ONEOK HYDROCARBON, L.P.

September 17, 2012

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. Environmental Protection Agency Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: **Application for PSD New Source Review Permit for Greenhouse Gas Emissions**
ONEOK Hydrocarbon, L.P.
Natural Gas Liquids Fractionation Facility
Mont Belvieu, Chambers County, Texas

Dear Mr. Robinson:

ONEOK Hydrocarbon, L.P. ("ONEOK") is submitting the enclosed application for a Prevention of Significant Deterioration ("PSD") New Source Review permit for authorization of greenhouse gas emissions from a proposed expansion of a natural gas liquids (NGL) fractionation facility at an existing ONEOK site in Mont Belvieu, Texas. With this project, ONEOK plans to add an additional 75,000 BPD NGL fractionation train to the existing site.

ONEOK will also submit to the Texas Commission on Environmental Quality a New Source Review application for authorization of non-greenhouse gas emissions from the proposed project. A copy of the TCEQ permit application will be forwarded to you at the time of submittal for your reference.

ONEOK prepared this application in accordance with PSD New Source Review requirements and available U.S. Environmental Protection Agency ("EPA") written guidance, and with the benefit of direct consultation with EPA Region 6 staff regarding this project. As directed by EPA staff, TCEQ forms were used to provide the required permit information and have formed the basis for the structure of the application.

ONEOK is committed to working closely with EPA staff to facilitate the timely review of this application and issuance of a permit. To that end, 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.

We thank you in advance for your assistance with this application.

Sincerely,

Scott Schingen
Vice President – NGL Fractionation and Storage

Enclosure

cc: Ms. Melanie Magee, EPA Region 6, Dallas, w/enclosure

Environmental Protection Agency – Region 6
Greenhouse Gas PSD Permit Application

ONEOK Hydrocarbon, L.P.
Mont Belvieu NGL Fractionation Plant

Mont Belvieu, Chambers County
TCEQ Regulated Entity No. RN106123714
TCEQ Customer No. CN603674086

September 2012

Prepared and Approved by:

Jason M. Graves, P.E.
Principal Engineer

STATE OF TEXAS
JASON M. GRAVES
86925
LICENSED
PROFESSIONAL ENGINEER
9/18/2012

Waid Corporation dba Waid Environmental
Certificate of Registration No. F-58

www.waid.com

Austin Office
10800 Pecan Park Blvd., Suite 300
Austin, Texas 78750
512.255.9999 • 512.255.8780 FAX

Houston Office
2600 South Shore Blvd., Suite 300
League City, Texas 77573
281.333.9990 • 512.255.8780 FAX

Midland Office
24 Smith Road, Suite 304
Midland, Texas 79705
432.682.9999 • 432.682.7774 FAX

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: ONEOK Hydrocarbon, L.P.		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Scott Schingen		
Title: Vice President - NGL Fractionation and Storage		
Mailing Address: 100 West 5th Street		
City: Tulsa	State: OK	ZIP Code: 74103
Telephone No.: (918) 588-7875	Fax No.:	E-mail Address: scott.schingen@oneok.com
C. Technical Contact Name: Terrie Blackburn		
Title: Manager, Regulatory Compliance ESH		
Company Name: ONEOK Hydrocarbon, L.P.		
Mailing Address: 100 West 5th Street		
City: Tulsa	State: OK	ZIP Code: 74103
Telephone No.: (918) 561-8052	Fax No.:	E-mail Address: Terrie.Blackburn@oneok.com
D. Site Name: Mont Belvieu NGL Fractionation Plant		
E. Area Name/Type of Facility: Mont Belvieu NGL Fractionation Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Liquids Fractionation		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: ~April 2013		
Projected Start of Operation Date: ~October 2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 11350 Fitzgerald		
City/Town: Baytown	County: Chambers	ZIP Code: 77523
Latitude (nearest second): 29º 51' 30"	Longitude (nearest second): 94º 53' 25"	

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): CN603674086	
L. Regulated Entity Number (RN): RN106123714	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 5-10	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Senator Tommy Williams	District No.: 4
Representative: Representative Craig Eiland	District No.: 23
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing): To Be Assigned	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other: EPA GHG PSD Permit	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested (continued)			
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.			☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List:			
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.			☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)			
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).			☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): To Be Determined			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☒ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐			

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐

IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM $_{10}$ microns or less (PM_{10}):	
PM $_{2.5}$ microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants **not** listed above: CO2e = 213,000 TPY	

V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Terrie Blackburn			
Title: Manager, Regulatory Compliance ESH			
Mailing Address: 100 West 5th Street			
City: Tulsa	State: OK	ZIP Code: 74103	
Telephone No.: (918) 561-8052			
B. Name of the Public Place: West Chambers Branch Library			
Physical Address (No P.O. Boxes): 10616 Eagle Drive			
City: Mont Belvieu	County: Chambers	ZIP Code: 77580	
The public place has granted authorization to place the application for public viewing and copying.			☒ YES ☐ NO
The public place has internet access available for the public.			☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	

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V. Public Notice Information (complete if applicable) (continued)			
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*			
Name of the Indian Governing Body:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
D. Bilingual Notice			
Is a bilingual program **required** by the Texas Education Code in the School District?			☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?			☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? Spanish			
VI. Small Business Classification (Required)			
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?			☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?			☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?			☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?			☐ YES ☒ NO
VII. Technical Information			
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)			
1. Current Area Map ☒			
2. Plot Plan ☒			
3. Existing Authorizations ☒			
4. Process Flow Diagram ☒			
5. Process Description ☒			
6. Maximum Emissions Data and Calculations ☒			
7. Air Permit Application Tables ☒			
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒			
b. Table 2 (Form 10155) entitled, Material Balance ☐			
c. Other equipment, process or control device tables ☐			

TCEQ

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 7	Week(s): 52	Year(s): 8760 hr/yr
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
See Attachments			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO

VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***		
D. Do nonattainment permitting requirements apply to this application?		☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?		☒ YES ☐ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?		☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?		☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal		
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.		
XI. Permit Fee Information		
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ (TCEQ)	
Company name on check:	Paid Online ☐ YES ☒ NO	
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☒ N/A	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A	

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XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Scott Schingen, Vice President, NGL Fractionation and Storage
Signature: [signature]   *Original Signature Required*
Date: 9/17/2012

RESET FORM PRINT FORM

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This permit application is submitted to authorize the expansion of the ONEOK Hydrocarbon, L.P. (ONEOK) Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant. The Texas Commission on Environmental Quality ("TCEQ") previously authorized the construction of the following units at the site:

- A 75,000 barrel-per-day (BPD) Y-grade fractionation plant (Frac-1) to treat and fractionate a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutane, normal butane, and natural gasoline. This unit was permitted in April 2011 (New Source Review Standard Permit No. 95807), and commenced actual construction in June 2011.

- A 40,000 BPD Ethane/Propane (E/P) splitter (EP-1) to separate ethane from propane and heavier materials in a mixed ethane-propane feed. This unit was permitted in April 2011 (New Source Review Standard Permit No. 95807), and commenced actual construction in June 2011.

- The ONEOK Hydrocarbon Southwest L.P. Mont Belvieu Storage Facility is currently operating on the site. This storage facility is operated by an affiliated company under SIC Code 4226 for storage of hydrocarbon materials in salt dome caverns, and is authorized under New Source Review Permit No. 79861.

In response to rapidly growing demand for natural gas liquids (NGL) fractionation, ONEOK proposes to expand the operations at the Fractionation Plant with this application to build an additional 75,000 BPD Y-grade fractionation plant (Frac-2) to treat and fractionate a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutane, normal butane, and natural gasoline. Construction of this unit is proposed to commence in the second quarter of 2013, with start of operation in the fourth quarter of 2014.

This permit application is submitted to authorize greenhouse gas emissions (GHG) from the addition of these units (the Project). GHG emissions from production operations as well as GHG emissions from planned maintenance, startup, and shutdown activities are included in this application. A corresponding permit application will be submitted to the TCEQ to authorize non-greenhouse gas emissions associated with this Project. This application is being submitted to the U.S. Environmental Protection Agency (EPA) under the Federal Implementation Plan (FIP) for Texas sources to authorize greenhouse gas emissions.

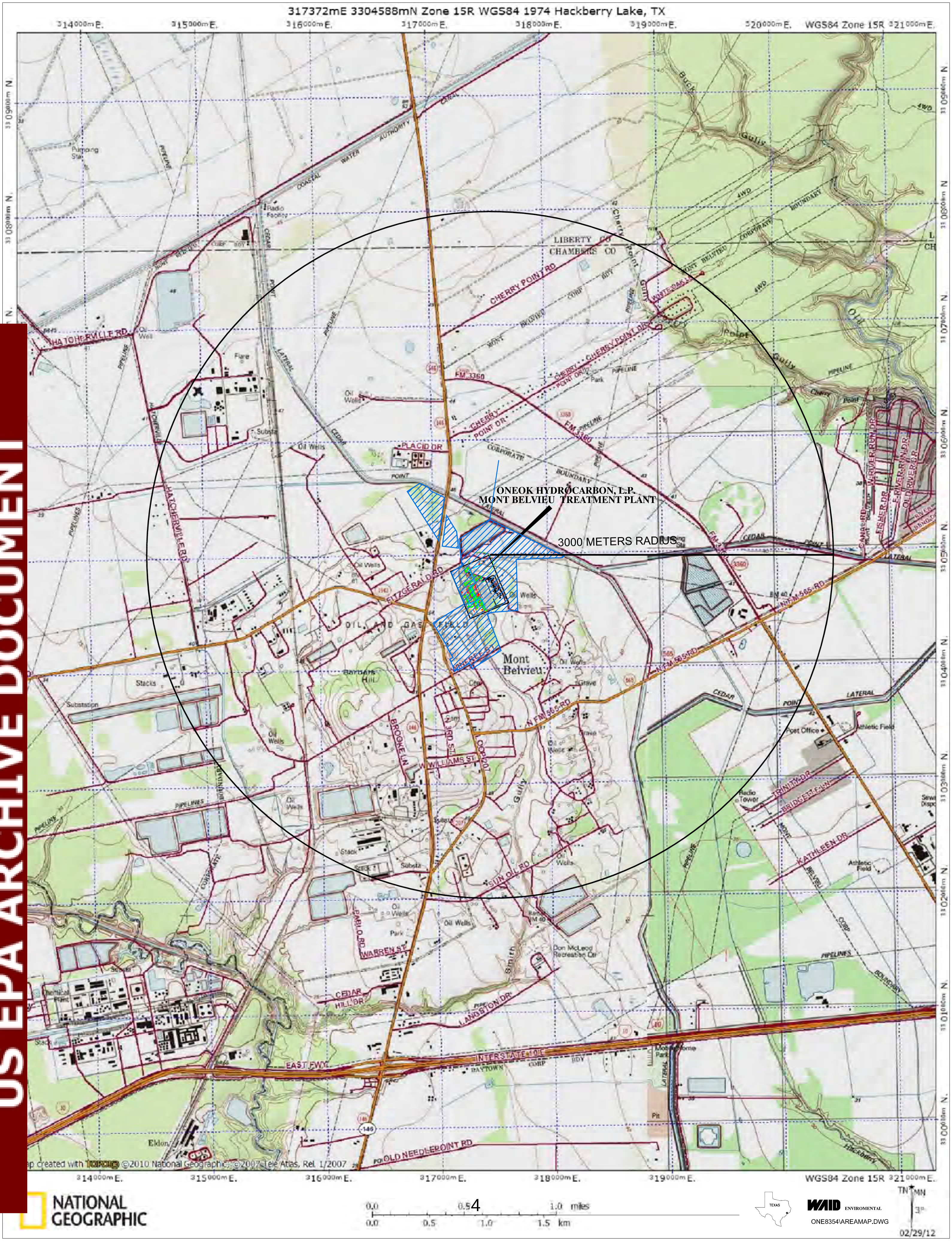
Under the Texas State Implementation Plan (SIP), the existing site is a minor source of non-greenhouse gas emissions for the purposes of both federal nonattainment and Prevention of Significant Deterioration (PSD) New Source Review permitting, and the proposed Project does not constitute a new major source of any non-greenhouse gases. Accordingly, within the regulatory context of the Texas SIP, the New Source Review permit application ONEOK is submitting to TCEQ for this Project is for a state-only permit. However, under the concurrent

Texas Federal Implementation Plan (FIP), the site is a major source of GHG emissions, and the proposed changes constitute a major modification for GHG emissions. Therefore, this separate application for a PSD permit is being submitted to EPA for this Project pursuant to the Texas greenhouse gas permitting FIP to authorize greenhouse gas emissions associated with the Project.

