS monitoring maintained at the plant site, shall include (but are not limited to) the following:

(1) Sample time and date.
(2) Monitoring results (ppmv).
(3) Corrective action taken including the time and date of that action.
(4) Process operations occurring at the time of sampling.

E. Alternate monitoring or sampling requirements that are equivalent or better may be approved by the TCEQ Regional Manager. Alternate requirements must be approved in writing before they can be used for compliance purposes

16. The firewater pump diesel engine (EPN ENG-06) and emergency generator (EPN ENG-05) are authorized to fire diesel fuel containing not more than 15 ppmw total sulfur and are each limited to a maximum of 100 non-emergency hours of operation annually and a maximum of two non-emergency hours of operation per day. Records kept shall include the Emission Point Number, the date of the non-emergency operation, and the event duration. Records shall be kept for a period of 5 years.

<u>Cooling Towers</u>

17. A. Cooling towers shall be equipped with drift eliminators with a drift rate of 0.001%.

B. The VOC associated with cooling tower water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method. The results of the monitoring, cooling water flow rate, and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly VOC emissions. The rolling 12 month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12 month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the 2 VOC monitored results.

C. Cooling water shall be sampled once a week for concentrations of total dissolved solids (TDS). 40% of the dissolved solids in the cooling water drift are considered to be emitted as PM_{10}. 10% of the dissolved solids in the cooling water drift are considered to be emitted as $PM_{2.5}$. The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, and SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water].

Cooling water shall either be sampled once a day for conductivity and analyzed using ASTM D1125-95A and SM 2510B [SA – 19th edition of Standard Methods for Examination of Water], or shall be continuously monitored for conductivity. Use of an alternative sampling method shall be approved by the TCEQ Regional Director prior to its implementation. Quality-assured (or valid) data must be generated when the cooling tower is operating except during the performance of a daily zero check. Loss of valid data due to periods of monitor breakdown, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided the total data loss period does not exceed 5 percent of the time (in hours) that the cooling tower operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

The TDS and conductivity data shall result from sampling or monitoring the cooling tower return stream (i.e., water stream routed to the tower for cooling), and represent the water being cooled in the tower. Water samples should be capped upon collection, and transferred to a laboratory area for analysis.

D. The permit holder may reduce the frequency of TDS sampling required by paragraph B of this condition by establishing a valid correlation between TDS and conductivity for the cooling tower as follows:

1. The sampling and analysis required by paragraph B of this condition (i.e., frequency of sampling for TDS and conductivity) shall be conducted as specified until a valid correlation is established between TDS and conductivity.

2. For a minimum period of six months, the cooling water shall be sampled at least weekly for analysis of TDS and conductivity. The data from the TDS and conductivity measurements shall be plotted, with a total range of two standard deviations (plus and minus one standard deviation) applied to the resulting plot. A report including the data analysis results and the correlation established between TDS concentrations and conductivity shall be maintained on site.

3. Following completion of the report, the cooling water may either be sampled daily or monitored continuously for conductivity, and the result converted to TDS with the use of the established correlation.

4. The correlation shall be re-validated annually with the analysis of a single cooling water sample for TDS and conductivity. The measured TDS value shall be compared to the correlation TDS value (i.e., the TDS value derived from the measured conductivity and the established correlation). If the measured TDS value is not within plus or minus one standard deviation of the correlation TDS value, a new correlation shall be developed according to paragraph B. of this condition.

E. Cooling tower PM emissions shall be determined using the cooling tower water circulation rate, cooling tower design drift, and the measured or estimated TDS

18. Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. The requirements of paragraphs F and G shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68EF or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);
(2) a written or electronic database or electronic file;
(3) color coding;
(4) a form of weatherproof identification; or
(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section

8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

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19. In addition to the weekly physical inspection required by Item E of Special Condition 18, all accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition 18.

A. Connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

B. The percent of connectors leaking used in paragraph A shall be determined using the following formula:

(Cl + Cs) x 100/Ct = Cp

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period.

Initial Demonstration of Compliance

20. The permit holder shall perform stack sampling and other testing as required to demonstrate compliance with the destruction efficiency specified in Special Condition 6 and establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the hot oil heaters (EPNs H-04, H-05, and H-06) to demonstrate compliance with the MAERT. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods.

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60) testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

(1) Proposed date for pretest meeting.
(2) Date sampling will occur.
(3) Name of firm conducting sampling.
(4) Type of sampling equipment to be used.
(5) Method or procedure to be used in sampling.
(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.
(7) Procedure/parameters to be used to determine worst case emissions during the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Air contaminants emitted from the hot oil heaters (EPNs H-04, H-05, and H-06) to be tested for include (but are not limited to) NO_x, CO, VOC, and NH_3.

C. Sampling shall occur within 60 days after achieving the maximum firing rate, but no later than 180 days after initial start-up of the facilities and at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

D. The facility being sampled shall operate at the maximum firing rate and be fired with both natural gas and process vent gas during stack emission testing. These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the firing rate is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

E. Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled "Chapter 14, Contents of Sampling Reports" of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One set of copies to the appropriate TCEQ Regional Office.
One set of copies to each local air pollution control program.

21. Sampling ports and platform(s) shall be incorporated into the design of the hot oil heaters (EPNs H-04, H-05, and H-06) according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities" of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director

Continuous Demonstration of Compliance

22. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of NO_x, CO, and NH_3 from the hot oil heaters (EPNs H-04, H-05, and H-06).

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional

Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

(2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is **not** required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of $\pm$15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to 1-hour average concentrations at least once everyday, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in the MAERT and Special Condition 6 at least once every week as follows:

Emissions calculations based on measured concentrations and exhaust flow rate shall be used to convert the 1-hour average concentration from the CEMS to lb/MMBtu, ppmvd, and lb/hr to demonstrate compliance with the NOx, CO, and NH_3 emission limits in Special Condition 6 and the MAERT. Exhaust flow rate may be monitored directly or calculated by monitoring fuel flow during testing and using EPA Test Method 19.

The permit holder shall install and operate a fuel flow meter to measure the natural gas and vent gas usage for each heater. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A

D. All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the hot oil heater is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the hot oil heater operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

<u>Maintenance, Start-up, and Shutdown</u>

23. Planned startup and shutdown emissions due to the activities identified in Special Condition 24 are authorized from facilities and emission points identified in this permit provided the facility and emissions are compliant with the respective MAERT and special conditions, or Special Condition 28 of this permit.

24. This permit authorizes the emissions from the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment B) attached to this permit.

    Routine maintenance activities, as identified in Attachment A may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment A shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

    The performance of each planned MSS activity not identified in Attachment A and the emissions associated with it shall be recorded and include at least the following information:

A. the process unit at which emissions from the MSS activity occurred, including the emission point number and common name of the process unit;

B. the type of planned MSS activity and the reason for the planned activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

D. the date and time of the MSS activity and its duration;

E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

25. Process units and facilities, with the exception of those identified in Special Condition 27 shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel or closed liquid recovery system unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC concentration following controlled depressurization. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

(1) For MSS activities identified in Attachment A, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures.

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable-VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 26. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. If there is not a connection (such as a sample, vent, or drain valve)

available from which a representative sample may be obtained, a sample may be taken upon entry into the system after degassing has been completed. The sample shall be taken from inside the vessel so as to minimize any air or dilution from the entry point. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or 10 percent of the LEL. Documented site procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above.

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lb of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition 25.E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order or equivalent for those planned MSS activities identified in Attachment A.

26. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor (RF) of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate (RF) shall be recorded. If the RF of the VOC (or mixture of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows:

VOC Concentration = Concentration as read from the instrument*RF

In no case should a calibration gas be used such that the RF of the VOC (or mixture of VOCs) to be monitored is greater than 5.0.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes, recording VOC concentration each minute. As an alternative the VOC concentration may be monitored over a five-minute period with an instrument designed to continuously measure concentration and record the highest concentration read. The highest measured VOC concentration shall be recorded and shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured as defined in (3) is less than 80 percent of the range of the tube and is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000*mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit measured with a lower explosive limit detector.

(1) The detector shall be calibrated within 30 days of use with a certified pentane gas standard at 25% of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use with a certified gas standard at 25% of the LEL for pentane. The LEL monitor shall read no lower than 90% of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 25% of the LEL for pentane may be used for calibration and functionality tests provided that the LEL response is within 95% of that for pentane.

27. The following requirements apply to fixed roof storage tanks.

A. The tank shall not be opened or ventilated without control, except as allowed by i below until one of the criteria in part B of this condition is satisfied.

(1). Minimize air circulation in the tank vapor space.

a. One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. Other manways or access points may be opened as necessary to remove or de-volatilize the remaining liquid. Wind barriers shall be installed at all open manways and access points to minimize air flow through the tank.

b. Access points shall be closed when not in use

B. The tank may be opened without restriction and ventilated without control, after all standing liquid has been removed from the tank or the liquid remaining in the tank has a VOC partial pressure less than 0.02 psia. These criteria shall be demonstrated in any one of the following ways.

(1). Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2). If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated:

a. Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A Appendix 1.

b. Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 26.

(3). No standing liquid verified through visual inspection.

(4). The permit holder shall maintain records to document the method used to release the tank.

C. If the ventilation of the vapor space is controlled, the emission control system shall meet the requirements of i through v. Controlled degassing of the vapor space shall be completed as follows:

(1). Any gas or vapor removed from the vapor space must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 10,000 ppmv or 10 percent of the LEL. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space when degassing to the control device or controlled recovery system.

(2). The vapor space shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design.

(3). A volume of purge gas equivalent to twice the volume of the vapor space must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of purge gas volume shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition 26.

