Statement of Basis - Narrative
NSR Permit

Type of Permit Action: Regular - Significant Revision

Facility: Roadrunner Gas Processing Plant
Company: Lucid Energy Delaware, LLC
Permit No(s).: 7200-M3
Tempo/IDEA ID No.: 36536 - PRN20200001
Permit Writer: Vanessa Springer

Fee Tracking

Tracking	**NSR tracking entries completed:** [] Yes [] No
	NSR tracking page attached to front cover of permit folder: [] Yes [] No
	Paid Invoice Attached: [X] Yes [] No
	Balance Due Invoice Attached: [] Yes [X] No
	Invoice Comments: Balance paid 6/01/2020

Permit Review	**Date to Enforcement:** N/A	**Date of Enforcement Reply:** N/A
	Date to Applicant: 8/18/2020	**Date of Applicant Reply:** TBD
	Date to EPA: N/A	**Date of EPA Reply:** N/A
	Date to Supervisor: 08/07/2020	

1.0 Plant Process Description:

The Roadrunner Gas Processing Plant is a natural gas processing plant located in Eddy County. The primary function of the plant is to separate natural gas (methane) from heavier (liquid) hydrocarbons, raw sweet field gas so that the gas can meet pipeline specifications. The plant has been designated a primary Standard Industrial Classification (SIC) Code of 1311.

The operation of the Roadrunner Gas Processing Plant is intended to process 880 MMscf/d of gas. The gas will be treated to remove CO2, H2S, dehydrated to remove water and processed to remove heavy (liquid) hydrocarbons from the gas stream. Several plant systems will be involved to perform these functions.

Slug Catcher / Separator
A large slug catcher has been placed at the front of the plant to catch and separate any free hydrocarbon liquids and water present in the inlet pipeline gas stream. It is capable of handling large slugs of liquid brought into the plant from pipeline pigging operations. The equipment also serves as a three-phase separator to separate the free hydrocarbons, gas to be processed, and any water that may have condensed out in the pipeline after field dehydration.

Stabilizers
The overhead stabilization system is in place to lower the Reid Vapor Pressure (RVP) of the pipeline liquids and condensate after they are dropped out of the gas stream. Through a process that heats the condensate to flash off lighter hydrocarbons so the RVP is lowered to 9.

The liquids out of the slug catcher are stabilized and sent to the tank farm for truck sales. Any remaining vapors are recycled back to the front of the Slug Catcher. The liquid in the tank farm is then stable and thus does not give off significant flashing vapors. Significant working and standing losses will occur at the tank farm. These emissions will be controlled with a vapor combustor.

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, the 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. The treating solution is a mixture of 50% RO water, 40% methyl-diethanolamine (MDEA) and 10% Piperazine. 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 are absorbed by amine. The amine is now known as rich amine and the remaining gas is sweet and continues to the dehydration systems.

The regeneration of the amine utilizes two 55 MBTU/hr heaters. Significant amounts of VOC and HAP can be generated in this process. The acid gas is sent to a thermal oxidizer where additional combustion will occur further minimizing emissions.

Glycol Dehydration

Triethylene glycol (TEG) is used to remove water from the natural gas stream. Water is saturated into the sweet gas stream during the Amine Treating process. This water is absorbed by the TEG solution. The wet gas is brought into contact with dry glycol in an absorber. Water vapor is absorbed in the glycol and consequently, the water content is reduced. The wet rich glycol then flows from the absorber to a regeneration system in which the entrained gas is separated and fractionated in a column and re-boiler. The heating allows boiling off the absorbed water vapor and the water dry lean glycol is cooled (via heat exchange) and pumped back to the absorber.

The regeneration of the TEG utilizes a small (3 MMBtu/hr) heater per TEG dehydration unit. This process produces VOC and HAP emission. This stream is condensed. The wastewater stream is sent to a wastewater tank. The non-condensable stream is sent to the thermal oxidizer for control where further combustion reduces the emissions.

