NMED AIR QUALITY
INITIAL TITLE V APPLICATION
DLK BLACK RIVER MIDSTREAM, LLC
BLACK RIVER GAS PROCESSING PLANT

Prepared By:

Jason Conway – Regulatory, Environmental and Safety Specialist

DLK Black River Midstream, LLC
5400 LBJ Freeway
Suite 1500
Dallas, TX 75240

Jaimy Karacaoglu – Consultant

TRINITY CONSULTANTS
9400 Holly Ave NE
Bldg 3, Suite B
Albuquerque, NM 87122
(505) 266-6611

December 2023

Project 233201.0144

Trinity Consultants
9400 Holly Ave NE, Bldg 3, Ste B, Albuquerque, NM 87122 / P 505.266.6611 / **trinityconsultants.com**

December 11, 2023

Permit Programs Manager
NMED Air Quality Bureau
525 Camino de los Marquez Suite 1
Santa Fe, NM 87505-1816

RE: Initial Title V Application
DLK Black River Midstream, LLC – Black River Gas Processing Plant

Permit Programs Manager:

On the behalf of DLK Black River Midstream LLC, we are submitting an initial Title V application for the existing Black River Gas Processing Plant. The facility is currently authorized under NSR 6567-M8 and is located approximately 2.6 miles southwest of Loving, New Mexico. This application is being submitted pursuant to 20.2.70.300.B(1) NMAC as a result of the facility exceeding Title V thresholds in the NSR 6567-M7 application. Details are included in Section 3 of the application.

The format and content of this application are consistent with the Bureau's current policy regarding Title V applications; it is a complete application package using the most current Universal Application forms. Enclosed is a hard copy of the application, including the original certification. Please feel free to contact either myself at (505) 266-6611 or by email at Jaimy.Karacaoglu@trinityconsultants.com if you have any questions regarding this application. Alternatively, you may contact Jason Conway, Regulatory, Environmental, and Safety Specialist for DLK Black River Midstream, LLC, at (972) 619-1607 or by email at Jason.conway@matadorresources.com.

Sincerely,

Jaimy Karacaoglu
Consultant

CC: Kha Mach (Environmental and Regulatory Engineer, Kha.Mach@matadorresources.com)

Trinity Project File: 233201.0144

Mail Application To:		For Department use only:
New Mexico Environment Department Air Quality Bureau Permits Section 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone: (505) 476-4300 Fax: (505) 476-4375 www.env.nm.gov/aqb		

Universal Air Quality Permit Application

Use this application for NOI, NSR, or Title V sources.

Use this application for: the initial application, modifications, technical revisions, and renewals. For technical revisions, complete Sections, 1-A, 1-B, 2-E, 3, 9 and any other sections that are relevant to the requested action; coordination with the Air Quality Bureau permit staff prior to submittal is encouraged to clarify submittal requirements and to determine if more or less than these sections of the application are needed. Use this application for streamline permits as well.

This application is submitted as (check all that apply): ☐ Request for a No Permit Required Determination (no fee)
☐ **Updating** an application currently under NMED review. Include this page and all pages that are being updated (no fee required).
Construction Status: ☐ Not Constructed ☒ Existing Permitted (or NOI) Facility ☐ Existing Non-permitted (or NOI) Facility
Minor Source: ☐ NOI 20.2.73 NMAC ☐ 20.2.72 NMAC application or revision ☐ 20.2.72.300 NMAC Streamline application
Title V Source: ☒ Title V (new) ☐ Title V renewal ☐ TV minor mod. ☐ TV significant mod. ☐ TV Acid Rain: ☐ New ☐ Renewal
PSD Major Source: ☐ PSD major source (new) ☐ Minor Modification to a PSD source ☐ a PSD major modification

Acknowledgements:

☒ I acknowledge that a pre-application meeting is available to me upon request. ☒ Title V Operating, Title IV Acid Rain, and NPR applications have no fees.
☐ $500 NSR application Filing Fee enclosed OR ☐ The full permit fee associated with 10 fee points (required w/ streamline applications).
☐ Check No.: in the amount of
☒ I acknowledge the required submittal format for the hard copy application is printed double sided 'head-to-toe', 2-hole punched (except the Sect. 2 landscape tables is printed 'head-to-head'), numbered tab separators. Incl. a copy of the check on a separate page.
☒ I acknowledge there is an annual fee for permits in addition to the permit review fee: www.env.nm.gov/air-quality/permit-fees-2/.
☐ This facility qualifies for the small business fee reduction per 20.2.75.11.C. NMAC. The full $500.00 filing fee is included with this application and I understand the fee reduction will be calculated in the balance due invoice. The Small Business Certification Form has been previously submitted or is included with this application. (Small Business Environmental Assistance Program Information: www.env.nm.gov/air-quality/small-biz-eap-2/.)

Citation: Please provide the **low level citation** under which this application is being submitted: **20.2.70.300.B(1) NMAC**
(e.g. application for a new minor source would be 20.2.72.200.A NMAC, one example for a Technical Permit Revision is 20.2.72.219.B.1.b NMAC, a Title V acid rain application would be: 20.2.70.200.C NMAC)

Section 1 – Facility Information

Section 1-A: Company Information

		AI # if known: 36133	Updating Permit/NOI #: N/A
1	Facility Name: Black River Gas Processing Plant	Plant primary SIC Code (4 digits): 1321	
		Plant NAIC code (6 digits): 211112	
a	Facility Street Address (If no facility street address, provide directions from a prominent landmark): 978 Bounds Road, Loving, New Mexico.		
2	Plant Operator Company Name: DLK Black River Midstream, LLC	Phone/Fax: (972) 371-5439/ N/A	
a	Plant Operator Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240		

b	Plant Operator's New Mexico Corporate ID or Tax ID: 32-0591911	
3	Plant Owner(s) name(s): DLK Black River Midstream, LLC	Phone/Fax: (972) 371-5439/ N/A
a	Plant Owner(s) Mailing Address(s): 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	
4	Bill To (Company): DLK Black River Midstream, LLC	Phone/Fax: (972) 371-5439/ N/A
a	Mailing Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	E-mail:
5	☒ Preparer: Jaimy Karacaoglu ☒ Consultant: Trinity Consultants Inc.	Phone/Fax: (505) 266-6611 / N/A
a	Mailing Address: 9400 Holly Ave NE, Bldg. 3, Ste B, Albuquerque, NM 87122.	E-mail: Jaimy.Karacaoglu@trinityconsultants.com
6	Plant Operator Contact: Mr. Casey Snow	Phone/Fax: (972) 371-5439
a	Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	E-mail: csnow@matadorresources.com
7	Air Permit Contact: Kha Mach	Title: Regulatory and Environmental Engineer
a	E-mail: kha.mach@matadorresources.com	Phone/Fax: (972) 371-5472
b	Mailing Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	
c	The designated Air permit Contact will receive all official correspondence (i.e. letters, permits) from the Air Quality Bureau.	

Section 1-B: Current Facility Status

1.a	Has this facility already been constructed? ☒ Yes ☐ No	1.b If yes to question 1.a, is it currently operating in New Mexico? ☒ Yes ☐ No
2	If yes to question 1.a, was the existing facility subject to a Notice of Intent (NOI) (20.2.73 NMAC) before submittal of this application? ☐ Yes ☒ No	If yes to question 1.a, was the existing facility subject to a construction permit (20.2.72 NMAC) before submittal of this application? ☒ Yes ☐ No
3	Is the facility currently shut down? ☐ Yes ☒ No	If yes, give month and year of shut down (MM/YY): N/A
4	Was this facility constructed before 8/31/1972 and continuously operated since 1972? ☐ Yes ☒ No	
5	If Yes to question 3, has this facility been modified (see 20.2.72.7.P NMAC) or the capacity increased since 8/31/1972? ☐ Yes ☐ No ☒ N/A	
6	Does this facility have a Title V operating permit (20.2.70 NMAC)? ☐ Yes ☒ No	If yes, the permit No. is: N/A
7	Has this facility been issued a No Permit Required (NPR)? ☐ Yes ☒ No	If yes, the NPR No. is: N/A
8	Has this facility been issued a Notice of Intent (NOI)? ☐ Yes ☒ No	If yes, the NOI No. is: N/A
9	Does this facility have a construction permit (20.2.72/20.2.74 NMAC)? ☒ Yes ☐ No	If yes, the permit No. is: NSR 6567-M8
10	Is this facility registered under a General permit (GCP-1, GCP-2, etc.)? ☐ Yes ☒ No	If yes, the register No. is: N/A

Section 1-C: Facility Input Capacity & Production Rate

1	What is the facility's maximum input capacity, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 21.25 MMSCF/hr	Daily: 510 MMSCFD	Annually: 186,150 MMSCF/yr
b	Proposed	Hourly: 21.25 MMSCF/hr	Daily: 510 MMSCFD	Annually: 186,150 MMSCF/yr
2	What is the facility's maximum production rate, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 21.25 MMSCF/hr	Daily: 510 MMSCFD	Annually: 186,150 MMSCF/yr
b	Proposed	Hourly: 21.25 MMSCF/hr	Daily: 510 MMSCFD	Annually: 186,150 MMSCF/yr

Section 1-D: Facility Location Information

1	Latitude (decimal degrees): 32.26459	Longitude (decimal degrees): -104.13198	County: Eddy	Elevation (ft): 3139
2	UTM Zone: ☐ 12 or ☒ 13	Datum: ☒ NAD 83 ☐ WGS 84		
a	UTM E (in meters, to nearest 10 meters): 581,750	UTM N (in meters, to nearest 10 meters): 3,570,090		
3	Name and zip code of nearest New Mexico town: Loving, NM 88256.			
4	Detailed Driving Instructions from nearest NM town (attach a road map if necessary): **From Loving, NM head south on N 4th Street toward W. Cedar St. (0.2 mi), Turn right at the 3rd cross street onto W Ash Road (0.3 mi), turn left onto US-285 S/S 8th St. (0.8 mi), turn right onto Higby Hole road (0.4 mi), turn right onto Bounds Road (1.8 mi), facility entrance will be on the right.**			
5	The facility is **2.6** miles **southwest** of **Loving, NM**.			
6	Land Status of facility (check one): ☒ Private ☐ Indian/Pueblo ☐ Government ☐ BLM ☐ Forest Service ☐ Military			
7	List all municipalities, Indian tribes, and counties within a ten (10) mile radius (20.2.72.203.B.2 NMAC) of the property on which the facility is proposed to be constructed or operated: City of Loving and City of Malaga.			
8	**20.2.72** NMAC applications **only**: Will the property on which the facility is proposed to be constructed or operated be closer than 50 km (31 miles) to other states, Bernalillo County, or a Class I area (see www.env.nm.gov/air-quality/modeling-publications/)? ☐ Yes ☐ No (20.2.72.206.A.7 NMAC) If yes, list all with corresponding distances in kilometers: N/A			
9	Name nearest Class I area: **Carlsbad Caverns National Park**			
10	Shortest distance (in km) from facility boundary to the boundary of the nearest Class I area (to the nearest 10 meters): **24.2 km**			
11	Distance (meters) from the perimeter of the Area of Operations (AO is defined as the plant site inclusive of all disturbed lands, including mining overburden removal areas) to nearest residence, school or occupied structure: **>500 m**			
12	Method(s) used to delineate the Restricted Area: Continuous fencing "**Restricted Area**" is an area to which public entry is effectively precluded. Effective barriers include continuous fencing, continuous walls, or other continuous barriers approved by the Department, such as rugged physical terrain with steep grade that would require special equipment to traverse. If a large property is completely enclosed by fencing, a restricted area within the property may be identified with signage only. Public roads cannot be part of a Restricted Area.			
13	Does the owner/operator intend to operate this source as a portable stationary source as defined in 20.2.72.7.X NMAC? ☐ Yes ☒ No A portable stationary source is not a mobile source, such as an automobile, but a source that can be installed permanently at one location or that can be re-installed at various locations, such as a hot mix asphalt plant that is moved to different job sites.			
14	Will this facility operate in conjunction with other air regulated parties on the same property? ☒ No ☐ Yes If yes, what is the name and permit number (if known) of the other facility?			

Section 1-E: Proposed Operating Schedule (The 1-E.1 & 1-E.2 operating schedules may become conditions in the permit.)

1	Facility **maximum** operating ($\frac{hours}{day}$): 24	($\frac{days}{week}$): 7	($\frac{weeks}{year}$): 52	($\frac{hours}{year}$): 8760	
2	Facility's maximum daily operating schedule (if less than 24 $\frac{hours}{day}$)? Start: N/A	☐AM ☐PM	End: N/A	☐AM ☐PM	
3	Month and year of anticipated start of construction: N/A				
4	Month and year of anticipated construction completion: N/A				
5	Month and year of anticipated startup of new or modified facility: N/A				
6	Will this facility operate at this site for more than one year? ☒ Yes ☐ No				

Section 1-F: Other Facility Information

1	Are there any current Notice of Violations (NOV), compliance orders, or any other compliance or enforcement issues related to this facility? ☐ Yes ☒ No If yes, specify:		
a	If yes, NOV date or description of issue: N/A		NOV Tracking No: N/A
b	Is this application in response to any issue listed in 1-F, 1 or 1a above? ☐ Yes ☒ No If Yes, provide the 1c & 1d info below:		
c	Document Title: N/A	Date: N/A	Requirement # (or page # and paragraph #): N/A
d	Provide the required text to be inserted in this permit: N/A		
2	Is air quality dispersion modeling or modeling waiver being submitted with this application? ☐ Yes ☒ No		
3	Does this facility require an "Air Toxics" permit under 20.2.72.400 NMAC & 20.2.72.502, Tables A and/or B? ☐ Yes ☒ No		
4	Will this facility be a source of federal Hazardous Air Pollutants (HAP)? ☒ Yes ☐ No		
a	If Yes, what type of source? ☐ **Major** (☐ ≥10 tpy of any single HAP **OR** ☐ ≥25 tpy of any combination of HAPS) **OR** ☒ **Minor** (☐ <10 tpy of any single HAP **AND** ☒ <25 tpy of any combination of HAPS)		
5	Is any unit exempt under 20.2.72.202.B.3 NMAC? ☐ Yes ☑ No		
a	If yes, include the name of company providing commercial electric power to the facility: ___________________________ Commercial power is purchased from a commercial utility company, which specifically does not include power generated on site for the sole purpose of the user.		

Section 1-G: Streamline Application (This section applies to 20.2.72.300 NMAC Streamline applications only)

1	☐ I have filled out Section 18, "Addendum for Streamline Applications."	☒ N/A (This is not a Streamline application.)

Section 1-H: Current Title V Information - Required for all applications from TV Sources

(Title V-source required information for all applications submitted pursuant to 20.2.72 NMAC (Minor Construction Permits), or 20.2.74/20.2.79 NMAC (Major PSD/NNSR applications), and/or 20.2.70 NMAC (Title V))

1	Responsible Official (R.O.) (20.2.70.300.D.2 NMAC): Mr. Casey Snow	Phone: (972) 371-5439
a	R.O. Title: VP – Regulatory, Environmental, and Safety	R.O. e-mail: csnow@matadorresources.com
b	R. O. Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	
2	Alternate Responsible Official (20.2.70.300.D.2 NMAC): Mr. Sean O'Grady	Phone: (972) 371-5284
a	A. R.O. Title: Vice President of Operations	A. R.O. e-mail: sogrady@sanmateomidstream.com
b	A. R. O. Address: 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	
3	Company's Corporate or Partnership Relationship to any other Air Quality Permittee (List the names of any companies that have operating (20.2.70 NMAC) permits and with whom the applicant for this permit has a corporate or partnership relationship): N/A	
4	Name of Parent Company ("Parent Company" means the primary name of the organization that owns the company to be permitted wholly or in part.): San Mateo Midstream, LLC.	
a	Address of Parent Company: One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240	
5	Names of Subsidiary Companies ("Subsidiary Companies" means organizations, branches, divisions or subsidiaries, which are owned, wholly or in part, by the company to be permitted.): N/A	
6	Telephone numbers & names of the owners' agents and site contacts familiar with plant operations: Jason Conway; (972) 619-1607	

7	Affected Programs to include Other States, local air pollution control programs (i.e. Bernalillo) and Indian tribes: Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B)? If yes, state which ones and provide the distances in kilometers: **37 km from Texas**

Section 1-I – Submittal Requirements

Each 20.2.73 NMAC (**NOI**), a 20.2.70 NMAC (**Title V**), a 20.2.72 NMAC (**NSR** minor source), or 20.2.74 NMAC (**PSD**) application package shall consist of the following:

Hard Copy Submittal Requirements:

1) One hard copy **original signed and notarized application package printed double sided 'head-to-toe' 2-hole punched** as we bind the document on top, not on the side; except Section 2 (landscape tables), which should be head-to-head. Please use **numbered tab separators** in the hard copy submittal(s) as this facilitates the review process. For NOI submittals only, hard copies of UA1, Tables 2A, 2D & 2F, Section 3 and the signed Certification Page are required. Please include a copy of the check on a separate page.

2) If the application is for a minor NSR, PSD, NNSR, or Title V application, include one working hard **copy** for Department use. This copy should be printed in book form, 3-hole punched, and **must be double sided**. Note that this is in addition to the head-to-to 2-hole punched copy required in 1) above. Minor NSR Technical Permit revisions (20.2.72.219.B NMAC) only need to fill out Sections 1-A, 1-B, 3, and should fill out those portions of other Section(s) relevant to the technical permit revision. TV Minor Modifications need only fill out Sections 1-A, 1-B, 1-H, 3, and those portions of other Section(s) relevant to the minor modification. NMED may require additional portions of the application to be submitted, as needed.

3) The entire NOI or Permit application package, including the full modeling study, should be submitted electronically. Electronic files for applications for NOIs, any type of General Construction Permit (GCP), or technical revisions to NSRs must be submitted with compact disk (CD) or digital versatile disc (DVD). For these permit application submittals, **two** CD copies are required (in sleeves, not crystal cases, please), with additional CD copies as specified below. NOI applications require only a single CD submittal. Electronic files for other New Source Review (construction) permits/permit modifications or Title V permits/permit modifications can be submitted on CD/DVD or sent through AQB's secure file transfer service.

Electronic files sent by (check one):

☐ CD/DVD attached to paper application

☒ Secure electronic transfer. Air Permit Contact Name **Jaimy Karacaoglu**, Email Jaimy.Karacaoglu@trinityconsultants.com Phone number **(505) 266-6611**.

a. If the file transfer service is chosen by the applicant, after receipt of the application, the Bureau will email the applicant with instructions for submitting the electronic files through a secure file transfer service. Submission of the electronic files through the file transfer service needs to be completed within 3 business days after the invitation is received, so the applicant should ensure that the files are ready when sending the hard copy of the application. The applicant will not need a password to complete the transfer. **Do not use the file transfer service for NOIs, any type of GCP, or technical revisions to NSR permits.**

4) Optionally, the applicant may submit the files with the application on compact disk (CD) or digital versatile disc (DVD) following the instructions above and the instructions in 5 for applications subject to PSD review.

5) If **air dispersion modeling** is required by the application type, include the **NMED Modeling Waiver** and/or electronic air dispersion modeling report, input, and output files. The dispersion modeling ***summary report only*** should be submitted as hard copy(ies) unless otherwise indicated by the Bureau.

6) If the applicant submits the electronic files on CD and the application is subject to PSD review under 20.2.74 NMAC (PSD) or NNSR under 20.2.79 NMC include,
   a. one additional CD copy for US EPA,
   b. one additional CD copy for each federal land manager affected (NPS, USFS, FWS, USDI) and,
   c. one additional CD copy for each affected regulatory agency other than the Air Quality Bureau.

   If the application is submitted electronically through the secure file transfer service, these extra CDs do not need to be submitted.

Electronic Submittal Requirements [in addition to the required hard copy(ies)]:

1) All required electronic documents shall be submitted as 2 separate CDs or submitted through the AQB secure file transfer service. Submit a single PDF document of the entire application as submitted and the individual documents comprising the application.

2) The documents should also be submitted in Microsoft Office compatible file format (Word, Excel, etc.) allowing us to access the text and formulas in the documents (copy & paste). Any documents that cannot be submitted in a Microsoft Office compatible format shall be saved as a PDF file from within the electronic document that created the file. If you are unable to provide Microsoft office compatible electronic files or internally generated PDF files of files (items that were not created electronically: i.e. brochures, maps, graphics, etc,), submit these items in hard copy format. We must be able to review the formulas and inputs that calculated the emissions.

3) It is preferred that this application form be submitted as 4 electronic files (3 MSWord docs: Universal Application section 1 [UA1], Universal Application section 3-19 [UA3], and Universal Application 4, the modeling report [UA4]) and 1 Excel file of the tables (Universal Application section 2 [UA2]). Please include as many of the 3-19 Sections as practical in a single MS Word electronic document. Create separate electronic file(s) if a single file becomes too large or if portions must be saved in a file format other than MS Word.

4) The electronic file names shall be a maximum of 25 characters long (including spaces, if any). The format of the electronic Universal Application shall be in the format: "A-3423-FacilityName". The "A" distinguishes the file as an application submittal, as opposed to other documents the Department itself puts into the database. Thus, all electronic application submittals should begin with "A-". Modifications to existing facilities should use the core permit number (i.e. '3423') the Department assigned to the facility as the next 4 digits. Use 'XXXX' for new facility applications. The format of any separate electronic submittals (additional submittals such as non-Word attachments, re-submittals, application updates) and Section document shall be in the format: "A-3423-9-description", where "9" stands for the section # (in this case Section 9-Public Notice). Please refrain, as much as possible, from submitting any scanned documents as this file format is extremely large, which uses up too much storage capacity in our database. Please take the time to fill out the header information throughout all submittals as this will identify any loose pages, including the Application Date (date submitted) & Revision number (0 for original, 1, 2, etc.; which will help keep track of subsequent partial update(s) to the original submittal. Do not use special symbols (#, @, etc.) in file names. The footer information should not be modified by the applicant.

Table of Contents

Table 2-A: Regulated Emission Sources

Unit and stack numbering must correspond throughout the application package. If applying for a NOI under 20.2.73 NMAC, equipment exemptions under 2.72.202 NMAC do not apply.

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
ENG-1	Inlet Gas Compressor Engine	Waukesha	P9394 GSI	5283705346	2250 hp	2250 hp	2016 	Catalyst-1 ENG-1	20200254	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
ENG-2	Inlet Gas Compressor Engine	Waukesha	P9394 GSI	5283705365	2250 hp	2250 hp	2016 	Catalyst-2 ENG-2	20200254	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
ENG-3	Inlet Gas Compressor Engine	Waukesha	P9394 GSI	5283705405	2250 hp	2250 hp	2016 	Catalyst-3 ENG-3	20200254	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
ENG-4	Inlet Gas Compressor Engine	Waukesha	P9394 GSI	5283705381	2250 hp	2250 hp	2016 	Catalyst-4 ENG-4	20200254	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
AM-1	Plant 2 - Amine Unit	Zeeco	N/A	N/A	290 MMSCFD	290 MMSCFD	2018 	TO-1 TO-1	31000201	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
AR-1	Plant 2 - Amine Reboiler	Tulsa Heaters	N/A	N/A	21.09 MMBtu/hr	21.09 MMBtu/hr	2018 	N/A AR-1	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
DEHY-1	Plant 2 - Dehydrator Unit	Tryer	Custom	N/A	290 MMSCFD	290 MMSCFD	2017 	FL-2 FL-2	31000227	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
DR-1	Plant 2 - Dehydrator Reboiler	Tryer	Custom	N/A	2.9 MMBtu/hr	2.9 MMBtu/hr	2017 	N/A DR-1	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
AM-2	Plant 3 - Amine Unit	Zeeco	N/A	N/A	220 MMSCFD	220 MMSCFD	2019 	TO-2 TO-2	31000201	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
AR-2	Plant 3 - Amine Reboiler	Tulsa Heaters	N/A	N/A	23.92 MMBtu/hr	23.92 MMBtu/hr	2019 	N/A AR-2	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
DEHY-2	Plant 3 - Dehydrator Unit	Tryer	Custom	N/A	220 MMSCFD	220 MMSCFD	2019 	TO-2 TO-2	31000227	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
DR-2	Plant 3 - Dehydrator Reboiler	Tryer	Custom	N/A	2.5 MMBtu/hr	2.5 MMBtu/hr	2019 	N/A DR-2	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HT-101	Plant 1 - Mole Sieve Heater	Heat Recovery Corp	N/A	N/A	6.97 MMBtu/hr	6.97 MMBtu/hr	2016 	N/A HT-101	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HT- 801	Plant 1 - Stabilizer Heater	Heat Recovery Corp	N/A	N/A	6.97 MMBtu/hr	6.97 MMBtu/hr	2019 	N/A HT-801	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HT - 102	Plant 2 - Mole Sieve Heater	Heat Recovery Corp	N/A	N/A	9.74 MMBtu/hr	9.74 MMBtu/hr	2016 	N/A HT - 102	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
HT - 103	Plant 3 - Mole Sieve Heater	Heat Recovery Corp	N/A	N/A	9.74 MMBtu/hr	9.74 MMBtu/hr	2019 	N/A HT - 103	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HT - 802	Plant 3 - Stabilizer Heater 1	Heat Recovery Corp	N/A	N/A	6.2 MMBtu/hr	6.2 MMBtu/hr	2019 	N/A HT - 802	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HT - 803	Plant 3 - Stabilizer Heater 2	Heat Recovery Corp	N/A	N/A	6.2 MMBtu/hr	6.2 MMBtu/hr	TBD 	N/A HT - 803	31000228	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TO - 1	Plant 2 - Thermal Oxidizer	Zeeco	N/A	N/A	9.9 MMBtu/hr	9.9 MMBtu/hr	2018 	N/A TO - 1	40400312	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TO - 2	Plant 3 - Thermal Oxidizer	Zeeco	N/A	N/A	9.9 MMBtu/hr	9.9 MMBtu/hr	2018 	N/A TO - 2	40400312	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FL - 1	Plant 1 - Flare SSM/M	Zeeco	N/A	N/A	85 MMBtu/hr	85 MMBtu/hr	2016 	N/A FL-1	30600904	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FL - 2	Plant 2 - Dehy -1 / Plant 2 - SSM/M	Zeeco	N/A	N/A	85 MMBtu/hr	85 MMBtu/hr	2016 	N/A FL-2	30600904	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FL - 3	Plant 3 - SSM/M	Zeeco	N/A	N/A	85 MMBtu/hr	85 MMBtu/hr	2019 	N/A FL-3	30600904	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
VCU - 1	Vapor Combustion Unit	Kimark Inc	N/A	N/A	7.11 MMBtu/hr	7.11 MMBtu/hr	2016 	N/A VCU-1	30600904	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK - 702 A-F	Condensate Tanks	N/A	N/A	N/A	500 bbl each	500 bbl each	2016 	VCU-1 VCU-1	40400312	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK 701	Produced Water Tank	N/A	N/A	N/A	500 bbl each	500 bbl each	2016 	VCU-1 VCU-1	40400315	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TL - 1	Condensate Tanks Truck Loading	N/A	N/A	N/A	N/A	N/A	2016 	N/A N/A	40600132	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TL - 2	Produced Water Tanks Truck Loading	N/A	N/A	N/A	N/A	N/A	2016 	N/A N/A	40600132	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
FUG	Fugitives	N/A	N/A	N/A	N/A	N/A	2016	N/A / N/A	31088811	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
CRYO - 1	Cryo Unit - 1	N/A	N/A	N/A	70 MMSCFD	70 MMSCFD	2016	N/A / N/A	31000299	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
CRYO - 2	Cryo Unit - 2	N/A	N/A	N/A	220 MMSCFD	220 MMSCFD	2017	N/A / N/A	31000299	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
CRYO - 3	Cryo Unit - 3	N/A	N/A	N/A	220 MMSCFD	220 MMSCFD	2019	N/A / N/A	31000299	☐ Existing (unchanged) ☐ To be Removed ☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

[1] Unit numbers must correspond to unit numbers in the previous permit unless a complete cross reference table of all units in both permits is provided.

[2] Specify dates required to determine regulatory applicability.

[3] To properly account for power conversion efficiencies, generator set rated capacity shall be reported as the rated capacity of the engine in horsepower, not the kilowatt capacity of the generator set.

[4] "4SLB" means four stroke lean burn engine, "4SRB" means four stroke rich burn engine, "2SLB" means two stroke lean burn engine, "CI" means compression ignition, and "SI" means spark ignition

Table 2-B: Exempted Equipment (20.2.72 NMAC)

All 20.2.70 NMAC (Title V) applications must list all Insignificant Activities in this table. All 20.2.72 NMAC applications must list Exempted Equipment in this table. If equipment listed on this table is exempt under 20.2.72.202.B.5, include emissions calculations and emissions totals for 202.B.5 "similar functions" units, operations, and activities in Section 6, Calculations. Equipment and activities exempted under 20.2.72.202 NMAC may not necessarily be Insignificant under 20.2.70 NMAC (and vice versa). Unit & stack numbering must be consistent throughout the application package. Per Exemptions Policy 02-012.00 (see http://www.env.nm.gov/aqb/permit/aqb_pol.html), 20.2.72.202.B NMAC Exemptions do not apply, but 20.2.72.202.A NMAC exemptions do apply to NOI facilities under 20.2.73 NMAC. List 20.2.72.301.D.4 NMAC Auxiliary Equipment for Streamline applications in Table 2-A. The List of Insignificant Activities (for TV) can be found online at https://www.env.nm.gov/wp-content/uploads/sites/2/2017/10/InsignificantListTitleV.pdf. TV sources may elect to enter both TV Insignificant Activities and Part 72 Exemptions on this form.

Unit Number	Source Description	Manufacturer	Model No. / Serial No.	Max Capacity / Capacity Units	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5) / Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Manufacture /Reconstruction[2] / Date of Installation /Construction[2]	For Each Piece of Equipment, Check One
ST-1	Glycol Storage Tanks	N/A	N/A	100			☐ Existing (unchanged) ☐ To be Removed
			N/A	bbl	IA List Item #5		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
ST-2	Amine Storage Tanks	N/A	N/A	300			☐ Existing (unchanged) ☐ To be Removed
			N/A	bbl	IA List Item #5		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
ST-3	Methanol Tanks	N/A	N/A	500			☐ Existing (unchanged) ☐ To be Removed
			N/A	bbl	IA List Item #5		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
ST-4	Lube Oil Tanks	N/A	N/A	500 & 2000			☐ Existing (unchanged) ☐ To be Removed
			N/A	gallons	IA List Item #5		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
ST-5	Antifreeze Tanks	N/A	N/A	1000			☐ Existing (unchanged) ☐ To be Removed
			N/A	gallons	IA List Item #5		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
Haul Road	Haul Raod Emissions	N/A	N/A	N/A			☐ Existing (unchanged) ☐ To be Removed
			N/A	N/A	IA List Item #1.a		☑ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced

[1] Insignificant activities exempted due to size or production rate are defined in 20.2.70.300.D.6, 20.2.70.7.Q NMAC, and the NMED/AQB List of Insignificant Activities, dated September 15, 2008. Emissions from these insignificant activities do not need to be reported, unless specifically requested.

[2] Specify date(s) required to determine regulatory applicability.

Table 2-C: Emissions Control Equipment

Unit and stack numbering must correspond throughout the application package. Only list control equipment for TAPs if the TAP's maximum uncontrolled emissions rate is over its respective threshold as listed in 20.2.72 NMAC, Subpart V, Tables A and B. In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and (e) NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions.

Control Equipment Unit No.	Control Equipment Description	Date Installed	Controlled Pollutant(s)	Controlling Emissions for Unit Number(s)[1]	Efficiency (% Control by Weight)	Method used to Estimate Efficiency
BTEX-1	Condenser	2018	VOC, HAP	DEHY-1	Varies	ProMax Simulation
BTEX-2	Condenser	2019	VOC, HAP	DEHY-2	Varies	ProMax Simulation
TO-1	Thermal Oxidizer	2018	VOC, HAP	AM-1	98%	Manufacturer Spec
TO-2	Thermal Oxidizer	2019	VOC, HAP	AM-2 and DEHY-2	98%	Manufacturer Spec
FL-1	Flare	2016	VOC, H_2S, HAP	Plant 1- SSM/M	98%	Manufacturer Spec
FL-2	Flare	2016	VOC, H_2S, HAP	DEHY-1 and Plant 2 - SSM/M	98%	Manufacturer Spec
FL-3	Flare	2019	VOC, H_2S, HAP	Plant 3 - SSM/M	98%	Manufacturer Spec
VCU-1	Vapor Combustion Unit	2016	VOC, H_2S, HAP	TK-702 A-F & TK 701	98%	Manufacturer Spec
ENG-1	Catalyst, AFR	2016	NO_X, CO, VOC, HCOH	Catalyst 1	Varies	Manufacturer Spec
ENG-2	Catalyst, AFR	2016	NO_X, CO, VOC, HCOH	Catalyst 2	Varies	Manufacturer Spec
ENG-3	Catalyst, AFR	2016	NO_X, CO, VOC, HCOH	Catalyst 3	Varies	Manufacturer Spec
ENG-4	Catalyst, AFR	2016	NO_X, CO, VOC, HCOH	Catalyst 4	Varies	Manufacturer Spec

[1] List each control device on a separate line. For each control device, list all emission units controlled by the control device.

Table 2-D: Maximum Emissions (under normal operating conditions)

☐ **This Table was intentionally left blank because it would be identical to Table 2-E.**

Maximum Emissions are the emissions at maximum capacity and prior to (in the absence of) pollution control, emission-reducing process equipment, or any other emission reduction. Calculate the hourly emissions using the worst case hourly emissions for each pollutant. For each pollutant, calculate the annual emissions as if the facility were operating at maximum plant capacity without pollution controls for 8760 hours per year, unless otherwise approved by the Department. List Hazardous Air Pollutants (HAP) & Toxic Air Pollutants (TAPs) in Table 2-I. Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ENG-1	72.42	317.21	47.12	206.4	2.58	11.3	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.0059	0.026	-	-
ENG-2	72.42	317.21	47.12	206.4	2.58	11.3	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.0059	0.026	-	-
ENG-3	72.42	317.21	47.12	206.4	2.58	11.3	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.0059	0.026	-	-
ENG-4	72.42	317.21	47.12	206.4	2.58	11.3	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.0059	0.026	-	-
HT-101	0.64	2.82	0.54	2.37	0.04	0.16	0.00	0.02	0.05	0.21	0.05	0.21	0.04	0.16	-	-	-	-
HT-801	0.64	2.82	0.54	2.37	0.04	0.16	0.00	0.02	0.05	0.21	0.05	0.21	0.04	0.16	-	-	-	-
HT-102	0.9	3.94	0.76	3.31	0.05	0.22	0.01	0.02	0.07	0.30	0.07	0.30	0.05	0.22	-	-	-	-
AR-1	1.95	8.54	1.64	7.17	0.11	0.47	0.01	0.05	0.15	0.65	0.15	0.65	0.11	0.49	-	-	-	-
DR-1	0.27	1.17	0.23	0.99	0.01	0.06	0.00	0.01	0.02	0.09	0.02	0.09	0.02	0.07	-	-	-	-
HT-103	0.9	3.94	0.76	3.31	0.05	0.22	0.01	0.02	0.07	0.30	0.07	0.30	0.05	0.22	-	-	-	-
HT-802	0.57	2.51	0.48	2.11	0.03	0.14	0.00	0.02	0.04	0.19	0.04	0.19	0.03	0.14	-	-	-	-
AR-2	2.21	9.68	1.86	8.14	0.12	0.53	0.01	0.06	0.17	0.74	0.17	0.74	0.13	0.55	-	-	-	-
DR-2	0.23	1.01	0.19	0.85	0.01	0.06	0.00	0.01	0.02	0.08	0.02	0.08	0.01	0.06	-	-	-	-
HT-803	0.57	2.51	0.48	2.11	0.03	0.14	0.00	0.02	0.04	0.19	0.04	0.19	0.03	0.14	-	-	-	-
DEHY-1	-	-	-	-	193.81	848.88	-	-	-	-	-	-	-	-	0.05	0.23	-	-
AM-1	-	-	-	-	19.49	85.35	-	-	-	-	-	-	-	-	6.54	28.64	-	-
DEHY-2	-	-	-	-	190.32	833.59	-	-	-	-	-	-	-	-	0.05	0.23	-	-
AM-2	-	-	-	-	18.95	2.99	-	-	-	-	-	-	-	-	4.93	21.58	-	-
TO-1	No emissions from this unit in an uncontrolled scenario.																	
TO-2	No emissions from this unit in an uncontrolled scenario.																	
TO-1 SSM	No emissions from this unit in an uncontrolled scenario.																	
TO-2 SSM	No emissions from this unit in an uncontrolled scenario.																	
DEHY-1 SSM	No emissions from this unit in an uncontrolled scenario.																	
FL-1	No emissions from this unit in an uncontrolled scenario.																	
FL-2	No emissions from this unit in an uncontrolled scenario.																	
FL-3	No emissions from this unit in an uncontrolled scenario.																	
VCU-1	No emissions from this unit in an uncontrolled scenario.																	
TK-702 A-F	-	-	-	-	17.94	78.58	-	-	-	-	-	-	-	-	0.00	0.00	-	-
TK-701	-	-	-	-	387.6	1697.69	-	-	-	-	-	-	-	-	0.00	0.00	-	-
TL-1	-	-	-	-	69.36	4.07	-	-	-	-	-	-	-	-	0.00	0.00	-	-
TL-2	-	-	-	-	129.71	0.22	-	-	-	-	-	-	-	-	0.00	0.00	-	-
FUG	-	-	-	-	7.89	34.54	-	-	-	-	-	-	-	-	0.040	0.16	-	-
SSM	-	-	-	-	66.43	12.12	-	-	-	-	-	-	-	-	-	-	-	-
MAL	517.79	6.21	1033.7	12.4	498.35	5.95	3.00	0.04	-	-	-	-	-	-	0.03	0.00	-	-
Totals	816.37	1314.01	1229.67	870.73	1610.64	3731.34	3.89	3.94	1.32	5.76	1.32	5.76	1.15	5.02	11.67	50.94	-	-

[1]**Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but PM is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

[2] Combustion emissions from pilot fuel combustion only

Table 2-E: Requested Allowable Emissions

Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or $1.41E^{-4}$).

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ENG-1	3.10	13.58	3.10	13.58	1.36	5.97	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.006	0.026	-	-
ENG-2	3.10	13.58	3.10	13.58	1.36	5.97	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.006	0.026	-	-
ENG-3	3.10	13.58	3.10	13.58	1.36	5.97	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.006	0.026	-	-
ENG-4	3.10	13.58	3.10	13.58	1.36	5.97	0.21	0.92	0.16	0.70	0.16	0.70	0.16	0.70	0.006	0.026	-	-
HT-101	0.64	2.82	0.54	2.37	0.04	0.16	0.004	0.02	0.05	0.21	0.05	0.21	0.04	0.16	-	-	-	-
HT-801	0.64	2.82	0.54	2.37	0.04	0.16	0.004	0.02	0.05	0.21	0.05	0.21	0.04	0.16	-	-	-	-
HT-102	0.90	3.94	0.76	3.31	0.05	0.22	0.005	0.02	0.07	0.30	0.07	0.30	0.05	0.22	-	-	-	-
AR-1	1.95	8.54	1.64	7.17	0.11	0.47	0.01	0.05	0.15	0.65	0.15	0.65	0.11	0.49	-	-	-	-
DR-1	0.27	1.17	0.23	0.99	0.01	0.06	0.002	0.01	0.02	0.09	0.02	0.09	0.02	0.07	-	-	-	-
HT-103	0.90	3.94	0.76	3.31	0.05	0.22	0.01	0.02	0.07	0.30	0.07	0.30	0.05	0.22	-	-	-	-
HT-802	0.57	2.51	0.48	2.11	0.03	0.14	0.003	0.02	0.04	0.19	0.04	0.19	0.03	0.14	-	-	-	-
AR-2	2.21	9.68	1.86	8.14	0.12	0.53	0.01	0.06	0.17	0.74	0.17	0.74	0.13	0.55	-	-	-	-
DR-2	0.23	1.01	0.19	0.85	0.01	0.06	0.001	0.01	0.02	0.08	0.02	0.08	0.01	0.06	-	-	-	-
HT-803	0.57	2.51	0.48	2.11	0.03	0.14	0.003	0.02	0.04	0.19	0.04	0.19	0.03	0.14	-	-	-	-
DEHY-1	Emissions are controlled by FL-2. Emissions are represented under FL-2.																	
AM-1	Emissions are controlled by thermal oxidizer, TO-1. Emissions are represented under TO-1.																	
DEHY-2	Emissions are controlled by thermal oxidizer, TO-2. Emissions are represented under TO-2.																	
AM-2	Emissions are controlled by thermal oxidizer, TO-2. Emissions are represented under TO-2.																	
TO-1	1.39	6.28	1.29	5.81	0.363	1.59	12.29	53.84	0.49	2.16	0.49	2.16	0.37	1.62	0.13	0.58	-	-
TO-2	2.17	9.71	2.02	9.00	3.78	16.55	9.36	41.01	0.42	1.84	0.42	1.84	0.31	1.38	0.10	0.44	-	-
FL-1 [2]	0.04	0.16	0.03	0.13	0.002	0.01	0.0002	0.001	-	-	-	-	-	-	0.0001	0.001	-	-
FL-2	1.70	7.44	3.33	14.60	3.49	15.29	0.100	0.43	-	-	-	-	-	-	0.001	0.01	-	-
FL-3 [2]	0.05	0.20	0.04	0.17	0.003	0.01	0.0003	0.001	-	-	-	-	-	-	0.0001	0.001	-	-
VCU-1	1.24	5.42	2.47	10.81	8.11	35.53	0.0006	0.0025	0.02	0.10	0.02	0.10	0.02	0.07	0.00001	0.00004	-	-
TK-702 A-F	Emissions are controlled by VCU-1. Controlled emissions are presented under VCU-1.																	
TK-701	Emissions are controlled by VCU-1. Controlled emissions are presented under VCU-1.																	
TL-1	-	-	-	-	69.36	4.07	-	-	-	-	-	-	-	-	0.000	0.000	-	-
TL-2	-	-	-	-	129.71	0.22	-	-	-	-	-	-	-	-	0.000	0.000	-	-
FUG	-	-	-	-	7.89	34.54	-	-	-	-	-	-	-	-	0.04	0.16	-	-
MAL (FL-1,2,3)	517.79	6.21	1033.70	12.40	498.35	5.98	3.000	0.04	-	-	-	-	-	-	0.032	0.0004	-	-
Malfunction	-	-	-	-	-	4.00	-	-	-	-	-	-	-	-	-	-	-	-
Totals	545.66	128.70	1062.75	139.97	726.99	143.82	25.64	99.23	2.25	9.86	2.25	9.86	1.85	8.09	0.33	1.30	-	-

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

[2] Pilot and sweep gas emissions only

Table 2-F: Additional Emissions during Startup, Shutdown, and Routine Maintenance (SSM)

☐ This table is intentionally left blank since all emissions at this facility due to routine or predictable startup, shutdown, or scehduled maintenance are no higher than those listed in Table 2-E and a malfunction emission limit is not already permitted or requested. If you are required to report GHG emissions as described in Section 6a, include any GHG emissions during Startup, Shutdown, and/or Scheduled Maintenance (SSM) in Table 2-P. Provide an explanations of SSM emissions in Section 6 and 6a.

All applications for facilities that have emissions during routine our predictable startup, shutdown or scheduled maintenance (SSM)[1], including NOI applications, must include in this table the Maximum Emissions during routine or predictable startup, shutdown and scheduled maintenance (20.2.7 NMAC, 20.2.72.203.A.3 NMAC, 20.2.73.200.D.2 NMAC). In Section 6 and 6a, provide emissions calculations for all SSM emissions reported in this table. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (https://www.env.nm.gov/aqb/permit/aqb_pol.html) for more detailed instructions. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		PM[2]		PM10[2]		PM2.5[2]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
TO-1 SSM	-	-	-	-	19.49	1.71	-	-	-	-	-	-	-	-	6.54	0.57	-	-
TO-2 SSM	-	-	-	-	190.32	16.67	-	-	-	-	-	-	-	-	0.05	0.00	-	-
DEHY-1 SSM	-	-	-	-	193.81	16.98	-	-	-	-	-	-	-	-	0.05	0.005	-	-
FL-1	103.56	4.97	206.74	9.92	99.67	4.78	0.60	0.01	-	-	-	-	-	-	0.01	0.0003	-	-
FL-2	173.8	9.34	346.97	18.64	168.06	9.68	1.03	0.080	-	-	-	-	-	-	0.01	0.001	-	-
FL-3	143.78	7.94	287.04	15.86	139.34	8.32	10.11	0.89	-	-	-	-	-	-	0.11	0.009	-	-
VCU-1 SSM	-	-	-	-	405.54	13.85	-	-	-	-	-	-	-	-	0.0003	0.00001	-	-
SSM	-	-	-	-	66.43	12.12	-	-	-	-	-	-	-	-	0.003	0.0006	-	-
Totals	421.19	22.48	840.79	44.61	1282.65	84.12	11.74	0.97	-	-	-	-	-	-	6.77	0.59	-	-

[1] **For instance**, if the short term steady-state Table 2-E emissions are 5 lb/hr and the SSM rate is 12 lb/hr, enter 7 lb/hr in this table. If the annual steady-state Table 2-E emissions are 21.9 TPY, and the number of scheduled SSM events result in annual emissions of 31.9 TPY, enter 10.0 TPY in the table below.

[2] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

Table 2-H: Stack Exit Conditions

Unit and stack numbering must correspond throughout the application package. Include the stack exit conditions for each unit that emits from a stack, including blowdown venting parameters and tank emissions. If the facility has multiple operating scenarios, complete a separate Table 2-H for each scenario and, for each, type scenario name here:

Stack Number	Serving Unit Number(s) from Table 2-A	Orientation (H-Horizontal V=Vertical)	Rain Caps	Height Above	Temp.	Flow Rate		Moisture by	Velocity	Inside Diameter (ft)
			(Yes or No)	Ground (ft)	(F)	(acfs)	(dscfs)	Volume (%)	(ft/sec)	
ENG-1	ENG-1	V	No	26.00	1085.00	172.77	N/A	N/A	130.16	1.29
ENG-2	ENG-2	V	No	26.00	1085.00	172.77	N/A	N/A	130.16	1.29
ENG-3	ENG-3	V	No	26.00	1085.00	172.77	N/A	N/A	130.16	1.29
ENG-4	ENG-4	V	No	26.00	1085.00	172.77	N/A	N/A	130.16	1.29
HT-101	HT-101	V	No	33.00	624.00	54.88	N/A	N/A	26.30	1.63
HT-801	HT-801	V	No	33.00	624.00	58.50	N/A	N/A	28.04	1.63
HT-102	HT-102	V	No	50.67	624.00	82.82	N/A	N/A	17.71	2.44
AR-1	AR-1	V	No	33.83	624.00	145.37	N/A	N/A	40.42	2.14
DR-1	DR-1	V	No	25.00	624.00	19.99	N/A	N/A	6.36	2.00
HT-103	HT-103	V	No	49.92	624.00	82.83	N/A	N/A	17.71	2.44
HT-802	HT-802	V	No	42.40	624.00	42.73	N/A	N/A	14.16	1.96
AR-2	AR-2	V	No	32.25	624.00	164.87	N/A	N/A	37.06	2.38
DR-2	DR-2	V	No	25.79	624.00	17.23	N/A	N/A	12.98	1.30
HT-803	HT-803	V	No	42.40	624.00	58.50	N/A	N/A	19.39	1.96
TO-1	TO-1	V	No	42.50	1600.00	274.45	N/A	N/A	7.21	6.96
TO-2	TO-2	V	No	61.17	1600.00	252.82	N/A	N/A	53.19	2.46
TO-1 SSM	TO-1 SSM	V	No	40.00	120.00	22.99	N/A	N/A	467.35	0.25
TO-2 SSM	TO-2 SSM	V	No	16.00	120.00	0.60	N/A	N/A	7.02	0.33
DEHY-1 SSM	DEHY-1 SSM	V	No	11.00	120.00	1.65	N/A	N/A	19.34	0.33
FL-1	FL-1	V	No	76.83	1832.00	209.62	N/A	N/A	65.62	34.37
FL-2	FL-2	V	No	90.75	1832.00	9.20	N/A	N/A	65.62	38.46
FL-3	FL-3	V	No	55.00	1832.00	82.48	N/A	N/A	65.62	27.37
VCU-1	VCU-1	V	No	33.17	1400.00	3.23	N/A	N/A	0.14	5.33
TK-702 A-F	TK-702 A-F	V	No	32.00	Ambient	1.12	N/A	N/A	0.0033	0.003
TK-701	TK-701	V	No	32.00	Ambient	0.003	N/A	N/A	0.0033	0.003
TL-1	TL-1	V	No	12.00	Ambient	0.98	N/A	N/A	0.0033	0.25
TL-2	TL-2	V	No	12.00	Ambient	0.001	N/A	N/A	0.0033	0.25
FUG	FUG	V	No	3.28	Ambient	0.38	N/A	N/A	0.0033	0.003

Table 2-I: Stack Exit and Fugitive Emission Rates for HAPs and TAPs

In the table below, report the Potential to Emit for each HAP from each regulated emission unit listed in Table 2-A, only if the entire facility emits the HAP at a rate greater than or equal to one (1) ton per year For each such emission unit, HAPs shall be reported to the nearest 0.1 tpy. Each facility-wide Individual HAP total and the facility-wide Total HAPs shall be the sum of all HAP sources calculated to the nearest 0.1 ton per year. Per 20.2.72.403.A.1 NMAC, facilities not exempt [see 20.2.72.402.C NMAC] from TAP permitting shall report each TAP that has an uncontrolled emission rate in excess of its pounds per hour screening level specified in 20.2.72.502 NMAC. TAPs shall be reported using one more significant figure than the number of significant figures shown in the pound per hour threshold corresponding to the substance. Use the HAP nomenclature as it appears in Section 112 (b) of the 1990 CAAA and the TAP nomenclature as it listed in 20.2.72.502 NMAC. Include tank-flashing emissions estimates of HAPs in this table. For each HAP or TAP listed, fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected or the pollutant is emitted in a quantity less than the threshold amounts described above.

Stack No.	Unit No.(s)	Total HAPs		Formaldehyde ☑ HAP		Benzene ☑ HAP		Toluene ☑ HAP		Acetaldehyde ☑ HAP		Acrolein ☑ HAP		Xylene ☑ HAP		Provide Pollutant Name Here HAP or TAP		Provide Pollutant Name Here HAP or TAP	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ENG-1	ENG-1	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01				
ENG-2	ENG-2	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01				
ENG-3	ENG-3	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01				
ENG-4	ENG-4	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01				
HT-101	HT-101	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
HT-801	HT-801	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
HT-102	HT-102	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
AR-1	AR-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
DR-1	DR-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
HT-103	HT-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
HT-802	HT-802	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
AR-2	AR-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
DR-2	DR-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
HT-803	HT-803	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
DEHY-1	DEHY-1	Emissions are controlled by flare, FL-2. Emissions are presented under FL-2a.																	
AM-1	AM-1	Emissions are controlled by thermal oxidizer, TO-1. Emissions are presented under TO-1.																	
DEHY-2	DEHY-2	Emissions are controlled by thermal oxidizer, TO-2. Emissions are presented under TO-2.																	
AM-2	AM-2	Emissions are controlled by thermal oxidizer, TO-2. Emissions are presented under TO-2.																	
TO-1	TO-1	0.15	0.65	-	-	0.15	0.65	-	-	-	-	-	-	-	-				
TO-2	TO-2	0.60	2.64	-	-	0.60	2.64	-	-	-	-	-	-	-	-				
TO-1 SSM	TO-1 SSM	7.44	0.65	-	-	7.44	0.65	-	-	-	-	-	-	-	-				
TO-2 SSM	TO-2 SSM	22.02	1.93	-	-	22.02	1.93	-	-	-	-	-	-	-	-				
DEHY-1 SSM	DEHY-1 SSM	18.75	1.64	-	-	18.75	1.64	-	-	-	-	-	-	-	-				
FL-1	FL-1	0.05	0.00	-	-	0.05	0.00	-	-	-	-	-	-	-	-				
FL-2	FL-2	0.09	0.01	-	-	0.47	1.66	-	-	-	-	-	-	-	-				
FL-3	FL-3	0.24	0.03	-	-	0.24	0.03	-	-	-	-	-	-	-	-				
VCU-1	VCU-1	0.05	0.22	-	-	0.05	0.22	-	-	-	-	-	-	-	-				
TK-702 A-F	TK-702 A-F	Emissions are controlled by Vapor Combustion Unit, VCU-1. Emissions are represented under VCU-1.																	
TK-701	TK-701	Emissions are controlled by Vapor Combustion Unit, VCU-1. Emissions are represented under VCU-1.																	
TL-1	TL-1	0.66	0.05	-	-	0.66	0.05	-	-	-	-	-	-	-	-				
TL-2	TL-2	8.94	0.01	-	-	8.94	0.01	-	-	-	-	-	-	-	-				
FUG	FUG	0.01	0.03	-	-	0.01	0.03	-	-	-	-	-	-	-	-				
SSM	SSM	8.94	0.01	-	-	0.02	0.00	-	-	-	-	-	-	-	-				
MAL	MAL	0.24	0.00	-	-	0.24	0.00	-	-	-	-	-	-	-	-				
Totals:		69.61	14.11	0.50	2.17	59.67	9.61	0.03	0.11	0.53	2.33	0.33	1.43	0.01	0.05				

Table 2-J: Fuel

Specify fuel characteristics and usage. Unit and stack numbering must correspond throughout the application package.

Unit No.	Fuel Type (low sulfur Diesel, ultra low sulfur diesel, Natural Gas, Coal, …)	Fuel Source: purchased commercial, pipeline quality natural gas, residue gas, raw/field natural gas, process gas (e.g. SRU tail gas) or other	Specify Units				
			Lower Heating Value	Hourly Usage (MMSCF/hr)	Annual Usage (MMSCF/yr)	% Sulfur	% Ash
ENG-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	14.69	128.69	N/A	N/A
ENG-2	Natural Gas	Pipeline Quality Natural Gas	1081.8	14.69	128.69	N/A	N/A
ENG-3	Natural Gas	Pipeline Quality Natural Gas	1081.8	14.69	128.69	N/A	N/A
ENG-4	Natural Gas	Pipeline Quality Natural Gas	1081.8	14.69	128.69	N/A	N/A
HT-101	Natural Gas	Pipeline Quality Natural Gas	1081.8	6.44	56.44	N/A	N/A
HT-801	Natural Gas	Pipeline Quality Natural Gas	1081.8	6.44	56.44	N/A	N/A
HT-102	Natural Gas	Pipeline Quality Natural Gas	1081.8	9.00	78.87	N/A	N/A
AR-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	19.50	170.78	N/A	N/A
DR-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	2.68	23.48	N/A	N/A
HT-103	Natural Gas	Pipeline Quality Natural Gas	1081.8	9.00	78.87	N/A	N/A
HT-802	Natural Gas	Pipeline Quality Natural Gas	1081.8	5.73	50.21	N/A	N/A
AR-2	Natural Gas	Pipeline Quality Natural Gas	1081.8	22.11	193.69	N/A	N/A
DR-2	Natural Gas	Pipeline Quality Natural Gas	1081.8	2.31	20.24	N/A	N/A
HT-803	Natural Gas	Pipeline Quality Natural Gas	1081.8	5.73	50.21	N/A	N/A
TO-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.47	4.12	N/A	N/A
TO-2	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.47	4.12	N/A	N/A
FL-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.36	3.15	N/A	N/A
FL-2	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.51	4.47	N/A	N/A
FL-3	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.46	4.03	N/A	N/A
VCU-1	Natural Gas	Pipeline Quality Natural Gas	1081.8	0.01	0.11	N/A	N/A

Table 2-K: Liquid Data for Tanks Listed in Table 2-L

For each tank, list the liquid(s) to be stored in each tank. If it is expected that a tank may store a variety of hydrocarbon liquids, enter "mixed hydrocarbons" in the Composition column for that tank and enter the corresponding data of the most volatile liquid to be stored in the tank. If tank is to be used for storage of different materials, list all the materials in the "All Calculations" attachment, run the newest version of TANKS on each, and use the material with the highest emission rate to determine maximum uncontrolled and requested allowable emissions rate. The permit will specify the most volatile category of liquids that may be stored in each tank. Include appropriate tank-flashing modeling input data. Use additional sheets if necessary. Unit and stack numbering must correspond throughout the application package.

Tank No.	SCC Code	Material Name	Composition	Liquid Density (lb/gal)	Vapor Molecular Weight (lb/lb*mol)	Average Storage Conditions		Max Storage Conditions	
						Temperature (°F)	True Vapor Pressure (psia)	Temperature (°F)	True Vapor Pressure (psia)
TK-702-A	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-702-B	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-702-C	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-702-D	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-702-E	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-702-F	40400311	Oil	Mixed Hydrocarbons	0.55	72.44	65	4.47	100	8.96
TK-701	40400311	Produced Water	Water	8.30	56.01	65	21.67	100	12.23

Table 2-L: Tank Data

Include appropriate tank-flashing modeling input data. Use an addendum to this table for unlisted data categories. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary. See reference Table 2-L2. Note: 1.00 bbl = 10.159 M3 = 42.0 gal

Tank No.	Date Installed	Materials Stored	Seal Type (refer to Table 2-LR below)	Roof Type (refer to Table 2-LR below)	Capacity		Diameter (M)	Vapor Space (M)	Color (from Table VI-C)		Paint Condition (from Table VI-C)	Annual Throughput (gal/yr)	Turn-overs (per year)
					(bbl)	(M^3)			Roof	Shell			
TK-702-A	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-702-B	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-702-C	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-702-D	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-702-E	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-702-F	2016	Oil			500	79.49	3.66		WH	WH	Good	15,330,000	906
TK-701	2016	Produced Water			500	79.49	3.66		WH	WH	Good	2,301,523	133

Table 2-L2: Liquid Storage Tank Data Codes Reference Table

Roof Type	Seal Type, Welded Tank Seal Type		Seal Type, Riveted Tank Seal Type		Roof, Shell Color	Paint Condition
	Mechanical Shoe Seal	Liquid-mounted resilient seal	Vapor-mounted resilient seal	Seal Type		
FX: Fixed Roof					**WH**: White	Good
IF: Internal Floating Roof	**A**: Primary only	**A**: Primary only	**A**: Primary only	**A**: Mechanical shoe, primary only	**AS**: Aluminum (specular)	Poor
EF: External Floating Roof	**B**: Shoe-mounted secondary	**B**: Weather shield	**B**: Weather shield	**B**: Shoe-mounted secondary	**AD**: Aluminum (diffuse)	
P: Pressure	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**LG**: Light Gray	
					MG: Medium Gray	
					BL: Black	
					OT: Other (specify)	

Note: 1.00 bbl = 0.159 M^3 = 42.0 gal

Table 2-M: Materials Processed and Produced (Use additional sheets as necessary.)

Material Processed				Material Produced			
Description	**Chemical Composition**	**Phase (Gas, Liquid, or Solid)**	**Quantity (specify units)**	**Description**	**Chemical Composition**	**Phase**	**Quantity (specify units)**
Natural Gas	Mixed Hydrocarbons	Gas	510 MMSCFD	Natural Gas	Mixed Hydrocarbons	Gas	510 MMSCFD
				Oil	Mixed Hydrocarbons	Liquid	6,000 BPD
				Natural Gas Liquids	Natural Gas Liquids	Liquid	75,000 BPD

Table 2-N: CEM Equipment

Enter Continuous Emissions Measurement (CEM) Data in this table. If CEM data will be used as part of a federally enforceable permit condition, or used to satisfy the requirements of a state or federal regulation, include a copy of the CEM's manufacturer specification sheet in the Information Used to Determine Emissions attachment. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Stack No.	Pollutant(s)	Manufacturer	Model No.	Serial No.	Sample Frequency	Averaging Time	Range	Sensitivity	Accuracy
N/A - No Continuous Emissions Measurement equipment at this facility.									

Table 2-O: Parametric Emissions Measurement Equipment

Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Unit No.	Parameter/Pollutant Measured	Location of Measurement	Unit of Measure	Acceptable Range	Frequency of Maintenance	Nature of Maintenance	Method of Recording	Averaging Time
N/A - No Parametric Emissions Measurement equipment at this facility.								

Table 2-P: Greenhouse Gas Emissions

Applications submitted under 20.2.70, 20.2.72, & 20.2.74 NMAC are required to complete this Table. Power plants, Title V major sources, and PSD major sources must report and calculate all GHG emissions for each unit. Applicants must report potential emission rates in short tons per year (see Section 6.a for assistance). Include GHG emissions during Startup, Shutdown, and Scheduled Maintenance in this table. For minor source facilities that are not power plants, are not Title V, or are not PSD, there are three options for reporting GHGs 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHG as a second separate unit; OR 3) check the following box ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

		CO_2 ton/yr	N_2O ton/yr	CH_4 ton/yr	SF_6 ton/yr	PFC/HFC ton/yr[2]									Total GHG Mass Basis ton/yr[4]	Total CO_2e ton/yr[5]
Unit No.	GWPs[1]	1	298	25	22,800	footnote 3										
ENG-1	mass GHG	9768.01	0.02	0.18												
	CO_2e	9768.01	5.49	4.60												
ENG-2	mass GHG	9768.01	0.02	0.18												
	CO_2e	9768.01	5.49	4.60												
ENG-3	mass GHG	9768.01	0.02	0.18												
	CO_2e	9768.01	5.49	4.60												
ENG-4	mass GHG	9768.01	0.02	0.18												
	CO_2e	9768.01	5.49	4.60												
HT-101	mass GHG	3571.12	0.01	0.07												
	CO_2e	3571.12	2.01	1.68												
HT-801	mass GHG	3571.12	0.01	0.07												
	CO_2e	3571.12	2.01	1.68												
HT-102	mass GHG	4990.34	0.01	0.09												
	CO_2e	4990.34	2.80	2.35												
AR-1	mass GHG	10805.57	0.02	0.20												
	CO_2e	10805.57	6.01	5.09												
DR-1	mass GHG	1485.83	0.00	0.03												
	CO_2e	1485.83	0.83	0.70												
HT-103	mass GHG	4990.34	0.01	0.09												
	CO_2e	4990.34	2.80	2.35												
HT-802	mass GHG	3176.60	0.01	0.06												
	CO_2e	3176.60	1.78	1.50												
AR-2	mass GHG	12255.54	0.02	0.23												
	CO_2e	12255.54	6.88	5.77												
DR-2	mass GHG	1280.89	0.00	0.02												
	CO_2e	1280.89	0.72	0.60												
HT-803	mass GHG	3176.60	0.01	0.06												
	CO_2e	3176.60	1.78	1.50												
TO-1	mass GHG	5021.08	0.01	0.09												
	CO_2e	5021.08	2.82	2.37												
TO-2	mass GHG	5021.08	0.01	0.09												
	CO_2e	5021.08	2.56	2.37												
FL-1	mass GHG	30.18	0.00	0.00												
	CO_2e	30.18	0.02	0.01												
FL-2	mass GHG	5200.20	0.01	0.10												
	CO_2e	5200.20	2.92	2.45												
FL-3	mass GHG	1895.71	0.00	0.00												
	CO_2e	1895.71	1.06	0.89												
VCU-1	mass GHG	3642.85	0.01	0.07												
	CO_2e	3642.85	2.05	1.72												

TK-702 A-F	**mass GHG**	2.08	0.11	42.32												
	CO_2e	2.80	32.63	1057.88												
TL-1	**mass GHG**	0.91	0.00	9.59												
	CO_2e	0.91	0.00	239.70												
TL-2	**mass GHG**	0.03	0.00	0.02												
	CO_2e	0.03	0.00	0.44												
FUG	**mass GHG**	2.08	0.00	99.47												
	CO_2e	2.08	0.00	2486.65												
Total	**mass GHG**	109192.17	0.31	111.06												
	CO_2e	109192.17	93.69	3836.11												

[1] **GWP** (Global Warming Potential): Applicants must use the most current GWPs codified in Table A-1 of 40 CFR part 98. GWPs are subject to change, therefore, applicants need to check 40 CFR 98 to confirm GWP values.

