Texas Commission on Environmental Quality
INTEROFFICE MEMORANDUM

TO: Office of Chief Clerk **Date:** July 28, 2025

THRU: Amy Browning
Senior Attorney
Environmental Law Division

FROM: Elizabeth Black
Staff Attorney
Environmental Law Division

SUBJECT: Backup Documents Filed for Consideration of Hearing Requests at Agenda

Applicant:	Beaumont New Ammonia LLC
Permit No.:	169687
Program:	Air
Docket No.:	TCEQ Docket No. 2025-0887-AIR

Enclosed please find a copy of the following documents for inclusion in the background material for this permit application:

- The final draft of the permit Special Conditions
- The Emission Sources – Maximum Allowable Emission Rates
- The Permit Amendment Source Analysis and Technical Review
- The Compliance History Report
- The Air Quality Analysis modeling audit

Special Conditions

Permit Number 169687

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

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

Federal Applicability

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

   A. Subpart A, General Provisions.

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

Fuel Specification

4. Combustion units as defined in 30 TAC §101.1 (Emission Point Numbers [EPNs] BLR1, HTR1, and HTR2) shall be fired with pipeline-quality natural gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf). **(TBD)**

   A. The natural gas shall be sampled at least every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

Boiler / Heater

5. NO_x and CO emissions from the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) shall not exceed the following: **(TBD)**

   A. For the Auxiliary Boiler (EPN BLR1): 100 parts per million by volume, dry basis (ppmvd) CO corrected to 3% oxygen (O_2) on a 1-hour average.

   B. For the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2):

      - 50 ppmv CO corrected to 3% oxygen on an annual average.

      - 0.036 pounds per million British thermal unit (lb/MMBtu) of NOx based on the higher heating value (HHV);

   C. Compliance with the NO_X and CO limits for EPNs HTR1 and HTR2 are demonstrated by meeting the requirements in Special Conditions 8 and 9.

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

   A. The maximum allowable emission rates are not exceeded.

   B. The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours.

7. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2), and fuel usage for each shall be recorded monthly. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A. **(TBD)**

   Quality assured (or valid) data must be generated when the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

8. Periodic emission testing shall be performed using a hand-held portable analyzer to measure and record the in-stack concentration of NO_x, CO, and O_2 from the Startup Heaters (EPNs HTR1 and HTR2). All testing data shall be maintained by the permit holder. Each period of operating the Startup Heater shall be recorded and include the date and time of startup and shutdown, as specified in Special Condition 6. At the discretion of the TCEQ, data from the testing and operating records shall be used to determine compliance with the conditions of this permit. Periodic testing shall be conducted on a semiannual basis as specified below, with each semiannual period defined as January 1 through June 30, or July 1 through December 31 of each calendar year. The required periodic testing frequency shall be determined for each semiannual period as follows: **(TBD)**

   - For each semiannual period in which the Startup Heater is not operated, no tests shall be performed.
   - For each semiannual period in which the Startup Heater is operated, one test shall be performed.

9. Startup Heater (EPNs HTR1 and HTR2) tune-ups shall be conducted at least once every 5 years as specified in 40 CFR 63, Subpart DDDDD, paragraphs §63.7540(a)(10)(i) through (vi). Reports do not need to be submitted to EPA or the regional office. **(TBD)**

10. Opacity of emissions from the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) shall not exceed 5 percent averaged over a six-minute period. The permit holder shall

demonstrate compliance with this Special Condition in accordance with the following procedures: **(TBD)**

A. Visible emission observations shall be conducted and recorded at least once during each calendar quarter while the facility is in operation, unless the emission unit is not operating for the entire calendar quarter.

B. Continuous demonstration of compliance with this special condition can be demonstrated by conducting and recording visible emissions observations during normal operations. This determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 mile from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70-degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points. A certified opacity reader is not required for these visible emission observations.

C. If visible emissions are observed from an emission point, then opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Reference Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition.

D. If the opacity limits of this Special Condition are exceeded, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

E. Visible emissions or opacity observations for any source authorized by this permit shall be made upon demand of a representative of the TCEQ or any air pollution control program with jurisdiction. When such observations are required, the methods used, and the observation period duration shall be as specified in this Special Condition unless otherwise specified by the person requiring the observation to be conducted.

Flare

11. The Flare (EPN FLR1) shall be designed and operated in accordance with the following requirements:

A. The flare systems shall be designed such that the combined assist natural gas and waste stream to the flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity at all times when emissions may be vented to them.