ATTACHMENT VII.A.1

AREA MAP

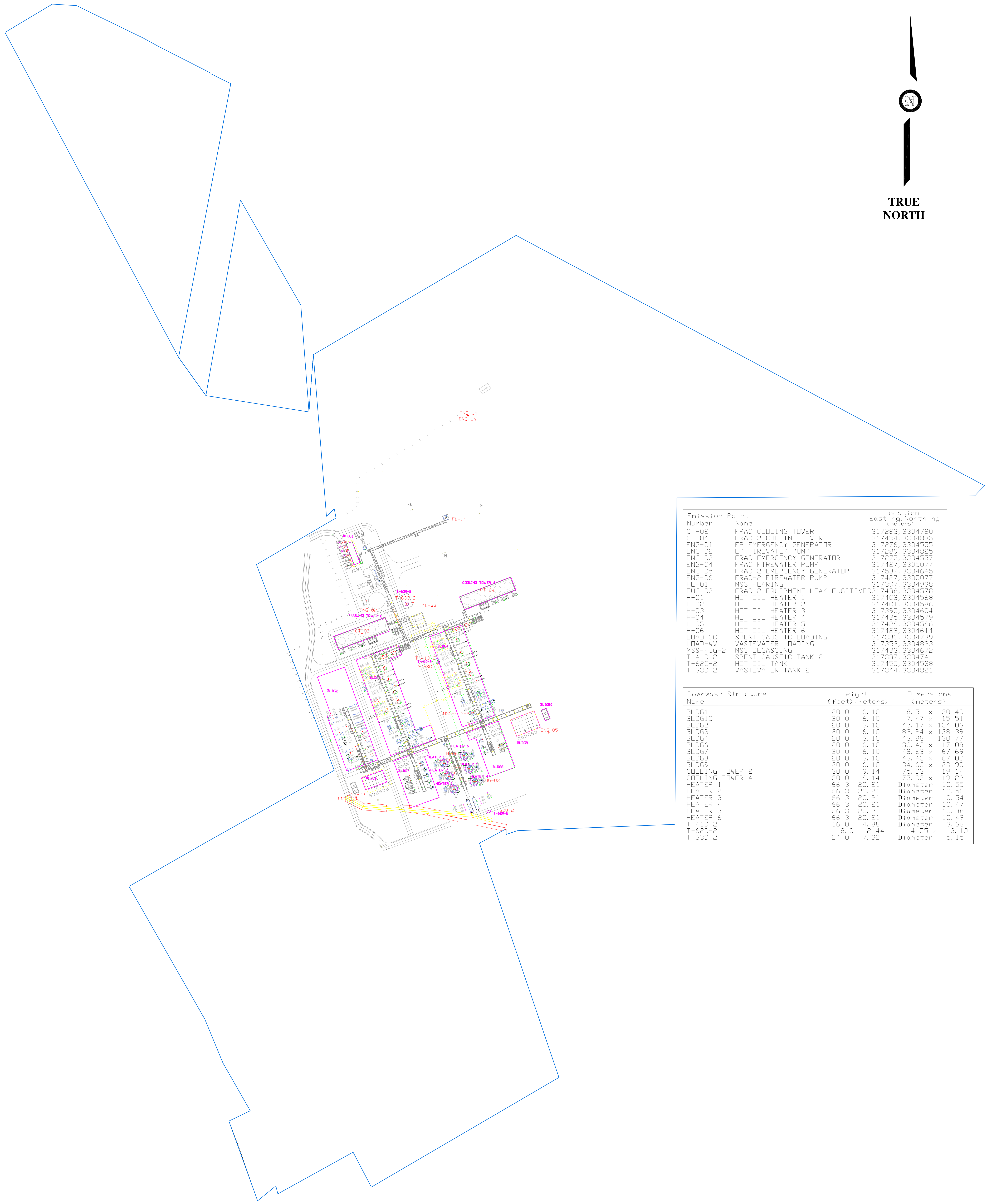
An area map is included on the following page.


317372mE 3304588mN Zone 15R WGS84 1974 Hackberry Lake, TX
ONEOK HYDROCARBON, L.P.
MONT BELVIEU TREATMENT PLANT
3000 METERS RADIUS
Mont Belvieu
Barbers Hill
OIL AND GAS FIELD
LIBERTY CO
CHAMBERS CO
CHERRY POINT RD
FM 3360
PLACID DR
FITZGERALD RD
HATCHERVILLE RD
INTERSTATE 10
EAST FWY
OLD NEEDLEPOINT RD
Map created with TOPO! ©2010 National Geographic; ©2007 Tele Atlas, Rel. 1/2007
WGS84 Zone 15R
NATIONAL GEOGRAPHIC
0.0 0.5 1.0 miles
0.0 0.5 1.0 1.5 km
WAID ENVIRONMENTAL
ONE8354\AREAMAP.DWG
02/29/12

ATTACHMENT VII.A.2

PLOT PLAN

A plot plan is included on the following page.



Emission Point Number	Name	Location Easting, Northing (meters)
CT-02	FRAC COOLING TOWER	317283, 3304780
CT-04	FRAC-2 COOLING TOWER	317454, 3304835
ENG-01	EP EMERGENCY GENERATOR	317276, 3304555
ENG-02	EP FIREWATER PUMP	317289, 3304825
ENG-03	FRAC EMERGENCY GENERATOR	317275, 3304557
ENG-04	FRAC FIREWATER PUMP	317427, 3305077
ENG-05	FRAC-2 EMERGENCY GENERATOR	317537, 3304645
ENG-06	FRAC-2 FIREWATER PUMP	317427, 3305077
FL-01	MSS FLARING	317397, 3304938
FUG-03	FRAC-2 EQUIPMENT LEAK FUGITIVES	317438, 3304578
H-01	HOT OIL HEATER 1	317408, 3304568
H-02	HOT OIL HEATER 2	317401, 3304586
H-03	HOT OIL HEATER 3	317395, 3304604
H-04	HOT OIL HEATER 4	317435, 3304579
H-05	HOT OIL HEATER 5	317429, 3304596
H-06	HOT OIL HEATER 6	317422, 3304614
LOAD-SC	SPENT CAUSTIC LOADING	317380, 3304739
LOAD-WW	WASTEWATER LOADING	317352, 3304823
MSS-FUG-2	MSS DEGASSING	317433, 3304672
T-410-2	SPENT CAUSTIC TANK 2	317387, 3304741
T-620-2	HOT OIL TANK	317455, 3304538
T-630-2	WASTEWATER TANK 2	317344, 3304821

Downwash Structure Name	Height (feet)	Height (meters)	Dimensions (meters)
BLDG1	20.0	6.10	8.51 x 30.40
BLDG10	20.0	6.10	7.47 x 15.51
BLDG2	20.0	6.10	45.17 x 134.06
BLDG3	20.0	6.10	82.24 x 138.39
BLDG4	20.0	6.10	46.88 x 130.77
BLDG6	20.0	6.10	30.40 x 17.08
BLDG7	20.0	6.10	48.68 x 67.69
BLDG8	20.0	6.10	46.43 x 67.00
BLDG9	20.0	6.10	34.60 x 23.90
COOLING TOWER 2	30.0	9.14	75.03 x 19.14
COOLING TOWER 4	30.0	9.14	75.03 x 19.22
HEATER 1	66.3	20.21	Diameter 10.55
HEATER 2	66.3	20.21	Diameter 10.50
HEATER 3	66.3	20.21	Diameter 10.54
HEATER 4	66.3	20.21	Diameter 10.47
HEATER 5	66.3	20.21	Diameter 10.38
HEATER 6	66.3	20.21	Diameter 10.49
T-410-2	16.0	4.88	Diameter 3.66
T-620-2	8.0	2.44	4.55 x 3.10
T-630-2	24.0	7.32	Diameter 5.15

WAID ENVIRONMENTAL

ONEOK HYDROCARBON, L.P.