[2] For **HFCs** or **PFCs** describe the specific HFC or PFC compound and use a separate column for each individual compound.

[3] For each new compound, enter the appropriate GWP for each HFC or PFC compound from Table A-1 in 40 CFR 98.

[4] Green house gas emissions on a **mass basis** is the ton per year green house gas emission before adjustment with its GWP.

[5] **CO_2e** means Carbon Dioxide Equivalent and is calculated by multiplying the TPY mass emissions of the green house gas by its GWP.

Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will affect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

The **Process Summary** shall include a brief description of the facility and its processes.

Startup, Shutdown, and Maintenance (SSM) routine or predictable emissions: Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

DLK Black River Midstream, LLC (DLK) owns and operates the Black River Gas Processing Plant, located 2.1 miles southwest of Loving, New Mexico in Eddy County. The facility is currently permitted under NSR #6567-M8. With the issuance of this NSR permit, the facility exceeds the Title V operating thresholds, and therefore DLK is submitting this initial Title V application pursuant 20.2.70.300.B(1) within twelve (12) months after the source commences operation as a Part 70 source.

Black River Gas Processing Plant consists of Plants 1, 2, and 3. The facility utilizes amine sweetening units to remove hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from raw natural gas, followed by dehydration to eliminate moisture. The sweetened gas then enters cryogenic units, where it is cooled to separate valuable natural gas liquids (NGLs) from the gas stream and transported in a sales line. Produced water and condensate are transported off the site via truck loadout.

Flares (FL-1, FL-2b, FL-3) control the startup, shutdown, maintenance, and upset conditions. SSM emissions from the flare result from maintenance activities per manufacturer recommendations or other preventative measures. The maintenance activities include, but are not limited to compressor catalyst changes, blowdowns for associated maintenance throughout the facility, instrument calibrations, and process safety device maintenance.

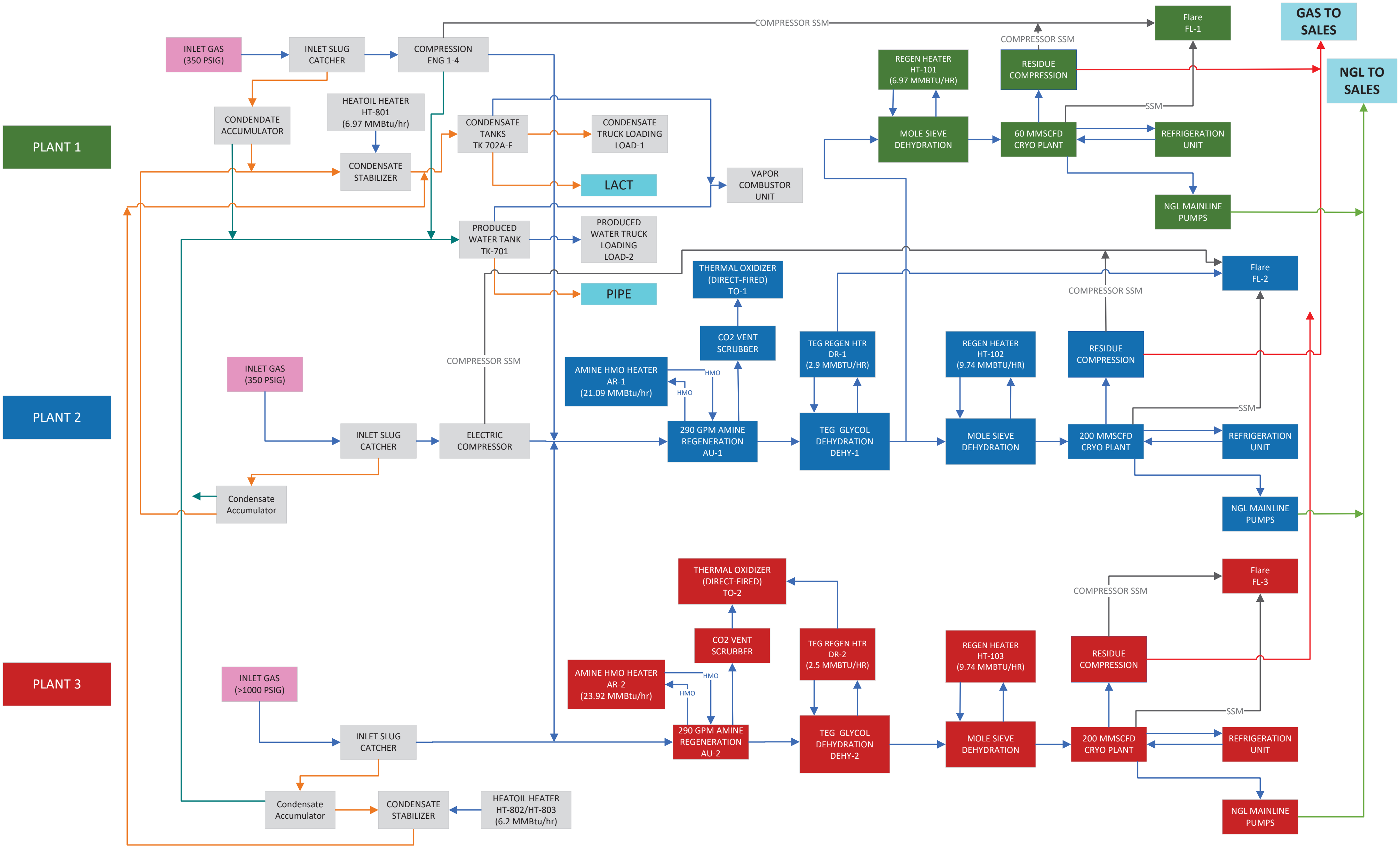
Section 4

Process Flow Sheet

A **process flow sheet** and/or block diagram indicating the individual equipment, all emission points and types of control applied to those points. The unit numbering system should be consistent throughout this application.

A process flow diagram is attached to this application.

BLACK RIVER GAS PROCESSING PLANT

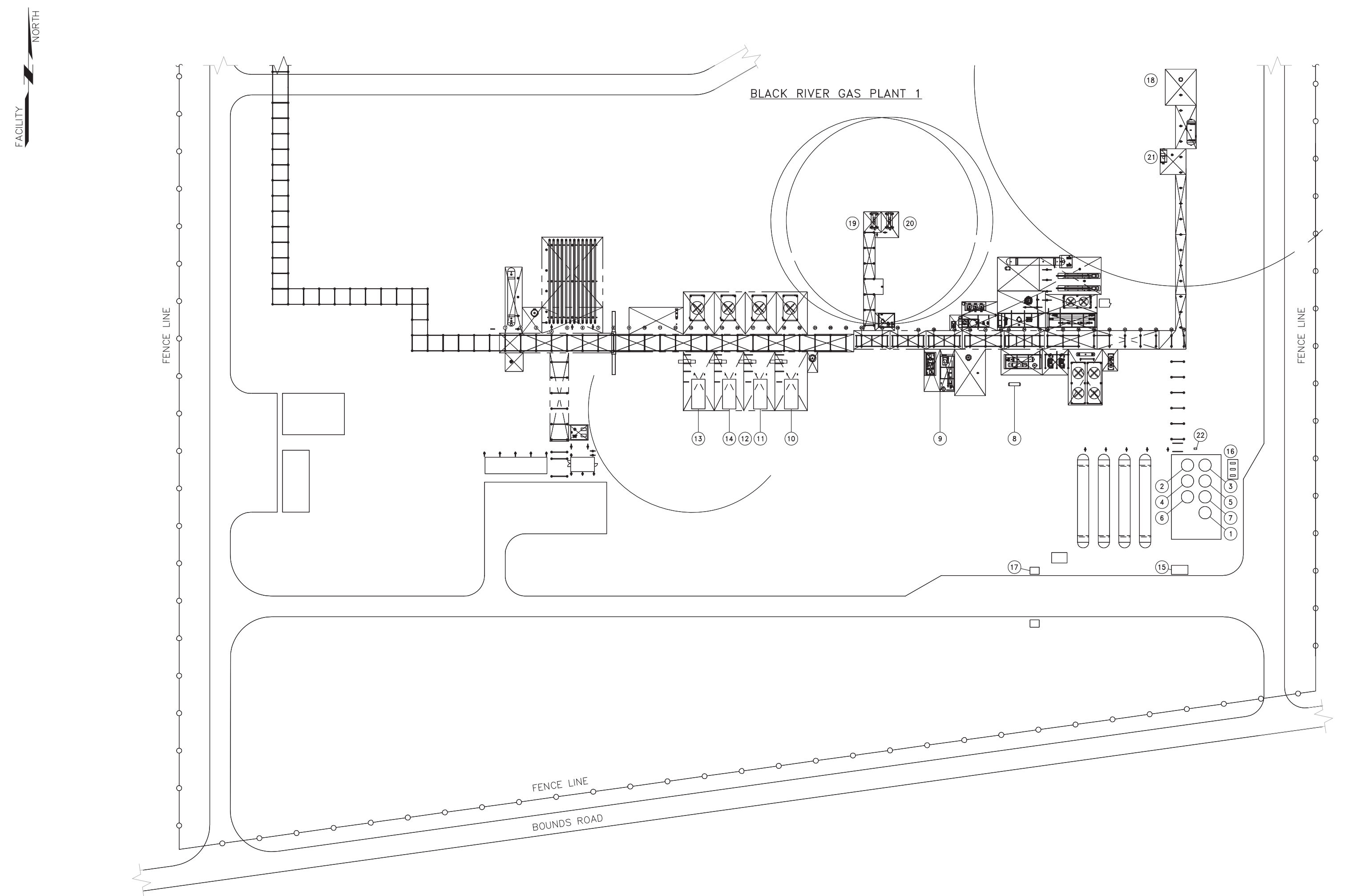


Section 5

Plot Plan Drawn to Scale

A **plot plan drawn to scale** showing emissions points, roads, structures, tanks, and fences of property owned, leased, or under direct control of the applicant. This plot plan must clearly designate the restricted area as defined in UA1, Section 1-D.12. The unit numbering system should be consistent throughout this application.

A plot plan is attached to the application.



EMISSIONS LEGEND
PLANT 1

MARK	TAG	DESCRIPTION
1	T-701	WASTE WATER
2	T-702A	STABILIZED CONDENSATE
3	T-702B	STABILIZED CONDENSATE
4	T-702C	STABILIZED CONDENSATE
5	T-702D	STABILIZED CONDENSATE
6	T-702E	STABILIZED CONDENSATE
7	T-703	STABILIZED CONDENSATE
8		PLANT #1 CRYOGENIC METHANOL STORAGE
9		PLANT #1 CONDENSATE STABILIZER COMPRESSOR LUBE OIL STORAGE
10		PLANT #1 RESIDUE COMPRESSOR "A" OIL STORAGE
11		PLANT #1 RESIDUE COMPRESSOR "B" OIL STORAGE
12		PLANT #1 COMPRESSOR BULK OIL STORAGE
13		PLANT #1 INLET COMPRESSOR "A" OIL STORAGE
14		PLANT #1 INLET COMPRESSOR "B" OIL STORAGE
15	LOAD-1	STABILIZED CONDENSATE
16	LOAD-2	PRODUCED (WASTE) WATER
17	LOAD-3	NGL
18	FL-1	PLANT #1 FLARE STACK
19	HT-1	MOLE SIEVE HEATER (PLANT #1 REGEN HEATER)
20	HT-801	HOT OIL HEATER (PLANT #1 STABILIZER)
21	VCU	CONDENSATE AND WASTE WATER VAPOR COMBUSTION UNIT (VCU)
22		PLANT #1 CONDENSATE TANK VENT (ENARDO)

EMISSIONS LAYOUT

SCALE: 1"=50'-0"

GENERAL NOTES:

REV.	REVISION	DATE	DRAFT	CHECKED	APP'D.
A	ISSUED FOR APPROVAL	01/11/18	KES		

PELICAN Energy Consultants, LLC

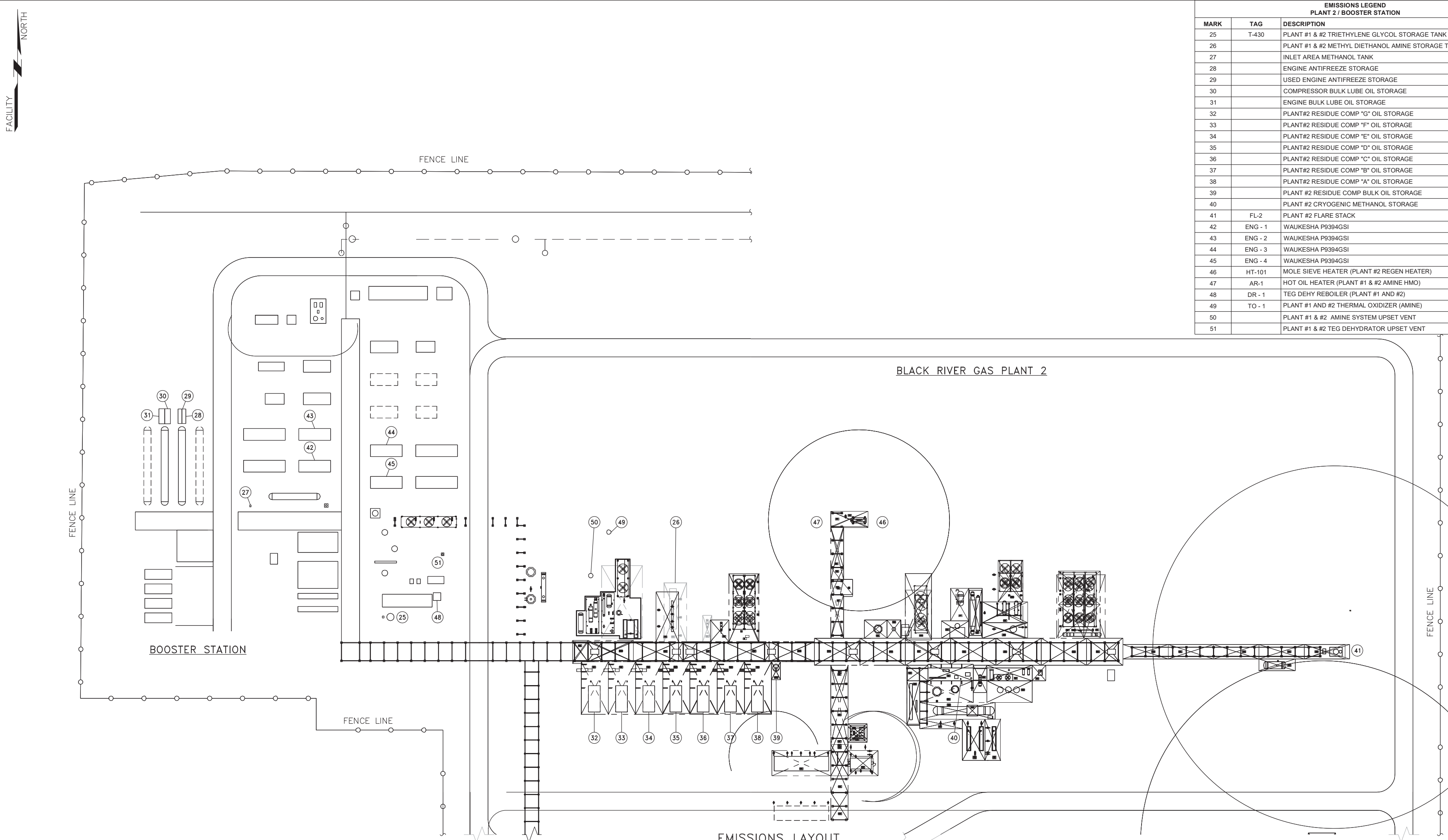
San Mateo MIDSTREAM

TITLE
BRNGPP FACILITIES
EDDY COUNTY, NEW MEXICO
EMISSIONS LAYOUT
GAS PLANT 1

DRAWING APPROVAL

DRAWN BY:	KES	04/01/20	CHECKED BY:	DAH	04/01/20
DESIGN ENGINEER:	DAH	04/01/20	CLIENT APPROVAL:		
CLIENT	SAN MATEO MIDSTREAM		JOB NO. 190625		DWG. NO. 31501

PLOT TIME: April 6, 2020 12:07 PM BY: KATY SCHILD FILE PATH: R:\CLIENT_PROJECTS\MATADOR\RUSTLER_BREAKS_COMPRESSOR_STATION\170206\DRAWINGS\30000 MECHANICAL\31000\31501-190625.DWG



EMISSIONS LEGEND
PLANT 2 / BOOSTER STATION

MARK	TAG	DESCRIPTION
25	T-430	PLANT #1 & #2 TRIETHYLENE GLYCOL STORAGE TANK
26		PLANT #1 & #2 METHYL DIETHANOL AMINE STORAGE TANK
27		INLET AREA METHANOL TANK
28		ENGINE ANTIFREEZE STORAGE
29		USED ENGINE ANTIFREEZE STORAGE
30		COMPRESSOR BULK LUBE OIL STORAGE
31		ENGINE BULK LUBE OIL STORAGE
32		PLANT#2 RESIDUE COMP "G" OIL STORAGE
33		PLANT#2 RESIDUE COMP "F" OIL STORAGE
34		PLANT#2 RESIDUE COMP "E" OIL STORAGE
35		PLANT#2 RESIDUE COMP "D" OIL STORAGE
36		PLANT#2 RESIDUE COMP "C" OIL STORAGE
37		PLANT#2 RESIDUE COMP "B" OIL STORAGE
38		PLANT#2 RESIDUE COMP "A" OIL STORAGE
39		PLANT #2 RESIDUE COMP BULK OIL STORAGE
40		PLANT #2 CRYOGENIC METHANOL STORAGE
41	FL-2	PLANT #2 FLARE STACK
42	ENG - 1	WAUKESHA P9394GSI
43	ENG - 2	WAUKESHA P9394GSI
44	ENG - 3	WAUKESHA P9394GSI
45	ENG - 4	WAUKESHA P9394GSI
46	HT-101	MOLE SIEVE HEATER (PLANT #2 REGEN HEATER)
47	AR-1	HOT OIL HEATER (PLANT #1 & #2 AMINE HMO)
48	DR - 1	TEG DEHY REBOILER (PLANT #1 AND #2)
49	TO - 1	PLANT #1 AND #2 THERMAL OXIDIZER (AMINE)
50		PLANT #1 & #2 AMINE SYSTEM UPSET VENT
51		PLANT #1 & #2 TEG DEHYDRATOR UPSET VENT

EMISSIONS LAYOUT
SCALE: 1"=50'-0"

GENERAL NOTES:

REV.	REVISION	DATE	DRAFT	CHECKED	APP'D.
A	ISSUED FOR APPROVAL	01/11/18	KES		

PELICAN
Energy Consultants, LLC

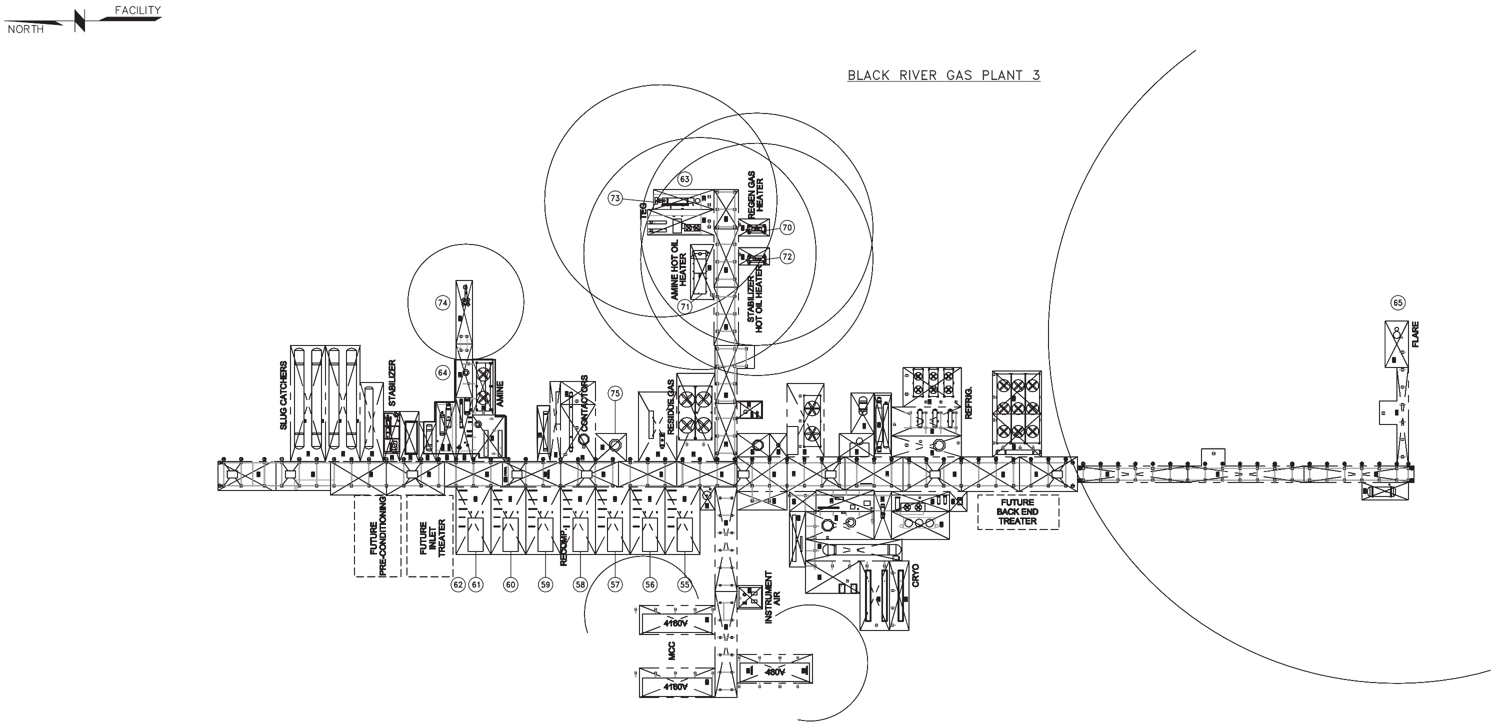
San Mateo MIDSTREAM

TITLE
BRNGPP FACILITIES
EDDY COUNTY, NEW MEXICO
EMISSIONS LAYOUT
GAS PLANT 2/BOOSTER STATION

DRAWING APPROVAL					
DRAWN BY:	KES	04/01/20	CHECKED BY:	DAH	04/01/20
DESIGN ENGINEER:	DAH	04/01/20	CLIENT APPROVAL:		

CLIENT	JOB NO.	DWG. NO.
SAN MATEO MIDSTREAM	190625	31502

PLOT TIME: April 6, 2020 12:12 PM BY: KATY SCHILD FILE PATH: R:\CLIENT_PROJECTS\MATADOR\RUSTLER_BREAKS_COMPRESSOR_STATION\170206\DRAWINGS\30000 MECHANICAL\31000\31502-190625.DWG



EMISSIONS LEGEND PLANT 3		
MARK	TAG	DESCRIPTION
55		PLANT #3 RESIDUE COMP "A" OIL STORAGE
56		PLANT #3 RESIDUE COMP "B" OIL STORAGE
57		PLANT #3 RESIDUE COMP "C" OIL STORAGE
58		PLANT #3 RESIDUE COMP "D" OIL STORAGE
59		PLANT #3 RESIDUE COMP "E" OIL STORAGE
60		PLANT #3 RESIDUE COMP "F" OIL STORAGE
61		PLANT #3 RESIDUE COMP "G" OIL STORAGE
62		PLANT #3 RESIDUE COMP BULK OIL STORAGE
63		PLANT #3 TRIETHYLENE GLYCOL STORAGE
64		PLANT #3 METHYL DIETHANOL AMINE STORAGE
65	FL-3	PLANT #3 FLARE STACK
70	HT-102	MOLE SIEVE HEATER (PLANT #3 REGEN HEATER)
71	AR-2	HOT OIL HEATER (PLANT #3 AMINE HMO)
72	HT-802	HOT OIL HEATER (PLANT #3 STABILIZER)
73	DR-2	TEG DEHY REBOILER (PLANT #3)
74	TO-2	PLANT #3 THERMAL OXIDIZER (AMINE/TEG)
75		PLANT #3 TEG DEHYDRATOR UPSET VENT

EMISSIONS LAYOUT

SCALE: 1"=50'-0"

GENERAL NOTES:

REV.	REVISION	DATE	DRAFT	CHECKED	APP'D.
A	ISSUED FOR APPROVAL	01/11/18	KES		

PELICAN Energy Consultants, LLC

San Mateo MIDSTREAM

TITLE
BRNGPP FACILITIES
EDDY COUNTY, NEW MEXICO
EMISSIONS LAYOUT
GAS PLANT 3

DRAWING APPROVAL

DRAWN BY:	KES	04/01/20	CHECKED BY:	DAH	04/01/20
DESIGN ENGINEER:	DAH	04/01/20	CLIENT APPROVAL:		

CLIENT	JOB NO.	DWG. NO.
SAN MATEO MIDSTREAM	190625	31503

Section 6

All Calculations

Show all calculations used to determine both the hourly and annual controlled and uncontrolled emission rates. All calculations shall be performed keeping a minimum of three significant figures. Document the source of each emission factor used (if an emission rate is carried forward and not revised, then a statement to that effect is required). If identical units are being permitted and will be subject to the same operating conditions, submit calculations for only one unit and a note specifying what other units to which the calculations apply. All formulas and calculations used to calculate emissions must be submitted. The "Calculations" tab in the UA2 has been provided to allow calculations to be linked to the emissions tables. Add additional "Calc" tabs as needed. If the UA2 or other spread sheets are used, all calculation spread sheet(s) shall be submitted electronically in Microsoft Excel compatible format so that formulas and input values can be checked. Format all spread sheets and calculations such that the reviewer can follow the logic and verify the input values. Define all variables. If calculation spread sheets are not used, provide the original formulas with defined variables. Additionally, provide subsequent formulas showing the input values for each variable in the formula. All calculations, including those calculations are imbedded in the Calc tab of the UA2 portion of the application, the printed Calc tab(s), should be submitted under this section.

Tank Flashing Calculations: The information provided to the AQB shall include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., NOI, permit, or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis. If Hysis is used, all relevant input parameters shall be reported, including separator pressure, gas throughput, and all other relevant parameters necessary for flashing calculation.

SSM Calculations: It is the applicant's responsibility to provide an estimate of SSM emissions or to provide justification for not doing so. In this Section, provide emissions calculations for Startup, Shutdown, and Routine Maintenance (SSM) emissions listed in the Section 2 SSM and/or Section 22 GHG Tables and the rational for why the others are reported as zero (or left blank in the SSM/GHG Tables). Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on calculating SSM emissions. If SSM emissions are greater than those reported in the Section 2, Requested Allowables Table, modeling may be required to ensure compliance with the standards whether the application is NSR or Title V. Refer to the Modeling Section of this application for more guidance on modeling requirements.

Glycol Dehydrator Calculations: The information provided to the AQB shall include the manufacturer's maximum design recirculation rate for the glycol pump. If GRI-Glycalc is used, the full input summary report shall be included as well as a copy of the gas analysis that was used.

Road Calculations: Calculate fugitive particulate emissions and enter haul road fugitives in Tables 2-A, 2-D and 2-E for:

1. If you transport raw material, process material and/or product into or out of or within the facility and have PER emissions greater than 0.5 tpy.
2. If you transport raw material, process material and/or product into or out of the facility more frequently than one round trip per day.

Significant Figures:

A. All emissions standards are deemed to have at least two significant figures, but not more than three significant figures.
B. At least 5 significant figures shall be retained in all intermediate calculations.
C. In calculating emissions to determine compliance with an emission standard, the following rounding off procedures shall be used:

(1) If the first digit to be discarded is less than the number 5, the last digit retained shall not be changed;
(2) If the first digit discarded is greater than the number 5, or if it is the number 5 followed by at least one digit other than the number zero, the last figure retained shall be increased by one unit; **and**
(3) If the first digit discarded is exactly the number 5, followed only by zeros, the last digit retained shall be rounded upward if it is an odd number, but no adjustment shall be made if it is an even number.
(4) The final result of the calculation shall be expressed in the units of the standard.

Control Devices: In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and € NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions. The applicant can indicate in this section of the application if they chose to not take credit for the reduction in emission rates. For notices of intent submitted under 20.2.73 NMAC, only uncontrolled emission rates can be considered to determine applicability unless the state or federal Acts require the control. This information is necessary to determine if federally enforceable conditions are necessary for the control device, and/or if the control device produces its own regulated pollutants or increases emission rates of other pollutant.

Engines (Units ENG-1, ENG-2, ENG-3, ENG-4)
NO_X, CO, and VOC were calculated using emission factors provided by the manufacturer and catalyst specifications. PM, SO_2, and hazardous emissions were calculated using AP-42 factors for internal natural gas combustion sources in Table 3.2-2. As a conservative measure, it was assumed that PM(Total) = PM_{10} and PM (condensable) = $PM_{2.5}$. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Heaters (Units HT-101, HT-801, HT-102, HT-103, HT-802, HT-803)
NO_X, CO, VOC, PM, SO_2, and hazardous emissions were calculated using AP-42 factors for external natural gas combustion sources in Tables 1.4-1, 1.4-2, and 1.4-3. As a conservative measure, it was assumed that PM(Total) = PM_{10} and PM (condensable) = $PM_{2.5}$. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Reboilers (Units AR-1, AR-2, DR-1, DR-2)
NO_X, VOC, PM, SO_2, and hazardous emissions were calculated using AP-42 factors for external natural gas combustion sources in Tables 1.4-1, 1.4-2, and 1.4-3. The CO emissions were calculated based on the manufacturer spec sheet with a safety factor of 50%. As a conservative measure, it was assumed that PM(Total) = PM_{10} and PM (condensable) = $PM_{2.5}$. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Glycol Dehydrators (Units DEHY-1, DEHY-2)
All emissions from these units are calculated using ProMax. Flash emissions from glycol dehydrators will be routed to the facility fuel system or back to the process. The regenerator emissions from DEHY-1 are routed to the FL-2. Controlled emissions from this unit will be represented under FL-2a. The regenerator emissions from DEHY-2 are routed to the TO-2. Controlled emissions from this unit will be represented under TO-2. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Glycol Dehydrator SSM (DEHY-1 SSM)
This accounts for emissions during startup shutdown and maintenance and upset conditions from the vapor combustion unit. VOC, H_2S, and HAP emissions were calculated using streams from ProMax.

Amine Vents (Units AM-1, AM-2)
All emissions from these units are calculated using ProMax. The amine flash is routed back to the process. The regenerator emissions from both amine units are routed to the thermal oxidizers, TO-1 and TO-2 respectively. Controlled emissions are represented under units TO-1 and TO-2. Emissions during maintenance and malfunction are accounted for in the thermal oxidizer SSM (TO-1 SSM/M and TO-2 SSM/M). Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Flare (Unit FL-2a)
This flare controls the DEHY-1 condenser stream. The basis of the flaring calculations is the expected composition and maximum expected volumes of the gas. The SO_2 composition is based on a 98% molar conversion of H_2S to SO_2. NO_X and CO emissions for both scenarios are calculated using AP-42 Table 13.5-1 emission factors. VOC emissions are calculated from the VOC volume fraction of the inlet gas to the flare, the specific volume of the VOC fraction of the inlet gas, and a 98% destruction removal efficiency. The ProMax inlet gas analysis can be found in Section 7. Emissions of greenhouse gases are calculated using methodology from 40 CFR Subpart 98.233(n).

Flare SSM (Units FL-1, FL-2b, FL-3)
The plant flares are used for flaring during startup, shutdown, maintenance and upset conditions. The only steady state conditions associated with these flares are from the pilot and purge gas streams. SSM from the plant flares is due to various

maintenance activities throughout the facility per manufacturer-recommended maintenance schedules. These maintenance activities include but are not limited to compressor catalyst changes, blowdowns for associated maintenance throughout the facility, instrumental calibrations, and process safety device maintenance.

The basis of the flaring calculations is the expected composition and maximum expected volumes of the gas. The SO_2 composition is based on a 98% molar conversion of H_2S to SO_2. NO_X and CO emissions for both scenarios are calculated using AP-42 Table 13.5-1 emission factors. VOC emissions are calculated from the VOC volume fraction of the inlet gas to the flare, the specific volume of the VOC fraction of the inlet gas, and a 98% destruction efficiency. The ProMax inlet gas analysis can be found in Section 7. Emissions of greenhouse gases are calculated using methodology from 40 CFR Subpart 98.233(n).

Thermal Oxidizers (Units TO-1 and TO-2)
NO_X and CO emissions were updated using the manufacturer specification sheet. PM and SO_2 emissions were calculated using AP-42 factors for external natural gas combustion sources in Tables 1.4-1 and 1.4-2. HAP and VOC emissions were calculated using streams from ProMax. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Thermal Oxidizers SSM (Unit TO-1 SSM, TO-2 SSM)
This accounts for emissions during startup shutdown and maintenance and upset conditions from the thermal oxidizer. VOC, H_2S, and HAP emissions were calculated using streams from ProMax. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Vapor Combustion Unit (Unit VCU-1)
NO_X, CO, and SO_2 emissions were calculated using AP-42 factors for external natural gas combustion sources in Tables 1.4-1 and 1.4-2. HAP and VOC emissions were calculated using streams from ProMax. Greenhouse gas emissions were estimated using methodology from 40 CFR Part 98 and emission factors from Tables C-1 and C-2 of Part 98.

Condensate Storage Tanks (Unit TK-702-A-F)
These units represent six (6) connected 500 bbl condensate storage tanks. Uncontrolled emissions are calculated using ProMax and an annual throughput of 6,000 bbl/day. Emissions will be routed to the vapor combustion unit, unit VCU-1.

Produced Water Tank (Unit TK-701)
Unit TK-701 represents one (1) 500 bbl produced water tank. Uncontrolled emissions are calculated using ProMax and an annual throughput of 80 bbl/day. Emissions will be routed to the vapor combustion unit, unit VCU-1.

Loading Emissions (Unit TL-1, TL-2)
Condensate and produced water are transferred out of the facility via LACT. Loading emissions are calculated for 7 days of condensate and produced water loading in case the LACT is down. Emissions from the loading of condensate and produced water out of the facility by truck were estimated using Equation 1 in AP-42 Section 5.2-4.

SSM (Units SSM-1, SSM-2)
SSM from the pig receiver and launchers blowdowns. Emissions are based on the volume, temperature, and pressure of the gas vented to the atmosphere during these operations.

Fugitive Emissions (Unit FUG)
Fugitive emissions were estimated using emission factors from Table 2-4 of EPA Protocol for Equipment Leak Emission Estimates, November 1995, EPA-453/R-95-017. Component counts were estimated as previously permitted. The percent VOC and HAPs are from the inlet gas analysis dated 8/22/2012. The percent VOC in liquids is conservatively assumed to be 100%. The percent H_2S in liquids is zero. The percent of HAPs in the liquids is estimated based on the ratio of VOC and HAP in the previous gas analysis. Total HAPs is the sum of n-Hexane, Benzene, Toluene, Ethylbenzene, and Xylene.

Haul Road Emissions (Unit HAUL)
Unpaved haul road emissions were estimated based on Equations 1a and 2 of AP-42 Section 13.2.1 (1/11). Particle size multipliers and constants for these equations are found in AP-42 Table 13.2.2-2, Industrial Roads. Silt content is taken from AP-42 Table 13.2.2-1 and annual wet days is from AP-42 Figure 13.2.2-1. The control efficiency is based on the NMED guidance document entitled Department Accepted Values For: Aggregate Handling, Storage Pile, and Haul Road Emissions. The length of the haul road is estimated from Google Earth.

Section 6.a

Green House Gas Emissions

(Submitting under 20.2.70, 20.2.72 20.2.74 NMA__

Title V (20.2.70 NMAC), Minor NSR (20.2.72 NMAC), and PSD (20.2.74 NMAC) applicants must estimate and report greenhouse gas (GHG) emissions to verify the emission rates reported in the public notice, determine applicability to 40 CFR 60 Subparts, and to evaluate Prevention of Significant Deterioration (PSD) applicability. GHG emissions that are subject to air permit regulations consist of the sum of an aggregate group of these six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Calculating GHG Emissions:

1. Calculate the ton per year (tpy) GHG mass emissions and GHG CO_2e emissions from your facility.
2. GHG mass emissions are the sum of the total annual tons of greenhouse gases without adjusting with the global warming potentials (GWPs). GHG CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its GWP found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. Emissions from routine or predictable start up, shut down, and maintenance must be included.
4. Report GHG mass and GHG CO_2e emissions in Table 2-P of this application. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).
5. All Title V major sources, PSD major sources, and all power plants, whether major or not, must calculate and report GHG mass and CO2e emissions for each unit in Table 2-P.
6. For minor source facilities that are not power plants, are not Title V, and are not PSD there are three options for reporting GHGs in Table 2-P: 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHGs as a second separate unit; 3) or check the following ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases:

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of air permit regulations is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7 NMAC, 20.2.74.7 NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Metric to Short Ton Conversion:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions).

DLK Black River Midstream LLC
Black River Gas Processing Plant

Uncontrolled Emissions

		NO_X		CO		VOC		TSP		PM_{10}		$PM_{2.5}$		SO_2		H_2S		Total HAP		Formaldehyde		Benzene		Toulene		Acetaldehyde		Acrolein		Xylene		CO_2	N_2O	CH_4
Unit ID	Equipment Description	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	ton/yr	ton/yr	ton/yr
ENG-1	Waukesha P9394GSI	72.42	317.21	47.12	206.40	2.58	11.30	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	1.07	4.70	0.84	3.69	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01	9768.01	0.02	0.18
ENG-2	Waukesha P9394GSI	72.42	317.21	47.12	206.40	2.58	11.30	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	1.07	4.70	0.84	3.69	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01	9768.01	0.02	0.18
ENG-3	Waukesha P9394GSI	72.42	317.21	47.12	206.40	2.58	11.30	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	1.07	4.70	0.84	3.69	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01	9768.01	0.02	0.18
ENG-4	Waukesha P9394GSI	72.42	317.21	47.12	206.40	2.58	11.30	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	1.07	4.70	0.84	3.69	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.01	9768.01	0.02	0.18
HT-101	Plant 1 - Mole Sieve Heater	0.64	2.82	0.54	2.37	0.04	0.16	0.05	0.21	0.05	0.21	0.04	0.16	0.004	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3571.12	0.01	0.07
HT-801	Plant 1 - Stabilizer Heater	0.64	2.82	0.54	2.37	0.04	0.16	0.05	0.21	0.05	0.21	0.04	0.16	0.004	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3571.12	0.01	0.07
HT-102	Plant 2 - Mole Sieve Heater	0.90	3.94	0.76	3.31	0.05	0.22	0.07	0.30	0.07	0.30	0.05	0.22	0.01	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4990.34	0.01	0.09
AR-1	Plant 2 - Amine Reboiler	1.95	8.54	1.64	7.17	0.11	0.47	0.15	0.65	0.15	0.65	0.11	0.49	0.01	0.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10805.57	0.02	0.20
DR-1	Plant 2 - Dehy Regen Heater	0.27	1.17	0.23	0.99	0.01	0.06	0.02	0.09	0.02	0.09	0.02	0.07	0.002	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1485.83	0.00	0.03
HT-103	Plant 3 - Mole Sieve Heater	0.90	3.94	0.76	3.31	0.05	0.22	0.07	0.30	0.07	0.30	0.05	0.22	0.01	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4990.34	0.01	0.09
HT-802	Plant 3 - Stabilizer Heater 1	0.57	2.51	0.48	2.11	0.03	0.14	0.04	0.19	0.04	0.19	0.03	0.14	0.003	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3176.60	0.01	0.06
AR-2	Plant 3 - Amine Reboiler	2.21	9.68	1.86	8.14	0.12	0.53	0.17	0.74	0.17	0.74	0.13	0.55	0.01	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11118.15	0.023	0.23
DR-2	Plant 3 - Dehy Regen Heater	0.23	1.01	0.19	0.85	0.01	0.06	0.02	0.08	0.02	0.08	0.01	0.06	0.00	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1162.01	0.00	0.02
HT-803	Plant 3 - Stabilizer Heater 2	0.57	2.51	0.48	2.11	0.03	0.14	0.04	0.19	0.04	0.19	0.03	0.14	0.00	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3176.60	0.01	0.06
DEHY-1	Plant 2 - Dehy Unit	-	-	-	-	193.81	848.88	-	-	-	-	-	-	-	-	0.0521	0.228	18.75	82.12	-	-	18.75	82.12	-	-	-	-	-	-	-	-	0.00	0.00	0.00
AM-1	Plant 2 - Amine Unit	-	-	-	-	19.49	85.35	-	-	-	-	-	-	-	-	6.54	28.64	7.58	33.22	-	-	7.58	33.22	-	-	-	-	-	-	-	-	0.00	0.00	0.00
DEHY-2	Plant 3 - Dehy Unit	-	-	-	-	190.32	833.59	-	-	-	-	-	-	-	-	0.0519	0.2275	18.68	81.82	-	-	18.68	81.82	-	-	-	-	-	-	-	-	0.00	0.00	0.00
AM-2	Plant 3 - Amine Unit	-	-	-	-	18.95	82.99	-	-	-	-	-	-	-	-	4.93	21.58	7.53	33.00	-	-	7.53	33.00	-	-	-	-	-	-	-	-	0.00	0.00	0.00
TO-1	Plant 2 -Thermal Oxidizer	No emissions from these unit in an uncontrolled scenario																														5021.08	0.01	0.09
TO-2	Plant 3 -Thermal Oxidizer	No emissions from these unit in an uncontrolled scenario																														5021.08	0.01	0.09
TO-1 SSM	Plant 2 -Thermal Oxidizer SSM	No emissions from these unit in an uncontrolled scenario																														0.00	0.00	0.00
TO-2 SSM	Plant 3 -Thermal Oxidizer SSM	No emissions from these unit in an uncontrolled scenario																														0.00	0.00	0.00
DEHY-1 SSM	Plant 2 - Dehy Overhead SSM	No emissions from these unit in an uncontrolled scenario																																
FL-1	Plant 1 - SSM	No emissions from these unit in an uncontrolled scenario																														84.92	0.00	0.00
FL-2	Plant 2 - Dehy-1 Control and SSM/M	No emissions from these unit in an uncontrolled scenario																														5200.20	0.01	0.10
FL-3	Plant 3 - SSM	No emissions from these unit in an uncontrolled scenario																														1895.71	0.00	0.04
VCU-1	Tanks Control	No emissions from these unit in an uncontrolled scenario																														3642.85	0.01	0.07
VCU-1 SSM	VCU-1 Downtime	No emissions from these unit in an uncontrolled scenario																																
TK-702A-F	Condensate Tanks	-	-	-	-	17.94	78.58	-	-	-	-	-	-	-	-	0.00	0.00	0.12	0.53	-	-	0.12	0.53	-	-	-	-	-	-	-	-	2.08	0.11	42.32
TK-701	Produced Water Tanks	-	-	-	-	387.60	1697.69	-	-	-	-	-	-	-	-	0.00	0.00	6.40	28.03	-	-	6.40	28.03	-	-	-	-	-	-	-	-	0.002	0.00	0.03
TL-1	Condensate Truck Loading	-	-	-	-	69.36	4.07	-	-	-	-	-	-	-	-	0.00	0.00	0.56	0.03	-	-	0.56	0.03	-	-	-	-	-	-	-	-	0.91	0.00	9.59
TL-2	Produced Water Truck Loading	-	-	-	-	129.71	0.22	-	-	-	-	-	-	-	-	0.00	0.00	2.15	0.00	-	-	2.15	0.00	-	-	-	-	-	-	-	-	0.03	0.00	0.02
FUG	Fugitives	-	-	-	-	7.89	34.54	-	-	-	-	-	-	-	-	0.04	0.16	0.01	0.03	-	-	-	-	-	-	-	-	-	-	-	-	2.08	0.00	99.47
SSM	Pig Launcher/Receiver (SSM 1 & 2)	-	-	-	-	66.43	12.12	-	-	-	-	-	-	-	-	0.003	0.001	0.02	0.00	-	-	0.02	0.004	-	-	-	-	-	-	-	-	-	-	-
MAL	Malfunction (FL-1, FL-2, FL-3)	517.79	6.21	1033.70	12.40	498.35	5.98	-	-	-	-	-	-	3.00	0.04	0.03	0.0004	0.24	0.003	-	-	0.24	0.003	-	-	-	-	-	-	-	-	-	-	-
	Totals	**816.37**	**1314.01**	**1229.67**	**870.73**	**1610.64**	**3731.34**	**1.32**	**5.76**	**1.32**	**5.76**	**1.15**	**5.02**	**3.89**	**3.94**	**11.67**	**50.94**	**66.35**	**277.61**	**3.37**	**14.77**	**62.07**	**258.88**	**0.03**	**0.11**	**0.53**	**2.33**	**0.33**	**1.43**	**0.01**	**0.05**	**107990.65**	**0.31**	**153.47**

Controlled Emissions

		NO_X		CO		VOC		TSP		PM_{10}		$PM_{2.5}$		SO_2		H_2S		Total HAP		Formaldehyde		Benzene		Toulene		Acetaldehyde		Acrolein		Xylene		CO_2	N_2O	CH_4
Unit ID	Equipment Description	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	ton/yr	ton/yr	ton/yr
ENG-1	Waukesha P9394GSI	3.10	13.58	3.10	13.58	1.36	5.97	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.013	9768.01	0.02	0.18
ENG-2	Waukesha P9394GSI	3.10	13.58	3.10	13.58	1.36	5.97	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.013	9768.01	0.02	0.18
ENG-3	Waukesha P9394GSI	3.10	13.58	3.10	13.58	1.36	5.97	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.013	9768.01	0.02	0.18
ENG-4	Waukesha P9394GSI	3.10	13.58	3.10	13.58	1.36	5.97	0.16	0.70	0.16	0.70	0.16	0.70	0.21	0.92	0.01	0.03	0.35	1.55	0.12	0.54	0.01	0.03	0.01	0.03	0.13	0.58	0.08	0.36	0.003	0.013	9768.01	0.02	0.18
HT-101	Plant 1 - Mole Sieve Heater	0.64	2.82	0.54	2.37	0.04	0.16	0.05	0.21	0.05	0.21	0.04	0.16	0.004	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3571.12	0.01	0.07
HT-801	Plant 1 - Stabilizer Heater	0.64	2.82	0.54	2.37	0.04	0.16	0.05	0.21	0.05	0.21	0.04	0.16	0.004	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3571.12	0.01	0.07
HT-102	Plant 2 - Mole Sieve Heater	0.90	3.94	0.76	3.31	0.05	0.22	0.07	0.30	0.07	0.30	0.05	0.22	0.005	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4990.34	0.01	0.09
AR-1	Plant 2 - Amine Reboiler	1.95	8.54	1.64	7.17	0.11	0.47	0.15	0.65	0.15	0.65	0.11	0.49	0.01	0.05	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10805.57	0.02	0.20
DR-1	Plant 2 - Dehy Regen Heater	0.27	1.17	0.23	0.99	0.01	0.06	0.02	0.09	0.02	0.09	0.02	0.07	0.002	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1485.83	0.00	0.03
HT-103	Plant 3 - Mole Sieve Heater	0.90	3.94	0.76	3.31	0.05	0.22	0.07	0.30	0.07	0.30	0.05	0.22	0.01	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4990.34	0.01	0.09
HT-802	Plant 3 - Stabilizer Heater 1	0.57	2.51	0.48	2.11	0.03	0.14	0.04	0.19	0.04	0.19	0.03	0.14	0.003	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3176.60	0.01	0.06
AR-2	Plant 3 - Amine Reboiler	2.21	9.68	1.86	8.14	0.12	0.53	0.17	0.74	0.17	0.74	0.13	0.55	0.01	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12255.54	0.02	0.23
DR-2	Plant 3 - Dehy Regen Heater	0.23	1.01	0.19	0.85	0.01	0.06	0.02	0.08	0.02	0.08	0.01	0.06	0.001	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1280.89	0.00	0.02
HT-803	Plant 3 - Stabilizer Heater 2	0.57	2.51	0.48	2.11	0.03	0.14	0.04	0.19	0.04	0.19	0.03	0.14	0.003	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3176.60	0.01	0.06
DEHY-1	Plant 2 - Dehy Unit	Emissions are controlled by flare, FL-2. Emissions are represented under FL-2.																														0.00	0.00	0.00
AM-1	Plant 2 - Amine Unit	Emissions are controlled by thermal oxidizer, TO-1. Emissions are represented under TO-1.																														0.00	0.00	0.00
DEHY-2	Plant 3 - Dehy Unit	Emissions are controlled by thermal oxidizer, TO-2. Emissions are represented under TO-2.																														0.00	0.00	0.00
AM-2	Plant 3 - Amine Unit	Emissions are controlled by thermal oxidizer, TO-2. Emissions are represented under TO-2.																														0.00	0.00	0.00
TO-1	Plant 2 -Thermal Oxidizer	1.39	6.28	1.29	5.81	0.36	1.59	0.49	2.16	0.49	2.16	0.37	1.62	12.29	53.84	0.13	0.58	0.15	0.664	-	-	0.15	0.664	-	-	-	-	-	-	-	-	5021.08	0.01	0.09
TO-2	Plant 3 -Thermal Oxidizer	2.17	9.71	2.02	9.00	3.78	16.55	0.42	1.84	0.42	1.84	0.31	1.38	9.36	41.01	0.10	0.44	0.52	2.30	-	-	0.52	2.30	-	-	-	-	-	-	-	-	5021.08	0.01	0.09
TO-1 SSM	Plant 2 -Thermal Oxidizer SSM	-	-	-	-	19.49	1.71	-	-	-	-	-	-	-	-	6.54	0.57	7.58	0.66	-	-	7.58	0.66	-	-	-	-	-	-	-	-	0.00	0.00	0.00
TO-2 SSM	Plant 3 -Thermal Oxidizer SSM	-	-	-	-	190.32	16.67	-	-	-	-	-	-	-	-	0.05	0.005	18.68	1.64	-	-	18.68	1.64	-	-	-	-	-	-	-	-	0.00	0.00	0.00
DEHY-1 SSM	Plant 2 - Dehy Overhead SSM	-	-	-	-	193.81	16.98	-	-	-	-	-	-	-	-	0.05	0.005	18.75	1.64	-	-	18.75	1.64	-	-	-	-	-	-	-	-	0.00	0.00	0.00
FL-1	Plant 1 - SSM	103.59	5.13	206.77	10.06	99.67	4.79	-	-	-	-	-	-	0.60	0.03	0.006	0.001	0.05	0.00	-	-	0.05	0.00	-	-	-	-	-	-	-	-	84.92	0.00	0.00
FL-2	Plant 2 - Dehy-1 Control and SSM/M	175.50	16.78	350.30	33.24	171.54	24.96	-	-	-	-	-	-	1.13	0.50	0.012	0.006	0.47	1.66	-	-	0.47	1.66	-	-	-	-	-	-	-	-	5200.20	0.01	0.10
FL-3	Plant 3 - SSM	143.83	8.15	287.08	16.03	139.34	8.34	-	-	-	-	-	-	10.11	0.89	0.11	0.01	0.23	0.03	-	-	0.23	0.03	-	-	-	-	-	-	-	-	1895.71	0.00	0.04
VCU-1	Tanks Control	1.24	5.42	2.47	10.81	8.11	35.53	0.02	0.10	0.02	0.10	0.02	0.07	0.0006	0.003	0.00001	0.00004	0.13	0.57	-	-	0.13	0.57	-	-	-	-	-	-	-	-	3642.85	0.01	0.07
VCU-1 SSM	VCU-1 Downtime	-	-	-	-	405.54	13.85	-	-	-	-	-	-	-	-	0.00030	0.00001	6.52	0.22	-	-	6.52	0.22	-	-	-	-	-	-	-	-	-	-	-
TK-702A-F	Condensate Tanks	Emissions are controlled by Vapor Combustion Unit, VCU-1. Emissions are represented under VCU-1.																														2.08	0.11	42.32
TK-701	Produced Water Tanks	Emissions are controlled by Vapor Combustion Unit, VCU-1. Emissions are represented under VCU-1.																														0.00	0.00	0.03
TL-1	Condensate Truck Loading	-	-	-	-	69.36	4.07	-	-	-	-	-	-	-	-	0.000	0.000	0.56	0.03	-	-	0.56	0.03	-	-	-	-	-	-	-	-	0.91	0.00	9.59
TL-2	Produced Water Truck Loading	-	-	-	-	129.71	0.22	-	-	-	-	-	-	-	-	0.0001	0.00000	2.15	0.004	-	-	2.15	0.004	-	-	-	-	-	-	-	-	0.03	0.00	0.02
FUG	Fugitives	-	-	-	-	7.89	34.54	-	-	-	-	-	-	-	-	0.037	0.162	0.01	0.03	-	-	-	-	-	-	-	-	-	-	-	-	2.08	0.00	99.47
SSM	Pig Launcher/Receiver (SSM 1 & 2)	-	-	-	-	66.43	12.12	-	-	-	-	-	-	-	-	0.003	0.001	0.02	0.00	-	-	0.02	0.00	-	-	-	-	-	-	-	-	-	-	-
MAL	Malfunction (FL-1, FL-2, FL-3)	517.79	6.21	1,033.70	12.40	498.35	5.98	-	-	-	-	-	-	3.00	0.04	0.032	0.000	0.24	0.00	-	-	0.24	0.00	-	-	-	-	-	-	-	-	-	-	-
MAL	Malfunction	-	-	-	-	-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Totals	**966.80**	**150.95**	**1,903.50**	**184.39**	**2,009.64**	**227.94**	**2.25**	**9.86**	**2.25**	**9.86**	**1.85**	**8.09**	**37.38**	**100.22**	**7.10**	**1.89**	**57.49**	**15.68**	**0.50**	**2.17**	**56.09**	**9.55**	**0.03**	**0.11**	**0.53**	**2.33**	**0.33**	**1.43**	**0.01**	**0.05**	**109,246.91**	**0.31**	**153.47**

DLK Black River Midstream LLC
Black River Gas Processing Plant

Reciprocating Engines

Unit Numbers:	ENG-1		
Source description:	4	Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha		
Model:	P9394GSI		
Aspiration:	Turbo-charged		

Engine Horsepower and RPM			
Engine speed:	1,200.0	rpm	Mfg data
Sea level hp:	2,250.0	hp	Mfg data

Fuel Consumption			
Hours of Operation	8,760.0	Hours per engine	
BSFC:	7,063.0	Btu/hp-hr	Mfd data for LHV
Fuel heat value:	1,081.8	Btu/scf	Fuel Gas Analysis
Heat input:	15.89	MMBtu/hr	BSFC * site hp
Fuel consumption:	14.690	Mscf/hr	Heat input / fuel heat value
Annual fuel usage:	128.69	MMscf/yr	8760 hrs/yr operation

Exhaust Parameters			
Exhaust temp (Tstk):	1085	°F	Mfg data
Stack height:	26.00	ft	Engineering Estimate
Stack diameter:	1.30	ft	Engineering Estimate
Exhaust flow:	10366.0	acfm	Mfg data
Exhaust flow:	172.77	acfs	Mfg data
Exhaust velocity:	130.16	ft/sec	Exhaust flow ÷ stack area

Emission Calculations

Uncontrolled Emissions[3]

NO_x	CO	NMNEHC	Total VOC	SO_2[1]	H_2S[1]		
14.6	9.5	0.35		0.042	0.001	g/hp-hr	Mfg data Engine data
				5		gr Total Sulfur/Ms	Pipeline specification
72.42	**47.12**	**1.74**	**2.58**	**0.21**	**0.01**	lb/hr	Hourly emission rate
317.21	**206.40**	**7.60**	**11.30**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.17		g/hp-hr	Mfg data
0.16	**0.84**	**1.07**	lb/hr	Hourly emission rate
0.70	**3.69**	**4.70**	tpy	Annual emission rate (8760 hrs/yr)

Controlled Emissions

NO_x	CO	NMNEHC	Total VOC	SO_2	H_2S		
0.63	0.63	0.25		0.042	0.001	g/hp-hr	Catalyst data with 25% safety factor
				5		gr Total Sulfur/Ms	Pipeline specification
3.100	**3.100**	**1.240**	**1.36**	**0.210**	**0.006**	lb/hr	Hourly emission rate
13.58	**13.58**	**5.43**	**5.97**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH[3]	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.025		g/hp-hr	Mfg data
0.16	**0.12**	**0.35**	lb/hr	Hourly emission rate
0.70	**0.54**	**1.55**	tpy	Annual emission rate (8760 hrs/yr)

[1] SO_2 emissions based on fuel sulfur content of 5 gr S/100 scf, or 0.00714 lb S/Mscf

0.00714 lb S/Mscf * fuel consumption (Mscf/hr) * 64 lb SO_2/32 lb S = lb SO2/hr

H_2S emissions based on 0.25 g H2S/100 scf, or 0.0004 lb H2S/Mscf in fuel

0.0004 lb H2S/Mscf fuel * fuel consumption (Mscf/hr) = lb H2S/hr

[2] It is assumed that TSP = PM_{10} = $PM_{2.5}$. The emission factor used is filterable plus condensable PM.

[3] Emission factor provided in Catalyst Spec sheet

Capacity:

15.9	MMBtu/hr.	Nameplate heat rate	(Manufacturers data)
19.07	MMBtu/hr.	Heat rate, max firing rate (20% safety factor added)	

Greenhouse Gases Emissions from Natural Gas Combustion

Tier 1

40 CFR 98 (b)(1)(v) The Tier 1 Calculation Methodology: (v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consuption is obtained from fuel billing records in units of therm or mmBtu.

Subpart C- General Stationary Fuel Combustion Sources 98.30

$CO_2 = 1 \times 10^{-3} \times Gas \times EF$ (Eq. C-1a)

where:

CO_2 = Annual CO_2 mass emission from natural gas combustion (metric ton).

Gas = Annual natural gas usage, from billing records (mmBtu)

EF = Fuel-specific default CO_2 emission factor for natural gas (kg CO_2/mmBtu)

Table C1 of this subpart = 53.02 (kg Co2/mmBtu)

Annual gas usage =

19.07	MMBtu	8,760	hrs	53.06	kg CO_2	1	Metric Ton
	hr		yr		MMBtu	1000	kg

CO_2 =	8,863.9	metric ton/yr
	9,768.0	ton (US)/yr

CH_4 or N_2O = 1 x 10-3 x Fuel x EF (Eq. C-8b)

where:

CH_4 or N_2O = Annual Emission from the combustion of natural gas (metric tons)

CH_4 = 1.0 x 10-3 kg CH_4/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-03	kg CH_4	1	Metric Ton
		hr		yr		MMBtu	1000	kg

CH_4 =	0.17	metric ton/yr
	0.18	ton (US)/yr

Converted to CO_{2e}	0.18	25	=	4.6	tons/yr CO_{2e}

N_2O = 1.0 x 10-4 kg N_20/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-04	kg N_2O	1	Metric Ton
		hr		yr		MMBtu	1000	kg

N_2O=	0.017	metric ton/yr
	0.018	ton (US)/yr

Converted to CO_{2e}	0.02	298	=	5.5	tons/yr CO_{2e}

Total Engine CO_{2e} 9,778.1 tons/yr CO_{2e}

DLK Black River Midstream LLC
Black River Gas Processing Plant

Reciprocating Engines

Unit Numbers:	ENG-2		
Source description:	4	Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha		
Model:	P9394GSI		
Aspiration:	Turbo-charged		

Engine Horsepower and RPM			
Engine speed:	1,200.0	rpm	Mfg data
Sea level hp:	2,250.0	hp	Mfg data

Fuel Consumption			
Hours of Operation	8,760.0	Hours per engine	
BSFC:	7,063.0	Btu/hp-hr	Mfd data for LHV
Fuel heat value:	1,081.8	Btu/scf	Fuel Gas Analysis
Heat input:	15.89	MMBtu/hr	BSFC * site hp
Fuel consumption:	14.690	Mscf/hr	Heat input / fuel heat value
Annual fuel usage:	128.69	MMscf/yr	8760 hrs/yr operation

Exhaust Parameters			
Exhaust temp (Tstk):	1085	°F	Mfg data
Stack height:	26.00	ft	Engineering Estimate
Stack diameter:	1.30	ft	Engineering Estimate
Exhaust flow:	10366.0	acfm	Mfg data
Exhaust flow:	172.77	acfs	Mfg data
Exhaust velocity:	130.16	ft/sec	Exhaust flow ÷ stack area

Emission Calculations

Uncontrolled Emissions [3]

NO_x	CO	NMNEHC	Total VOC	SO_2 [1]	H_2S [1]		
14.6	9.5	0.35		0.042	0.001	g/hp-hr	Mfg data Engine data
				5		gr Total Sulfur/Msc	Pipeline specification
72.42	**47.12**	**1.74**	**2.58**	**0.21**	**0.01**	lb/hr	Hourly emission rate
317.21	**206.40**	**7.60**	**11.30**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.17		g/hp-hr	Mfg data
0.16	**0.84**	**1.07**	lb/hr	Hourly emission rate
0.70	**3.69**	**4.70**	tpy	Annual emission rate (8760 hrs/yr)

Controlled Emissions

NO_x	CO	NMNEHC	Total VOC	SO_2	H_2S		
0.63	0.63	0.25		0.042	0.001	g/hp-hr	Catalyst data with 25% safety factor
				5		gr Total Sulfur/Msc	Pipeline specification
3.100	**3.100**	**1.240**	**1.36**	**0.210**	**0.006**	lb/hr	Hourly emission rate
13.58	**13.58**	**5.43**	**5.97**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH[3]	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.025		g/hp-hr	Mfg data
0.16	**0.12**	**0.35**	lb/hr	Hourly emission rate
0.70	**0.54**	**1.55**	tpy	Annual emission rate (8760 hrs/yr)

[1] SO_2 emissions based on fuel sulfur content of 5 gr S/100 scf, or 0.00714 lb S/Mscf
0.00714 lb S/Mscf * fuel consumption (Mscf/hr) * 64 lb SO_2/32 lb S = lb SO2/hr
H_2S emissions based on 0.25 g H2S/100 scf, or 0.0004 lb H2S/Mscf in fuel
0.0004 lb H2S/Mscf fuel * fuel consumption (Mscf/hr) = lb H2S/hr
[2] It is assumed that TSP = PM_{10} = $PM_{2.5}$. The emission factor used is filterable plus condensable PM.
[3] Emission factor provided in Catalyst Spec sheet

DLK Black River Midstream LLC
Greenhouse Gas Emissions

Capacity:

15.9	MMBtu/hr.	Nameplate heat rate	(Manufacturers data)
19.07	MMBtu/hr.	Heat rate, max firing rate (20% safety factor added)	

<u>Greenhouse Gases Emissions from Natural Gas Combustion</u>

Tier 1

Subpart C- General Stationary Fuel Combustion Sources 98.30

$CO_2 = 1 \times 10^{-3} \times Gas \times EF$ (Eq. C-1a)

40 CFR 98 (b)(1)(v) The Tier 1 Calculation Methodology: (v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consuption is obtained from fuel billing records in units of therm or mmBtu.

where:

CO_2 = Annual CO_2 mass emission from natural gas combustion (metric ton).