(4). The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

D. Records shall be maintained as follows.

(1). for the purpose of estimating emissions, the date, time, and other information specified for each of the following events:

a. start and completion of controlled degassing, and total volumetric flow,

b. all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,

c. if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow;

(2). the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between events a with the data and methods used to determine it.

28. All permanent facilities must comply with all operating requirements, limits, and representations during planned startup and shutdown unless alternate requirements and limits are identified in this permit. Alternate requirements for emissions from routine emission points are identified below.

A. Combustion units, with the exception of flares, at this site are exempt from NOx and CO operating requirements identified in special condition 6.E during planned startup and shutdown if the following criteria are satisfied.

(1) The maximum allowable emission rates in the permit authorizing the facility are not exceeded.

(2) The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 8 hours.

(3) Control devices are started and operating properly when venting a waste gas stream.

B. The limits identified below apply to the operations of the specified facilities during startup and shutdown.

(1) The following applies to hot oil heaters (EPNs H-04, H-05, and H-06).

(a) NOx and CO concentrations from the hot oil heaters (EPNs H-04, H-05, and H-06) during planned startups shall not exceed 0.05 lb NOx/MMBtu on an hourly average and 400 ppmvd CO corrected to 3 percent oxygen on an hourly average. Startup is defined as the period that begins when fuel is introduced to the furnace and ends when the SCR catalyst bed reaches operating temperature.

(b) Condition 28.B(1)(a) does not apply to the hot oil heaters during periods of turndown or standby. For purposes of this permit, turndown or standby is defined as any operating condition below 20% of the maximum firing rate that is not part of a start-up or shutdown.

(d) Unit shutdown begins with the firing rate falls below 60 % of the maximum firing rate and shall not exceed 8 hours.

(2) The higher emission limits idenfied in Special Condition 18.B(1)(a) from planned start-up or shutdown of the hot oil heaters are limited to emissions from no more than two of the heaters occurreing simultaneously.

C. A record shall be maintained indicating that the start and end times of each of the activities identified above occur and documentation that the requirements for each have been satisfied.

Additional Requirements

29. Within 180 days after the start of operation, the permit holder shall submit the appropriate application updating the representation to reflect the as-built facility

30. The following sources and/or activities are authorized under a Standard Permit (SP) by Title 30 Texas Administrative Code Chapter 116 (30 TAC Chapter 116) for the Frac-1 fractionation plant. These lists are not intended to be all inclusive and can be altered without modifications to this permit.

Authorization	Source or Activity
SP No. 95807 (Effective May 25, 2011)	Hot Oiler Heaters, Flare, Cooling Tower, Tanks, Loading, Emergency Engines, and Maintenance, Start-up, and Shutdown Activities.

Dated: July 25, 2013

Permit 106921
Attachment A
ROUTINE MAINTENANCE ACTIVITIES

Pump repair/replacement
Fugitive component (valve, pipe, flange) repair/replacement
Compressor repair/replacement
Heat exchanger repair/replacement
Vessel repair/replacement

Dated: July 25, 2013

Permit 106921
Attachment B
MSS ACTIVITY SUMMARY

Facilities	**Description**	**Emissions Activity**	**EPN**
all process vessels	process unit depressurize/drain/degas	vent to flare	FL-01
all process vessels	opening	vent to atmosphere	MSS-FUG2
tanks	Draining/opening	vent to atmosphere	MSS-FUG2
Heaters	Start up and Shutdown	vent to atmosphere	H-04, H-05, H-06
Attachment A	Degas	vent to Flare	FL-01
Attachment A	Opening	vent to atmosphere	MSS-FUG2

Dated: July 25, 2013

Emission Sources - Maximum Allowable Emission Rates

Permit Number 106921

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
ENG-05	Frac-2 Emergency Generator	VOC	0.89	0.05
		NO_x	0.89	0.05
		CO	0.77	0.04
		SO_2	<0.01	<0.01
		PM	0.04	<0.01
		PM_{10}	0.04	<0.01
		$PM_{2.5}$	0.04	<0.01
ENG-06	Frac-2 Firewater Pump	VOC	3.80	0.19
		NO_x	3.80	0.19
		CO	3.30	0.17
		SO_2	0.01	<0.01
		PM	0.19	0.01
		PM_{10}	0.19	0.01
		$PM_{2.5}$	0.19	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
H-04	Hot Oil Heater 4 (6)	VOC	0.48	-
		NO_x	1.54	-
		CO	5.76	-
		SO_2	10.21	-
		H_2S	0.02	-
		NH_3	0.71	-
		PM	0.77	-
		PM_{10}	0.77	-
		$PM_{2.5}$	0.77	-
	Heater MSS Emissions (6)	NO_x	7.68	-
		CO	46.10	-
H-05	Hot Oil Heater 5 (6)	VOC	0.48	-
		NO_x	1.54	-
		CO	5.76	-
		SO_2	10.21	-
		H_2S	0.02	-
		NH_3	0.71	-
		PM	0.77	-
		PM_{10}	0.77	-
		$PM_{2.5}$	0.77	-
	Heater MSS Emissions (6)	NO_x	7.68	-
		CO	46.10	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
H-06	Hot Oil Heater 6 (6)	VOC	0.48	-
		NO_x	1.54	-
		CO	5.76	-
		SO_2	10.21	-
		H_2S	0.02	-
		NH_3	0.71	-
		PM	0.77	-
		PM_{10}	0.77	-
		$PM_{2.5}$	0.77	-
	Heater MSS Emissions (6)	NO_x	7.68	-
		CO	46.10	-
H-04/H-05/H-06	Hot Oil Heater Cap	VOC	-	4.45
		NO_x	-	18.45
		CO	-	69.12
		SO_2	-	35.02
		H_2S	-	0.10
		NH_3	-	8.49
		PM	-	9.21
		PM_{10}	-	9.21
		$PM_{2.5}$	-	9.21
	Heater MSS Emissions (6)	NO_x	-	0.34
		CO	-	2.02

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
Fl-01	Flare (Frac-2)	VOC	0.01	0.06
		NO_x	0.35	1.50
		CO	1.40	6.10
		SO_2	<0.01	0.01
CT-04	Frac-2 Cooling Tower	VOC	2.53	4.71
		PM	1.50	6.57
		PM_{10}	0.60	2.63
		$PM_{2.5}$	0.15	0.66
T-410-2	Spent Caustic Tank (Frac-2)	VOC	0.41	0.01
		H_2S	<0.01	0.01
T-630-2	Wastewater Tank (Frac-2)	VOC	0.43	<0.01
CAS1	Controlled Emissions from Spent Caustic Tank (EPN T-410-2)	VOC	0.02	<0.01
CAS2	Controlled Emissions from Wastewater Tank (EPN T-630-2)	VOC	0.03	<0.01
LOAD-SC	Spent Caustic Loading (Frac-2)	VOC	0.09	<0.01
LOAD WW	Wastewater Loading (Frac-2)	VOC	0.09	<0.01
FUG-03	Frac-2 Equipment Leak Fugitives (5)	VOC	0.86	3.78
FL-01	MSS Flaring (Frac-2)	VOC	175.01	2.16
		NO_x	39.41	1.97
		CO	336.40	10.13
		SO_2	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
MSS-FUG-2	MSS Opening (Frac-2)	VOC	86.70	3.25
		NH_3	0.24	<0.001

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
H_2S - Hydrogen Sulfide
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
NH_3 - ammonia
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Annual Emissions represent combined annual emissions from heaters H-04, H-05, and H-06.

Date: July 25, 2013

ATTACHMENT B

TCEQ TECHNICAL REVIEW FOR PERMIT NO. 106921

Construction Permit

Source Analysis & Technical Review

Company	**ONEOK Hydrocarbon, L.P.**	Permit Number	**106921**
City	**Mont Belvieu**	Project Number	**185336**
County	**Chambers**	Account Number	**N/A**
Project Type	**Initial**	Regulated Entity Number	**RN106123714**
Project Reviewer	**Mr. Rick Goertz**	Customer Reference Number	**CN603674086**
Site Name	**Mont Belvieu NGL Fractionation Unit**		

Project Overview

Oneok Hydrocarbon L.P. (Oneok) owns and operates the Mont Belvieu Natural Gas Liquids (NGL) fractionation plant located in Mont Belvieu, Chambers County, Texas. In response to the rapidly growing demand for natural gas liquids fractionation, Onoek is submitting an application to authorize the expansion of the existing facility authorized by Standard Permit number 95807 to accommodate an additional 75,000 barrel per day (Y-grade) fractionation plant (frac-2) to treat and fractionate a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutene, normal butane, and natural gasoline.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)	Project Changes at Major Sources (Baseline Actual to Allowable)
PM	0	15.80	15.80	15.80
PM_{10}	0	11.86	11.86	11.86
$PM_{2.5}$	0	9.89	9.89	9.89
VOC	0	18.71	18.71	18.71
NO_X	0	22.50	22.50	22.50
CO	0	87.58	87.58	87.58
SO_2	0	35.06	35.06	35.06
HAPs	0	0.11	0.11	0.11

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	**May 13, 2013**
Compliance period:	**September 1, 2007 to August 31, 2012**
Site rating & classification:	**NA/ Unclassified**
Company rating & classification:	**NA/ Unclassified**
If the rating is 50<RATING<55, what was the outcome, if any, based on the findings in the formal report:	**N/A**
Has the permit changed on the basis of the compliance history or rating?	**No**