E/P SPLITTER TRAIN FOR MONT BELVIEU TREATMENT PLANT

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	2/14/11	9/12/12	PLOTPLAN-5	18

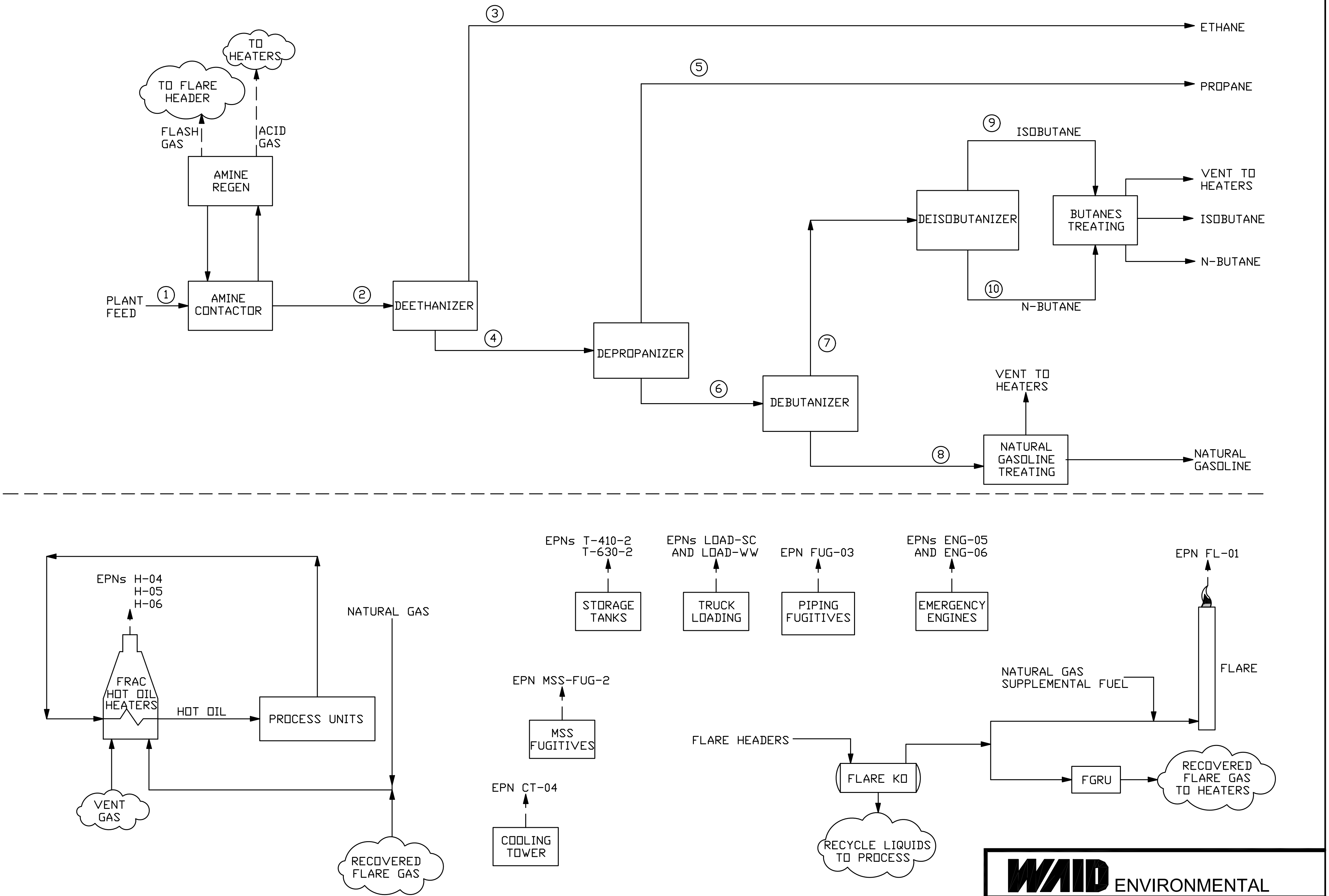
H:\CLIENTS\ONEOK\ONE8354\ACAD

ATTACHMENT VII.A.4

PROCESS FLOW DIAGRAM

A process flow diagram is included on the following page.

NEW FRACTIONATION TRAIN FOR MONT BELVIEU NGL FRACTIONATION PLANT



WAID ENVIRONMENTAL

ONEOK HYDROCARBON, L.P.

NEW FRACTIONATION TRAINS FOR MONT BELVIEU NGL FRACTIONATION PLANT

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	1/14/09	9/12/12	FRAC2-PFD	9

H:\CLIENTS\ONEOK\ONE8354\ACAD

ATTACHMENT VII.A.5

PROCESS DESCRIPTION

Process descriptions for the Frac-2 Unit and associated utilities are summarized below:

Additional Frac-2 Fractionation Train

Inlet Gas Treating

The Y-Grade Feed (stream 1) is received via pipelines and is treated in an amine contactor to remove carbon dioxide and hydrogen sulfide as required to meet customer product specifications. The treated feed (stream 2) 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 (stream 3) and C3+ (Deethanizer bottoms) as a bottoms product (stream 4). Heat for the Deethanizer is supplied by the hot oil system. The ethane product exits the facility via pipeline. The Deethanizer bottoms stream (stream 4) is routed to the Depropanizer for further fractionating.

Depropanizer

The Deethanizer bottoms (stream 4) is fed to the Depropanizer. This stream is separated into propane as an overhead product (stream 5) and C4+ (Depropanizer bottoms) as a bottoms product (stream 6). Heat for the Depropanizer is supplied by the hot oil system. The propane product exits the facility via pipeline. The Depropanizer bottoms stream (stream 6) is routed to the debutanizer for further fractionating.

Debutanizer/Natural Gasoline Treating

The Depropanizer bottoms (stream 6) are fed to the Debutanizer and separated into mixed C4's as an overhead product (stream 7) and natural gasoline (primarily C5+) as the Debutanizer bottoms (stream 8). Heat for the Debutanizer is supplied by the hot oil system. The Debutanizer bottoms stream (natural gasoline product, stream 8) is fed to a Natural Gasoline Treating unit for treating.

The natural gasoline product streams may contain naturally occurring sulfur compounds that can be corrosive to downstream equipment and therefore must be treated to meet customer product specifications. These sulfur compounds are removed from the natural gasoline stream using a caustic scrubbing process. 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.

Deisobutanizer

The Debutanizer overhead product (stream 7) is composed of two butane isomers (isobutane and n-butane). Separation of these isomers is accomplished by fractionation in a Deisobutanizer (DIB). The mixed butane stream is fed to the DIB unit (stream 7) and separated into isobutane as an overhead product and n-butane as a bottoms product. Heat for the Deisobutanizer is supplied by the hot oil system. The isobutane and n-butane are routed to a butanes treating unit prior to exiting the facility via pipeline.

Butanes Treating

The isobutane (stream 9) and n-butane (stream 10) product streams may contain naturally occurring sulfur compounds. These sulfur compounds are removed from the isobutane product stream as well as the n-butane product stream using a caustic treatment process. The process consists of vessels containing a contactor. The contactor serves as a mass transfer device and utilizes caustic as the treating reagent to remove mercaptan from the isobutane stream and the n-butane stream. The isobutane stream and n-butane stream are treated independently after fractionation. Off gases from the process are routed directly to the site's heaters and combusted. The treated isobutane and n-butane exit the facility via pipeline.

Utilities and Ancillary Operations

Heaters/Hot Oil System

There are no steam boilers for these facilities. The heat required to operate the units is supplied by hot oil. This duty will be supplied by three 127 MMBtu/hr hot oil heaters.

The hot oil heaters are fired with sweet natural gas. This natural gas mixture is enriched with recovered gas from the Flare Gas Recovery Unit (FGRU). The hot oil heaters are also designed to combust vent streams from the process equipment. Flue gas from the hot oil heater(s) is treated with selective catalytic reduction (SCR) prior to being released to the atmosphere.

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 flare header collects 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 are routed to a FGRU.

The FGRU is composed of electric compressors which recover the 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 all of the vent gas, and the flare will only combust pilot and sweep gas. Rather than sending all waste gases to the flare stack for combustion some of the vapors are recovered and routed to the hot oil heaters as fuel via the flare gas recovery unit.

Compressors

Compressors will be electrically-powered.

Cooling Tower

The Frac-2 Unit will require cooling water service. In the cooling tower, re-circulated water enters the tower and is cooled by ambient air through evaporation. The cooled water is collected in the concrete basin of the tower and is distributed by pumps to the various cooling water users in the plant. The cooling water does not come in direct contact with the process material being cooled; however, the potential for leaks to occur from time to time is present. As a result, residual volatile organic compounds (VOCs) entrained in the cooling water may be released to the atmosphere during the cooling process. Some particulate matter is also entrained in the cooling tower's drift loss.

Tanks

Spent materials, cold oil storage, lube oil, amine, water treatment chemicals, and wastewater will be stored in atmospheric fixed roof storage tanks.

Loading

Finished products leave the plant by pipeline. Therefore, no loading fugitive emissions from finished products are expected.

Waste materials (spent caustic, wastewater) leave the plant by truck. Loading fugitive emissions from these operations are accounted for in the emission calculations.

Pressurized loading and unloading of propane refrigerant and ammonia also occur on site.

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 depressured 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.

ATTACHMENT VII.A.6

EMISSIONS DATA

The following is a description of the emissions calculation methodology for each source type at the plant.

Heaters

The Frac-2 units require a hot oil system which includes fired heaters as the heat source. Greenhouse gas emissions estimates from the natural gas fired heaters are based on the emission factors found in 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

In addition to natural gas combustion in the heaters, vents from the treaters and FGRU are routed to the heaters for combustion of residual VOC and recovery of available heating value. Process simulations, which were used in the equipment design to perform mass and energy balances, were used to determine the CO_2 and methane content of the process vent streams. The heater emissions are calculated based on a minimum control efficiency of 99% of methane from the FGRU and vent streams. This control efficiency is consistent with EPA and TCEQ guidance for VOC control for streams routed to process heaters.

Flare

The flare system is equipped with an FGRU. Under normal operating conditions, the FGRU will recover the process vent streams, and the flare will only combust pilot and sweep gas. The flare header may also process emergency upsets and MSS activities. Anticipated emissions from MSS activities are discussed in the “MSS” section below.

Greenhouse gas emissions estimates from the flare are based on the emission factors found in 40 CFR Part 98, Subpart C, Tables C-1 and C-2 for each material sent to the flare.

Cooling Towers

GHG emissions from the cooling towers are estimated using the controlled emission factor from AP-42, Section 5.1 (1/95), Petroleum Refining, applying the speciation profile to account for the potential for methane emission leaks into the cooling water. The cooling water will be sampled so that leaks can be detected and repaired.

Emergency Diesel Engines

Greenhouse gas emissions estimates from the emergency diesel engines are based on the emission factors found in 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

Equipment Leak Fugitives

Equipment leak fugitive emissions are calculated using an estimated component count, TCEQ’s Oil and Gas Production Operation emission factors, and a 28VHP LDAR program. The 28VHP program is a fugitive Leak Detection and Repair (LDAR) permit condition, which specifies stringent requirements for routine monitoring of equipment using audio, visual, and olfactory means and using EPA Method 21 to identify and repair leaking equipment. For example, under this condition, valves would be required to be monitored quarterly using a leak definition of 500 parts per million by volume (ppmv). In addition to the 28VHP program, gas/vapor and light liquid flanges and connectors will also be monitored quarterly at 500 ppmv. The combination of these requirements makes the proposed combined LDAR program nearly equivalent to the TCEQ's most-stringent 28-LAER monitoring program. The emission factors, control credits, and descriptions of the monitoring programs used are in the TCEQ guidance document "Equipment Leak Fugitives," dated October 2000.

Maintenance, Startup and Shutdown

Given vessel volume and materials stored, degassing amounts are calculated using the ideal gas law. The degassing calculations quantify the emissions sent to the flare and the residual emissions to atmosphere for each vessel. A 30% allowance was included to account for the volume of associated piping, based on volumetric estimates from the engineering design contractor. The estimated degassing volumes also account for methane purges used during commissioning and decommissioning the equipment.

Greenhouse gas emissions estimates from the flare are based on the emission factors found in 40 CFR Part 98, Subpart C, Tables C-1 and C-2 for each material sent to the flare. Emissions from methane are based on 99% destruction efficiency for MSS venting to the flare. Maximum site-wide annual emissions from degassing to the flare are calculated by conservatively assuming each vessel is cleared once per year when the FGRU is not operational. Note that the FGRU will not function to recover MSS emissions associated with degassing because the process heaters used for the recovered fuel stream will not be operating at that time.

