FEDERAL OPERATING PERMIT - TECHNICAL REVIEW SUMMARY
SITE OPERATING PERMIT (SOP) INITIAL ISSUANCE

Permit #:	**O4448**	Company:	**ET Gathering & Processing LLC**
Project #:	**34972**	Site:	**Panther Gas Plant**
Regulated Entity #:	**RN109124057**	Application Area:	**Panther Gas Plant**
Region:	**7**	Customer #:	**CN606187110**
NAICS Code:	**211111**	County:	**Upton**
Permit Reviewer:	**Liam Lin**	NAICS Name:	**Crude Petroleum and Natural Gas Extraction**

SITE INFORMATION

Physical Location:	FROM THE INTERSECTION OF FM 1787 AND FM 1492 GO SOUTH ON FM 1492 1.7 MILES TO UNNAMED ENTRANCE ROAD ON THE LEFT
Nearest City:	Rankin
Major Pollutants:	CO, NOX, SO2, VOC
Additional FOPs:	O3934

PROJECT SUMMARY

ET Gathering and Processing LLC's Panther Gas Plant is a crude petroleum and natural gas extraction facility and a major source of emissions. It is subject to 30 TAC Chapter 122 which requires it to apply and obtain a Federal Operating Permit (FOP). This initial application was received by TCEQ on March 31, 2023. This is a GOP to SOP conversion project. ET Gathering & Processing LLC, Panther Gas Plant operated under General Operating Permit (GOP) O3934 which will be voided upon issuance of Site Operating Permit (SOP) O4448. The GOP void project is 34973.

Some of the significant emission sources at the site include compressors, flares, boilers, heaters and fugitive equipment, which are subject to State and/or Federal regulations. Case-by-Case CAM was included for group IDs GRP-ENG and GRP-ENG2 for pollutants CO and CH20. CAM was also added for unit IDs DEHY, DEHY2, LOAD1A, LOAD1B, PRO-AMINE and PRO-AMINE2. PM was added for unit IDs AG-FL and AG-FL2. The FOP includes general and special terms and conditions and unit-specific applicable requirements which were identified using information provided by the applicant in various forms (OP-1, OP-2, OP-SUM, OP-REQ1, OP-REQ2, OP-REQ3, OP-PBRSUP, and various Unit Attribute forms).

PROCESS DESCRIPTION

The Panther Gas Plant is comprised of two trains (Panther 1 and Panther 2) that closely resemble each other in equipment and operations. Natural gas enters the Plants through horizontal separators or slug catchers which separate entrained liquids from the inlet gases. In addition, condensate can be received via pressurized trucks bringing in liquids from the field (Facility Identification Number [FIN] NGLUNLD) as well as through pipeline maintenance pigging operations. Pigging liquids are routed to the slug catcher. Liquids collected in the slug catcher are routed to the condensate stabilizer feed tank, which is a pressurized vessel. Field liquids unloaded from pressurized trucks are also stored in pressurized holding vessels prior to being sent through the stabilization process. Additionally, raw condensate from the pressure vessels may be periodically loaded into pressurized trucks (FIN PLOAD) for stabilization at another facility.

The liquids are processed in a condensate stabilization system which produces Y-Grade product and stabilized condensate with a target Reid Vapor Pressure (RVP) of two (2) pounds per square inch (psi). At times the system may be used to produce stabilized condensate with a target RVP of nine (9) psi. The stabilized condensate is pumped into six (6) 750-barrel (bbl) atmospheric storage tanks [FIN GRP-PRODTK]) and loaded out by trucks as necessary. Vapors from the storage tanks are captured by a vapor recovery unit (VRU) and routed back to the inlet with a control efficiency of 98%. Truck loading emissions (FINS LOAD1A and LOAD1B) are combusted by the vapor combustor unit (VCU) with a destruction efficiency of 99% and 98% for C4+ and hydrogen sulfide (H_2S). Y-Grade product is stored in pressurized tanks and exits the Plant via pipeline.

Overhead flash gas from the stabilization system is captured by three (3) electric driven vapor recovery units (VRUs), compressed, and recycled back to inlet suction. During normal operations, the VRUs each operate at 60% capacity. In the event that one (1) VRU is taken down for maintenance, stabilization operations will be scaled back so that the vapors can all be captured by the remaining VRUs. If overhead vapors briefly exceed the capacity of the remaining VRUs as stabilization is curtailed, the excess will be routed to the Plant 1 flare (Unit ID FL-PL) for combustion. These emissions are represented and authorized as maintenance, startup, and shutdown (MSS) under PBR Title 30 of the Texas Administrative Code (30 TAC) §106.359.