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Date Application Received:	**November 15, 2012**
	Date Administratively Complete:	**November 30, 2012**
	Small Business Source?	**No**
	Date Leg Letters mailed:	**November 30, 2012**
39.603	Date Published:	**December 11, 2012**
	Publication Name:	***The Baytown Sun***
	Pollutants:	particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen oxides, sulfur dioxide, organic compounds, ammonia and hydrogen sulfide
	Date Affidavits/Copies Received:	**December 17, 2012**
	Is bilingual notice required?	**Yes**
	Language:	**Yes**
	Date Published:	**No Spanish periodical could be identified at the time notice occurred.**
	Publication Name:	***N/A***
	Date Affidavits/Copies Received:	**N/A**
	Date Certification of Sign	

	Posting / Application Availability Received:	**May 20, 2013**
39.604	Public Comments Received?	**No**
	Hearing Requested?	**No**
	Meeting Request?	**No**
	Date Response to Comments sent to OCC:	**N/A**
	Consideration of Comments:	**N/A**
	Is 2nd Public Notice required?	**Yes**
39.419	Date 2nd Public Notice/Preliminary Decision Letter Mailed:	**June 13, 2013**
39.603	Date Published:	**June 19, 2013**
	Publication Name:	***The Baytown Sun***
	Pollutants:	particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen oxides, sulfur dioxide, organic compounds, ammonia and hydrogen sulfide
	Date Affidavits/Copies Received:	**June 25, 2013**
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**June 19, 2013**
	Publication Name:	***Buena Suerte***
	Date Affidavits/Copies Received:	**June 25, 2013**
	Date Certification of Sign Posting / Application Availability Received:	**July 19, 2013**
	Public Comments Received?	**No**
	Meeting Request?	**No**
	Date Meeting Held:	**N/A**

	Hearing Request?	**No**
	Date Hearing Held:	**N/A**
	Request(s) withdrawn?	**N/A**
	Date Withdrawn:	**N/A**
	Consideration of Comments:	**N/A**
39.421	Date RTC, Technical Review & Draft Permit Conditions sent to OCC:	**N/A**
	Request for Reconsideration Received?	**N/A**
	Final Action:	**N/A**
	Are letters Enclosed?	**N/A**

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	**Requirement**	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	**Yes**
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	**Yes**
116.111(a)(2)(B)	Emissions will be measured using the following method:	**Heaters – Sampling and CEMs for NOx, CO, and NH3. Fuel sampling for Sulfur** **Storage tanks – Sampling or recordkeeping and engineering calculations** **Carbon Adsorption System (CAS)- flowrate and monitored breakthrough concentration** **Fugitives – 28VHP and CTNQ fugitive monitoring program.** **Loading – Recordkeeping and engineering calculation.**

		Cooling Towers – Sampling for VOC and total dissolved solids and conductivity. **Flare – Monitoring of flow and BTU content** **MSS – Recordkeeping and Engineering calculation.**	
	Comments on emission verification:	**None**	
116.111(a)(2)(D)	Subject to NSPS?		**Yes**
	Subparts **A** & Db, IIII, OOOO		
116.111(a)(2)(E)	Subject to NESHAP?		**No**
	Subparts &		
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?		**Yes**
	Subparts **A** & **ZZZZ**		
116.111(a)(2)(H)	**Nonattainment review applicability:**		
	The site is located in a county designated as severe nonattainment. The site is an existing minor source and project increases of VOC and NO_x do not exceed major source thresholds. Nonattainment review is not required.		
116.111(a)(2)(I)	**PSD review applicability:**		
	The site is an existing minor source and project increases of VOC, NO_x, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, and H_2S do not exceed major source thresholds. PSD review is not required.		
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?		**No**
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:		**N/A**
116.140 - 141	Permit Fee: $ **75,000**	Fee certification:	R307605

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement

122.10(13)	**Title V applicability:**
	The site is not currently a major source but will become major at the issuance of the project. No Title V permit has been issued at this time.
122.602	**Periodic Monitoring (PM) applicability:**
	The site is not a major source subject to the Title V Federal Operating Permits (Title V) program. However, periodic monitoring will be accomplished by the following; **Heaters** – Sampling and CEMs for NOx, CO, and NH3. Fuel sampling for Sulfur **Storage tanks** – Sampling or recordkeeping **CAS System** - Sampling **Fugitives** – 28VHP and CTNQ fugitive monitoring program. **Loading** – Recordkeeping **Cooling Towers** – Sampling for VOC and total dissolved solids and conductivity. **MSS** – Recordkeeping and sampling
122.604	**Compliance Assurance Monitoring (CAM) applicability:**
	The site is not currently a major source but will become major at the issuance of the project. The flare will continuously monitor flow and VOC/Btu content to demonstrate compliance with the requirements of 60.18.

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	**12**	**Corey Zindler**	**None**
City:	**Mont Belvieu**		
County:	**Chambers**		
Toxicology:			
Compliance:			
Legal:			
Comment resolution and/or			

unresolved issues:			

Process/Project Description

Onoek is submitting an application to authorize the expansion of the existing facility to accommodate an additional 75,000 barrel per day (Y-grade) fractionation plant (frac-2) to treat and fractionate a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutene, normal butane, and natural gasoline. Standard permit number 95807 is being incorporated into the permit by reference at this time.

Inlet Gas Treating

Y-Grade feed that is pretested for sulfur content by the supplier is received via pipeline, water washed, and then treated in an amine contactor to remove carbon dioxide and hydrogen sulfide required to meet customer specifications. The treated feed is sent to the Deethanizer section. The rich amine from the contactor is fed to an amine regeneration unit. The amine regeneration vent stream will be routed directly to the site's heaters and combusted. The amine regeneration flash gas stream is routed to the flare gas recovery unit (FGRU) where it is recovered and used as fuel gas in the site's heaters. Heat for the regeneration of the amine is supplied by the plant's hot oil system.

Deethanizer

The Deethanizer separates ethane as an overhead product and C3+ as a bottoms product. Heat for the unit is supplied by the hot oil system. Ethane product exits the facility via pipeline. The bottoms stream is routed to the Depropanizer for further fractionating.

Depropanizer

The Deethanizer bottoms are fed to the Depropanizer. The stream is separated into propane as an overhead product and C4+ as a bottoms product. Heat for the unit is supplied by the hot oil system. The bottoms stream is routed to the debutanizer for further processing.

Debutanizer

The Depropanizer bottoms are fed to the Debutanizer and separated into mixed C4+'s as an overhead product and natural gasoline (primarily C5+) as a bottoms product. Heat is supplied by the hot oil system. The bottoms stream (natural gasoline) is fed to a natural gasoline treating unit for treating.

Natural Gasoline Treating

The natural gasoline product streams may contain naturally occurring sulfur compounds that can be corrosive to downstream equipment and must be treated to meet customer specifications. These sulfur compounds as mercaptans are converted to disulfide oil through an oxidation process over a catalyst bed. Vent streams from the treatment process are routed directly to the site's heaters and combusted. The treated natural gasoline exits the facility via pipeline.

Utilities and Ancillary Operations

Heaters/Hot Oil System – Heat required to operate the units are supplied by three 127 MMBtu/hr hot oil heaters. The heaters are fired with sweet natural gas. The natural gas mixture is enriched with recovered gas from the FGRU. The heaters are also designed to combust vent streams from the process equipment.

Flare/FGRU – Process vent gases are collected throughout the plant and routed to the flare header. The flare header is a closed-vent system. The header collects vapors from process vent streams and relief valves. The header may also process emergency upsets and maintenance, start-up, and shutdown activities. The FRGU is composed of electric compressors that recover vapors via condensing and pump them to the deethanizer feed or to storage. Any uncondensed vapors are routed to the heaters for use as fuel. The FGRU is designed to recover the routine vent gases and the flare is designed to only combust pilot and sweep gas during routine operations.

Cooling Towers – The cooling water does not come in direct contact with the process material being cooled; however, the potential for leaks to occur is present. Residual volatile organic compounds (VOCs) entrained in the cooling water may be released to the atmosphere during the cooling process. Particulate matter due to dissolved solids in the cooling water may also be emitted in the cooling tower's drift loss.

Tanks – Spent materials, water treatment chemicals, wastewater, and other liquids will be stored in fixed roof storage tanks. Spent caustic and wastewater is comprised of water and Hexane. Since hexane is insoluble in water, emissions are calculated based on 100% hexane being stored in the tank. Emissions from the wastewater and spent caustic tanks will be controlled using a CAS system. Pressure tanks storing propane refrigerant and anhydrous ammonia will also be located at the site.

Loading - Finished products leave the facility via pipeline so no fugitive loading losses are expected from finished products. Waste materials (spent caustic and wastewater) leave the plant by tank truck. Pressurized loading and unloading off propane refrigerant and ammonia will also occur.

Emergency Diesel Engines – Diesel engines will power emergency generators, air compressors, and firewater pumps.

Maintenance, Start-Up, and Shutdown (MSS) – MSS emissions have been determined for the hot oil heaters, depressurizing and purging off lines to the flare, and emissions due to opening. Additional activities include valve maintenance, rupture disk replacement, pump maintenance, gasket/bolt replacement, and instrumentation maintenance.

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

Hot Oil Heaters – The hot oil heaters will be used to control emissions from the FGRU and vent streams piped directly to heaters. The heaters will achieve a 99% control efficiency of VOC and H_2S emissions vented to the heaters. Hot oil heaters will be equipped with ultro-low NO_x burners and SCR Systems. NOx and CO emissions are based on an emission limit of 0.01 lb NO_x/MMBtu and 50 ppmvd CO. SO2 emissions are based on the sulfur content in the natural gas of 0.25 grains/100 scf. BACT is applied.

Flare – The flare will achieve a VOC control efficiency of at least 98% and will comply with the heating value and velocity requirements of 40 CFR 60.18. BACT is applied.