Maximum site-wide annual emissions from degassing of residual vapors to atmosphere are calculated by conservatively assuming each vessel is cleared four times per year. The assumed residual VOC content of the vessel is 10,000 ppmv, which is 20% of methane's lower explosive limit (LEL).

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	September 2012	Permit No.:	TBD	Regulated Entity No.:	RN106123714
Area Name:	Mont Belvieu NGL Fractionation Plant			Customer Reference No.:	CN603674086

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pounds per Hour	(B) TPY
H-04	H-04	Hot Oil Heater 4	CO_2e		65,063
H-05	H-05	Hot Oil Heater 5	CO_2e		65,063
H-06	H-06	Hot Oil Heater 6	CO_2e		65,063
H-04/H-05/H-06	VENTS	Frac-2 Process Vents to Heaters	CO_2e		15,000
FL-01	FL-01	Flare (Frac-2 Contribution)	CO_2e		1,301
CT-04	CT-04	Frac-2 Cooling Tower	CO_2e		Work Practice Standard
ENG-05	ENG-05	Frac-2 Emergency Generator	CO_2e		43
ENG-06	ENG-06	Frac-2 Firewater Pump	CO_2e		
FUG-03	FUG-03	Frac-2 Equipment Leak Fugitives	CO_2e		Work Practice Standard
FL-01	MSS-FL-2	MSS-Flaring (Frac-2 Contribution)	CO_2e		Work Practice Standard
MSS-FUG-2	ATM-MSS-2	MSS-Degassing (Frac-2 Contribution)	CO_2e		Work Practice Standard

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: September 2012	Permit No.: TBD	Regulated Entity No.:	RN106123714
Area Name: Mont Belvieu NGL Fractionation Plant		Customer Reference No.:	CN603674086

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height (Ft.)	6. Height Above Ground (Feet)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) Name	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
H-04	H-04	Hot Oil Heater 4	15	317435	3304579		146.33	8.33	25	305			
H-05	H-05	Hot Oil Heater 5	15	317429	3304596		146.33	8.33	25	305			
H-06	H-06	Hot Oil Heater 6	15	317422	3304614		146.33	8.33	25	305			
H-04/H-05/H-06	VENTS	Frac-2 Process Vents to Heaters	15	317435	3304579		146.33	8.33	25	305			
FL-01	FL-01	Flare (Frac-2 Contribution)	15	317397	3304938		210	1.22	65.6	1832			
CT-04	CT-04	Frac-2 Cooling Tower	15	317454	3304835		30	12	1	Amb.			
ENG-05	ENG-05	Frac-2 Emergency Generator	15	317537	3304645		10	0.67	35	500			
ENG-06	ENG-06	Frac-2 Firewater Pump	15	317427	3305077		10	0.67	35	500			
FUG-03	FUG-03	Frac-2 Equipment Leak Fugitives	15	317438	3304578		3				184	678	-20
FL-01	MSS-FL-2	MSS-Flaring (Frac-2 Contribution)	15	317397	3304938		210	1.22	65.6	1832			
MSS-FUG-2	ATM-MSS-2	MSS-Degassing (Frac-2 Contribution)	15	317432	3304672		30				20	20	0

EPN = Emission Point Number
FIN = Facility Identification Number

ONEOK Frac-2 Emissions Summary

FIN	EPN	Description	Previously Authorized (tons/yr)	Proposed (tons/yr)	Increase/(Decrease) (tons/yr)	Basis of Change
Proposed New Equipment/Emissions						
H-04	H-04	Hot Oil Heater 4	0	65,063	65,063	New Emissions Unit
H-05	H-05	Hot Oil Heater 5	0	65,063	65,063	New Emissions Unit
H-06	H-06	Hot Oil Heater 6	0	65,063	65,063	New Emissions Unit
VENTS	H-04/H-05/H-06	Frac-2 Process Vents to Heaters	0	15,000	15,000	New Emissions Unit
FL-01	FL-01	Flare (Frac-2 Contribution)	0	1,301	1,301	Modified Emissions Unit
CT-04	CT-04	Frac-2 Cooling Tower	0	0.34	0.34	New Emissions Unit
ENG-05	ENG-05	Frac-2 Emergency Generator	0	8	8	New Emissions Unit
ENG-06	ENG-06	Frac-2 Firewater Pump	0	35	35	New Emissions Unit
FUG-03	FUG-03	Frac-2 Equipment Leak Fugitives	0	10.6	11	New Emissions Unit
MSS-FL-2	FL-01	MSS-Flaring (Frac-2 Contribution)	0	978	978	Modified Emissions Unit
ATM-MSS-2	MSS-FUG-2	MSS-Degassing (Frac-2 Contribution)	0	21	21	New Emissions Unit
Total			**-**	**213,000**	**213,000**	

Hot Oil Heater 4

EPN: H-04
FIN: H-04

Annual Average Duty:	127	MM Btu/hr (HHV)	
Maximum Duty:	127	MM Btu/hr (24-hr average, HHV)	
Hours of Operation:	8760	hr/yr	
Sulfur Content in Fuel =	2	gr/100 dscf	
Fuel Heating Value:	1000	Btu/scf	(HHV basis, natural gas average)
Fuel F-Factor:	8710	dscf/MM Btu (HHV)	40 CFR Part 60, Appendix A, Table 19-2 value for natural gas

Pollutant	Assumed	Emission Factor				Emissions		GWP	CO2e	
	MW	lb/MM scf	lb/MM Btu	ppmvd @ 3% O2	Source	lb/hr	(ton/yr)		lb/hr	(ton/yr)
CH4			0.00220		40 CFR 98 Subpart C, Table C-2	0.3	1.2	21.00	6	25
CO2			116.9		40 CFR 98 Subpart C, Table C-1	14,800	65,000	1.00	14,800	65,000
N2O			0.00022		40 CFR 98 Subpart C, Table C-2	0.0	0.1	310.00	9	38
								Total CO2e	14,815	65,063

Notes
1. lb/hr Emissions = Maximum Duty * Emission Factor
2. ton/yr Emissions = Annual Average Duty * Annual Operating Hours* Emission Factor / 2000

Hot Oil Heater 5

EPN: H-05
FIN: H-05

Annual Average Duty:	127	MM Btu/hr (HHV)	
Maximum Duty:	127	MM Btu/hr (24-hr average, HHV)	
Hours of Operation:	8760	hr/yr	
Sulfur Content in Fuel =	2	gr/100 dscf	
Fuel Heating Value:	1000	Btu/scf	(HHV basis, natural gas average)
Fuel F-Factor:	8710	dscf/MM Btu (HHV)	40 CFR Part 60, Appendix A, Table 19-2 value for natural gas

Pollutant	Assumed MW	Emission Factor				Emissions		GWP	CO2e	
		lb/MM scf	lb/MM Btu	ppmvd @ 3% O2	Source	lb/hr	(ton/yr)		lb/hr	(ton/yr)
CH4			0.00220		40 CFR 98 Subpart C, Table C-2	0.3	1.2	21.00	6	25
CO2			116.9		40 CFR 98 Subpart C, Table C-1	14,800	65,000	1.00	14,800	65,000
N2O			0.00022		40 CFR 98 Subpart C, Table C-2	0.0	0.1	310.00	9	38
								Total CO2e	14,815	65,063

Notes
1. lb/hr Emissions = Maximum Duty * Emission Factor
2. ton/yr Emissions = Annual Average Duty * Annual Operating Hours* Emission Factor / 2000

Hot Oil Heater 6

EPN: H-06
FIN: H-06

Annual Average Duty:	127	MM Btu/hr (HHV)	
Maximum Duty:	127	MM Btu/hr (24-hr average, HHV)	
Hours of Operation:	8760	hr/yr	
Sulfur Content in Fuel =	2	gr/100 dscf	
Fuel Heating Value:	1000	Btu/scf	(HHV basis, natural gas average)
Fuel F-Factor:	8710	dscf/MM Btu (HHV)	40 CFR Part 60, Appendix A, Table 19-2 value for natural gas

Pollutant	Assumed	Emission Factor				Emissions		GWP	CO2e	
	MW	lb/MM scf	lb/MM Btu	ppmvd @ 3% O2	Source	lb/hr	(ton/yr)		lb/hr	(ton/yr)
CH4			0.00220		40 CFR 98 Subpart C, Table C-2	0.3	1.2	21.00	6	25
CO2			116.9		40 CFR 98 Subpart C, Table C-1	14,800	65,000	1.00	14,800	65,000
N2O			0.00022		40 CFR 98 Subpart C, Table C-2	0.0	0.1	310.00	9	38
								Total CO2e	14,815	65,063

Notes
1. lb/hr Emissions = Maximum Duty * Emission Factor
2. ton/yr Emissions = Annual Average Duty * Annual Operating Hours* Emission Factor / 2000

Frac-2 Process Vents to Heaters

EPN: H-04/H-05/H-06
FIN: VENTS
Conversion Factor = 385 scf/lbmol
Hours of Operation = 8760 hr/yr

Chemical	Mol. Wt.	Rich Amine Flash	Amine Acid Gas	Perco Vent[1]	Merox Vent	Total Flow to Fuel Gas	Destruction Efficiency	Methane	CO2	CO2e	Methane	CO2	CO2e
(---)	**(lb/lbmol)**	**(lbmol/hr)**	**(lbmol/hr)**	**(lbmol/hr)**	**(lbmol/hr)**	**(lbmol/hr)**	**%**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(ton/yr)**	**(ton/yr)**	**(ton/yr)**
Cabon Dioxide	44.01	0.01	78.53	0	0	78.54	---	---	3500	3500	---	15000	15000
Methane	16.04	0.07	0.02	0	0	0.09	99	0.014	---	0.294	0.061	---	1.3
								0.014	**3500**	**3500**	**0.061**	**15000**	**15000**

Note CO2 from products of combustion is already accounted for in heater emissions calculations based on total heat input.

Flare (Frac-2 Contribution)

EPN: **FL-01**
FIN: **FL-01**

Pilot/Sweep Gas Flow Rate: 2500 scf/hr
Hours of Operation: 8760 hr/yr
Fuel Heating Value: 1000 Btu/scf (HHV basis, natural gas average)

Pollutant	Emission Factor		Emissions		GWP	CO2e	
	(lb/MM Btu)	Source	(lb/hr)	(ton/yr)		lb/hr	(ton/yr)
CH4	0.00220	40 CFR 98 Subpart C, Table C-2	0.0055	0.024	21.00	0.1	0.5
CO2	116.9	40 CFR 98 Subpart C, Table C-1	290	1300	1.00	290.0	1,300.0
N2O	0.00022	40 CFR 98 Subpart C, Table C-2	0.00055	0.0024	310.00	0.2	0.7
					Total CO2e	290	1,301

Notes
1. Emissions are from combustion of pilot and sweep gas only and does not include emissions from other vent streams

Cooling Tower

EPN: CT-04
FIN: CT-04

Inputs:	Water circulation rate =	60000	gal/min
	Annual hours of operation =	8760	hr/yr
	VOC Emission Factor -Short Term (AP-42, Chapter 5) =	0.7	lb/10^6 gal cooling water
	VOC Emissions Factor - Annual	0.3	lb/10^6 gal cooling water

Calculations:

EPN	Source Description	HC Emissions	
		lb/hr	(ton/yr)
CT-04	Frac-2 Cooling Tower	2.50	4.70

Speciation:

Assume composition is same as inlet gas feed.