Molecular Sieve Dehydration

Molecular sieve dehydration is used upstream of the cryogenic processes to achieve a -160°F water dew point. The process uses three molecular sieve vessels with two vessels in service adsorbing moisture from the gas stream and the other vessel in the regeneration mode.

During the regeneration mode, hot, dry gas (regen gas) is passed up through the vessel to drive off the adsorbed moisture from the molecular sieve. The gas comes from the discharge of the residue compressors and it is passed through a heat exchanger and a 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 to the inlet of the cryogenic unit.

Cryogenic Unit

The cryogenic unit is designed to liquefy natural gas components from the sweet, dehydrated inlet gas by removing work from the gas be means of the turbo expander/compressor. The cryogenic unit recovers natural gas liquids (NGL) by cooling the gas stream to extremely cold temperatures (-160°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 lowering the pressure of the gas from around 950 PSIG to approximately 190 PSIG. Once the gas has passed through the system of heat exchangers and expansion it is re-compressed using the energy obtained from expanding the gas.

The gas will flow through the following heat exchangers:

- Gas to Gas Exchanger – This unit exchanges heat from the warm inlet gas and the cold residue gas that has already been expanded. This cools the inlet gas.
- Product Heater – This unit will cool the inlet gas by exchanging heat with the cold liquid product that has been recovered.
- Side-Reboiler – This unit uses heat from the inlet gas to boil the methane out of the liquid. One stream comes off the side of the tower and one stream comes off of the bottom of the tower. This also cools the inlet gas.

The gas is expanded and recompressed in the expander/compressor.

SSM Flares

Three SSM flares are proposed. These flares' header system gathers hydrocarbons from Pressure Safety Devices in the plant, and routes them to the flares. These systems are also used to safely control blow-down hydrocarbons from equipment in the plant.

2.0 Description of this Modification:

Lucid is proposing a significant revision to its NSR Permit No. 7200-M2 to authorize a proposed expansion project to expand its current Road Runner Gas Processing Plant by adding two processing trains (processing trains 3 and 4).

The expansion project will add two additional processing trains (trains 3 and 4) to the exiting trains 1 and 2; however, some design changes of the entire gas processing plant will also be implemented:

1. Eliminating the second Thermal Oxidizer, as well as the second Amine unit (and 2 associated amine reboilers) which were never installed.
2. A total of three flares is proposed: One for train 1, one for train 2 and 3 (larger flare) and one for train 4
3. The processing capacity will increase from 160,600 MMScf/year to 321,200 MMScf/yr
4. No additional storage tanks are proposed and the existing tanks remain unchanged
5. Proposed SSM flare emissions will be based on actual SSM flare data from the current facility plus a safety factor of 25% per the pre-application meeting discussions. The previously permitted SSM flare emissions were over estimated.

This expansion project will not trigger prevention of significant deterioration (PSD) review as the facility will stay below 250 tons per year (tpy) for any criteria pollutant.

3.0 Source Determination:

1. The emission sources evaluated include **Roadrunner Gas Processing Plant**.

2. Single Source Analysis:

A. SIC Code: Do the facilities belong to the same industrial grouping (i.e., same two-digit SIC code grouping, or support activity)? **Yes**

B. Common Ownership or Control: Are the facilities under common ownership or control? **Yes**

C. Contiguous or Adjacent: Are the facilities located on one or more contiguous or adjacent properties? **Yes**

3. Is the source, as described in the application, the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes? **Yes**

4.0 PSD Applicability:

A. The source, as determined in 3.0 above, is **a PSD minor source before and after this modification.**
B. The project emissions for this modification are **not significant.**
C. Netting **is not required (project is not significant).**
D. BACT is **not required for this modification (minor Mod).**