Gas = Annual natural gas usage, from billing records (mmBtu)

EF = Fuel-specific default CO_2 emission factor for natural gas (kg CO_2/mmBtu)

Table C1 of this subpart = 53.02 (kg Co2/mmBtu)

Annual gas usage =

19.07	MMBtu	8,760	hrs	53.06	kg CO_2	1	Metric Ton
	hr		yr		MMBtu	1000	kg

CO_2 =	8,863.9	metric ton/yr
	9,768.0	ton (US)/yr

CH_4 or N_2O = 1 x 10-3 x Fuel x EF (Eq. C-8b)

where:

CH_4 or N_2O = Annual Emission from the combustion of natural gas (metric tons)

CH_4 = 1.0 x 10-3 kg CH_4/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: <u>Natural Gas</u>

Annual gas usage =								
	19.07	MMBtu	8,760	hrs	1.00E-03	kg CH_4	1	Metric Ton
		hr		yr		MMBtu	1000	kg

CH_4 =	0.17	metric ton/yr
	0.18	ton (US)/yr

Converted to CO_{2e}	0.18	25	=	4.6	tons/yr CO_{2e}

N_2O = 1.0 x 10-4 kg N_20/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: <u>Natural</u> Gas

Annual gas usage =								
	19.07	MMBtu	8,760	hrs	1.00E-04	kg N_2O	1	Metric Ton
		hr		yr		MMBtu	1000	kg

N_2O=	0.017	metric ton/yr
	0.018	ton (US)/yr

Converted to CO_{2e}	0.02	298	=	5.5	tons/yr CO_{2e}

Total Engine CO_{2e} 9,778.1 tons/yr CO_{2e}

DLK Black River Midstream LLC
Black River Gas Processing Plant

Reciprocating Engines

Unit Numbers:	ENG-3		
Source description:	4	Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha		
Model:	P9394GSI		
Aspiration:	Turbo-charged		

Engine Horsepower and RPM			
Engine speed:	1,200.0	rpm	Mfg data
Sea level hp:	2,250.0	hp	Mfg data

Fuel Consumption			
Hours of Operation	8,760.0	Hours per engine	
BSFC:	7,063.0	Btu/hp-hr	Mfd data for LHV
Fuel heat value:	1,081.8	Btu/scf	Fuel Gas Analysis
Heat input:	15.89	MMBtu/hr	BSFC * site hp
Fuel consumption:	14.690	Mscf/hr	Heat input / fuel heat value
Annual fuel usage:	128.69	MMscf/yr	8760 hrs/yr operation

Exhaust Parameters			
Exhaust temp (Tstk):	1085	°F	Mfg data
Stack height:	26.00	ft	Engineering Estimate
Stack diameter:	1.30	ft	Engineering Estimate
Exhaust flow:	10366.0	acfm	Mfg data
Exhaust flow:	172.77	acfs	Mfg data
Exhaust velocity:	130.16	ft/sec	Exhaust flow ÷ stack area

Emission Calculations

Uncontrolled Emissions[3]

NO_x	CO	NMNEHC	Total VOC	SO_2[1]	H_2S[1]		
14.6	9.5	0.35		0.042	0.001	g/hp-hr	Mfg data Engine data
				5		gr Total Sulfur/Ms	Pipeline specification
72.42	**47.12**	**1.74**	**2.58**	**0.21**	**0.01**	lb/hr	Hourly emission rate
317.21	**206.40**	**7.60**	**11.30**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.17		g/hp-hr	Mfg data
0.16	**0.84**	**1.07**	lb/hr	Hourly emission rate
0.70	**3.69**	**4.70**	tpy	Annual emission rate (8760 hrs/yr)

Controlled Emissions

NO_x	CO	NMNEHC	Total VOC	SO_2	H_2S		
0.63	0.63	0.25		0.042	0.001	g/hp-hr	Catalyst data with 25% safety factor
				5		gr Total Sulfur/Ms	Pipeline specification
3.100	**3.100**	**1.240**	**1.36**	**0.210**	**0.006**	lb/hr	Hourly emission rate
13.58	**13.58**	**5.43**	**5.97**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM[2]	HCOH[3]	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.025		g/hp-hr	Mfg data
0.16	**0.12**	**0.35**	lb/hr	Hourly emission rate
0.70	**0.54**	**1.55**	tpy	Annual emission rate (8760 hrs/yr)

[1] SO_2 emissions based on fuel sulfur content of 5 gr S/100 scf, or 0.00714 lb S/Mscf

0.00714 lb S/Mscf * fuel consumption (Mscf/hr) * 64 lb SO_2/32 lb S = lb SO2/hr

H_2S emissions based on 0.25 g H2S/100 scf, or 0.0004 lb H2S/Mscf in fuel

0.0004 lb H2S/Mscf fuel * fuel consumption (Mscf/hr) = lb H2S/hr

[2] It is assumed that TSP = PM_{10} = $PM_{2.5}$. The emission factor used is filterable plus condensable PM.

[3] Emission factor provided in Catalyst Spec sheet

Capacity:

15.9	MMBtu/hr.	Nameplate heat rate	(Manufacturers data)
19.07	MMBtu/hr.	Heat rate, max firing rate (20% safety factor added)	

Greenhouse Gases Emissions from Natural Gas Combustion

Tier 1

Subpart C- General Stationary Fuel Combustion Sources 98.30

$CO_2 = 1 \times 10^{-3} \times \text{Gas} \times \text{EF}$ (Eq. C-1a)

40 CFR 98 (b)(1)(v) The Tier 1 Calculation Methodology: (v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consuption is obtained from fuel billing records in units of therm or mmBtu.

where:

CO_2 = Annual CO_2 mass emission from natural gas combustion (metric ton).

Gas = Annual natural gas usage, from billing records (mmBtu)

EF = Fuel-specific default CO_2 emission factor for natural gas (kg CO_2/mmBtu)

Table C1 of this subpart = 53.02 (kg Co2/mmBtu)

Annual gas usage =

19.07	MMBtu	8,760	hrs	53.06	kg CO_2	1	Metric Ton
	hr		yr		MMBtu	1000	kg

CO_2 =	8,863.9	metric ton/yr
	9,768.0	ton (US)/yr

CH_4 or N_2O = 1 x 10-3 x Fuel x EF (Eq. C-8b)

where:

CH_4 or N_2O = Annual Emission from the combustion of natural gas (metric tons)

CH_4 = 1.0 x 10-3 kg CH_4/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-03	kg CH_4	1	Metric Ton
		hr		yr		MMBtu	1000	kg

CH_4 =	0.17	metric ton/yr
	0.18	ton (US)/yr

Converted to CO_{2e}	0.18	25	=	4.6	tons/yr CO_{2e}

N_2O = 1.0 x 10-4 kg N_20/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-04	kg N_2O	1	Metric Ton
		hr		yr		MMBtu	1000	kg

N_2O=	0.017	metric ton/yr
	0.018	ton (US)/yr

Converted to CO_{2e}	0.02	298	=	5.5	tons/yr CO_{2e}

Total Engine CO_{2e} 9,778.1 tons/yr CO_{2e}

DLK Black River Midstream LLC
Black River Gas Processing Plant

Reciprocating Engines

Unit Numbers:	ENG-4		
Source description:	4	Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha		
Model:	P9394GSI		
Aspiration:	Turbo-charged		

Engine Horsepower and RPM			
Engine speed:	1,200.0	rpm	Mfg data
Sea level hp:	2,250.0	hp	Mfg data

Fuel Consumption			
Hours of Operation	8,760.0	Hours per engine	
BSFC:	7,063.0	Btu/hp-hr	Mfd data for LHV
Fuel heat value:	1,081.8	Btu/scf	Fuel Gas Analysis
Heat input:	15.89	MMBtu/hr	BSFC * site hp
Fuel consumption:	14.690	Mscf/hr	Heat input / fuel heat value
Annual fuel usage:	128.69	MMscf/yr	8760 hrs/yr operation

Exhaust Parameters			
Exhaust temp (Tstk):	1085	°F	Mfg data
Stack height:	26.00	ft	Engineering Estimate
Stack diameter:	1.30	ft	Engineering Estimate
Exhaust flow:	10366.0	acfm	Mfg data
Exhaust flow:	172.77	acfs	Mfg data
Exhaust velocity:	130.16	ft/sec	Exhaust flow ÷ stack area

Emission Calculations

Uncontrolled Emissions [3]

NO_x	CO	NMNEHC	Total VOC	SO_2 [1]	H_2S [1]			
14.6	9.5	0.35		0.042	0.001	g/hp-hr	Mfg data	Engine data
				5		gr Total Sulfur/Ms	Pipeline specification	
72.42	**47.12**	**1.74**	**2.58**	**0.21**	**0.01**	lb/hr	Hourly emission rate	
317.21	**206.40**	**7.60**	**11.30**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)	

PM [2]	HCOH	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.17		g/hp-hr	Mfg data
0.16	**0.84**	**1.07**	lb/hr	Hourly emission rate
0.70	**3.69**	**4.70**	tpy	Annual emission rate (8760 hrs/yr)

Controlled Emissions

NO_x	CO	NMNEHC	Total VOC	SO_2	H_2S		
0.63	0.63	0.25		0.042	0.001	g/hp-hr	Catalyst data with 25% safety factor
				5		gr Total Sulfur/Ms	Pipeline specification
3.100	**3.100**	**1.240**	**1.36**	**0.210**	**0.006**	lb/hr	Hourly emission rate
13.58	**13.58**	**5.43**	**5.97**	**0.92**	**0.03**	tpy	Annual emission rate (8760 hrs/yr)

PM [2]	HCOH [3]	Total HAPs		
0.010			lb/MMBtu	AP-42 Table 3.2-2
	0.025		g/hp-hr	Mfg data
0.16	**0.12**	**0.35**	lb/hr	Hourly emission rate
0.70	**0.54**	**1.55**	tpy	Annual emission rate (8760 hrs/yr)

[1] SO_2 emissions based on fuel sulfur content of 5 gr S/100 scf, or 0.00714 lb S/Mscf

0.00714 lb S/Mscf * fuel consumption (Mscf/hr) * 64 lb SO_2/32 lb S = lb SO2/hr

H_2S emissions based on 0.25 g H2S/100 scf, or 0.0004 lb H2S/Mscf in fuel

0.0004 lb H2S/Mscf fuel * fuel consumption (Mscf/hr) = lb H2S/hr

[2] It is assumed that TSP = PM_{10} = $PM_{2.5}$. The emission factor used is filterable plus condensable PM.

[3] Emission factor provided in Catalyst Spec sheet

DLK Black River Midstream LLC
Greenhouse Gas Emissions

Capacity:

15.9	MMBtu/hr.	Nameplate heat rate	(Manufacturers data)
19.07	MMBtu/hr.	Heat rate, max firing rate (20% safety factor added)	

Greenhouse Gases Emissions from Natural Gas Combustion

Tier 1

Subpart C- General Stationary Fuel Combustion Sources 98.30

$CO_2 = 1 \times 10^{-3} \times Gas \times EF$ (Eq. C-1a)

where:

CO_2 = Annual CO_2 mass emission from natural gas combustion (metric ton).

Gas = Annual natural gas usage, from billing records (mmBtu)

EF = Fuel-specific default CO_2 emission factor for natural gas (kg CO_2/mmBtu)

Table C1 of this subpart = 53.02 (kg Co2/mmBtu)

40 CFR 98 (b)(1)(v) The Tier 1 Calculation Methodology: (v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consuption is obtained from fuel billing records in units of therm or mmBtu.

Annual gas usage =

19.07	MMBtu	8,760	hrs	53.06	kg CO_2	1	Metric Ton
	hr		yr		MMBtu	1000	kg

CO_2 =	8,863.9	metric ton/yr
	9,768.0	ton (US)/yr

CH_4 or N_2O = 1 x 10-3 x Fuel x EF (Eq. C-8b)

where:

CH_4 or N_2O = Annual Emission from the combustion of natural gas (metric tons)

CH_4 = 1.0 x 10-3 kg CH_4/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-03	kg CH_4	1	Metric Ton
		hr		yr		MMBtu	1000	kg

CH_4 =	0.17	metric ton/yr
	0.18	ton (US)/yr

Converted to CO_{2e}	0.18	25	=	4.6	tons/yr CO_{2e}

N_2O = 1.0 x 10-4 kg N_20/mmBtu

From Table C-2 To Subpart C of Part 68 - Default CH4 and N2O Emission Factors for Various Types of Fuel: Natural Gas

Annual gas usage =	19.07	MMBtu	8,760	hrs	1.00E-04	kg N_2O	1	Metric Ton
		hr		yr		MMBtu	1000	kg

N_2O=	0.017	metric ton/yr
	0.018	ton (US)/yr

Converted to CO_{2e}	0.02	298	=	5.5	tons/yr CO_{2e}

Total Engine CO_{2e} 9,778.1 tons/yr CO_{2e}

DLK Black River Midstream LLC
Black River Gas Processing Plant

Unit Numbers:	ENG-1	
Source description:	4 Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha	
Model:	P9394GSI	
Aspiration:	Turbo-charged	
Hours of Operation	8760	
Rated Horsepower	2250	
Heat Input	15.89	MMBtu/hr
Fuel Type	Natural Gas	

HAPs	**Emission Factor[1]**	**Emissions**	
	lb/MMBtu	**pph**	**tpy**
Benzene	0.0004	0.0070	0.0306
Toluene	0.0004	0.0065	0.0284
Acetaldehyde	0.0084	0.1329	0.5819
Acrolein	0.0051	0.0817	0.3578
Xylenes	0.0002	0.0029	0.0128
	Total:	**0.231**	**1.012**

Unit Numbers:	ENG-2	
Source description:	4 Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha	
Model:	P9394GSI	
Aspiration:	Turbo-charged	
Hours of Operation	8760	
Rated Horsepower	2250	
Heat Input	15.89	MMBtu/hr
Fuel Type	Natural Gas	

HAPs	**Emission Factor[1]**	**Emissions**	
	lb/MMBtu	**pph**	**tpy**
Benzene	0.0004	0.0070	0.0306
Toluene	0.0004	0.0065	0.0284
Acetaldehyde	0.0084	0.1329	0.5819
Acrolein	0.0051	0.0817	0.3578
Xylenes	0.0002	0.0029	0.0128
	Total:	**0.231**	**1.012**

Unit Numbers:	ENG-3	
Source description:	4 Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha	
Model:	P9394GSI	
Aspiration:	Turbo-charged	
Hours of Operation	8760	
Rated Horsepower	2250.00	
Heat Input	15.89	MMBtu/hr
Fuel Type	Natural Gas	

HAPs	**Emission Factor[1]**	**Emissions**	
	lb/MMBtu	**pph**	**tpy**
Benzene	0.0004	0.0070	0.0306
Toluene	0.0004	0.0065	0.0284
Acetaldehyde	0.0084	0.1329	0.5819
Acrolein	0.0051	0.0817	0.3578
Xylenes	0.0002	0.0029	0.0128
	Total:	**0.231**	**1.012**

Unit Numbers:	ENG-4	
Source description:	4 Stroke	Rich Burn Natural Gas Engine
Manufacturer:	Waukesha	
Model:	P9394GSI	
Aspiration:	Turbo-charged	
Hours of Operation	8760	
Rated Horsepower	2250.00	
Heat Input	15.89	MMBtu/hr
Fuel Type	Natural Gas	

HAPs	**Emission Factor[1]**	**Emissions**	
	lb/MMBtu	**pph**	**tpy**
Benzene	0.0004	0.0070	0.0306
Toluene	0.0004	0.0065	0.0284
Acetaldehyde	0.0084	0.1329	0.5819
Acrolein	0.0051	0.0817	0.3578
Xylenes	0.0002	0.0029	0.0128
	Total:	**0.231**	**1.012**

DLK Black River Midstream LLC
Black River Gas Processing Plant

Heater Treater/Bioler Calculations

Unit No.	HT-101	
Heater/Boiler rating (MMBtu/hr):	6.97	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.644	2.822
CO	84.000	0.541	2.370
VOC	5.500	0.035	0.155
PM_{10}	7.600	0.049	0.214
$PM_{2.5}$	5.700	0.037	0.161
SO_2	0.600	0.004	0.017

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:	
Fuel H_2S content (mol %) =	**0.0000**
SO_2 produced (lb/hr) =	**0.0000**
SO_2 produced (tpy) =	**0.0000**

assumptions:		
SO2 MW	64.06	lb/lb-mole
Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	HT-801	
Heater/Boiler rating (MMBtu/hr):	6.97	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.644	2.822
CO	84.000	0.541	2.370
VOC	5.500	0.035	0.155
PM_{10}	7.600	0.049	0.214
$PM_{2.5}$	5.700	0.037	0.161
SO_2	0.600	0.004	0.017

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:	
Fuel H_2S content (mol %) =	**0.0000**
SO_2 produced (lb/hr) =	**0.0000**
SO_2 produced (tpy) =	**0.0000**

assumptions:		
SO2 MW	64.06	lb/lb-mole
Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	HT-102	
Heater/Boiler rating (MMBtu/hr):	9.74	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.900	3.944
CO	84.000	0.756	3.313
VOC	5.500	0.050	0.217
PM_{10}	7.600	0.068	0.300
$PM_{2.5}$	5.700	0.051	0.225
SO_2	0.600	0.005	0.024

If the heater/boiler is fueled by Sour Gas, cannot use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:				
Fuel H_2S content (mol %) =	**0.0000**	assumptions:		
SO_2 produced (lb/hr) =	**0.0000**	SO2 MW	64.06	lb/lb-mole
SO_2 produced (tpy) =	**0.0000**	Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	AR-1	
Heater/Boiler rating (MMBtu/hr):	21.09	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	1.950	8.539
CO	84.000	1.638	7.173
VOC	5.500	0.107	0.470
PM_{10}	7.600	0.148	0.649
$PM_{2.5}$	5.700	0.111	0.487
SO_2	0.600	0.012	0.051

If the heater/boiler is fueled by Sour Gas, cannot use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:				
Fuel H_2S content (mol %) =	**0.0000**	assumptions:		
SO_2 produced (lb/hr) =	**0.0000**	SO2 MW	64.06	lb/lb-mole
SO_2 produced (tpy) =	**0.0000**	Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	DR-1	
Heater/Boiler rating (MMBtu/hr):	2.9	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.268	1.174
CO	84.000	0.225	0.986
VOC	5.500	0.015	0.065
PM_{10}	7.600	0.020	0.089
$PM_{2.5}$	5.700	0.015	0.067
SO_2	0.600	0.002	0.007

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:				
Fuel H_2S content (mol %) =	**0.0000**	assumptions:		
SO_2 produced (lb/hr) =	**0.0000**	SO2 MW	64.06	lb/lb-mole
SO_2 produced (tpy) =	**0.0000**	Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	HT-103	
Heater/Boiler rating (MMBtu/hr):	9.74	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.900	3.944
CO	84.000	0.756	3.313
VOC	5.500	0.050	0.217
PM_{10}	7.600	0.068	0.300
$PM_{2.5}$	5.700	0.051	0.225
SO_2	0.600	0.005	0.024

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:				
Fuel H_2S content (mol %) =	**0.0000**	assumptions:		
SO_2 produced (lb/hr) =	**0.0000**	SO2 MW	64.06	lb/lb-mole
SO_2 produced (tpy) =	**0.0000**	Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	HT-802	
Heater/Boiler rating (MMBtu/hr):	6.2	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	0.573	2.510
CO	84.000	0.481	2.109
VOC	5.500	0.032	0.138
PM_{10}	7.600	0.044	0.191
$PM_{2.5}$	5.700	0.033	0.143
SO_2	0.600	0.003	0.015

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:	
Fuel H_2S content (mol %) =	**0.0000**
SO_2 produced (lb/hr) =	**0.0000**
SO_2 produced (tpy) =	**0.0000**

assumptions:		
SO2 MW	64.06	lb/lb-mole
Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	AR-2	
Heater/Boiler rating (MMBtu/hr):	23.92	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	Emission Factor (lb/MMCF)	lb/hr	tpy
NO_x	100.000	2.211	9.685
CO	84.000	1.857	8.135
VOC	5.500	0.122	0.533
PM_{10}	7.600	0.168	0.736
$PM_{2.5}$	5.700	0.126	0.552
SO_2	0.600	0.013	0.058

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:	
Fuel H_2S content (mol %) =	**0.0000**
SO_2 produced (lb/hr) =	**0.0000**
SO_2 produced (tpy) =	**0.0000**

assumptions:		
SO2 MW	64.06	lb/lb-mole
Ideal Gas Law	378.61	SCF/lb-mole

Unit No.	DR-2	
Heater/Boiler rating (MMBtu/hr):	2.5	
Rating above is **(select from list)**:	*below 100 MMBtu/hr, uncontrolled*	(assume uncontrolled, unless specifically stated otherwise)
Operating hours/year:	8760	
Fuel Heat Value, LHV (Btu/SCF):	1081.8	

Pollutant	**Emission Factor (lb/MMCF)**	**lb/hr**	**tpy**
NO_x	100.000	0.231	1.012
CO	84.000	0.194	0.850
VOC	5.500	0.013	0.056
PM_{10}	7.600	0.018	0.077
$PM_{2.5}$	5.700	0.013	0.058
SO_2	0.600	0.001	0.006

If the heater/boiler is fueled by Sour Gas, <u>cannot</u> use emission factors above to calculate SO_2 emissions, must use SO_2 mass balance:

SO_2 Mass Balance calculation:	
Fuel H_2S content (mol %) =	**0.0000**
SO_2 produced (lb/hr) =	**0.0000**
SO_2 produced (tpy) =	**0.0000**

assumptions:		
SO2 MW	64.06	lb/lb-mole
Ideal Gas Law	378.61	SCF/lb-mole

DLK Black River Midstream LLC
Black River Gas Processing Plant

Glycol Dehydrator Emissions

Calculated Using GRI-GLYCalc or a Process Simulator

A) Enter information into the yellow boxes.

B) VOC and H2S control efficiencies may be entered (if applicable). VOC, benzene, and H2S regenerator condenser efficiencies may also be entered (if applicable).

C) There are two separate areas to enter information about the two emissions points, the flash tank and the regenerator. Then underneath, there is a table of the sum of flash tank and regenerator emissions.

D) The program results and any lab analysis results used as the calculation basis must be provided.

E) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

F) Make sure to answer the control device question.

G) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN	DEHY-1
Identifier	Plant 2 - Dehy Unit

Glycol Dehydrator Unit Information	
Are you using GLYCalc or a Process Simulator?	Process Simulator
GLYCalc Calculation Method (if using GLYCalc)	NA
Type of Glycol Used:	TEG
Annual Hours of Operation (hrs/yr):	8760
Dry Gas Flow Rate (MMscf/day)	291.66
Laboratory Wet Gas Analysis Provided? If not, explain why. (Use notes box below if more space needed.)	Yes
Date of Sample:	2/11/2021
Is sample site specific or representative? If representative, please justify. (Use notes box below if more space needed.)	Site specific
At what point in the process was the sample taken?	Dehy Inlet
Wet Gas Temperature (°F)	105.02
Wet Gas Pressure (psig)	926.10
Lean Glycol Pump Type	Multi Stage Centrifugal
Lean Glycol Pump Make and Model	Multi Stage Centrifugal
Lean Glycol Flow Rate (gpm)	51.00
Number of Pump Stokes per Minute for the Lean Glycol Pump (pump strokes/min, if applicable)	NA
Flash Tank Temperature (°F)	109.51
Flash Tank Pressure (psig)	80.00

Flash Tank		
Is there a flash tank? (If no, leave the inputs in this block blank.)	**Yes**	
	lb/hr	**tpy**
Emissions Uncontrolled VOC,(lb/hr, tpy)	104.804	459.041
Emissions Uncontrolled Benzene, (lb/hr, tpy)	0.279	1.223
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.011	0.048
Are flash tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(C) controlled by another type of control device	
VOC Control Efficiency (%)	100	
H2S Control Efficiency (%)	100	
VOC Results, (lb/hr, tpy)	0	0
Benzene Results, (lb/hr, tpy)	0	0
H2S Results, (lb/hr, tpy)	0	0

Regenerator		
	lb/hr	**tpy**
Emissions Uncontrolled VOC (lb/hr, tpy)	253.877	1111.980
Emissions Uncontrolled Benzene, (lb/hr, tpy)	30.158	132.093
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.053	0.233
Are regenerator vapors controlled by a condenser?	Yes	
VOC Condenser Efficiency (%) - if applicable	23.66	
Benzene Condenser Efficiency (%) - if applicable	37.83	
H2S Condenser Efficiency (%) - if applicable	2.00	
Are regenerator vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(B) cont. by flare/ VC/TO/VRU	
VOC Results, (lb/hr, tpy)	193.808	848.880
Benzene Results, (lb/hr, tpy)	18.749	82.119
H2S Results, (lb/hr, tpy)	0.052	0.228

Sum of Flash Tank and Regenerator Results		
	lb/hr	**tpy**
VOC Results	0	0
Benzene Results	0	0
H2S Results	0	0

Federal Applicability	
40 CFR Part 63 - Subpart HH	
All area sources, with TEG dehydration units, will have some requirements under the rule. Emission reduction requirements may apply or only recordkeeping requirements may apply.	
Is this subpart applicable?	Yes
If yes, how will compliance be achieved? If no, please explain why.	The permittee shall monitor as required by 40 CFR 63.772(b)(2) to demonstrate facility is exempt from general standards. The permittee shall generate and maintain the records required by 40 CFR 63.774(d)(1)(ii) to demonstrate compliance with the general standard exemptions found in 40 CFR 63.764(e).

Enter any notes here:
TEG Flash routed back to the process. Regenerator stream is routed to Flare, FL-2

DLK Black River Midstream LLC
Black River Gas Processing Plant

Glycol Dehydrator Emissions

Calculated Using GRI-GLYCalc or a Process Simulator
A) Enter information into the yellow boxes.
B) VOC and H2S control efficiencies may be entered (if applicable). VOC, benzene, and H2S regenerator condenser efficiencies may also be entered (if applicable).
C) There are two separate areas to enter information about the two emissions points, the flash tank and the regenerator. Then underneath, there is a table of the sum of flash tank and regenerator emissions.
D) The program results and any lab analysis results used as the calculation basis must be provided.
E) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

F) Make sure to answer the control device question.

G) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN	DEHY-2
Identifier	Plant 3 - Dehy Unit

Glycol Dehydrator Unit Information	
Are you using GLYCalc or a Process Simulator?	Process Simulator
GLYCalc Calculation Method (if using GLYCalc)	NA
Type of Glycol Used:	TEG
Annual Hours of Operation (hrs/yr):	8760
Dry Gas Flow Rate (MMscf/day)	220.8
Laboratory Wet Gas Analysis Provided? If not, explain why. (Use notes box below if more space needed.)	Yes
Date of Sample:	2/11/2021
Is sample site specific or representative? If representative, please justify. (Use notes box below if more space needed.)	Site specific
At what point in the process was the sample taken?	Dehy Inlet
Wet Gas Temperature (°F)	104.96
Wet Gas Pressure (psig)	940.80
Lean Glycol Pump Type	Multi Stage Centrifugal
Lean Glycol Pump Make and Model	Multi Stage Centrifugal
Lean Glycol Flow Rate (gpm)	51.00
Number of Pump Stokes per Minute for the Lean Glycol Pump (pump strokes/min, if applicable)	NA
Flash Tank Temperature (°F)	109.57
Flash Tank Pressure (psig)	80.00

Flash Tank		
Is there a flash tank? (If no, leave the inputs in this block blank.)	**Yes**	
	lb/hr	**tpy**
Emissions Uncontrolled VOC,(lb/hr, tpy)	104.502	457.717
Emissions Uncontrolled Benzene, (lb/hr, tpy)	0.277	1.212
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.011	0.048
Are flash tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(C) controlled by another type of control device	
VOC Control Efficiency (%)	100	
H2S Control Efficiency (%)	100	
VOC Results, (lb/hr, tpy)	0	0
Benzene Results, (lb/hr, tpy)	0	0
H2S Results, (lb/hr, tpy)	0	0

Regenerator		
	lb/hr	**tpy**
Emissions Uncontrolled VOC (lb/hr, tpy)	248.279	1087.463
Emissions Uncontrolled Benzene, (lb/hr, tpy)	29.819	130.605
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.053	0.231
Are regenerator vapors controlled by a condenser?	Yes	
VOC Condenser Efficiency (%) - if applicable	23.35	
Benzene Condenser Efficiency (%) - if applicable	37.35	
H2S Condenser Efficiency (%) - if applicable	1.68	
Are regenerator vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(B) cont. by flare/ VC/TO/VRU	
VOC Results, (lb/hr, tpy)	190.317	833.590
Benzene Results, (lb/hr, tpy)	18.680	81.819
H2S Results, (lb/hr, tpy)	0.052	0.227

Sum of Flash Tank and Regenerator Results		
	lb/hr	**tpy**
VOC Results	0	0
Benzene Results	0	0
H2S Results	0	0

Federal Applicability	
40 CFR Part 63 - Subpart HH	
All area sources, with TEG dehydration units, will have some requirements under the rule. Emission reduction requirements may apply or only recordkeeping requirements may apply.	
Is this subpart applicable?	Yes
If yes, how will compliance be achieved? If no, please explain why.	The permittee shall monitor as required by 40 CFR 63.772(b)(2) to demonstrate facility is exempt from general standards. The permittee shall generate and maintain the records required by 40 CFR 63.774(d)(1)(ii) to demonstrate compliance with the general standard exemptions found in 40 CFR 63.764(e).

Enter any notes here:
TEG Flash routed back to the process. Regenerator stream is routed to thermal oxidizer TO-2

DLK Black River Midstream LLC
Black River Gas Processing Plant

Amine Unit Emissions

Calculated Using GRI-GLYCalc or a Process Simulator
A) Enter information into the yellow boxes.
B) VOC and H2S control efficiencies may be entered (if applicable). VOC, benzene, and H2S regenerator condenser efficiencies may also be entered (if applicable).
C) There are two separate areas to enter information about the two emissions points, the flash tank and the regenerator. Then underneath, there is a table of the sum of flash tank and regenerator emissions.
D) The program results and any lab analysis results used as the calculation basis must be provided.

E) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

F) Make sure to answer the control device question.

G) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN	AM-1
Identifier	Plant 2 - Amine Unit

Amine Unit Information	
Are you using AmineCalc or a Process Simulator?	Process Simulator
AmineCalc Model Selection (if using AmineCalc):	NA
Type of Amine Used:	DEA
Annual Hours of Operation (hrs/yr):	8760
Feed Gas Flow Rate (MMscf/day):	292.77
Laboratory Feed Gas Analysis Provided? If not, explain why. (Use notes box below if more space needed.)	Yes
Date of Sample:	2/11/2021
Is sample site specific or representative? If representative, please justify. (Use notes box below if more space needed.)	Site specific
At what point in the process was the sample taken?	Amine inlet
Feed Gas Temperature (°F)	89.62
Feed Gas Pressure (psia)	914.70
Lean Amine Flow Rate (gpm)	290.00
Flash Tank Temperature (°F)	94.84
Flash Tank Pressure (psia)	84.69

Flash Tank		
Is there a flash tank? (If no, leave the inputs in this block blank.)	Yes	
	lb/hr	tpy
Emissions Uncontrolled VOC,(lb/hr, tpy)	23.8881	104.6298
Emissions Uncontrolled Benzene, (lb/hr, tpy)	0.2928	1.2826
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.0048	0.0212
Are flash tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(C) controlled by another type of control device	
VOC Control Efficiency (%)	100	
H2S Control Efficiency (%)	100	
VOC Results, (lb/hr, tpy)	0	0
Benzene Results, (lb/hr, tpy)	0	0
H2S Results, (lb/hr, tpy)	0	0

Regenerator		
	lb/hr	tpy
Emissions Uncontrolled VOC (lb/hr, tpy)	19.4865	85.3507
Emissions Uncontrolled Benzene, (lb/hr, tpy)	7.5842	33.2187
Emissions Uncontrolled H2S, (lb/hr, tpy)	6.5380	28.6364
Are regenerator vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(B) cont. by flare/ VC/TO/VRU	
VOC Results, (lb/hr, tpy)	19.4865	85.3507
Benzene Results, (lb/hr, tpy)	7.5842	33.2187
H2S Results, (lb/hr, tpy)	6.5380	28.6364

Sum of Flash Tank and Regenerator Results		
	lb/hr	tpy
VOC Results	0	0
Benzene Results	0	0
H2S Results	0	0

Federal Applicability	
40 CFR Part 60 - Subpart LLL	
Is this subpart applicable?	No
If yes, how will compliance be achieved? If no, please explain why.	The facility is a natural gas processing plant, however, there is not sulfur recovery plant, thus this location does not meet the applicability criteria of 40 CFR 60.640.

Enter any notes here:
Amine flash is routed back to the process or burned as fuel and regenerator stream is routed to the thermal oxidizer, TO-1.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Amine Unit Emissions

Calculated Using AmineCalc or a Process Simulator
A) Enter information into the yellow boxes.
B) VOC and H2S control efficiencies may be entered (if applicable).

C) There are two separate areas to enter information about the two emissions points, the flash tank and the regenerator. Then underneath, there is a table of the sum of flash tank and regenerator emissions.

D) The program results and any lab analysis results used as the calculation basis must be provided.

E) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

F) Make sure to answer the control device question.

EPN	AM-2
Identifier	Plant 3 - Amine Unit

Amine Unit Information	
Are you using AmineCalc or a Process Simulator?	Process Simulator
AmineCalc Model Selection (if using AmineCalc):	NA
Type of Amine Used:	DEA
Annual Hours of Operation (hrs/yr):	8760
Feed Gas Flow Rate (MMscf/day):	219.2
Laboratory Feed Gas Analysis Provided? If not, explain why. (Use notes box below if more space needed.)	Yes
Date of Sample:	2/11/2021
Is sample site specific or representative? If representative, please justify. (Use notes box below if more space needed.)	Site specific
At what point in the process was the sample taken?	Amine inlet
Feed Gas Temperature (°F)	80.01
Feed Gas Pressure (psia)	1014.70
Lean Amine Flow Rate (gpm)	290.00
Flash Tank Temperature (°F)	96.19
Flash Tank Pressure (psia)	77.30

Flash Tank		
Is there a flash tank? (If no, leave the inputs in this block blank.)	**Yes**	
	lb/hr	**tpy**
Emissions Uncontrolled VOC,(lb/hr, tpy)	27.3166	119.6468
Emissions Uncontrolled Benzene, (lb/hr, tpy)	0.3337	1.4618
Emissions Uncontrolled H2S, (lb/hr, tpy)	0.0037	0.0161
Are flash tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(C) controlled by another type of control device	
VOC Control Efficiency (%)	100	
H2S Control Efficiency (%)	100	
VOC Results, (lb/hr, tpy)	0	0
Benzene Results, (lb/hr, tpy)	0	0
H2S Results, (lb/hr, tpy)	0	0

Regenerator		
	lb/hr	**tpy**
Emissions Uncontrolled VOC (lb/hr, tpy)	18.9481	82.9925
Emissions Uncontrolled Benzene, (lb/hr, tpy)	7.5346	33.0017
Emissions Uncontrolled H2S, (lb/hr, tpy)	4.9279	21.5841
Are regenerator vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(B) cont. by flare/ VC/TO/VRU	
VOC Results, (lb/hr, tpy)	18.9481	82.9925
Benzene Results, (lb/hr, tpy)	7.5346	33.0017
H2S Results, (lb/hr, tpy)	4.9279	21.5841

Sum of Flash Tank and Regenerator Results		
	lb/hr	**tpy**
VOC Results	0	0
Benzene Results	0	0
H2S Results	0	0

Federal Applicability	
40 CFR Part 60 - Subpart LLL	
Is this subpart applicable?	No
If yes, how will compliance be achieved? If no, please explain why.	The facility is a natural gas processing plant, however, there is not sulfur recovery plant, thus this location does not meet the applicability criteria of 40 CFR 60.640.

Enter any notes here:
Amine flash is routed back to the process or burned as fuel and regenerator stream is routed to the thermal oxidizer, TO-2.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Tank Emissions - Process Simulator

A) Enter information into the yellow boxes.
B) VOC and H2S control efficiencies may be entered (if applicable).
C) A reduction for produced water tank emissions calculated as oil/condensate may be entered.
D) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).
E) Make sure to answer the control device question.
F) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

Process Simulator

EPN	Tank Identifier	Throughput (gal/year)	Stream Identification	Turnovers per year	Mixture/ Component	RVP (psia)	Temperature (°F)	Emissions Uncontrolled VOC (lb/hr)	Emissions Uncontrolled VOC (ton/yr)	Emissions Uncontrolled Benzene (lb/hr)	Emissions Uncontrolled Benzene (ton/yr)	Emissions Uncontrolled H_2S (lb/hr)	Emissions Uncontrolled H_2S (ton/yr)	Are tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	VOC Control Efficiency (%)	H_2S Control Efficiency (%)	Reduction for Produced Water Tank Calc. as Oil/Cond. (%)	VOC Results (lb/hr)	VOC Results (tpy)	Benzene Results (lb/hr)	Benzene Results (tpy)	H_2S Results (lb/hr)	H_2S Results (tpy)
TK-702A	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
TK-702B	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
TK-702C	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
TK-702D	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
TK-702E	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
TK-702F	Condensate Storage Tanl	15330000	T-702 CONDENSATE STOR	906	Condensate	8.83	75.56	2.99	13.10	0.02	0.09	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0.00	2.99	13.10	0.02	0.09	0.00	0.00
																	Totals:	**17.94**	**78.58**	**0.12**	**0.53**	**0.00**	**0.00**

VOC Type:
Crude Oil or Condensate VOC

0.78577

Emission Type:
Steady State (continuous)

Enter any notes here:

DLK Black River Midstream LLC
Black River Gas Processing Plant

Tank Emissions - Process Simulator

A) Enter information into the yellow boxes.
B) VOC and H2S control efficiencies may be entered (if applicable).
C) A reduction for produced water tank emissions calculated as oil/condensate may be entered.
D) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).
E) Make sure to answer the control device question.
F) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

Process Simulator

EPN	Tank Identifier	Throughput (gal/year)	Stream Identification	Turnovers per year	Mixture/ Component	RVP (psia)	Temperature (°F)	Emissions Uncontrolled VOC (lb/hr)	Emissions Uncontrolled VOC (ton/yr)	Emissions Uncontrolled Benzene (lb/hr)	Emissions Uncontrolled Benzene (ton/yr)	Emissions Uncontrolled H2S (lb/hr)	Emissions Uncontrolled H2S (ton/yr)	Are tank vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	VOC Control Efficiency (%)	H2S Control Efficiency (%)	Percent Reduction for Produced Water Tank Calc. as Oil/Cond. (%)	VOC Results (lb/hr)	VOC Results (tpy)	Benzene Results (lb/hr)	Benzene Results (tpy)	H2S Results (lb/hr)	H2S Results (tpy)
TK-701	Produced Water Tank	2076371	T-701 PRODUCED WATER TANK	150	Produced Water	18.28	75.87	387.60	1697.69	6.40	28.03	0.00	0.00	(B) cont. by flare/ VC/TO/VRU	98	98	0	387.60	1697.69	6.40	28.03	0.00	0.00
																	Totals:	**387.60**	**1697.69**	**6.40**	**28.03**	**0.00**	**0.00**

VOC Type:
Crude Oil or Condensate VOC

Emission Type:
Steady State (continuous)

Enter any notes here:

DLK Black River Midstream LLC
Black River Gas Processing Plant

Thermal Oxidizer Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Thermal Oxidizer
(2) EPN:	TO-1
(3) What kind of device is this? Pick from list.	Thermal Oxidizer
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu) NOx 0.14 CO 0.13
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If there is more than one pilot stream, please enter it as one combined stream.
	Emission Factors for Pilot Stream (lb/MMscf) NOx 100 CO 84
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No
	Please move on to next question below.
	Emission Factors for Pilot Stream (ppmv) NOx 0 CO 0
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes
	Enter added fuel stream information into the boxes in the column for Steam No. 2 below.
	Emission Factors for Added Fuel Stream (ppmv) NOx CO

Emission Factors

[1]**Emission Factors from Zeeco Guarantee (lb/MMBtu)**

NOx	0.14	lb/MMBtu
CO	0.13	lb/MMBtu

[2]**Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)**

PM10	7.6	lb/MMscf
PM2.5	5.7	lb/MMscf

Zeeco Guarantee (MMBtu/hr)

Maximum Heating Value Acid Gas	9.9	MMBtu/hr
Maximum Heating Value Glycol Gas	5.6	MMBtu/hr

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100	
CO	84	
PM10, PM2.5	7.6	5.7

(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Added Fuel Stream (lb/MMBtu) NOx 0 CO 0	
(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	99	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	automatic ignition system	

Thermal Oxidizer No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Thermal Oxidizer Name (Enter Names of Each Stream Here)	Pilot + Sweep Gas	Waste Gas from Amine, AM-1 (stream 219)											-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	470	64872											65342.08333
Amount of Time Stream Fired (hrs/yr)	8760	8760											-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	4,117,200	568,279,450											572,396,650
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	16.67											-
propane weight percent of total stream (%) *OPTIONAL*	0.73	0.04											-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	0.27											-

Hourly (lb/hr)													
Stream Sent to Thermal Oxidizer No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-1 (stream 219)**											-
H2S	-	6.54											**6.54**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	19.49											**19.49**
Total VOC	-	19.49											**19.49**
Benzene	-	7.58											**7.58**
Annual (tpy)													
H2S	-	28.64											**28.64**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	85.35											**85.35**
Total VOC	-	85.35											**85.35**
Benzene	-	33.22											**33.22**

Controlled Emissions

Hourly (lb/hr)													
Stream Sent to Thermal Oxidizer No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-1 (stream 219)**											-
NOx	0.000	1.386	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.39**
CO	0.000	1.287	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.29**
PM2.5	0.000	0.370	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.37**
PM10	0.000	0.493	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.49**
H2S	0.001	0.131	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.13**
SO2	0.003	12.289	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**12.29**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	`	0.000	**0.00**
Natural Gas VOC	0.00	0.36	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.36**
Total VOC	0.00	0.36	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.36**
Benzene	0.000	0.15168	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.15**

Annual (tpy)													
Stream Sent to Thermal Oxidizer No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-1 (stream 219)**											**-**
NOx	0.206	6.071	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**6.28**
CO	0.173	5.637	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**5.81**
PM2.5	0.002	1.620	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.62**
PM10	0.003	2.159	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**2.16**
H2S	0.006	0.573	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.58**
SO2	0.012	53.828	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**53.84**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.000	1.592	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.59**
Total VOC	0.000	1.592	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.59**
Benzene	0.000	0.6644	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.66**

[1] CO and NOx emissions calculated based on the emission gurantees from manufacturer and the exhaust flue from the TO.

[2] $PM_{10}/PM_{2.5}$ AP-42 Factors

Thermal Oxidizer Total Emissions		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	0.00	0.00
Natural Gas VOC	0.36	1.59
Total VOC	0.36	1.59
NO_x	1.39	6.28
CO	1.29	5.81
$PM_{2.5}$	0.37	1.62
PM_{10}	0.49	2.16
H_2S	0.13	0.58
SO_2	12.29	53.84
Benzene	0.15	0.66

DLK Black River Midstream LLC
Black River Gas Processing Plant

Thermal Oxidizer SSM

A) Enter information into the yellow boxes.

B) Please provide a separate detailed calculation for these emissions; also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).

C) Since these emissions fall into the category of "Other", which does not have a pre-made emission estimation sheet with pre-approved methods, the time to review this project cannot be guaranteed to be as quick as if only pre-made sheets had been used.
D) VOC and H2S control efficiencies may be entered (if applicable).
E) Make sure to answer the control device question.

F) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN:	TO-1 SSM
Name:	Thermal Oxidizer SSM

Are these vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Uncontrolled Emissions			
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Control Efficiency
Total VOC	19.486	1.707	0
NO_x	0.000	0.000	0
CO	0.000	0.000	0
$PM_{2.5}$	0.000	0.000	0
PM_{10}	0.000	0.000	0
H_2S	6.538	0.573	0
SO_2	0.000	0.000	0
Benzene	7.584	0.664	0
Formaldehyde	0.000	0.000	0

Total Emissions (control efficiencies factored in if applicable)		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Total VOC	19.49	1.71
NO_x	0.00	0.00
CO	0.00	0.00
$PM_{2.5}$	0.00	0.00
PM_{10}	0.00	0.00
H_2S	6.54	0.57
SO_2	0.00	0.00
Benzene	7.58	0.66
Formaldehyde	0.00	0.00

Enter any notes here:
SSM assumed 2% of total hours of operation in a year.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Thermal Oxidizer Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Thermal Oxidizer	
(2) EPN:	TO-2	
(3) What kind of device is this? Pick from list.	Thermal Oxidizer	
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu)	
	NOx	0.14
	CO	0.13
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes	
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If there is more than one pilot stream, please enter it as one combined stream.	
	Emission Factors for Pilot Stream (lb/MMscf)	
	NOx	100
	CO	84
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Pilot Stream (ppmv)	
	NOx	0
	CO	0
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Added Fuel Stream (ppmv)	
	NOx	
	CO	

Emission Factors

[1]Emission Factors from Zeeco Guarantee (lb/MMBtu)

NOx	0.14	lb/MMBtu
CO	0.13	lb/MMBtu

[2]Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

PM10	7.6	lb/MMscf
PM2.5	5.7	lb/MMscf

Zeeco Guarantee (MMBtu/hr)

Maximum Heating Value Acid Gas	9.9	MMBtu/hr
Maximum Heating Value Glycol Gas	5.6	MMBtu/hr

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100	
CO	84	
PM10, PM2.5	7.6	5.7

(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Added Fuel Stream (lb/MMBtu) NOx 0 CO 0	
(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	99	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	automatic ignition system	

Stream Sent to Thermal Oxidizer No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-2 (Stream 94)**	**Waste gas from Dehy, DEHY-2 (Stream Condenser OVHD2)**										-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	470	53575	1550										**55594.83333**
Amount of Time Stream Fired (hrs/yr)	8760	8760	8760										-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	4,117,200	469,317,000	13,576,540										**487,010,740**
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	18.51	2561.12										-
propane weight percent of total stream (%) *OPTIONAL*	0.73	0.04	16.24										-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	0.32	81.25										-

Hourly (lb/hr)													
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-2 (Stream 94)**	**Waste gas from Dehy, DEHY-2 (Stream Condenser OVHD2)**										-
H2S	-	4.93	0.05										**4.98**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	18.95	190.32										**209.27**
Total VOC	-	18.95	190.32										**209.27**
Benzene	-	7.53	18.68										**26.21**
Annual (tpy)													
H2S	-	21.58	0.23										**21.81**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	82.99	833.59										**916.58**
Total VOC	-	82.99	833.59										**916.58**
Benzene	-	33.00	81.82										**114.82**

Controlled Emissions

Hourly (lb/hr)													
Stream Sent to Thermal Oxidizer No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-2 (Stream 94)**	**Waste gas from Dehy, DEHY-2 (Stream Condenser OVHD2)**										-
NOx	0.000	1.386	0.784	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**2.17**
CO	0.000	1.287	0.728	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**2.02**
PM2.5	0.000	0.305	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.31**
PM10	0.000	0.407	0.012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.42**
H2S	0.001	0.099	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.10**
SO2	0.003	9.263	0.098	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**9.36**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	`	0.000	**0.00**
Natural Gas VOC	0.00	0.35	3.426	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**3.78**
Total VOC	0.00	0.35	3.426	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**3.78**
Benzene	0.000	0.15069	0.374	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.52**

Annual (tpy)

Stream Sent to Thermal Oxidizer No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Thermal Oxidizer Name	**Pilot + Sweep Gas**	**Waste Gas from Amine, AM-2 (Stream 94)**	**Waste gas from Dehy, DEHY-2 (Stream Condenser OVHD2)**										-
NOx	0.206	6.071	3.434	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**9.71**
CO	0.173	5.637	3.189	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**9.00**
PM2.5	0.002	1.338	0.039	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.38**
PM10	0.003	1.783	0.052	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.84**
H2S	0.006	0.432	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.44**
SO2	0.012	40.572	0.428	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**41.01**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.000	1.546	15.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**16.55**
Total VOC	0.000	1.546	15.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**16.55**
Benzene	0.000	0.6600	1.636	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**2.30**

[1] CO and NOx emissions calculated based on the emission gurantees from manufacturer and the exhaust flue from the TO.
[2] $PM_{10}/PM_{2.5}$ AP-42 Factors

Thermal Oxidizer Total Emissions

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	0.00	0.00
Natural Gas VOC	3.78	16.55
Total VOC	3.78	16.55
NO_x	2.17	9.71
CO	2.02	9.00
$PM_{2.5}$	0.31	1.38
PM_{10}	0.42	1.84
H_2S	0.10	0.44
SO_2	9.36	41.01
Benzene	0.52	2.30

DLK Black River Midstream LLC
Black River Gas Processing Plant

Thermal Oxidizer SSM

A) Enter information into the yellow boxes.

B) Please provide a separate detailed calculation for these emissions; also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).
C) Since these emissions fall into the category of "Other", which does not have a pre-made emission estimation sheet with pre-approved methods, the time to review this project cannot be guaranteed to be as quick as if only pre-made sheets had been used.

D) VOC and H2S control efficiencies may be entered (if applicable).
E) Make sure to answer the control device question.

F) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN:	TO-2 SSM
Name:	Thermal Oxidizer SSM

Are these vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Uncontrolled Emissions			
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Control Efficiency
Total VOC	190.317	16.672	0
NOx	0.000	0.000	0
CO	0.000	0.000	0
PM2.5	0.000	0.000	0
PM10	0.000	0.000	0
H2S	0.052	0.005	0
SO2	0.000	0.000	0
benzene	18.680	1.636	0
formaldehyde	0.000	0.000	0

Total Emissions (control efficiencies factored in if applicable)		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Total VOC	190.32	16.67
NOx	0.00	0.00
CO	0.00	0.00
PM2.5	0.00	0.00
PM10	0.00	0.00
H2S	0.05	0.00
SO2	0.00	0.00
benzene	18.68	1.64
formaldehyde	0.00	0.00

Enter any notes here:
SSM assumed 2% of total hours of operation in a year.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Plant 2 - Dehydrator Overhead SSM

A) Enter information into the yellow boxes.

B) Please provide a separate detailed calculation for these emissions; also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).

C) Since these emissions fall into the category of "Other", which does not have a pre-made emission estimation sheet with pre-approved methods, the time to review this project cannot be guaranteed to be as quick as if only pre-made sheets had been used.

D) VOC and H2S control efficiencies may be entered (if applicable).

E) Make sure to answer the control device question.

menus below.

EPN:	DEHY-1 SSM
Name:	Dehydrator Overhead SSM

Are these vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Uncontrolled Emissions			
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Control Efficiency
Total VOC	193.808	16.978	0
NOx	0.000	0.000	0
CO	0.000	0.000	0
PM2.5	0.000	0.000	0
PM10	0.000	0.000	0
H2S	0.052	0.005	0
SO2	0.000	0.000	0
benzene	18.749	1.642	0
formaldehyde	0.000	0.000	0

Total Emissions (control efficiencies factored in if applicable)		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Total VOC	193.81	16.98
NOx	0.00	0.00
CO	0.00	0.00
PM2.5	0.00	0.00
PM10	0.00	0.00
H2S	0.05	0.005
SO2	0.00	0.00
benzene	18.75	1.64
formaldehyde	0.00	0.00

Enter any notes here:
SSM assumed 2% of total hours of operation in a year.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Flare/Vapor Combustor Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Plant 1 SSM/M		
(2) EPN:	FL-1		
(3) What kind of device is this? Pick from list.	Flare		
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu)		
	NOx	0.138	
	CO	0.2755	
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes		
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If		
	Emission Factors for Pilot Stream (lb/MMscf)		
	NOx	100	
	CO	84	
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Pilot Stream (ppmv)		
	NOx	0	
	CO	0	
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (ppmv)		
	NOx		
	CO		
(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (lb/MMBtu)		
	NOx	0	
	CO	0	

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100
CO	84

Emission Factors from TCEQ Guidance (lb/MMBtu)

Non-steam assisted, high Btu		Steam assisted, high Btu	
NOx	0.138	NOx	0.0485
CO	0.2755	CO	0.3503
Non-steam assisted, low Btu		Steam assisted, low Btu	
NOx	0.0641	NOx	0.068
CO	0.5496	CO	0.3465

Emission Factors from AP-42 Table 1.4-2 and 1.4-3 (lb/MMscf)

SO_2	0.6
VOC	5.5
benzene	0.002

(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	99	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	continuous pilot	

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name (Enter Names of Each Stream Here)	Pilot + Sweep Gas	Compressor Blowdowns	Plant 1 Malfunction										-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	360	600000	1000000										1600360
Amount of Time Stream Fired (hrs/yr)	8760	96	24										-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	3,153,600	57,600,000	24,000,000										84,753,600
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	1250.70	1,250.70										-
propane weight percent of total stream (%) *OPTIONAL*	0.733805024	11.18068475	11.18										-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	20.84	20.840										-

Hourly (lb/hr)

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name	Pilot + Sweep Gas	Compressor Blowdowns	Plant 1 Malfunction										
H2S	-	0.3187	0.53										0.85
Crude or Condensate VOC	-												0.00
Natural Gas VOC	-	6810.41	11350.69										18161.10
Total VOC	-	6810.41	11350.69										18161.10
Benzene	-	2.43	4.06										6.49
Annual (tpy)													
H2S	-	0.01530	0.01										0.02
Crude or Condensate VOC	-												0.00
Natural Gas VOC	-	326.90	136.21										463.11
Total VOC	-	326.90	136.21										463.11
Benzene	-	0.1169	0.05										0.17

Controlled Emissions													
						Hourly (lb/hr)							
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Compressor Blowdowns**	**Plant 1 Malfunction**										
NOx	0.036	103.558	172.597	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**276.19**
CO	0.030	206.741	344.568	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**551.34**
H2S	0.000	0.006	0.011	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.02**
SO2	0.000	0.599	0.998	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.60**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	`	0.000	**0.00**
Natural Gas VOC	0.00	99.67	166.116	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**265.79**
Total VOC	0.00	99.67	166.116	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**265.79**
Benzene	0.000	0.04869	0.081	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.13**
						Annual (tpy)							
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Compressor Blowdowns**	**Plant 1 Malfunction**										-
NOx	0.158	4.971	2.071	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**7.20**
CO	0.132	9.924	4.135	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**14.19**
H2S	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
SO2	0.001	0.029	0.012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.04**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.009	4.784	1.993	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**6.79**
Total VOC	0.009	4.784	1.993	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**6.79**
Benzene	0.000	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**

Flare/Vapor Combustor Total Emissions				
	SSM Emissions		**Malfunction Emissions**	
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	0.000	0.000	0.000	0.000
Natural Gas VOC	99.67	4.79	166.12	1.99
Total VOC	99.67	4.79	166.12	1.99
NO_x	103.59	5.13	172.60	2.07
CO	206.77	10.06	344.57	4.13
H_2S	0.01	0.001	0.01	0.0001
SO_2	0.60	0.03	1.00	0.01
Benzene	0.05	0.00	0.08	0.001

DLK Black River Midstream LLC
Black River Gas Processing Plant

Flare/Vapor Combustor Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Plant 2 - DEHY-1 Control and SSM/M		
(2) EPN:	FL-2		
(3) What kind of device is this? Pick from list.	Flare		
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu)		
	NOx	0.138	
	CO	0.2755	
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes		
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If		
	Emission Factors for Pilot Stream (lb/MMscf)		
	NOx	100	
	CO	84	
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Pilot Stream (ppmv)		
	NOx	0	
	CO	0	
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (ppmv)		
	NOx		
	CO		
(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (lb/MMBtu)		
	NOx	0	
	CO	0	

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100
CO	84

Emission Factors from TCEQ Guidance (lb/MMBtu)

Non-steam assisted, high Btu		Steam assisted, high Btu	
NOx	0.138	NOx	0.0485
CO	0.2755	CO	0.3503
Non-steam assisted, low Btu		Steam assisted, low Btu	
NOx	0.0641	NOx	0.068
CO	0.5496	CO	0.3465

Emission Factors from AP-42 Table 1.4-2 and 1.4-3 (lb/MMscf)

SO_2	0.6
VOC	5.5
benzene	2.10E-03

(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	99	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	automatic ignition system	

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name (Enter Names of Each Stream Here)	Pilot + Sweep Gas	Dehy-1 SSM Flash Gas - Stream 16	AM-1 SSM Flash Gas Stream220	Compressor Blowdowns	Plant 2 Malfunction	Dehy Overhead, DEHY-1 (Stream Condenser Ovhd)							-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	510	3446	2725	1000000.00	1000000.00	4676.21							2011357.092
Amount of Time Stream Fired (hrs/yr)	8760	1752	1752	96.00	24.00	8760							-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	4,467,600	6,037,589	4,773,791	96000000.00	24000000.00	40963621.5							176,242,602
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	1560.44	1,220.51	1250.70	1250.70	2554.53							-
propane weight percent of total stream (%) *OPTIONAL*	0.733805024	19.94	9.48	11.18	11.18	16.25							-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	41.97	16.33	20.84	20.84	81.09							-

Hourly (lb/hr)

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name	Pilot + Sweep Gas	Dehy-1 SSM Flash Gas - Stream 16	AM-1 SSM Flash Gas Stream220	Compressor Blowdowns	Plant 2 Malfunction	Dehy Overhead, DEHY-1 (Stream Condenser Ovhd)							-
H2S	-	0.0109	0.00	0.53	0.53	0.05							1.13
Crude or Condensate VOC	-												0.00
Natural Gas VOC	-	104.80	23.89	11350.69	11350.69	193.81							23023.88
Total VOC	-	104.80	23.89	11350.69	11350.69	193.81							23023.88
Benzene	-	0.28	0.29	4.06	4.06	18.75							27.44
Annual (tpy)													
H2S	-	0.00954	0.00424	0.02550	0.00637	0.23							0.27
Crude or Condensate VOC	-												0.00
Natural Gas VOC	-	91.81	20.93	544.83	136.21	848.88							1642.66
Total VOC	-	91.81	20.93	544.83	136.21	848.88							1642.66
Benzene	-	0.2446	0.2565	0.1948	0.0487	82.12							82.86

Controlled Emissions

	Hourly (lb/hr)												
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Dehy-1 SSM Flash Gas - Stream 16**	**AM-1 SSM Flash Gas Stream220**	**Compressor Blowdowns**	**Plant 2 Malfunction**	**Dehy Overhead, DEHY-1 (Stream Condenser Ovhd)**							-
NOx	0.051	0.742	0.459	172.597	172.597	1.648	0.000	0.000	0.000	0.000	0.000	0.000	**348.09**
CO	0.043	1.481	0.916	344.568	344.568	3.291	0.000	0.000	0.000	0.000	0.000	0.000	**694.87**
H2S	0.000	0.000	0.000	0.011	0.011	0.001	0.000	0.000	0.000	0.000	0.000	0.000	**0.02**
SO2	0.000	0.020	0.009	0.998	0.998	0.098	0.000	0.000	0.000	0.000	0.000	0.000	**2.12**
Crude or Condensate VOC	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.003	1.60	0.339	166.116	166.116	3.488	0.000	0.000	0.000	0.000	0.000	0.000	**337.66**
Total VOC	0.003	1.60	0.339	166.116	166.116	3.488	0.000	0.000	0.000	0.000	0.000	0.000	**337.66**
Benzene	0.000	0.00559	0.006	0.081	0.081	0.375	0.000	0.000	0.000	0.000	0.000	0.000	**0.55**
	Annual (tpy)												
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Dehy-1 SSM Flash Gas - Stream 16**	**AM-1 SSM Flash Gas Stream220**	**Compressor Blowdowns**	**Plant 2 Malfunction**	**Dehy Overhead, DEHY-1 (Stream Condenser Ovhd)**							-
NOx	0.223	0.650	0.402	8.285	2.071	7.220	0.000	0.000	0.000	0.000	0.000	0.000	**18.85**
CO	0.188	1.298	0.803	16.539	4.135	14.415	0.000	0.000	0.000	0.000	0.000	0.000	**37.38**
H2S	0.001	0.000	0.000	0.001	0.000	0.005	0.000	0.000	0.000	0.000	0.000	0.000	**0.01**
SO2	0.001	0.018	0.008	0.048	0.012	0.429	0.000	0.000	0.000	0.000	0.000	0.000	**0.52**
Crude or Condensate VOC	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.012	1.400	0.297	7.974	1.993	15.276	0.000	0.000	0.000	0.000	0.000	0.000	**26.95**
Total VOC	0.012	1.400	0.297	7.974	1.993	15.276	0.000	0.000	0.000	0.000	0.000	0.000	**26.95**
Benzene	0.000	0.005	0.005	0.004	0.001	1.642	0.000	0.000	0.000	0.000	0.000	0.000	**1.66**

Flare/Vapor Combustor Emissions

	Normal Operations Emissions		**SSM Emissions**		**Malfunction Emissions**	
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	-	-	-	-	-	-
Natural Gas VOC	3.49	15.28	168.06	9.68	166.12	1.99
Total VOC	3.49	15.28	168.06	9.68	166.12	1.99
NO_x	1.65	7.22	173.85	9.56	172.60	2.07
CO	3.29	14.41	347.01	18.83	344.57	4.13
H_2S	0.00	0.005	0.01	0.00	0.01	0.0001
SO_2	0.10	0.43	1.03	0.08	1.00	0.01
Benzene	0.37	1.64	0.09	0.01	0.08	0.00

DLK Black River Midstream LLC
Black River Gas Processing Plant

Flare/Vapor Combustor Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Plant 3 SSM/M		
(2) EPN:	FL-3		
(3) What kind of device is this? Pick from list.	Flare		
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu)		
	NOx	0.138	
	CO	0.2755	
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes		
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If		
	Emission Factors for Pilot Stream (lb/MMscf)		
	NOx	100	
	CO	84	
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Pilot Stream (ppmv)		
	NOx	0	
	CO	0	
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (ppmv)		
	NOx		
	CO		
(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No		
	Please move on to next question below.		
	Emission Factors for Added Fuel Stream (lb/MMBtu)		
	NOx	0	
	CO	0	

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100
CO	84

Emission Factors from TCEQ Guidance (lb/MMBtu)

Non-steam assisted, high Btu		Steam assisted, high Btu	
NOx	0.138	NOx	0.0485
CO	0.2755	CO	0.3503
Non-steam assisted, low Btu		Steam assisted, low Btu	
NOx	0.0641	NOx	0.068
CO	0.5496	CO	0.3465

Emission Factors from AP-42 Table 1.4-2 and 1.4-3 (lb/MMscf)

SO_2	0.6
VOC	5.5
benzene	2.10E-03

(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	99	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	continuous pilot	

Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name (Enter Names of Each Stream Here)	**Pilot + Sweep Gas**	**Dehy-2 SSM Flash Gas - Stream 30**	**AM-2 SSM Flash Gas Stream 95**	**Compressor Blowdowns**	**Plant 3 Malfunction**	**AM-2 To Thermal Oxidizer Stream 94**							-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	460	3437	3033	825,000	1000000	53575							**1885505.788**
Amount of Time Stream Fired (hrs/yr)	8760	1752	1752	96	24	175.2							-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	4,029,600	6,022,456	5,314,364	79,200,000	24,000,000	9,386,340							**127,952,760**
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	1561	1,223.94	1,251	1,250.70	18.51							-
propane weight percent of total stream (%) *OPTIONAL*	0.733805024	19.97	4.44	11.18068475	11.18068475	0.04							-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	41.95	6.770	20.84	20.83959131	0.18							-

						Hourly (lb/hr)							
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Dehy-2 SSM Flash Gas - Stream 30**	**AM-2 SSM Flash Gas Stream 95**	**Compressor Blowdowns**	**Plant 3 Malfunction**	**AM-2 To Thermal Oxidizer Stream 94**							-
H2S	-	0.0109	0.00	0.44	0.53	4.93							**5.91**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	104.50	27.32	9364.32	11350.69	18.95							**20865.77**
Total VOC	-	104.50	27.32	9364.32	11350.69	18.95							**20865.77**
Benzene	-	0.28	0.33	3.35	4.06	7.53							**15.55**
						Annual (tpy)							
H2S	-	0.00959	0.00322	0.02103	0.00637	0.43							**0.47**
Crude or Condensate VOC	-												**0.00**
Natural Gas VOC	-	91.54	23.93	449.49	136.21	1.66							**702.83**
Total VOC	-	91.54	23.93	449.49	136.21	1.66							**702.83**
Benzene	-	0.2425	0.2924	0.1607	0.0487	0.66							**1.40**

Controlled Emissions

	Hourly (lb/hr)												
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Dehy-2 SSM Flash Gas - Stream 30**	**AM-2 SSM Flash Gas Stream 95**	**Compressor Blowdowns**	**Plant 3 Malfunction**	**AM-2 To Thermal Oxidizer Stream Stream 94**							**-**
NOx	0.046	0.740	0.512	142.392	172.597	0.137	0.000	0.000	0.000	0.000	0.000	0.000	**316.42**
CO	0.039	1.478	1.023	284.268	344.568	0.273	0.000	0.000	0.000	0.000	0.000	0.000	**631.65**
H2S	0.000	0.000	0.000	0.009	0.011	0.099	0.000	0.000	0.000	0.000	0.000	0.000	**0.12**
SO2	0.000	0.021	0.007	0.824	0.998	9.263	0.000	0.000	0.000	0.000	0.000	0.000	**11.11**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	`	0.000	**0.00**
Natural Gas VOC	0.00	1.59	0.367	137.046	166.116	0.337	0.000	0.000	0.000	0.000	0.000	0.000	**305.46**
Total VOC	0.00	1.59	0.367	137.046	166.116	0.337	0.000	0.000	0.000	0.000	0.000	0.000	**305.46**
Benzene	0.000	0.00554	0.007	0.067	0.081	0.151	0.000	0.000	0.000	0.000	0.000	0.000	**0.31**
	Annual (tpy)												
Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot + Sweep Gas**	**Dehy-2 SSM Flash Gas - Stream 30**	**AM-2 SSM Flash Gas Stream 95**	**Compressor Blowdowns**	**Plant 3 Malfunction**	**AM-2 To Thermal Oxidizer Stream Stream 94**							**-**
NOx	0.201	0.649	0.449	6.835	2.071	0.012	0.000	0.000	0.000	0.000	0.000	0.000	**10.22**
CO	0.169	1.295	0.896	13.645	4.135	0.024	0.000	0.000	0.000	0.000	0.000	0.000	**20.16**
H2S	0.001	0.000	0.000	0.000	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	**0.01**
SO2	0.001	0.018	0.006	0.040	0.012	0.811	0.000	0.000	0.000	0.000	0.000	0.000	**0.89**
Crude or Condensate VOC	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Natural Gas VOC	0.011	1.395	0.322	6.578	1.993	0.030	0.000	0.000	0.000	0.000	0.000	0.000	**10.33**
Total VOC	0.011	1.395	0.322	6.578	1.993	0.030	0.000	0.000	0.000	0.000	0.000	0.000	**10.33**
Benzene	0.000	0.005	0.006	0.003	0.001	0.013	0.000	0.000	0.000	0.000	0.000	0.000	**0.03**

Flare/Vapor Combustor Total Emissions

	SSM Emissions		**Malfunction Emissions**	
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	0.00	0.00	0.00	0.00
Natural Gas VOC	139.34	8.34	166.12	1.99
Total VOC	139.34	8.34	166.12	1.99
NO_x	143.83	8.15	172.60	2.07
CO	287.08	16.03	344.57	4.13
H_2S	0.11	0.01	0.01	0.0001
SO_2	10.11	0.89	1.00	0.01
Benzene	0.23	0.03	0.08	0.00

DLK Black River Midstream LLC
Black River Gas Processing Plant

Flare/Vapor Combustor Emissions

General Information

Flare functions as emergency control device. When streams are fed to flare it will be treated as an emission event.