Component	Mass Fraction	Emissions (lb/hr)	Emissions (ton/yr)	CO2e lb/hr	CO2e tpy	GWP
Methane	0.003	0.0083	0.016	0.17	0.34	21

Auxiliary Diesel Engines

EPN: Various
FIN: Various

Emergency Generator Engine:	134	hp
Firewater Pump Engine:	575	hp
Fuel Consumption Rate:	7500	BTU/hp-hr
Hours of Operation:	100	hr/yr

GHG Emissions

EPN	Pollutant	Emission Factor			Emissions		GWP	CO2e	
		kg/MMBtu	lb/MM Btu	Source	lb/hr	(ton/yr)		lb/hr	(ton/yr)
ENG-05	CH4	0.003	0.0066	40 CFR 98 Subpart C, Table C-2	0.007	0.0003	21.00	0.14	0.007
	CO2	73.96	163.1	40 CFR 98 Subpart C, Table C-1	164	8.1935	1.00	163.87	8.193
	N2O	0.0006	0.0013	40 CFR 98 Subpart C, Table C-2	0.0013	0.00007	310.00	0.41	0.021
	Total CO2e							164	8
ENG-06	CH4	0.003	0.0066	40 CFR 98 Subpart C, Table C-2	0.029	0.0014	21.00	0.60	0.030
	CO2	73.96	163.1	40 CFR 98 Subpart C, Table C-1	703	35.1585	1.00	703.17	35.158
	N2O	0.0006	0.0013	40 CFR 98 Subpart C, Table C-2	0.0057	0.00029	310.00	1.77	0.088
	Total CO2e							706	35

Unit: Frac-2 Equipment Leak Fugitives
EPN: FUG-03
FIN: FUG-03

Hours of Operation: 8760 hr/yr

Equipment Type	Component Count	Emission Factor* (lb/hr-component)	Control Efficiency*	Emission Rate (lb/hr)	(tons/yr)
Compressors - GV	7	0.0194	0.85	0.020	0.089
Flanges - GV	1834	0.00086	0.97	0.047	0.207
Flanges - HL	1212	0.000243	0.3	0.206	0.903
Flanges - LL	3942	8.6E-07	0.97	0.0001	0.0004
Pressure Relief Valves - GV	69	0.0194	0.97	0.040	0.176
Pressure Relief Valves - HL	10	0.0000683	0	0.001	0.003
Pressure Relief Valves - LL	33	0.0165	0.97	0.016	0.072
Pumps - HL	11	0.00113	0	0.012	0.054
Pumps - LL	35	0.02866	0.85	0.150	0.659
Valves - GV	975	0.00992	0.97	0.290	1.271
Valves - HL	758	0.0000185	0	0.014	0.061
Valves - LL	2985	0.0055	0.97	0.493	2.157

* The emission factors are from the TCEQ's 2000 "Equipment Leak Fugitives" for Oil and Gas Production Operations.

Material Name	Hourly Emissions lb/hr	Annual Emissions tpy	CO2e lb/hr	CO2e tpy	GWP
Methane	0.115	0.502	2.415	10.542	21
CO2	0.00491	0.0215	0.00491	0.0215	1
Total	**1.29**	**5.66**	**2.42**	**10.60**	

MSS Hydrocarbons to Flare Emissions Summary (Frac-2 Contribution)

FIN: MSS-FL-2

EPN: FL-01

						GWP	21.00	GWP	1	GWP	310.00	
Constituent	**Molecular Weight**	**Max Annual Rate****	**Max Annual Rate****	**Heating Value**	**Destruction Efficiency**	**Methane Emissions**		**CO2 Emissions**		**N2O Emissions**		**CO2e Emissions**
	(lb/lbmol)	**(lb/yr)**	**(scf/yr)**	**(BTU/scf)**	**(%)**	**(lb/MMBtu)**	**(tpy)**	**(lb/MMBtu)**	**(tpy)**	**(lb/MMBtu)**	**(tpy)**	**(tpy)**
Methane	16.04	392,000	9,410,000	896	99	N/A	1.96000	116.9	493	0.0002	0.00093	534
Ethane	30.07	56,700	726,000	1595	N/A	0.0066	0.00383	138.1	80	0.0013	0.00077	80
Propane	44.1	94,500	825,000	2282	N/A	0.0066	0.00623	135.5	128	0.0006	0.00057	128
Butanes	58.12	92,000	609,000	2958	N/A	0.0066	0.00596	143.1	129	0.0006	0.00054	129
Pentanes	72.15	45,800	244,000	3618	N/A	0.0066	0.00292	154.4	68	0.0006	0.00027	68
Hexanes+	86.18	25,200	113,000	4305	N/A	0.0066	0.00161	154.4	38	0.0006	0.00015	38
Total							**1.98**		**936**		**0.003212**	**978**

MSS Hydrocarbons to Atmosphere Summary (Frac-2 Contribution)

FIN: ATM-MSS-2

EPN: MSS-FUG-2

Constituent	Concentration*	Residual Mass in Unit	Methane Emissions***	CO2e	GWP
	(ppmv)	(lb/unit)	(ton/yr)	(ton/yr)	
Methane	10,000	500	1.00	21.00	21

* Assumes controlled degassing down to 20% or less of methane LEL.

*** Based on total volume of unit being degassed 4 times per year.

ATTACHMENT VIII.B

MEASUREMENT OF EMISSIONS

Measuring greenhouse gas emissions will be conducted as required by the issued permit.

The hot oil heaters, which are the primary GHG emissions sources at the site, will be equipped with continuous fuel flow monitors for each fuel stream sent to the heaters. ONEOK proposes to determine actual GHG emissions using continuous fuel flow meters and the factors included in 40 CFR Part 98, Subpart C.

Records of fuel consumption for the emergency diesel engines will be maintained, and are proposed to be used to determine actual GHG emissions based on the factors included in 40 CFR Part 98, Subpart C.

Process vents will be monitored as required by 40 CFR Part 98, Subpart W. This will include measurement of vent gas flow and determination of GHG emissions based on estimated or periodic measurements of vent stream composition.

A similar approach is proposed to measure flare stream flow rates to determine GHG emissions from flares based on the factors included in 40 CFR 98, Subpart C. This will include measurement of flare gas flow and determination of GHG emissions based on estimated or periodic measurements of vent stream composition.

Cooling towers will be checked for leaks periodically using the TCEQ Appendix P air stripping method. The Appendix P air stripping method uses an air stripping column to measure concentration of strippable hydrocarbons in the cooling water stream. A known flow rate of purified air is passed countercurrent through a packed column in contact with a known flow rate of cooling water. The air leaving the stripper is measured for hydrocarbons by using an organic vapor analyzer.

Process fugitives will be monitored using EPA Method 21 based on the 28VHP program with quarterly connector monitoring. Details on the 28VHP program are included in the Best Available Control Technology (BACT) section of this application (Section VIII.C).

ATTACHMENT VIII.C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Introduction

As explained in Attachment IX.E of this application, the Project constitutes a major modification at an existing major source of GHG emissions. Therefore, an analysis of Best Available Control Technology (BACT) is required as part of the permit application. BACT is defined in 40 CFR Section 52.21(b)(12) as follows:

> *Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

Scope of Analysis

The federal requirements for BACT review are outlined in 40 CFR Section 52.21(j)(3), as follows:

> *A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.*

This application addresses GHG pollutants under the scope of the Federal Implementation Plan issued by EPA for the state of Texas. Emissions of all other pollutants are addressed in the application to TCEQ for an amendment under state minor New Source Review. The FIP issued by EPA for the state of Texas was limited to address only greenhouse gases. Therefore, emissions of all other pollutants are addressed in the separate TCEQ application for which BACT review for all non-GHG emissions will be conducted as a part of the minor NSR program application review process.

The following table lists the new and modified sources within the scope of the BACT analysis provided in this application:

Source Category	FIN	EPN	Description	PSD Source Type
Hot Oil Heaters	H-04	H-04	Hot Oil Heater 4	New
	H-05	H-05	Hot Oil Heater 5	New
	H-06	H-06	Hot Oil Heater 6	New
Process Vents	VENTS	H-04/H-05/H-06	Frac-2 Process Vents to Heaters	New
Equipment Leak Fugitives	FUG-03	FUG-03	Frac-2 Equipment Leak Fugitives	New
Cooling Towers	CT-04	CT-04	Frac-2 Cooling Tower	New
Emergency Diesel Engines	ENG-05	ENG-05	Frac-2 Emergency Generator	New
	ENG-06	ENG-06	Frac-2 Firewater Pump	New
Flare	FL-01	FL-01	Flare (Frac-2 Contribution)	Modified
Maintenance, Startup, and Shutdown	MSS-FL-2	FL-01	MSS-Flaring (Frac-2 Contribution)	Modified
	ATM-MSS-2	MSS-FUG-2	MSS-Degassing (Frac-2 Contribution)	New

BACT for each affected unit is addressed by source category in the sections that follow, with distinctions made for individual units as needed.

BACT Analysis Methodology

The method used in this analysis follows the guidance on pages 17 to 44 of the EPA document titled "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011). In this document, EPA recommends the use of the EPA five-step, top-down process to determine BACT for GHG emissions. The steps in this process are as follows:

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

Additional description of the methodology for each step is provided below:

<u>Step 1: Identify all available control technologies.</u>

The first step of a top-down analysis is to identify all available control technologies for each emission unit. As explained in the EPA's 1990 Draft New Source Review (NSR) Manual at B.17, "a technology is considered 'available' if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term."

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Control technologies that are determined to be technically infeasible are eliminated from further consideration.

Step 3: Rank remaining control technologies.

In the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness, with the most effective control alternative ranked at the top.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." (EPA NSR Manual at B.8.)

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the emission unit under review.

Resources Consulted

For preparation of its GHG BACT analysis, ONEOK followed the EPA guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011).

ONEOK also consulted the following resources to develop a list of available technologies and to complete the BACT analyses:

- EPA's Clean Air Act Advisory Committee (CAAAC) website;
- U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL) websites;
- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA white paper from October 2010 entitled "Available and Emerging Technologies for Reducing Greenhouse Gas Emission from the Petroleum Industry";
- EPA white paper from October 2010 entitled "Available and Emerging Technologies for Reducing Greenhouse Gas Emission from Industrial, Commercial, and Institutional Boilers";

- Other EPA-issued and State-issued New Source Review permits.
- Applicable Standards under 40 C.F.R. Parts 60 (NSPS), 61 (NESHAP), and 63 (NESHAP/MACT); and
- ONEOK Engineering Staff and Contractor Engineering Staffs.