5.0 History (In descending chronological order, showing NSR and TV): *The asterisk denotes the current active NSR and Title V permits that have not been superseded.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
*7200-M3	TBD	NSR Significant Revision	Increasing the facility processing capacity to 321,200 MScf/yr; Adding two process trains (with identical equipment including reboilers, heaters, glycol dehydrators, and electric compressors) to the facility; Increasing the facility fugitives (Unit FUG2) and correcting fugitive emissions calculations; Adding two SSM flares (one for trains 2 and 3 and one for train 4) and revising the calculations for the existing flare so that the three flare units' emissions are based on actual SSM flare data from the facility (plus a 25% safety factor); And removing one thermal oxidizer, one amine unit, and two amine reboilers from the permit (these units were never installed).
7200-M2	11/28/18	NSR Significant Revision	This modification consists of adding a second processing train and changing facility source classification to Major Title V. The added units are 2-EP-1, 2-EP-2, 2-EP-3A, 2-EP-3B, 2-EP-4, 2-EP-5, 2-EP-7, 2-EP-8, 2-EP-9, 2-D-1, 2-D-2, 2-D-3, 2-D-4, T-6.
7200-M1	1/19/2018	NSR Significant	This modification consists of changes to the facility layout, updated emissions, and modeling.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
		Revision	
7200	4/3/2017	NSR- New	This permitting action authorized a new gas processing plant. The operation of the Roadrunner Gas Processing Plant is intended to process 220 MMscfd of gas. The gas will be treated to remove CO_2, dehydrated to remove water and processed to remove heavy (liquid) hydrocarbons from the gas stream. Several plant systems will be involved to perform these functions.

6.0 Public Response/Concerns:

WildEarth Guardians submitted a comment and hearing request on June 12, 2020. A hearing request has been submitted to the Secretary. A decision on whether to have a hearing has not yet been made.

7.0 Compliance Testing:

Unit No.	Compliance Test	Test Dates
EP-9	Initial Compliance Test for NOx, CO	03/14/2019

8.0 Startup and Shutdown:

A. If applicable, did the applicant indicate that a startup, shutdown, and emergency operational plan was developed in accordance with 20.2.70.300.D(5)(g) NMAC? **N/A**

B. If applicable, did the applicant indicate that a malfunction, startup, or shutdown operational plan was developed in accordance with 20.2.72.203.A.5 NMAC? **Yes**

C. Did the applicant indicate that a startup, shutdown, and scheduled maintenance plan was developed and implemented in accordance with 20.2.7.14.A and B NMAC? **No**

D. Does the facility have emissions due to routine or predictable startup, shutdown, and maintenance? If so, have all emissions from startup, shutdown, and scheduled maintenance operations been permitted? **Yes, the facility has 3 SSM flares and also has SSM emissions from blowdowns and tank cleaning (Units SSMB and SSM-misc).**

9.0 Compliance and Enforcement Status:

Shannon Duran, Enforcement Manager, confirmed on 4/24/2020 that there are no ongoing NOV actions or outstanding Settlement Agreements with Enforcement for this facility.

10.0 Modeling:

Modeling was completed by Angela Raso on 7/10/2020. The Modeling Summary concluded: "This modeling analysis demonstrates that operation of the facility described in this report neither causes nor contributes to any exceedances of applicable air quality standards. The standards relevant at this facility are NAAQS for CO, NO2, PM2.5, PM10 and SO2; NMAAQS for CO, H2S, NO2, and SO2; and Class I and Class II PSD increments for NO2, PM10, PM2.5, and SO2."