(1) Control Equipment:	Vapor Combustion Unit	
(2) EPN:	VCU-1	
(3) What kind of device is this? Pick from list.	Vapor Combustor	
	Emission Factors for Waste Gas Stream(s) (lb/MMbtu)	
	NOx	0.138
	CO	0.2755
(4) Is there one or more pilot streams fired with pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	Yes	
	Enter pilot stream information into the boxes in the column for Stream No. 1 below. If	
	Emission Factors for Pilot Stream (lb/MMscf)	
	NOx	100
	CO	84
(5) Is there one or more pilot streams fired with field gas? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Pilot Stream (ppmv)	
	NOx	0
	CO	0
(6) Is there an added fuel stream made up of pipeline quality natural gas or propane? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Added Fuel Stream (ppmv)	
	NOx	
	CO	
(7) Is there an added fuel stream made up of field gas? Pick Yes or No. Follow instructions below.	No	
	Please move on to next question below.	
	Emission Factors for Added Fuel Stream (lb/MMBtu)	
	NOx	0
	CO	0

Emission Factors

Emission Factors from AP-42 Table 1.4-1 and 1.4-2 (lb/MMscf)

NOx	100	
CO	84	
PM10, PM2.5	7.6	5.7

Emission Factors from TCEQ Guidance (lb/MMBtu)

Non-steam assisted, high Btu		Steam assisted, high Btu	
NOx	0.138	NOx	0.0485
CO	0.2755	CO	0.3503
Non-steam assisted, low Btu		Steam assisted, low Btu	
NOx	0.0641	NOx	0.068
CO	0.5496	CO	0.3465

Emission Factors from AP-42 Table 1.4-2 and 1.4-3 (lb/MMscf)

SO_2	0.6
VOC	5.5
benzene	2.10E-03

(8) VOC percent destruction efficiency (%)	98	
(9) propane percent destruction efficiency (%) *OPTIONAL*	98	
(10) H_2S percent destruction efficiency (%)	98	
(11) Which is utilized for this device?	automatic ignition system	

Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name (Enter Names of Each Stream Here)	**Pilot**	**Condensate Tanks**	**Produced Water Tanks**										-
Maximum Expected Hourly Volumtric Flow Rate of Stream (scf/hr)	12	93.86	2768.64										**2874.5**
Amount of Time Stream Fired (hrs/yr)	8760	8760	8760										-
Maximum Expected Annual Volumtric Flow Rate of Stream (scf/yr)	105,120	822,214	24,253,286										**25,180,620**
Heat Value of Stream - from program results or gas analysis (Btu/scf)	1081.80	4015.82	3098.29										-
propane weight percent of total stream (%) *OPTIONAL*	0.73	0.13	16.23										-
VOC weight percent of total stream (%) *OPTIONAL*	0.77	100.00	94.83										-

Hourly (lb/hr)

Stream Sent to Flare/Vapor Combustor No.	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**Total**
Stream Sent to Flare/Vapor Combustor Name	**Pilot**	**Condensate Tanks**	**Produced Water Tanks**										-
H2S	-	0.0000	0.0003										**0.00**
Crude or Condensate VOC	-	17.94	387.60										**405.54**
Natural Gas VOC	-												**0.00**
Total VOC	-	17.94	387.60										**405.54**
Benzene	-	0.12	6.40										**6.52**

Annual (tpy)

H2S	-	0.00000	0.00131										**0.00**
Crude or Condensate VOC	-	78.58	1697.68800										**1776.27**
Natural Gas VOC	-	0.00	0.00										**0.00**
Total VOC	-	78.58	1697.69										**1776.27**
Benzene	-	0.5256	28.0320										**28.56**

Controlled Emissions

Hourly (lb/hr)

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name	**Pilot**	**Condensate Tanks**	**Produced Water Tanks**										-
NOx	0.001	0.052	1.184	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**1.24**
CO	0.001	0.104	2.363	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**2.47**
PM2.5	0.000	0.001	0.016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.02**
PM10	0.000	0.001	0.021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.02**
H2S	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
SO2	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Crude or Condensate VOC	0.000	0.359	7.752	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**8.11**
Natural Gas VOC	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Total VOC	0.00	0.36	7.752	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**8.11**
Benzene	0.000	0.00240	0.128	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.13**

Annual (tpy)

Stream Sent to Flare/Vapor Combustor No.	1	2	3	4	5	6	7	8	9	10	11	12	Total
Stream Sent to Flare/Vapor Combustor Name	**Pilot**	**Condensate Tanks**	**Produced Water Tanks**										-
NOx	0.005	0.228	5.185	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**5.42**
CO	0.004	0.455	10.351	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**10.81**
PM2.5	0.000	0.002	0.069	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.07**
PM10	0.000	0.003	0.092	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.10**
H2S	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
SO2	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Crude or Condensate VOC	-	-	33.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**33.95**
Natural Gas VOC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.00**
Total VOC	0.000	1.572	33.954	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**35.53**
Benzene	0.000	0.011	0.561	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.57**

Flare/Vapor Combustor Total Emissions

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Crude or Condensate VOC	8.11	33.95
Natural Gas VOC	0.00	0.00
Total VOC	8.11	35.53
NO_x	1.24	5.42
CO	2.47	10.81
$PM_{2.5}$	0.02	0.07
PM_{10}	0.02	0.10
H_2S	0.00001	0.00004
SO_2	0.0006	0.0025
Benzene	0.13	0.57

DLK Black River Midstream LLC
Black River Gas Processing Plant

Flare/Vapor Combustor SSM Emissions

A) Enter information into the yellow boxes.

B) Please provide a separate detailed calculation for these emissions; also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).

C) Since these emissions fall into the category of "Other", which does not have a pre-made emission estimation sheet with pre-approved methods, the time to review this project cannot be guaranteed to be as quick as if only pre-made sheets had been used.

D) VOC and H2S control efficiencies may be entered (if applicable).

E) Make sure to answer the control device question.

F) Make sure to select the correct VOC Type and Emission Type from the pull down menus below.

EPN:	VCU-1 SSM
Name:	Vapor Combustion Unit SSM

Are these vapors (A) uncontrolled, (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Uncontrolled Emissions			
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Control Efficiency
Total VOC	405.540	13.855	0
NOx	0.000	0.000	0
CO	0.000	0.000	0
PM2.5	0.000	0.000	0
PM10	0.000	0.000	0
H2S	0.000	0.000	0
SO2	0.000	0.000	0
benzene	6.520	0.223	0
formaldehyde	0.000	0.000	0

Total Emissions (control efficiencies factored in if applicable)		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Total VOC	405.54	13.85
NOx	0.00	0.00
CO	0.00	0.00
PM2.5	0.00	0.00
PM10	0.00	0.00
H2S	0.00	0.00
SO2	0.00	0.00
benzene	6.52	0.22
formaldehyde	0.00	0.00

Enter any notes here:
SSM assumed 0.78% of total hours of operation in a year.

DLK Black River Midstream LLC
Black River Gas Processing Plant

Loading Emissions

Truck Hourly Loading Emission Calculations

Using equation L_L = 12.46* SPM/T from AP-42, Chapter 5, Section 5.2-4

S =	0.60	Saturation Factor
P =	8.96	True vapor pressure of liquid loaded (psia)
M =	72.44	Molecular Weight of Vapors (lb/lb-mole)
T =	559.67	Temperature of bulk liquid loaded (in degrees Rankine)
Hourly Loading Rate	8000.00	Gallons Loaded per Hour
L_L =	8.67	Loading Loss (lb VOC released/1000 gal liquid loaded)
	69.36	VOC Uncontrolled Emissions (lb/hr)
		Tank Vapor Weight Percents
VOC	100.00	Tank Vapor VOC wt%
benzene	0.81	Tank Vapor Benzene wt%
H_2S	0.00	Tank Vapor H2S wt%
		Produced Water Reduction
	0.00	Percent Reduction for Produced Water Tank Calc. as Oil/Cond. (%)
		Uncontrolled Emissions
VOC	69.36	Emissions Uncontrolled VOC (lb/hr)
benzene	0.56	Emissions Uncontrolled Benzene (lb/hr)
H_2S	0.00	Emissions Uncontrolled H_2S (lb/hr)
		Collection Efficiency (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Collection Efficiency (%)
H_2S	0.00	H_2S Collection Efficiency (%)
		Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)
VOC	69.36	VOC Uncaptured Vapors (lb/hr)
benzene	0.56	benzene Uncaptured Vapors (lb/hr)
H_2S	0.00	H_2S Uncaptured Vapors (lb/hr)
		Control Efficiency (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Control Efficiency (%)
H_2S	0.00	H_2S Control Efficiency (%)
		Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Results (lb/hr)
benzene	0.00	Benzene Results (lb/hr)
H_2S	0.00	H_2S Results (lb/hr)

Enter temperature in Fahrenheit °F):	Temperature in Rankine (°R):
100	559.67

Enter Barrels of	Gallons of liquid:
8000	336000

Gallons per Year	Barrels per day:
	0

Enter any notes here:

Truck Annual Loading Emission Calculations
Using equation L_L = 12.46* SPM/T from AP-42, Chapter 5, Section 5.2-4

S =	0.60	= Saturation Factor
P =	4.47	= True vapor pressure of liquid loaded (psia)
M =	72.44	= Molecular Weight of Vapors (lb/lb-mole)
T =	524.67	= Temperature of bulk liquid loaded (in degrees Rankine)
Annual Loading Rate	1764000.00	= Gallons Loaded per Year
L_L =	4.61	Loading Loss (lb VOC released/1000 gal liquid loaded)
	4.07	VOC Uncontrolled Emissions (ton/yr)
	Tank Vapor Weight Percents	
VOC	100.00	Tank Vapor VOC wt%
benzene	0.81	Tank Vapor Benzene wt%
H_2S	0.00	Tank Vapor H2S wt%
	Produced Water Reduction	
	0.00	Percent Reduction for Produced Water Tank Calc. as Oil/Cond. (%)
	Uncontrolled Emissions	
VOC	4.07	Emissions Uncontrolled VOC (ton/yr)
benzene	0.03	Emissions Uncontrolled Benzene (ton/yr)
H_2S	0.00	Emissions Uncontrolled H_2S (ton/yr)
	Collection Efficiency (only fill out if loading vapors are routed to a control device)	
VOC	0.00	VOC Collection Efficiency (%)
H_2S	0.00	H_2S Collection Efficiency (%)
	Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)	
VOC	4.07	VOC Uncaptured Vapors (ton/yr)
benzene	0.03	benzene Uncaptured Vapors (ton/yr)
H_2S	0.00	H_2S Uncaptured Vapors (ton/yr)
	Control Efficiency (only fill out if loading vapors are routed to a control device)	
VOC	0.00	VOC Control Efficiency (%)
H_2S	0.00	H_2S Control Efficiency (%)
	Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)	
VOC	0.00	VOC Results (ton/yr)
benzene	0.00	Benzene Results (ton/yr)
H_2S	0.00	H_2S Results (ton/yr)

Enter temperature in Fahrenheit °F):	Temperature in Rankine (°R):
65	524.67

Enter Barrels of Liquid	Gallons of liquid:
6000	252000

Enter gallons per year	Barrels per day:
1764000	115.0684932

Enter any notes here:

The condensate liquids have LACT to transfer the liquids out of the facility. Truck loading equal to 7 days condensate production is included in case the LACT is down.

Loading Emissions

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC	69.36	4.07
benzene	0.56	0.03
H2S	0.00	0.00

DLK Black River Midstream LLC
Black River Gas Processing Plant

Loading Emissions

Truck Hourly Loading Emission Calculations

Using equation L_L = 12.46* SPM/T from AP-42, Chapter 5, Section 5.2-4

S =	0.60	Saturation Factor
P =	21.67	True vapor pressure of liquid loaded (psia)
M =	56.01	Molecular Weight of Vapors (lb/lb-mole)
T =	559.67	Temperature of bulk liquid loaded (in degrees Rankine)
Hourly Loading Rate	8000.00	Gallons Loaded per Hour
L_L =	16.21	Loading Loss (lb VOC released/1000 gal liquid loaded)
	129.71	VOC Uncontrolled Emissions (lb/hr)
Tank Vapor Weight Percents		
VOC	94.83	Tank Vapor VOC wt%
benzene	1.57	Tank Vapor Benzene wt%
H_2S	0.00	Tank Vapor H2S wt%
Produced Water Reduction		
	0.00	Percent Reduction for Produced Water Tank Calc. as Oil/Cond. (%)
Uncontrolled Emissions		
VOC	129.71	Emissions Uncontrolled VOC (lb/hr)
benzene	2.15	Emissions Uncontrolled Benzene (lb/hr)
H_2S	0.00	Emissions Uncontrolled H_2S (lb/hr)
Collection Efficiency (only fill out if loading vapors are routed to a control device)		
VOC	0.00	VOC Collection Efficiency (%)
H_2S	0.00	H_2S Collection Efficiency (%)
Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)		
VOC	129.71	VOC Uncaptured Vapors (lb/hr)
benzene	2.15	benzene Uncaptured Vapors (lb/hr)
H_2S	0.00	H_2S Uncaptured Vapors (lb/hr)
Control Efficiency (only fill out if loading vapors are routed to a control device)		
VOC	0.00	VOC Control Efficiency (%)
H_2S	0.00	H_2S Control Efficiency (%)
Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)		
VOC	0.00	VOC Results (lb/hr)
benzene	0.00	Benzene Results (lb/hr)
H_2S	0.00	H_2S Results (lb/hr)

Enter temperature in Fahrenheit °F):	Temperature in Rankine (°R):
100	559.67

Enter Barrels of	Gallons of liquid:
8000	336000

Gallons per Year	Barrels per day:
	0

Enter any notes here:

Truck Annual Loading Emission Calculations

Using equation L_L = 12.46* SPM/T from AP-42, Chapter 5, Section 5.2-4

S =	0.60	= Saturation Factor
P =	12.23	= True vapor pressure of liquid loaded (psia)
M =	56.01	= Molecular Weight of Vapors (lb/lb-mole)
T =	524.67	= Temperature of bulk liquid loaded (in degrees Rankine)
Annual Loading Rate	44100.00	= Gallons Loaded per Year
L_L =	9.76	Loading Loss (lb VOC released/1000 gal liquid loaded)
	0.22	VOC Uncontrolled Emissions (ton/yr)
		Tank Vapor Weight Percents
VOC	94.83	Tank Vapor VOC wt%
benzene	1.57	Tank Vapor Benzene wt%
H_2S	0.00	Tank Vapor H2S wt%
		Produced Water Reduction
	0.00	Percent Reduction for Produced Water Tank Calc. as Oil/Cond. (%)
		Uncontrolled Emissions
VOC	0.22	Emissions Uncontrolled VOC (ton/yr)
benzene	0.00	Emissions Uncontrolled Benzene (ton/yr)
H_2S	0.00	Emissions Uncontrolled H_2S (ton/yr)
		Collection Efficiency (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Collection Efficiency (%)
H_2S	0.00	H_2S Collection Efficiency (%)
		Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)
VOC	0.22	VOC Uncaptured Vapors (ton/yr)
benzene	0.00	benzene Uncaptured Vapors (ton/yr)
H_2S	0.00	H_2S Uncaptured Vapors (ton/yr)
		Control Efficiency (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Control Efficiency (%)
H_2S	0.00	H_2S Control Efficiency (%)
		Vapors Uncaptured by Control Device (only fill out if loading vapors are routed to a control device)
VOC	0.00	VOC Results (ton/yr)
benzene	0.00	Benzene Results (ton/yr)
H_2S	0.00	H_2S Results (ton/yr)

Enter temperature in Fahrenheit °F):	Temperature in Rankine (°R):
65	524.67

Enter Barrels of Liquid	Gallons of liquid:
150	6300

Enter gallons per year	Barrels per day:
44100	2.876712329

Enter any notes here:

The produced water liquids are transfered by pipe out of the facility. Truck loading equal to 7 days produced water production is included in case the pipe is down.

Loading Emissions		
	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC	129.71	0.22
benzene	2.15	0.00
H2S	0.0001	0.00000017

DLK Black River Midstream LLC
Black River Gas Processing Plant

Planned MSS Emissions

A) Enter information into the yellow boxes.

B) VOC and H_2S control efficiencies may be entered (if applicable).

C) The vapor VOC, benzene, and H_2S weight percents may be entered. The weight percents from the Analyses tab are displayed

D) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

E) Make sure to answer the control device question.

F) Make sure to select the correct *VOC Type* and *Emission Type* from the pull down menus below.

EPN	SSM-1
Identifier	Pig Launcher Blowdowns

Describe this MSS event in detail, include specifically what is being done	Pig Launcher = 90 acf each 2 pig launch/day for 12 months

Venting Emission Calculation

Warning: This calculation should provide a conservatively high (potentially overestimated) result for emissions from venting when only gas is present in a unit. If liquids are present in the unit, this calculation could potentially significantly underestimate emissions because this calculation does not factor in emissions resulting from the evaporation of liquids present in the unit. If liquids are present or if you wish to use another calculation methodology, do not use this calculation tab. Instead, use the calculation tab for "Other" and make sure to provide a separate detailed calculation for these emissions and also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).

If emissions from this source are uncontrolled:

The formula is set up to do one calculation, which assumes that the entire volume of gas inside the unit is vented from the unit. The calculation of the mass of vented gas is done based on the volume of the unit vented, which is assumed to be saturated with vapor, and the temperature and pressure inside the unit before the venting occurs.

If emissions from this source are controlled:

The formula is set up to do two calculations. To preface the explanation of the two calculations, it is understood that for a release from a pressurized vessel, initial venting due to depressurization could occur rapidly until the vapor inside the vessel is equal to the atmospheric pressure, then further venting of the vapor still left in the vessel at atmospheric conditions could occur at a slower rate. This calculation assumes that any releases at atmospheric pressure cannot be controlled.

In order to move the vapor present in the vessel at atmospheric conditions to a control device, a flare for example, some sort of extra operation is needed such as using air or nitrogen to move the vapor out, and if all of that vapor is routed to the control device, it may be diluted to the point where it would not have a sufficient heating value to combust, and if a supplemental fuel stream is added, there would be additional emissions associated with this.

If you do have a way to move the vapor present in the vessel at atmospheric conditions to a control device, do not use this calculation tab. Instead, use the calculation tab for "Other" and make sure to provide a separate detailed calculation for these emissions and also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs). Also, please describe this MSS event in detail, include specifically what is being done, how it is being done, and how all of the vapor is controlled.

The first calculation of the mass of vented gas, which assumes that the entire volume of gas inside the unit is vented from the unit, is done based on the volume of the unit vented, which is assumed to be saturated with vapor, and the temperature and pressure inside the unit before the venting occurs.

The second calculation is done the same as the first one except using the atmospheric pressure (instead of the pressure inside the unit before the venting occurs) and represents all of the mass vented from the vessel that is present at atmospheric conditions (after the vessel depressurization).

The final result is the first calculation plus the second calculation, with the control efficiency only applied to the first calculation (which uses the pressure inside the unit before venting and represents the entire volume of gas inside the unit being vented).

(acf - actual cubic feet)	180
Before Venting (psig)	400
Final Pressure (psia)	14.7
Before Venting (psia)	414.7
Temperature of Gas Inside the Unit Before Venting (°F)	100
Temperature of Gas Inside the Unit Before Venting (°R)	559.27
(hours/event)	1
Frequency of Events (events/year)	365
(lb/lb-mol)	20.97
VOC wt %	20.84
benzene wt%	0.01
H_2S wt%	0.00
Are planned MSS vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Ideal Gas Constant, [(ft3*psia)/(R*lb-mol)]
10.73159

Gas Molecular Weight and Weight Percents From Analyses Tab:

Molecular Weight	20.97
VOC wt %	20.84
Benzene wt %	0.01
H2S wt %	0.00

Vapors Captured by Control Device

You need to input these values into the appropriate control device emission calculation tab.

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC Results:	54.351	9.919
Benzene Results:	0.019	0.004
H_2S Results:	0.003	0.0005

Planned MSS Emissions

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC Results:	54.35	9.92
Benzene Results:	0.02	0.00
H_2S Results:	0.003	0.0005

VOC Type: (pick from
Natural Gas VOC

Emission Type: (pick
Periodic

Enter any notes here:	

DLK Black River Midstream LLC
Black River Gas Processing Plant

Planned MSS Emissions

A) Enter information into the yellow boxes.
B) VOC and H_2S control efficiencies may be entered (if applicable).
C) The vapor VOC, benzene, and H_2S weight percents may be entered. The weight percents from the Analyses tab are displayed

D) Use the box provided below for entering any notes necessary (such as the source/justification for any calculation inputs).

E) Make sure to answer the control device question.

F) Make sure to select the correct *VOC Type* and *Emission Type* from the pull down menus below.

EPN	SSM-2
Identifier	Pig Launcher Blowdowns

Describe this MSS event in detail, include specifically what is being done	Pig Launcher = 40 acf 1 pig launch/day for 12 months

Venting Emission Calculation

Warning: This calculation should provide a conservatively high (potentially overestimated) result for emissions from venting when only gas is present in a unit. If liquids are present in the unit, this calculation could potentially significantly underestimate emissions because this calculation does not factor in emissions resulting from the evaporation of liquids present in the unit. If liquids are present or if you wish to use another calculation methodology, do not use this calculation tab. Instead, use the calculation tab for "Other" and make sure to provide a separate detailed calculation for these emissions and also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs).

If emissions from this source are uncontrolled:

The formula is set up to do one calculation, which assumes that the entire volume of gas inside the unit is vented from the unit. The calculation of the mass of vented gas is done based on the volume of the unit vented, which is assumed to be saturated with vapor, and the temperature and pressure inside the unit before the venting occurs.

If emissions from this source are controlled:

The formula is set up to do two calculations. To preface the explanation of the two calculations, it is understood that for a release from a pressurized vessel, initial venting due to depressurization could occur rapidly until the vapor inside the vessel is equal to the atmospheric pressure, then further venting of the vapor still left in the vessel at atmospheric conditions could occur at a slower rate. This calculation assumes that any releases at atmospheric pressure cannot be controlled.

In order to move the vapor present in the vessel at atmospheric conditions to a control device, a flare for example, some sort of extra operation is needed such as using air or nitrogen to move the vapor out, and if all of that vapor is routed to the control device, it may be diluted to the point where it would not have a sufficient heating value to combust, and if a supplemental fuel stream is added, there would be additional emissions associated with this.

If you do have a way to move the vapor present in the vessel at atmospheric conditions to a control device, do not use this calculation tab. Instead, use the calculation tab for "Other" and make sure to provide a separate detailed calculation for these emissions and also include any necessary supplemental information and notes (such as the source/justification for any calculation inputs). Also, please describe this MSS event in detail, include specifically what is being done, how it is being done, and how all of the vapor is controlled.

The first calculation of the mass of vented gas, which assumes that the entire volume of gas inside the unit is vented from the unit, is done based on the volume of the unit vented, which is assumed to be saturated with vapor, and the temperature and pressure inside the unit before the venting occurs.

The second calculation is done the same as the first one except using the atmospheric pressure (instead of the pressure inside the unit before the venting occurs) and represents all of the mass vented from the vessel that is present at atmospheric conditions (after the vessel depressurization).

The final result is the first calculation plus the second calculation, with the control efficiency only applied to the first calculation (which uses the pressure inside the unit before venting and represents the entire volume of gas inside the unit being vented).

(acf - actual cubic feet)	40
Before Venting (psig)	400
Final Pressure (psia)	14.7
Before Venting (psia)	414.7
Before Venting (°F)	100
Before Venting (°R)	559.27
(hours/event)	1
Frequency of Events (events/year)	365
(lb/lb-mol)	20.97
VOC wt %	20.84
benzene wt%	0.01
H_2S wt%	0.00
Are planned MSS vapors (A) uncontrolled; (B) controlled by a flare, vapor combustor, thermal oxidizer, or vapor recovery unit (VRU); or (C) controlled by another type of control device?	(A) uncontrolled

Ideal Gas Constant, [(ft3*psia)/(R*lb-mol)]
10.73159

Gas Molecular Weight and Weight Percents From Analyses Tab:

Molecular Weight	20.97
VOC wt %	20.84
Benzene wt %	0.01
H2S wt %	0.00

Vapors Captured by Control Device

You need to input these values into the appropriate control device emission calculation tab.

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC Results:	12.078	2.204
Benzene Results:	0.004	0.001
H_2S Results:	0.001	0.0001

Planned MSS Emissions

	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
VOC Results:	12.08	2.20
Benzene Results:	0.00	0.00
H_2S Results:	0.0006	0.0001

VOC Type: (pick from	
Natural Gas VOC	

Emission Type: (pick	
Periodic	

Enter any notes here:	

DLK Black River Midstream LLC
Black River Gas Processing Plant

Fugitive Emissions

Equip Cat	Type	Monitor Frequency	Component Count	Emission Factor[1] (kg/hr/source)	Control (%)	Inlet Gas % VOC	Inlet Gas % HAP	Inlet Gas % H_2S	Inlet Gas % CH4	Inlet Gas % CO2	Uncontrolled Rate (lb/hr)	Controlled Rate (lb/hr)
Connector	Vapor	Yearly (SS)	6611	2.00E-04	0%	20.84%	0.02%	0.10%	60.01%	1.26%	2.9149	2.9149
Press Relief Device	Vapor	Yearly (SS)	51	8.80E-03	0%						0.9894	0.9894
Valve	Vapor	Monthly (SS)	3408	4.50E-03	0%						33.8097	33.8097
Pumps	Vapor	Monthly (SS)	24	2.40E-03	0%						0.1270	0.1270
Hourly Total											37.84	37.84
Annual											165.7	165.7

Equip Cat	Type	VOC Uncontrolled Rate (lb/hr)	VOC Controlled Rate (lb/hr)	Total HAP Uncontrolled Rate (lb/hr)	Total HAP Controlled Rate (lb/hr)	H_2S Uncontrolled Rate (lb/hr)	H_2S Controlled Rate (lb/hr)	CH_4 Uncontrolled Rate (lb/hr)	CH_4 Controlled Rate (lb/hr)	CO_2 Uncontrolled Rate (lb/hr)	CO_2 Controlled Rate (lb/hr)
Connector	Vapor	0.61	0.61	6.01E-04	6.01E-04	2.84E-03	2.84E-03	1.75E+00	1.75E+00	3.66E-02	3.66E-02
Press Relief Device	Vapor	0.206	0.206	2.04E-04	2.04E-04	9.65E-04	9.65E-04	5.94E-01	5.94E-01	1.24E-02	1.24E-02
Valve	Vapor	7.05	7.05	6.98E-03	6.98E-03	3.30E-02	3.30E-02	2.03E+01	2.03E+01	4.24E-01	4.24E-01
Pumps	Vapor	0.03	0.03	2.62E-05	2.62E-05	1.24E-04	1.24E-04	7.62E-02	7.62E-02	1.59E-03	1.59E-03
Hourly Total		**7.89**	**7.89**	**0.01**	**0.01**	**0.04**	**0.04**	**22.71**	**22.71**	**0.47**	**0.47**
Annual Total (tpy)		**34.5**	**34.5**	**0.03**	**0.034**	**0.16**	**0.16**	**99.47**	**99.47**	**2.08**	**2.08**

Notes

[1] Emission factors from Table 2-4 of the EPA Protocol for Equipment Leak Emission Estimates, November 1995

GHG Emissions from Natural Gas Combustion

Emission Source	Source Description	Heat Rate	CO_2 EF	CO_2 Emissions		CH_4 EF	CH_4 Emissions		N_2O EF	N_2O Emissions	
		MMBtu/hr	kg/mmbtu	metric TPY	short tpy	kg/mmbtu	metric TPY	short tpy	kg/mmbtu	metric TPY	short tpy
HT-101	Plant 1 - Mole Sieve Heater	6.97	53.06	3239.70	3571.12	0.001	0.061	0.067	0.0001	0.006	0.007
HT-801	Plant 1 - Stabilizer Heater	6.97	53.06	3239.70	3571.12	0.001	0.061	0.067	0.0001	0.006	0.007
HT-102	Plant 2 - Mole Sieve Heater	9.74	53.06	4527.21	4990.34	0.001	0.085	0.094	0.0001	0.009	0.009
AR-1	Plant 2 - Amine Reboiler	21.09	53.06	9802.75	10805.57	0.001	0.185	0.204	0.0001	0.018	0.020
DR-1	Plant 2 - Dehy Regen Heater	2.9	53.06	1347.94	1485.83	0.001	0.025	0.028	0.0001	0.003	0.003
HT-103	Plant 3 - Mole Sieve Heater	9.74	53.06	4527.21	4990.34	0.001	0.085	0.094	0.0001	0.009	0.009
HT-802	Plant 3 - Stabilizer Heater 1	6.2	53.06	2881.79	3176.60	0.001	0.054	0.060	0.0001	0.005	0.006
AR-2	Plant 3 - Amine Reboiler	23.92	53.06	11118.15	12255.54	0.001	0.210	0.231	0.0001	0.021	0.023
DR-2	Plant 3 - Dehy Regen Heater	2.5	53.06	1162.01	1280.89	0.001	0.022	0.024	0.0001	0.002	0.002
HT-803	Plant 3 - Stabilizer Heater 2	6.2	53.06	2881.79	3176.60	0.001	0.054	0.060	0.0001	0.005	0.006
TO-1	Plant 2 -Thermal Oxidizer	9.80	53.06	4555.09	5021.08	0.001	0.086	0.095	0.0001	0.009	0.009
TO-2	Plant 3 -Thermal Oxidizer	9.80	53.06	4555.09	5021.08	0.001	0.086	0.095	0.0001	0.009	0.009
FL-1	Plant 1 - Flare	12.10	53.06	77.04	84.92	0.001	0.001	0.002	0.0001	0.000	0.000
FL-2	Plant 2 - Flare	25.23	53.06	4717.59	5200.20	0.001	0.089	0.098	0.0001	0.009	0.010
FL-3	Plant 3 - Flare	18.50	53.06	1719.78	1895.71	0.001	0.032	0.036	0.0001	0.003	0.004
VCU-1	Tanks Control	7.11	53.06	3304.77	3642.85	0.001	0.062	0.069	0.0001	0.006	0.007

Emission Factors (EF) from Tables C-1 and C-2 to 40 CFR 98 Subpart C

Haul Road Inputs

Unpaved haul road emissions from trucking operations for condensate tanks - Exempt under NMAC 20.2.72.202.B.5

Site-Wide

Description	Value	Unit
Liquid Throughput	6,081	bbl/day
Annual Operating Hours:	168	hr
Daily Operating Hours:	24	hr

Unpaved Haul Road

Parameter	Value	Unit
Empty Vehicle Weight[1]	16	ton
Load Size [2]	21.2	ton
Loaded Vehicle Weight[3]	37.2	ton
Mean Vehicle Weight[4]	26.6	ton
Vehicles Per Day [5]	12	VPD
Vehicles Per Year	4380	VPY
Segment Length	0.04	mile
Trips per Segment	2	-
Effective Segment Length[6]	0.08	mile
Trips per Hour[7]	1.00	-
Wet Days[8]	60	day
Surface Silt Content[9]	4.8	%
Control Efficiency	0	%

[1] Empty vehicle weight includes driver and occupants and full fuel load.

[2] Include cargo, transported materials, etc. (5.6 lb/gal RVP10 *7560 gal truck/ 2000lb/ton)

[3] Loaded vehicle weight = Empty + Load Size

[4] Mean Vehicle weight = (Loaded Weight + Empty Weight) / 2

[5] Vehicles per day = (Turnovers/year) / (365 days/year)

[6] Effective segment length = trips per segment * segment length

[7] Trips per hour = Vehicles per day * Segments per trip ÷ Hours of Operation per Day

[8] Wet days is the NM default allowed by NMED without additional justification

[9] Surface silt content based on AP-42 Section 13.2.2.3

Unpaved Road Emission Factors

Route	Calculation Parameters [1]												Hourly Emission Factors			Annual Emission Factors		
	s	W	P	k			a			b			E [2]			E_{ext} [5]		
	Silt Content [1]	Mean Vehicle Weight	Wet Days	PM_{30}	PM_{10}	$PM_{2.5}$	PM_{30}	PM_{10}	$PM_{2.5}$	PM_{30}	PM_{10}	$PM_{2.5}$	PM_{30} [3]	PM_{10}	$PM_{2.5}$	PM_{30}	PM_{10}	$PM_{2.5}$
	%	tons	day	lb/VMT	lb/VMT	lb/VMT							lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT	lb/VMT
Trucks	4.8	26.6	60	4.9	1.5	0.15	0.70	0.90	0.90	0.45	0.45	0.45	6.9	1.8	0.18	5.8	1.5	0.15

[1] Emission factors calculated per AP-42 Sec. 13.2.2.3 November, 2006, Equation 2.

Unpaved Road Emissions

Route	Calculation Inputs						Uncontrolled Emissions						Controlled Emissions [6]					
	Annual Operation	Segment Length	Trips per Segment	Number of Trucks per Year	Effective Segment Length	Average VMT/yr [4]	PM_{30}		PM_{10}		$PM_{2.5}$		PM_{30}		PM_{10}		$PM_{2.5}$	
	hr	mi		trucks/yr	mi	mi/yr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Trucks	8,760	0.04	2	4380	0.08	350	0.28	1.0	0.07	0.26	0.007	0.026	0.28	1.0	0.07	0.26	0.007	0.026
						Totals	***0.28***	***1.0***	***0.07***	***0.26***	***0.007***	***0.026***	***0.28***	***1.0***	***0.07***	***0.26***	***0.007***	***0.026***

[1] Surface silt = % of 75 micron diameter and smaller particles

[2] E = k x (s/12)^a x (W/3)^b (AP-42 page 13.2.2-4 Equation 1a, November 2006)

E= Size Specific Emission Factor (lb/VMT)

s = surface material silt content (%)

k, a, b = constants from AP-42 Table 13.2.2-2

W = Weighted Mean Vehicle Weight from Haul Road Inputs (tons)

[3] PM_{30} emission factor in equation is assumed as a surrogate for TSP emissions

[4] VMT/yr = Vehicle Miles Travelled per year= Trips per year * Segment Length

[5] Wet Day Emission Factor = E * (365 - Wet Days)/365. Wet days value is the NM default allowed by NMED without additional justification.

[6] Controlled Emissions = Uncontrolled Emissions * (1 - Control Factor/100%)

Control Efficiency = 0%

Section 7

Information Used to Determine Emissions

Information Used to Determine Emissions shall include the following:

- ☒ If manufacturer data are used, include specifications for emissions units and control equipment, including control efficiencies specifications and sufficient engineering data for verification of control equipment operation, including design drawings, test reports, and design parameters that affect normal operation.
- ☐ If test data are used, include a copy of the complete test report. If the test data are for an emissions unit other than the one being permitted, the emission units must be identical. Test data may not be used if any difference in operating conditions of the unit being permitted and the unit represented in the test report significantly effect emission rates.
- ☒ If the most current copy of AP-42 is used, reference the section and date located at the bottom of the page. Include a copy of the page containing the emissions factors, and clearly mark the factors used in the calculations.
- ☐ If an older version of AP-42 is used, include a complete copy of the section.
- ☐ If an EPA document or other material is referenced, include a complete copy.
- ☐ Fuel specifications sheet.
- ☒ If computer models are used to estimate emissions, include an input summary (if available) and a detailed report, and a disk containing the input file(s) used to run the model. For tank-flashing emissions, include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., permit or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis.

Engines (Units ENG-1, ENG-2, ENG-3, ENG-4)
- Manufacturers data and catalyst specification sheet
- AP-42 Tables 1.4-1 and 1.4-2 from AP-42
- 40 CFR Part 98 methodology
- 40 CFR 98 Tables C-1 and C-2 Emission Factors

Heaters (Units HT-101, HT-801, HT-102, HT-103, HT-802, HT-803)
- AP-42 Tables 1.4-1 and 1.4-2 from AP-42
- 40 CFR Part 98 methodology
- 40 CFR 98 Tables C-1 and C-2 Emission Factors

Reboilers (Units AR-1, AR-2, DR-1, DR-2)
- AP-42 Tables 1.4-1 and 1.4-2 from AP-42
- Manufacture spec sheet
- 40 CFR Part 98 methodology
- 40 CFR 98 Tables C-1 and C-2 Emission Factors

Glycol Dehydrators (Units DEHY-1, DEHY-2)
- ProMax

Amine Vents (Units AM-1, AM-2)
- ProMax

Flare SSM (Units FL-1, FL-2b, FL-3)
- AP-42 Table 13.5-1
- ProMax
- 40 CFR Part 98 methodology

Thermal Oxidizes (Units TO-1 and TO-2)
- AP-42 Tables 1.4-1 and 1.4-2 from AP-42
- Manufacturer's specifications
- 40 CFR Part 98 methodology
- 40 CFR 98 Tables C-1 and C-2 Emission Factors

Vapor Combustion Unit (Unit VCU-1)
- AP-42 Tables 1.4-1 and 1.4-2 from AP-42
- 40 CFR Part 98 methodology

Condensate Storage Tanks (Unit TK-702-A-F)
- ProMax

Produced Water Tank (Unit TK-701)
- Promax

Loading Emissions (Unit TL-1, TL-2)
- AP-42, Table 5.2-1 from AP-42

SSM (Units SSM-1, SSM-2)
- Ideal Gas law
- Inlet gas analysis, pressure temperature

Fugitive Emissions (Unit FUG-1)
- Tables 2-4 and 5-2 of the EPA Protocol for Equipment Leak Emission Estimates, November 1995
- Inlet gas and liquid analyses from ProMax

Haul Road Emissions (Unit HAUL-1)
- Equations 1a and 2 of AP-42 Section 13.2.2 (11/06)
- AP-42 Table 13.2.2-1
- AP-42 Figure 13.2.2-1
- AP-42 Table 13.2.2-2, Industrial Roads
- NMED Guidance Document - Department Accepted Values For: Aggregate Handling, Storage Pile, and Haul Road Emissions
- Google Earth

GE
Power

BR Gas Plant - New Mexico
San Mateo

VHP - P9394GSI
Gas Compression

ENGINE SPEED (rpm):	1200	NOx SELECTION (g/bhp-hr):	Customer Catalyst
DISPLACEMENT (in3):	9388	COOLING SYSTEM:	JW, IC + OC
COMPRESSION RATIO:	9.7:1	INTERCOOLER WATER INLET (°F):	130
IGNITION SYSTEM:	ESM	JACKET WATER OUTLET (°F):	180
EXHAUST MANIFOLD:	Water Cooled	JACKET WATER CAPACITY (gal):	148
COMBUSTION:	Rich Burn, Turbocharged	AUXILIARY WATER CAPACITY (gal):	16
ENGINE DRY WEIGHT (lbs):	33900	LUBE OIL CAPACITY (gal):	259
AIR/FUEL RATIO SETTING:	ESM	MAX. EXHAUST BACKPRESSURE (in. H2O):	18
ENGINE SOUND LEVEL (dBA)	103	MAX. AIR INLET RESTRICTION (in. H2O):	15
		EXHAUST SOUND LEVEL (dBA)	107

SITE CONDITIONS:

FUEL:	Natural Gas	ALTITUDE (ft):	953
FUEL PRESSURE RANGE (psig):	30 - 60	MAXIMUM INLET AIR TEMPERATURE (°F):	77
FUEL HHV (BTU/ft3):	1,078.2	FUEL WKI:	82.9
FUEL LHV (BTU/ft3):	974.7		

SITE SPECIFIC TECHNICAL DATA

POWER RATING	UNITS		MAX RATING AT 100 °F AIR TEMP	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE OF 77 °F 100%	75%	50%
CONTINUOUS ENGINE POWER	BHP		2250	2250	1688	1124
OVERLOAD	% 2/24 hr		0	0	-	-
MECHANICAL EFFICIENCY (LHV)	%		34.4	34.4	32.8	30.1
CONTINUOUS POWER AT FLYWHEEL	BHP		2250	2250	1688	1124
based on no auxiliary engine driven equipment						
AVAILABLE TURNDOWN SPEED RANGE	RPM	900 - 1200				
FUEL CONSUMPTION						
FUEL CONSUMPTION (LHV)	BTU/BHP-hr		7399	7399	7755	8471
FUEL CONSUMPTION (HHV)	BTU/BHP-hr		8185	8185	8579	9370
FUEL FLOW *based on fuel analysis LHV*	SCFM		285	285	224	163
HEAT REJECTION						
JACKET WATER (JW)	BTU/hr x 1000		4766	4672	3868	2986
LUBE OIL (OC)	BTU/hr x 1000		540	529	479	417
INTERCOOLER (IC)	BTU/hr x 1000		678	564	330	147
EXHAUST	BTU/hr x 1000		4602	4726	3641	2591
RADIATION	BTU/hr x 1000		660	754	728	703
EMISSIONS (ENGINE OUT):						
NOx (NO + NO2)	g/bhp-hr		11.7	11.6	11.3	10.3
CO	g/bhp-hr		10.9	10.9	12.2	13.8
THC	g/bhp-hr		0.5	0.5	0.6	0.7
NMHC	g/bhp-hr		0.10	0.10	0.11	0.13
NM,NEHC (VOC)	g/bhp-hr		0.00	0.00	0.00	0.01
CO2	g/bhp-hr		457	457	479	523
CO2e	g/bhp-hr		467	467	490	536
CH2O	g/bhp-hr		0.050	0.050	0.050	0.050
CH4	g/bhp-hr		0.42	0.42	0.47	0.54
AIR INTAKE / EXHAUST GAS						
INDUCTION AIR FLOW	SCFM		3116	3116	2449	1782
EXHAUST GAS MASS FLOW	lb/hr		14487	14487	11388	8284
EXHAUST GAS FLOW *at exhaust temp, 14.5 psia*	ACFM		10366	10418	8078	5791
EXHAUST TEMPERATURE	°F		1150	1158	1136	1113

HEAT EXCHANGER SIZING[12]			
TOTAL JACKET WATER CIRCUIT (JW)	BTU/hr x 1000		5404
TOTAL AUXILIARY WATER CIRCUIT (IC + OC)	BTU/hr x 1000		1381

COOLING SYSTEM WITH ENGINE MOUNTED WATER PUMPS		
JACKET WATER PUMP MIN. DESIGN FLOW	GPM	850
JACKET WATER PUMP MAX. EXTERNAL RESTRICTION	psig	18
AUX WATER PUMP MIN. DESIGN FLOW	GPM	101
AUX WATER PUMP MAX. EXTERNAL RESTRICTION	psig	29

All data provided per the condtions listed in the notes section on page three.
Data Generated by EngCalc Program Version 3.8 GE Distributed Power, Inc.
2/25/2021 3:59 PM

FUEL COMPOSITION

HYDROCARBONS:		Mole or Volume %
Methane	CH_4	87.508
Ethane	C_2H_6	10.454
Propane	C_3H_8	0.298
Iso-Butane	I-C_4H_{10}	0.005
Normal Butane	N-C_4H_{10}	0.006
Iso-Pentane	I-C_5H_{12}	0
Normal Pentane	N-C_5H_{12}	0
Hexane	C_6H_{14}	0
Heptane	C_7H_{16}	0
Ethene	C_2H_4	0
Propene	C_3H_6	0
	SUM HYDROCARBONS	98.271
NON-HYDROCARBONS:		
Nitrogen	N_2	1.083
Oxygen	O_2	0
Helium	He	0
Carbon Dioxide	CO_2	0.646
Carbon Monoxide	CO	0
Hydrogen	H_2	0
Water Vapor	H_2O	0
	TOTAL FUEL	100

FUEL:	Natural Gas
FUEL PRESSURE RANGE (psig):	30 - 60
FUEL WKI:	82.9
FUEL SLHV (BTU/ft3):	957.69
FUEL SLHV (MJ/Nm3):	37.66
FUEL LHV (BTU/ft3):	974.65
FUEL LHV (MJ/Nm3):	38.33
FUEL HHV (BTU/ft3):	1078.15
FUEL HHV (MJ/Nm3):	42.40
FUEL DENSITY (SG):	0.62

Standard Conditions per ASTM D3588-91 [60°F and 14.696psia] and ISO 6976:1996-02-01[25, V(0;101.325)].
Based on the fuel composition, supply pressure and temperature, liquid hydrocarbons may be present in the fuel. No liquid hydrocarbons are allowed in the fuel. The fuel must not contain any liquid water. Waukesha recommends both of the following:
1) Dew point of the fuel gas to be at least 20°F (11°C) below the measured temperature of the gas at the inlet of the engine fuel regulator.
2) A fuel filter separator to be used on all fuels except commercial quality natural gas.
Refer to the 'Fuel and Lubrication' section of 'Technical Data' or contact the Waukesha Application Engineering Department for additional information on fuels, or LHV and WKI* calculations.
* Trademark of General Electric Company

FUEL CONTAMINANTS

Total Sulfur Compounds	0	% volume
Total Halogen as Cloride	0	% volume
Total Ammonia	0	% volume
Siloxanes		
Tetramethyl silane	0	% volume
Trimethyl silanol	0	% volume
Hexamethyldisiloxane (L2)	0	% volume
Hexamethylcyclotrisiloxane (D3)	0	% volume
Octamethyltrisiloxane (L3)	0	% volume
Octamethylcyclotetrasiloxane (D4)	0	% volume
Decamethyltetrasiloxane (L4)	0	% volume
Decamethylcyclopentasiloxane (D5)	0	% volume
Dodecamethylpentasiloxane (L5)	0	% volume
Dodecamethylcyclohexasiloxane (D6)	0	% volume
Others	0	% volume

Total Sulfur Compounds	0 µg/BTU
Total Halogen as Cloride	0 µg/BTU
Total Ammonia	0 µg/BTU
Total Siloxanes (as Si)	0 µg/BTU

Calculated fuel contaminant analysis will depend on the entered fuel composition and selected engine model.

No water or hydrocarbon condensates are allowed in the engine. Requires liquids removal.

NOTES

1. All data is based on engines with standard configurations unless noted otherwise.

2. Power rating is adjusted for fuel, site altitude, and site air inlet temperature, in accordance with ISO 3046/1 with tolerance of ± 3%.

3. Fuel consumption is presented in accordance with ISO 3046/1 with a tolerance of -0 / +5% at maximum rating. Fuel flow calculation based on fuel LHV and fuel consumption with a tolerance of -0/+5 %. For sizing piping and fuel equipment, it is recommended to include the 5% tolerance.

4. Heat rejection tolerances are ± 30% for radiation, and ± 8% for jacket water, lube oil, intercooler, and exhaust energy.

5. Emission levels for engines with GE supplied 3-way catalyst are given at catalyst outlet flange. For all other engine models, emission levels are given at engine exhaust outlet flange prior to any after treatment. Values are based on a new engine operating at indicated site conditions, and adjusted to the specified timing and air/fuel ratio at rated load. Catalyst out emission levels represent emission levels the catalyst is sized to achieve. Manual adjustment may be necessary to achieve compliance as catalyst/engine age. Catalyst-out emission levels are valid for the duration of the engine warranty. Emissions are at an absolute humidity of 75 grains H_2O/lb (10.71 g H_2O/kg) of dry air. Emission levels may vary subject to instrumentation, measurement, ambient conditions, fuel quality, and engine variation. Engine may require adjustment on-site to meet emission values, which may affect engine performance and heat output. NO_x, CO, THC, and NMHC emission levels are listed as a not to exceed limit, all other emission levels are estimated. CO_2 emissions based on EPA Federal Register/Vol. 74, No. 209/Friday, October 30, 2009 Rules and Regulations 56398, 56399 (3) Tier 3 Calculation Methodology, Equation C-5.

6. Air flow is based on undried air with a tolerance of ± 7%.

7. Exhaust temperature given at engine exhaust outlet flange with a tolerance of ± 50°F (28°C).

8. Exhaust gas mass flow value is based on a "wet basis" with a tolerance of ± 7%.

9. Inlet air restrictions based on full rated engine load. Exhaust backpressure based on 158 PSI BMEP and 1200 RPM. Refer to the engine specification section of Waukesha's standard technical data for more information.

10. Cooling circuit capacity, lube oil capacity, and engine dry weight values are typical.

11. Fuel must conform to Waukesha's "Gaseous Fuel Specification" S7884-7 or most current version. Fuel may require treatment to meet current fuel specification.

12. Heat exchanger sizing values given as the maximum heat rejection of the circuit, with applied tolerances and an additional 5% reserve factor.

13. Fuel volume flow calculation in english units is based on 100% relative humidity of the fuel gas at standard conditions of 60°F and 14.696 psia (29.92 inches of mercury; 101.325 kPa).

14. Fuel volume flow calculation in metric units is based on 100% relative humidity of the fuel gas at a combustion temperature of 25°C and metering conditions of 0°C and 101.325 kPa (14.696 psia; 29.92 inches of mercury). This is expressed as [25, V(0;101.325)].

15. Engine sound data taken with the microphone at 1 m (3.3 ft) from the side of the engine at the approximate front-to-back centerline. Microphone height was at intake manifold level. Engine sound pressure data may be different at front, back and opposite side locations. Exhaust sound data taken with microphone 1 meter (3.3 ft) away and 1 meter (3.3 ft) to the side of the exhaust outlet.

16. Due to variation between test conditions and final site conditions, such as exhaust configuration and background sound level, sound pressure levels under site conditions may be different than those tabulated above.

17. Cooling system design flow is based on minimum allowable cooling system flow. Cooling system maximum external restriction is defined as the allowable restriction at the minimum cooling system flow.

18. Continuous Power Rating: The highest load and speed that can be applied 24 hours per day, seven days per week, 365 days per year except for normal maintenance at indicated ambient reference conditions and fuel. No engine overload power rating is available.

19. emPact emission compliance available for entire range of operable fuels; however, fuel system and/or O_2 set point may need to be adjusted in order to maintain compliance.

20. In cold ambient temperatures, heating of the engine jacket water, lube oil and combustion air may be required. See Waukesha Technical Data.

21. Available Turndown Speed Range refers to the constant torque speed range available. Reduced power may be available at speeds outside of this range. Contact application engineering.

SPECIAL REQUIREMENTS

Cypress Engine Accessories

MIRATECH

Equipment Specification

Proposal Information

Proposal Number:	CEA-20-003803	Date:	**6/17/2020**
Project Reference:	Vanguard Processing Solutions		

Engine Information

Engine Make:	Waukesha	Speed:	Rated
Engine Model:	P9394GSI	Power Output:	2,250 bhp
Rated Speed:	1200 RPM	Exhaust Flow Rate:	13,650 lb/hr
Fuel Description:	Natural Gas	Exhaust Temperature:	1,085 F
Hours Of Operation:	8760 Hours per year	O_2:	0.3%
Load:	100%	H_2O:	20%

Emission Data (100% Load)

Emission	Raw Engine Emissions						Target Outlet Emissions						Calculated Reduction
	g/bhp-hr	*tons/yr*	*ppmvd @ 15% O_2*	*ppmvd*	*g/kW-hr*	*lb/MW-hr*	*g/bhp-hr*	*tons/yr*	*ppmvd @ 15% O_2*	*ppmvd*	*g/kW-hr*	*lb/MW-hr*	
NO_x*	*14.6*	317.21	1,198	4,184	19.579	43.16	*0.5*	10.86	41	143	0.671	1.48	96.6%
CO	*9.5*	206.4	1,281	4,471	12.74	28.09	*0.5*	10.86	67	235	0.671	1.48	94.7%
THC**	*1.69*	36.72	398	1,389	2.266	5							
NMNEHC***	*0.35*	7.6	82	288	0.469	1.03	0.2	4.35	47	164	0.268	0.59	42.9%
CH_2O	*0.17*	3.69	21	75	0.228	0.5	*0.02*	0.43	3	9	0.027	0.06	88.2%

System Specifications

Catalyst (Replacement Catalyst)

Design Exhaust Flow Rate:	13,650 lb/hr
Design Exhaust Temperature:	1,085°F
Element Model Number:	MEC-TW-SQ-1500-3600-350
Number of Catalyst Layers:	2
Number of Catalyst Per Layer:	2
Catalyst Back Pressure:	5.0 inches of WC (Clean) (12.5 mBar)
Dimensions:	15 x 36
Exhaust Temperature Limits†:	750 – 1250°F (catalyst inlet); 1350°F (catalyst outlet) 399 – 677°C (catalyst inlet); 732°C (catalyst outlet)

* MW referenced as NO_2

** MW referenced as CH_4

*** MW referenced as CH_4. Propane in the exhaust shall not exceed 15% by volume of the NMNEHC compounds in the exhaust, excluding aldehydes. The 15% (vol.) shall be established on a wet basis, reported on a methane molecular weight basis. The measurement of exhaust NMNEHC composition shall be based upon EPA method 320 (FTIR), and shall exclude formaldehyde

† General catalyst temperature operating range. Performance is based on the Design Exhaust Temperature.