Source-Specific Analysis

The selection of BACT is done on a case-by-case basis by following each of these steps for each affected emissions unit. Since the steps are often redundant for similar emissions sources, we have grouped emissions units into source categories where possible, as addressed in each of the following sections.

BACT for Hot Oil Heaters

GHG emissions from process heaters are the result of combustion of natural gas, recovered flare gas, and process vents. The emissions are dominated by carbon dioxide (CO_2), but methane (CH_4), and nitrous oxide (N_2O) are present in substantially smaller amounts. Because emissions are predominantly CO_2, the BACT analysis focuses on mitigating CO_2 emissions, with a BACT limit expressed in terms of carbon dioxide equivalent (CO_2e). Carbon dioxide equivalent is defined by EPA in 40 CFR Part 98 Subpart A as follows:

> *Carbon dioxide equivalent or CO_2e means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A–1 of this subpart.*

<u>Step 1: Identify all available control technologies.</u>

In reviewing the resources outlined above, the following technologies were identified as potentially available for the hot oil heaters that will be newly constructed as part of the Project:

Technology	Description	Availability
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel needed to be burned based on design measures, such as: • Install Energy Efficient Burners • Draft/Trim Instrumentation and Controls which are used to manage the amount of combustion air available in the heater • Waste Heat Recovery (Economizer / Air Preheater) • Insulation/Insulating Jackets • Reduce air leakage • Reduce slagging and fouling of heat transfer surfaces	Available

Technology	Description	Availability
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel needed to be burned based on operational practices, such as: • Initial Heater Tuning and Testing • Annual Heater Tune-Up • Optimization	Available
Carbon Capture and Sequestration (CCS)	CCS technology is made up of three main steps: • Capturing CO_2, • Transporting captured CO_2 to a suitable storage location, and • Permanently storing the CO_2	Not available, but EPA requires site-specific cost evaluation, so included in next step despite unavailability.
Use of Low-Carbon Fuels	Utilizing low-carbon fuels to minimize CO_2 emissions.	Available

As shown in the table above, energy efficient design and operational measures, as well as the use of low-carbon fuels are considered available. For the reasons described under Step 2 below, ONEOK does not believe that Carbon Capture and Sequestration is an available technology at this time; however, it is analyzed in the context of the five-step BACT review process as directed by EPA due to the Agency's specific interest in this technology.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel needed to be burned based on design measures, such as: • Replace/Upgrade Burners • Draft/Trim Instrumentation and Controls • Waste Heat Recovery (Economizer / Air Preheater) • Insulation/Insulating Jackets • Reduce air leakage • Process Heat Integration • Reduce slagging and fouling of heat transfer surfaces	Technically Feasible

Technology	Description	Feasibility
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel needed to be burned based on operational practices, such as: • Initial Heater Tuning and Testing • Annual Heater Tune-Up • Optimization	Technically Feasible
Carbon Capture and Sequestration	CCS technology is made up of three main steps: • Capturing of the CO_2, • Transporting the captured CO_2 to a suitable storage location, and • Permanently storing the CO_2	Technically infeasible, but EPA requires site-specific cost evaluation, so included in next step.
Use of Low-Carbon Fuels	Switching to lower-carbon fuels to minimize CO_2 emissions.	Technically Feasible

As shown in the table above, energy efficient design and operational measures, as well as the use of low-carbon fuels are considered technically feasible.

Carbon Capture and Sequestration (CCS) has not been implemented in a commercial project without significant federal funding to support the added cost burden. Further, such demonstration projects funded by the federal government have not been implemented on units in the size range of this Project, Such federal projects involve sources with more than a million tons/yr CO_2 available for capture because a greater, more reasonable economy of scale can be achieved only at such volumes. ONEOK has not been able to identify any natural gas liquids fractionation plant that has been fit, or that is targeted or planned to be fit, with CCS.

Additionally, of the large-scale, government-financed projects to research CCS feasibility, none have matured to the extent that the viability or feasibility of the project is fully understood. One significant question yet to be answered is the efficacy of long-term storage technology, and whether any storage options under study will be able to permanently contain injected CO_2 without eventual leakage to the atmosphere. Until these research projects have been implemented and demonstrated to be successful through long-term testing, CCS technology is not considered to be available or technically feasible.

For the reasons described above, ONEOK does not consider Carbon Capture and Sequestration to be technically feasible at this time; however, it is an option included in the rest of this five-step BACT evaluation process as directed by EPA due to the Agency's specific interest in this technology.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of energy efficient design, implementing energy efficient operational practices, and use of low carbon fuels are not exclusive of each other, and would be ranked in combination at the top of the list as the only available and technically feasible control options available for the hot oil heaters. Energy efficient design and operating practices are estimated to have the potential to reduce GHG emissions by 10-15% in total. Natural gas is an inherently low carbon fuel that was the intended fuel as part of the initial project design, so no additional “reductions” are quantified for relying on this fuel.

For the reasons described above, ONEOK does not believe that CCS is available or technically feasible at this time. If CCS were available and technically feasible, it would be ranked above the combination of efficient design and operational practices, with the potential for reducing GHG emissions by over 90%.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” (As included in the EPA NSR Manual, page B.8.)

ONEOK is proposing to implement efficient design, efficient operational practices, and use of low-carbon fuels as BACT. In combination, these are the top control alternatives that have been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of these measures proposed as BACT.

Although ONEOK believes CCS technology is currently unavailable and technically infeasible, a preliminary cost analysis for CCS has been completed which demonstrates that CCS technology is ineffective on a cost basis. In addition, the use of CCS has adverse collateral energy and environmental impacts. The energy consumption of the CCS capture and transportation or injection systems would significantly increase the overall energy consumption of the plant, and would create additional CO_2 emissions (both on-site from amine solvent regeneration heaters, and off-site for electrical consumption) that would impose further mitigation requirements.
An initial cost estimate was completed based upon the *Report of the Interagency Task Force on Carbon Capture and Storage* dated August 2010. Cost estimates for natural gas combined cycle power plants were used as a surrogate for hot oil heaters, since small hot oil heaters were not included in the cost analysis. To be conservative it was assumed that access to a commercial CO_2 pipeline would be available within 10 km from the site. The estimated cost for CCS is as follows, based on capturing 90% of the available CO_2 from the heaters:

CCS System Component	**Cost ($/tonne CO_2 Captured)**	**Tonnes CO_2 Captured Annually**	**Total Annual Cost (2009 Dollars)**
CO_2 Capture and Compression	95	159,000	$ 15,100,000
CO_2 Transportation (per 10 km)	0.25	159,000	$ 39,800
Total CCS Cost	**96**	**NA**	**$ 15,140,000**

Based on the cost analysis, ONEOK has determined that the added capital and operating cost of implementing CCS for the new heaters would make the proposed Project as a whole economically infeasible. The estimated capital cost for the new unit is about $400 million. Annualized, this equates to about $40 million, so the cost of CCS would increase the cost of the project (or reduce the rate of return) by about 35%.

In addition to being unavailable, technically infeasible, and not cost-effective, the implementation of CCS also results in significant adverse collateral energy and environmental impacts. The increased energy consumption for the CCS system would completely negate any efficiency savings from implementing efficient design and operational practices for the heaters themselves. The additional regeneration heater demand would result in additional increases for all other criteria pollutant emissions and creates another GHG source which would have to be captured.

<u>Step 5: Select the BACT.</u>

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the hot oil heaters, ONEOK proposes use of the top and only remaining options as BACT, which are to implement energy efficient design and operating practices and burn low-carbon fuel (by using natural gas, recovered flare gas, and process vent gases). The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	Greenhouse gas emissions from each hot oil heater will be limited to 65,063 tons CO_2e per year on a 365-day rolling average. The hot oil heaters will maintain a minimum efficiency by maintaining a maximum stack exit temperature of 385 degrees F on a 365-day rolling average basis, excluding periods of start-up and shutdown.
	In accordance with 40 C.F.R. Part 63, Subpart DDDDD, the permittee will conduct annual tune-up (burner inspection and cleaning, flame inspection and optimization, air-to-fuel ratio, and CO optimization).
Monitoring Requirements	The permittee shall maintain compliance with 40 C.F.R. Part 98, Subpart C including flow monitoring of fuel usage and fuel gas analysis. The permittee shall maintain a flue gas temperature monitor to continuously record flue gas exit temperature on each hot oil heater while the heaters are in service.
Compliance Demonstration	The permittee shall calculate compliance with the 365-day rolling average limitations following the procedures specified in 40 C.F.R. Part 98, Subpart C, with a conversion from metric tons to short tons.

Category	Demonstration
	The permittee shall maintain records of flue gas temperature and annual heater tuning performed for compliance and may utilize normal business records for this purpose.

Because the proposed BACT is inclusive of a number of design and operating strategies associated with efficiency, the following summary table is being provided to describe with specificity the design and practices proposed for each heater. Overall, the heater is designed for up to a 91% overall thermal efficiency. This efficiency is based on the initial design. Actual operating efficiency may vary over time based on normal performance degradation even with ongoing maintenance. The efficiency will also vary with operating mode based on start-up and shutdown conditions, and a small percentage of operating hours in natural draft mode due to operating conditions. Benchmarking data for the heaters are not available because they are custom-fabricated units that will be purpose-built for this operation.

Efficiency Technology	Description	Proposed?	Comments on Application
Reduce Energy Loss by Minimizing Excess O2/Stack Flow	Install Energy Efficient Burners	Yes	Efficient burners will be selected that enable complete combustion (low CO) with low excess air and targeted NO_x performance.
	Combustion Tuning & Optimization	Yes	This will be part of the heater startup with equipment vendors. Tuning to optimize efficiency will be part of an annual efficiency audit.
	Draft/Trim Instrumentation and Controls	Yes	Heaters will be equipped with instrumentation and controls to regulate and optimize excess O_2
	Reduce Air Leakage	Yes	In addition to firebox O_2 instrumentation to monitor O_2 near the burners, the heaters will be equipped with stack O_2 instrumentation which will help to identify and minimize air leaks. The heaters will be subject to a preventive maintenance program as well as regular visual inspections.
Reduce Energy Loss by Minimizing Stack Temperature	Waste Heat Recovery (Economizer/Air Preheater)	Yes	The heaters will use air preheat to recover the energy in the flue gas to preheat combustion air. This will maximize energy efficiency by reducing the flue gas temperature.
	Reduce Fouling of Heat Transfer Surfaces	Yes	Natural gas and recovered fuel gas are low particulate/low fouling fuels that provide an inherently favorable design

Efficiency Technology	Description	Proposed?	Comments on Application
Reduce Conductive Heat Energy Loss	Insulation/Insulating Jackets	Yes	New heater designs will minimize heat losses through proper selection of refractory and insulation materials

BACT for Process Vents

GHG emissions from process vents are primarily the result of CO_2 emissions from the amine regeneration vent. A small amount of GHG emissions is contributed from methane entrained in process vents and resulting CO_2 emissions from oxidation of hydrocarbon materials in the heaters.