11.0 State Regulatory Analysis(NMAC/AQCR):

STATE REGU-LATIONS **Citation 20 NMAC**	**Title**	**Applies (Y/N)**	**Unit(s) or Facility**	**Justification:**
2.1	General Provisions	Yes, Always	Entire Facility	The facility is subject to Title 20 Environmental Protection Chapter 2 Air Quality of the New Mexico Administrative Code so is subject to Part 1 General Provisions, Update to Section 116 of regulation for Significant figures & rounding. Applicable with no permitting requirements.
2.3	Ambient Air Quality Standards	Yes for NSR	Entire Facility	**NSR:** 20.2.3 NMAC is a SIP approved regulation that limits the maximum allowable concentration of Sulfur Compounds, Carbon Monoxide and Nitrogen Dioxide.
2.7	Excess Emissions	Yes, Always	Entire Facility	Applies to all facilities' sources
2.33	Gas Burning Equipment - Nitrogen Dioxide	No		This facility has no new gas burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit.
2.34	Oil Burning Equipment - Nitrogen Dioxide	No		This facility has no oil burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit.
2.35	Natural Gas Processing Plant – Sulfur	No	Entire Facility	AQB determined on 3/04/16 that 20.2.35 NMAC does not apply to natural gas processing plants that do not use a Sulfur Recovery Unit to control sulfur emissions but instead use acid gas injection (AGI), flaring, enclosed combustion, re-routing, and/or any other type of sulfur control other than an SRU. See "Guidance and Clarification Regarding Applicability to 20.2.35 NMAC". This facility does not use an SRU.
2.38	Hydrocarbon Storage Facilities	No		The proposed facility is not a tank battery or petroleum production facility as defined in this regulation [20.2.38.7 (D) and (E) NMAC]. The facility does not receive crude oil or condensate from a well. All gas and liquids enter the facility through a pipeline.

STATE REGU-LATIONS Citation 20 NMAC	Title	Applies (Y/N)	Unit(s) or Facility	Justification:
2.61	Smoke and Visible Emissions	Yes	EP-1, 2/3-EP-1, 4-EP-1, EP-2, 2-EP-2, 3-EP-2, 4-EP-2, EP-3A, EP-3B, EP-4, 2-EP-4, 3-EP-4, 4-EP-4, EP-5, 2-EP-5, 3-EP-5, 4-EP-5, EP-6, 2-EP-6, EP-9, COMB-1	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).
2.70	Operating Permits	Yes	Entire Facility	The source is a Title V Major Source as defined at 20.2.70.7 NMAC.
2.71	Operating Permit Fees	Yes	Entire Facility	Source is subject to 20.2.70 NMAC as cited at 20.2.71.109 NMAC.
2.72	Construction Permits	Yes	Entire Facility	NSR Permits are the applicable requirement, including 20.2.72 NMAC.
2.73	NOI & Emissions Inventory Requirements	Yes, Always	Entire Facility	Applicable to all facilities that require a permit.
2.74	Permits-Prevention of Significant Deterioration	No		This facility is PSD Minor before and after this modification (see PSD determination above).
2.75	Construction Permit Fees	Yes	Entire Facility	This facility is subject to 20.2.72 NMAC.
2.77	New Source Performance Standards	Yes	See Sources subject to 40 CFR 60	Applies to any stationary source constructing or modifying and which is subject to the requirements of 40 CFR Part 60.
2.78	Emissions Standards for HAPs	No	See Sources subject to 40 CFR 61	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 61.
2.79	Permits - Nonattainment Areas	No		This facility is not located in, not does it affect, a nonattainment area. Link to Non-attainment Link areas
2.82	MACT Standards for Source Categories of HAPs	Yes	See sources subject to 40 CFR 63	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63.

12.0 Federal Regulatory Analysis:

Federal Regulation	Title	Applies (Y/N)	Unit(s) or Facility	Comments
Air Programs Subchapter C (40 CFR 50)	National Primary and Secondary Ambient Air Quality Standards	Yes	Entire Facility	Independent of permit applicability; applies to all sources of emissions for which there is a Federal Ambient Air Quality Standard.
NSPS Subpart A (40 CFR 60)	General Provisions	Yes	See sources subject to a Subpart in 40 CFR 60	Applies if any other subpart applies.
40 CFR 60.40c, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Yes	EP-2, 2-EP-2, 3-EP-2, 4-EP-2, EP-3A, EP-3B, EP-6, 2-EP-6	Applicable: facility has steam generating units for which construction, modification or reconstruction is commenced after June 9, 1989 and that have a maximum design heat input capacity of 29 MW or less, but greater than or equal to 2.9 MW. Units E P-2, 2-EP-2, 3-EP-2, 4-EP-2, EP-3A, EP-3B, 2-EP-3A, 2-EP-3B, EP-6, and 2-EP-6 have been or will be installed after June 9, 1989, with a heat input capacity greater than or equal to 10 MMbtu/hr but less than 100 MMbtu/hr. The units will only burn natural gas and therefore will not subject to performance tests, reporting requirements, or emission limits under this regulation. The facility will follow all record keeping requirements for these units.
40 CFR 60, Subpart Kb	Standards of Performance for Storage Vessels for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced **After** July 23, 1984	No		This facility has storage vessels with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. However, this subpart does not apply as per 60.110b(d)(4) Vessels with a design capacity less than or equal to 1,589.874 m^3 used for petroleum or condensate stored, processed, or treated prior to custody transfer.
40 CFR 60, Subpart KKK	Standards of Performance for	No		This facility will have commenced construction after August 23, 2011. Thus