The inlet gas streams are routed to the amine sweetening units (FINs AMINE and AMINE2) for removal of carbon dioxide (CO_2) H_2S. CO_2 and H_2S are removed from the natural gas in a two-step amine process. Gas enters the bottom of the amine contactors where it encounters lean amine solution in counter-current flow. CO_2 and H_2S contained in the natural gas are absorbed in the amine. Sweetened natural gas exits the top of the amine contactors and flows to the Plant's dehydration systems.

Rich amine containing absorbed CO_2 and H_2S flows to amine flash tanks where entrained natural gas vapors are separated from the rich amine. The flash gas is used as fuel for the HMO heaters (FINs H-3 and H-6) and the thermal oxidizer burners (FINs TO and TO2), which are equipped with burner management systems. Rich amine then enters the amine regenerator stills where it is heated to drive off CO_2 and H_2S. Lean amine is pumped from the bottom of the stills to the amine contactors to repeat the process.

CO_2 and H_2S rich vapors exit the top of the regenerator stills, are cooled in aerial coolers, and then flow into still reflux accumulators where condensed liquids and acid gas are separated. The condensed liquids are pumped back to the amine stills as reflux. The acid gas vapors from the amine stills are routed as needed through Sulfaguard H_2S stripping systems to ensure the total site-wide sulfur emissions do not exceed 0.3 long tons per day (LTPD). The remaining waste gases are routed to the thermal oxidizers and/or the acid gas flares (FINs AG-FL and AG-FL2) where any remaining H_2S and volatile organic compounds (VOC) are incinerated. The Sulfaguard systems may be bypassed and the acid gas sent directly to the thermal oxidizers/flares when the inlet gas sulfur concentration is less than 0.3 LTPD.

Natural gas dehydration is accomplished using two (2) separate systems in each Plant: triethylene glycol (TEG) systems (FIN DEHY and DEHY2) and mol sieve units. Sweet natural gas from the amine contactors enters the bottom of the glycol contactors where it encounters TEG in counter-current flow. The TEG absorbs water from the natural gas. Dry natural gas exits the top of the glycol contactors and is routed to the mol sieve units where the water content is further reduced. The mol sieve regenerator heaters (FINs H- 1 and H-4) are used to heat a small amount of natural gas that is slip-streamed from the inlet gas lines as needed to regenerate the beds. There are three (3) beds in each mol sieve, and one (1) bed is regenerated at a time. The residue gas stream from regeneration is routed back to the inlet; therefore, the only emissions associated with the mol sieve units are due to fugitive piping/equipment leaks and combustion emissions from the regenerator heaters.

Rich TEG (water-saturated) leaving the glycol contactors is sent to flash tanks where entrained vapors are separated from the TEG. The flash gas is routed into the fuel system for the HMO heaters (FINs H-3 and H- 6) and the thermal oxidizer burners (FINs TO and TO2). Rich glycol leaves the flash tanks and enters the glycol regenerator stills. Absorbed water and hydrocarbons are driven off by heat from the glycol reboilers (FINs H-2 and H-5). Lean glycol is recirculated to the glycol contactors. The still overhead vapors pass through BTEX condensers to remove water and heavy hydrocarbons. The non-condensable vapors can be routed to either the plant flares (FINs FL and FL2) or the thermal oxidizers (FINs TO and TO2) for combustion. The condensed water and hydrocarbons are sent along with produced water and slop water from other plant processes to four (4) 500-bbl atmospheric wastewater storage tanks (FIN GRP-TKWW) and loaded out by truck (FIN LOAD2) as necessary.

After dehydration, sweet, dry natural gas is routed to the cryogenic process for recovery of natural gas liquids (NGL). Liquids are removed by chilling the natural gas while reducing the stream pressure using electric motor-driven compressors and turboexpanders. The resulting NGL is treated in amine liquid contactors prior to being discharged from the Plants via pipeline. Rich amine from the NGL amine contactors is regenerated with the rich amine from the natural gas amine contactors.