Cooling Towers – The VOC associated with cooling tower water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P. Cooling towers will be equipped with drift eliminators with a drift rating of 0.001%. BACT is applied.

Tanks – Tanks capacity will be less than 25,000 gallons. Although no control is BACT, emissions from loading of spent caustic and wastewater will be controlled by using a Carbon Adsorption System (CAS). The CAS will achieve a VOC collection efficiency of at least 99%. BACT is applied.

Loading – Emissions from loading spent caustic and wastewater are not controlled as the partial pressure of the mixture is less than 0.5 psia. BACT is applied.

Fugitives- Emissions will be monitored using 28VHP and CTNQ fugitive monitoring program. BACT is applied

Emergency Engines – Emissions will be minimized by restricting the number of hours of nonemergency testing of the engines. Each engine is limited to a maximum of 2 hours of non-emergency operational testing per day and 100 hours annually. BACT is applied.

Maintenance, Start-up, and Shutdown – process units and vessels will be drained to the maximum extent possible. Process units and vessels containing liquids having a vapor pressure greater than or equal to 0.5 psia will be vented to control (Flare EPN FL-01) until the vapor space concentration is less than or equal to 10,000 ppmv. At that point the process unit or vessel may be opened to the atmosphere without control. Process units and vessels containing liquids having a vapor pressure less than 0.5 psia may be vented to the atmosphere uncontrolled. Emissions from other MSS activities will be minimized using best management practices. BACT is applied.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	Yes	Type of Modeling:	AERMOD
Will GLC of any air contaminant cause violation of NAAQS?		**No**	
Is this a sensitive location with respect to nuisance?		**No**	
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?		**No**	
Additional site/land use information: None			

Summary of Modeling Results

A state property line evaluation was conducted for SO_2 and H_2S. The one hour maximum ground level concentration of 6.0μg/m^3 and 0.2μg/m^3 did not exceed the deminimis concentration of 20.0μg/m^3 and 2.0μg/m^3 respectively. Impacts are acceptable.

A minor NSR NAAQS analysis was performed for SO_2, PM_{10}, $PM_{2.5}$, NO_2 and CO with the following results.

Modeling Results for Minor NSR NAAQS De Minimis			
Pollutant	Averaging Time	GLCmax (μg/m^3)	De Minimis (μg/m^3)
SO_2	1-hr	6.0	7.8
SO_2	3-hr	4.0	25
SO_2	24-hr	2.0	5
SO_2	Annual	0.2	1
PM_{10}	24-hr	4.7	5
$PM_{2.5}$	24-hr	1.1	1.2
$PM_{2.5}$	Annual	0.2	0.3
NO_2	1-hr	6.0	7.5
NO_2	Annual	0.2	1
CO	1-hr	173	2000
CO	8-hour	121	500

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda, the EPA believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr NO_2 and SO_2 NAAQS.

The 24-hr $PM_{2.5}$ GLCmax is the five-year average of the maximum predicted 24-hr concentrations determined for each year. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the predicted annual concentrations determined for each receptor across five years. The GLCmax for all other pollutants and averaging times is the highest predicted concentration based on five years of meteorological data.

NSR production and MSS Project-Related modeling was submitted for Ammonia, n-Butane, n-Hexane, and n-Pentane. A modeling audit was conducted by the Air Permits Modeling Team with the results compiled in the memo dated June 11, 2013. Results of modeling were as follows:

1. At no time did the production related (1-hour average) maximum ground level concentration (GLCmax) of any chemical exceed 10% of the corresponding ESL.
2. At no time did the MSS related (annual average) maximum ground level concentration (GLCmax) of any chemical exceed 25% of the corresponding ESL.
3. At no time did the MSS related (annual average) maximum ground level concentration (GLCmax) of any chemical exceed 25% of the corresponding ESL.
4. At no time did the MSS related (1-hour average) maximum ground level concentration (GLCmax) for n-Butane, n-Hexane, or n-Pentane exceed the corresponding ESL.
5. At no time did the MSS related (1-hour average) maximum ground level concentration (GLCmax) for ammonia exceed the corresponding ESL for more than 8 hours per year, 2 times the ESL for more than 8 hours per year, or 4 times the ESL for more than 8 hours per year.

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**Ms. Miranda Cheatham**
Contacted Via:	**Email**
Date of contact:	**May 31, 2013**
Other permit(s) or permits by rule affected by this action:	**Standard Permit 95807**
List permit and/or PBR number(s) and actions required or taken:	

Project Reviewer	Date	Team Leader/Section Manager/Backup	Date

ATTACHMENT C

EPA's Statement of Basis for Permit No. PSD-TX-106921-GHG, dated May, 2013

Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit for ONEOK Hydrocarbon, L.P., Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant

Permit Number: PSD-TX-106921-GHG

May 2013

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On September 21, 2012, ONEOK Hydrocarbon, L.P. (ONEOK) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification at ONEOK's Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant. At EPA's request, ONEOK submitted additional information on January 14, 2013. In connection with the same proposed modification, ONEOK submitted a minor NSR permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on November 14, 2012. The proposed project would expand operations at ONEOK's existing Mont Belvieu NGL Fractionation Plant by adding an additional 75,000 (nominal) barrel per day (bbl/day) fractionation plant (Frac-2) to process a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutane, normal butane, and natural gasoline. After reviewing the application, EPA has prepared the following SOB and draft PSD permit that, when finalized, will authorize the construction of air emission sources at the ONEOK Hydrocarbon Mont Belvieu Gas NGL Fractionation Plant.

This SOB provides the information and analysis used to support EPA's decisions in drafting the PSD permit. It includes a description of the facility and proposed modification, the PSD permit requirements based on BACT analyses conducted on the proposed new units, and the compliance terms of the permit.

EPA Region 6 concludes that ONEOK's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by ONEOK, and EPA's own technical analysis. EPA is making this information available as part of the public record.

II. Applicant

ONEOK Hydrocarbon, L.P.
100 West 5th Street
Tulsa, OK 74103

Physical Address:
11350 Fitzgerald Road
Baytown, TX 77523

Contact:
Terrie Blackburn
Manager, Regulatory Compliance ESH
ONEOK Hydrocarbons, L.P.
(918) 561-8052

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

The ONEOK Mont Belvieu NGL Fractionation Plant is located in Chambers County, TX. This area is currently designated as "nonattainment" for ozone. The nearest Class I area is the Caney Creek Wilderness area in Arkansas, which is located over 400 kilometers from the site. The geographic coordinates for the facility are as follows:

Latitude:	29° 51' 30" North
Longitude:	-94° 53' 25" West

Below, Figure 1 illustrates the facility location for this draft permit:

Figure 1: ONEOK NGL Fractionation Plant

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that ONEOK's application is subject to PSD review for the pollutant GHGs, because the project would result in an emissions increase of 75,000 tpy CO_2e or more as described at 40 CFR § 52.21(b)(49)(v)(*b)* and an emissions increase greater than zero tpy on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (ONEOK calculates CO_2e emissions of 212,523 tpy). As noted above in Section III, EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR section 52.21 (except paragraph (a)(1)). *See,* 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not equal or exceed the significant emissions rates at 40 CFR 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs has not issued the permit amendment for non-GHG pollutants. Emission limits below the rates identified in (b)(23) must be in place prior to construction to ensure the validity of this applicability analysis and the source's authorization to construct a source of GHG emissions.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR 52.21 (o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules, with respect to emissions of GHGs. The applicant has, however, submitted an analysis to evaluate the additional impacts of the non-GHG pollutants, as it may otherwise apply to the proposed project.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ONEOK to construct a new 75,000 (nominal) barrels per day (bbl/day) fractionation unit at the Mount Belvieu facility. The new Frac-2 unit will fractionate Y-grade NGL into the constituent products, including ethane, propane, isobutane, normal butane, and natural gasoline for sale to customers. The proposed process train includes: an amine contactor/amine regenerator for inlet gas treatment, a deethanizer, a depropanizer, a debutanizer, natural gasoline treatment, a deisobutanizer, post fractionation sulfur removal, and a number of process related utilities and ancillary operations. Each step in the process is described in detail below:

Inlet Gas Treatment

The Y-grade feedstock will be piped to an amine contactor where CO_2 and H_2S will be removed, per customer specifications. The treated feed will then be sent to the deethanizer. The rich amine solution will be directed to the amine regeneration unit where the CO_2 and H_2S will be stripped out in the amine regenerator and the lean amine recycled back to the contactor. The vent stream from the amine regenerator will be piped directly to the plant's heaters and combusted. Flash gas from the amine regeneration unit will be piped to the flare gas recovery unit (FGRU) where it will be treated before being piped to the facility's heaters and combusted.

Deethanizer

After pre-treatment, the feed stream will be directed to the deethanizer. Ethane will be separated and removed as a product. Deethanizer bottoms will be directed to the depropanizer for additional fractionation.

Depropanizer

Bottoms from the deethanizer will be piped to the depropanizer. Propane will be separated and removed as a product. Depropanizer bottoms will be directed to the debutanizer for additional fractionation.

Debutanizer

Bottoms from the depropanizer will be piped to the debutanizer. The debutanizer will separate the feedstock into two fractions: mixed butanes (isobutane and n-butane), and natural gasoline. The mixed butanes will be piped to the deisobutanizer for additional fractionation. The natural gasoline will be directed to an additional treatment unit.

Natural Gasoline Treatment

The natural gasoline stream must undergo additional treatment to remove naturally occurring sulfur compounds in order to prevent corrosion of downstream equipment and to meet customer specifications. The sulfur compounds will be catalytically converted in a reactor process. Vent streams from the treatment unit will be directed to the facility's heaters and combusted. The treated natural gasoline will be removed as a product.