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED GAS REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Plant 3 Inlet Port # 3		**For:**	11376G
Sample Date:	02/11/2021		**Cyl. Ident.:**	2021039068
Sampled By:	JP		**Company:**	San Mateo
Time Sampled:	14:30		**Analysis Date:**	02/13/2021
Sample Temp:	88.7 F		**Analysis By:**	TG
Sample Press:	976.5	**H_2S (PPM)** = 1.0	**Data File:**	LS_6131.D

Component	Mole%	GPM REAL	GPM IDEAL
H_2S	0.000		
Nitrogen	0.994		
Methane	78.444		
CO2	0.598		
Ethane	11.552	3.089	3.082
Propane	5.317	1.464	1.461
Isobutane	0.716	0.234	0.234
N-Butane	1.525	0.481	0.480
Isopentane	0.305	0.112	0.111
N-Pentane	0.302	0.109	0.109
Hexanes+	0.247	0.126	0.124
Total	100.000	5.615	5.601

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	20.975
VAPOR PRESS PSIA:	4026.1
SPECIFIC GRAVITY	
AIR = 1 (REAL):	0.7265
AIR = 1 (IDEAL):	0.7242
H2O = 1 (IDEAL):	0.348
REPORTED BASIS:	14.73
Unnormalized Total:	102.332

HEATING VALUE

BTU/CUFT (DRY)	1250.7
BTU/CUFT (WET)	1229.4

BTEX SUMMARY

WT% BENZENE	14.961
WT% TOLUENE	2.642
WT% E BENZENE	0.000
WT% XYLENES	0.000

LAB MANAGER

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Plant 3 Inlet Port # 3
Company: San Mateo

Data File: LS_6131.D

*ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%
2,2 DIMETHYL BUTANE	0.003	0.013
CYCLOPENTANE	0.006	0.024
2-METHYLPENTANE	0.008	0.033
3-METHYLPENTANE	0.004	0.017
HEXANE (C6)	0.014	0.056
DIMETHYLPENTANES	0.014	0.069
METHYLCYCLOPENTANE	0.007	0.030
2,2,3 TRIMETHYLBUTANE	0.002	0.011
BENZENE	0.002	0.006
CYCLOHEXANE	0.003	0.012
2-METHYLHEXANE	0.001	0.004
3-METHYLHEXANE	0.002	0.010
DIMETHYCYCLOPENTANES	0.008	0.040
HEPTANE (C7)	0.004	0.017
METHYLCYCLOHEXANE	0.001	0.007
2,5 DIMETHYLHEXANE	0.006	0.031
TOLUENE	0.003	0.015
2-METHYLHEPTANE	0.000	0.000
OTHER OCTANES	0.033	0.167
OCTANE (C8)	0.000	0.000
ETHYLCYCLOHEXANE	0.000	0.000
ETHYL BENZENE	0.000	0.000
M,P-XYLENE	0.000	0.000
O-XYLENE	0.000	0.000
OTHER NONANES	0.035	0.205
NONANE (C-9)	0.000	0.000
IC3 BENZENE	0.004	0.025
CYCLOOCTANE	0.002	0.014
NC3 BENZENE	0.000	0.000
TM BENZENE(S)	0.002	0.015
IC4 BENZENE	0.003	0.018
NC4 BENZENE	0.002	0.010
DECANES + (C10+)	0.072	0.504

*HEXANES PLUS SUMMARY

AVG MOLE WT	117.507
VAPOR PRESS PSIA	9.860
API GRAVITY @ 60F	57.7
SPECIFIC GRAVITY	
AIR = 1 (IDEAL):	2.975
H2O = 1 (IDEAL):	0.748

COMPONENT RATIOS

HEXANES (C6) MOLE%	14.379
HEPTANES (C7) MOLE%	19.994
OCTANES (C8) MOLE%	17.167
NONANES (C9) MOLE%	13.771
DECANES+ (C10+) MOLE%	34.689

HEXANES (C6) WT%	10.369
HEPTANES (C7) WT%	16.470
OCTANES (C8) WT%	15.824
NONANES (C9) WT%	14.916
DECANES+ (C10+) WT%	42.421

Remarks:

* Hexane+ portion calculated by Allocation Process

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED GAS REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Amine Gas Port # 5	**For:**	11375G
Sample Date:	02/11/2021	**Cyl. Ident.:**	2021039067
Sampled By:	JP	**Company:**	San Mateo
Time Sampled:	12:00	**Analysis Date:**	02/12/2021
Sample Temp:	71.4 F	**Analysis By:**	TG
Sample Press:	940.8	**Data File:**	LS_6130.D

H_2S (PPM) = 0.5

Component	Mole%	GPM REAL	GPM IDEAL
H_2S	0.000		
Nitrogen	1.018		
Methane	76.636		
CO2	0.590		
Ethane	11.575	3.095	3.088
Propane	5.682	1.565	1.561
Isobutane	0.856	0.280	0.279
N-Butane	1.934	0.610	0.608
Isopentane	0.490	0.179	0.179
N-Pentane	0.524	0.190	0.189
Hexanes+	0.695	0.281	0.278
Total	100.000	6.200	6.182

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	21.799
VAPOR PRESS PSIA:	3937.0
SPECIFIC GRAVITY	
AIR = 1 (REAL):	0.7551
AIR = 1 (IDEAL):	0.7525
H2O = 1 (IDEAL):	0.356
REPORTED BASIS:	14.73
Unnormalized Total:	100.575

HEATING VALUE

BTU/CUFT (DRY)	1295.1
BTU/CUFT (WET)	1273.1

BTEX SUMMARY

WT% BENZENE	2.525
WT% TOLUENE	1.787
WT% E BENZENE	0.000
WT% XYLENES	0.687

LAB MANAGER

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Amine Gas Port # 5
Company: San Mateo

Data File: LS_6130.D

*ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%
2,2 DIMETHYL BUTANE	0.009	0.034
CYCLOPENTANE	0.039	0.140
2-METHYLPENTANE	0.122	0.483
3-METHYLPENTANE	0.063	0.248
HEXANE (C6)	0.149	0.578
DIMETHYLPENTANES	0.007	0.032
METHYLCYCLOPENTANE	0.058	0.225
2,2,3 TRIMETHYLBUTANE	0.001	0.003
BENZENE	0.020	0.070
CYCLOHEXANE	0.063	0.241
2-METHYLHEXANE	0.015	0.070
3-METHYLHEXANE	0.021	0.097
DIMETHYCYCLOPENTANES	0.006	0.029
HEPTANE (C7)	0.027	0.124
METHYLCYCLOHEXANE	0.040	0.181
2,5 DIMETHYLHEXANE	0.001	0.003
TOLUENE	0.012	0.050
2-METHYLHEPTANE	0.004	0.022
OTHER OCTANES	0.013	0.068
OCTANE (C8)	0.003	0.017
ETHYLCYCLOHEXANE	0.001	0.005
ETHYL BENZENE	0.000	0.002
M,P-XYLENE	0.003	0.014
O-XYLENE	0.001	0.002
OTHER NONANES	0.001	0.014
NONANE (C-9)	0.001	0.006
IC3 BENZENE	0.000	0.001
CYCLOOCTANE	0.000	0.000
NC3 BENZENE	0.000	0.000
TM BENZENE(S)	0.000	0.002
IC4 BENZENE	0.000	0.000
NC4 BENZENE	0.000	0.000
DECANES + (C10+)	0.000	0.010

*HEXANES PLUS SUMMARY

AVG MOLE WT	89.290
VAPOR PRESS PSIA	9.860
API GRAVITY @ 60F	69.8
SPECIFIC GRAVITY	
AIR = 1 (IDEAL):	2.975
H2O = 1 (IDEAL):	0.703

COMPONENT RATIOS

HEXANES	(C6)	MOLE%	54.494
HEPTANES	(C7)	MOLE%	33.506
OCTANES	(C8)	MOLE%	10.544
NONANES	(C9)	MOLE%	1.177
DECANES+	(C10+)	MOLE%	0.279
HEXANES	(C6)	WT%	52.088
HEPTANES	(C7)	WT%	33.945
OCTANES	(C8)	WT%	12.008
NONANES	(C9)	WT%	1.524
DECANES+	(C10+)	WT%	0.435

Remarks:

* Hexane+ portion calculated by Allocation Process

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED GAS REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Dehy Inlet Port #7		**For:**	11378G
Sample Date:	02/11/2021		**Cyl. Ident.:**	2021039070
Sampled By:	JP		**Company:**	San Mateo
Time Sampled:	13:30		**Analysis Date:**	02/12/2021
Sample Temp:	91.0 F		**Analysis By:**	TG
Sample Press:	940.8	**H_2S (PPM)** = 0.5	**Data File:**	LS_6129.D

Component	Mole%	GPM REAL	GPM IDEAL
H_2S	0.000		
Nitrogen	0.976		
Methane	76.552		
CO2	0.594		
Ethane	11.732	3.137	3.130
Propane	5.850	1.611	1.608
Isobutane	0.887	0.290	0.290
N-Butane	1.985	0.626	0.624
Isopentane	0.478	0.175	0.174
N-Pentane	0.500	0.181	0.181
Hexanes+	0.446	0.179	0.176
Total	100.000	6.199	6.183

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	21.694
VAPOR PRESS PSIA:	3934.4
SPECIFIC GRAVITY	
AIR = 1 (REAL):	0.7515
AIR = 1 (IDEAL):	0.7489
H2O = 1 (IDEAL):	0.355
REPORTED BASIS:	14.73
Unnormalized Total:	102.072

HEATING VALUE

BTU/CUFT (DRY)	1290.2
BTU/CUFT (WET)	1268.3

BTEX SUMMARY

WT% BENZENE	2.572
WT% TOLUENE	1.634
WT% E BENZENE	0.000
WT% XYLENES	0.269

LAB MANAGER

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Dehy Inlet Port #7
Company: San Mateo

Data File: LS_6129.D

*ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%
2,2 DIMETHYL BUTANE	0.006	0.025
CYCLOPENTANE	0.027	0.096
2-METHYLPENTANE	0.082	0.326
3-METHYLPENTANE	0.042	0.166
HEXANE (C6)	0.101	0.381
DIMETHYLPENTANES	0.004	0.020
METHYLCYCLOPENTANE	0.037	0.145
2,2,3 TRIMETHYLBUTANE	0.000	0.001
BENZENE	0.013	0.045
CYCLOHEXANE	0.039	0.152
2-METHYLHEXANE	0.009	0.043
3-METHYLHEXANE	0.013	0.059
DIMETHYCYCLOPENTANES	0.004	0.018
HEPTANE (C7)	0.016	0.074
METHYLCYCLOHEXANE	0.023	0.107
2,5 DIMETHYLHEXANE	0.000	0.002
TOLUENE	0.007	0.030
2-METHYLHEPTANE	0.002	0.013
OTHER OCTANES	0.008	0.041
OCTANE (C8)	0.002	0.010
ETHYLCYCLOHEXANE	0.001	0.003
ETHYL BENZENE	0.000	0.001
M,P-XYLENE	0.001	0.007
O-XYLENE	0.000	0.002
OTHER NONANES	0.000	0.007
NONANE (C-9)	0.000	0.003
IC3 BENZENE	0.000	0.000
CYCLOOCTANE	0.000	0.000
NC3 BENZENE	0.000	0.000
TM BENZENE(S)	0.000	0.001
IC4 BENZENE	0.000	0.000
NC4 BENZENE	0.000	0.000
DECANES + (C10+)	0.000	0.003

*HEXANES PLUS SUMMARY

AVG MOLE WT	88.871
VAPOR PRESS PSIA	9.860
API GRAVITY @ 60F	70.4
SPECIFIC GRAVITY	
AIR = 1 (IDEAL):	2.975
H2O = 1 (IDEAL):	0.701

COMPONENT RATIOS

HEXANES (C6) MOLE%	56.723
HEPTANES (C7) MOLE%	32.522
OCTANES (C8) MOLE%	9.627
NONANES (C9) MOLE%	0.989
DECANES+ (C10+) MOLE%	0.139

HEXANES (C6) WT%	54.464
HEPTANES (C7) WT%	33.024
OCTANES (C8) WT%	11.006
NONANES (C9) WT%	1.286
DECANES+ (C10+) WT%	0.220

Remarks:

* Hexane+ portion calculated by Allocation Process

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED GAS REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Mole Sieve Port #10	**For:**	11377G
Sample Date:	02/11/2021	**Cyl. Ident.:**	2021039069
Sampled By:	JP	**Company:**	San Mateo
Time Sampled:	14:00	**Analysis Date:**	02/12/2021
Sample Temp:	85.0 F	**Analysis By:**	TG
Sample Press:	919.0	**Data File:**	LS_6128.D

H_2S (PPM) = 2.0

Component	Mole%	GPM REAL	GPM IDEAL
H_2S	0.000		
Nitrogen	1.017		
Methane	77.476		
CO2	0.602		
Ethane	11.602	3.102	3.095
Propane	5.583	1.538	1.534
Isobutane	0.800	0.262	0.261
N-Butane	1.781	0.561	0.560
Isopentane	0.399	0.146	0.146
N-Pentane	0.408	0.148	0.148
Hexanes+	0.332	0.134	0.133
Total	100.000	5.891	5.877

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	21.308
VAPOR PRESS PSIA:	3978.8
SPECIFIC GRAVITY	
AIR = 1 (REAL):	0.7380
AIR = 1 (IDEAL):	0.7356
H2O = 1 (IDEAL):	0.351
REPORTED BASIS:	14.73
Unnormalized Total:	101.023

HEATING VALUE

BTU/CUFT (DRY)	1268.3
BTU/CUFT (WET)	1246.8

BTEX SUMMARY

WT% BENZENE	3.083
WT% TOLUENE	1.877
WT% E BENZENE	0.000
WT% XYLENES	1.081

LAB MANAGER

LABORATORY SERVICES
Natural Gas Analysis
www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Mole Sieve Port #10
Company: San Mateo
Data File: LS_6128.D

*ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%
2,2 DIMETHYL BUTANE	0.004	0.018
CYCLOPENTANE	0.021	0.077
2-METHYLPENTANE	0.060	0.244
3-METHYLPENTANE	0.031	0.125
HEXANE (C6)	0.073	0.276
DIMETHYLPENTANES	0.003	0.015
METHYLCYCLOPENTANE	0.028	0.111
2,2,3 TRIMETHYLBUTANE	0.000	0.001
BENZENE	0.010	0.035
CYCLOHEXANE	0.029	0.113
2-METHYLHEXANE	0.006	0.030
3-METHYLHEXANE	0.009	0.043
DIMETHYCYCLOPENTANES	0.003	0.015
HEPTANE (C7)	0.011	0.052
METHYLCYCLOHEXANE	0.017	0.079
2,5 DIMETHYLHEXANE	0.000	0.002
TOLUENE	0.006	0.024
2-METHYLHEPTANE	0.002	0.009
OTHER OCTANES	0.007	0.031
OCTANE (C8)	0.001	0.007
ETHYLCYCLOHEXANE	0.000	0.002
ETHYL BENZENE	0.000	0.001
M,P-XYLENE	0.002	0.012
O-XYLENE	0.001	0.003
OTHER NONANES	0.000	0.005
NONANE (C-9)	0.000	0.002
IC3 BENZENE	0.000	0.000
CYCLOOCTANE	0.000	0.001
NC3 BENZENE	0.000	0.000
TM BENZENE(S)	0.001	0.008
IC4 BENZENE	0.000	0.000
NC4 BENZENE	0.000	0.001
DECANES + (C10+)	0.000	0.014

*HEXANES PLUS SUMMARY

AVG MOLE WT	89.271
VAPOR PRESS PSIA	9.860
API GRAVITY @ 60F	69.5
SPECIFIC GRAVITY	
AIR = 1 (IDEAL):	2.975
H2O = 1 (IDEAL):	0.704

COMPONENT RATIOS

HEXANES (C6) MOLE%	55.861
HEPTANES (C7) MOLE%	32.095
OCTANES (C8) MOLE%	9.571
NONANES (C9) MOLE%	1.493
DECANES+ (C10+) MOLE%	0.980

HEXANES (C6) WT%	53.352
HEPTANES (C7) WT%	32.392
OCTANES (C8) WT%	10.894
NONANES (C9) WT%	1.876
DECANES+ (C10+) WT%	1.486

Remarks:

* Hexane+ portion calculated by Allocation Process

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED GAS REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Plant 3 Residue	**For:**	11374G
Sample Date:	02/11/2021	**Cyl. Ident.:**	2021039066
Sampled By:	JP	**Company:**	San Mateo
Time Sampled:	13:00	**Analysis Date:**	02/12/2021
Sample Temp:	99.6 F	**Analysis By:**	TG
Sample Press:	903.1	**Data File:**	LS_6127.D

H_2S (PPM) = 0.2

Component	Mole%	GPM REAL	GPM IDEAL
H_2S	0.000		
Nitrogen	1.083		
Methane	87.508		
CO2	0.646		
Ethane	10.454	2.795	2.789
Propane	0.298	0.082	0.082
Isobutane	0.005	0.002	0.002
N-Butane	0.006	0.002	0.002
Isopentane	0.000	0.000	0.000
N-Pentane	0.000	0.000	0.000
Hexanes+	0.000	0.000	0.000
Total	100.000	2.881	2.875

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	17.907
VAPOR PRESS PSIA:	4459.6
SPECIFIC GRAVITY	
AIR = 1 (REAL):	0.6195
AIR = 1 (IDEAL):	0.6183
H2O = 1 (IDEAL):	0.316
REPORTED BASIS:	14.73
Unnormalized Total:	102.028

HEATING VALUE

BTU/CUFT (DRY)	1081.8
BTU/CUFT (WET)	1063.4

BTEX SUMMARY

WT% BENZENE	#
WT% TOLUENE	#
WT% E BENZENE	#
WT% XYLENES	#

LAB MANAGER

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Plant 3 Residue
Company: San Mateo

Data File: LS_6127.D

*ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%
2,2 DIMETHYL BUTANE	0.000	0.000
CYCLOPENTANE	0.000	0.000
2-METHYLPENTANE	0.000	0.000
3-METHYLPENTANE	0.000	0.000
HEXANE (C6)	0.000	0.000
DIMETHYLPENTANES	0.000	0.000
METHYLCYCLOPENTANE	0.000	0.000
2,2,3 TRIMETHYLBUTANE	0.000	0.000
BENZENE	0.000	0.000
CYCLOHEXANE	0.000	0.000
2-METHYLHEXANE	0.000	0.000
3-METHYLHEXANE	0.000	0.000
DIMETHYCYCLOPENTANES	0.000	0.000
HEPTANE (C7)	0.000	0.000
METHYLCYCLOHEXANE	0.000	0.000
2,5 DIMETHYLHEXANE	0.000	0.000
TOLUENE	0.000	0.000
2-METHYLHEPTANE	0.000	0.000
OTHER OCTANES	0.000	0.000
OCTANE (C8)	0.000	0.000
ETHYLCYCLOHEXANE	0.000	0.000
ETHYL BENZENE	0.000	0.000
M,P-XYLENE	0.000	0.000
O-XYLENE	0.000	0.000
OTHER NONANES	0.000	0.000
NONANE (C-9)	0.000	0.000
IC3 BENZENE	0.000	0.000
CYCLOOCTANE	0.000	0.000
NC3 BENZENE	0.000	0.000
TM BENZENE(S)	0.000	0.000
IC4 BENZENE	0.000	0.000
NC4 BENZENE	0.000	0.000
DECANES + (C10+)	0.000	0.000

*HEXANES PLUS SUMMARY

AVG MOLE WT	0.000
VAPOR PRESS PSIA	9.860
API GRAVITY @ 60F	#
SPECIFIC GRAVITY	
AIR = 1 (IDEAL):	2.975
H2O = 1 (IDEAL):	0.000

COMPONENT RATIOS

HEXANES	(C6)	MOLE%	0.000
HEPTANES	(C7)	MOLE%	0.000
OCTANES	(C8)	MOLE%	0.000
NONANES	(C9)	MOLE%	0.000
DECANES+	(C10+)	MOLE%	0.000

HEXANES	(C6)	WT%	0.000
HEPTANES	(C7)	WT%	0.000
OCTANES	(C8)	WT%	0.000
NONANES	(C9)	WT%	0.000
DECANES+	(C10+)	WT%	0.000

Remarks:

* Hexane+ portion calculated by Allocation Process

Constants: GPA 2145
Method(s): GPA 2286.m ; GPA 2172.m

Report Rev 18-05.16
Template: eC6+ Gas

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

EXTENDED LIQUID REPORT
SUMMARY OF CHROMATOGRAPHIC ANALYSIS

Sample Name:	Plant 3 Condensate Port #15	**For code:**	11379L
Sample Date:	02/11/2021	**Identification:**	2021039071
Sampled By:	JP	**Company:**	San Mateo
Time Sampled:	11:30	**Analysis Date:**	02/15/2021
Sample Temp:	54.0 F	**Analysis By:**	TG
Sample Press:	300.0	**Data File:**	LS_6132.D

Component	**Mole%**	**Wt%**	**L.V.%**
H_2S	0.000	0.000	0.000
Nitrogen	0.029	0.014	0.010
Methane	8.025	2.263	4.309
CO2	0.203	0.157	0.110
Ethane	12.908	6.823	10.936
Propane	20.504	15.894	17.895
Isobutane	6.002	6.132	6.221
N-Butane	16.912	17.285	16.895
Isopentane	7.240	9.183	8.388
N-Pentane	9.040	11.465	10.380
*Hexanes+	19.137	30.784	24.856
Total	100.000	100.000	100.000

CALCULATED PARAMETERS

TOTAL ANALYSIS SUMMARY

MOLE WT:	56.886
SP. GRAVITY (IDEAL):	0.571
API GRAVITY @ 60F	116.300
ABS. DENSITY (LBS/GAL)	4.760
ft3 VAPOR/GAL LIQUID:	31.68
VAPOR PRESSURE:	559.92
REPORTED BASIS:	14.73
UNNORMALIZED TOTAL:	90.81

HEATING VALUE

BTU/CUFT	3181.0
BTU/GAL	100776.9
BTU/LB	21171.6

RATIOS

C1 to C2	28.27 : 1
CO2 to C2	1.00 : 1

BTEX SUMMARY

WT% BENZENE	1.991
WT% TOLUENE	2.300
WT% E BENZENE	0.103
WT% XYLENES	0.958

LAB MANAGER

* Hexane+ portion calculated by Allocation Process

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com
575.397.3713 2609 W MARLAND HOBBS, NEW MEXICO 88240

Sample Name: Plant 3 Condensate Port #15
Company: San Mateo

Data File: LS_6132.D

ANALYSIS OF HEXANES PLUS

Component	MOLE%	WT%	L.V.%
2,2 DIMETHYL BUTANE	0.154	0.233	0.203
CYCLOPENTANE	0.718	0.986	0.795
2-METHYLPENTANE	2.636	3.993	3.466
3-METHYLPENTANE	1.415	2.144	1.830
HEXANE (C6)	3.626	5.491	4.718
DIMETHYLPENTANES	0.227	0.399	0.329
METHYLCYCLOPENTANE	1.400	2.071	1.569
2,2,3 TRIMETHYLBUTANE	0.000	0.000	0.000
BENZENE	0.430	0.590	0.381
CYCLOHEXANE	1.780	2.634	1.919
2-METHYLHEXANE	0.563	0.991	0.828
3-METHYLHEXANE	0.730	1.287	1.063
DIMETHYCYCLOPENTANES	0.203	0.350	0.264
OTHER HEPTANES	0.487	0.922	0.753
HEPTANE (C7)	1.136	2.000	1.659
METHYLCYCLOHEXANE	1.587	2.760	2.124
2,5 DIMETHYLHEXANE	0.034	0.067	0.055
TOLUENE	0.433	0.701	0.459
2-METHYLHEPTANE	0.253	0.508	0.413
OTHER OCTANES	0.638	1.245	0.958
OCTANE (C8)	0.225	0.452	0.365
ETHYLCYCLOHEXANE	0.056	0.110	0.079
ETHYL BENZENE	0.017	0.032	0.021
M,P-XYLENE	0.138	0.257	0.178
O-XYLENE	0.020	0.038	0.025
OTHER NONANES	0.138	0.304	0.235
NONANE (C-9)	0.046	0.103	0.081
IC3 BENZENE	0.002	0.005	0.003
CYCLOOCTANE	0.007	0.016	0.011
NC3 BENZENE	0.000	0.000	0.000
TM BENZENE(S)	0.007	0.016	0.011
IC4 BENZENE	0.000	0.000	0.000
NC4 BENZENE	0.001	0.001	0.001
DECANES + (C10+)	0.030	0.078	0.060

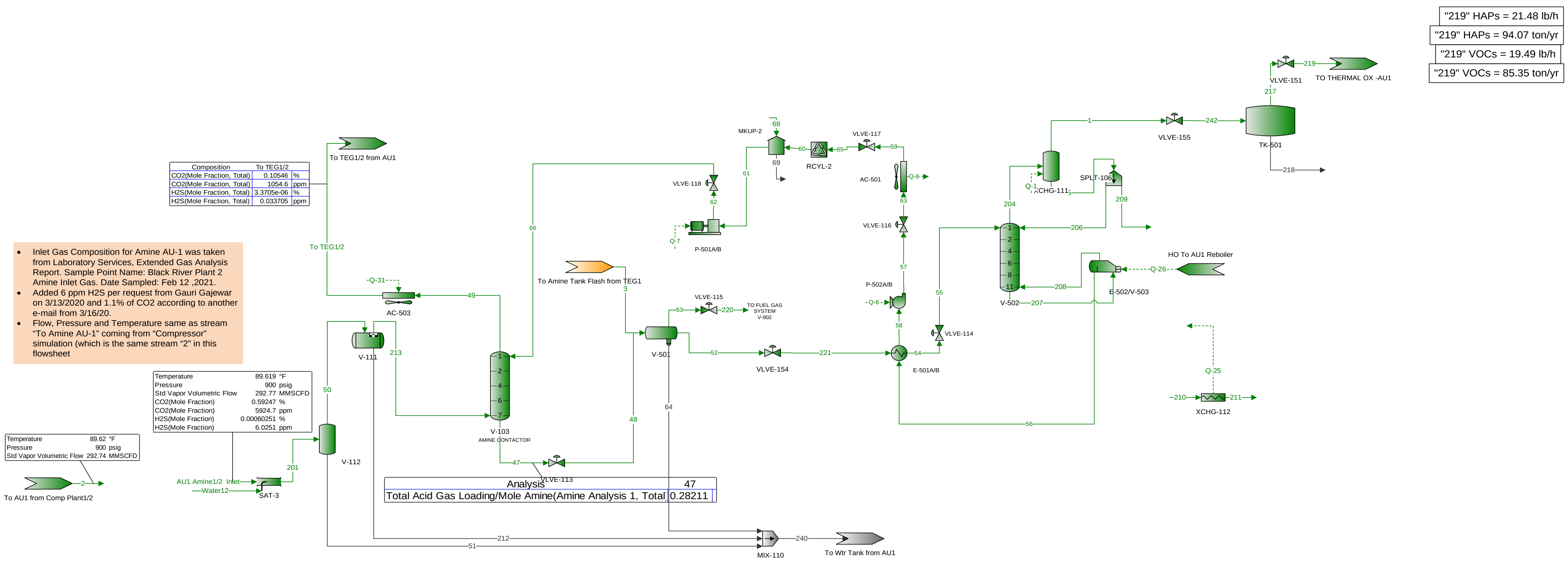
Remarks NR=NOT REPORTED ON FIELD TAG

HEXANES PLUS SUMMARY

AVG MOLE WT	91.505
SP GRAV @ 60F	0.707
API GRAVITY @ 60F	68.6
ABS. DENSITY (LBS/GAL)	5.896
VAPOR PRESSURE:	3.98

COMPONENT RATIOS

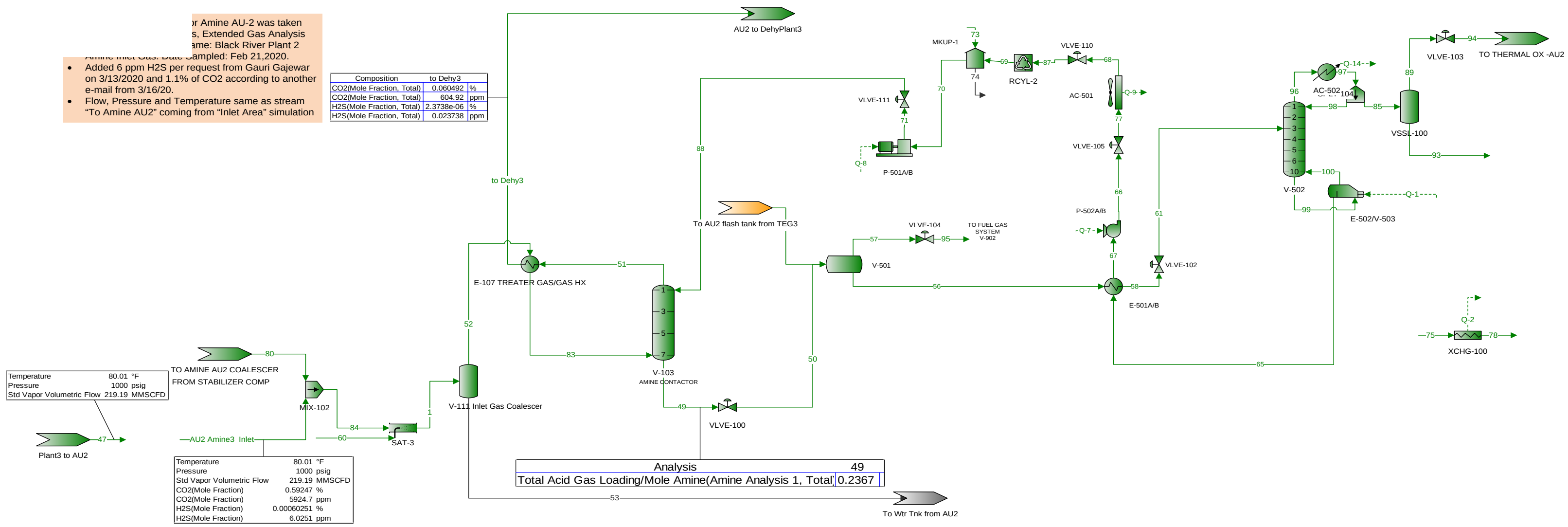
HEXANES	(C6)	MOLE%	44.652
HEPTANES	(C7)	MOLE%	36.342
OCTANES	(C8)	MOLE%	16.562
NONANES	(C9)	MOLE%	2.181
DECANES+	(C10+)	MOLE%	0.263
HEXANES	(C6)	WT%	41.725
HEPTANES	(C7)	WT%	36.524
OCTANES	(C8)	WT%	18.625
NONANES	(C9)	WT%	2.746
DECANES+	(C10+)	WT%	0.380
HEXANES	(C6)	LV%	44.308
HEPTANES	(C7)	LV%	35.261
OCTANES	(C8)	LV%	17.597
NONANES	(C9)	LV%	2.490
DECANES+	(C10+)	LV%	0.344



"219" HAPs = 21.48 lb/h
"219" HAPs = 94.07 ton/yr
"219" VOCs = 19.49 lb/h
"219" VOCs = 85.35 ton/yr
Composition To TEG1/2
CO2(Mole Fraction, Total) 0.10546 %
CO2(Mole Fraction, Total) 1054.6 ppm
H2S(Mole Fraction, Total) 3.3705e-06 %
H2S(Mole Fraction, Total) 0.033705 ppm
• Inlet Gas Composition for Amine AU-1 was taken from Laboratory Services, Extended Gas Analysis Report. Sample Point Name: Black River Plant 2 Amine Inlet Gas. Date Sampled: Feb 12 ,2021.
• Added 6 ppm H2S per request from Gauri Gajewar on 3/13/2020 and 1.1% of CO2 according to another e-mail from 3/16/20.
• Flow, Pressure and Temperature same as stream "To Amine AU-1" coming from "Compressor" simulation (which is the same stream "2" in this flowsheet
Temperature 89.619 °F
Pressure 900 psig
Std Vapor Volumetric Flow 292.77 MMSCFD
CO2(Mole Fraction) 0.59247 %
CO2(Mole Fraction) 5924.7 ppm
H2S(Mole Fraction) 0.00060251 %
H2S(Mole Fraction) 6.0251 ppm
Temperature 89.62 °F
Pressure 900 psig
Std Vapor Volumetric Flow 292.74 MMSCFD
To AU1 from Comp Plant1/2
AU1 Amine1/2 Inlet
Water12
SAT-3
V-112
V-111
To TEG1/2 from AU1
To TEG1/2
AC-503
V-103
AMINE CONTACTOR
VLVE-113
Analysis 47
Total Acid Gas Loading/Mole Amine(Amine Analysis 1, Total 0.28211
To Amine Tank Flash from TEG1
V-501
VLVE-115
TO FUEL GAS SYSTEM V-902
VLVE-154
MIX-110
To Wtr Tank from AU1
MKUP-2
RCYL-2
VLVE-117
VLVE-118
P-501A/B
AC-501
VLVE-116
P-502A/B
E-501A/B
VLVE-114
V-502
ACHG-111
SPLT-106
E-502/V-503
HO To AU1 Reboiler
XCHG-112
VLVE-155
TK-501
VLVE-151
TO THERMAL OX -AU1

Process Streams		AU1 Amine1/2 Inlet	To TEG1/2	53	61	219	220	242
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	--	AC-503	V-501	MKUP-2	VLVE-151	VLVE-115	VLVE-155
	To Block:	SAT-3	To TEG1/2 from AU1	VLVE-115	P-501A/B	TO THERMAL OX -AU1	--	TK-501
Mole Fraction		%	%	%	%	%	%	%
CO2		0.592467*	0.105460	0.218856	0.111092	91.5183	0.218856	91.5183
H2S		0.000602509*	3.37047E-06	0.00197681	0.000428754	0.112220	0.00197681	0.112220
N2		1.02226*	1.02603	0.450768	0	0.000769415	0.450768	0.000769415
C1		76.9564*	77.2287	78.0829	0	0.405544	78.0829	0.405544
C2		11.6234*	11.6637	13.7796	0	0.128880	13.7796	0.128880
C3		5.70576*	5.72624	4.38213	0	0.0340489	4.38213	0.0340489
iC4		0.859579*	0.862735	0.408544	0	0.00241151	0.408544	0.00241151
nC4		1.94209*	1.94912	1.21744	0	0.0104790	1.21744	0.0104790
iC5		0.492049*	0.493871	0.173032	0	0.00106638	0.173032	0.00106638
nC5		0.526191*	0.528128	0.222057	0	0.00165741	0.222057	0.00165741
C6		0.149623*	0.150180	0.0401273	0	0.000244418	0.0401273	0.000244418
C7		0.0271129*	0.0272149	0.00343203	0	1.21920E-05	0.00343203	1.21920E-05
Benzene		0.0200836*	0.0198441	0.0522115	0	0.0567974	0.0522115	0.0567974
Toluene		0.0120502*	0.0119224	0.0244099	0	0.0314128	0.0244099	0.0314128
o-Xylene		0.00100418*	0.000990934	0.00142936	0	0.00312772	0.00142936	0.00312772
p-Xylene		0.00301254*	0.00296981	0.00452058	0	0.00993331	0.00452058	0.00993331
C8		0.00301254*	0.00302391	0.000254245	0	8.01383E-07	0.000254245	8.01383E-07
Water		0*	0.136201	0.868971	88.2093	7.68055	0.868971	7.68055
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	0	0	0	0	0	0
Cyclohexane		0.0632634*	0.0634749	0.0671924	0	0.00251944	0.0671924	0.00251944
UCARSOL™ AP-814		0*	0.000217207	5.22784E-05	11.6792	7.53466E-08	5.22784E-05	7.53466E-08
2-Methylpentane		0*	0	2.44636E-07	0	0	2.44636E-07	0
3-Methylpentane		0*	0	2.79457E-07	0	0	2.79457E-07	0
C9		0*	0	0	0	0	0	0
C10		0*	0	0	0	0	0	0
Mass Fraction		%	%	%	%	%	%	%
CO2		1.21214*	0.216921	0.472686	0.168693	96.0876	0.472686	96.0876
H2S		0.000954586*	5.36868E-06	0.00330631	0.000504183	0.0912417	0.00330631	0.0912417
N2		1.33127*	1.34336	0.619709	0	0.000514209	0.619709	0.000514209
C1		57.3927*	57.9049	61.4746	0	0.155211	61.4746	0.155211
C2		16.2478*	16.3916	20.3342	0	0.0924526	20.3342	0.0924526
C3		11.6963*	11.8013	9.48307	0	0.0358189	9.48307	0.0358189
iC4		2.32257*	2.34361	1.16533	0	0.00334384	1.16533	0.00334384
nC4		5.24749*	5.29478	3.47264	0	0.0145303	3.47264	0.0145303
iC5		1.65036*	1.66536	0.612668	0	0.00183551	0.612668	0.00183551
nC5		1.76487*	1.78088	0.786253	0	0.00285280	0.786253	0.00285280
C6		0.599408*	0.604870	0.169704	0	0.000502491	0.169704	0.000502491
C7		0.126297*	0.127453	0.0168770	0	2.91450E-05	0.0168770	2.91450E-05
Benzene		0.0729289*	0.0724461	0.200148	0	0.105842	0.200148	0.105842
Toluene		0.0516149*	0.0513417	0.110376	0	0.0690495	0.110376	0.0690495
o-Xylene		0.00495603*	0.00491691	0.00744720	0	0.00792177	0.00744720	0.00792177
p-Xylene		0.0148681*	0.0147359	0.0235529	0	0.0251587	0.0235529	0.0251587
C8		0.0159974*	0.0161439	0.00142527	0	2.18387E-06	0.00142527	2.18387E-06
Water		0*	0.114680	0.768272	54.8308	3.30101	0.768272	3.30101
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	0	0	0	0	0	0
Cyclohexane		0.247512*	0.249673	0.277518	0	0.00505847	0.277518	0.00505847
UCARSOL™ AP-814		0*	0.000935096	0.000270987	45	1.74739E-07	0.000270987	1.74739E-07
2-Methylpentane		0*	0	1.03460E-06	0	0	1.03460E-06	0
3-Methylpentane		0*	0	1.18186E-06	0	0	1.18186E-06	0
C9		0*	0	0	0	0	0	0
C10		0*	0	0	0	0	0	0
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h
CO2		8381.67*	1486.32	0.691576	240.958	6885.23	0.691576	6885.23
H2S		6.60077*	0.0367856	0.00483739	0.720168	6.53799	0.00483739	6.53799
N2		9205.47*	9204.53	0.906682	0	0.0368460	0.906682	0.0368460
C1		396859*	396758	89.9421	0	11.1217	89.9421	11.1217
C2		112350*	112314	29.7504	0	6.62475	29.7504	6.62475
C3		80877.7*	80861.3	13.8745	0	2.56663	13.8745	2.56663
iC4		16060.1*	16058.2	1.70497	0	0.239605	1.70497	0.239605
nC4		36285.3*	36279.2	5.08074	0	1.04118	5.08074	1.04118
iC5		11411.9*	11410.9	0.896380	0	0.131524	0.896380	0.131524
nC5		12203.7*	12202.4	1.15035	0	0.204419	1.15035	0.204419
C6		4144.78*	4144.50	0.248290	0	0.0360064	0.248290	0.0360064
C7		873.318*	873.291	0.0246924	0	0.00208841	0.0246924	0.00208841
Benzene		504.289*	496.392	0.292832	0	7.58418	0.292832	7.58418
Toluene		356.906*	351.788	0.161489	0	4.94779	0.161489	4.94779
o-Xylene		34.2700*	33.6901	0.0108958	0	0.567640	0.0108958	0.567640
p-Xylene		102.810*	100.968	0.0344596	0	1.80276	0.0344596	1.80276
C8		110.619*	110.616	0.00208527	0	0.000156487	0.00208527	0.000156487
Water		0*	785.775	1.12404	78319.5	236.536	1.12404	236.536
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	0	0	0	0	0	0
Cyclohexane		1711.50*	1710.73	0.406031	0	0.362468	0.406031	0.362468
UCARSOL™ AP-814		0*	6.40717	0.000396475	64277.3	1.25211E-05	0.000396475	1.25211E-05
2-Methylpentane		0*	0	1.51370E-06	0	0	1.51370E-06	0
3-Methylpentane		0*	0	1.72915E-06	0	0	1.72915E-06	0
C9		0*	0	0	0	0	0	0
C10		0*	0	0	0	0	0	0

Process Streams		AU1 Amine1/2 Inlet	To TEG1/2	53	61	219	220	242
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	--	AC-503	V-501	MKUP-2	VLVE-151	VLVE-115	VLVE-155
	To Block:	SAT-3	To TEG1/2 from AU1	VLVE-115	P-501A/B	TO THERMAL OX -AU1	--	TK-501
Property	**Units**							
Temperature	°F	89.6189*	105*	94.8381	119.258	119.182	94.4475	119.182
Pressure	psia	914.696*	912.129	84.6959*	47.3	15.6959*	79.6959*	15.6959*
Mole Fraction Vapor	%	100	100	100	0	100	100	100
Mole Fraction Light Liquid	%	0	0	0	100	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0	0	0	0	0
Molecular Weight	lb/lbmol	21.5109	21.3961	20.3766	28.9822	41.9167	20.3766	41.9167
Mass Density	lb/ft^3	4.19783	3.94096	0.295353	63.9853	0.106442	0.277824	0.106442
Molar Flow	lbmol/h	32145.5	32024.0	7.18019	4928.50	170.948	7.18019	170.948
Mass Flow	lb/h	691480	685188	146.308	142839	7165.57	146.308	7165.57
Vapor Volumetric Flow	ft^3/h	164723	173863	495.365	2232.37	67319.0	526.620	67319.0
Liquid Volumetric Flow	gpm	20536.9	21676.4	61.7598	278.321	8393.02	65.6565	8393.02
Std Vapor Volumetric Flow	MMSCFD	292.769*	291.663	0.0653944	44.8869	1.55693	0.0653944	1.55693
Std Liquid Volumetric Flow	sgpm	3916.56	3900.25	0.860377	290*	17.4948	0.860377	17.4948
Compressibility		0.795147	0.817202	0.981931	0.00344845	0.995017	0.982952	0.995017
Specific Gravity		0.742717	0.738751	0.703551	1.02592	1.44727	0.703551	1.44727
API Gravity					4.34869			
Enthalpy	Btu/h	-1.14211E+09	-1.11291E+09	-246630	-6.18989E+08	-2.78028E+07	-246630	-2.78028E+07
Mass Enthalpy	Btu/lb	-1651.68	-1624.25	-1685.69	-4333.48	-3880.06	-1685.69	-3880.06
Mass Cp	Btu/(lb*°F)	0.645312	0.633658	0.498437	0.840861	0.217506	0.497713	0.217506
Ideal Gas CpCv Ratio		1.23923	1.23508	1.24890	1.16436	1.28038	1.24900	1.28038
Dynamic Viscosity	cP	0.0129599	0.0130285	0.0110509	2.89863	0.0160536	0.0110380	0.0160536
Kinematic Viscosity	cSt	0.192733	0.206381	2.33580	2.82808	9.41541	2.48026	9.41541
Thermal Conductivity	Btu/(h*ft*°F)	0.0217692	0.0222011	0.0184026	0.210266	0.0106617	0.0183692	0.0106617
Surface Tension	lbf/ft				0.00374821			
Net Ideal Gas Heating Value	Btu/ft^3	1154.31	1158.39	1106.16	407.382	11.8511	1106.16	11.8511
Net Liquid Heating Value	Btu/lb	20299.9	20480.4	20534.8	4605.94	-0.425818	20534.8	-0.425818
Gross Ideal Gas Heating Value	Btu/ft^3	1271.74	1276.30	1220.51	487.917	16.6733	1220.51	16.6733
Gross Liquid Heating Value	Btu/lb	22371.9	22572.2	22664.9	5660.44	43.2327	22664.9	43.2327



...or Amine AU-2 was taken ...s, Extended Gas Analysis ...ame: Black River Plant 2 Amine Inlet Gas. Date Sampled: Feb 21,2020.

- Added 6 ppm H2S per request from Gauri Gajewar on 3/13/2020 and 1.1% of CO2 according to another e-mail from 3/16/20.
- Flow, Pressure and Temperature same as stream "To Amine AU2" coming from "Inlet Area" simulation

Composition	to Dehy3	
CO2(Mole Fraction, Total)	0.060492	%
CO2(Mole Fraction, Total)	604.92	ppm
H2S(Mole Fraction, Total)	2.3738e-06	%
H2S(Mole Fraction, Total)	0.023738	ppm

Temperature	80.01	°F
Pressure	1000	psig
Std Vapor Volumetric Flow	219.19	MMSCFD

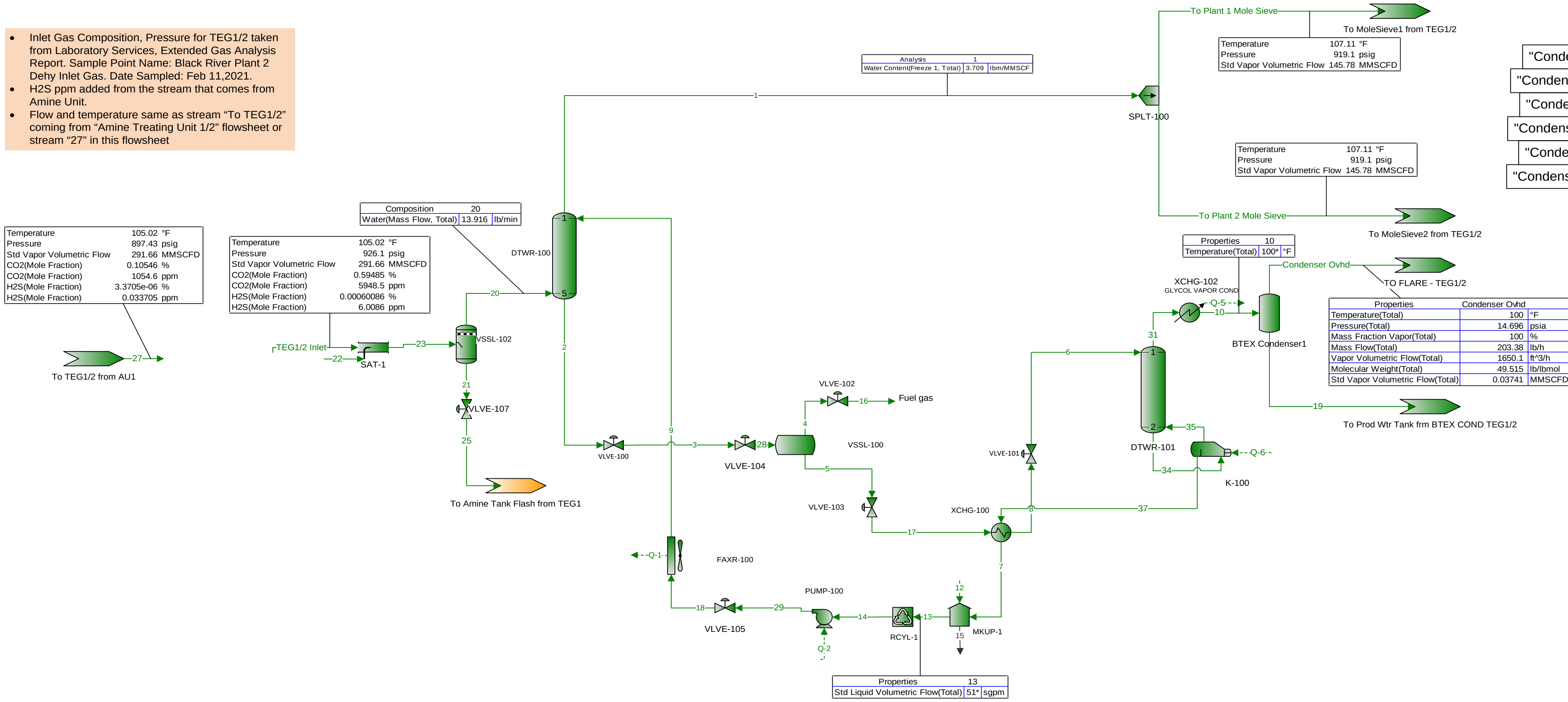
Temperature	80.01	°F
Pressure	1000	psig
Std Vapor Volumetric Flow	219.19	MMSCFD
CO2(Mole Fraction)	0.59247	%
CO2(Mole Fraction)	5924.7	ppm
H2S(Mole Fraction)	0.00060251	%
H2S(Mole Fraction)	6.0251	ppm

Analysis	49
Total Acid Gas Loading/Mole Amine(Amine Analysis 1, Total)	0.2367

Process Streams		AU2 Amine3 Inlet	to Dehy3	57	70	94	95	100
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: Total	From Block:	--	E-107 TREATER GAS/GAS HX	V-501	MKUP-1	VLVE-103	VLVE-104	E-502/V-503
	To Block:	MIX-102	AU2 to DehyPlant3	VLVE-104	P-501A/B	TO THERMAL OX -AU2	--	V-502
Mole Fraction		%	%	%	%	%	%	%
CO2		0.592467*	0.0604916	0.135010	0.139007	91.4219	0.135010	0.746496
H2S		0.000602509*	2.37382E-06	0.00134868	0.000392090	0.102419	0.00134868	0.00110347
N2		1.02226*	1.01078	0.444412	0	0.000831150	0.444412	0
C1		76.9564*	76.2533	77.8580	0	0.455992	77.8580	0
C2		11.6234*	11.7797	13.8035	0	0.149115	13.8035	0
C3		5.70576*	6.08065	4.43898	0	0.0400367	4.43898	0
iC4		0.859579*	0.973644	0.429335	0	0.00298731	0.429335	0
nC4		1.94209*	2.25526	1.31471	0	0.0133851	1.31471	0
iC5		0.492049*	0.562463	0.177220	0	0.00130250	0.177220	0
nC5		0.526191*	0.588788	0.223516	0	0.00199052	0.223516	0
C6		0.149623*	0.166352	0.0389529	0	0.000287368	0.0389529	0
C7		0.0271129*	0.0325948	0.00346656	0	1.49564E-05	0.00346656	0
Benzene		0.0200836*	0.0204826	0.0534518	0	0.0683244	0.0534518	0
Toluene		0.0120502*	0.0120465	0.0235859	0	0.0363594	0.0235859	0
o-Xylene		0.00100418*	0.000976323	0.00128391	0	0.00340424	0.00128391	0
p-Xylene		0.00301254*	0.00294802	0.00412189	0	0.0109704	0.00412189	0
C8		0.00301254*	0.00421846	0.000292930	0	1.14541E-06	0.000292930	0
Water		0*	0.131967	0.988649	88.1767	7.68798	0.988649	99.0490
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	4.87354E-06	6.42423E-06	0	1.05653E-05	6.42423E-06	0
Cyclohexane		0.0632634*	0.0624966	0.0600364	0	0.00268582	0.0600364	0
UCARSOL™ AP-814		0*	0.000261216	8.05251E-05	11.6839	1.31287E-12	8.05251E-05	0.203444
2-Methylpentane		0*	0.000113044	2.98548E-05	0	2.21929E-07	2.98548E-05	0
3-Methylpentane		0*	5.67637E-05	1.49393E-05	0	1.10992E-07	1.49393E-05	0
C9		0*	0.000193140	4.87370E-06	0	9.17160E-09	4.87370E-06	0
C10		0*	0.000152597	2.20295E-06	0	0	2.20295E-06	0
Mass Fraction		%	%	%	%	%	%	%
CO2		1.21214*	0.122329	0.290963	0.210998	96.0093	0.290963	1.78898
H2S		0.000954586*	3.71746E-06	0.00225085	0.000460883	0.0832930	0.00225085	0.00204787
N2		1.33127*	1.30110	0.609645	0	0.000555600	0.609645	0
C1		57.3927*	56.2105	61.1646	0	0.174560	61.1646	0
C2		16.2478*	16.2758	20.3252	0	0.106993	20.3252	0
C3		11.6963*	12.3206	9.58528	0	0.0421280	9.58528	0
iC4		2.32257*	2.60034	1.22198	0	0.00414323	1.22198	0
nC4		5.24749*	6.02318	3.74194	0	0.0185644	3.74194	0
iC5		1.65036*	1.86470	0.626136	0	0.00224246	0.626136	0
nC5		1.76487*	1.95198	0.789704	0	0.00342699	0.789704	0
C6		0.599408*	0.658718	0.164380	0	0.000590933	0.164380	0
C7		0.126297*	0.150076	0.0170099	0	3.57618E-05	0.0170099	0
Benzene		0.0729289*	0.0735171	0.204459	0	0.127353	0.204459	0
Toluene		0.0516149*	0.0510021	0.106419	0	0.0799418	0.106419	0
o-Xylene		0.00495603*	0.00476280	0.00667484	0	0.00862418	0.00667484	0
p-Xylene		0.0148681*	0.0143813	0.0214291	0	0.0277920	0.0214291	0
C8		0.0159974*	0.0221419	0.00163857	0	3.12213E-06	0.00163857	0
Water		0*	0.109243	0.872187	54.7885	3.30499	0.872187	97.1678
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	2.37746E-05	3.33986E-05	0	2.67658E-05	3.33986E-05	0
Cyclohexane		0.247512*	0.241683	0.247425	0	0.00539382	0.247425	0
UCARSOL™ AP-814		0*	0.00110748	0.000401843	45	2.78448E-12	0.000401843	1.04113
2-Methylpentane		0*	0.000447629	0.000125986	0	4.56366E-07	0.000125986	0
3-Methylpentane		0*	0.000224772	6.30434E-05	0	2.28241E-07	6.30434E-05	0
C9		0*	0.00113824	3.06097E-05	0	2.80696E-08	3.06097E-05	0
C10		0*	0.000997657	1.53490E-05	0	0	1.53490E-05	0
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h
CO2		6275.31*	648.648	0.474936	301.358	5680.22	0.474936	268.110
H2S		4.94195*	0.0197118	0.00367404	0.658258	4.92788	0.00367404	0.306909
N2		6892.08*	6899.07	0.995118	0	0.0328711	0.995118	0
C1		297126*	298055	99.8384	0	10.3275	99.8384	0
C2		84115.7*	86302.2	33.1766	0	6.33008	33.1766	0
C3		60552.7*	65330.1	15.6460	0	2.49243	15.6460	0
iC4		12024.1*	13788.3	1.99463	0	0.245127	1.99463	0
nC4		27166.6*	31937.9	6.10794	0	1.09833	6.10794	0
iC5		8544.01*	9887.58	1.02204	0	0.132671	1.02204	0
nC5		9136.86*	10350.4	1.28903	0	0.202752	1.28903	0
C6		3103.17*	3492.85	0.268316	0	0.0349615	0.268316	0
C7		653.848*	795.778	0.0277650	0	0.00211578	0.0277650	0
Benzene		377.558*	389.824	0.333736	0	7.53463	0.333736	0
Toluene		267.214*	270.438	0.173707	0	4.72962	0.173707	0
o-Xylene		25.6577*	25.2547	0.0108953	0	0.510234	0.0108953	0
p-Xylene		76.9732*	76.2569	0.0349785	0	1.64426	0.0349785	0
C8		82.8195*	117.407	0.00267462	0	0.000184715	0.00267462	0
Water		0*	579.258	1.42366	78251.9	195.534	1.42366	14562.3
Triethylene Glycol		0*	0	0	0	0	0	0
Ethylbenzene		0*	0.126065	5.45162E-05	0	0.00158355	5.45162E-05	0
Cyclohexane		1281.39*	1281.52	0.403870	0	0.319116	0.403870	0
UCARSOL™ AP-814		0*	5.87238	0.000655925	64271.4	1.64739E-10	0.000655925	156.031
2-Methylpentane		0*	2.37355	0.000205646	0	2.70001E-05	0.000205646	0
3-Methylpentane		0*	1.19185	0.000102905	0	1.35034E-05	0.000102905	0
C9		0*	6.03551	4.99640E-05	0	1.66069E-06	4.99640E-05	0
C10		0*	5.29006	2.50540E-05	0	0	2.50540E-05	0

Process Streams		AU2 Amine3 Inlet	to Dehy3	57	70	94	95	100
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	--	E-107 TREATER GAS/GAS HX	V-501	MKUP-1	VLVE-103	VLVE-104	E-502/V-503
	To Block:	MIX-102	AU2 to DehyPlant3	VLVE-104	P-501A/B	TO THERMAL OX -AU2	--	V-502
Property	**Units**							
Temperature	°F	80.0104*	104.697	96.1590	119.186	119.182	96.3484	247.227
Pressure	psia	1014.70*	1005.70	77.3	47.3	15.6959*	79.6959*	25.3
Mole Fraction Vapor	%	100	99.9958	100	0	100	100	100
Mole Fraction Light Liquid	%	0	0.00418768	0	100	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0	0	0	0	0
Molecular Weight	lb/lbmol	21.5109	21.7627	20.4209	28.9938	41.9067	20.4209	18.3640
Mass Density	lb/ft^3	4.95974	4.55863	0.269068	64.0312	0.106417	0.277452	0.0620517
Molar Flow	lbmol/h	24067.1	24365.0	7.99325	4926.06	141.179	7.99325	816.090
Mass Flow	lb/h	517707	530249	163.229	142825	5916.32	163.229	14986.7
Vapor Volumetric Flow	ft^3/h	104382	116318	606.645	2230.56	55595.8	588.315	241520
Liquid Volumetric Flow	gpm	13013.9	14501.9	75.6337	278.096	6931.42	73.3484	30111.6
Std Vapor Volumetric Flow	MMSCFD	219.194*	221.908	0.0727995	44.8647	1.28580	0.0727995	7.43264
Std Liquid Volumetric Flow	sgpm	2932.31	2989.51	0.958418	290*	14.4527	0.958418	30.1603
Compressibility		0.759865	0.792720	0.983527	0.00344779	0.995016	0.983038	0.986997
Specific Gravity		0.742717		0.705079	1.02666	1.44693	0.705079	0.634063
API Gravity					4.26568			
Enthalpy	Btu/h	-8.60812E+08	-8.53006E+08	-274468	-6.18805E+08	-2.29424E+07	-274468	-8.40118E+07
Mass Enthalpy	Btu/lb	-1662.74	-1608.69	-1681.49	-4332.61	-3877.81	-1681.49	-5605.75
Mass Cp	Btu/(lb*°F)	0.686626	0.659112	0.498194	0.839896	0.217667	0.498541	0.461309
Ideal Gas CpCv Ratio		1.24177	1.23136	1.24782	1.16434	1.28020	1.24777	1.31091
Dynamic Viscosity	cP	0.0133588		0.0110536	2.92045	0.0160472	0.0110599	0.0133885
Kinematic Viscosity	cSt	0.168147		2.56461	2.84733	9.41389	2.48852	13.4697
Thermal Conductivity	Btu/(h*ft*°F)	0.0222135		0.0184120	0.210103	0.0106674	0.0184281	0.0166478
Surface Tension	lbf/ft				0.00374708			
Net Ideal Gas Heating Value	Btu/ft^3	1154.31	1178.00	1109.21	407.545	13.5439	1109.21	6.66526
Net Liquid Heating Value	Btu/lb	20299.9	20473.6	20545.3	4606.35	14.8527	20545.3	-896.272
Gross Ideal Gas Heating Value	Btu/ft^3	1271.74	1297.35	1223.84	488.079	18.5000	1223.84	57.0450
Gross Liquid Heating Value	Btu/lb	22371.9	22555.0	22675.8	5660.41	59.7346	22675.8	144.801

- Inlet Gas Composition, Pressure for TEG1/2 taken from Laboratory Services, Extended Gas Analysis Report. Sample Point Name: Black River Plant 2 Dehy Inlet Gas. Date Sampled: Feb 11,2021.
- H2S ppm added from the stream that comes from Amine Unit.
- Flow and temperature same as stream "To TEG1/2" coming from "Amine Treating Unit 1/2" flowsheet or stream "27" in this flowsheet



"Condenser Ovhd" BTEX = 29.71 lb/h
"Condenser Ovhd" BTEX = 130.1 ton/yr
"Condenser Ovhd" HAPs = 36.46 lb/h
"Condenser Ovhd" HAPs = 159.7 ton/yr
"Condenser Ovhd" VOCs = 164.9 lb/h
"Condenser Ovhd" VOCs = 722.4 ton/yr

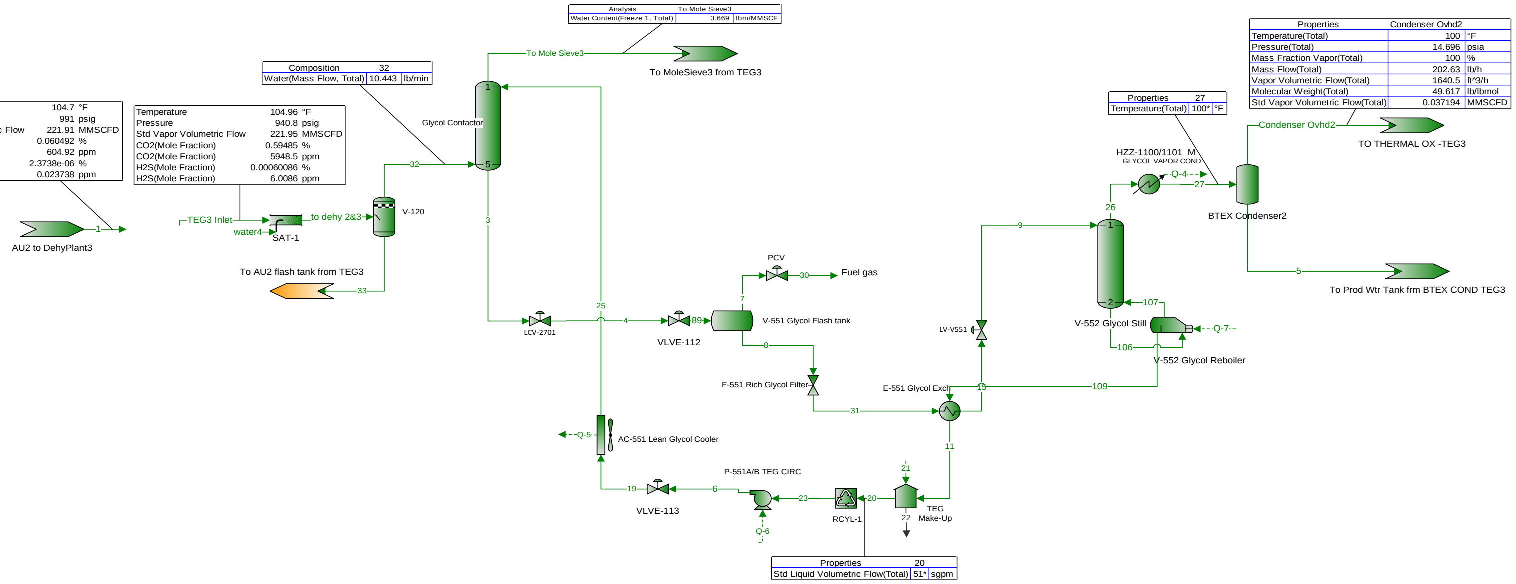
"10" BTEX = 65.4 lb/h
"10" BTEX = 286.5 ton/yr
"10" HAPs = 74.28 lb/h
"10" HAPs = 325.4 ton/yr
"10" VOCs = 253.9 lb/h
"10" VOCs = 1,112 ton/yr