Residue gas is compressed by seven (7) dual-drive engine-driven recompressors (FINs C-1 through C-7) prior to being sent out through the residue pipeline. Two (2) compressor engines (FINs C-8 and C-9) are used to transfer excess inlet gas to different parts of ETC's system and are not associated with the gas processing at Panther. An emergency generator engine (FIN E-1) is used when purchase power to the site is lost.

Heat for the amine treating systems, stabilization systems, and cryogenic plants are provided by hot oil systems and two (2) natural gas-fueled heaters (FINs H-3 and H-6). The hot oil systems are networks of piping that circulate hot oil through the Plant and provide heat as needed. The Plant is also equipped with various fixed roof tanks (FINs GRP-TKHVY and GRP-TKHVY2) storing lube oil, antifreeze, methanol, glycol, and amine to support the operations on site.

Fugitive emissions (FINs CAT 3606 FUG, FUG, and FUG2) are generated from equipment components such as compressor engines, piping fittings, pumps, and compressor seals. ETC implements a Leak Detection and Repair (LDAR) program in order to minimize emissions from leaks at the Plants.

Additional emissions sources include compressor blowdowns, equipment startups and shutdowns, vessel blowdowns, and miscellaneous maintenance activities. All maintenance activities are authorized under PBR via 30 TAC §106.359.

TECHNICAL REVIEW

Permit Content Summary

1. Was Periodic Monitoring (PM) required and included in the permit?.. Yes
2. Was Compliance Assurance Monitoring (CAM) required and included in the permit?.. Yes
3. Was case-by-case PM or CAM included in the permit?.. Yes
4. Was a permit shield requested?.. Yes
5. If a permit shield was requested, was any permit shield request denied?... No
6. Identify if the following are applicable for this project:
   (a) Manually-built applicable requirements... Yes
   (b) Customized Special Terms and Conditions... Yes
   (c) Manual changes to the IMS-generated applicable requirements.. No
   (d) Alternate means of compliance for any emission unit/source at the site.. No
7. Is the site subject to the requirements of 40 CFR Part 72 (Acid Rain Permit)?.. No
8. Did the applicant's review/comments on the working draft permit result in changes
   to the permit content?.. ...Yes
9. Will the draft permit be sent to public notice with unresolved issues
   (i.e., disagreements with applicant)?.. No

<u>Permit reviewer notes:</u>

- PM was added for unit IDs AG-FL and AG-FL2. PM Option No. PM-V-053 was used.
- CAM was added to the following unit IDs:
  - DEHY, DEHY2, PRO-AMINE, & PRO-AMINE2 – CAM Option No. CAM-T1-001
  - LOAD1A & LOAD1B – CAM Option No. CAM-VC-001.
- Group IDs GRP-ENG and GRP-ENG2 require CAM for the CO limit from their standard permit registration 139259. GRP-ENG also requires CAM for the CH2O (formaldehyde) limit from that registration. Catalytic converters are used to control these pollutants, and the two parameters below are used for each. This case-by-case CAM was approved by PM/CAM specialists Carolyn Maus and John Walker.

  i. CAM was added for monitoring the inlet gas temperature to the catalyst on a daily basis. The CAM is similar to option CAM-CC-029, except that a new basis was written for each pollutant (since the option's basis is for NOx). The deviation limit uses minimum and maximum temperatures from the manufacturer's specifications for the catalyst. This manufacturer's data sheet was provided for the 4,735 hp engines in the 2020 standard permit revision application, and the applicant submitted that data again in this project. The applicant had also provided those temperatures for the 5,000 hp engines in previous applications when this site was authorized by a GOP. Therefore, catalyst inlet temperatures of 550 F and 1250 F are used as minimum and maximum values, respectively.

ii. CAM was also added for monitoring the outlet CO concentration every 15,000 hours of operation. It is similar to option CAM-CC-030 except the test method in the text is appropriate for CO instead of NOx. The deviation limits are set to the maximum allowable CO emission rates from the standard permit registration (4.31 lb/hr for GRP-ENG and 3.64 lb/hr for GRP-ENG2). This monitoring was used for both CO and CH2O because industry data has shown that oxidation catalysts on engines reduce HAP emissions like CH2O proportionally to CO emissions, so CO monitoring can be used as a surrogate for CH2O. If the catalyst is adequately reducing CO emissions it should also be adequately reducing the CH2O emissions. Federal rules such as MACT ZZZZ use this principle. Also, changes in the CO concentration can indicate degradation of the catalyst, so testing for CO will verify the catalyst is functioning effectively. A separate basis was written for CO and for CH2O, with the CH2O basis addressing the surrogacy. The monitoring table for CH2O also includes a note in the deviation limit about the surrogacy.