Deisobutanizer

The mixed butanes from the debutanizer will be piped to the deisobutanizer, for fractionation into n-butane, and isobutane. Both isomers will then undergo additional treatment.

Butanes Treatment

Both the n-butane and isobutane can contain naturally occurring sulfur compounds (including mercaptan) that must be removed. Each isomer will be treated independently after fractionation in a caustic contactor which will strip the sulfur compounds. Off gases from the treatment unit will be piped to the facility's heaters and combusted. The treated n-butane and isobutane will be removed as products.

Heaters/Hot Oil System

The heat required for all of the process units will be supplied by a hot oil system. ONEOK has proposed construction of three, 154 MMBtu/hr oil heaters. These will be fired with a combination of natural gas and recovered gas from the flare gas recovery unit (FGRU) and vent streams from process equipment. Flue gas from the heaters will be treated with selective catalytic reduction (SCR) prior to release into the atmosphere.

Flare/FGRU

Process vent gases will be collected throughout the plant and routed to the flare header. The flare header is a closed-vent system. The flare header will collect vapors from process vent streams and relief valves. The flare header may also process emergency upsets and startup, shutdown, or maintenance activities. Rather than sending all waste gases to the flare, the vapors will be routed to a FGRU.

The FGRU will be composed of electric driven compressors which will recover the vapors via condensing and pump them to the deethanizer feed or to storage. Any uncondensed vapors will be routed to the heaters for use as fuel. The proposed FGRU is designed to recover all of the vent gas from normal operations. The flare will normally combust pilot and sweep gas. Rather than sending all waste gases to the flare stack for combustion some of the vapors will be recovered and routed to the hot oil heaters as fuel via the flare gas recovery unit.

Cooling Tower

Various processes within the Frac-2 unit will require non-contact cooling water. A cooling tower is proposed for cooling and re-circulation of the necessary cooling water. Re-circulated cooling water will be cooled by ambient air via evaporation, and pumped to the various units as needed. Although the cooling water system will be closed loop and non-contact, the potential exists for leaks in the various process units to cause VOCs to be entrained in the cooling water and released during evaporation. Particulate matter is also typically entrained in drift loss from a cooling tower.

Tanks

The proposed Frac-2 unit will include tanks for the storage of spent materials, amine, cold oil, lube oil, water treatment chemicals, and wastewater. The tanks are not a source of GHG emissions.

Loading Activities

Finished products will be transported offsite via pipeline. No fugitive emissions from product loading are expected.

Waste materials will be transported offsite via truck. Fugitive emissions from these activities have been included in the emission calculations for the proposed project.

Pressurized loading and unloading of propane refrigerant and ammonia will also occur onsite.

Emergency Diesel Engines

Diesel engines will power emergency generators/air compressors and firewater pumps. Given that the actual configuration and sizing of this equipment may vary, the represented emissions cases include conservative, highest-possible emission estimates by accounting for the maximum expected horsepower of the engines.

Maintenance, Startup, and Shutdown (MSS)

Emissions can occur when lines or equipment are de-pressured and purged to the flare and when they are opened to the atmosphere. MSS emissions include all operations that open lines and equipment to the atmosphere, such as for unit shutdown, vessel inspection, valve maintenance, rupture disk replacement, pump maintenance, gasket/bolt replacement, and instrumentation maintenance.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit are consistent with the statutory requirements of CAA sections 165(a)(4) and 169(3) and 40 CFR sections 52.21 (b)(12) and 52.21 (j). The analyses are also consistent with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units

The majority of the GHG emissions associated with the proposed Frac-2 unit will be generated by combustion sources. Stationary combustion sources primarily emit CO_2, but also emit relatively small amounts of N_2O and CH_4. Emissions from the following units or processes are within the scope of the BACT analysis submitted by ONEOK in their application:

- Hot Oil Heaters (EPNs: H-04, H-05, and H-06)
- Process Vents (FIN: VENTS; EPNs: H-04, H-05, and H-06)
- Equipment Leak Fugitives (EPN: FUG-03)
- Cooling Towers (EPN: CT-04)
- Emergency Diesel Engines (EPNs: ENG-05 and ENG-06)
- Flare (EPN: FL-01)
- Maintenance, Start-up, and Shut-down (EPN: MSS-FUG-2)

IX. Hot Oil Heaters (EPNs: H-04, H-05, and H-06) BACT Analysis

GHG emissions, primarily CO_2, are generated from the combustion of natural gas enriched with recovered gas from the flare gas recovery unit (FGRU) in the proposed heaters. The new fractionation unit (Frac-2) will utilize three hot oil heaters each with a maximum firing rate of 154 MMBtu/hr. The hot oil heaters will serve as a control device for the amine regeneration vent streams and for the natural gasoline and butane sulfur treating processes. The hot oil heaters will supply heat to the amine regeneration unit, the deethanizer, depropanizer, debutanizer, and deisobutanizer. Flue gas from the hot oil heaters is treated with selective catalytic reduction (SCR) prior to being released to the atmosphere.

As part of the PSD review, ONEOK provides in the GHG permit application a 5-step top-down BACT analysis for the three heaters. EPA has reviewed ONEOK's BACT analysis for the heaters, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- Energy Efficient Design
  - Installation of energy efficient burners
  - Draft/Trim instrumentation to control the amount of combustion air available in the heaters
  - Waste heat recovery (economizer/air pre-heater)
  - Insulation
  - Reduction of air leakage
  - Reduction of slagging and fouling of heat transfer surfaces
- Energy Efficient Operating Procedures
  - Initial heater tuning and testing
  - Annual heater tune-up
  - Optimization
- Carbon Capture and Storage (CCS)
  - Capture of CO_2
  - Transportation of captured CO_2 to a suitable storage location
  - Permanent storage of CO_2
- Use of Low-Carbon Fuels
  - Switching to lower carbon fuels to minimize CO_2 emissions

Carbon Capture and Storage (CCS)

CCS is an available GHG control technology for "facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)".[1] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy,

[1]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011).

2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for this type of application. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed modification. However, the third approach, post-combustion capture, is available and applicable to heaters.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

All bulleted options identified in Step 1 are considered technically feasible for this project.[3] The only available and applicable CO_2 capture technology, post-combustion capture, is also believed to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Energy efficient design (10-15%)
- Energy efficient operation (10-15%)
- Use of low carbon fuel

CCS may be capable of achieving up to 90% reduction of produced CO_2 emissions in some circumstances and thus would be considered the most effective control method. ONEOK determined that the combination of all of the proposed energy efficient design and operating parameters will result in approximately a 10-15% reduction in GHG emissions in total. Natural gas was the intended fuel for the project so no additional reductions were identified for the use of lower-carbon fuel.

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[2] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

[3] Based on the information provided by ONEOK and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Carbon Capture and Storage</u>

ONEOK provided a five-step top-down BACT analysis for CCS that provided the basis for eliminating the technology as a viable control option in step 4 of the BACT process based on economic costs and environmental impacts. ONEOK also provided a cost analysis to support its conclusion that the energy consumption of the CCS capture and transportation to injection systems would significantly increase the overall energy consumption of the plant, and would create additional CO_2 emissions (from amine solvent regeneration heaters) that would require further mitigation requirements. As explained more fully below, EPA has reviewed ONEOK's CCS analysis and has determined that CCS is not cost-effective at this time for this application and has negative environmental and energy impacts, which in combination support the elimination of CCS as BACT.

Based on ONEOK's cost analysis, the majority of the cost was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $15,140,000 per year for the three hot oil heaters. EPA Region 6 reviewed ONEOK's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project without CCS, which is estimated at $400,000,000. Based on a 20-year equipment life, this cost equates to an overall annualized cost of about $40,000,000 without CCS. The annualized cost of CCS would result in at least a 35% increase in this cost.

In addition, there would be additional negative environmental and energy impacts associated with use of CCS for the proposed heaters. The additional process equipment required to separate, cool, and compress the CO_2 would require significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy would be provided from additional combustion units, including heaters, engines, and/or combustion turbines. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or, if not captured, reduce the net amount of GHG emission reduction, making CCS even less cost effective. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 30%. The proposed plant is located in an area of ozone non-attainment and the generation of additional NOx and VOC could have an adverse environmental impact.

Therefore, EPA has determined that CCS should be eliminated as BACT for this proposed modification due to the excessive economic impacts and negative environmental and energy impacts.

Energy Efficient Design, Energy Efficient Operating Practices, and Use of a Low Carbon Fuel

There are no expected adverse collateral energy, environmental, or economic impacts as a result of these measures proposed as BACT.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regenerant Heaters (28.5 MMBtu/hr each	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis. Regenerant heaters with good combustion practices.	2012	PSD-TX-154-GHG

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each) 2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 7.6 lb CO_2/bbl of NGL processed per heater. Regenerator Heaters - 1.3 lbs CO_2/bbl of NGL processed per heater. 365-day average, rolling daily	2012	PSD-TX-93813-GHG
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG
KM Liquids Terminals LLC, Galena Park Terminal Galena Park, TX	2 Hot Oil Heaters (247 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis.	2013*	PSD-TX-101199-GHG
Targa Gas Processing LLC, Longhorn Gas Plant Decatur, TX	Glycol Reboiler (2 MMBtu/hr) Mol Sieve Heater (12 MMBtu/hr) Hot Oil Heater (98 MMBtu/hr)	Energy Efficiency/ Good Design & Combustion Practices	1,783.23 lb CO_2/ MMSCF for three heaters combined 365-day rolling average	2013*	PSD-TX-106793-GHG

* These permits are not issued as of 05/06/13.