Step 1: Identify all available control technologies.

In reviewing the resources outlined above, the following technologies were identified as potentially available for the process vent emissions in this application:

Technology	Description	Availability
Burn Residual Hydrocarbons as Fuel in Heaters	Burn residual hydrocarbons (including methane) as fuel in process heater to recover heating value	Available
Burn Residual Hydrocarbons in Control Device	Burn residual hydrocarbons (including methane) in control device such as a flare or thermal oxidizer	Available
Carbon Capture and Sequestration	CCS technology is made up of three main steps: • Capturing of the CO_2, • Transporting the captured CO_2 to a suitable storage location, and • Permanently storing the CO_2	Not Available – See CCS discussion for heaters

As shown in the table above, burning residual hydrocarbons in the hot oil heaters is available.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Burn Residual Hydrocarbons as Fuel in Heaters	Burn residual hydrocarbons (including methane) as fuel in process heater to recover heating value	Technically Feasible
Burn Residual Hydrocarbons in Control Device	Burn residual hydrocarbons (including methane) in control device such as a flare or thermal oxidizer	Technically Feasible

As shown in the table above, each of these technologies are considered available and feasible, and will be evaluated in Step 3.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In the case of the competing combustion options, the most effective control measures is to use the vent streams as a fuel in heaters, so that the heat can be recovered and can offset fuel combustion. Combustion in a flare or thermal oxidizer would require supplemental fuel firing at the control device, creating more GHG emissions than the alternative option of using the stream as fuel. As such, the ranking for these technologies is as follows:

1. Burn Residual Hydrocarbons as Fuel in Heaters
2. Burn Residual Hydrocarbons in Control Device

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to burn residual hydrocarbons as fuel in heaters as BACT. This is the top control alternative that has been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of this option.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the process vent streams associated with this application, ONEOK proposes use of the top option as BACT, which is to burn residual hydrocarbons as fuel in heaters. The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	Greenhouse gas emissions from process vents routed to the hot oil heaters will be limited to 15,000 tons CO_2e per year on a 365-day rolling average.
Monitoring Requirements	Maintain compliance with 40 C.F.R. Part 98, Subpart W based on one of the available calculation options. Monitoring will include measurement of vent gas flow and determination of GHG emissions based on estimated or periodic measurements of vent stream composition.
Compliance Demonstration	Calculate compliance with the 365-day rolling average limitations following the procedures specified in 40 C.F.R. Part 98, Subpart W, with a conversion from metric tons to short tons.

BACT for Equipment Leak Fugitives

GHG emissions from equipment leak fugitives are the result of potential leaks from piping fugitive components (valves, flanges, pumps, compressors, etc.) that will be added as a part of the proposed Project. Methane is present in variable concentrations in the fractionation process streams, with highest concentrations in natural gas. Because methane is a GHG, the analysis focuses on mitigating methane emissions.

Step 1: Identify all available control technologies.

In reviewing the resources outlined above, the following technologies were identified as potentially available for the equipment leak fugitives in this application:

Technology	Description	Availability
LDAR	LDAR would consist of Method 21 monitoring of equipment components (*e.g.*, valves, pumps, connectors, compressors, and agitators) for detection of leaks and subsequent repair, or attempt to repair, any components that have been determined to be leaking.	Available
Enhanced LDAR	Potential enhancements to the LDAR program may include: • Lower the definition of a "leaking" component threshold concentration • Increase the leak monitoring frequency which allows for early detection and repair of leaking components • Installation of components with "low leak" and/or "leakless" technologies in certain applications	Available

Technology	Description	Availability
	• Flange/connector monitoring	
Optical Gas Imaging LDAR	Optical Gas Imaging consists of using an infrared camera to identify leaks, which would then be repaired as in a traditional LDAR program.	Available

As shown in the table above, each of these technologies are considered technically feasible, and will be evaluated in Step 2.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
LDAR	LDAR includes requirements for Method 21 monitoring of equipment components (*e.g.*, valves, pumps, connectors, compressors, and agitators) for detection of leaks and subsequent repair, or attempt to repair, any components that have been determined to be leaking.	Technically Feasible
Enhanced LDAR	Potential enhancements to the LDAR program may include: • Lower the definition of a "leaking" component threshold concentration • Increase the leak monitoring frequency which allows for early detection and repair of leaking components • Installation of components with "low leak" and/or "leakless" technologies in certain applications • Flange/connector monitoring	Technically Feasible
Optical Gas Imaging LDAR	Optical Gas Imaging consists of using an infrared camera to identify leaks, which would then be repaired as in a traditional LDAR program.	Technically Feasible

As shown in the table above, each of these technologies are considered available and feasible, and will be evaluated in Step 3.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In the case of the competing LDAR programs, the most effective control measures are fundamentally a matter of leak detection threshold. As such, the ranking for these technologies is as follows:

1. Enhanced LDAR (500 ppmv leak definitions for most component types – including flanges/connectors)
2. LDAR (500 – 10,000 ppmv leak definitions for most component types, with no instrument monitoring of connectors)
3. Optical Gas Imaging LDAR (generally greater than 10,000 ppmv leak threshold, which varies by application)

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to implement enhanced LDAR practices as BACT, by including flange and connector monitoring as a part of the LDAR program. This is the top control alternative that has been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of the LDAR measures proposed as BACT. In this case, the economic impact is limited since most streams containing methane are also subject to monitoring for VOCs.

Step 5: Select the BACT

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the equipment leak fugitives associated with this application, ONEOK proposes use of the top option as BACT, which is to implement an enhanced LDAR program.

ONEOK is proposing adherence to enhanced LDAR standards as BACT. ONEOK will operate in compliance with the TCEQ 28VHP program with quarterly flange/connector monitoring. Because of the very low GHG emissions resulting from equipment leaks and due to the fact that it is nearly impossible to quantify the amount of GHG emitted from leaking components, no specific emission limit is being proposed for GHG emissions resulting from equipment leaks. Compliance with these LDAR standards is proposed as BACT for GHG emissions resulting from equipment leaks. The proposed form of the limitations is summarized in the following table:

Category	Demonstration
Limitations	No specific emission limitation.
Monitoring Requirements	The permittee shall conduct LDAR monitoring per the TCEQ 28VHP program with quarterly flange/connector monitoring. The leak thresholds and repair timelines will be as designated in the TCEQ air permit for VOC emissions.
Compliance Demonstration	The permittee shall maintain records of LDAR monitoring per the TCEQ 28VHP program.

BACT for Cooling Towers

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. Because methane is a GHG, the analysis focuses on mitigating methane emissions from leaks into cooling water.

Step 1: Identify all available control technologies.

In reviewing the resources outlined above, the following technologies were identified as potentially available for the cooling towers in this application:

Technology	Description	Availability
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 that have been determined to be leaking.	Available

As shown in the table above, the only technology identified is considered available, and will be evaluated in Step 2.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
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 that have been determined to be leaking.	Technically Feasible

As shown in the table above, the only technology identified is considered feasible, and will be evaluated in Step 3.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of cooling tower monitoring and repair is ranked at the top of the list as the only available and technically feasible control option available. Quantifying the reduction potential is not necessary.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to implement cooling tower monitoring and repair as BACT. This is the only control alternative that has been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of the LDAR measures proposed as BACT. In this case, the economic impact is limited since most streams containing methane are also subject to monitoring for VOCs.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the cooling towers associated with this application, ONEOK proposes use of the top option as BACT, which is to implement a cooling tower monitoring and repair program.

The proposed form of the limitations is summarized in the following table:

Category	Demonstration
Limitations	No specific emission limitation because monitoring is not selective of GHG/Methane vs. VOCs in general. The monitoring method detects total hydrocarbons, and will not distinguish between Methane or VOCs. Instead, a work practice standard is proposed in lieu of an emissions limitation.
Monitoring Requirements	The permittee shall implement a cooling tower monitoring program on a monthly basis consistent with the TCEQ Appendix P Air Stripping method. The leak thresholds and repair timelines will be as designated in the TCEQ air permit for VOC emissions.
Compliance Demonstration	The permittee shall maintain records of cooling tower monitoring and corrective actions as required by special provisions in the state NSR permit for VOCs.

BACT for Emergency Diesel Engines

GHG emissions from emergency diesel engines used to power emergency generators and firewater pumps are the result of combustion of diesel fuel. The emissions are dominated by carbon dioxide (CO_2), but methane (CH_4), and nitrous oxide (N_2O) are present in substantially smaller amounts. Because emissions are predominantly CO_2, the analysis focuses on mitigating CO_2 emissions, with a BACT limit expressed in terms of CO_2e.

Step 1: Identify all available control technologies.
In reviewing the resources outlined above, the following technologies were identified as potentially available for the emergency engines that will be newly constructed as part of the Project:

Technology	Description	Availability
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel needed to be burned based on design measures by using efficient Tier 3 engine designs, compliant with the non-road compression ignition engine standards in 40 CFR Section 89.112.	Available
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel needed to be burned based on operational practices, such as: • Initial Engine Tuning and Testing • Annual Tune-Ups • Limiting hours of operation for testing	Available
Carbon Capture and Sequestration (CCS)	CCS technology is made up of three main steps: • Capturing of the CO_2, • Transporting the captured CO_2 to a suitable storage location, and • Permanently storing the CO_2	Not available, see discussion for heaters.
Use of Low-Carbon Fuels	Switching to lower-carbon fuels to minimize CO_2 emissions.	Available

As shown in the table above, energy efficient design and operational measures, as well as the use of low-carbon fuels are considered available. For the reasons described above in the BACT analysis for heaters, ONEOK does not believe that Carbon Capture and Sequestration is an available technology at this time.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel needed to be burned based on design measures by using efficient Tier 3 engine designs.	Technically Feasible

Technology	Description	Feasibility
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel needed to be burned based on operational practices, such as: • Initial Engine Tuning and Testing • Annual Tune-Ups • Limiting hours of operation for testing	Technically Feasible
Use of Low-Carbon Fuels	Switching to lower-carbon fuels to minimize CO_2 emissions.	Technically Infeasible – Diesel fuel is used because supply for emergency use must be available in the event of interruptions in delivery of other fuel supplies or power sources.

As shown in the table above, energy efficient design and operational measures are considered technically feasible.

<u>Step 3: Rank remaining control technologies.</u>

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of energy efficient design and operational practices would be ranked in combination at the top of the list as the only available and technically feasible control options available for the emergency engines, with the potential for reducing GHG emissions by an estimated 10-15% in total.

<u>Step 4: Evaluate most effective controls and document results.</u>

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to implement efficient design and efficient operational practices as BACT. In combination, these are the top control alternative that has been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of these measures proposed as BACT.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the emergency diesel engines, ONEOK proposes use of the top and only remaining options as BACT, which is to implement energy efficient design and operating practices. The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	Total greenhouse gas emissions from the emergency diesel engines will be limited to 43 tons CO_2e per year on a 365-day rolling average, for all non-emergency operations.
	The permittee will conduct annual tune-ups and manufacturer's recommended inspections and maintenance.
Monitoring Requirements	The permittee shall maintain compliance with 40 C.F.R. Part 98, Subpart C including maintaining records of fuel usage or hours of operation.
Compliance Demonstration	The permittee shall calculate compliance with the 365-day rolling average limitations following the procedures specified in 40 C.F.R. Part 98, Subpart C, with a conversion from metric tons to short tons.
	The permittee shall maintain records of annual engine tuning performed for compliance and may utilize normal business records for this purpose.