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

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

C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

D. The permit holder shall install a continuous flow monitor, gas analyzer, and ammonia analyzer (such as gas chromatography, dispersive ultraviolet-visible absorbance spectrophotometry, near infrared Tunable Diode Laser Absorption Spectroscopy, or comparable ammonia technology) that provide a record of the vent stream flow, ammonia measurement, and composition or Btu content to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow, composition (or Btu content), and ammonia measurement shall be recorded each hour.

The flow monitor shall be calibrated or have a calibration check performed on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0% over the expected range of flows for normal operations and planned MSS operations, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg.

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

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12-month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §§60.18(f)(3) and 60.18(f)(4) shall be recorded at least once every hour. Hourly mass emission rates shall be determined and recorded using the above readings and the emission factors used in the permit application, PI-1 dated July 18, 2022.

12. The flare (EPN FLR2) system shall be designed and operated in accordance with the following requirements: **(TBD)**

A. The flare system shall be designed such that the combined natural gas and waste stream to the flare meets the 40 CFR § 63.670 specifications for minimum combustion zone net heating value and maximum tip velocity at all times that flare vent gas may be directed to the flare for more than 15 minutes. Flared gas actual exit velocity, vent gas net heating value, and flared gas combustion zone net heating value shall be determined in accordance with 40 CFR §63.670(k), §63.670(l), and §63.670(m) on a 15-minute block average and recorded at least once every 15 minutes.

B. The flare shall be operated with a pilot flame present at all times during which flare vent gas may be directed to the flare. The pilot flame shall be continuously monitored by a thermocouple, infrared monitor, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours, demonstrated and recorded per the requirements of §63.670(h).

D. The permit holder shall install a flow monitor that continuously measure, calculate, and record the total volumetric vent stream flow rate (including waste gas, purge gas, supplemental gas, and sweep gas), and shall install a monitoring system capable of determining the concentration of individual components in the flare vent gas or the net heating value of the flare vent gas. The flow monitor sensor and analyzer sample points shall be installed in the vent stream such that the total vent stream to the flare is measured and analyzed.

If one or more gas streams that combine to comprise the total flare vent gas flow are monitored separately for net heating value and flow, the 15-minute block average net heating value shall be determined separately for each measurement location and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

The monitors shall be calibrated or have a calibration check performed as specified in Table 13 of the appendix to 40 CFR 63, Part CC to meet the following accuracy specifications: the vent flow monitor shall be ±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second) ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second), all other gas flow monitors shall be ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute) whichever is greater, temperature monitor shall be ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater, and pressure monitor shall be ±5 percent over the normal operating range or 0.12 kilopascals (0.5 inches of water column), whichever is greater. For purposes of this permit, a calibration check means, at a minimum, using a second device or method to verify that the monitor is accurate as specified in the permit.

Calorimeters shall have an accuracy of at least ±2% of span and be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in Table 13 of the appendix to 40 CFR 63, Part CC, to continuously measure and record the net heating value of the vent gas sent to the flare, in British thermal units/standard cubic foot of the gas.

For determination of net heating value by gas chromatograph, the minimum accuracy shall be as specified in Performance Specification 9 of Part 60, appendix B. Composition monitoring instruments shall be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in 40 CFR §63.671(e) and Table 13 of 40 CFR Pt. 63, Subpart CC. Individual component properties specified in Table 12 of Subpart CC shall apply to net heating value calculations.

For determination of net heating value by continuous process mass spectrometer, the minimum accuracy; composition monitoring; calibration; installation; operation and maintenance shall be done in accordance with 40 CFR §63.671(f).

E. Quality assured (or valid) data must be generated during periods that the specified flare is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the flare operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

F. Hourly mass emission rates shall be determined and recorded using the monitoring data collected pursuant to paragraph D of this Special Condition and the emission factors specified in the permit amendment application PI-1 dated June 17, 2024.

G. The permit holder shall operate the flare to maintain the net heating value of the flare vent gas at or above 400 British thermal units per standard cubic feet (Btu/scf).

H. Pilot and supplemental (fuel) gas combusted in the flare shall be sweet natural gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet.