The Enterprise Eagleford Fractionation and Energy Transfer Partners Lone Star NGL BACT determinations are both applied to natural gas liquids (NGL) fractionation facilities. The Lone Star NGL facility produces a higher grade of propane for export purposes that requires a higher heat duty than the Enterprise facility. ONEOK has proposed an output-based BACT limit of 14.25 lb CO_2/bbl of Y-grade feed processed for all three of the hot oil heaters combined. The Energy Transfer Partners, Lone Star NGL facility also proposed an output-based limit. The hot oil heaters at the Lone Star NGL facility have a heat input rate of 270 MMBtu/hr each. The hot oil heaters proposed by ONEOK have a heat input rate of 154 MMBtu/hr each, combined they have a heat input rate of 462 MMBtu/hr. The Lone Star NGL heaters are approximately 54% larger than those proposed by ONEOK on an individual basis, but the ONEOK heaters combined have a heat input rate 52% greater than each of Lone Star's hot oil heaters. The BACT limit proposed by ONEOK for all three hot oil heaters combined is higher than the BACT limit for the Lone Star NGL hot oil heater by 46%. This increase is mainly attributed to the greater overall heat input of the ONEOK hot oil heaters. Also, the Lone Star facility design includes two separate regeneration heaters for their process where EPA established a separate BACT limit for those heaters in that permit, but in ONEOK's design, the heat for the regeneration process is provided by the hot oil system with no separate regeneration heaters. The increased BACT is also based on the feed composition and processing rate that is expected at the ONEOK facility. This BACT limit only applies to the firing of natural gas and recovered flare gas in the hot oil heater burners. It does not include the emissions attributed to the control of the process vent gases from the amine regeneration vent and other process vents. EPA Region 6 analyzed the proposed BACT and has determined it is consistent with other BACT determinations for similar units.

The following specific BACT practices are proposed by ONEOK for the hot oil heaters:

- *Energy Efficient Heater Design*
  - Use of high efficiency burners to allow complete combustion and low excess air;
  - Draft/trim instrumentation and controls to optimize excess O_2;
  - Firebox and stack O_2 instrumentation to identify and control O_2 leaks;
  - Economizer/air preheater for waste heat recovery and reduction of flue gas temperature;
  - Installation of proper refractory and insulation materials to reduce heat loss; and
  - Combustion of natural gas and recovered flare gas to reduce fouling of heat transfer surfaces.
- *Energy Efficient Operating Practices*
  - Combustion tuning and optimization to maximize efficiency, both at start-up and as part of an annual efficiency audit;
  - Preventive maintenance program and regular visual inspections of heaters;
  - Annual tune-up to include burner inspection and cleaning, flame inspection and optimization, air-to-fuel ratio, and CO optimization; and
  - Monitoring the flue gas temperature.
- *Use of Low-Carbon Fuels* - ONEOK will combust natural gas, recovered flare gas, and process vent gases in the heaters.

BACT Limits and Compliance

Each hot oil heater will have an annual GHG limit of 71,760 tons CO_2e/year, based on a 365-day rolling average. Additionally, the three heaters shall have a combined, output based limit of 14.25 lb CO_2/barrel (bbl) of y-grade feed. This BACT limit only applies to the firing of natural gas and recovered flare gas in the hot oil heater burners. Additionally, ONEOK shall maintain a maximum flue gas exit temperature of 385 °F on a 365-day rolling average basis (except during periods of start-up and shut-down). Flow and fuel usage shall be monitored in accordance with 40 CFR Part 98. Additionally, the flue gas temperature must be continuously monitored on each hot oil heater while it is operating.

Compliance with the CO_2 limit shall be determined using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the greatest (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily.

An initial stack test demonstration will be required for CO_2 emissions from each emissions unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4

and N_2O emissions are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Process Vents (EPNs: H-04, H-05, and H-06) BACT Analysis

CO_2 from the amine regenerator vent represents the bulk of the GHG emissions from process vents. Some additional GHG emissions are also generated from CH_4 entrained in process vents and from CO_2 emissions generated through the combustion of process gases in the hot oil heaters.

Step 1 – Identification of Potential Control Technologies for GHGs

- Combustion of residual hydrocarbons as fuel in the hot oil heaters
- Destruction (combustion) of residual hydrocarbons in a control device
- Carbon Capture and Storage (CCS)

<u>Carbon Capture and Storage</u>

Based on the determination discussed above in section IX that CCS is not cost-effective at this time for this application and has negative environmental and energy impacts, which in combination support the elimination of CCS as BACT, as, CCS will not be considered further in this BACT analysis for process vents.

Step 2 – Elimination of Technically Infeasible Alternatives

Both remaining technologies were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Combustion in a control device would require supplementary fuel and would generate additional GHG emissions. Therefore, the remaining technologies were ranked as follows:

- Use of the residual gases as fuel in the process heaters
- Combustion of the residual gases in a control device, such as a flare or thermal oxidizer

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

ONEOK's proposed design incorporates the top control option. ONEOK is proposing to burn residual hydrocarbons as fuel in hot oil heaters. No adverse collateral impacts were identified.

Step 5 – Selection of BACT

ONEOK proposes to burn the residual gas as fuel in the hot oil heaters.

BACT Limits and Compliance

GHG emissions from residual gases routed to and combusted in the hot oil heaters will be limited to 15,000 tons CO_2e/yr based on a 365-day rolling average. The draft permit shall require quarterly sampling of the process vent gas, as well as measurement of the vent gas flow to the process heaters.

ONEOK will demonstrate compliance with the CO_2 emission limit for the process vent emissions using the site specific analysis for process vent gas. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method in which ONEOK may install, calibrate, and operate a CO_2 Continuous Emissions Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site-specific analysis of process fuel gas, and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the greatest (greater than

99%) to the overall emissions from the heaters. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily.

XI. Equipment Leak Fugitives (FUG-03) BACT Analysis

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 11 tpy CO_2e. Fugitive emissions of methane account for less than 0.001% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Leak Detection and Repair (LDAR) – Method 21 monitoring of valves, pumps, flanges/connections, etc., for leak detection and subsequent repair.
- Enhanced LDAR – Enhancements to LDAR program, including lower threshold for a determination that a piece of equipment is leaking and requires repair, increased. monitoring frequency, use of "leakless" or "low-leak" equipment where appropriate
- Optical Gas Imaging LDAR – Use of IR camera to identify leaks.

Step 2 – Elimination of Technically Infeasible Alternatives

All three control technologies were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

ONEOK ranked the technically feasible options in order of control effectiveness

- Enhanced LDAR – includes leak detection limit of 500 ppmv for most equipment types, including flanges.
- LDAR – includes leak detection limit of 500-10,000 ppmv. No instrument monitoring of connections.
- Optical Gas Imaging LDAR – according to ONEOK's analysis, generally has a leak detection limit of greater than 10,000 ppmv.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because ONEOK is proposing to implement the top control option in Step 3 – Enhanced LDAR, there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

The process lines in VOC service are proposed to incorporate the TCEQ 28VHP leak detection and repair (LDAR) program for fugitive emissions control in the New Source Review (NSR) permit No. 106921 to be issued by TCEQ. The TCEQ 28VHP LDAR program is an enhanced LDAR program that has a lower threshold for determining leaks, increased monitoring frequency, and use of "leakless" or "low leak" equipment where appropriate. ONEOK has proposed to implement enhanced LDAR practices as BACT for GHG fugitive emissions, and will operate according to TCEQ's 28VHP program, with quarterly flange/connector monitoring. EPA concurs with ONEOK's assessment that using the TCEQ 28VHP[4] LDAR program is an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the small amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XII. Cooling Towers (CT-04) BACT Analysis

GHG emissions from cooling towers are the result of potential leaks from heat exchangers into cooling water which would be stripped and emitted from the cooling towers associated with the proposed Project. Methane is present in variable concentrations in process streams, with highest concentrations in natural gas. Methane entrained in the cooling water could be air-stripped during the evaporative cooling of the water in the cooling towers generating GHG emissions.

Step 1 – Identification of Potential Control Technologies

ONEOK identified only one available technology: leak detection through monthly monitoring of cooling water and the subsequent repair of any heat exchangers that have been determined to be leaking. EPA identified other available technologies.

- Cooling Tower Monitoring and Repair

[4] The boilerplate special conditions for the TCEQ 28VHP LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf. These conditions are included in the TCEQ issued NSR permit.

- Low Cycles of Concentration
- Acid and Blowdown Control
- Pretreatment of Make-up Water
- Once Through Seawater Cooling
- Air Cooling

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for once through seawater cooling. The proposed facility is not located adjacent to the ocean, therefore this control technology is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All of the remaining proposed technologies are intended to reduce PM and VOC emissions. The effectiveness of these technologies is not readily quantifiable.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Cooling Tower Monitoring and Repair

This technology consists of monthly monitoring of the cooling water to detect leaks, and subsequent repair of any exchangers that have been determined to be leaking. This technology does not have any negative economic, energy, or environmental impacts.

Low Cycles of Concentration

By using a higher rate of make-up water, the concentration of total dissolved solids in the recirculating water stream can be reduced. This reduces particulate matter in the cooling water drift. This technology has no impact on GHG emissions and would increase wastewater discharge. This approach is considered extremely wasteful of fresh water and therefore, this control technology is eliminated as BACT due to environmental impact.

Acid and Blowdown Control

By carefully controlling the acid addition and cooling tower water blowdown rate, the concentration of total dissolved solids in the recirculating stream can be reduced. This reduces particulate matter in the cooling water drift. It is uncertain that this technology would have any impact on the GHG emissions.