Federal Regulation	Title	Applies (Y/N)	Unit(s) or Facility	Comments
	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants			the facility is not subject to this subpart.
40 CFR Part 60 Subpart LLL	Standards of Performance for Onshore Natural Gas Processing: SO2 Emissions	No		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.
NSPS 40 CFR Part 60 Subpart OOOO (Quad -O)	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		Construction commenced 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	D-1, D-2, D-3, D-4, 2-D-1, 2-D-2, 2-D-3, 2-D-4, 3-D-1, 3-D-2, 3-D-3, 3-D-4, 4-D-1, 4-D-2, 4-D-3, 4-D-4, T-1, T-2, T-3, T-4, T-5, EP-8	The facility is defined as an onshore natural gas processing plant covered by 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a. D-1, D-2, D-3, D-4, 2-D-1, 2-D-2, 2-D-3, 2-D-4, 3-D-1, 3-D-2, 3-D-3, 3-D-4, 4-D-1, 4-D-2, 4-D-3, and 4-D-4 are electric driven compressors manufactured after September 18, 2015 and are thus subject to 60.5385a, 60.5410a, 60.5415a, and 60.5420a. T-1, T-2, T-3, T-4, and T-5 are storage vessels constructed after September 18, 2015 which use an internal combustion device COMB-1 co reduce emissions to less than 6 tpy of VOCs. T-6 is a storage vessel that emits less than 6 tpy of VOCs. EP-8 is an amine sweetening unit as defined in this subpart and is constructed

Federal Regulation	Title	Applies (Y/N)	Unit(s) or Facility	Comments
				after September 18, 2015. Per 60.5365a(g) (3) the unit is required to comply with 60.5423a(c) but not required to comply with 60.5405a through 60.5407 a and 60.5410a(g) and 60.5415a(g).
NESHAP Subpart A (40 CFR 61)	General Provisions	No		Applies if any other subpart applies.
MACT Subpart A (40 CFR 63)	General Provisions	Yes	See sources subject to a Subpart in 40 CFR 63	Applies if any other subpart applies.
40 CFR 63.760 Subpart HH	Oil and Natural Gas Production Facilities –	Yes	EP-7, 2-EP-7, 3-EP-7, 4-EP-7	This regulation establishes national emission standards for hazardous air pollutants from oil and natural gas production facilities. The facility is an area source of HAPs and meets the definition of a natural gas processing plant. This regulation applies to units EP-7 and 2-EP-7. These units must comply with 40 CFR 63.764(d)(2) as area sources not located in a UA plus offset and UC boundary.
40 CFR 63 Subpart JJJJJJ (6-Js)	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources	No		Not subject to MACT 6-J per 63.11195(e) since units are gas-fired boilers as defined.
40 CFR 64	Compliance Assurance Monitoring	No		This will be evaluated in future TV permitting actions.
40 CFR 68	Chemical Accident Prevention	Yes	Entire 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 a RMP Plan for these chemicals.