13. The following additional operational limitations apply to flare EPNs FLR1 and FLR2, as represented in the initial permit application, PI-1 dated July 18, 2022 for EPN FLR1, and permit amendment application, PI-1 dated June 17, 2024 for EPN FLR2: **(TBD)**

(1) Routine flare operations, flare planned MSS equipment clearing, and flare startup operations shall not occur simultaneously.

(2) Flare planned MSS equipment clearing shall occur for no more than 4 hours per year for each train.

(3) Flare startup operations shall occur for no more than 40 hours per year for each train.

Cooling Tower

14. The NH_3 associated with cooling tower (EPNs CT1 and CT2) water shall be monitored at least once per calendar month with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition), an online NH_3 analyzer, or an approved equivalent sampling method. The results of the monitoring, cooling water flow rate and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly NH_3 emissions. The rolling 12-month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the NH_3 emissions between NH_3 monitoring periods over the rolling 12-month period. The emissions between NH_3 monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the two NH_3 monitored results.

PM Monitoring for Cooling Tower

15. The cooling towers (EPNs CT1 and CT2) shall be operated and monitored in accordance with the following:

A. Cooling towers shall each be equipped with drift eliminators having manufacturer's design assurance of 0.001% drift or less. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

B. Total dissolved solids (TDS) shall not exceed 3,000 parts per million by weight (ppmw). Dissolved solids in the cooling water drift are considered to be emitted as PM, PM_{10}, and $PM_{2.5}$ as represented in the permit application calculations.

C. Cooling towers shall be analyzed for particulate emissions using one of the following methods:

(1) Cooling water shall be sampled at least once per day for TDS; or

(2) TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per µmho/cm or ppmw/siemens). The ratio of TDS-to-conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or

(3) TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation factor established for each cooling tower. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using C(2) above provided the highest ratio is not more than 10% larger than the smallest ratio.

(4) The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.

D. A sample of cooling tower water shall be taken from the circulated water stream(s) entering the cooling tower. The analysis shall be conducted using the approved methods below:

(1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, or SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection and transferred to a laboratory area for analysis.

(2) The analysis method for conductivity shall be either ASTM D1125-14 Test Method A (field or routine laboratory testing) or ASTM D1125-14 Test Method B (continuous monitor). The analysis may be conducted at the sample site or with a calibrated process conductivity meter. If a conductivity meter is used, it shall be calibrated at least annually. Documentation of the method and any associated calibration records shall be maintained.

(3) Alternate sampling and analysis methods may be used to comply with D(1) and D(2) with written approval from the TCEQ Regional Director. If approved by the TCEQ Regional Director, the permit holder shall submit a permit application to incorporate the alternative sampling and analysis method into the permit within 2 months of the date of written approval.

(4) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

E. Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, the design drift rate and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

Fugitives

Piping, Valves, Pumps, and Compressors in contact with NH_3 – 28AVO

16. Except as may be provided for in the Special Conditions of this permit, the following requirements apply to the above-referenced equipment:

A. Audio, olfactory, and visual checks for leaks within the operating area shall be made every four hours.

B. Immediately, but no later than four hours upon detection of a leak, plant personnel shall take at least one of the following actions:

(1) Isolate the leak.

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

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

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

Catalyst Handling

17. Catalyst handling for each train shall be limited to 5.21 tons per hour and 2,500 tons per year. Records of catalyst handling shall be totaled for each calendar month and retained for a rolling 24-month period. **(TBD)**

Wastewater

18. Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered to minimize emissions.

19. Wastewater emissions shall be estimated every month using the following procedure:

A. The permit holder shall sample the wastewater prior to the oil-water separator monthly to determine the concentrations of ammonia. Sampling locations, sampling procedures, test methods and calculations shall be as specified in permit application, PI-1 dated June 17, 2024 The oil-water separator outlet flow rate shall be measured and recorded when a sample required by this condition is collected. Records of sampling results shall be maintained for ammonia. **(TBD)**

Initial Demonstration of Compliance

20. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) to demonstrate compliance with the MAERT. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and the U.S. EPA Reference Methods. **(TBD)**

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

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

(1) Proposed date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

(7) Procedure/parameters to be used to determine worst case emissions during the sampling period.

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

B. Air contaminants emitted from the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) to be tested for include (but are not limited to) CO and NO_x.

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

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

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

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

One copy to the appropriate TCEQ Regional Office.