Process Streams		Condenser Ovhd	TEG1/2 Inlet	10	14	16	28	37
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	BTEX Condenser1	--	XCHG-102	RCYL-1	VLVE-102	VLVE-104	K-100
	To Block:	TO FLARE - TEG1/2	SAT-1	BTEX Condenser1	PUMP-100	--	VSSL-100	XCHG-100
Mole Fraction		%	%	%	%	%	%	%
CO2		4.86071	0.594847*	0.414034	1.49094E-07	2.32781	0.156452	1.24770E-07
H2S		0.0372147	0.000600856*	0.00321453	5.24913E-08	0.00351908	0.000713189	4.40949E-08
N2		0.00934219	0.977392*	0.000791033	0	0.209490	0.00736472	3.21718E-13
C1		10.6064	76.6612*	0.898522	0	55.5314	2.07907	5.07559E-09
C2		14.4577	11.7487*	1.22801	9.21155E-08	19.7106	0.905344	7.59473E-08
C3		18.2505	5.85834*	1.55967	4.58753E-07	12.4352	0.715701	3.77796E-07
iC4		3.68634	0.888265*	0.319508	1.93641E-07	1.83625	0.122108	1.58975E-07
nC4		14.5587	1.98783*	1.27673	1.55436E-06	4.82249	0.401267	1.28240E-06
iC5		4.88412	0.478682*	0.448465	1.48450E-06	1.04904	0.118726	1.22279E-06
nC5		6.48441	0.500713*	0.609867	2.80141E-06	1.17724	0.152863	2.30446E-06
C6		1.89172	0.101144*	0.211050	9.47087E-06	0.211554	0.0461566	7.76852E-06
C7		0.347769	0.0160228*	0.0578939	2.72268E-06	0.0290229	0.0116618	2.24432E-06
Benzene		5.84350	0.0130185*	0.795701	0.00166814	0.0393689	0.148978	0.00142073
Toluene		2.67673	0.00700998*	0.658258	0.00410418	0.0169524	0.124542	0.00352433
o-Xylene		0	0*	0	0	0	0	0
p-Xylene		0.190827	0.00100143*	0.112917	0.00172287	0.00181835	0.0220219	0.00149467
C8		0.0293860	0.00200285*	0.0104420	1.20169E-06	0.00294556	0.00202494	9.92468E-07
Water		6.41862	0*	90.3183	8.01776	0.223906	22.9121	8.02938
Triethylene Glycol		7.25057E-07	0*	0.518970	91.9746	6.03490E-05	71.9574	91.9641
Ethylbenzene		0	0*	0	0	0	0	0
C9		0	0*	0	0	0	0	0
C10		0	0*	0	0	0	0	0
Cyclohexane		2.55465	0.0390556*	0.324784	6.39410E-05	0.0974153	0.0632005	5.31542E-05
2-Methylpentane		1.34400	0.0821169*	0.140132	4.42294E-06	0.179123	0.0319776	3.63659E-06
3-Methylpentane		0.867346	0.0420599*	0.0927426	4.31890E-06	0.0947357	0.0203439	3.56624E-06
Undecane		0	0*	0	0	0	0	0
Dodecane		0	0*	0	0	0	0	0
Argon		0	0*	0	0	0	0	0
O2		0	0*	0	0	0	0	0
UCARSOL™ AP-814		0	0*	0	0	0	0	0
Mass Fraction		%	%	%	%	%	%	%
CO2		4.32024	1.21247*	0.820777	4.70119E-08	3.72517	0.0603519	3.93460E-08
H2S		0.0256146	0.000948415*	0.00493482	1.28174E-08	0.00436105	0.000213048	1.07683E-08
N2		0.00528538	1.26810*	0.000998167	0	0.213393	0.00180836	6.45783E-14
C1		3.43637	56.9592*	0.649296	0	32.3937	0.292349	5.83450E-10
C2		8.77973	16.3617*	1.66328	1.98451E-08	21.5512	0.238614	1.63636E-08
C3		16.2529	11.9643*	3.09793	1.44935E-07	19.9388	0.276624	1.19371E-07
iC4		4.32712	2.39112*	0.836500	8.06380E-08	3.88084	0.0622084	6.62088E-08
nC4		17.0894	5.35105*	3.34260	6.47283E-07	10.1921	0.204427	5.34088E-07
iC5		7.11667	1.59953*	1.45747	7.67379E-07	2.75216	0.0750825	6.32159E-07
nC5		9.44846	1.67315*	1.98201	1.44813E-06	3.08847	0.0966706	1.19136E-06
C6		3.29232	0.403683*	0.819242	5.84754E-06	0.662911	0.0348642	4.79697E-06
C7		0.703766	0.0743588*	0.261308	1.95467E-06	0.105747	0.0102425	1.61141E-06
Benzene		9.21832	0.0470974*	2.79969	0.000933578	0.111821	0.102000	0.000795195
Toluene		4.98088	0.0299141*	2.73200	0.00270937	0.0567968	0.100582	0.00232682
o-Xylene		0	0*	0	0	0	0	0
p-Xylene		0.409151	0.00492400*	0.539988	0.00131049	0.00701956	0.0204926	0.00113703
C8		0.0677916	0.0105960*	0.0537279	9.83482E-07	0.0122347	0.00202745	8.12338E-07
Water		2.33531	0*	73.2925	1.03489	0.146675	3.61800	1.03650
Triethylene Glycol		2.19900E-06	0*	3.51056	98.9601	0.000329544	94.7173	98.9592
Ethylbenzene		0	0*	0	0	0	0	0
C9		0	0*	0	0	0	0	0
C10		0	0*	0	0	0	0	0
Cyclohexane		4.34206	0.152231*	1.23123	3.85552E-05	0.298113	0.0466214	3.20543E-05
2-Methylpentane		2.33908	0.327743*	0.543954	2.73083E-06	0.561287	0.0241542	2.24555E-06
3-Methylpentane		1.50951	0.167868*	0.360002	2.66659E-06	0.296857	0.0153667	2.20211E-06
Undecane		0	0*	0	0	0	0	0
Dodecane		0	0*	0	0	0	0	0
Argon		0	0*	0	0	0	0	0
O2		0	0*	0	0	0	0	0
UCARSOL™ AP-814		0	0*	0	0	0	0	0

Mass Flow	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h
CO2	8.78671	8383.55*	8.84140	1.35295E-05	9.30316	18.1446	1.13071E-05
H2S	0.0520961	6.55778*	0.0531578	3.68870E-06	0.0108912	0.0640521	3.09455E-06
N2	0.0107497	8768.20*	0.0107522	0	0.532924	0.543676	1.85583E-11
C1	6.98905	393842*	6.99421	0	80.8995	87.8937	1.67670E-07
C2	17.8566	113132*	17.9169	5.71121E-06	53.8215	71.7383	4.70251E-06
C3	33.0559	82726.8*	33.3709	4.17110E-05	49.7949	83.1658	3.43045E-05
iC4	8.80070	16533.3*	9.01077	2.32068E-05	9.69194	18.7027	1.90269E-05
nC4	34.7572	36999.6*	36.0064	0.000186281	25.4536	61.4602	0.000153485
iC5	14.4742	11059.9*	15.6999	0.000220844	6.87318	22.5733	0.000181668
nC5	19.2167	11568.9*	21.3502	0.000416756	7.71309	29.0637	0.000342370
C6	6.69607	2791.25*	8.82486	0.00168286	1.65554	10.4818	0.00137854
C7	1.43135	514.151*	2.81480	0.000562533	0.264091	3.07936	0.000463083
Benzene	18.7486	325.653*	30.1582	0.268674	0.279259	30.6660	0.228521
Toluene	10.1303	206.840*	29.4290	0.779728	0.141843	30.2395	0.668675
o-Xylene	0	0*	0	0	0	0	0
p-Xylene	0.832150	34.0468*	5.81674	0.377145	0.0175305	6.16103	0.326756
C8	0.137878	73.2655*	0.578756	0.000283036	0.0305547	0.609544	0.000233447
Water	4.74966	0*	789.506	297.831	0.366304	1087.74	297.866
Triethylene Glycol	4.47243E-06	0*	37.8158	28479.7	0.000822997	28476.4	28438.6
Ethylbenzene	0	0*	0	0	0	0	0
C9	0	0*	0	0	0	0	0
C10	0	0*	0	0	0	0	0
Cyclohexane	8.83109	1052.60*	13.2628	0.0110958	0.744502	14.0166	0.00921167
2-Methylpentane	4.75733	2266.17*	5.85946	0.000785905	1.40175	7.26186	0.000645320
3-Methylpentane	3.07012	1160.72*	3.87794	0.000767419	0.741366	4.61994	0.000632836
Undecane	0	0*	0	0	0	0	0
Dodecane	0	0*	0	0	0	0	0
Argon	0	0*	0	0	0	0	0
O2	0	0*	0	0	0	0	0
UCARSOL™ AP-814	0	0*	0	0	0	0	0

Process Streams		Condenser Ovhd	TEG1/2 Inlet	10	14	16	28	37
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	BTEX Condenser1	--	XCHG-102	RCYL-1	VLVE-102	VLVE-104	K-100
	To Block:	TO FLARE - TEG1/2	SAT-1	BTEX Condenser1	PUMP-100	--	VSSL-100	XCHG-100
Property	Units							
Temperature	°F	100	105.019*	100*	207.614	108.016	109.512	390
Pressure	psia	14.6959	940.8*	14.6959	14.1959	79.6959*	94.6959	15.1959
Mole Fraction Vapor	%	100	100	8.46528	0	100	3.44602	0
Mole Fraction Light Liquid	%	0	0	1.21925	100	0	96.5540	100
Mole Fraction Heavy Liquid	%	0	0	90.3155	0	0	0	0
Molecular Weight	lb/lbmol	49.5152	21.5915	22.2002	139.572	27.5010	114.087	139.558
Mass Density	lb/ft^3	0.123254	4.13675	0.647219	65.4363	0.370293	29.9872	58.4753
Molar Flow	lbmol/h	4.10752	32024.0	48.5220	206.194	9.08105	263.523	205.920
Mass Flow	lb/h	203.385	691446	1077.20	28779.0	249.738	30064.6	28737.7
Vapor Volumetric Flow	ft^3/h	1650.12	167147	1664.35	439.802	674.434	1002.58	491.450
Liquid Volumetric Flow	gpm	205.730	20839.1	207.503	54.8324	84.0853	124.997	61.2717
Std Vapor Volumetric Flow	MMSCFD	0.0374097	291.663*	0.441920	1.87794	0.0827067	2.40006	1.87544
Std Liquid Volumetric Flow	sgpm	0.703998	3910.51	2.46745	51	1.24558	54.6398	50.9268
Compressibility		0.982966	0.810302	0.0839282	0.00422836	0.971556	0.0589818	0.00397736
Specific Gravity		1.70963	0.745498		1.04918	0.949539		0.937574
API Gravity					-6.66702			-6.66694
Enthalpy	Btu/h	-208183	-1.13449E+09	-5.64448E+06	-6.55046E+07	-362716	-7.32383E+07	-6.18678E+07
Mass Enthalpy	Btu/lb	-1023.59	-1640.76	-5239.96	-2276.13	-1452.39	-2436.03	-2152.85
Mass Cp	Btu/(lb*°F)	0.388340	0.637610	0.840981	0.640318	0.462907	0.609107	0.709017
Ideal Gas CpCv Ratio		1.11611	1.23424	1.26247	1.03030	1.18978	1.04211	1.02644
Dynamic Viscosity	cP	0.00885961	0.0131654		3.69444	0.0106062		0.797942
Kinematic Viscosity	cSt	4.48737	0.198680		3.52459	1.78811		0.851879
Thermal Conductivity	Btu/(h*ft*°F)	0.0108492	0.0223035		0.113707?	0.0165066		0.107256?
Surface Tension	lbf/ft				0.00267654?			0.00204974?
Net Ideal Gas Heating Value	Btu/ft^3	2363.56	1159.06	269.909	3474.02	1424.06	2813.06	3473.57
Net Liquid Heating Value	Btu/lb	17941.1	20306.8	3791.65	9177.60	19546.4	9070.54	9177.37
Gross Ideal Gas Heating Value	Btu/ft^3	2554.53	1276.87	335.910	3801.65	1560.44	3085.90	3801.17
Gross Liquid Heating Value	Btu/lb	19405.1	22377.9	4919.88	10068.4	21428.9	9978.09	10068.2

- Inlet Gas Composition, Pressure for TEG3 taken from Laboratory Services, Extended Gas Analysis Report. Sample Point Name: Black River Plant 2 Dehy Inlet Gas. Date Sampled: Feb 11,2021.
- H2S ppm added from the stream that comes from Amine Unit.
- Flow and temperature same as stream “to Dehy3” coming from “Amine Treating Unit3” flowsheet or stream 1 in this flowsheet



Process Streams		Condenser Ovhd2	TEG3 Inlet ˉo Mole Sieve	8	23	27	30	109
Composition	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	BTEX Condenser2	--	Glycol Contactor	V-551 Glycol Flash tank	RCYL-1	HZZ-1100/1101 M	PCV	52 Glycol Reboiler
	To Block:	TO THERMAL OX -TEG3	SAT-1	loleSieve3 from T	F-551 Rich Glycol Filter	P-551A/B TEG CIRC	BTEX Condenser2	--	-551 Glycol Exch
Mole Fraction		%	%	%	%	%	%	%	%
CO2		4.81745	0.594847*	0.593449	0.0812213	1.70644E-07	0.527011	2.33605	1.95741E-07
H2S		0.0373142	0.000600856*	0.000593459	0.000636623	6.02791E-08	0.00413041	0.00354647	6.86715E-08
N2		0.00913882	0.977392*	0.977776	0.000153321	0	0.000994840	0.208701	5.22821E-13
C1		10.4779	76.6612*	76.6751	0.175868	0	1.14114	55.5257	8.21441E-09
C2		14.4007	11.7487*	11.7445	0.242338	1.07489E-07	1.57243	19.7418	1.22558E-07
C3		18.2793	5.85834*	5.85340	0.309489	5.32836E-07	2.00815	12.4558	6.09631E-07
iC4		3.69874	0.888265*	0.887369	0.0635073	2.25007E-07	0.412072	1.83574	2.57616E-07
nC4		14.6019	1.98783*	1.98445	0.253642	1.79798E-06	1.64577	4.81860	2.05551E-06
iC5		4.90309	0.478682*	0.477629	0.0891469	1.71809E-06	0.578428	1.04409	1.95984E-06
nC5		6.56053	0.500713*	0.499293	0.122160	3.24359E-06	0.792625	1.17379	3.70770E-06
C6		1.91580	0.101144*	0.100691	0.0422840	1.10689E-05	0.274295	0.209816	1.25365E-05
C7		0.352862	0.0160228*	0.0159038	0.0116017	3.12713E-06	0.0752590	0.0286470	3.56824E-06
Benzene		5.85596	0.0130185*	0.0114407	0.158576	0.00184269	1.01736	0.0391231	0.00210917
Toluene		2.66488	0.00700998*	0.00571488	0.133067	0.00447423	0.835421	0.0167710	0.00510089
o-Xylene		0	0*	0	0	0	0	0	0
p-Xylene		0.187162	0.00100143*	0.000781815	0.0235218	0.00185362	0.141128	0.00178844	0.00209441
C8		0.0299235	0.00200285*	0.00198179	0.00209563	1.37182E-06	0.0135891	0.00289294	1.56393E-06
Water		6.41212	0*	0.00772869	20.2939	8.01638	87.6461	0.188746	8.02264
Triethylene Glycol		8.44877E-07	0*	7.12788E-05	77.8858	91.9753	0.594457	6.36017E-05	91.9679
Ethylbenzene		0	0*	0	0	0	0	0	0
C9		0	0*	0	0	0	0	0	0
C10		0	0*	0	0	0	0	0	0
Cyclohexane		2.57196	0.0390556*	0.0383925	0.0646635	7.32231E-05	0.419118	0.0965389	8.33117E-05
2-Methylpentane		1.35372	0.0821169*	0.0818106	0.0279326	5.17217E-06	0.181211	0.177830	5.84337E-06
3-Methylpentane		0.869548	0.0420599*	0.0418610	0.0183988	5.02822E-06	0.119351	0.0939538	5.67471E-06
Undecane		0	0*	0	0	0	0	0	0
Dodecane		0	0*	0	0	0	0	0	0
Argon		0	0*	0	0	0	0	0	0
O2		0	0*	0	0	0	0	0	0
UCARSOL™ AP-814		0	0*	0	0	0	0	0	0
Mass Fraction		%	%	%	%	%	%	%	%
CO2		4.27300	1.21247*	1.21010	0.0293845	5.38062E-08	0.995602	3.73818	6.17237E-08
H2S		0.0256303	0.000948415*	0.000937116	0.000178359	1.47188E-08	0.00604259	0.00439481	1.67691E-08
N2		0.00515971	1.26810*	1.26910	3.53078E-05	0	0.00119630	0.212580	1.04940E-13
C1		3.38777	56.9592*	56.9925	0.0231932	0	0.785830	32.3890	9.44215E-10
C2		8.72715	16.3617*	16.3624	0.0599022	2.31569E-08	2.02960	21.5844	2.64050E-08
C3		16.2452	11.9643*	11.9590	0.112187	1.68339E-07	3.80111	19.9710	1.92613E-07
iC4		4.33277	2.39112*	2.38967	0.0303437	9.36988E-08	1.02810	3.87960	1.07285E-07
nC4		17.1049	5.35105*	5.34409	0.121190	7.48725E-07	4.10611	10.1835	8.56023E-07
iC5		7.12965	1.59953*	1.59666	0.0528735	8.88118E-07	1.79142	2.73904	1.01315E-06
nC5		9.53975	1.67315*	1.66908	0.0724536	1.67668E-06	2.45480	3.07929	1.91671E-06
C6		3.32738	0.403683*	0.402038	0.0299545	6.83414E-06	1.01466	0.657438	7.74075E-06
C7		0.712608	0.0743588*	0.0738363	0.00955651	2.24501E-06	0.323708	0.104373	2.56185E-06
Benzene		9.21901	0.0470974*	0.0414059	0.101826	0.00103125	3.41124	0.111118	0.00118046
Toluene		4.94865	0.0299141*	0.0243972	0.100789	0.00295362	3.30419	0.0561867	0.00336752
o-Xylene		0	0*	0	0	0	0	0	0
p-Xylene		0.400469	0.00492400*	0.00384572	0.0205284	0.00140993	0.643153	0.00690381	0.00159319
C8		0.0688901	0.0105960*	0.0104888	0.00196785	1.12271E-06	0.0666323	0.0120156	1.28001E-06
Water		2.32816	0*	0.00645118	3.00545	1.03470	67.7786	0.123638	1.03558
Triethylene Glycol		2.55714E-06	0*	0.000495957	96.1506	98.9598	3.83205	0.000347291	98.9582
Ethylbenzene		0	0*	0	0	0	0	0	0
C9		0	0*	0	0	0	0	0	0
C10		0	0*	0	0	0	0	0	0
Cyclohexane		4.36250	0.152231*	0.149707	0.0447367	4.41517E-05	1.51411	0.295419	5.02380E-05
2-Methylpentane		2.35116	0.327743*	0.326652	0.0197878	3.19339E-06	0.670329	0.557211	3.60803E-06
3-Methylpentane		1.51024	0.167868*	0.167142	0.0130339	3.10451E-06	0.441498	0.294395	3.50389E-06
Undecane		0	0*	0	0	0	0	0	0
Dodecane		0	0*	0	0	0	0	0	0
Argon		0	0*	0	0	0	0	0	0
O2		0	0*	0	0	0	0	0	0
UCARSOL™ AP-814		0	0*	0	0	0	0	0	0
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h
CO2		8.65823	6379.68*	6361.66	8.70284	1.54849E-05	8.70282	9.31266	1.77412E-05
H2S		0.0519338	4.99031*	4.92654	0.0528247	4.23593E-06	0.0528199	0.0109485	4.81995E-06
N2		0.0104549	6672.39*	6671.85	0.0104571	0	0.0104571	0.529585	3.01630E-11
C1		6.86452	299705*	299617	6.86915	0	6.86915	80.6883	2.71395E-07
C2		17.6835	86090.9*	86019.4	17.7413	6.66433E-06	17.7413	53.7716	7.58958E-06
C3		32.9171	62953.1*	62870.1	33.2265	4.84462E-05	33.2265	49.7524	5.53627E-05
iC4		8.77934	12581.5*	12562.8	8.98691	2.69655E-05	8.98688	9.66496	3.08369E-05
nC4		34.6590	28155.8*	28094.6	35.8929	0.000215475	35.8926	25.3693	0.000246046
iC5		14.4466	8416.33*	8393.85	15.6596	0.000255591	15.6593	6.82356	0.000291209
nC5		19.3301	8803.69*	8774.56	21.4586	0.000482532	21.4581	7.67121	0.000550919
C6		6.74216	2124.08*	2113.57	8.87164	0.00196679	8.86942	1.63783	0.00222492
C7		1.44393	391.257*	388.167	2.83036	0.000646090	2.82962	0.260017	0.000736352
Benzene		18.6802	247.814*	217.676	30.1578	0.296784	29.8185	0.276819	0.339299
Toluene		10.0273	157.400*	128.259	29.8508	0.850021	28.8828	0.139974	0.967925
o-Xylene		0	0*	0	0	0	0	0	0
p-Xylene		0.811456	25.9088*	20.2174	6.07990	0.405764	5.62198	0.0171990	0.457929
C8		0.139590	55.7533*	55.1408	0.582819	0.000323105	0.582451	0.0299337	0.000367914
Water		4.71746	0*	33.9147	890.126	297.776	592.471	0.308010	297.655
Triethylene Glycol		5.18144E-06	0*	2.60731	28477.0	28479.6	33.4970	0.000865181	28443.5
Ethylbenzene		0	0*	0	0	0	0	0	0
C9		0	0*	0	0	0	0	0	0
C10		0	0*	0	0	0	0	0	0
Cyclohexane		8.83959	801.002*	787.029	13.2497	0.0127064	13.2353	0.735955	0.0144399
2-Methylpentane		4.76407	1724.50*	1717.25	5.86056	0.000919025	5.85953	1.38814	0.00103705
3-Methylpentane		3.06015	883.280*	878.687	3.86026	0.000893447	3.85925	0.733404	0.00100712
Undecane		0	0*	0	0	0	0	0	0
Dodecane		0	0*	0	0	0	0	0	0
Argon		0	0*	0	0	0	0	0	0
O2		0	0*	0	0	0	0	0	0
UCARSOL™ AP-814		0	0*	0	0	0	0	0	0

Process Streams		Condenser Ovhd2	TEG3 Inlet	ˉo Mole Sieve	8	23	27	30	109
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	BTEX Condenser2	--	Glycol Contactor	V-551 Glycol Flash tank	RCYL-1	HZZ-1100/1101 M	PCV	52 Glycol Reboiler
	To Block:	TO THERMAL OX -TEG3	SAT-1	loleSieve3 from T	F-551 Rich Glycol Filter	P-551A/B TEG CIRC	BTEX Condenser2	--	-551 Glycol Exch
Property	Units								
Temperature	°F	100	104.955*	107.188	109.565	211.239	100*	108.069	390
Pressure	psia	14.6959	955.496*	948.496	94.6959	14.1959	14.6959	79.6959*	15.1959
Mole Fraction Vapor	%	100	100	100	0	0	10.8836	100	0
Mole Fraction Light Liquid	%	0	0	0	100	100	1.55238	0	100
Mole Fraction Heavy Liquid	%	0	0	0	0	0	87.5640	0	0
Molecular Weight	lb/lbmol	49.6170	21.5915	21.5828	121.646	139.574	23.2960	27.5022	139.565
Mass Density	lb/ft^3	0.123517	4.21513	4.14380	68.3145	65.3028	0.529312	0.370271	58.4747
Molar Flow	lbmol/h	4.08381	24369.5	24358.0	243.469	206.192	37.5227	9.05829	205.947
Mass Flow	lb/h	202.627	526174	525713	29617.1	28779.0	874.127	249.123	28743.0
Vapor Volumetric Flow	ft^3/h	1640.47	124830	126867	433.540	440.700	1651.44	672.812	491.545
Liquid Volumetric Flow	gpm	204.526	15563.2	15817.2	54.0517	54.9444	205.894	83.8830	61.2835
Std Vapor Volumetric Flow	MMSCFD	0.0371938	221.948*	221.843	2.21743	1.87791	0.341742	0.0824994	1.87568
Std Liquid Volumetric Flow	sgpm	0.700882	2975.80	2973.81	52.9969	51	2.06052	1.24278	50.9364
Compressibility		0.982890	0.807749	0.812094	0.0276033	0.00421414	0.107689	0.971564	0.00397761
Specific Gravity		1.71315	0.745498	0.745198	1.09533	1.04704		0.949579	0.937565
API Gravity					-5.22488	-6.66684			-6.66625
Enthalpy	Btu/h	-206982	-8.63669E+08	-8.62399E+08	-7.15175E+07	-6.54371E+07	-4.29356E+06	-361663	-6.18767E+07
Mass Enthalpy	Btu/lb	-1021.49	-1641.41	-1640.44	-2414.74	-2273.78	-4911.83	-1451.75	-2152.76
Mass Cp	Btu/(lb*°F)	0.388401	0.640897	0.637535	0.605692	0.641917	0.809809	0.462902	0.709008
Ideal Gas CpCv Ratio		1.11583	1.23426	1.23375	1.03942	1.03019	1.25012	1.18977	1.02644
Dynamic Viscosity	cP	0.00885017	0.0132196	0.0132084	14.8312	3.54336		0.0106066	0.797899
Kinematic Viscosity	cSt	4.47304	0.195788	0.198990	13.5533	3.38737		1.78829	0.851841
Thermal Conductivity	Btu/(h*ft*°F)	0.0108341	0.0223853	0.0224070	0.115145	0.113663?		0.0165084	0.107253?
Surface Tension	lbf/ft				0.00296112	0.00266474?			0.00204966?
Net Ideal Gas Heating Value	Btu/ft^3	2369.70	1159.06	1158.58	2991.50	3474.07	344.087	1424.30	3473.84
Net Liquid Heating Value	Btu/lb	17950.8	20306.8	20306.7	9049.38	9177.65	4832.44	19549.1	9177.62
Gross Ideal Gas Heating Value	Btu/ft^3	2561.12	1276.87	1276.37	3279.45	3801.71	414.371	1560.70	3801.46
Gross Liquid Heating Value	Btu/lb	19415.2	22377.9	22378.1	9947.68	10068.5	5977.39	21431.6	10068.4

"2" HAPs = 21.48 lb/h
"2" BTEX = 14.9 lb/h
"2" VOCs = 19.49 lb/h

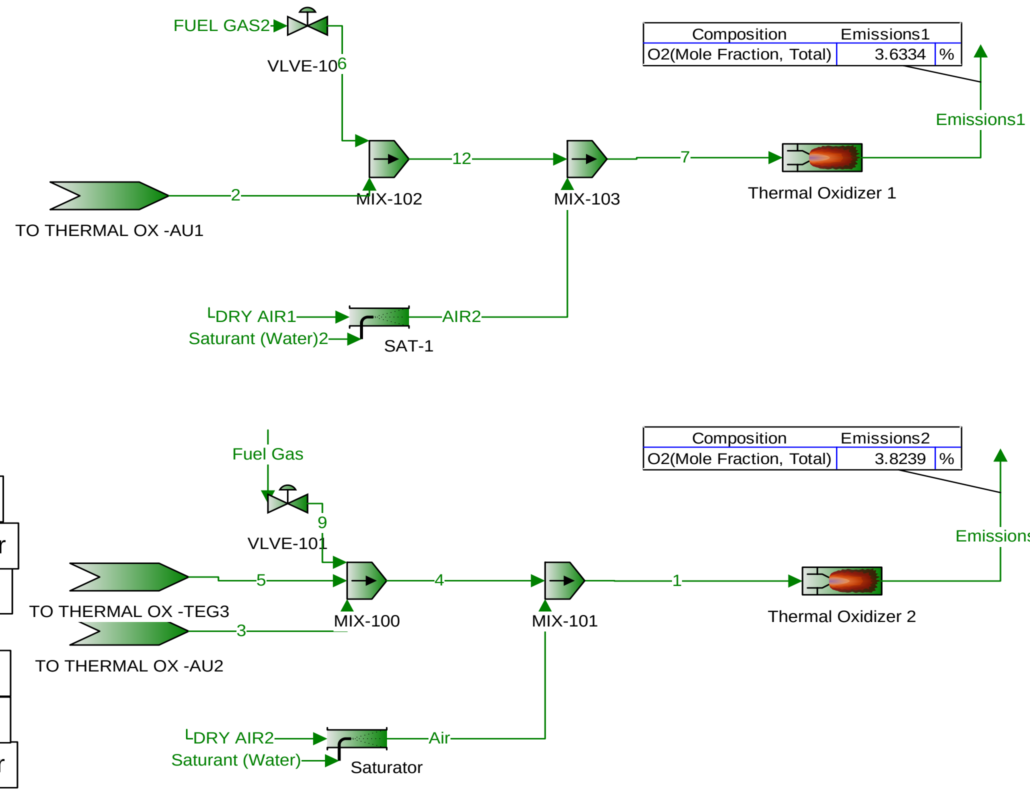
"2" HAPs = 94.07 ton/yr
"2" BTEX = 65.27 ton/yr
"2" VOCs = 85.35 ton/yr

"3" HAPs = 19.38 lb/h
"3" BTEX = 14.42 lb/h
"3" VOCs = 18.95 lb/h

"3" HAPs = 84.9 ton/yr
"3" BTEX = 63.16 ton/yr
"3" VOCs = 82.99 ton/yr

"5" HAPs = 36.31 lb/h
"5" BTEX = 29.52 lb/h
"5" VOCs = 164.6 lb/h

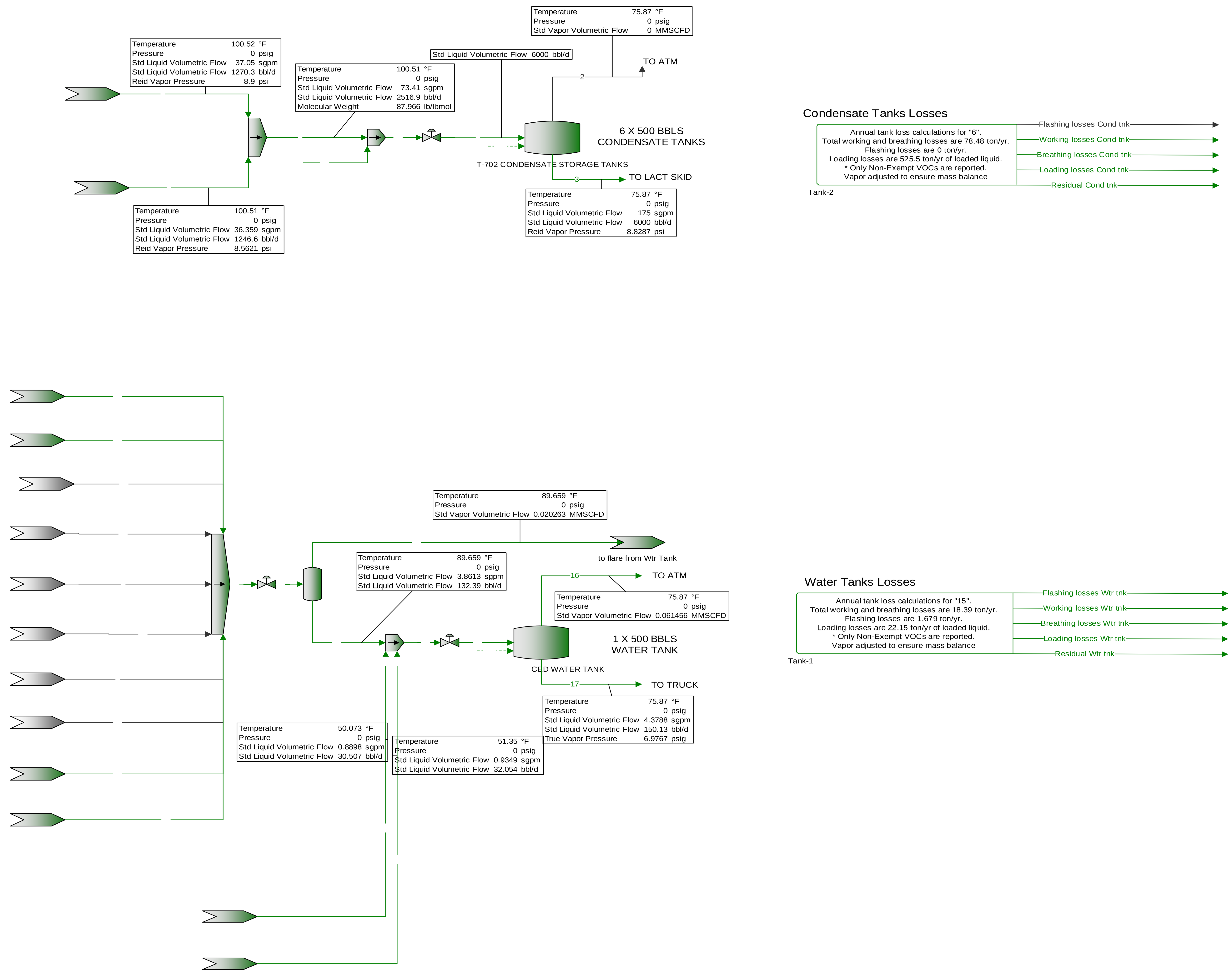
"5" HAPs = 159.1 ton/yr
"5" BTEX = 129.3 ton/yr
"5" VOCs = 721.1 ton/yr



Process Streams		Air	AIR2	DRY AIR1	DRY AIR2	Emissions1	Emissions2	Fuel Gas	FUEL GAS2	12
Composition	**Status:**	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	**From Block:**	Saturator	SAT-1	--	--	Thermal Oxidizer 1	Thermal Oxidizer 2	--	--	MIX-102
	To Block:	MIX-101	MIX-103	SAT-1	Saturator	--	--	VLVE-101	VLVE-100	MIX-103
Mole Fraction		%	%	%	%	%	%	%	%	%
CO2		0.0319272	0.0319272	0.033*	0.033*	32.2641	31.9512	0.0170073*	0.0252378*	81.0862
H2S		0	0	0*	0*	0.0331184	0.0296334	0*	0*	0.0994244
N2		75.5486	75.5486	78.087*	78.087*	49.9633	50.8987	0.528291*	0.525969*	0.0606529
C1		0	0	0*	0*	0	0	79.3471*	79.0312*	9.37048
C2		0	0	0*	0*	0	0	13.5741*	13.6855*	1.67461
C3		0	0	0*	0*	0	0	4.02259*	4.19361*	0.508324
iC4		0	0	0*	0*	0	0	0.337022*	0.361004*	0.0432984
nC4		0	0	0*	0*	0	0	0.972671*	1.03898*	0.127749
iC5		0	0	0*	0*	0	0	0.103732*	0.114854*	0.0140405
nC5		0	0	0*	0*	0	0	0.117050*	0.128756*	0.0161492
C6		0	0	0*	0*	0	0	0.0339009*	0.0384297*	0.00459832
C7		0	0	0*	0*	0	0	1.87457E-06*	0*	1.08019E-05
Benzene		0	0	0*	0*	0	0	2.23902E-05*	0*	0.0503213
Toluene		0	0	0*	0*	0	0	2.05705E-06*	0*	0.0278311
o-Xylene		0	0	0*	0*	0	0	1.00978E-08*	0*	0.00277110
p-Xylene		0	0	0*	0*	0	0	6.84740E-08*	0*	0.00880071
C8		0	0	0*	0*	0	0	8.60715E-08*	0*	7.10009E-07
Water		3.25076	3.25076	0*	0*	13.5087	12.6879	0.946350*	0.856422*	6.90246
Triethylene Glycol		0	0	0*	0*	0	0	0*	0*	0
Ethylbenzene		0	0	0*	0*	0	0	1.08038E-08*	0*	0
C9		0	0	0*	0*	0	0	0*	0*	0
C10		0	0	0*	0*	0	0	0.000184351*	0*	0
Cyclohexane		0	0	0*	0*	0	0	0*	0*	0.00223217
2-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
3-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
Undecane		0	0	0*	0*	0	0	0*	0*	0
Dodecane		0	0	0*	0*	0	0	0*	0*	0
Argon		0.903638	0.903638	0.934*	0.934*	0.597370	0.608668	0*	0*	0
O2		20.2651	20.2651	20.946*	20.946*	3.63338	3.82391	0*	0*	0
UCARSOL™ AP-814		0	0	0*	0*	0	0	0*	0*	6.67555E-08
Mass Fraction		%	%	%	%	%	%	%	%	%
CO2		0.0491140	0.0491140	0.0501404*	0.0501404*	44.3148	43.8292	0.0376867*	0.0555958*	90.5377
H2S		0	0	0*	0*	0.0352259	0.0314791	0*	0*	0.0859686
N2		73.9758	73.9758	75.5218*	75.5218*	43.6816	44.4429	0.745155*	0.737514*	0.0431075
C1		0	0	0*	0*	0	0	64.0929*	63.4621*	3.81389
C2		0	0	0*	0*	0	0	20.5512*	20.5980*	1.27752
C3		0	0	0*	0*	0	0	8.93118*	9.25610*	0.568685
iC4		0	0	0*	0*	0	0	0.986299*	1.05026*	0.0638484
nC4		0	0	0*	0*	0	0	2.84653*	3.02269*	0.188380
iC5		0	0	0*	0*	0	0	0.376834*	0.414780*	0.0257008
nC5		0	0	0*	0*	0	0	0.425216*	0.464986*	0.0295608
C6		0	0	0*	0*	0	0	0.147096*	0.165766*	0.0100535
C7		0	0	0*	0*	0	0	9.45771E-06*	0*	2.74607E-05
Benzene		0	0	0*	0*	0	0	8.80610E-05*	0*	0.0997251
Toluene		0	0	0*	0*	0	0	9.54317E-06*	0*	0.0650590
o-Xylene		0	0	0*	0*	0	0	5.39781E-08*	0*	0.00746395
p-Xylene		0	0	0*	0*	0	0	3.66029E-07*	0*	0.0237047
C8		0	0	0*	0*	0	0	4.95042E-07*	0*	2.05766E-06
Water		2.04703	2.04703	0*	0*	7.59513	7.12461	0.858422*	0.772277*	3.15486
Triethylene Glycol		0	0	0*	0*	0	0	0*	0*	0
Ethylbenzene		0	0	0*	0*	0	0	5.77517E-08*	0*	0
C9		0	0	0*	0*	0	0	0*	0*	0
C10		0	0	0*	0*	0	0	0.00132070*	0*	0
Cyclohexane		0	0	0*	0*	0	0	0*	0*	0.00476613
2-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
3-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
Undecane		0	0	0*	0*	0	0	0*	0*	0
Dodecane		0	0	0*	0*	0	0	0*	0*	0
Argon		1.26179	1.26179	1.28816*	1.28816*	0.744767	0.757889	0*	0*	0
O2		22.6663	22.6663	23.1399*	23.1399*	3.62850	3.81392	0*	0*	0
UCARSOL™ AP-814		0	0	0*	0*	0	0	0*	0*	1.64641E-07
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h	lb/h
CO2		4.66676	5.38047	5.38047*	4.66676*	8224.89	6933.53	0.0748481*	0.244355*	6885.47
H2S		0	0	0*	0*	6.53799	4.97982	0*	0*	6.53799
N2		7029.10	8104.10	8104.10*	7029.10*	8107.38	7030.62	1.47992*	3.24152*	3.27837
C1		0	0	0*	0*	0	0	127.292*	278.928*	290.050
C2		0	0	0*	0*	0	0	40.8159*	90.5321*	97.1568
C3		0	0	0*	0*	0	0	17.7378*	40.6824*	43.2490
iC4		0	0	0*	0*	0	0	1.95885*	4.61612*	4.85572
nC4		0	0	0*	0*	0	0	5.65338*	13.2853*	14.3265
iC5		0	0	0*	0*	0	0	0.748415*	1.82304*	1.95457
nC5		0	0	0*	0*	0	0	0.844504*	2.04370*	2.24812
C6		0	0	0*	0*	0	0	0.292142*	0.728572*	0.764578
C7		0	0	0*	0*	0	0	1.87836E-05*	0*	0.00208841
Benzene		0	0	0*	0*	0	0	0.000174894*	0*	7.58418
Toluene		0	0	0*	0*	0	0	1.89533E-05*	0*	4.94779
o-Xylene		0	0	0*	0*	0	0	1.07204E-07*	0*	0.567640
p-Xylene		0	0	0*	0*	0	0	7.26954E-07*	0*	1.80276
C8		0	0	0*	0*	0	0	9.83182E-07*	0*	0.000156487
Water		194.506	224.253	0*	0*	1409.67	1127.07	1.70488*	3.39431*	239.930
Triethylene Glycol		0	0	0*	0*	0	0	0*	0*	0
Ethylbenzene		0	0	0*	0*	0	0	1.14698E-07*	0*	0
C9		0	0	0*	0*	0	0	0*	0*	0
C10		0	0	0*	0*	0	0	0.00262298*	0*	0
Cyclohexane		0	0	0*	0*	0	0	0*	0*	0.362468
2-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
3-Methylpentane		0	0	0*	0*	0	0	0*	0*	0
Undecane		0	0	0*	0*	0	0	0*	0*	0
Dodecane		0	0	0*	0*	0	0	0*	0*	0
Argon		119.894	138.230	138.230*	119.894*	138.230	119.894	0*	0*	0
O2		2153.72	2483.10	2483.10*	2153.72*	673.455	603.340	0*	0*	0
UCARSOL™ AP-814		0	0	0*	0*	0	0	0*	0*	1.25211E-05

Process Streams		Air	AIR2	DRY AIR1	DRY AIR2	Emissions1	Emissions2	Fuel Gas	FUEL GAS2	12
Properties	Status:	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved	Solved
Phase: **Total**	From Block:	Saturator	SAT-1	--	--	Thermal Oxidizer 1	Thermal Oxidizer 2	--	--	MIX-102
	To Block:	MIX-101	MIX-103	SAT-1	Saturator	--	--	VLVE-101	VLVE-100	MIX-103
Property	**Units**									
Temperature	°F	80	80	80*	80*	1929.84	1956.89	94.9840*	94.0663*	115.422
Pressure	psia	15.6959	15.6959	15.6959*	15.6959*	15.4459	14.4459	79.6959*	79.6959*	15.6959
Mole Fraction Vapor	%	100	100	100	100	100	100	100	100	100
Mole Fraction Light Liquid	%	0	0	0	0	0	0	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0	0	0	0	0	0	0
Molecular Weight	lb/lbmol	28.6090	28.6090	28.9649	28.9649	32.0419	32.0826	19.8606	19.9782	39.4153
Mass Density	lb/ft^3	0.0775745	0.0775745	0.0785278	0.0785278	0.0192960	0.0178677	0.270287	0.272417	0.100714
Molar Flow	lbmol/h	332.129	382.924	370.476*	321.333*	579.246	493.084	10*	22*	192.948
Mass Flow	lb/h	9501.88	10955.1	10730.8	9307.38	18560.2	15819.4	198.606	439.520	7605.09
Vapor Volumetric Flow	ft^3/h	122487	141220	136650	118523	961868	885366	734.797	1613.41	75512.0
Liquid Volumetric Flow	gpm	15271.1	17606.6	17036.9	14776.9	119921	110383	91.6111	201.152	9414.49
Std Vapor Volumetric Flow	MMSCFD	3.02491	3.48753	3.37415	2.92658	5.27556	4.49082	0.0910762	0.200368	1.75730
Std Liquid Volumetric Flow	sgpm	21.7562	25.0835	24.6352	21.3673	44.4185	37.8739	1.18706	2.61961	20.1144
Compressibility		0.999491	0.999491	0.999643	0.999643	1.00022	1.00020	0.983826	0.983537	0.995319
Specific Gravity		0.987794	0.987794	1.00008	1.00008	1.10632	1.10773	0.685734	0.689794	1.36091
API Gravity										
Enthalpy	Btu/h	-1.13484E+06	-1.30840E+06	-14346.6	-12443.5	-2.98584E+07	-2.46237E+07	-339471	-747122	-2.85500E+07
Mass Enthalpy	Btu/lb	-119.433	-119.433	-1.33695	-1.33695	-1608.73	-1556.54	-1709.27	-1699.86	-3754.06
Mass Cp	Btu/(lb*°F)	0.244872	0.244872	0.240567	0.240567	0.322509	0.321520	0.502623	0.501468	0.233538
Ideal Gas CpCv Ratio		1.39691	1.39691	1.39987	1.39987	1.23790	1.23843	1.25384	1.25275	1.27684
Dynamic Viscosity	cP	0.0182602	0.0182602	0.0183453	0.0183453	0.0491630	0.0494945	0.0110925	0.0110609	0.0155513
Kinematic Viscosity	cSt	14.6948	14.6948	14.5841	14.5841	159.056	172.929	2.56202	2.53476	9.63959
Thermal Conductivity	Btu/(h*ft*°F)	0.0149197	0.0149197	0.0149444	0.0149444	0.0513687	0.0517183	0.0185583	0.0184789	0.0116262
Surface Tension	lbf/ft									
Net Ideal Gas Heating Value	Btu/ft^3	0	0	0	0	0.194336	0.173886	1083.55	1090.19	134.803
Net Liquid Heating Value	Btu/lb	-21.7303	-21.7303	-0.0375319	-0.0375319	-111.431	-106.318	20641.4	20645.4	1192.75
Gross Ideal Gas Heating Value	Btu/ft^3	1.63546	1.63546	0	0	7.00720	6.57208	1196.48	1203.57	152.004
Gross Liquid Heating Value	Btu/lb	-0.0367636	-0.0367636	-0.0375319	-0.0375319	-30.7433	-30.6381	22799.6	22799.6	1358.39

ProMax Flowsheet



	UOM	Gas	T-701 PRODUCED WATER TANK	T-702 CONDENSATE STORAGE TANKS
Daily Rate	MMSCFD	510		
Daily Throughput	bbl/d		150	6000
Annual Throughput	gal/yr		2301523	91980000
Per Tank Throughput	gal/yr		2301523	15330000
# of Tanks			1	6
Turnover Per Tank	per year		133	906
Total Flow	lb/hr		408.75	17.92
VOC [C3+] total	lb/hr		387.60	17.92
VOC [C3+] per tank	lb/hr		387.60	2.99
Bz total	lb/hr		6.40	0.14
Bz per tank	lb/hr		6.40	0.02
H2S total	lb/hr		0.00	0.00
H2S per tank	lb/hr		0.0003	0.0000
Temperature	°F		75.87	75.56
VOC [C3+] wt %	%		94.83	100.00
Bz wt %	%		1.57	0.81
H2S wt %	%		0.0000767	0.0000000
MW Vapors	lb/lbmol		56.01	72.44
SCF/hr	SCF/hr		2768.64	93.86
HV	btu/ft^3		3098.29	4015.82
C3 % (mass)	%		16.23	0.13
			17	3
RVP	psi		18.28	8.83
Vapor Pressure @ 100 °F	psia		21.67	8.96
Vapor Pressure @ 65 °F	psia		12.23	4.47

*Results for vapor streams are for flashing, working ,and breathing combined unless otherwise noted in cell comments

BURNER DATA SHEET

PROJECT TITLE	:
LOCATION	:
OWNER	: Matador Resources Co
OWNER REFERENCE	: H-801
PURCHASER	: Tulsa Heaters Midstream
PURCHASER REFERENCE	: MJ18-325
UNIT	:
HEATER SERVICE	: Hot Oil Heater
ITEM NUMBER	:
CALLIDUS REFERENCE	: BB-9024982
CALLIDUS DOCUMENT #	: BB-9024982-DS

APPROVED BY THM

Rev.	Date	Description	Prepared	Approved
0	3/22/2018	ISSUED FOR APPROVAL	SM	DW

UOP
A Honeywell Company

Document Number: BB-9024982-DS

Rev 0

				REV
1	**GENERAL DATA**			REV
2	TYPE OF HEATER		Hot Oil Heater	
3	ALTITUDE ABOVE SEA LEVEL	ft.	3051	
4	AIR SUPPLY		Ambient	
5	TEMPERATURE (MIN/MAX/DESIGN)	°F	MINIMUM = -20 MAXIMUM = 110 DESIGN = 60	
6	RELATIVE HUMIDITY	%	50	
7	DRAFT TYPE		Forced Draft, Ambient	
8	REQUIRED TURNDOWN		5:1	
9	DRAFT AVAILABLE			
10	ACROSS BURNER	in. W.C.	7.00	
11	ACROSS PLENUM	in. W.C.		
12	DISTANCE BURNER C_L:			
13	TO TUBE C_L (HORIZ./VERT.)	in.	51	
14	TO BURNER C_L (HORIZ.)	in.	n/a	
15	TO UNSHIELDED REFRACTORY	in.		
16	BURNER FLOOR LINING THICKNESS	in.	6	
17	HEATER CASING THICKNESS	in.	0.1875	
18	FURNACE HEIGHT	ft.	10.5	
19	FURNACE WIDTH	ft.	10.5	
20	FURNACE LENGTH	ft.	19	
21	TUBE CIRCLE DIAMETER	ft.	8.5	
22	BURNER CIRCLE DIAMETER	in.	n/a	
23	**BURNER DATA**			
24	TYPE OF BURNER		GAS ONLY	
25	DIRECTION OF FIRING		HORIZONTALLY FIRED	
26	LOCATION		WALL	
27	BURNER MODEL		CUBL-5W-HC-HZ	
28	NUMBER REQ'D / HEATER		1	
29	PILOTS :			
30	NUMBER REQUIRED		1	
31	TYPE		Standard	
32	IGNITION METHOD		Electric	
33	FLAME DETECTION		None	
34	FUEL		Natural Gas	
35	FUEL PRESSURE RANGE	psig	**Minimum = 10.0 to Maximum = 15.0**	
36	FUEL CONNECTION SIZE		1/2" 150# RFSW	
37	CAPACITY	Btu/hr	100,000	
38	**BURNER OPERATING DATA**			
39	OPERATING CASE		Design	
40	HEAT RELEASE (LHV)			
41	MAXIMUM	MMBtu/hr	21.09	
42	NORMAL	MMBtu/hr	19.17	
43	MINIMUM	MMBtu/hr	4.22	
44	EXCESS AIR	%	15%	
45	COMB. AIR TEMPERATURE	°F	Ambient	
46	AIR SIDE DP @ MAXIMUM	in. W.C.	7.00	
47	AIR SIDE DP @ NORMAL	in. W.C.		
48	AIR SIDE DP @ MINIMUM	in. W.C.		
49	VISIBLE FLAME LENGTH (EXPECTED)	ft.	16.00	
50	VISIBLE FLAME DIAMETER (EXPECTED)	ft.	3.00	
51	FLAME SHAPE		ROUND	
52				
53	NOTES :			
54				
55				
56				

OWNER:	Matador Resources Co	CALLIDUS REF:	BB-9024982
OWNER REF.:	H-801	DOCUMENT NUMBER:	BB-9024982-DS
PURCHASER:	Tulsa Heaters Midstream		
PURCHASER REF.:	MJ18-325		
HEATER SERVICE	Hot Oil Heater		
UNIT:			
ITEM NO.:			

UOP
A Honeywell Company

BURNER DATA SHEET

FIRED HEATER DATA SHEET CUSTOMARY UNITS	Unit		Plant Loc.	
	Service	Regeneration Gas Heater	Equip.No.	H-101
	Type	Horizontal	No. Req.	1
	Owner		Client No.	J-387
	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 15400
Approved: LC/JB	Date	8/6/2015	Page 1 of 5	

Process Design Conditions

*	1 Total duty per heater, MM Btu/Hr	4.870			
*	2 Heater section	Rad+Conv			
*	3 Service	Regen. Gas			
*	4 Heat Absorption, MM Btu/Hr	4.87			
*	5 Fluid name	Natural Gas			
*	6 Flow rate, lb/hr	15,568			
	7 Flow rate, bpd				
*	8 Pressure drop (allowable, clean), psi	5			
	9 Pressure drop (calculated, clean), psi ..with 1/8" coke	4			
*	10 Average flux density (allowable), Btu/hr-ft²				
	11 Average flux density (calculated), Btu/hr-ft²	11,978			
	12 Maximum flux density, Btu/hr-ft²	20,519			
	13 Velocity Limitations				
	14 Maximum allowable inside film temperature, °F				
	15 Fouling Factor	0.001			
	16 Corrosion or Erosion Characteristics				
Inlet Conditions:					
*	17 Temperature, °F	100			
*	18 Pressure, psig	1020			
*	19 Vapor flow, lb/hr	15,568			
	20 Vapor, molecular weight	21.48			
	21 Vapor Viscosity, Cp	0.014			
*	22 Vapor, Specific Heat, Btu/lb-F	0.65			
*	23 Vapor Thermal Conductivity, Btu/hr-ft-F	0.022			
Outlet Conditions:					
*	23 Temperature, °F	550			
*	24 Pressure, psig	1016			
*	25 Vapor flow, lb/hr	15,568			
*	26 Vapor molecular weight	21.48			
*	27 Vapor Viscosity, Cp	0.02			
*	28 Vapor, Specific Heat, Btu/hr-F	0.74			
*	29 Vapor Thermal Conductivity, Btu/hr-ft-F	0.0425			
Remarks and Special Requirements:					
*	30 Distillation Data or Composition Attached				

Combustion Design Conditions

*	1 Type of fuel	Natural Gas			
*	2 Excess air, percent	15%			
	3 Guaranteed Efficiency, Percent (LHV)	86.30			
	4 Calculated Efficiency, Percent (LHV)	87.30			
	5 Radiation loss, percent of heat release (LHV)	2.00			
	6 Flue gas temperature leaving radiant section, °F	1,734			
	7 Flue gas temperature leaving convection section, °F	493			
	8 Flue Gas Mass Velocity Thru Convection Section, lb/sq ft-s	0.22			
	9 Draft at Bridge Wall, In. H20	0.010			
	10 Draft at Burners, In. H20	0.040			
*	11 Ambient Air Temperature, °F ... comb/draft	60/80			
*	12 Altitude, Ft. Above Sea Level	2,000			
	13 Calculated Heat Release, MM BTU per Hr (LHV)	5.58			
	14 Volumetric Heat Release, Btu/hr-ft³ (LHV)				

Note: A fuel savings of ________ MM Btu/hr will offset a $1,000 increase in furnace cost (erected)

FIRED HEATER DATA SHEET	Service		Plant Loc.		
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip.No.	H-101	
	Type	Horizontal	No. Req.	1	
	Owner		Job No.	J-387	
	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 15400	
Approved: LC/JB	Date	8/6/2015		Page 2	of 5

Fuel Characteristics

			Composition	Composition	
*	1 Type of fuel	Natural Gas			
*	2 Heating value (HHV)				
*	3 Heating value (LHV)	901 Btu/SCF			
*	4 Specific gravity				
*	5 H/C ratio (by weight)				
*	6 Temperature at Burner, °F				
*	7 Viscosity, @ ____ °F,				
*	8 Viscosity, @ ____ °F,				
*	9 Fuel Pressure Available @ burner, psig				
*	10 Atomizing Steam Pressure, psig				
*	11 Vanadium Content, ppm for Liquid Fuels				
*	12 Sodium Content, ppm for Liquid Fuels				
*	13 Sulfur Content, Percent by Weight				
*	14 Gases: Molecular weight				
*	Composition, Mole Percent				

Mechanical Design Conditions

General

*	1 Plot limitations		* Stack Limitations	
*	2 Tube limitations		Other Limitations	
	3 Required Drawings			
	4 Structural Design Data: Wind Load		Seismic Factor	
	5 List of Applicable Standards or Specifications:	1	3	
		2	4	

Coil Design:

		Radiant	Shield	Conv.	
*	6 Heater Section	Radiant	Shield	Conv.	
*	7 Design Pressure, psig	1100	1100	1100	
*	8 Design Fluid Temperature, °F	600	600	600	
*	9 Corrosion Allowance: Tubes	0.063	0.063	0.063	
	Fittings	0.063	0.063	0.063	
	10 Hydrostatic Test Pressure, psig	1,750	1,750	1,750	
	11 Number of Passes	1	1	1	
	12 Overall Tube Length, Ft	14.230	14.230	14.230	
	13 Effective Tube length, ft	13.000	13.000	13.000	
	14 Bare Tubes, number	14	4		
	15 Bare tubes, total exposed surface, ft^2	214	61		
	16 Extended surface tubes, number	--	--	6	
	17 Extended surface tubes, total expsoed surface, ft^2	--	--	895	
	18 Tube spacing, center-to-center (staggered), in	8	8	8	
	19 Tube Center to furnace wall In. Min.	6	4	4	
*	20 Stress Relieve	←	No	→	
*	21 Weld Inspection Requirements, X-Ray or Other	10% of buttwelds will be 100% X-rayed			

Tubes:

*	22 Vertical or Horizontal	Horizontal	Horizontal	Horizontal	
	23 Tube Material (ASTM Specifications & Grade)	←	SA 106 Gr B	→	
	24 Outside Diameter, in	4.5	4.5	4.5	
	25 Wall Thickness (minimum) (average), in	←	Sch 80	→	
	26 Maximum Tube Wall Temp., °F (Calculated)	716			
	27 Inside Film Coefficient (Calculated)	175			
	28 Maximum Tube Wall Temperature, °F (Design)	←	730	→	
	27 Design Basis for Tube Wall Thickness	←	ASME SECT VIII Div I	→	

FIRED HEATER DATA SHEET	Service		Plant Loc.		
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip.No.	H-101	
	Type	Horizontal	No. Req.	1	
	Owner		Client No.	J-387	
	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 15400	
Approved: LC/JB	Date	8/6/2015		Page 3	of 5

Mechanical Design Conditions (continued)

	Radiant	Shield	Conv.	
Description of Extended Surface:				
28 Type	None	None	Serrated	
29 Fin Material			C.S.	
30 Fin Dimensions ..... ht/thck			3/4" x 0.05	
31 Fin Spacing ..... #/in			5	
32 Maximum Fin Temperature °F			763	
33 Extension ratio				
Plug-Type Headers:				
34 Manufacturer and Type	←	None	→	None
* 35 Material (ASTM specification and grade)				
36 Nominal Rating				
* 37 Location				
38 Welded or Rolled				
Return Bends:				
39 Manufacturer and Type	←	SR 180° WPB	→	
* 40 Material (ASTM specification and grade)	←	WPB	→	
41 Nominal Rating or Schedule	←	Same as Tubes	→	
* 42 Location	←	Header Box	→	
Terminals: NOTE:				
43 Manufacturer and Type	←	Flanged	→	
* 44 Material (ASTM specification and grade)	←	Same as Tubes	→	
45 Nominal Rating	←	Same as Tubes	→	
* 46 Location	heater outlets		heater inlets	
47 Welded or Rolled	welded		welded	
48 Flange: Size and Rating	4"-600# RFWN		4"-600# RFWN	
Location	Radiant		Top Conv.	
Crossovers:				
* 49 Welded or Flanged	←	Welded	→	
* 50 Pipe material (ASTM specification and grade)	←	Same as Tubes	→	
51 Pipe Size and Wall Thicknes	←	Same as Tubes	→	
* 52 Location	←	Header Box	→	
53 Flange Rating				
Tube Supports:				
54 Ends, Top, Bottom:		← Ends	→	
Material		CS		
Thickness		3/8"		
Type and Thickness of Insulation		4"-8# 2300 F	Ceramic Fiber	
Insulation Reinforcement		310 SS anchors		
55 Intermediate:				
Material	←	None	→	
Spacing				
Type and Thickness of Coating				
56 Guides: Location				
Material				

Header Boxes

1 Location: Radiant and Convection Ends — Material: CS — Thickness: 3/16"

2 Insulation: Material: 2"-6# 2300°F Ceramic Fiber — Thickness: 2"

Anchoring Material: 304 SS

3 Are Header Box Doors Bolted or Hinged? Bolted

Burners

4 Manufacturer and Type: Universal Combustion TPS-4-4 — Number: 1

5 Location: One End

6 Size and Type of Pilots: Electric

7 Heat Release per Burner at Design Excess Air and Draft:

Normal 5.580 MM BTU per Hr; Maximum 6.98 MM Btu per Hr.

8 Minimum Distance Burner Centerline to Tube Centerline:

Horizontal 2'-2 5/8" — Vertical 3.3'

FIRED HEATER DATA SHEET CUSTOMARY UNITS	Service		Plant Loc.	
	Unit	Regeneration Gas Heater	Equip.No.	H-101
	Type	Horizontal	No. Req.	1
	Owner		Client No.	J-387
	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 15400
Approved: LC/JB	Date	8/6/2015	Page 4	of 5

Mechanical Design Conditions (continued)

Settings:

1 Exposed Vertical Walls: N/A

Thickness 4" Hot-Face Temp.: Design 2300°F Calculated 1690

Wall Construction 2"-8# 2300°F + 2"-6# 2300°F Ceramic Fiber

Outside Casing: Thickness 3/16" Material C.S. Outside Temperature

Tieback Material 310 SS

Support Material C.S.

Method of Fastening Tiebacks to Structure Welded

2 Shielded Vertical Walls:

Thickness 3" Hot-Face Temp.: Design 2300°F Calculated

Wall Construction 1"-8# 2300°F + 2"-6# 2300°F Ceramic Fiber

Outside Casing: Thickness 3/16" Material CS Outside Temperature

Tieback Material 304 SS

Support Material C.S.

Method of Fastening Tiebacks to Structure Welded

3 Arch: None

Thickness Hot-Face Temp.: Design Calculated

Arch Construction

Outside Casing: Thickness Material Outside Temperature

Tieback Material

Support Material

Method of Fastening Tiebacks to Structure

4 Floor:

Thickness 7.5" Hot-Face Temp.: Design 1900°F Calculated

Floor Construction 5" 1:2:4 LHV Castable plus 2.5" 1st. Quality FireBrick

Minimum Floor Elevation

Outside Casing: Thickness 1/4" Material CS Outside Temperature

5 Convection Section:

Thickness 3" Design Hot-Face Temperature 2300 F

Construction 1"-8# 2300°F + 2"-6# 2300°F Ceramic Fiber

Outside Casing: Thickness 3/16" Material CS Outside Temperature

Tieback Material 304 SS

Support Material C.S.