13.0 Exempt and/or Insignificant Equipment that do not require monitoring:

Unit Number	Source Description	Manufacturer	Max Capacity	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5)	Date of Manufacture /Reconstruction[2]

			Capacity Units	Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Installation /Construction[2]
T-7	Used Oil/Slop Oil/Skid Runoff	NA	400	20.72.202.B(2)(a)	2020
			BBL	IA List Item #1.a	TBD
T-8	Used Oil/Slop Oil/Skid Runoff	NA	400	20.72.202.B(2)(a)	2020
			BBL	IA List Item #1.a	TBD
HAUL	Haul Road Emissions	NA	526	20.72.202.B(5)	NA
			Miles/year	IA List Item #1.a	NA

14.0 <u>**New/Modified/Unique Conditions**</u> <u>(Format: Condition#: Explanation):</u>

A. Condition A107.D SSM Flaring Emissions was revised to match AQB's current monitoring protocol for flare emissions.

B. Conditions A107.E and F from NSR Permit 7200-M2 were moved to the flare section of the permit, Section A206 (Conditions A206.A and C).

C. Condition A108.B Facility Inlet Flowrate Limit was added, per instruction from TV Manager Melinda Owens, who stated that this condition is being added by AQB into all gas processing plant permits.

D. Condition A112.A: Facility 20.2.35 NMAC was removed from the permit per NSR template instructions. AQB determined on 3-4-16 that 20.2.35 NMAC does not apply to natural gas processing plants that do not use a Sulfur Recovery Unit to control sulfur emissions but instead use acid gas injection (AGI), flaring, enclosed combustion, re-routing, and/or any other type of sulfur control other than an SRU. See "Guidance and Clarification Regarding Applicability to 20.2.35 NMAC."

E. Condition A203.C: Opacity condition for the combustor revised to better match flare template language.

F. A206.B Flare Gas Flow Monitoring and Gas Analysis condition added to match AQB's current flare emissions monitoring protocol. Previously, these requirements were rolled into the condition A107.D SSM Flaring (that condition is being revised as well, see A. above).

G. Condition A206.D Flare Construction and Stack Height added

H. Condition A208.B Thermal Oxidizer Visible Emissions condition added to better match the template language for flare opacity.

I. Condition A208E (D in previous NSR permit) revised from initial compliance test to periodic emissions testing. Language added to assure 99.9% destruction efficiency, as represented in the application. This unit will be subject to CAM as a control device to the amine unit in the TV permit.

J. Conditions A209.A and B. for OOOOa (fugitives and compressors) were updated to match monitoring protocol language.

K. Condition A209.D OOOOa added for amine unit. The amine unit was previously included in the OOOOa condition for tanks; this condition has citations specific to this unit.

15.0 **Permit specialist's notes to other NSR or Title V permitting staff concerning changes and updates to permit conditions.**

A. Applicant listed unit HAUL, haul roads in Table 2-A and emissions tables. However, this unit is NSR exempt (emits under 0.5 tpy of any pollutant) so it was not included in this permit.

B. The permit application referred to the flares as “Emergency Flares” and used terms “SSM” “Emergency” and “Malfunction” interchangeably/incorrectly. The previous NSR permit for this facility authorizes SSM emissions but no Malfunction emissions. There was concern that the facility may have been binning Malfunctions into their SSM limits. C&E pointed out that the facility has never reported Excess Emissions, even with no Malfunction emissions limits. After some discussion via email, the applicant verified that they have not been binning Malfunctions into their SSM emissions limits and that they would report any Malfunctions as excess emissions if they occurred. In this application/permit, the flares have ben “re-labeled” as SSM Flares, not Emergency flares, since this is more accurate.
C. Although the previous NSR permit classifies the facility as Major Source, TV Melinda Owens discussed with the facility’s air permit contact and confirmed that they have not constructed the second train that was permitted in NSR 7200-M2. As such, they are not operating at Major Source capacity which is why they have not yet applied for a TV Permit.
D. In this NSR permit, the order of the equipment in Tables 104.A and 106.A was revised so that the units are grouped by equipment type, not by train.
E. The previous NSR permit had SO2 flaring emissions permitted, but this permit will not. This is because the flare calculations were revised in this permit application to be based on the actual flaring emissions data from the flare EP-1 in 2019. There were no SO2 SSM emissions in 2019 so the emission limit has been removed from the permit.