BACT for Flares

GHG emissions from flares are the result of combustion of hydrocarbon streams vented to the flare. The emissions are dominated by carbon dioxide (CO_2), but methane (CH_4), and nitrous oxide (N_2O) are present in substantially smaller amounts. Because emissions are predominantly CO_2, the analysis focuses on mitigating CO_2 emissions, with a BACT limit expressed in terms of CO_2e.

Step 1: Identify all available control technologies.
In reviewing the resources outlined above, the following technologies were identified as potentially available for the flare that will be modified as part of the Project:

Technology	Description	Availability
Good Combustion Practices	Minimize GHG emissions by operating the flare with a flame present at all times and in compliance with 40 CFR Section 60.18.	Available
Minimizing volume of gas flared	Minimize GHG emissions by limiting amount of gas flared by good operating practices and with the use of a flare gas recovery unit.	Available

As shown in the table above, good combustion practices and flare gas recovery are considered available.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Good Combustion Practices	Minimize GHG emissions by operating the flare with a flame present at all times and in compliance with 40 CFR Section 60.18.	Technically Feasible
Minimizing volume of gas flared	Minimize GHG emissions by limiting amount of gas flared by good operating practices and with the use of a flare gas recovery unit.	Technically Feasible

As shown in the table above, good combustion practices and flare gas recovery are considered technically feasible.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of good combustion practices and flare gas recovery would be ranked in combination at the top of the list as the only available and technically feasible control options available for the flares, with the potential for reducing GHG emissions by more than an estimated 90% in total.

TCEQ flare guidance provides that maintaining compliance with 40 CFR Section 60.18 demonstrates a minimum destruction efficiency of 98% for all hydrocarbons, and 99% for hydrocarbons containing two carbons or less, including Methane.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to implement good combustion practices and flare gas recovery as BACT. In combination, these are the top control alternatives that have been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of these measures proposed as BACT.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the flares, ONEOK proposes use of the top two and only remaining options as BACT, which are to implement good combustion practices and flare gas recovery. The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	Greenhouse gas emissions from contributions to the flare from routine emissions from the Frac-2 process unit will be limited to 1,301 tons CO_2e per year on a 365-day rolling average, for all non-MSS and non-emergency operations.
Monitoring Requirements	The permittee shall maintain compliance with 40 C.F.R. Part 98, Subpart C, including maintaining records of fuel usage and composition analysis.
Compliance Demonstration	The permittee shall calculate compliance with the 365-day rolling average limitations following the procedures specified in 40 C.F.R. Part 98, Subpart C, with a conversion from metric tons to short tons.

BACT for MSS Emissions

GHG emissions from MSS emissions are the result of degassing process vessels and equipment. The emissions are dominated by carbon dioxide (CO_2) emissions from degassing to the flare, but methane (CH_4), and nitrous oxide (N_2O) are present in substantially smaller amounts. Because emissions are predominantly CO_2, the analysis focuses on mitigating CO_2 emissions, with a BACT limit expressed in terms of CO_2e.

Step 1: Identify all available control technologies.

In reviewing the resources outlined above, the following technology was identified as potentially available for the MSS activities that are part of the Project:

Technology	Description	Availability
Minimize degassing emissions through good operational practices	Minimize degassing emissions by first pumping liquids to recovery, depressuring and purging to flare or flare gas recovery unit, and opening equipment to atmosphere only when the concentration is below 10,000 ppmv where practical.	Available

As shown in the table above, minimizing degassing emissions through good operational practices is considered available.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Minimize degassing emissions through good operational practices	Minimize degassing emissions by first pumping liquids to recovery, depressuring and purging to flare or flare gas recovery unit, and opening equipment to atmosphere only when the concentration is below 10,000 ppmv where practical.	Technically Feasible

As shown in the table above, minimizing degassing emissions through good operational practices is considered technically feasible.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, minimizing degassing emissions through good operational practices would be ranked at the top of the list as the only available and technically feasible control option available for MSS activities, with the potential for reducing GHG emissions by more than an estimated 90% in total.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” (As shown in the EPA NSR Manual, page B.8.)

ONEOK is proposing to minimize degassing emissions through good operational practices as BACT. This is the only control alternative that has been determined to be available and technically feasible. There are no expected adverse collateral energy, environmental, or economic impacts as a result of this control alternative proposed as BACT.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For MSS emissions, ONEOK proposes use of the only option as BACT, which is to minimize degassing emissions through good operational practices. The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	No specific emission limitation because monitoring is not selective of GHG/Methane vs. VOCs in general. Monitoring equipment for residual hydrocarbon content using an LEL meter or Organic Vapor Analyzer provides an indication of total hydrocarbon concentration, but does not distinguish between methane and other hydrocarbons that may be present.
Monitoring Requirements	The permittee shall implement a recordkeeping system consistent with special provisions in the state NSR permit for VOCs.
Compliance Demonstration	The permittee shall maintain records of MSS activities as required by special provisions in the state NSR permit for VOCs.

ATTACHMENT IX.A

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart IIII (stationary compression ignition engines), and Subpart OOOO (crude oil and natural gas production, transmission and distribution) are applicable to this facility. ONEOK will comply with the control, monitoring, reporting, and recording requirements of all applicable NSPS.

ATTACHMENT IX.E

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW

As noted previously, under the concurrent Federal Implementation Plan (FIP), the already-permitted ONEOK Mont Belvieu NGL Fractionation Plant is an existing major source of greenhouse gas (GHG) emissions, and the proposed changes associated with this Project constitute a major modification for GHG emissions permitting. Therefore, this application for a PSD permit is being submitted to EPA to authorize greenhouse gas emissions associated with the Project.

ONEOK's Mont Belvieu NGL Fractionation Plant is an existing major source of GHG emissions because the potential to emit of GHGs prior to the modification is greater than 250 tons/yr GHG on a mass basis and greater than 100,000 tons/yr CO_2e. According to EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011), PSD applicability for modification at existing major sources requires a two-step analysis (see page 14 of the Guidance). Furthermore, for GHG emissions, each step requires calculation of mass-based emissions and CO_2e emissions. Therefore, four applicability conditions must be met for modifications at existing major sources to be subject to PSD for GHG emissions. The four conditions are listed below:

1. The CO_2e emissions increase resulting from the modification, without considering any emissions decrease, is greater than or equal to 75,000 tons/yr.
2. The "net emissions increase" of CO_2e over the contemporaneous period is greater than or equal to 75,000 tons/yr.
3. The GHG emissions increase resulting from the modification, on a mass basis, and without considering any emissions decreases, is greater than zero tons/yr.
4. The "net emissions increase" of GHG emissions on a mass basis over the contemporaneous period is greater than or equal to zero tons/yr.

As shown in the tables provided at the end of this section, the emissions increases resulting from the modification are greater than 75,000 tons/yr and 0 tons/yr mass basis. In addition, the net emissions increase during the contemporaneous period is also greater than 75,000 tons/yr CO_2e. Therefore, this application has been prepared to obtain a greenhouse gas PSD permit from the EPA pursuant to the FIP applicable in Texas.

<u>Air Dispersion Modeling</u>

This application does not include an air dispersion analysis, which is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 20 11), which on page 47 states:

"Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs."

GHG Preconstruction Monitoring

This application does not include a preconstruction monitoring analysis, which is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011) which on page 48 states:

"EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs."

Additional Impacts Analysis

This application does not include a PSD additional impacts analysis, which is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011) which on page 48 states:

"Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions 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 with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs."

Endangered Species Act & National Historic Preservation Act

EPA permitting of this Project is a federal action that triggers Section 7 of the Endangered Species Act. To satisfy the requirements of Section 7, a biological assessment must be conducted to evaluate potential impacts to species with federal oversight (i.e., those species protected under the Endangered Species Act, the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act, the Marine Mammal Protection Act, and the Magnuson-Stevens Fishery Conservation and Management Reauthorization Act). ONEOK retained Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to conduct the required biological assessment to evaluate potential Project-related impacts to federally protected species, Bald Eagles, marine mammals, migratory birds, and managed marine fishery populations that are known or likely to occur in the vicinity of the proposed Project. ONEOK will separately submit a report regarding the results of the biological assessment that Burns & McDonnell conducted.

The Project is also subject to National Historic Preservation Act (NHPA) Section 106 review of the Project's potential impact on historic properties because the Project needs to be authorized by an EPA-issued permit. ONEOK retained Burns & McDonnell to conduct the required cultural resources report, and will separately submit a report of the results of that cultural resources review and evaluation.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: To Be Assigned	Application Submittal Date: September 18, 2012
Company: ONEOK Hydrocarbon, L.P.	
RN: RN106123714	Facility Location: 11350 Fitzgerald
City: Baytown	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] CO2e	Other[1]
	VOC	NO_X						
Nonattainment? (yes or no)							NO	
Existing site PTE (tpy)?							221,000	
Proposed project emission increases (tpy from 2F)[3]							213,000	
Is the existing site a major source? [2]If not, is the project a major source by itself? (yes or no)							YES	
If site is major, is project increase significant?							YES	
If netting required, estimated start of construction?	April 2013							
Five years prior to start of construction	April 2008				contemporaneous			
Estimated start of operation	~October 2014					period		
Net contemporaneous change, including proposed project, from Table 3F. (tpy)							434,000	
FNSR APPLICABLE? (yes or no)							YES	

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).

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

[signature] VICE PRESIDENT, NGL FRACTIONATION + STORAGE 9/17/2012
Signature Title Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[(1)]:	CO2e		Permit: To Be Assigned
Baseline Period:	NA	to	NA

	Affected or Modified Facilities[(2)] FIN	EPN	Permit No.	Actual Emissions[(3)]	A Basline Emissions[(4)]	B Proposed Emissions [(5)]	Projected Actual Emissions	Difference (B-A) [(6)]	Correction[(7)]	Project Increase [(8)]
1	H-04	H-04		0	0	65,063		65,063		65,063
2	H-05	H-05		0	0	65,063		65,063		65,063
3	H-06	H-06		0	0	65,063		65,063		65,063
4	VENTS	H-04/H-05/H-06		0	0	15,000		15,000		15,000
5	FL-01	FL-01		0	0	1,301		1,301		1,301
6	CT-04	CT-04		0	0	0.34		0.34		0.34
7	ENG-05	ENG-05		0	0	8		8		8
8	ENG-06	ENG-06		0	0	35		35		35
9	FUG-03	FUG-03		0	0	11		11		11
10	MSS-FL-2	FL-01		0	0	978		978		978
11	ATM-MSS-2	MSS-FUG-2		0	0	21.000		21.000		21.000
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