Pretreatment of Make-up Water

By pre-treating make-up water, the concentration of total dissolved solids in the recirculating water stream can be reduced. This reduces particulate matter in the cooling water drift. Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 2 MMBtu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions. Therefore, pretreatment of the make-up water is rejected due to the overall increase in GHG emissions.

Air Cooling

By using air as a cooling medium, the recirculating cooling tower could be eliminated. However, any GHG leaks from heat exchangers would still leak into the air, and would be emitted at the same rate from equipment leak fugitives. In addition, using air cooling in this region would force distillation processes to be operated at higher temperatures and pressures. As a result, using air cooling would increase the firing rate of the hot oil heaters and would increase overall GHG emissions. Therefore, this control technology is eliminated based on environmental impacts.

Step 5 – Selection of BACT

ONEOK has proposed cooling tower monitoring and repair as BACT for the cooling tower. The method for monitoring leaks in a heat exchanger/cooling tower does not differentiate between VOCs, and CH_4. Therefore, a numerical BACT limit is technically infeasible. BACT for the cooling towers shall consist of a monthly monitoring program, consistent with the TCEQ Appendix P Air Stripping method[5]. This method has been approved as an acceptable method for determining in heat exchange systems that are in organic Hazardous Air Pollutant (HAP) service at petroleum refineries 40 CFR Part 63 Subpart CC (74 FR 55671)[6]. Leak thresholds and timelines for repair will be consistent with the TCEQ air permit requirements for VOC emissions.

XIII. Emergency Diesel Engines (EPNs: ENG-05 and ENG-06) BACT Analysis

The proposed facility design includes emergency diesel engines for generators and firewater pumps. GHG emissions from these engines result from the combustion of diesel fuel and are comprised primarily of CO_2, with CH_4 and N_2O present in smaller quantities.

[5] Appendix P "Cooling Tower Monitoring" can be found at http://www.tceq.texas.gov/assets/public/compliance/field_ops/guidance/samplingappp.pdf
[6] See http://www.epa.gov/ttn/atw/petrefine/fr28oc09.pdf

Step 1 – Identification of Potential Control Technologies

- Energy Efficient Design – Reduce the amount of fuel necessary by the use of Tier 3 efficient engines that are compliant with the non-road, compression ignition standards at 40 CFR 89.112.
- Energy Efficient Operating Practices – Increase engine efficiency through operational practices including initial tuning/testing, annual tune-ups, limiting hours of operation for testing
- Use of lower-carbon fuels

Step 2 – Elimination of Technically Infeasible Alternatives

ONEOK's analysis determined that the design and operational parameters designed to increase the engines' efficiency are all technically feasible. However, due to the fact that emergency engines are designed to operate during disruptions of availability of other fuel supplies or power sources, the use of lower-carbon fuels such as natural gas, which may experience fuel supply disruptions during natural disasters and emergencies, was determined to be technically infeasible and eliminated from further consideration.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining two control technologies, energy efficient design and operation, were ranked in combination as the top control option. ONEOK estimated that potential reduction in GHG emissions is in the 10-15% range with the implementation of both of these measures.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because the remaining two options were evaluated together, a detailed energy, environmental and economic impact analysis is not required under Step 4.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the emergency generators:

- Energy Efficient Design - ONEOK will install efficient Tier 3 design engines as found at 40 CFR § 89.112.
- Energy Efficient Operation
    - Initial engine tuning and testing.

- Annual tune-ups to include changing the oil and filter, inspecting hoses and belts every 500 hours of operation or annually, whichever comes first.
- Limiting hours of operation for testing to 100 hours/year for each engine.

BACT Limits and Compliance

Using the practices identified above results in an emission limit of 8 tpy CO_2e for the emergency generator engine and 35 tpy CO_2e for the firewater pump engine for non-emergency operations. Additionally, each of the emergency engines shall be limited to 100 hours/year of non-emergency operation. ONEOK shall employ good combustion practices, including annual tune-ups and manufacturer's recommended inspections and maintenance.
To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 as published on October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily. Additionally, ONEOK shall maintain records of fuel usage, hours of operation, and maintenance/tune-ups performed on the engines.

XIV. Flare (EPN: FL-01) BACT Analysis

GHG emissions from the flare are generated through process gases that are vented to and combusted in the flare and from the combustion of natural gas in the pilots. The flare system is equipped with a flare gas recovery unit (FGRU). The FGRU will send the recovered flare gas to the hot oil heaters to be utilized as a fuel. The process vent gases are collected throughout the plant and routed to the flare header. The flare header is a closed-vent system. The flare header collects vapors from process vent streams and relief valves from MSS activities. CO_2 comprises the bulk of the GHG emissions from the flares, with CH_4 and N_2O being present in lesser amounts.

Step 1 – Identification of Potential Control Technologies

- Good Combustion Practices – Implement good combustion practices in the flare, and operate flare in compliance with 40 CFR 60.18
- Minimize Amount of Gas Flared – Reduce amount of gas flared through good operating practices and use of a flare gas recovery unit (FGRU)

Step 2 – Elimination of Technically Infeasible Alternatives

Both options were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Good combustion practices and flare gas recovery were evaluated together as the top option. ONEOK estimated that GHG emissions from the flare could thereby be reduced by approximately 90%. Compliance with 40 CFR 60.18 requires a destruction efficiency of 98% for all hydrocarbons, and 99% for hydrocarbons with two carbons or less, including CH_4. Because the combination of all of the control options in Step 1 are being proposed by the applicant, a ranking of the individual control options is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because the combination of all of the control options in Step 1 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

EPA has reviewed and concurs with ONEOK that the following are BACT:

- Good Combustion Practices – Implement good combustion practices in the flare, and operate flare in compliance with 40 CFR 60.18
- Minimize Amount of Gas Flared – Reduce amount of gas flared through good operating practices and use of a flare gas recovery unit (FGRU)

GHG emissions from the flare resulting from normal and MSS operations of the Frac-2 process unit will be limited to 2,279 tons CO_2e/year based on a 365-day rolling average. The flow will be continuously monitored at the flare header and recorded electronically when emissions are directed to the flare. The composition of the process vent streams and relief valve vapors from MSS will be determined on an hourly basis by a composition analyzer or equivalent at the flare header. The composition analyzer will be calibrated and will identify at least 95% of the compounds in the waste gas. Metered supplemental fuel (natural gas) will also be continuously monitored to maintain the minimum heating value necessary for flame stability. The presence of flame will be continuously monitored by thermocouple or IR camera. The flow meter and analyzers used for flare compliance will be operational at least 95% of the time when the flare is operational, averaged over a calendar year. The flow meter will be calibrated or certified biannually. The composition analyzer will have a single point calibration check monthly when the flare is receiving waste gas vents. Implementing these control practices and design technologies results in an emission limit of 2,278 TPY CO_2e for EPN FL-01.

ONEOK will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific composition and flow for process gas (MSS emission sources). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.99 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.99 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y, site specific analysis of process fuel gas, and the actual heat input (HHV).

XV. MSS Emissions (MSS-FUG-2) BACT Analysis

GHG emissions from maintenance, start-up, and shut-down (MSS) activities occur from degassing process vessels and equipment. The GHG emissions are primarily CH_4.

Step 1 – Identification of Potential Control Technologies for GHGs

The only technology identified by ONEOK as being available is good operational practices. Degassing emissions will be minimized by pumping liquids for recovery, depressurizing and purging vessels to either the flare or the flare gas recovery unit, and venting to the atmosphere only when concentrations are below 10,000 ppmv where practical.

A detailed analysis under Steps 2-4 is not necessary because the applicant has selected the only available control option.

Step 5 – Selection of BACT

EPA concurs with ONEOK that good operational practices are proposed as BACT. A numerical BACT limit was not determined to be technically feasible for MSS emissions released to the atmosphere because work practices are difficult to numerically quantify for purposes of emission limits. ONEOK will maintain records of significant MSS activities to include the date, time, and duration. Additionally, ONEOK will monitor residual hydrocarbon concentrations in process equipment vented to the atmosphere using an LEL meter or Organic Vapor Analyzer.

X. Endangered Species Act (ESA)

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and adopted by EPA.

A draft BA has identified ten (10) species listed as federally endangered or threatened in Chambers County, Texas:

Federally Listed Species for Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Piping Plover	*Charadrius melodus*
Whooping Crane	*Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*

Federally Listed Species for Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Mammals	
Red Wolf	*Canis rufus*
Louisiana Black Bear	*Ursus americanus luteolus*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Atlantic Hawksbill Sea Turtle	*Eretmochelys imbricata*

EPA has determined that issuance of the proposed permit will have no effect on any of the ten (10) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XI. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Burns & McDonnell on behalf of ONEOK submitted on March 27, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 522 acres of land within and adjacent to the construction footprint of the existing facility. Burns & McDonnell conducted a reconnaissance survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the results of the desktop survey, no archaeological resources or historic structures were found within the APE. Based on the results of the reconnaissance survey, two residential historic-aged structures were identified within three hundred (300) feet of the APE. Both structures were determined to be not eligible for inclusion in the NHRP because: 1) it is not unique in architectural design, they were considered typical vernacular residences constructed through Texas in the mid-twentieth century and 2) they did not appear to meet any criteria of significance for inclusion in the NHRP. Additionally, several archaeological surveys, which included shovel testing, have been conducted in the area, five of which were within the boundaries of the APE. No cultural resource sites were identified to be eligible or potentially eligible for listing in the National Register as a result of those surveys.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to ONEOK will not affect properties potentially eligible for listing on the National Register.