- The permit shields requested in this application were approved.
- Appliable requirement was manually built to add CAM for LOAD1A and LOAD1B on the permit side of the IMS.
- Special Term and Condition No. 1.E (IMS Term A.001.G) was added to include the citation and the subparts from 30 TAC Chapter 113 that incorporate MACT subparts by reference.
- Special Term and Condition No. 10 (IMS Term B.142) was added to include the submittal date and project number for the OP-PBRSUP Submittal.
- Customized Special Term and Condition No. 18 (IMS term J.160) was added for an off-site permit location, as listed on Form OP-1.
- After the applicant reviewed the WDP, they requested a few formatting changes and typo corrections.

Statement of Basis

A Statement of Basis sets forth the legal and factual basis for the applicable requirements that are included in the FOP. A Statement of Basis was prepared for this project and is included in the permit file.

Compliance History Review

1. In accordance with 30 TAC Chapter 60, the compliance history was reviewed on November 8, 2024.
   Site rating: N/A Company rating: N/A
   (High < 0.10; Satisfactory ≥ 0.10 and ≤ 55; Unsatisfactory > 55)
2. Has the permit changed on the basis of the compliance history or site/company rating?.. No

Permit reviewer notes:

- There was no Compliance History information or there were no applicable enforcement components for the site at the time of the last Mass Classification in September of 2024 because the site is new.

Site/Permit Area Compliance Status Review

1. Were there any out-of-compliance units listed on Form OP-ACPS?... No
2. Is a compliance plan and schedule included in the permit?... No

Delinquent Fee Check

1. The delinquent fee check was performed on **November 8, 2024**.
2. Were there any delinquent fees owed? .... No

Public Notice Information

1. Were comments received from the applicant after the draft permit was mailed and before Public Notice was published?.. No
2. Was a revised draft permit or public notice authorization package (PN-Errata) sent

for any reason?.. No
3. Publication date: February 13, 2025 Newspaper name: Crane News
4. Was bilingual public notice published?.. No
Publication date: Newspaper name:
5. Were comments received during Public Notice period?.. No
(a) Was a public hearing requested?.. No
(b) Was a public hearing held?.. No
(c) Was the public hearing request withdrawn?.. No
(d) Was permit content changed as a result of any public comments?... No
6. Was re-publication necessary?... No

Permit reviewer notes:

- The Commissioner's Integrated Database (CID) was checked on 4/10/2025 to verify no public comments.

EPA Review
1. Did EPA comment on the draft permit?... No
2. Was a separate NOPP - Notice of Proposed Permit sent to the EPA?.. No
If yes, did the EPA comment on the proposed permit?... No
3. Were any changes made to the permit after the EPA Review Period?... No
If yes, were these changes made within the 60 day Public Petition Period?... No

Permit reviewer notes:

- The CID was checked on 4/10/2025 to verify no EPA comments.

IMPORTANT MILESTONES

Milestone (Standard)	Start Date	End Date
Date Application Received by TCEQ	03/31/2023	
Date Project Received by Engineer	04/12/2023	
Technical Review Period	04/19/2023	11/07/2024
1st Working Draft Permit Reviewed by Applicant	05/20/2024	06/10/2024
2nd Working Draft Permit Reviewed by Applicant	09/20/2024	09/30/2024
3rd Working Draft Permit Reviewed by Applicant	10/08/2024	11/07/2024
Date PNAP/Draft Permit Mailed	01/17/2025	
Public Notice Comment Period	02/13/2025	03/13/2025
EPA Review Period	02/18/2025	04/04/2025
Date Sign Posting Certification Received	02/13/2025	

EFFECTIVE PERMIT ISSUANCE DATE: April 16, 2025

Liam Lin

04/10/2025

Liam Lin | Date
Permit Reviewer
Operating Permits Section
Air Permits Division

04/10/2025

Elizabeth A. Moorhead

Elizabeth Moorhead | Date
Team Leader
Operating Permits Section
Air Permit Division

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