Method of Fastening Tiebacks to Structure Welded

6 Internal Wall: N/A

Type Dimensions Material

FIRED HEATER DATA SHEET	Service		Plant Loc.		
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip No	H-101	
	Type	Horizontal	No Rqd	1	
	Owner		Job No	J-387	
	Purchaser	EPC, Inc.	Model No	4HE-14-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref No	HRC 15400	
Approved: LC/JB	Date	8/6/2015		Page 5	of 5

Mechanical Design Conditions (continued)

Stack:

1 Number 1 Self-Supporting or Guyed Self-Supporting Location Top Convection
2 Material C.S. Thickness Min. Thickness 3/16"
3 Inside Metal Diameter 20" OD Pipe Sch10 Height Above Grade Stack Length 20'-0"
4 Lining: Material None Thickness --
Type of Material or Reinforcement --
Extent of Lining --

Dampers:

1 Location: Stack or Bottom Air Plenum
2 Material Multiple or Single Leaf
3 Description of Provision for Operation from Grade

Breeching, Flues None

1 Material ASTM Specification Size
2 Insulation: Thickness
Type of Anchoring Material
3 Size of Access Door into Breeching

Air Ducts and Plenum

1 Material N/A ASTM Specification Size

Miscellaneous

1 Overall Dimensions of Furnace Refer to drawing 15400-001
2 Platforms: Location None
Width
Type of Floor
3 Stairs: Location None
4 Ladders: Location None

5 Access Doors: Location and Size One End 18" x 18"
6 Observation Doors: Location and Size Each End 3" x 6"
7 Miscellaneous Connections (Number and Size): Couplings Only
Draft (3) 3/4"-3000# Cplgs. Flue Gas Sample (2) 3/4"-3000# Cplgs
Temp. (3) 3/4"-3000# Cplgs. Smothering Steam (1) 1"-3000# Cplgs.
Header Box Drain (3) 3/4"-3000# Cplgs. Stack Drain --
Coil Drains Other TWO (2) Scanner Connections
8 Painting and Galvanizing Requirements Heater and Stack commercial sandblasted cleaned, SP-6, and painted with one coat of Sherwin Williams KEM HI-Temp 850 No.1 Black 2-3 mils dft

9 Are Painter's Trolley and Rail Included? N/A
10 Extent of Tube-Handling Facilities Removable Header Boxes
11 Explosion Doors: Location and Size None

Special Equipment (Soot Blower, Air Preheaters, Noise Suppressors, Fans, Etc.)

HRC - HEAT RECOVERY CORP.

FIRED HEATER DATA SHEET
CUSTOMARY UNITS

Date: 12/17/2015
Revision: 0
Approved: LJC

Unit	Condensate Stablizer	Plant Loc.	
Service	Hot Oil	Equip.No.	H-801
Type	Horizontal	No. Req.	1
Owner	Matador	Job No.	387
Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E
Vendor	Heat Recovery Corp.	Ref. No.	15405
Date	12/17/2015		

Process Design Conditions

*	1 Total duty per heater, MM Btu/Hr	4.19 x 1.1			
*	2 Heater section	Rad+Conv			
*	3 Service	Condensate Stablizer			
*	4 Heat Absorption, MM Btu/Hr	4.609			
*	5 Fluid name	Chemitherm 550			
*	6 Flow rate, lb/hr	74,938			
	7 Flow rate, bpd				
*	8 Pressure drop (allowable, clean), psi	10			
	9 Pressure drop (calculated, clean), psi ..with 1/8" coke	3			
*	10 Average flux density (allowable), Btu/hr-ft²				
	11 Average flux density (calculated), Btu/hr-ft²	11,366			
	12 Maximum flux density, Btu/hr-ft²	19,021			
	13 Velocity Limitations				
	14 Maximum allowable inside film temperature, °F	600 (564 Calc)			
	15 Fouling Factor	0.0015			
	16 Corrosion or Erosion Characteristics				
	Inlet Conditions:				
*	17 Temperature, °F	350			
*	18 Pressure, psig	40			
*	19 Liquid flow, lb/hr	74,938			
*	20 Thermal Conductivity Btu / hr ft oF	0.069			
	21 Specific Gravity	0.908			
	22 Specific Heat Btu / lbm oF	0.59			
*	23 Liquid Viscosity, Cp	1.27			
	Outlet Conditions:				
*	23 Temperature, °F	450			
*	24 Pressure, psig	37			
*	25 Liquid flow, lb/hr	74,938			
*	26 Thermal Conductivity Btu / hr ft oF	0.067			
*	27 Specific Gravity	0.908			
*	28 Specific Heat Btu / lbm oF	0.64			
*	29 Liquid Viscosity, Cp	0.727			
	Remarks and Special Requirements:				
*	30 Distillation Data or Composition Attached				

Combustion Design Conditions

*	1 Type of fuel	Natural Gas			
*	2 Excess air, percent	15			
	3 Guaranteed Efficiency, Percent (LHV)	83.38			
	4 Calculated Efficiency, Percent (LHV)	84.38			
	5 Radiation loss, percent of heat release (LHV)	1.50			
	6 Flue gas temperature leaving radiant section, °F	1,790			
	7 Flue gas temperature leaving convection section, °F	606			
	8 Flue Gas Mass Velocity Thru Convection Section, lb/sq ft-s	0.23			
	9 Draft at Bridge Wall, In. H20	-0.010			
	10 Draft at Burners, In. H20	-0.050			
*	11 Ambient Air Temperature, °F....comb/draft	60/95			
*	12 Altitude, Ft. Above Sea Level	3,000			
	13 Calculated Heat Release, MM BTU per Hr (LHV)	5.46			
	14 Volumetric Heat Release, Btu/hr-ft³ (LHV)				

Note: A fuel savings of ________ MM Btu/hr will offset a $1,000 increase in furnace cost (erected)

HRC - HEAT RECOVERY CORP.

FIRED HEATER DATA SHEET	Service	Condensate Stablizer	Plant Loc.		
CUSTOMARY UNITS	Unit	Hot Oil	Equip No.	H-801	
	Type	Horizontal	No. Req.	1	
	Owner	Matador	Job No.	387	
Date: 12/17/2015	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corp.	Ref. No.	15405	
Approved: LJC	Date	12/17/2015		Page 2 of 5	

Fuel Characteristics

			Composition	Volume %	
*	1 Type of fuel	Natural Gas			
*	2 Heating value (HHV)				
*	3 Heating value (LHV)	901 btu/scf			
*	4 Specific gravity				
*	5 H/C ratio (by weight)				
*	6 Temperature at Burner, °F				
*	7 Viscosity, @ °F				
*	8 Viscosity, @ °F				
*	9 Fuel Pressure Available @ burner, psig				
*	10 Atomizing Steam Pressure, psig				
*	11 Vanadium Content, ppm for Liquid Fuels				
*	12 Sodium Content, ppm for Liquid Fuels				
*	13 Sulfur Content, Percent by Weight				
*	14 Gases: Molecular weight				
*	Composition, Mole Percent				

Mechanical Design Conditions

General

*	1 Plot limitations	* Stack Limitations	
*	2 Tube limitations	Other Limitations	
*	3 Required Drawings		
*	4 Structural Design Data: Wind Load	Seismic Factor	
	5 List of Applicable Standards or Specifications:	1	3
		2	4

Coil Design:

*	6 Heater Section	Radiant	Shield	Conv.	
*	7 Design Pressure, psig	150	150	150	
*	8 Design Fluid Temperature, °F	500	500	500	
*	9 Corrosion Allowance: Tubes	0.063	0.063	0.063	
	Fittings	0.063	0.063	0.063	
	10 Hydrostatic Test Pressure, psig	215	215	215	
	11 Number of Passes	1	1	1	
	12 Overall Tube Length, Ft	14.230	14.230	14.230	
	13 Effective Tube length, ft	13.000	13.000	13.000	
	14 Bare Tubes, number	14	4		
	15 Bare tubes, total exposed surface, ft²	214	61		
	16 Extended surface tubes, number	--	--	6	
	17 Extended surface tubes, total expsoed surface, ft²	--	--	1,167	
	18 Tube spacing, center-to-center (staggered), in	8	8	8	
	19 Tube Center to furnace wall In. Min.	6	4	4	
*	20 Stress Relieve	←	No	→	
*	21 Weld Inspection Requirements, X-Ray or Other	100% of 10%			

Tubes:

*	22 Vertical or Horizontal	Horizontal	Horizontal	Horizontal	
	23 Tube Material (ASTM Specifications & Grade)	←	SA 106 Gr B	→	
	24 Outside Diameter, in	4.5	4.5	4.5	
	25 Wall Thickness (minimum) (average), in	←	Sch 40	→	
	26 Maximum Tube Wall Temp., °F (Calculated)	611			
	27 Inside Film Coefficient (Calculated)	173			
	28 Maximum Tube Wall Temperature, °F (Design)	←	636	→	
	27 Design Basis for Tube Wall Thickness	←	ASME SEC. VIII DIV.1	→	

HRC - HEAT RECOVERY CORP.

FIRED HEATER DATA SHEET		Service	Condensate Stablizer	Plant Loc.	
CUSTOMARY UNITS		Unit	Hot Oil	Equip.No.	H-801
		Type	Horizontal	No. Req.	1
		Owner	Matador	Job No.	387
Date:	########	Purchaser	EPC, Inc.	Model No.	4HE-14-4HE-4-6-E
Revision:	0	Vendor	Heat Recovery Corp.	Ref. No.	15405
Approved:	LJC	Date	12/17/2015	Page 3 of 5	

Mechanical Design Conditions (continued)

		Radiant	Shield	Conv.	
Description of Extended Surface:					
	28 Type	None	None	Serrated	
	29 Fin Material			C.S.	
	30 Fin Dimensions ..... ht/thck			1@ 1/2" + 2@ 1" x 0.05	
	31 Fin Spacing .....#/in			6/inch	
	32 Maximum Fin Temperature °F			745	
	33 Extension ratio				
Plug-Type Headers:					
	34 Manufacturer and Type	←	None	→	
*	35 Material (ASTM specification and grade)				
	36 Nominal Rating				
*	37 Location				
	38 Welded or Rolled				
Return Bends:					
	39 Manufacturer and Type	SR 180°	SR 180º	SR 180º	
*	40 Material (ASTM specification and grade)	←	A234-WPB	→	
	41 Nominal Rating or Schedule	←	Same as Tubes	→	
*	42 Location	←	Header Box	→	
Terminals: NOTE:					
	43 Manufacturer and Type	←	Flanged	→	
*	44 Material (ASTM specification and grade)	←	Same as Tubes	→	
	45 Nominal Rating	←	Same as Tubes	→	
*	46 Location	heater outlet		heater inlet	
*	47 Welded or Rolled	welded		welded	
	48 Flange: Size and Rating	4"-300# RFWN		4"-300# RFWN	
	Location	Radiant		Top Conv.	
Crossovers:					
*	49 Welded or Flanged	←	WELDED	→	
*	50 Pipe material (ASTM specification and grade)	←	SA-106-B	→	
	51 Pipe Size and Wall Thicknes	←	4" SCH 40	→	
*	52 Location	←	HEADER BOX	→	
	53 Flange Rating		--		
Tube Supports:					
	54 Ends, Top, Bottom:	←	Ends	→	
	Material		CS		
	Thickness		3/8 "		
	Type and Thickness of Insulation		4" Ceramic Fiber		
	Insulation Reinforcement		310 SS		
	55 Intermediate:				
	Material	←	None	→	
	Spacing				
	Type and Thickness of Coating				
	56 Guides: Location				
	Material				

Header Boxes

1 Location Radaint & Convection Ends Material CS Thickness 3/16"

2 Insulation: Material 6 # 1800 F Ceramic Fiber Thickness 2"

Anchoring Material 304 SS

3 Are Header Box Doors Bolted or Hinged? Bolted

Burners

4 Manufacturer and Type UNIVERSAL COMBUSTION TPS-4-4 Number 1

5 Location Radiant Ends

6 Size and Type of Pilots Electric ignition

7 Heat Release per Burner at Design Excess Air and Draft:

Normal 5.380 MM BTU per Hr; Maximum 6.2 MM Btu per Hr.

8 Minimum Distance Burner Centerline to Tube Centerline:

Horizontal 2.22' Vertical

FIRED HEATER DATA SHEET	Unit	Black River Plant 2	Plant Loc.	Eddy County, NM
CUSTOMARY UNITS	Service	Regeneration Gas Heater	Equip.No.	H-101
	Type	Horizontal	No. Req.	1
	Owner	Matador Resources	Job No.	J412
	Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 17417
Approved: LC	Date	9/26/2017	Page 1	of 5

Process Design Conditions

*	1	Total duty per heater, MM Btu/Hr	6.544			
*	2	Heater section	Rad+Conv			
*	3	Service	Regen. Gas			
*	4	Heat Absorption, MM Btu/Hr	6.544			
*	5	Fluid name	Natural Gas			
*	6	Flow rate, lb/hr	23,279			
	7	Flow rate, bpd				
*	8	Pressure drop (allowable, clean), psi	10			
	9	Pressure drop (calculated, clean), psi ..with 1/8" coke	6			
*	10	Average flux density (allowable), Btu/hr-ft²				
	11	Average flux density (calculated), Btu/hr-ft²	12,000			
	12	Maximum flux density, Btu/hr-ft²	17,832			
	13	Velocity Limitations				
	14	Maximum allowable inside film temperature, °F				
	15	Fouling Factor	0.001			
	16	Corrosion or Erosion Characteristics				
Inlet Conditions:						
*	17	Temperature, °F	120			
*	18	Pressure, psig	975			
*	19	Vapor flow, lb/hr	23,279			
*	20	Vapor, molecular weight	19.28			
*	21	Vapor Viscosity, Cp	0.0142			
*	22	Vapor, Specific Heat, Btu/lb-F	0.64			
*	23	Vapor Thermal Conductivity, Btu/hr-ft-F	0.024			
Outlet Conditions:						
*	23	Temperature, °F	550			
*	24	Pressure, psig	969			
*	25	Vapor flow, lb/hr	23,279			
*	26	Vapor molecular weight	19.28			
*	27	Vapor Viscosity, Cp	0.0186			
*	28	Vapor, Specific Heat, Btu/hr-F	0.71			
*	29	Vapor Thermal Conductivity, Btu/hr-ft-F	0.042			
Remarks and Special Requirements:						
*	30	Distillation Data or Composition Attached				

Combustion Design Conditions

*	1	Type of fuel	Natural Gas			
*	2	Excess air, percent	15%			
	3	Guaranteed Efficiency, Percent (LHV)	83.00			
	4	Calculated Efficiency, Percent (LHV)	84.00			
	5	Radiation loss, percent of heat release (LHV)	2.00			
	6	Flue gas temperature leaving radiant section, °F	1,683			
	7	Flue gas temperature leaving convection section, °F	620			
	8	Flue Gas Mass Velocity Thru Convection Section, lb/sq ft-s	0.30			
	9	Draft at Bridge Wall, In. H20	0.010			
	10	Draft at Burners, In. H20	0.060			
*	11	Ambient Air Temperature, °F ... comb/draft	60/95			
*	12	Altitude, Ft. Above Sea Level	3200			
	13	Calculated Heat Release, MM BTU per Hr (LHV)	7.79			
	14	Volumetric Heat Release, Btu/hr-ft³ (LHV)				

Note: A fuel savings of ________ MM Btu/hr will offset a $1,000 increase in furnace cost (erected)

FIRED HEATER DATA SHEET	Service	Black River Plant 2	Plant Loc.	Eddy County, NM	
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip No.	H-101	
	Type	Horizontal	No. Req.	1	
	Owner	Matador Resources	Job No.	J412	
	Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 17417	
Approved: LC	Date	9/26/2017		Page 2	of 5

Fuel Characteristics

			Composition	Volume %	
*	1 Type of fuel	Natural Gas			
*	2 Heating value (HHV)				
*	3 Heating value (LHV)	901 btu/scf			
*	4 Specific gravity				
*	5 H/C ratio (by weight)				
*	6 Temperature at Burner, °F				
*	7 Viscosity, @ °F,				
*	8 Viscosity, @ °F,				
*	9 Fuel Pressure Available @ burner, psig				
*	10 Atomizing Steam Pressure, psig				
*	11 Vanadium Content, ppm for Liquid Fuels				
*	12 Sodium Content, ppm for Liquid Fuels				
*	13 Sulfur Content, Percent by Weight				
*	14 Gases: Molecular weight				
*	Composition, Mole Percent				

Mechanical Design Conditions

General

*	1 Plot limitations	* Stack Limitations	
*	2 Tube limitations	Other Limitations	
*	3 Required Drawings		
*	4 Structural Design Data: Wind Load	Seismic Factor	
*	5 List of Applicable Standards or Specifications:	1	3
		2	4

Coil Design:

		Radiant	Shield	Conv.	
*	6 Heater Section	Radiant	Shield	Conv.	
*	7 Design Pressure, psig	1100	1100	1100	
*	8 Design Fluid Temperature, °F	600	600	600	
*	9 Corrosion Allowance: Tubes	0.063	0.063	0.063	
	Fittings	0.063	0.063	0.063	
	10 Hydrostatic Test Pressure, psig	2,200	2,200	2,200	
	11 Number of Passes	1	1	1	
	12 Overall Tube Length, Ft	14.230	14.230	14.230	
	13 Effective Tube length, ft	13.000	13.000	13.000	
	14 Bare Tubes, number	10 / 6	4		
	15 Bare tubes, total exposed surface, ft²	317	61		
	16 Extended surface tubes, number	- -	--	6	
	17 Extended surface tubes, total expsoed surface, ft²	--	--	735	
	18 Tube spacing, center-to-center (staggered), in	12	8	8	
	19 Tube Center to furnace wall In. Min.	9	4	4	
*	20 Stress Relieve	←	No	→	
*	21 Weld Inspection Requirements, X-Ray or Other	100% of buttwelds will be 10% X-rayed			

Tubes:

*	22 Vertical or Horizontal	Horizontal	Horizontal	Horizontal	
	23 Tube Material (ASTM Specifications & Grade)	←	SA 106 Gr B	→	
	24 Outside Diameter, in	6.625 / 4.5	4.5	4.5	
	25 Wall Thickness (minimum) (average), in	←	Sch 80	→	
	26 Maximum Tube Wall Temp., °F (Calculated)	745			
	27 Inside Film Coefficient (Calculated)	117			
	28 Maximum Tube Wall Temperature, °F (Design)	←	770	→	
	27 Design Basis for Tube Wall Thickness	←	ASME SECT VIII Div I	→	

FIRED HEATER DATA SHEET CUSTOMARY UNITS				
	Service	Black River Plant 2	Plant Loc.	Eddy County, NM
	Unit	Regeneration Gas Heater	Equip.No.	H-101
	Type	Horizontal	No. Req.	1
	Owner	Matador Resources	Job No.	J412
	Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	HRC 17417
Approved: LC	Date	9/26/2017		

Mechanical Design Conditions (continued)

		Radiant	Shield	Conv.	
Description of Extended Surface:					
28 Type		None	None	Serrated	
29 Fin Material				C.S.	
30 Fin Dimensions	ht/thck			3/4" x 0.05	
31 Fin Spacing	#/in			4	
32 Maximum Fin Temperature	°F			766	
33 Extension ratio					
Plug-Type Headers:					
34 Manufacturer and Type		←	None	→	
* 35 Material (ASTM specification and grade)					
36 Nominal Rating					
* 37 Location					
38 Welded or Rolled					
Return Bends:					
39 Manufacturer and Type		SR / LR	SR 180° WPB	→	
* 40 Material (ASTM specification and grade)		←	WPB	→	
41 Nominal Rating or Schedule		←	Same as Tubes	→	
* 42 Location		←	Header Box	→	
Terminals: NOTE:					
43 Manufacturer and Type		←	Flanged	→	
* 44 Material (ASTM specification and grade)		←	Same as Tubes	→	
45 Nominal Rating		←	Same as Tubes	→	
* 46 Location		heater outlets		heater inlets	
* 47 Welded or Rolled		welded		welded	
48 Flange: Size and Rating		6"-600# RFWN		4"-600# RFWN	
Location		Radiant		Top Conv.	
Crossovers:					
* 49 Welded or Flanged		←	Welded	→	
* 50 Pipe material (ASTM specification and grade)		←	SA-106-B	→	
51 Pipe Size and Wall Thicknes		←	6" Sch 80	→	
* 52 Location		←	Header Box	→	
53 Flange Rating			--		
Tube Supports:					
54 Ends, Top, Bottom:		←	Ends	→	
Material			CS		
Thickness			3/8"		
Type and Thickness of Insulation		2"- 8# 2300°F +	2" -6# 2300°F Ceramic Fiber Blanket		
Insulation Reinforcement		- -	310 SS Studs And Clips		
55 Intermediate:					
Material		←	None	→	
Spacing					
Type and Thickness of Coating					
56 Guides: Location					
Material					

Header Boxes

1 Location: Radiant and Convection Ends — Material: CS — Thickness: 3/16"

2 Insulation: Material: 6# 2300°F Ceramic Fiber Blanket — Thickness: 2"

Anchoring Material: 304 SS Studs and Clips

3 Are Header Box Doors Bolted or Hinged? Bolted

Burners

4 Manufacturer and Type: Universal Combustion LoNOx TPS 4-3 — Number: Two

5 Location: Each End

6 Size and Type of Pilots: Electric Ignition

7 Heat Release per Burner at Design Excess Air and Draft:

Normal 3.900 MM BTU per Hr; Maximum 4.8 MM Btu per Hr.

8 Minimum Distance Burner Centerline to Tube Centerline:

Horizontal 2.45' — Vertical 5'

FIRED HEATER DATA SHEET
CUSTOMARY UNITS

Unit	Black River Plant- 3	Plant Loc.	Loving, NM
Service	Regeneration Gas Heater	Equip.No.	H-101
Type	Horizontal	No. Req.	1
Owner	Matador Resources	Job No.	J423
Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E
Vendor	Heat Recovery Corporation	Ref. No.	19439
Date	9/27/2019		Page 1 of 5

Revision: 0
Approved: JB

Process Design Conditions

*	1	Total duty per heater, MM Btu/Hr	6.544			
*	2	Heater section	Rad+Conv			
*	3	Service	Regen. Gas			
*	4	Heat Absorption, MM Btu/Hr	6.544			
*	5	Fluid name	Natural Gas			
*	6	Flow rate, lb/hr	23,279			
	7	Flow rate, bpd				
*	8	Pressure drop (allowable, clean), psi	10			
	9	Pressure drop (calculated, clean), psi ..with 1/8" coke	6			
*	10	Average flux density (allowable), Btu/hr-ft²				
	11	Average flux density (calculated), Btu/hr-ft²	12,000			
	12	Maximum flux density, Btu/hr-ft²	17,832			
	13	Velocity Limitations				
	14	Maximum allowable inside film temperature, °F				
	15	Fouling Factor	0.001			
	16	Corrosion or Erosion Characteristics				
Inlet Conditions:						
*	17	Temperature, °F	120			
*	18	Pressure, psig	975			
*	19	Vapor flow, lb/hr	23,279			
*	20	Vapor, molecular weight	19.28			
*	21	Vapor Viscosity, Cp	0.0142			
*	22	Vapor, Specific Heat, Btu/lb-F	0.64			
*	23	Vapor Thermal Conductivity, Btu/hr-ft-F	0.024			
Outlet Conditions:						
*	23	Temperature, °F	550			
*	24	Pressure, psig	969			
*	25	Vapor flow, lb/hr	23,279			
*	26	Vapor molecular weight	19.28			
*	27	Vapor Viscosity, Cp	0.0186			
*	28	Vapor, Specific Heat, Btu/hr-F	0.71			
*	29	Vapor Thermal Conductivity, Btu/hr-ft-F	0.042			
Remarks and Special Requirements:						
*	30	Distillation Data or Composition Attached				

Combustion Design Conditions

*	1	Type of fuel	Natural Gas			
*	2	Excess air, percent	15%			
	3	Guaranteed Efficiency, Percent (LHV)	83.00			
	4	Calculated Efficiency, Percent (LHV)	84.00			
	5	Radiation loss, percent of heat release (LHV)	2.00			
	6	Flue gas temperature leaving radiant section, °F	1,683			
	7	Flue gas temperature leaving convection section, °F	620			
	8	Flue Gas Mass Velocity Thru Convection Section, lb/sq ft-s	0.30			
	9	Draft at Bridge Wall, In. H20	0.010			
	10	Draft at Burners, In. H20	0.060			
*	11	Ambient Air Temperature, °F.......... comb/draft	60/95			
*	12	Altitude, Ft. Above Sea Level	3200			
	13	Calculated Heat Release, MM BTU per Hr (LHV)	7.79			
	14	Volumetric Heat Release, Btu/hr-ft³ (LHV)				

Note: A fuel savings of __________________ MM Btu/hr will offset a $1,000 increase in furnace cost (erected)
Note: At 3200 ASL & 620 degF Stack exit temperature, density is approxiatly 0.03123 PCF. ACFM ~4037

FIRED HEATER DATA SHEET	Service	Black River Plant- 3	Plant Loc.	Loving, NM	
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip No.	H-101	
	Type	Horizontal	No. Req.	1	
	Owner	Matador Resources	Job No.	J423	
	Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	19439	
Approved: JB	Date	9/27/2019		Page 2	of 5

Fuel Characteristics

			Composition	Volume %	
*	1 Type of fuel	Natural Gas			
*	2 Heating value (HHV)				
*	3 Heating value (LHV)	901 btu/scf			
*	4 Specific gravity				
*	5 H/C ratio (by weight)				
*	6 Temperature at Burner, °F				
*	7 Viscosity, @ °F,				
*	8 Viscosity, @ °F,				
*	9 Fuel Pressure Available @ burner, psig				
*	10 Atomizing Steam Pressure, psig				
*	11 Vanadium Content, ppm for Liquid Fuels				
*	12 Sodium Content, ppm for Liquid Fuels				
*	13 Sulfur Content, Percent by Weight				
*	14 Gases: Molecular weight				
*	Composition, Mole Percent				

Mechanical Design Conditions

General

*	1 Plot limitations		* Stack Limitations	
*	2 Tube limitations		Other Limitations	
*	3 Required Drawings			
*	4 Structural Design Data: Wind Load		Seismic Factor	
*	5 List of Applicable Standards or Specifications:	1	3	
		2	4	

Coil Design:

*	6 Heater Section	Radiant	Shield	Conv.	
*	7 Design Pressure, psig	1100	1100	1100	
*	8 Design Fluid Temperature, °F	600	600	600	
*	9 Corrosion Allowance: Tubes	0.063	0.063	0.063	
	Fittings	0.063	0.063	0.063	
	10 Hydrostatic Test Pressure, psig	2,200	2,200	2,200	
	11 Number of Passes	1	1	1	
	12 Overall Tube Length, Ft	14.230	14.230	14.230	
	13 Effective Tube length, ft	13.000	13.000	13.000	
	14 Bare Tubes, number	10 / 6	4		
	15 Bare tubes, total exposed surface, ft²	317	61		
	16 Extended surface tubes, number	- -	--	6	
	17 Extended surface tubes, total expsoed surface, ft²	--	--	735	
	18 Tube spacing, center-to-center (staggered), in	12	8	8	
	19 Tube Center to furnace wall In. Min	9	4	4	
*	20 Stress Relieve	←	No	→	
*	21 Weld Inspection Requirements, X-Ray or Other	100% of buttwelds will be 10% X-rayed			

Tubes:

*	22 Vertical or Horizontal	Horizontal	Horizontal	Horizontal	
	23 Tube Material (ASTM Specifications & Grade)	←	SA 106 Gr B	→	
	24 Outside Diameter, in	6.625 / 4.5	4.5	4.5	
	25 Wall Thickness (minimum) (average), in	←	Sch 80	→	
	26 Maximum Tube Wall Temp., °F (Calculated)	745			
	27 Inside Film Coefficient (Calculated)	117			
	28 Maximum Tube Wall Temperature, °F (Design)	←	770	→	
	27 Design Basis for Tube Wall Thickness	←	ASME SECT VIII Div I	→	

FIRED HEATER DATA SHEET	Service	Black River Plant- 3	Plant Loc.	Loving, NM	
CUSTOMARY UNITS	Unit	Regeneration Gas Heater	Equip.No.	H-101	
	Type	Horizontal	No. Req.	1	
	Owner	Matador Resources	Job No.	J423	
	Purchaser	Veritas Gas Processing	Model No.	6HE-10-4H-6-4HE-4-6-E	
Revision: 0	Vendor	Heat Recovery Corporation	Ref. No.	19439	
Approved: JB	Date	9/27/2019		Page 3	of 5

Mechanical Design Conditions (continued)

		Radiant	Shield	Conv.	
Description of Extended Surface:					
	28 Type	None	None	Serrated	
	29 Fin Material			C.S.	
	30 Fin Dimensions ht/thck			3/4" x 0.05	
	31 Fin Spacing #/in			4	
	32 Maximum Fin Temperature °F			766	
	33 Extension ratio				
Plug-Type Headers:					
	34 Manufacturer and Type	←	None	→	
*	35 Material (ASTM specification and grade)				
	36 Nominal Rating				
*	37 Location				
	38 Welded or Rolled				
Return Bends:					
	39 Manufacturer and Type	SR / LR	SR 180° WPB	→	
*	40 Material (ASTM specification and grade)	←	WPB	→	
	41 Nominal Rating or Schedule	←	Same as Tubes	→	
*	42 Location	←	Header Box	→	
Terminals: NOTE:					
	43 Manufacturer and Type	←	Flanged	→	
*	44 Material (ASTM specification and grade)	←	Same as Tubes	→	
	45 Nominal Rating	←	Same as Tubes	→	
*	46 Location	heater outlets		heater inlets	
*	47 Welded or Rolled	welded		welded	
	48 Flange: Size and Rating	6"-600# RFWN		4"-600# RFWN	
	Location	Radiant		Top Conv.	
Crossovers:					
*	49 Welded or Flanged	←	Welded	→	
*	50 Pipe material (ASTM specification and grade)	←	SA-106-B	→	
	51 Pipe Size and Wall Thicknes	←	6" Sch 80	→	
*	52 Location	←	Header Box	→	
	53 Flange Rating		--		
Tube Supports:					
	54 Ends, Top, Bottom:	←	Ends	→	
	Material		CS		
	Thickness		3/8 "		
	Type and Thickness of Insulation	2"- 8# 2300°F +	2" -6# 2300°F Ceramic Fiber Blanket		
	Insulation Reinforcement	- -	310 SS Studs And Clips		
	55 Intermediate:				
	Material	←	None	→	
	Spacing				
	Type and Thickness of Coating				
	56 Guides: Location				
	Material				

Header Boxes

1 Location Radiant and Convection Ends Material CS Thickness 3/16"

2 Insulation: Material 6# 2300°F Ceramic Fiber Blanket Thickness 2"

Anchoring Material 304 SS Studs and Clips

3 Are Header Box Doors Bolted or Hinged? Bolted

Burners

4 Manufacturer and Type Universal Combustion LoNOx TPS 4-3 Number Two

5 Location Each End

6 Size and Type of Pilots Electric Ignition

7 Heat Release per Burner at Design Excess Air and Draft:

Normal 3.900 MM BTU per Hr; Maximum 4.8 MM Btu per Hr.

8 Minimum Distance Burner Centerline to Tube Centerline:

Horizontal 2.45' Vertical 5'

Owner:	San Mateo Midstream	Owner Ref.:	H-801
Purchaser:	Veritas	Purchaser Ref.:	J-423
Manufacturer:	Tulsa Heaters Midstream, LLC	THM Ref.:	MJ19-409 /
Service:	Hot Oil Heater	Project:	290 GPM Amine Treating Unit
Quantity:	1	Location:	Loving, Eddy County, NM
SHO Duty:	18.61 MMBTU/ hr	SHO Model:	SHO1750
CMS Release:	23.92 MMBTU/ hr	CMS Model:	CMS2500

Ftnt & Rev

PROCESS DESIGN CONDITIONS

Heater Section	- - -	Radiant / Convection	Radiant / Convection	Radiant / Convection	Radiant / Convection
Operating Case	- - -	Design Case			
Service	- - -	Hot Oil Heater			
Heat Absorption (R/C)	MMBTU/ hr	12.36 / 6.25			
Process Fluid	- - -	Chemtherm 550			
Process Mass Flow Rate, Total	Lb/ hr	321,260			
Process Bulk Velocity (calc. R/C)	ft/ s	7 / 10			
Process Mass Velocity (calc. R/C)	Lb/ s ft2	321 / 505			
Coking Allowance (dP calcs)	in				
Pressure Drop, Clean (allow. / calc.)	psi	15 / 17			
Pressure Drop, Fouled (allow. / calc.)	psi				
Average Heat Flux (allowable)	BTU/ hr ft2	13,000			
Average Heat Flux (calculated)	BTU/ hr ft2	12,730			
Maximum Heat Flux (allowable)	BTU/ hr ft2				
Maximum Heat Flux (calc. R/C)	BTU/ hr ft2	22,600 / 28,620			
Fouling Factor, Internal	hr ft2 °F/ BTU	0.002			
Corrosion or Erosion Characteristics	- - -				
Max. Film Temperature (allow. / calc.)	°F	635 / 516			
Inlet Conditions:					
Temperature	°F	275			
Pressure	psig	55			
Mass Flow Rate, Liquid	Lb/ hr	321,260			
Mass Flow Rate, Vapor	Lb/ hr	0			
Weight Percent, Liquid / Vapor	wt%	100% / 0%			
Density, Liquid / Vapor	Lb/ ft3	51.46 / 0.00			
Molecular Weight, Liquid / Vapor	Lb/ Lbmole	- - - / 0.0			
Viscosity, Liquid / Vapor	cp	2.1651 / 0.000			
Specific Heat, Liquid / Vapor	BTU/ Lb °F	0.5556 / 0.000			
Thermal Conductivity, Liq./Vap.	BTU/hr ft °F	0.0675 / 0.000			
Outlet Conditions:					
Temperature	°F	375			
Pressure	psig	38			
Mass Flow Rate, Liquid	Lb/ hr	321,260			
Mass Flow Rate, Vapor	Lb/ hr	0			
Weight Percent, Liquid / Vapor	wt%	100% / 0%			
Density, Liquid / Vapor	Lb/ ft3	49.24 / 0.00			
Molecular Weight, Liquid / Vapor	Lb/ Lbmole	- - - / 0.0			
Viscosity, Liquid / Vapor	cp	0.977 / 0.000			
Specific Heat, Liquid / Vapor	BTU/ Lb °F	0.603 / 0.000			
Thermal Conductivity, Liq./Vap.	BTU/hr ft °F	0.066 / 0.000			

revision	date	description	by	chk'd	appv'd
0	1-Aug-19	Flow and duty changed	JF		
A		Issued with Proposal			

USA Applications

SHO = Superior Quality, Flexibility, Dependability & Modularity

FIRED HEATER DATA SHEET

AMERICAN ENGINEERING SYSTEM of UNITS

MJ19-409-HTRds- 0

HRC - HEAT RECOVERY CORP.

FIRED HEATER DATA SHEET		Unit	Black River 3 Gas Plant	Plant Loc.	Loving, NM
CUSTOMARY UNITS		Service	Hot Oil Heater	Equip.No.	H-851
		Type	Horizontal	No. Req.	1
		Owner	Matador Resources	Job No.	19438 / J-423
Date:	10/27/2019	Purchaser	Veritas Gas Processing	Model No.	4HE-14-4HE-4-6-E
Revision:	0	Vendor	Heat Recovery Corp.	Proposal No.	HRC 19-03
Approved:	JB	Date	10/27/2019		Page 1 of 5

Process Design Conditions

*	1	Total duty per heater, MM Btu/Hr	4.600			
*	2	Heater section	Rad+Conv			
*	3	Service	Hot Oil Heater			
*	4	Heat Absorption, MM Btu/Hr	4.6			
*	5	Fluid name	Chemitherm 550			
*	6	Flow rate, lb/hr	74,938			
	7	Flow rate, bpd				
*	8	Pressure drop (allowable, clean), psi	10			
	9	Pressure drop (calculated, clean), psi ..with 1/8" coke	3			
*	10	Average flux density (allowable), Btu/hr-ft²				
	11	Average flux density (calculated), Btu/hr-ft²	11,366			
	12	Maximum flux density, Btu/hr-ft²	19,021			
	13	Velocity Limitations				
	14	Maximum allowable inside film temperature, °F	600 (564 Calc)			
	15	Fouling Factor	0.0015			
	16	Corrosion or Erosion Characteristics				
Inlet Conditions:						
*	17	Temperature, °F	350			
*	18	Pressure, psig	40			
*	19	Liquid flow, lb/hr	74,938			
*	20	Thermal Conductivity Btu / hr ft oF	0.069			
*	21	Specific Gravity	0.908			
*	22	Specific Heat Btu / lbm oF	0.59			
*	23	Liquid Viscosity, Cp	1.27			
Outlet Conditions:						
*	23	Temperature, °F	450			
*	24	Pressure, psig	37			
*	25	Liquid flow, lb/hr	74,938			
*	26	Thermal Conductivity Btu / hr ft oF	0.067			
*	27	Specific Gravity	0.908			
*	28	Specific Heat Btu / lbm oF	0.64			
*	29	Liquid Viscosity, Cp	0.727			
Remarks and Special Requirements:						
*	30	Distillation Data or Composition Attached				

Combustion Design Conditions

*	1	Type of fuel	Natural Gas			
*	2	Excess air, percent	15			
	3	Guaranteed Efficiency, Percent (LHV)	83.38			
	4	Calculated Efficiency, Percent (LHV)	84.38			
	5	Radiation loss, percent of heat release (LHV)	1.50			
	6	Flue gas temperature leaving radiant section, °F	1,790			
	7	Flue gas temperature leaving convection section, °F	606			
	8	Flue Gas Mass Velocity Thru Convection Section, lb/sq ft-s	0.23			
	9	Draft at Bridge Wall, In. H20	-0.010			
	10	Draft at Burners, In. H20	-0.050			
*	11	Ambient Air Temperature, °F....... comb/draft	60/95			
*	12	Altitude, Ft. Above Sea Level	3,000			
	13	Calculated Heat Release, MM BTU per Hr (LHV)	5.46			
	14	Volumetric Heat Release, Btu/hr-ft³ (LHV)				

Note: A fuel savings of _________________ MM Btu/hr will offset a $1,000 increase in furnace cost (erected)

Zeeco S.O. No. **35563**

Customer **Veritas Gas Processing, LP**

Customer PO No. **4122000238**

This manual covers the component description, installation, operation and maintenance of the below description.

- (1) 7' Dia. x 40' OAH Self-Supported Enclosed Flare Stack w/ Damper
- (1) Utility Flare Tip w/ flame tabs
- (2) EGF-Z-HEI Electric Ignition Pilot w/ Flame Scanner
- (1) Nema 4, Skid Mounted Pilot Ignition and Monitoring Panel
- (1) Shutdown Monitoring Logic and Controls
  a. Stack Mounted Thermocouple for Monitoring and High Temperature Shutdown
  b. Pilot Gas Solenoid
  c. 6" Butterfly Valve for Flare Shutdown

PLANT #1 TO FOR AMINE

Utility Requirements

Client:	Vertias Gas Pro	Zeeco Ref.:	35563	Date:	12-Jun-18
Location:	0.00	Client Ref.:	Flare	Rev.	AS SOLD

Pilot Gas

# Pilots:	2
Total Fuel Gas:	130 Scfh @ 15 psig or 58 Scfh Propane @ 7 psig

Electricity

Control Panel:	120V / 60 Hz / 1 Phase

Recommended Flare Purge Rate

Flare Tip Size:	14
Seal Type:	Velocity Seal
Purge Rate:	145 Scfh of a gas that will not go to dew point at operating temperatures

Assist Media

None	Flow: TBD (Field adjusted based on smoke production)

From:	Gauri Gajewar
To:	Kuhn, Julia, NMENV
Subject:	FW: [EXTERNAL] FW: Plant 3 Data Request
Date:	Wednesday, August 19, 2020 9:41:00 AM
Attachments:	image001.png

Good Morning Julia,

Please see below for the thermal oxidizer specs. Please let me know if you have any questions.

Gauri Gajewar, P.E.
Senior Consultant, Air Quality

Contek Solutions LLC, an ERM Group Company
*****Until further notice, ERM employees are working from home.*****
~~6221 Chapel Hill Blvd, Suite 300 | Plano, TX | 75093~~
D +1 469 294 5945 | M +1 214 315 5749
E Gauri.Gajewar@erm.com | **W** www.contekllc.com

ERM *The business of sustainability*

From: Sydney Levine <Sydney_Levine@zeeco.com>
Sent: Friday, March 13, 2020 10:42 AM
To: Duane Nash <dnash@veritasgas.com>
Cc: Darrell Petty <dpetty@veritasgas.com>; Sean O'Grady <sogrady@sanmateomidstream.com>; Shaun Napier <Shaun_Napier@zeeco.com>
Subject: RE: [EXTERNAL] FW: Plant 3 Data Request

EXTERNAL EMAIL
Hi Duane,

Please see the requested information below and let us know if you have additional questions.

- Maximum Acid Gas Flowrate (composition is detailed in the attached email) : 267.8 lbmol/hr
- Maximum Vent Flowrate (composition is detailed in the attached pdf): 7.3 lbmol/hr
- The flue gas information is shown below for the three cases when operating at 1500°F:

Components	**Acid and Glycol Gas Case Mol %**	**Acid Gas Only Case Mol %**	**Glycol Gas Only Case Mol %**
Carbon Dioxide	39.78	39.11	4.16
Water	15.41	15.98	14.86
Nitrogen	41.80	41.91	69.72
Oxygen	3.0	3.00	11.26
Sulfur Dioxide	0.01	0.01	0.00
Total, lbmol/hr	698.76	705.40	447.13
Mol. Wt.	32.96	32.80	27.64

- Emissions:

Stack Parameter	**Values for Acid Gas and Glycol Gas Case**	**Values for Acid Gas Only Case**	**Values for Glycol Gas Only Case**
VOC Destruction Efficiency	**>99%**	**>99%**	**>99%**
CO, ppmvd@3%O2 (lb/MMBtu)	**85 (0.14)**	**85 (0.14)**	**85 (0.08)**
NOx, ppmvd@3%O2 (lb/MMBtu)	**50 (0.13)**	**50 (0.13)**	**85 (0.13)**

  - These values are understood to apply only when the system is operated in accordance with the operating conditions stipulated in the design summary and for the waste(s) stipulated in the design basis of Zeeco's proposal & change order.
  - VOC is defined as non-methane and non-ethane hydrocarbons.
  - Emissions factors given in lb/MMBtu are based on LHV heat release of the total heat release in the system, including heat release from waste and fuel gasses. The total maximum heat release (combined fuel and

waste) for the three cases are shown below:

- Acid Gas and Glycol Gas: 9.8 MMBtu/hr
- Acid Gas Only: 9.9 MMBtu/hr
- Glycol Gas Only: 5.6 MMBtu/hr

Best Regards,

Sydney Levine
Midstream and End User Business Manager

Zeeco World Headquarters | Main: +1 918 258 8551 | Direct: +1 918 893 8416

Table 13.5-1 (English Units). THC, NOx AND SOOT EMISSIONS FACTORS FOR FLARE OPERATIONS FOR CERTAIN CHEMICAL MANUFACTURING PROCESSES[a]

Pollutant	SCC[e]	Emissions Factor Value	Emissions Factor Units	Grade or Representativeness
THC, elevated flares[c]	30190099; 30119701; 30119705; 30119709; 30119741	0.14[b,f]	lb/10^6 Btu	B
THC, enclosed ground flares[g,h] Low Percent Load[i]		8.37[j] or 3.88e-3[f]	lb/10^6 scf gas burned lb/10^6 Btu heat input	Moderately
THC, enclosed ground flares[g,h] Normal to High Percent Load[i]		2.56[j] or 1.20e-3[f]	lb/10^6 scf gas burned lb/10^6 Btu heat input	Moderately
Nitrogen oxides, elevated flares[d]		0.068[b,k]	lb/10^6 Btu	B
Soot, elevated flares[d]		0 – 274[b]	μg/L	B

[a] All of the emissions factors in this table represent the emissions exiting the flare. Since the flare is not the originating source of the THC emissions, but rather the device controlling these pollutants routed from a process at the facility, the emissions factors are representative of controlled emissions rates for THC. These values are not representative of the uncontrolled THC routed to the flare from the associated process, and as such, they may not be appropriate for estimating the uncontrolled THC emissions or potential to emit from the associated process.

[b] Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.

[c] Measured as methane equivalent. The THC emissions factor may not be appropriate for reporting volatile organic compounds (VOC) emissions when a VOC emissions factor exists.

[d] Soot in concentration values: nonsmoking flares, 0 micrograms per liter (μg/L); lightly smoking flares, 40 μg/L; average smoking flares, 177 μg/L; and heavily smoking flares, 274 μg/L.

[e] See Table 13.5-4 for a description of these SCCs.

[f] Factor developed using the lower (net) heating value of the vent gas.

[g] THC measured as propane by US EPA Method 25A.

[h] These factors apply to well operated ground flares achieving at least 98% destruction efficiency and operating in compliance with the current General Provisions requirements of 40 CFR Part 60, i.e. >200 btu/scf net heating value in the vent gas and less than the specified maximum exit velocity. The emissions factor data set had an average destruction efficiency of 99.99%. Based on tests using pure propylene fuel. References 12 through 33 and 39 through 45.

[i] The dataset for these tests were broken into four different test conditions: ramping back and forth between 0 and 30% of load; ramping back and forth between 30% and 70% of load; ramping back and forth between 70% and 100% of load; and a fixed rate maximum load condition. Analyses determined that only the first condition was statistically different. Low percent load is represented by a unit operating at approximately less than 30% of maximum load.

[j] Heat input is an appropriate basis for combustion emissions factor. However, based on available data, heat input data is not always known, but gas flowrate is generally available. Therefore, the emissions factor is presented in two different forms.

[k] Factor developed using the higher (gross) heating value of the vent gas.

CLIENT:	Veritas Gas Processing	ZEECO DOC NO:	42050-7050
JOBSITE:	Loving, NM	CLIENT DOC NO:	
CLIENT PO:	4232000188	TOTAL PAGES:	2

UTILITY CONSUMPTION

FILE COPY
at 9:44:41 AM, 01/20/2020
VERITAS
GAS PROCESSING

REV	DATE	BY	APP	DESCRIPTION
0	15NOV19	CMM	GAC	ISSUED FOR APPROVAL

Predicted Utility Requirements (Process)

Client:	Veritas Gas Processing	Zeeco Ref.:	42050	Date:	7-Nov-19
Location:	Loving, NM	Client Ref.:	4232000188	Rev.	0
		Doc. No.	42050-7050		

Equipment	Normal Operations Utility Requirements
AFDS-14/42 J-423, D-701	**Pilot Gas Consumption (Fuel Gas):** 76 SCFH @ 15 PSIG per pilot (2.04 Nm^3/hr @ 1.05 kg/cm^2g) /B\\ ***(2 pilots total = 152 SCFH @ 15 PSIG / 4.07 Nm^3/hr @ 1.05 kg/cm^2g)*** ***Continuous Purge Gas Requirement:*** ***300*** SCFH (8.037 Nm^3/hr) Fuel Gas
GENERAL	**Power Consumption:** Control Rack Assembly: 425.2 Watts (Maximum & Continuous)

NOTES:

(1) Fuel gas requirements are based upon a fuel gas with a LHV of 913 BTU/SCF (8591.3 $kcal/Nm^3$) and a specific gravity of 0.57.
(2) Pressure requirement is defined at the inlet to Zeeco supplied piping.
(3) Control Rack Tag #: J-423

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 scf] = (3.67) (CON) (C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6\ m^3$, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6\ scf] = (3.67)\ (CON)\ (C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4\ lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
207-08-9	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D
74-98-6	Propane	1.6E+00	E

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES
(Concluded)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Chlorobenzene[l]	<1.29 E-05	E
Chloroform[l]	<1.37 E-05	E
Ethane[n]	7.04 E-02	C
Ethylbenzene[l]	<2.48 E-05	E
Ethylene Dibromide[l]	<2.13 E-05	E
Formaldehyde[l,m]	2.05 E-02	A
Methanol[l]	3.06 E-03	D
Methylene Chloride[l]	4.12 E-05	C
Naphthalene[l]	<9.71 E-05	E
PAH[l]	1.41 E-04	D
Styrene[l]	<1.19 E-05	E
Toluene[l]	5.58 E-04	A
Vinyl Chloride[l]	<7.18 E-06	E
Xylene[l]	1.95 E-04	A

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM-10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM10 = Particulate Matter $\leq$ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})(\text{heat input, MMBtu/hr})(\text{1/operating HP, 1/hp})$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2,

C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and h = heating value of natural gas (assume 1020 Btu/scf at 60°F).

[e] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6scf.

[f] Emission factor for TOC is based on measured emission levels from 6 source tests.

[g] Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor.

[h] VOC emission factor is based on the sum of the emission factors for all speciated organic compounds. Methane and ethane emissions were not measured for this engine category.

[i] No data were available for uncontrolled engines. PM10 emissions are for engines equipped with a PCC.

[j] Considered $\leq$ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

[k] No data were available for condensable emissions. The presented emission factor reflects emissions from 4SLB engines.

[l] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

[m] For rich-burn engines, no interference is suspected in quantifying aldehyde emissions. The presented emission factors are based on FTIR and CARB 430 emissions data measurements.

[n] Ethane emission factor is determined by subtracting the VOC emission factor from the NMHC emission factor.

loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ±30 percent)[4] using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \tag{1}$$

where:

L_L = loading loss, pounds per 1000 gallons (lb/10^3 gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Section 7.1, "Organic Liquid Storage Tanks")
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Section 7.1, "Organic Liquid Storage Tanks")
T = temperature of bulk liquid loaded, °R (°F + 460)

The following empirical expressions may be used to estimate the quantity in pounds (lb) of size-specific particulate emissions from an unpaved road, per vehicle mile traveled (VMT):

For vehicles traveling on unpaved surfaces at industrial sites, emissions are estimated from the following equation:

$$E = k\ (s/12)^a (W/3)^b \tag{1a}$$

and, for vehicles traveling on publicly accessible roads, dominated by light duty vehicles, emissions may be estimated from the following:

$$E = \frac{k\ (s/12)^a (S/30)^d}{(M/0.5)^c} - C \tag{1b}$$

where k, a, b, c and d are empirical constants (Reference 6) given below and

E = size-specific emission factor (lb/VMT)
s = surface material silt content (%)
W = mean vehicle weight (tons)
M = surface material moisture content (%)
S = mean vehicle speed (mph)
C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.

The source characteristics s, W and M are referred to as correction parameters for adjusting the emission estimates to local conditions. The metric conversion from lb/VMT to grams (g) per vehicle kilometer traveled (VKT) is as follows:

1 lb/VMT = 281.9 g/VKT

The constants for Equations 1a and 1b based on the stated aerodynamic particle sizes are shown in Tables 13.2.2-2 and 13.2.2-4. The PM-2.5 particle size multipliers (k-factors) are taken from Reference 27.

Table 13.2.2-2. CONSTANTS FOR EQUATIONS 1a AND 1b

Constant	Industrial Roads (Equation 1a)			Public Roads (Equation 1b)		
	PM-2.5	PM-10	PM-30*	PM-2.5	PM-10	PM-30*
k (lb/VMT)	0.15	1.5	4.9	0.18	1.8	6.0
a	0.9	0.9	0.7	1	1	1
b	0.45	0.45	0.45	-	-	-
c	-	-	-	0.2	0.2	0.3
d	-	-	-	0.5	0.5	0.3
Quality Rating	B	B	B	B	B	B

*Assumed equivalent to total suspended particulate matter (TSP)
"-" = not used in the emission factor equation

Table 13.2.2-2 also contains the quality ratings for the various size-specific versions of Equation 1a and 1b. The equation retains the assigned quality rating, if applied within the ranges of source conditions, shown in Table 13.2.2-3, that were tested in developing the equation:

Table 13.2.2-3. RANGE OF SOURCE CONDITIONS USED IN DEVELOPING EQUATION 1a AND 1b

Emission Factor	Surface Silt Content, %	Mean Vehicle Weight		Mean Vehicle Speed		Mean No. of Wheels	Surface Moisture Content, %
		Mg	ton	km/hr	mph		
Industrial Roads (Equation 1a)	1.8-25.2	1.8-260	2-290	8-69	5-43	4-17[a]	0.03-13
Public Roads (Equation 1b)	1.8-35	1.4-2.7	1.5-3	16-88	10-55	4-4.8	0.03-13

[a] See discussion in text.

As noted earlier, the models presented as Equations 1a and 1b were developed from tests of traffic on unpaved surfaces. Unpaved roads have a hard, generally nonporous surface that usually dries quickly after a rainfall or watering, because of traffic-enhanced natural evaporation. (Factors influencing how fast a road dries are discussed in Section 13.2.2.3, below.) The quality ratings given above pertain to the mid-range of the measured source conditions for the equation. A higher mean vehicle weight and a higher than normal traffic rate may be justified when performing a worst-case analysis of emissions from unpaved roads.

The emission factors for the exhaust, brake wear and tire wear of a 1980's vehicle fleet (*C*) was obtained from EPA's MOBILE6.2 model [23]. The emission factor also varies with aerodynamic size range average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual average emissions are inversely proportional to the number of days with measurable (more than 0.254 mm [0.01 inch]) precipitation:

$$E_{ext} = E\ [(365 - P)/365] \tag{2}$$

where:

E_{ext} = annual size-specific emission factor extrapolated for natural mitigation, lb/VMT

E = emission factor from Equation 1a or 1b

P = number of days in a year with at least 0.254 mm (0.01 in) of precipitation (see below)

Figure 13.2.2-1 gives the geographical distribution for the mean annual number of "wet" days for the United States.

Equation 2 provides an estimate that accounts for precipitation on an annual average basis for the purpose of inventorying emissions. It should be noted that Equation 2 does not account for differences in the temporal distributions of the rain events, the quantity of rain during any event, or the potential for the rain to evaporate from the road surface. In the event that a finer temporal and spatial resolution is desired for inventories of public unpaved roads, estimates can be based on a more complex set of assumptions. These assumptions include:

1. The moisture content of the road surface material is increased in proportion to the quantity of water added;
2. The moisture content of the road surface material is reduced in proportion to the Class A pan evaporation rate;
3. The moisture content of the road surface material is reduced in proportion to the traffic volume; and
4. The moisture content of the road surface material varies between the extremes observed in the area. The CHIEF Web site (http://www.epa.gov/ttn/chief/ap42/ch13/related/c13s02-2.html) has a file which contains a spreadsheet program for calculating emission factors which are temporally and spatially resolved. Information required for use of the spreadsheet program includes monthly Class A pan evaporation values, hourly meteorological data for precipitation, humidity and snow cover, vehicle traffic information, and road surface material information.

It is emphasized that <u>the simple assumption underlying Equation 2 and the more complex set of assumptions underlying the use of the procedure which produces a finer temporal and spatial resolution</u> have not been verified in any rigorous manner. For this reason, the quality ratings for either approach should be downgraded one letter from the rating that would be applied to Equation 1.

13.2.2.3 Controls[18-22]

A wide variety of options exist to control emissions from unpaved roads. Options fall into the following three groupings:

1. <u>Vehicle restrictions</u> that limit the speed, weight or number of vehicles on the road;

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of August 23, 2017

Title 40 → Chapter I → Subchapter C → Part 98 → Subpart C → Appendix

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

TABLE C-1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Link to an amendment published at 81 FR 89252, Dec. 9, 2016.

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO_2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	61.71
Propane[1]	0.091	62.87
Propylene[2]	0.091	67.77
Ethane[1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene[2]	0.058	65.96
Isobutane[1]	0.099	64.94
Isobutylene[1]	0.103	68.86
Butane[1]	0.103	64.77
Butylene[1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste	9.95[3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00

Petroleum Coke	30.00	102.41
Other fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas[4]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Wood and Wood Residuals (dry basis)[5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2]Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3]Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4]Reporters subject to subpart X of this part that are complying with §98.243(d) or subpart Y of this part may only use the default HHV and the default CO_2 emission factor for fuel gas combustion under the conditions prescribed in §98.243(d)(2)(i) and (d)(2)(ii) and §98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.

[5]Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C-1.

[78 FR 71950, Nov. 29, 2013]

Need assistance?

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of August 23, 2017

Title 40 → Chapter I → Subchapter C → Part 98 → Subpart C → Appendix

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

Table C-2 to Subpart C of Part 98—Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Link to an amendment published at 81 FR 89252, Dec. 9, 2016.

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1, except wood and wood residuals)	3.2×10^{-02}	4.2×10^{-03}
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels—Gaseous (All fuel types in Table C-1)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1g of CH_4/mmBtu.

[78 FR 71952, Nov. 29, 2013]

For flares subject to Chapter 115, Subchapter H, relating to highly reactive volatile organic compounds, valid flow rate and composition data required by 30 TAC 115.725–115.726 must be used to determine emissions for any portions of the current reporting year during which HRVOC monitors were installed and operational.

In the absence of monitoring data, selection of the most accurate method may sometimes require exercising scientific judgment. For example, when using the results of a one-time performance test, the test conditions must be compared to the flare's actual operating conditions during the inventory year to determine whether the test accurately represents the flare's performance. If test conditions do not accurately model flare operation, then engineering determinations based on detailed process evaluation may provide the best data.

NO_x and CO Emissions

To calculate NO_x and CO emissions, the net heating value of the flared gas must be known. Using the actual short-term flared gas composition and flow rate data for the inventory year, calculate the net heating value of the flared gas and the total heat release for each short time period. Use these total heat release data, in conjunction with the appropriate emission factors listed below, to determine NO_x and CO emissions for each time segment. Since the calculated net heating value of the gas and the assist gas type will determine the appropriate emission factors, carefully select the correct factors for each flare from Table A-7.

Calculate emissions using the most accurate data for the gas flow rate and composition available. (See "Flared Gas Flow Rate and Composition" earlier in this supplement for more information on preferred data.)

Regardless of the source of the data on gas flow and composition, the determination methodology for NO_x and CO emissions must be coded "A" for 'TCEQ-approved factor' when using the factors below.

Please note: at the time of publication, the EPA was proposing to update several of the emissions factors for flares in AP-42, Chapter 13.5. Once it has finalized the updates, the TCEQ will comment on the appropriateness of any revised factors for the EI. However, the current proposed EPA factors should not be used for determining flare emissions at this time and will not be accepted for the EI.

For flares subject to the HRVOC regulations in Chapter 115, Subchapter H, use the net heating value data required by 30 TAC 115.725 and 115.726 to determine NO_x and CO emissions for any portions of the current reporting year during which HRVOC monitors were installed and operational.

Table A-7. Flare Emission Factors

Contaminant	Assist Type	Waste Gas Stream Net Heating Value[a,b]	Emission Factor
NO_x	Steam	High Btu	0.0485 lb/MMBtu
		Low Btu	0.068 lb/MMBtu
	Air or Unassisted	High Btu	0.138 lb/MMBtu
		Low Btu	0.0641 lb/MMBtu
CO	Steam	High Btu	0.3503 lb/MMBtu
		Low Btu	0.3465 lb/MMBtu
	Air or Unassisted	High Btu	0.2755 lb/MMBtu
		Low Btu	0.5496 lb/MMBtu

[a] High Btu: > 1000 Btu/scf

[b] Low Btu: 192–1000 Btu/scf

Uncombusted Flared Gas Emissions

Uncombusted flared gas emissions usually include VOCs, H_2S, or both. Emissions calculations for these contaminants are based on the flared gas flow rate and composition, and the appropriate destruction efficiency, which depends upon the actual flare operation.

Destruction Efficiencies

Flare destruction efficiency varies with assist gas flow rate, flame stability, operating conditions, flare tip size and design, the specific compounds being combusted, and gas composition. HRVOC regulations in 30 TAC 115 address flare operational requirements. If flare operations are consistent with Chapter 115, the destruction efficiencies specified in 30 TAC 115.725 may be used to determine VOC emissions.

Otherwise, if the flare met all applicable regulations, the appropriate destruction efficiencies from either an applicable permit or the destruction efficiencies in Table A-8—the maximum destruction efficiencies for EI purposes—may be used to determine flare emissions. For assisted flares, there is the potential for over-assisting the waste gas stream, and the destruction efficiency may be lower than either the permitted efficiency or the appropriate efficiencies contained in the Chapter 115 HRVOC regulations or Table A-8. Emissions determinations must be adjusted accordingly.

Of course, if the flare flame (not the flare pilot) is ever extinguished, the destruction efficiency for the period when the flame was out will be zero. The pilot combustion zone is separate from the flame combustion zone. Therefore, the flare flame can be extinguished while the flare pilots are still lit.

Section 8

Map(s)

A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 0.8km (0.5 miles)	Access and haul roads
Topographic features of the area	Facility property boundaries
The name of the map	The area which will be restricted to public access
A graphical scale	

A topographic map is attached to this application.

GENERAL NOTES:

REV.	REVISION	DATE	DRAFT	CHECKED	APP'D.
A	ISSUED FOR APPROVAL	04/01/20	KES		

PELICAN
Energy Consultants, LLC

San Mateo MIDSTREAM

TITLE
BRNGPP FACILITIES
EDDY COUNTY, NEW MEXICO
EMISSIONS LAYOUT
KEY PLAN

DRAWING APPROVAL

DRAWN BY:	KES	04/01/20	CHECKED BY:	DAH	04/01/20
DESIGN ENGINEER:	DAH	04/01/20	CLIENT APPROVAL:		

CLIENT	JOB NO.	DWG. NO.
SAN MATEO MIDSTREAM	190625	31500

PLOT TIME: April 1, 2020 4:49 PM BY: KATY SCHILD FILE PATH: R:\CLIENT_PROJECTS\MATADOR\RUSTLER_BREAKS_COMPRESSOR_STATION\170206\DRAWINGS\30000 MECHANICAL\31000\31500-190625.DWG

Section 9

Proof of Public Notice

(for NSR applications submitting under 20.2.72 or 20.2.74 NMAC)
(This proof is required by: 20.2.72.203.A.14 NMAC "Documentary Proof of applicant's public notice")

☑ **I have read the AQB "Guidelines for Public Notification for Air Quality Permit Applications"**
This document provides detailed instructions about public notice requirements for various permitting actions. It also provides public notice examples and certification forms. Material mistakes in the public notice will require a re-notice before issuance of the permit.

Unless otherwise allowed elsewhere in this document, the following items document proof of the applicant's Public Notification. Please include this page in your proof of public notice submittal with checkmarks indicating which documents are being submitted with the application.

New Permit and **Significant Permit Revision** public notices must include all items in this list.

Technical Revision public notices require only items 1, 5, 9, and 10.

Per the Guidelines for Public Notification document mentioned above, include:

1. ☐ A copy of the certified letter receipts with post marks (20.2.72.203.B NMAC)
2. ☐ A list of the places where the public notice has been posted in at least four publicly accessible and conspicuous places, including the proposed or existing facility entrance. (e.g: post office, library, grocery, etc.)
3. ☐ A copy of the property tax record (20.2.72.203.B NMAC).
4. ☐ A sample of the letters sent to the owners of record.
5. ☐ A sample of the letters sent to counties, municipalities, and Indian tribes.
6. ☐ A sample of the public notice posted and a verification of the local postings.
7. ☐ A table of the noticed citizens, counties, municipalities and tribes and to whom the notices were sent in each group.
8. ☐ A copy of the public service announcement (PSA) sent to a local radio station and documentary proof of submittal.
9. ☐ A copy of the classified or legal ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
10. ☐ A copy of the display ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
11. ☐ A map with a graphic scale showing the facility boundary and the surrounding area in which owners of record were notified by mail. This is necessary for verification that the correct facility boundary was used in determining distance for notifying landowners of record.