On April 9, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company,* 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIII. Conclusion and Proposed Action

Based on the information supplied by ONEOK, our review of the analyses contained in the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue ONEOK Hydrocarbon, L.P. a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 365-day total, rolled daily, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
H-04 H-05 H-06	H-04 H-05 H-06	Hot Oil Heaters	CO_2	215,100[4]	215,281[4]	14.25 lbs CO_2/bbl y-grade feed for all heaters combined (365-day rolling average). Maintain an exhaust temperature of 385 °F or less for each heater (365-day rolling average). See permit conditions III.A.2.a. and b.
			CH_4	4.2[4]		
			N_2O	0.3[4]		
VENTS	H-04 H-05 H-06	Process Vents to Heaters	CO_2	15,000	15,001	Combustion of process vent gases in hot oil heaters. Quarterly gas analysis required. See permit conditions III.B.1.
			CH_4	0.061		
			N_2O	No Numerical Limit Established[5]		
FL-01	FL-01	Flare (Frac-2 Contribution)	CO_2	2,236	2,278	Good combustion practices and flare gas recovery. See permit condition III.C.1.
			CH_4	2		
			N_2O	No Numerical Limit Established[5]		
FUG-03	FUG-03	Fugitive Process Emissions	CH_4	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of Enhanced LDAR Program. See permit conditions III.D.1.
CT-04	CT-04	Cooling Tower	CH_4	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Leak detection/monthly monitoring of cooling water; heat exchanger repair. See permit condition III.E.1.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
ENG-05	ENG-05	Generator	CO_2	8	8.0	Good combustion practices, non-emergency operation limited to 100 hrs./year See permit conditions III.F.1.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		
ENG-06	ENG-06	Firewater Pump Engine	CO_2	35	35.0	Good combustion practices, non-emergency operation limited to 100 hrs./year See permit conditions III.F.1.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		
ATM-MSS-02	MSS-FUG-02	MSS emissions to atmosphere from process vents	CH_4	No Numerical Limit Established[8]	No Numerical Limit Established[8]	Good Operational Practices - Minimize atmospheric venting emissions. See permit condition III.G.1
Totals[9]			**CO_2**	**232,379**	**CO_2e 232,635**	
			CH_4	**7.8**		
			N_2O	**0.3**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): $CH_4 = 21$, $N_2O = 310$
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the hot oil heaters is for all three heaters combined (HY-04, H-05, and H-06). The emissions for each heater shall not exceed 71,700 TPY CO_2, 1.4 TPY CH_4, and 0.1 TPY N_2O.
5. The emissions are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
6. Fugitive process emissions from EPN FUG-03 are estimated to be 0.50 TPY of CH_4, 0.02 TPY CO_2, and 10.6 TPY CO_2e.
7. Cooling Tower emissions from EPN CT-04 are estimated to be 0.016 TPY of CH_4, and 0.34 TPY CO_2e.
8. MSS emissions to the atmosphere are estimated to be 1 tpy CH_4 and 21tpy CO_2e.
9. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.

Magee, Melanie

From: Blackburn, Terrie A. <Terrie.Blackburn@oneok.com>
Sent: Friday, January 22, 2016 3:47 PM
To: Magee, Melanie
Cc: Blackburn, Terrie A.
Subject: RE: (External) Additional Information Request for ONEOK Rescission Request of PSD-TX-106921-GHG
Attachments: Pages from 2013-04-16 Application Update Letter TCEQ - Nonconfidential.pdf

Ms. Magee,

Thank you for speaking with our permitting consultant Miranda Cheatham of WAID Environmental today regarding your questions. It's my understanding several of your questions were answered, and this email responds further to your questions below.

Standard Permit No. 95807 authorized a separate project (the Frac-1 Unit) at the Mont Belvieu site. The Frac-2 Unit was a separate project, which did not include any project emission increases attributable to the sources authorized by Standard Permit No. 95807. Since the Frac-2 Unit project authorized only new emission sources associated with the Frac-2 Unit, the Texas Commission on Environmental Quality's (TCEQ) Technical Review summary for the Frac-2 Unit lists the project's "Current Allowable Emission Rates," or baseline emissions, as zero.

As you note, at the time EPA issued the Prevention of Significant Deterioration (PSD) permit for greenhouse gases (GHGs) for the Frac-2 Unit, the Mont Belvieu site was an existing minor New Source Review (NSR) source. Attached please find the table (Table 1F) submitted to TCEQ as part of ONEOK's Frac-2 Unit permit review. Table 1F summarizes both the pre-project non-GHG allowable emissions and the project's non-GHG allowable emissions. This table documents that the site was an existing minor NSR source and that the Frac-2 Unit project did not exceed PSD major source thresholds.

Please let me know if you have further questions or need additional information.

Thanks,

Terrie Blackburn
ESH Regulatory Compliance | ONEOK Partners, NGL | (918) 561-8052 office | (918) 521-1858 cell

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From: Magee, Melanie [mailto:Magee.Melanie@epa.gov]
Sent: Tuesday, January 19, 2016 4:28 PM
To: Blackburn, Terrie A.
Subject: (External) Additional Information Request for ONEOK Rescission Request of PSD-TX-106921-GHG

Ms. Blackburn:

I am reviewing the rescission request submitted from ONEOK on January 5, 2016 for the EPA issued GHG Step 2 permit number PSD-TX-106921-GHG. Attached to ONEOK's request is a copy of the TCEQ permit number 106921. Special Condition 30 of this permit states that the Hot Oil Heaters, Flare, Cooling Tower, Tanks, Loading, Emergency Engines and Maintenance, Start-up and Shutdown Activities are authorized under Standard Permit number 95807. From the January 5, 2016 submittal, it is unclear what project changes may have been authorized for the Standard Permit 95807. Please submit additional information to support Frac-2 Unit project changes that were associated with the Standard Permit.

The January 5, 2016 rescission request also includes a copy of the TCEQ Technical Review summary. I understand that at the time of EPA's permit issuance, ONEOK was an existing minor NSR source that was permitted under Standard Permit 95807. However, the TCEQ emission summary shows that the current allowable emission rates is zero tons per year.

Please submit additional information to support the baseline non-GHG emission levels at the time of EPA's permit issuance. Also, please verify that the project emission level changes noted in the table include the minor NSR permit 106921 and any standard permit emission level changes associated with the Frac-2 Unit project. I would like to verify for the permitting record that the non-GHG emission rates associated with the addition of the Frac-2 Unit project to the existing minor NSR source (Standard Permit 95807) did not exceed PSD major source thresholds.

If you have any questions, please feel free to email or call me at 214-665-7161.

Thanks, Melanie

Melanie Magee
Environmental Engineer
Air Permits Section (6MM-AP)
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202
(214) 665-7161

ONEOK
HYDROCARBON
A SUBSIDIARY OF ONEOK PARTNERS

April 16, 2013

Mr. Rick Goertz
Office of Permitting, Remediation, and Registration
Air Permits Division, MC-163
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

VIA EMAIL

Re: ONEOK Hydrocarbon, L.P.
Mont Belvieu NGL Fractionation Plant
TCEQ Project No. 185336
Customer Reference No. CN603674086
Regulated Entity No. RN106123714

AIR PERMITS DIVISION
APR 17 2013
RECEIVED

Dear Mr. Goertz:

On behalf of ONEOK Hydrocarbon, L.P., I am submitting additional information for the above-referenced permit application. This submittal includes revised emission calculations, revised application forms, supporting documentation for the percentages of PM_{10} and $PM_{2.5}$ from the cooling tower, and comments on the draft permit. An updated air dispersion modeling analysis will be submitted under separate cover.

The application includes CONFIDENTIAL information. The CONFIDENTIAL information is segregated in a separate document; please handle accordingly.

Please feel free to contact Ms. Terrie Blackburn at (918) 561-8052 or Terrie.Blackburn@oneok.com if you have any questions.

Sincerely,

Scott Schingen
VP NGL Fractionation and Storage

SS/tp

Enclosure

cc: Air Section Manager, TCEQ, Region 12, Houston, w/enclosure
Mr. Jason Graves, P.E., Waid Environmental, League City, w/enclosure

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: To Be Assigned	Application Submittal Date: October 2012
Company: ONEOK Hydrocarbon, L.P.	
RN: RN106123714	Facility Location: 1802 N. Loop 207
City: Mont Belvieu	County: Chambers
Permit Unit I.D.: Mont Belvieu NGL Fractionation Plant	Permit Name: Mont Belvieu NGL Fractionation Plant
Permit Activity: ☒ New Source ☐ Modification	
Project or Process Description: Mont Belvieu NGL Fractionation Plant Expansion	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS							
	Ozone		CO	PM_{10}	NO_X	SO_2	Other[1] H_2S	Other[1] $PM_{2.5}$
	VOC	NO_X						
Nonattainment? (yes or no)	YES	YES	NO	NO	NO	NO	NO	NO
Existing site PTE (tpy)?[4]	24.48	21.25	81.04	15.24	21.25	74.67	0.19	13.26
Proposed project emission increases (tpy from 2F)[3]	18.71	22.49	87.58	11.85	22.49	35.03	0.10	9.88
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)	NO NO	NO NO	NO NO	NO NO	NO NO	NO NO	NO NO	NO NO
If site is major, is project increase significant?								
If netting required, estimated start of construction?								
Five years prior to start of construction						contemporaneous		
Estimated start of operation	~October 2014					period		
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								
FNSR APPLICABLE? (yes or no)	NO	NO	NO	NO	NO	NO	NO	NO

1. Other PSD pollutants.
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).
4. Does not include fugitive emissions

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

[signature]	VP-NGL FRACTIONATION + STORAGE	4/16/2013
Signature	Title	Date