N/A – Public notice requirements are not applicable for applications submitted pursuant to 20.2.70 NMAC.

Section 10

Written Description of the Routine Operations of the Facility

<u>A written description of the routine operations of the facility</u>. Include a description of how each piece of equipment will be operated, how controls will be used, and the fate of both the products and waste generated. For modifications and/or revisions, explain how the changes will affect the existing process. In a separate paragraph describe the major process bottlenecks that limit production. The purpose of this description is to provide sufficient information about plant operations for the permit writer to determine appropriate emission sources.

The Black River Gas Processing Plant is an existing natural gas processing plant located in Eddy County. The primary function of the plant is to remove CO_2, water, and natural gas liquids from sweet field gas so that the gas can meet pipeline specifications. The plant has been designated a primary Standard Industrial Classification (SIC) Code of 1321.

Stabilizer
The stabilizer system is a distillation process to lower the Reid Vapor Pressure (RVP) of field condensate/ pipeline hydrocarbon liquids that are swept into the plant slug catchers from the gas pipeline. This process uses heat from a hot oil system to drive off volatile components in the condensate and reduce the RVP to less than 9. The liquid in the tank is then stable and thus does not give off significant vapors. The tank is equipped with a fuel gas blanket for further protection.

Amine Treating
The amine unit is designed to remove CO_2 and H_2S from the natural gas stream to meet pipeline specifications. In addition, carbon dioxide can freeze in the cryogenic unit, forming dry ice and forcing the shutdown of the facility. Amine treating is an exothermic chemical reaction process. This aqueous mixture is regenerated and reused. Lean MDEA solution is pumped to the top of the contactor and allowed to flow downward. Wet gas is fed into the bottom of the contactor and flows upward. As the lean MDEA solution flows down through the contactor, it comes into contact with the wet gas. The CO_2 and H_2S react with the amine to form an amine carbonate. The reacted amine, known as “sour” or “rich” amine is returned to a regeneration unit, and the processed (“sweet”) gas continues to the dehydration system. Emissions from amine units AM-1 and AM-2 are controlled by the thermal oxidizers unit TO-1 and TO-2 respectively. The amine reboiler is heated by a natural gas-fired hot oil heater.

Glycol Dehydration
Triethylene glycol (TEG) dehydration is used to remove water from the natural gas stream and is accomplished by reducing the inlet water dew point (temperature at which vapor begins to condense into a liquid) to the outlet dew point temperature which will contain a specified amount of water. The wet gas is brought into contact with dry “lean” glycol in a countercurrent contactor tower. Water vapor is absorbed in the TEG solution and consequently, its dew point reduces. Wet gas passing through the contactor tower is dehydrated, and then passed to the mole sieve beds. The wet (or “rich”) glycol then flows from the absorber to a regeneration system in which it is partially decompressed, and then heated to remove water vapor, resulting in “lean” glycol that is reintroduced to the contactor tower. Emissions from glycol dehydrator units, DEHY-1 and DEHY-2, are controlled by flare, FL-2a and thermal oxidizer, TO-2, respectively.

Molecular Sieve Dehydration
Molecular sieve dehydration is used upstream of the cryogenic units to achieve a gas stream dew point of -150°F. The process uses three molecular sieve vessels with one vessel in service absorbing moisture from the gas stream, one vessel in regeneration mode, and one vessel in standby. During the regeneration mode, hot, dry gas (regen gas) is passed up through the vessel to drive off the absorbed moisture from the molecular sieve. The gas comes from the discharge of the residue compressors and it is passed through a direct fired heater to achieve a temperature of approximately 500°F. After the gas passes through the bed it is cooled in an air-cooled exchanger. The water in the gas condenses and is separated from the gas stream in a separator. The regen gas is routed back to the inlet of the plant.

Cryogenic Unit
The cryogenic unit is designed to liquefy natural gas components from the sweet, dehydrated inlet gas by removing work (heat) from the gas by means of the turbo expander. The cryogenic unit recovers natural gas liquids (NGL) by cooling the gas stream to extremely cold temperatures (-150°F and lower) and condensing components such as ethane, propane, butanes

and heavier. The gas is cooled by a series of heat exchangers and by rapidly lowering the pressure of the gas from around 1000 PSIG to approximately 300 PSIG. Once the gas has passed through the system of heat exchangers and expansion, it is recompressed using the energy obtained from expanding the gas. The gas is sent to residue compressors and pipelined out of the facility.

Storage and Loading Operations

The natural gas liquids are transferred to a third-party pipeline. In the event that the pipeline is not available, bullet storage tanks are used to store NGL and load pressurized tanker trucks.
Stabilized condensate is stored in condensate tanks TK-702-A-F, and produced water tank, TK-701. Both the condensate and produce water tanks are controlled by the vapor combustion unit, VCU-1.

Flares

The plant flares are used as control equipment and during startup, shutdown, maintenance and upset conditions. Flares, FL-1, FL-2b and FL-3 operate during startup, shutdown, maintenance and upset conditions. The only steady state operations associated with these flares are from the pilot and purge gas streams and flare, FL-2a which controls the DEHY-1 condenser overhead off gases. SSM emissions from the plant flare result from maintenance activities per manufacturer-recommended or other preventative maintenance schedules. These maintenance activities include, but are not limited to compressor catalyst changes, blowdowns for associated maintenance throughout the facility, instrument calibrations, and process safety device maintenance.

Section 11

Source Determination

Source submitting under 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC

Sources applying for a construction permit, PSD permit, or operating permit shall evaluate surrounding and/or associated sources (including those sources directly connected to this source for business reasons) and complete this section. Responses to the following questions shall be consistent with the Air Quality Bureau's permitting guidance, Single Source Determination Guidance, which may be found on the Applications Page in the Permitting Section of the Air Quality Bureau website.

Typically, buildings, structures, installations, or facilities that have the same SIC code, that are under common ownership or control, and that are contiguous or adjacent constitute a single stationary source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes. Submission of your analysis of these factors in support of the responses below is optional, unless requested by NMED.

A. Identify the emission sources evaluated in this section (list and describe)**: Please refer Table 2-A**

B. Apply the 3 criteria for determining a single source:

SIC Code: Surrounding or associated sources belong to the same 2-digit industrial grouping (2-digit SIC code) as this facility, OR surrounding or associated sources that belong to different 2-digit SIC codes are support facilities for this source.

☐ **Yes** ☑ **No**

Common Ownership or Control: Surrounding or associated sources are under common ownership or control as this source.

☑ **Yes** ☐ **No**

Contiguous or Adjacent: Surrounding or associated sources are contiguous or adjacent with this source.

☑ **Yes** ☐ **No**

C. Make a determination:

☑ The source, as described in this application, constitutes the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes. If in "A" above you evaluated only the source that is the subject of this application, all "**YES**" boxes should be checked. If in "A" above you evaluated other sources as well, you must check **AT LEAST ONE** of the boxes "**NO**" to conclude that the source, as described in the application, is the entire source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes.

☐ The source, as described in this application, **does not** constitute the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes (A permit may be issued for a portion of a source). The entire source consists of the following facilities or emissions sources (list and describe):

Section 12

Section 12.A

PSD Applicability Determination for All Sources

(Submitting under 20.2.72, 20.2.74 NMAC)

<u>A PSD applicability determination for all sources</u>. For sources applying for a significant permit revision, apply the applicable requirements of 20.2.74.AG and 20.2.74.200 NMAC and to determine whether this facility is a major or minor PSD source, and whether this modification is a major or a minor PSD modification. It may be helpful to refer to the procedures for Determining the Net Emissions Change at a Source as specified by Table A-5 (Page A.45) of the <u>EPA New Source Review Workshop Manual</u> to determine if the revision is subject to PSD review.

A. This facility is:

- ☑ **a minor PSD source before and after this modification (if so, delete C and D below).**
- ☐ **a major PSD source before this modification. This modification will make this a PSD minor source.**
- ☐ **an existing PSD Major Source that has never had a major modification requiring a BACT analysis.**
- ☐ **an existing PSD Major Source that has had a major modification requiring a BACT analysis**
- ☐ **a new PSD Major Source after this modification**.

N/A – This application is being submitted pursuant to 20.2.70 NMAC.

Section 13

Determination of State & Federal Air Quality Regulations

This section lists each state and federal air quality regulation that may apply to your facility and/or equipment that are stationary sources of regulated air pollutants.

Not all state and federal air quality regulations are included in this list. Go to the Code of Federal Regulations (CFR) or to the Air Quality Bureau's regulation page to see the full set of air quality regulations.

Required Information for Specific Equipment:
For regulations that apply to specific source types, in the 'Justification' column **provide any information needed to determine if the regulation does or does not apply**. **For example**, to determine if emissions standards at 40 CFR 60, Subpart IIII apply to your three identical stationary engines, we need to know the construction date as defined in that regulation; the manufacturer date; the date of reconstruction or modification, if any; if they are or are not fire pump engines; if they are or are not emergency engines as defined in that regulation; their site ratings; and the cylinder displacement.

Required Information for Regulations that Apply to the Entire Facility:
See instructions in the 'Justification' column for the information that is needed to determine if an 'Entire Facility' type of regulation applies (e.g. 20.2.70 or 20.2.73 NMAC).

Regulatory Citations for Regulations That Do Not, but Could Apply:
If there is a state or federal air quality regulation that does not apply, but you have a piece of equipment in a source category for which a regulation has been promulgated, you must **provide the low level regulatory citation showing why your piece of equipment is not subject to or exempt from the regulation. For example** if you have a stationary internal combustion engine that is not subject to 40 CFR 63, Subpart ZZZZ because it is an existing 2 stroke lean burn stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, your citation would be 40 CFR 63.6590(b)(3)(i). **We don't want a discussion of every non-applicable regulation, but if it is possible a regulation could apply, explain why it does not. For example,** if your facility is a power plant, you do not need to include a citation to show that 40 CFR 60, Subpart OOO does not apply to your non-existent rock crusher.

Regulatory Citations for Emission Standards:
For each unit that is subject to an emission standard in a source specific regulation, such as 40 CFR 60, Subpart OOO or 40 CFR 63, Subpart HH, include the low level regulatory citation of that emission standard. Emission standards can be numerical emission limits, work practice standards, or other requirements such as maintenance. **Here are examples:** a glycol dehydrator is subject to the general standards at 63.764C(1)(i) through (iii); an engine is subject to 63.6601, Tables 2a and 2b; a crusher is subject to 60.672(b), Table 3 and all transfer points are subject to 60.672(e)(1)

Federally Enforceable Conditions:
All federal regulations are federally enforceable. All Air Quality Bureau State regulations are federally enforceable except for the following: affirmative defense portions at 20.2.7.6.B, 20.2.7.110(B)(15), 20.2.7.11 through 20.2.7.113, 20.2.7.115, and 20.2.7.116; 20.2.37; 20.2.42; 20.2.43; 20.2.62; 20.2.63; 20.2.86; 20.2.89; and 20.2.90 NMAC. Federally enforceable means that EPA can enforce the regulation as well as the Air Quality Bureau and federally enforceable regulations can count toward determining a facility's potential to emit (PTE) for the Title V, PSD, and nonattainment permit regulations.

INCLUDE ANY OTHER INFORMATION NEEDED TO COMPLETE AN APPLICABILITY DETERMINATION OR THAT IS RELEVENT TO YOUR FACILITY'S NOTICE OF INTENT OR PERMIT.

EPA Applicability Determination Index for 40 CFR 60, 61, 63, etc: http://cfpub.epa.gov/adi/

Table for State Regulations:

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
20.2.1 NMAC	General Provisions	Yes	Facility	General Provisions apply to Notice of Intent, Construction, and Title V permit applications.
20.2.3 NMAC	Ambient Air Quality Standards NMAAQS	Yes	Facility	20.2.3 NMAC is a State Implementation Plan (SIP) approved regulation that limits the maximum allowable concentration of Sulfur Compounds, Carbon Monoxide and Nitrogen Dioxide. This facility is an affected facility.
20.2.7 NMAC	Excess Emissions	Yes	Facility	The entire facility is subject to emissions limits both federal and state regulation. Thus, the facility is subject to this regulation.
20.2.23 NMAC	Fugitive Dust Control	No	N/A	This regulation does not apply as the facility has no need for fugitive dust control measures. This facility does not fall under applicability facility listed mentioned in this regulation.
20.2.33 NMAC	Gas Burning Equipment - Nitrogen Dioxide	No	N/A	This regulation applies to facilities that have gas-burning external combustion sources with more than 1,000,000 MMBtu/hr capacity. None of the external combustion equipment of this facility has a capacity greater than 1,000,000 MMBtu/hr. Therefore, this regulation does not apply to this facility.
20.2.34 NMAC	Oil Burning Equipment: NO_2	No	N/A	This regulation applies to facilities that have oil-burning external combustion sources with more than 1,000,000 MMBtu/hr capacity. This facility does not have any oil-burning external combustion equipment.
20.2.35 NMAC	Natural Gas Processing Plant – Sulfur	Yes	Facility	This regulation establishes sulfur emission standards for natural gas processing plants. The proposed facility meets the definition of a new natural gas processing plant under this regulation and is subject to the requirements of this regulation [20.2.35.7 (B) NMAC]. The facility will comply with all requirements under 20.2.35 NMAC as applicable.
20.2.37 and 20.2.36 NMAC	Petroleum Processing Facilities and Petroleum Refineries	N/A	N/A	**These regulations were repealed by the Environmental Improvement Board. If you had equipment subject to 20.2.37 NMAC before the repeal, your combustion emission sources are now subject to 20.2.61 NMAC.**
20.2.38 NMAC	Hydrocarbon Storage Facility	No	**N/A**	This regulation could apply to storage tanks at petroleum production facilities, processing facilities, tanks batteries, or hydrocarbon storage facilities. The oil storage tanks meets the applicable threshold for the capacity of each tank. But all tanks are equipped with control devices that minimizes hydrocarbons and hydrogen sulfide loss to the atmosphere. Therefore, this regulation does not apply to this facility.
20.2.39 NMAC	Sulfur Recovery Plant - Sulfur	No	**N/A**	This regulation could apply to sulfur recovery plants that are not part of petroleum or natural gas processing facilities. This facility is a natural gas processing plant. Thus, the facility is not subject to this regulation.
20.2.50 NMAC	Oil and Gas Sector – Ozone Precursor Pollutants	No	ENG-1 through ENG-4, FUG, AR-1, AR-2, TL-1, TL-2	This regulation establishes emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production, processing, compression, and transmission sources. 20.2.50 NMAC subparts below: Include the construction status of applicable units as “New”, “Existing”, “Relocation of Existing”, or “Reconstructed” as defined by this Part in your justification: Check the box for the subparts that are applicable: ☒113 – Engines and Turbines: This facility has natural gas-fired spark ignition engines (ENG-1 through ENG-4). The facility will comply with this regulation. **(ENG-1 through ENG-4) [Existing]** ☒114 – Compressor Seals: Engines and Turbines: This facility has reciprocating compressors (Units ENG-1 through ENG-4). Thus, this facility is subject to this

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
				subpart. The facility will comply with this subpart as stated in the 20.2.50.114.B(4). **(ENG-1 through ENG-4) [Existing]** ☐115 – Control Devices and Closed Vent Systems: The control devices and closed vent systems at this facility are not used to comply with the requirements of this rule; therefore, the facility is not subject to the requirements of this rule. ☒116 – Equipment Leaks and Fugitive Emissions: This facility has equipment leaks and fugitive emissions. Thus, the facility will comply with this regulation. **(FUG) [Existing]** ☐ 117 – Natural Gas Well Liquid Unloading: This facility is a natural gas processing plant and liquid unloading operations do not result in the venting of natural gas. Thus, the facility is not subject to this rule. ☒ 118 – Glycol Dehydrators: Dehydrators (Units DEHY-1 and DEHY-2) have federally enforceable control with VOC PTE less than 2 tpy. Thus, this facility is not subject to this regulation. ☒ 119 – Heaters: Each amine reboilers (AR-1 & AR-2) at this facility has a capacity greater than 20 MMBtu/hr. Thus, this facility is subject to this subpart. **(AR-1 & AR-2) [Existing]** ☒ 120 – Hydrocarbon Liquid Transfers: This facility trucks out more than 13 times a year and is therefore subject to this subpart. **(TL-1 and TL-2) [Existing]** ☐121 – Pig Launching and Receiving: This facility does not have pig launching and receiving VOC emission. Therefore, this facility is not subject to this subpart. ☐122 – Pneumatic Controllers and Pumps: This facility does not have any drive gas emissions and all pneumatic controllers are compressed air-driven. Thus, this regulation does not apply to this facility. ☒ 123 – Storage Vessels: The storage vessels of this facility have federally enforceable control with VOC PTE less than 3 tpy. Thus, the facility is not subject to this subpart. ☐124 – Well Workovers: No applicable activities for this facility. Thus, the facility is not subject to this regulation. ☐ 125 – Small Business Facilities: This facility is not defined as a small business facility. Thus, this regulation does not apply to this facility. ☐126 – Produced Water Management Unit: No applicable activities for this facility. Thus, the facility is not subject to this regulation. ☐127 – Flowback Vessels and Preproduction Operations: No applicable activities for this facility. Thus, the facility is not subject to this regulation.
20.2.61.109 NMAC	Smoke & Visible Emissions	Yes	ENG-1 through ENG-4, HT-101 through HT-103, HT-801 through HT-803,	This regulation that limits opacity to 20% applies to Stationary Combustion Equipment, such as engines, boilers, heaters, and flares unless your equipment is subject to another state regulation that limits particulate matter such as 20.2.19 NMAC (see 20.2.61.109 NMAC). The facility will comply with this regulation.

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
			AR-1, AR-2, DR-1, DR-2, TO-1, TO-2, VCU-1, FL-1, FL-2, FL-3	
20.2.70 NMAC	Operating Permits	Yes	Facility	This regulation establishes requirements for obtaining a major source operating permit. The facility is a Title V major source and submitting this initial Title V permit application within one (1) year of commencing operations per 20.2.70.300.B(1) NMAC.
20.2.71 NMAC	Operating Permit Fees	Yes	Facility	This facility is subject to 20.2.70 NMAC and will therefore comply with the fee requirements of this regulation.
20.2.72 NMAC	Construction Permits	Yes	Facility	This regulation establishes the requirement for obtaining a construction permit. This facility is currently permitted under NSR #6567-M8 and complies with all the requirements of this regulation.
20.2.73 NMAC	NOI & Emissions Inventory Requirements	Yes	Facility	This regulation establishes emission inventory requirements. The facility meets the applicability requirements of 20.2.73.300 NMAC. The facility will meet all applicable reporting requirements under 20.2.73.300.B.1 NMAC.
20.2.74 NMAC	Permits – Prevention of Significant Deterioration (PSD)	No	N/A	This regulation establishes requirements for obtaining a prevention of significant deterioration permit. This facility is not a major source with respect to PSD and is therefore not subject to 20.2.74 NMAC.
20.2.75 NMAC	Construction Permit Fees	No	Facility	This regulation establishes a schedule of operating permit emission fees. This facility is subject to 20.2.72 NMAC and in turn subject to 20.2.75 NMAC. The facility is exempt from annual fees under this part (20.2.75.11.E NMAC) as it is subject to fees pursuant to 20.2.71 NMAC.
20.2.77 NMAC	New Source Performance	Yes	ENG-1 through ENG-4, AM-1, AM-2, FUG, CRYO-1 through CRYO-3	The following equipment of this facility are subject under the subparts of 40 CFR Part 60: • 40 CFR 60, Subpart JJJJ: Compressor engines of this facility (ENG-1 through ENG-4) • 40 CFR 60, Subpart OOOOa: Fugitives (FUG), Amine Units (AM-1 & AM-2), Cryogenic units (CRYO-1 through CRYO-3), Compressors associated with ENG-1 through ENG-4, Six (6) condensate tanks (TK-702 A-F) and produced water tank (TK 701).
20.2.78 NMAC	Emission Standards for HAPS	No	Units Subject to 40 CFR 61	This regulation establishes state authority to implement emission standards for hazardous air pollutants subject to 40 CFR Part 61. This facility does not emit hazardous air pollutants which are subject to the requirements of 40 CFR Part 61 and is therefore not subject to this regulation.

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
20.2.79 NMAC	Permits – Nonattainment Areas	No	N/A	This regulation establishes the requirements for obtaining a nonattainment area permit. The facility is not located in a non-attainment area and therefore is not subject to this regulation.
20.2.80 NMAC	Stack Heights	No	N/A	This regulation establishes requirements for the evaluation of stack heights and other dispersion techniques. This regulation does not apply as all stacks at the facility follow good engineering practice.
20.2.82 NMAC	MACT Standards for source categories of HAPS	Yes	ENG-1 through ENG-4, DEHY-1, DEHY-2	The following equipment are subject to the requirements of 40 CFR 63: • 40 CFR 63, Subpart HH: Dehydrator units (DEHY-1 & DEHY-2) • 40 CFR 63, Subpart ZZZZ: ENG-1 through ENG-4

Table for Applicable Federal Regulations:

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
40 CFR 50	NAAQS	Yes	Facility	This regulation defines national ambient air quality standards. The facility meets all applicable national ambient air quality standards for NOx, CO, SO_2, H_2S, PM_{10}, and $PM_{2.5}$ under this regulation.
NSPS 40 CFR 60, Subpart A	General Provisions	Yes	ENG-1 through ENG-4, AM-1, AM-2, FUG, CRYO-1 through CRYO-3	The following equipment of this facility is subject to the subparts of 40 CFR Part 60: • 40 CFR 60, Subpart JJJJ: Compressor engines of this facility (ENG-1 through ENG-4) • 40 CFR 60, Subpart OOOOa: Fugitives (FUG), Amine Units (AM-1 & AM-2), Cryogenic units (CRYO-1 through CRYO-3), Compressors associated with ENG-1 through ENG-4, Six (6) condensate tanks (TK-702 A-F) and produced water tank (TK 701).
NSPS 40 CFR60.40a, Subpart Da	Subpart Da, Performance Standards for **Electric Utility Steam Generating Units**	No	N/A	This regulation establishes standards of performance for fossil-fuel-fired steam generators. This regulation does not apply as the facility does not have any fossil fuel-fired steam-generating units with a heat input rate of 250 MMBtu/hr [60.40(a)(1)].

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
NSPS 40 CFR60.40b Subpart Db	**Electric Utility Steam Generating Units**	No	N/A	This regulation establishes standards of performance for industrial-commercial-institutional steam generating units. This regulation does not apply because the facility does not operate any industrial-commercial-institutional steam generating units with a heat capacity greater than 100 MMBtu/hr.
40 CFR 60.40c, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	No	N/A	This regulation does not apply as the facility does not have any steam generating units which meet the applicability criteria of a heat input greater than or equal to 10 MMBtu/hr.
NSPS 40 CFR 60, Subpart Ka	Standards of Performance for **Storage Vessels for Petroleum Liquids** for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and **Prior** to July 23, 1984	No	N/A	This regulation establishes performance standards for storage vessels for petroleum liquids for which construction, reconstruction, or modification commenced after May 18, 1978, and prior to July 23, 1984. The facility was not constructed prior to July 23, 1984. Thus, this rule does not apply to this facility.
NSPS 40 CFR 60, Subpart Kb	Standards of Performance for **Volatile Organic Liquid Storage Vessels** (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced **After** July 23, 1984	No	N/A	This regulation establishes the standard performance for volatile organic liquid storage vessels with a capacity greater than 75 m^3 (~471 bbl). The condensate tanks of this facility have a design capacity of less than 1,589.874 m^3. These tanks are exempt from this regulation per 40 CFR 60.110b(d)(4). Therefore, this regulation does not apply to the facility.
NSPS 40 CFR 60.330 Subpart GG	**Stationary Gas Turbines**	No	N/A	The facility does not have any applicable units. Therefore, the facility is not subject to this regulation.
NSPS 40 CFR 60, Subpart KKK	Leaks of VOC from **Onshore Gas Plants**	No	N/A	This regulation defines standards of performance for equipment leaks of VOC emissions from onshore natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. The was constructed after August 23, 2011. Therefore, this regulation does not apply to this facility.
NSPS 40 CFR Part 60 Subpart LLL	Standards of Performance for **Onshore Natural**	No	N/A	This regulation establishes standards of performance for SO_2 emissions from onshore natural gas processing for which construction, reconstruction, or modification of the amine sweetening unit commenced after January 20, 1984,

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
	Gas Processing: SO_2 Emissions			and on or before August 23, 2011. The facility is not subject to this regulation as the amine sweetening unit was constructed after August 23, 2011.
NSPS 40 CFR Part 60 Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which construction, modification or reconstruction commenced after August 23, 2011 and before September 18, 2015	No	N/A	The rule applies to “affected” facilities that are constructed, modified, or reconstructed after Aug 23, 2011 (40 CFR 60.5365): gas wells, including fractured and hydraulically refractured wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, certain equipment at natural gas processing plants, sweetening units at natural gas processing plants, and storage vessels. The facility is not subject to this regulation as the facility was constructed after September 18, 2015.
NSPS 40 CFR Part 60 Subpart OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced **After** September 18, 2015	Yes	Compressors (ENG-1 through ENG-4), CRYO-1 through CRYO-3, AM-1, AM-2, FUG, TK-702 A-F, TK-701	The amine recovery units (AM-1 and AM-2) are constructed within the applicable period and have more than 2 long tons/yr H_2S. Therefore, AM-1 and AM-2 are subject to this regulation. The cryogenic units (CRYO-1 through CRYO-3) are associated with the liquefaction of natural gas. These units are subject to this regulation per 40 CFR 60.5365a(f). The storage vessels (TK-702 A-F and TK-701) at this facility each has PTE greater than 6 tpy. Therefore, storage vessels are subject to this regulation. Compressors associated with (ENG-1 through ENG-4) were constructed within the applicable period and are subject to this regulation. The fugitive components (FUG) are subject to this regulation.
NSPS 40 CFR 60 Subpart IIII	Standards of performance for Stationary Compression Ignition Internal Combustion Engines	No	N/A	This regulation establishes standards of performance for stationary compression ignition combustion engines. The engines at this facility are not compression ignition combustion engines. This regulation does not apply.
NSPS 40 CFR Part 60 Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Yes	ENG-1 through ENG-4	This regulation establishes standards of performance for stationary spark ignition internal combustion engines. Internal combustion engines (ENG-1 through ENG-4) at this facility commenced operation after June 12, 2006 and were manufactured on or after July 1, 2007. Therefore, ENG-1 through ENG-4 are subject to this regulation.
NSPS 40 CFR 60 Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	No	N/A	This regulation establishes standards of performance for greenhouse gas emissions for electric generating units. This facility does not have electric generating units. This regulation does not apply.
NSPS 40 CFR 60 Subpart UUUU	Emissions Guidelines for Greenhouse Gas Emissions and Compliance Times	No	N/A	This regulation establishes emissions guidelines for greenhouse gas emissions and compliance times for electric generating units. This facility does not have electric generating units. This regulation does not apply.

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
	for Electric Utility Generating Units			
NSPS 40 CFR 60, Subparts WWW, XXX, Cc, and Cf	Standards of performance for Municipal Solid Waste (MSW) Landfills	No	N/A	This facility is not a municipal solid waste landfill. This regulation does not apply.
NESHAP 40 CFR 61 Subpart A	General Provisions	No	Units Subject to 40 CFR 61	NSPS 40 CFR 61 does not apply to the facility because the facility does not emit or have the triggering substances on site and/or the facility is not involved in the triggering activity. The facility is not subject to this regulation. None of the subparts of Part 61 apply to the facility.
NESHAP 40 CFR 61 Subpart E	National Emission Standards for **Mercury**	No	N/A	The provisions of this subpart are applicable to those stationary sources that process mercury ore to recover mercury, use mercury chlor-alkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge
NESHAP 40 CFR 61 Subpart V	National Emission Standards for **Equipment Leaks** (Fugitive Emission Sources)	No	N/A	This regulation establishes national emission standards for equipment leaks (fugitive emission sources). The facility does not have equipment that operates in volatile hazardous air pollutant (VHAP) service [40 CFR Part 61.240]. The regulated activities subject to this regulation do not take place at this facility. The facility is not subject to this regulation.
MACT 40 CFR 63, Subpart A	General Provisions	Yes	DEHY-1 and DEHY-2	This regulation defines general provisions for relevant standards that have been set under this part. This regulation applies because 40 CFR Part 63, Subpart HH applies to dehydrator units (DEHY-1 and DEHY-2).
MACT 40 CFR 63.760 Subpart HH	**Oil and Natural Gas Production Facilities**	**Yes**	DEHY-1 and DEHY-2	This regulation establishes national emission standards for hazardous air pollutants from oil and natural gas production facilities. The facility is a minor source of HAPs with TEG dehydrators and meets the definition of a natural gas processing plant. The dehydrator will have a natural gas flow rate equal to or greater than 85 thousand standard cubic feet. The dehydrator vents less than 0.90 megagrams of benzene per year to the atmosphere and is therefore exempt from the emissions control requirements of MACT HH per 63.764(e)(1)(ii). The facility will comply with this regulation.
MACT 40 CFR 63 Subpart HHH	National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities	No	N/A	This regulation establishes national emission standards for hazardous air pollutants from natural gas transmission and storage facilities. This regulation does not apply because this facility is not a natural gas transmission or storage facility as defined in this regulation [40 CFR Part 63.1270(a)].
MACT 40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Industrial, Commercial, and Institutional Boilers & Process Heaters	No	N/A	This regulation establishes national emission standards for a major source of HAPs for industrial, commercial, and institutional boilers and process heaters. This facility is not a major source of HAPs. Therefore, this regulation does not apply to this facility.
MACT 40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants Coal & Oil Fire Electric Utility Steam Generating Unit	No	N/A	This regulation establishes national emission standards for hazardous air pollutants from coal and oil-fired electric utility steam generating units. The facility does not contain the affected units. This regulation does not apply.

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
MACT 40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (**RICE MACT**)	Yes	ENG-1 through ENG-4	This regulation defines national emissions standards for HAPs from stationary reciprocating Internal Combustion Engines. The internal spark ignition compressor engines (ENG-1 through ENG-4) are subject to MACT ZZZZ and comply by following the requirements of NSPS JJJJ.
40 CFR 64	**Compliance Assurance Monitoring**	Yes	DEHY-1, DEHY-2, and TK-701	Compressor engines (ENG-1 through ENG-4) have an uncontrolled PTE greater than 100 tpy of NO_X and CO but are subject to NSPS JJJJ and per 40 CFR 64.2(b)(1)(i) can take credit for an emissions reduction. TK-701 has an uncontrolled PTE greater than 100 tpy of VOC but is subject to NSPS OOOOa and per 40 CFR 64.2(b)(1)(i) can take credit for an emissions reduction. These units are therefore not subject to 40 CFR 64. Dehydrators have uncontrolled VOC emissions greater than 100 tpy. DEHY-1 and DEHY-2 emissions are controlled by FL-2a and TO-2. Thus, DEHY-1 and DEHY-2 are subject to this regulation.
40 CFR 68	**Chemical Accident Prevention**	Yes	Facility	The facility is an affected facility, as it will use flammable process chemicals such as propane at quantities greater than the thresholds. The facility will develop and maintain an RMP for these chemicals.
Title IV – Acid Rain 40 CFR 72	**Acid Rain**	Yes	Facility	The facility does not operate an affected source under this subpart.
Title IV – Acid Rain 40 CFR 73	**Sulfur Dioxide** Allowance Emissions	No	N/A	This regulation establishes sulfur dioxide allowance emissions for certain types of facilities. This facility is not an acid rain source. This regulation does not apply.
Title IV-Acid Rain 40 CFR 75	**Continuous Emissions Monitoring**	No	N/A	The facility is not an acid rain source and is therefore not subject to this regulation.
Title IV – Acid Rain 40 CFR 76	**Acid Rain** Nitrogen Oxides **Emission Reduction Program**	No	N/A	This regulation establishes an acid rain nitrogen oxide emission reduction program. This regulation applies to each coal-fired utility unit that is subject to an acid rain emissions limitation or reduction requirement for SO_2. This part does not apply because the facility does not operate any coal-fired units [40 CFR Part 76.1].
Title VI – 40 CFR 82	Protection of **Stratospheric Ozone**	No	N/A	This regulation establishes a regulation for the protection of the stratospheric ozone. The regulation is not applicable because the facility does not “service”, “maintain” or “repair” class I or class II appliances nor “dispose” of the appliances [40 CFR Part 82.1(a)].

Section 14

Operational Plan to Mitigate Emissions

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

☒ **Title V Sources** (20.2.70 NMAC)**:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Emissions During Startups, Shutdowns, and Emergencies** defining the measures to be taken to mitigate source emissions during startups, shutdowns, and emergencies as required by 20.2.70.300.D.5(f) and (g) NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☐ **NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Source Emissions During Malfunction, Startup, or Shutdown** defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown as required by 20.2.72.203.A.5 NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☒ **Title V** (20.2.70 NMAC)**, NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has established and implemented a Plan to Minimize Emissions During Routine or Predictable Startup, Shutdown, and Scheduled Maintenance through work practice standards and good air pollution control practices as required by 20.2.7.14.A and B NMAC. This plan shall be kept on site or at the nearest field office to be made available to the Department upon request. This plan should not be submitted with this application.

- The Black River Gas Processing Plant has multiple residue gas and NGL outlets planned to ensure offloading of the process streams. In the event that the 3rd party pipeline offloads have issues or outages, and they cannot take the residue gas or NGL, the inlet gas will be appropriately curtailed to ensure that gas is not flared.
- The Amine and Glycol flash gases are routed back to the process instead of routing to the flare, thus reducing the amount of gas burned in the flare. These streams can be routed to the flare if needed, to ensure control.
- Emissions from the condensate tanks and produced water tanks are controlled by the vapor combustor to reduce VOC emissions. Compressor blowdowns are routed to flare to reduce emissions during maintenance and malfunction.
- The thermal oxidizers installed at the Black River Gas Processing Plant have 99% destruction efficiency
- Glycol still vapors (BTEX) in Plant 3 are routed to the thermal oxidizer (TO-2), instead of the flare. This increases the destruction efficiency of the BTEX vapors and reduces the fuel consumption in the thermal oxidizer.
- The facility has an LDAR program in place to ensure leaks are found and the components are repaired in a timely manner. DLK also utilizes enviro seal valve for components and nitrile rubber for seals, for efficiency and longevity.
- The Black River Gas Processing Plant has modern process and safety systems in place that monitor fire and hazardous gases continuously. The Black River Gas Processing Plant has fulltime monitors to observe and locate any safety and/or process issues that could result in an incident. This safeguards health and safety of not only the employees working at the facility but the surrounding area and environment.
- All required documentation is kept on site and will be made available to the department upon request.

Section 15

Alternative Operating Scenarios

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

Alternative Operating Scenarios: Provide all information required by the department to define alternative operating scenarios. This includes process, material and product changes; facility emissions information; air pollution control equipment requirements; any applicable requirements; monitoring, recordkeeping, and reporting requirements; and compliance certification requirements. Please ensure applicable Tables in this application are clearly marked to show alternative operating scenario.

Construction Scenarios: When a permit is modified authorizing new construction to an existing facility, NMED includes a condition to clearly address which permit condition(s) (from the previous permit and the new permit) govern during the interval between the date of issuance of the modification permit and the completion of construction of the modification(s). There are many possible variables that need to be addressed such as: Is simultaneous operation of the old and new units permitted and, if so for example, for how long and under what restraints? In general, these types of requirements will be addressed in Section A100 of the permit, but additional requirements may be added elsewhere. Look in A100 of our NSR and/or TV permit template for sample language dealing with these requirements. Find these permit templates at: www.env.nm.gov/air-quality/permitting-section-procedures-and-guidance/. Compliance with standards must be maintained during construction, which should not usually be a problem unless simultaneous operation of old and new equipment is requested.

In this section, under the bolded title “Construction Scenarios”, specify any information necessary to write these conditions, such as: conservative-realistic estimated time for completion of construction of the various units, whether simultaneous operation of old and new units is being requested (and, if so, modeled), whether the old units will be removed or decommissioned, any PSD ramifications, any temporary limits requested during phased construction, whether any increase in emissions is being requested as SSM emissions or will instead be handled as a separate Construction Scenario (with corresponding emission limits and conditions, etc.

There are no alternative operating scenarios at Black River Gas Processing Plant.

Section 16

Air Dispersion Modeling

1) Minor Source Construction (20.2.72 NMAC) and Prevention of Significant Deterioration (PSD) (20.2.74 NMAC) ambient impact analysis (modeling): Provide an ambient impact analysis as required at 20.2.72.203.A(4) and/or 20.2.74.303 NMAC and as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines found on the Planning Section's modeling website. If air dispersion modeling has been waived for one or more pollutants, attach the AQB Modeling Section modeling waiver approval documentation.
2) SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions during routine or predictable startup, shutdown, or maintenance (SSM) using realistic worst case scenarios following guidance from the Air Quality Bureau's dispersion modeling section. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.
3) Title V (20.2.70 NMAC) ambient impact analysis: Title V applications must specify the construction permit and/or Title V Permit number(s) for which air quality dispersion modeling was last approved. Facilities that have only a Title V permit, such as landfills and air curtain incinerators, are subject to the same modeling required for preconstruction permits required by 20.2.72 and 20.2.74 NMAC.

What is the purpose of this application?	Enter an X for each purpose that applies
New PSD major source or PSD major modification (20.2.74 NMAC). See #1 above.	
New Minor Source or significant permit revision under 20.2.72 NMAC (20.2.72.219.D NMAC). See #1 above. **Note:** Neither modeling nor a modeling waiver is required for VOC emissions.	
Reporting existing pollutants that were not previously reported.	
Reporting existing pollutants where the ambient impact is being addressed for the first time.	
Title V application (new, renewal, significant, or minor modification. 20.2.70 NMAC). See #3 above.	X
Relocation (20.2.72.202.B.4 or 72.202.D.3.c NMAC)	
Minor Source Technical Permit Revision 20.2.72.219.B.1.d.vi NMAC for like-kind unit replacements.	
Other: i.e. SSM modeling. See #2 above.	
This application does not require modeling since this is a No Permit Required (NPR) application.	
This application does not require modeling since this is a Notice of Intent (NOI) application (20.2.73 NMAC).	
This application does not require modeling according to 20.2.70.7.E(11), 20.2.72.203.A(4), 20.2.74.303, 20.2.79.109.D NMAC and in accordance with the Air Quality Bureau's Modeling Guidelines.	

Check each box that applies:

☐ See attached, approved modeling **waiver for all** pollutants from the facility.
☐ See attached, approved modeling **waiver for some** pollutants from the facility.
☐ Attached in Universal Application Form 4 (UA4) is a **modeling report for all** pollutants from the facility.
☐ Attached in UA4 is a **modeling report for some** pollutants from the facility.
☒ No modeling is required.

Modeling is not being submitted with this application pursuant to 20.2.70 NMAC. Air dispersion modeling for this facility was completed and submitted with NSR Permit 6567-M8

Section 17

Compliance Test History

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

To show compliance with existing NSR permits conditions, you must submit a compliance test history. The table below provides an example.

Compliance Test History Table

Unit	Test Description	Test Date
ENG-1	Annual Test	8/13/2020
ENG-2	Annual Test	8/14/2020
ENG-3	Annual Test	8/13/2020
ENG-4	Annual Test	8/14/2020

Section 19

Requirements for Title V Program

Who Must Use this Attachment:

* Any major source as defined in 20.2.70 NMAC.
* Any source, including an area source, subject to a standard or other requirement promulgated under Section 111 - Standards of Performance for New Stationary Sources, or Section 112 Hazardous Air Pollutants, of the 1990 federal Clean Air Act ("federal Act"). Non-major sources subject to Sections 111 or 112 of the federal Act are exempt from the obligation to obtain an 20.2.70 NMAC operating permit until such time that the EPA Administrator completes rulemakings that require such sources to obtain operating permits. In addition, sources that would be required to obtain an operating permit solely because they are subject to regulations or requirements under Section 112(r) of the federal Act are exempt from the requirement to obtain an Operating Permit.
* Any Acid Rain source as defined under title IV of the federal Act. The Acid Rain program has additional forms. See www.env.nm.gov/air-quality/air-quality-title-v-operating-permits-guidance-page/. Sources that are subject to both the Title V and Acid Rain regulations are encouraged to submit both applications simultaneously.
* Any source in a source category designated by the EPA Administrator ("Administrator"), in whole or in part, by regulation, after notice and comment.

19.1 - 40 CFR 64, Compliance Assurance Monitoring (CAM) (20.2.70.300.D.10.e NMAC)

Any source subject to 40CFR, Part 64 (Compliance Assurance Monitoring) must submit all the information required by section 64.7 with the operating permit application. The applicant must prepare a separate section of the application package for this purpose; if the information is already listed elsewhere in the application package, make reference to that location. Facilities not subject to Part 64 are invited to submit periodic monitoring protocols with the application to help the AQB to comply with 20.2.70 NMAC. Sources subject to 40 CFR Part 64, must submit a statement indicating your source's compliance status with any enhanced monitoring and compliance certification requirements of the federal Act.

Each engine (Units ENG-1 through ENG-4) has uncontrolled NOX and CO emissions greater than 100 tpy, and the dehydrators (Units DEHY-1 and DEHY-2) and produced water tanks (Unit TK-701) have uncontrolled VOC emissions greater than 100 tpy. ENG-1 through ENG-4 have inherent process controls or are subject to federal regulation that brings their respective emission rates below emission monitoring thresholds. DEHY-1 , DEHY-2, and TK-701 are subject to 40 CFR 64. CAM Plans for the respective units are attached to this section.

19.2 - Compliance Status (20.2.70.300.D.10.a & 10.b NMAC)

Describe the facility's compliance status with each applicable requirement at the time this permit application is submitted. This statement should include descriptions of or references to all methods used for determining compliance. This statement should include descriptions of monitoring, recordkeeping and reporting requirements and test methods used to determine compliance with all applicable requirements. Refer to Section 2, Tables 2-N and 2-O of the Application Form as necessary. (20.2.70.300.D.11 NMAC) For facilities with existing Title V permits, refer to most recent Compliance Certification for existing requirements. Address new requirements such as CAM, here, including steps being taken to achieve compliance.

DLK believes that the Black Water Gas Processing Plant complies with each applicable state and federal regulation identified in Section 13 (Determination of State & Federal Air Quality Regulations). In the event that DLK discovers new information affecting the compliance status of the facility, DLK will make appropriate notifications and/or take corrective actions to maintain the required compliance.

19.3 - Continued Compliance (20.2.70.300.D.10.c NMAC)

Provide a statement that your facility will continue to be in compliance with requirements for which it is in compliance at the time of permit application. This statement must also include a commitment to comply with other applicable requirements as they come into effect during the permit term. This compliance must occur in a timely manner or be consistent with such schedule expressly required by the applicable requirement.

The facility will continue to comply with currently applicable regulations and is committed to complying with newly effective regulations.

19.4 - Schedule for Submission of Compliance (20.2.70.300.D.10.d NMAC)

You must provide a proposed schedule for submission to the department of compliance certifications during the permit term. This certification must be submitted annually unless the applicable requirement or the department specifies a more frequent period. A sample form for these certifications will be attached to the permit.

Compliance certification will be submitted annually and will begin with the issuance of this Title V operating permit.

19.5 - Stratospheric Ozone and Climate Protection

In addition to completing the four (4) questions below, you must submit a statement indicating your source's compliance status with requirements of Title VI, Section 608 (National Recycling and Emissions Reduction Program) and Section 609 (Servicing of Motor Vehicle Air Conditioners).

1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ☐ **Yes** ☒ **No**
2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ☐ **Yes** ☒ **No**
   (If the answer is yes, describe the type of equipment and how many units are at the facility.)
3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ☐ **Yes** ☒ **No**
4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40 CFR Part 82, Subpart A through G.)

No 40 CFR 82 requirements apply to this facility.

19.6 - Compliance Plan and Schedule

Applications for sources, which are not in compliance with all applicable requirements at the time the permit application is submitted to the department, must include a proposed compliance plan as part of the permit application package. This plan shall include the information requested below:

A. Description of Compliance Status: (20.2.70.300.D.11.a NMAC)

A narrative description of your facility's compliance status with respect to all applicable requirements (as defined in 20.2.70 NMAC) at the time this permit application is submitted to the department.

B. Compliance plan: (20.2.70.300.D.11.B NMAC)
A narrative description of the means by which your facility will achieve compliance with applicable requirements with which it is not in compliance at the time you submit your permit application package.

C. Compliance schedule: (20.2.70.300D.11.c NMAC)
A schedule of remedial measures that you plan to take, including an enforceable sequence of actions with milestones, which will lead to compliance with all applicable requirements for your source. This schedule of compliance must be at least as stringent as that contained in any consent decree or administrative order to which your source is subject. The obligations of any consent decree or administrative order are not in any way diminished by the schedule of compliance.

D. Schedule of Certified Progress Reports: (20.2.70.300.D.11.d NMAC)
A proposed schedule for submission to the department of certified progress reports must also be included in the compliance schedule. The proposed schedule must call for these reports to be submitted at least every six (6) months.

E. Acid Rain Sources: (20.2.70.300.D.11.e NMAC)
If your source is an acid rain source as defined by EPA, the following applies to you. For the portion of your acid rain source subject to the acid rain provisions of title IV of the federal Act, the compliance plan must also include any additional requirements under the acid rain provisions of title IV of the federal Act. Some requirements of title IV regarding the schedule and methods the source will use to achieve compliance with the acid rain emissions limitations may supersede the requirements of title V and 20.2.70 NMAC. You will need to consult with the Air Quality Bureau permitting staff concerning how to properly meet this requirement.

NOTE: The Acid Rain program has additional forms. See www.env.nm.gov/air-quality/air-quality-title-v-operating-permits-guidance-page/. Sources that are subject to both the Title V and Acid Rain regulations are **encouraged** to submit both applications **simultaneously**.

No compliance plan is required as the Black River Gas Processing Plant is within the compliance.

19.7 - 112(r) Risk Management Plan (RMP)

Any major sources subject to section 112(r) of the Clean Air Act must list all substances that cause the source to be subject to section 112(r) in the application. The permittee must state when the RMP was submitted to and approved by EPA.

The facility is subject to RMP requirements for NGLs. Matador will submit the list of all applicable substances to the EPA.

19.8 - Distance to Other States, Bernalillo, Indian Tribes and Pueblos

Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B NMAC)?

(If the answer is yes, state which apply and provide the distances.)

Yes, the facility is 37 km away from the Texas border. The facility is more than 50 km away from local pollution control programs, Indian Tribes, and Pueblos.

19.9 - Responsible Official

Provide the Responsible Official as defined in 20.2.70.7.AD NMAC:
Name: MR. Casey Snow
Title: VP – Regulatory, Environmental, and Safety
Phone: (972) 371-5284
E-mail: csnow@matadorresources.com
Address: 5400 LBJ Freeway, Suite 1500, Dallas, TX 75240

DLK Black River Midstream LLC /Black River Gas Processing Plant
CAM Plan for Dehydrator Vent Controlled by Flare

I. Background

A. *Emissions Unit*

Description: Dehydrator Vent
Identification: DEHY-1
Facility: Black River Gas Plant

B. *Applicable Regulation, Emission Limit, and Pre-CAM Monitoring Requirements*

Regulation: Operation and reporting requirements created in NSR Permit 6567-M8 et seq. to establish federally enforceable recognition of the Dehydrator Vent.
Uncontrolled Emissions:

VOC (tpy)	H_2S (tpy)	HAPs (tpy)
848.88	0.23	82.12

Pre-CAM Monitoring Requirements: There are no pre-CAM monitoring requirements.

C. *Control Technology, Capture System, Bypass, PER*

Controls: Flare (FL-2)
Capture System: N/A
Bypass: The flare is the primary control for the Dehydrator still vent non-condensable vapors.

Potential pre-control device emissions: 848.88 tpy VOC, 82.12 tpy HAPs, 0.23 tpy H_2S
Under 40 CFR § 64.2(a) this is a CAM affected unit.

Potential post-control device emissions: 0 tpy VOC, 0 tpy HAPs, 0 tpy H_2S
The flare destruction removal efficiency (DRE) is 98%.

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

Per 40 CFR §64.1, excursion is defined as: a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring. Excursions of the flare system will trigger an inspection, corrective action, and reporting. Maintenance personnel will inspect the flare within 24 hours and make needed repairs as soon as practicable.

Monitoring Approach: Black River Gas Plant Flare (FL-2)

	Indicator No. 1	**Indicator No. 2**	**Indicator No. 3**
I. Indicator	Presence of combustion in the flare.	Presence of visible emissions.	Totalized flow volume.
Measurement Approach	The presence of combustion in the flare shall be monitored by a thermocouple with alarm that signals non-combustion of gas.	The flare should be monitored for visible emissions once during each week that the flare is operational.	Flow rate shall be measured continuously with a flow meter and the hourly flow rate shall be determined by averaging a minimum of 4 equally spaced readings throughout the hour.
II. Indicator Range	Flame present (sensed) or no flame present (sensed).	Visible emissions present or not present, in accordance with 40 CFR § 60, Appendix A, Reference Method 22.	Flow rate should be within the operating velocities specified in 40 CFR § 60 Subpart A.
III. Performance Criteria A. Data Representativeness	Destruction depends upon the presence of a flame. If the flame is not present, VOC and H_2S are not being destroyed.	Efficient combustion is assumed if no visible emissions are observed when a flame is present.	Efficient combustion is assumed if flow rates are within 60 ft/s and 400 ft/s determined based on 40 CFR § 60.18.
B. QA/QC Practices and Criteria	Proper operation of the flare achieved by maintaining the non-combustion thermocouple with alarm system. Operators will record the date and result of each such maintenance activity, as well as repairs or replacements made.	Visible emissions to be determined in accordance with Method 22 of Appendix A of 40 CFR § 60 Subpart A.	Verification will be in accordance with 40 CFR § 60 Subpart A, Appendix A Test method used to measure flow.
C. Monitoring Frequency	The thermocouple and alarm system will be tested twice a year by turning off the thermocouples and recording the time required for the alarm to respond.	Visible emissions observation in accordance with Method 22 shall be conducted annually.	Continuous monitoring with flow rates determined hourly.
D. Data Collection Procedures	Records will be maintained of flare shutdown for any reason, including failure to deliver fuel, and of inspection and maintenance to the flare and flare pilot.	Records shall be maintained of all visible emissions observations.	Hourly flow rates shall be recorded.
E. Averaging Period	Not applicable.	A 15-min Method 22 observation will be performed annually.	Hourly.

Justification

I. Background

The monitoring approach outlined here applies to the flare (FL-2) which is a control device for non-condensable vapors from the dehydrator still vent. The dehydrator still vent is the CAM affected unit.

II. Rationale for Selection of Performance Indicators

The destruction and removal of VOC is dependent upon combustion and on proper operation of the flare. Thus, the monitoring approach is based on three primary indicators: presence of combustion in the flare, presence of visible emissions, and gas volume flow to the flare.

III. Rationale for Selection of Indicator Ranges

When ensuring proper operation of the flare, the presence of a flame to initiate or maintain combustion has only two states: a flame is present or a flame is not present. By design, a thermocouple-based alarm system will indicate the state of combustion. For the purposes of Method 22, the presence of visible emissions has only two states: there are visible emissions or there are not. Proper operation of the flare would correspond with no visible emissions in the presence of a flame. The measurement of totalized flow volume will determine if the volumetric flow is within the design specifications and the maximum velocity determined from manufacturer specifications of the flare.

The permit issued by the NMED requires the flare to achieve 98 percent or greater destruction efficiency.

DLK Black River Midstream LLC /Black River Gas Processing Plant
CAM Plan for Dehydrator Vent Controlled by Thermal Oxidizer

I. Background

A. *Emissions Unit*

Description: Dehydrator Vent
Identification: DEHY-2
Facility: Black River Gas Plant

B. *Applicable Regulation, Emission Limit, and Pre-CAM Monitoring Requirements*

Regulation: Operation and reporting requirements created in NSR Permit 6567-M8 et seq. to establish federally enforceable recognition of the Dehydrator Vent.

Uncontrolled Emissions:

VOC (tpy)	H_2S (tpy)	HAPs (tpy)
833.59	0.23	81.82

Pre-CAM Monitoring Requirements: There are no pre-CAM monitoring requirements.

C. *Control Technology, Capture System, Bypass, PER*

Controls: Thermal Oxidizer (Unit TO-2)
Capture System: N/A
Bypass: The thermal oxidizer is the primary control for the dehydrator non-condensable still vent overheads.

Potential pre-control device emissions: 833.59 tpy VOC, 81.82 tpy HAPs, 0.23 tpy H_2S Under 40 CFR § 64.2(a) this is a CAM affected unit.

Potential post-control device emissions: 0 Tpy VOC, 0 tpy HAPs, 0 tpy H_2S The thermal oxidizer destruction removal efficiency (DRE) is 98%.

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

Per 40 CFR §64.1, excursion is defined as: a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring. Excursions of the thermal oxidizer will trigger an inspection, corrective action, and reporting. Maintenance personnel will inspect the thermal oxidizer within 24 hours and make needed repairs as soon as practicable.

Monitoring Approach: Black River Gas Plant Thermal Oxidizer (TO-2)

	Indicator No. 1	**Indicator No. 2**	**Indicator No. 3**
I. Indicator	Presence of combustion in the thermal oxidizer.	Combustion Temperature.	Equipment Inspection.
Measurement Approach	The presence of combustion in the thermal oxidizer shall be monitored by a flame-detection device with an alarm that signals non-combustion of gas.	The temperature of the thermal oxidizer shall be measured with a thermocouple.	The thermal oxidizer is inspected on a semi-annual basis to ensure that the process is properly controlled. The unit is inspected according to a Manufacturer's recommended procedure or NMED-approved inspection protocol which includes at minimum the methods for inspecting and adjusting proper minimum combustion temperature and proper air distribution.
II. Indicator Range	Flame present (sensed) or no flame present (sensed).	$>1600^{\circ}$ F	Pass or fail of equipment inspection.
III. Performance Criteria A. Data Representativeness	Destruction depends upon the presence of a flame. If the flame is not present, VOC, HAPs, and H_2S emissions are not being destroyed.	Destruction depends upon achieving a temperature of $\geq 1600^{\circ}$ F.	Inspections and maintenance are being conducted on the thermal oxidizer.
B. QA/QC Practices and Criteria	Proper operation of the thermal oxidizer achieved by maintaining the flame-detection device with alarm system. Operators will record the date and result of each such maintenance activity, as well as repairs or replacements made.	Proper operation of the thermal oxidizer shall be achieved by maintaining the non-combustion thermocouple. Operators will record the date and result of each thermocouple maintenance activity, as well as repairs and replacements made.	The thermal oxidizer is inspected on a semi-annual basis to ensure that the process is properly controlled. The unit is inspected according to a Manufacturer's recommended procedure or NMED-approved inspection protocol which includes at minimum the methods for inspecting and adjusting proper minimum combustion temperature, and proper air distribution.
C. Monitoring Frequency	The flame detection device and alarm system will be tested twice a year by turning off the flame detection device and recording the time required for the alarm to respond.	One measurement will be recorded per 24 hours.	Semi-annually.
D. Data Collection Procedures	Records will be maintained of thermal oxidizer shutdown for any reason, including failure to deliver fuel, and of inspection and maintenance to the thermal oxidizer.	Temperature will be recorded automatically once per day with a data logger. Records will be available for review at the site.	Semi-annually inspections are performed and documented by the observer. Any repairs or adjustments are documented.
E. Averaging Period	Not applicable.	Not applicable.	Not applicable.

Justification

I. Background

The monitoring approach outlined here applies to the thermal oxidizer (TO-2) which is a control device for vapors from the dehydrator non-condensable still vent overheads The dehydrator vent is the CAM affected unit.

II. Rationale for Selection of Performance Indicators

The destruction and removal of VOC, HAPs, and H_2S is dependent upon combustion and on proper operation of the thermal oxidizer. Thus, the monitoring approach is based on three primary indicators: presence of combustion in the flare, monitoring combustion temperature, inspecting integrity of the ducting from the process equipment to the thermal oxidizer.

III. Rationale for Selection of Indicator Ranges

In the case of ensuring proper operation of the thermal oxidizer, the presence of a flame to initiate or maintain combustion has only two states: a flame is present or a flame is not present. By design, a thermocouple-based alarm system will indicate the state of combustion. The combustion temperature will determine the design-specified combustion of VOC, HAPs and H_2S. An inspection of the ducting from the process equipment to thermal oxidizer will ensure the proper operation of the thermal oxidizer.

The permit issued by the NMED requires the thermal oxidizer to achieve 98 percent or greater destruction efficiency.

DLK Black River Midstream LLC /Black River Gas Processing Plant
CAM Plan for Produced Water Tank emissions Controlled by Vapor combustion unit

I. Background

A. *Emissions Unit*

Description: Produced water tank emissions
Identification: TK-701
Facility: Black River Gas Plant

B. *Applicable Regulation, Emission Limit, and Pre-CAM Monitoring Requirements*

Regulation: Operation and reporting requirements created in NSR Permit 6567-M8 et seq. to establish federally enforceable recognition of the Produced water tank emissions.

Uncontrolled Emissions:

VOC (tpy)	HAPs (tpy)
1697.69	28.03

Pre-CAM Monitoring Requirements: There are no pre-CAM monitoring requirements.

C. *Control Technology, Capture System, Bypass, PER*

Controls: Vapor Combustion Unit (Unit VCU-1)
Capture System: N/A
Bypass: The vapor combustion unit is the primary control for the produced water tank working, standing, and flash emissions.

Potential pre-control device emissions: 1697.69 tpy VOC, 28.03 tpy HAPs
Under 40 CFR § 64.2(a) this is a CAM affected unit.

Potential post-control device emissions: 0 tpy VOC, 0 tpy HAPs.
The vapor combustion unit DRE is 98%.

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

Per 40 CFR §64.1, excursion is defined as: a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring. Excursions of the vapor combustion unit (VCU) will trigger an inspection, corrective action, and reporting. Maintenance personnel will inspect the vapor combustion unit within 24 hours and make needed repairs as soon as practicable.

Monitoring Approach: Black River Gas Plant Vapor combustion unit (VCU-1)

	Indicator No. 1	**Indicator No. 2**
I. Indicator	Presence of combustion in the vapor combustion unit.	Equipment Inspection.
Measurement Approach	The presence of combustion in the vapor combustion unit shall be monitored by a flame-detection device with an alarm that signals non-combustion of gas.	The vapor combustion unit is inspected on a semi-annual basis to ensure that the process is properly controlled. The unit is inspected according to a manufacturer's recommended procedure and NMED-approved inspection protocol which includes at minimum the methods for inspecting and adjusting proper minimum combustion temperature and proper air distribution.
II. Indicator Range	Flame present (sensed) or no flame present (sensed).	Pass or fail of equipment inspection.
III. Performance Criteria A. Data Representativeness	Destruction depends upon the presence of a flame.	Inspections and maintenance are being conducted on the vapor combustion unit.
B. QA/QC Practices and Criteria	Proper operation of the vapor combustion unit achieved by maintaining the flame-detection device with alarm system. Operators will record the date and result of each such maintenance activity, as well as repairs or replacements made.	The vapor combustion unit is inspected on a semi-annual basis to ensure that the process is properly controlled. The unit is inspected according to a manufacturer's recommended procedure and NMED-approved inspection protocol which includes at minimum the methods for inspecting and adjusting proper minimum combustion temperature, and proper air distribution.
C. Monitoring Frequency	The flame-detection device and alarm system will be tested twice a year by turning off the flame-detection devices and recording the time required for the alarm to respond.	Semi-annually.
D. Data Collection Procedures	Records will be maintained of vapor combustion unit shutdown for any reason, including failure to deliver fuel, and of inspection and maintenance to the vapor combustion unit.	Semi-annually inspections are performed and documented by the observer. Any repairs or adjustments are documented.
E. Averaging Period	Not applicable.	Not applicable.

Justification

I. Background

The monitoring approach outlined here applies to the vapor combustion unit (VCU-1) which is a control device for working, standing, and flash emissions from the produced water tank. The produced water tank is the CAM affected unit.

II. Rationale for Selection of Performance Indicators

The destruction and removal of VOC and HAPs are dependent upon combustion and on proper operation of the vapor combustion unit. Thus, the monitoring approach is based on two primary indicators: presence of combustion in the flare, inspecting integrity of the ducting from the process equipment to the thermal oxidizer.

III. Rationale for Selection of Indicator Ranges

In the case of ensuring proper operation of the vapor combustion unit, the presence of a flame to initiate or maintain combustion has only two states: a flame is present or a flame is not present. By design, a thermocouple-based alarm system will indicate the state of combustion. An inspection of the ducting from the process equipment to thermal oxidizer will ensure the proper operation of the thermal oxidizer.

The permit issued by the NMED requires the vapor combustion unit to achieve 98 percent or greater destruction efficiency.

Section 20

Other Relevant Information

<u>Other relevant information</u>. Use this attachment to clarify any part in the application that you think needs explaining. Reference the section, table, column, and/or field. Include any additional text, tables, calculations or clarifying information.

Additionally, the applicant may propose specific permit language for AQB consideration. In the case of a revision to an existing permit, the applicant should provide the old language and the new language in track changes format to highlight the proposed changes. If proposing language for a new facility or language for a new unit, submit the proposed operating condition(s), along with the associated monitoring, recordkeeping, and reporting conditions. In either case, please limit the proposed language to the affected portion of the permit.

N/A – the facility does not have any other relevant information.

Section 22: Certification

Company Name: DLK Black River Midstream, LLC

I, SEAN O'GRADY, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 13 day of DEC., 2023, upon my oath or affirmation, before a notary of the State of

Texas.

*Signature 12/13/23 Date

SEAN O'GRADY
Printed Name

PRESIDENT
Title

Scribed and sworn before me on this 13 day of December, 2023.

My authorization as a notary of the State of Texas expires on the

27th day of September, 2025.

Notary's Signature

12.13.2023
Date

Susan Pepin
Notary's Printed Name

SUSAN PEPIN
Notary Public, State of Texas
Comm. Expires 09-27-2025
Notary ID 133355037

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.