F. Sampling ports and platform(s) shall be incorporated into the design of the Auxiliary Boiler (EPN BLR1) and Startup Heaters (EPNs HTR1 and HTR2) according to the specifications set forth in the attachment entitled "Chapter 2, Guidelines For Stack Sampling Facilities" of the TCEQ Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

Continuous Demonstration of Compliance

21. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of NO_x, CO, and O_2 from the Auxiliary Boiler (EPN BLR1).

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

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

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

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

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

All CGA exceedances of +15 percent accuracy indicate that the CEMS is out of control.

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

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

E. Quality-assured (or valid) data must be generated when the Auxiliary Boiler (EPN BLR1) is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the Auxiliary Boiler (EPN BLR1) operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

Planned Maintenance, Startup and Shutdown

22. This permit authorizes the emissions from the facilities identified in this permit for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

Attachment A identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

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

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

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

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

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

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

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

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

23. Process units and facilities, with the exception of those identified in Attachment A, shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements:

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

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

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

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

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

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 24. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into

the sample probe or the collection system downstream of the process equipment or vessel being purged. If there is not a connection (such as a sample, vent, or drain valve) available from which a representative sample may be obtained, a sample may be taken upon entry into the system after degassing has been completed. The sample shall be taken from inside the vessel so as to minimize any air or dilution from the entry point. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or 10 percent of the LEL. Documented site procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above.

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

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

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

VOC Concentration = Concentration as read from the instrument*RF

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

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

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

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

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

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

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

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

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

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

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

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

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

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

25. Additional occurrences of MSS activities authorized by this permit may be authorized under permit by rule only if conducted in compliance with this permit's procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

26. The following sources and/or activities are authorized under a Permit by Rule (PBR) by 30 TAC Chapter 106. These lists are not intended to be all inclusive and can be altered without modifications to this permit.

Authorization	**Source or Activity**
30 TAC § 106.261	Facilities Emission Limitations
30 TAC § 106.472	Diesel Fuel Storage Tanks, Lube Oil Storage Tanks
30 TAC § 106.511	Fire Water Pumps and Portable Engines

Date: TBD

Permit 169687

Attachment A

Inherently Low Emitting Activities

Activity	Emissions	
	VOC	NH_3
Calibration / Maintenance of Process Instruments		X
Aerosol Cans	X	

Date: December 1, 2022

Permit 169687

Attachment B

Routine Maintenance Activities

Compressor Maintenance

Pump Maintenance

Filter Maintenance

Heat Exchanger Maintenance

Relief Valve Replacement

Valve & Piping Maintenance / Replacement

Date: December 1, 2022

Permit 169687

Attachment C

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN(s)
See Attachment A	Miscellaneous low emitting activities	See Attachment A	FUG1MSS, FUG2MSS
See Attachment B	Routine Maintenance Activities	See Attachment B	FUG1MSS, FUG2MSS
All process units	Process unit shutdown/depressurize/drain	Vent to flare	FLR1MSS, FLR2MSS
All process units	Process unit startup	Vent to flare	FLR1MSS, FLR2MSS
All process units	Process unit purge/degas/drain	Vent to flare	FLR1MSS, FLR2MSS
All process units	Preparation for facility/component repair/replacement	Vent to flare	FLR1MSS, FLR2MSS
All process units	Process unit purge/degas/drain	Vent to atmosphere	FUG1MSS, FUG2MSS
All process units	Process unit startup	Vent to atmosphere	FUG1MSS, FUG2MSS
All process units	Process unit purge/degas/drain	Vent to atmosphere	FUG1MSS, FUG2MSS
See Attachment B	Solids handling operations	PM from catalyst loadouts for return to process - Vent to atmosphere	FUG1MSS, FUG2MSS

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number 169687

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

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
BLR1	Auxiliary Boiler	VOC	0.78	0.68
		NO_x	5.22	4.50
		CO	10.72	4.62
		PM	1.09	0.94
		PM_{10}	1.09	0.94
		$PM_{2.5}$	1.09	0.94
		SO_2	2.03	1.74
HTR1	Startup Heater	VOC	0.64	0.28
		NO_x	4.28	1.87
		CO	8.80	1.92
		PM	0.89	0.39
		PM_{10}	0.89	0.39
		$PM_{2.5}$	0.89	0.39
		SO_2	1.67	0.73
HTR2	Startup Heater	VOC	0.64	0.28
		NO_x	4.28	1.87
		CO	8.8	1.92
		PM	0.89	0.39
		PM_{10}	0.89	0.39
		$PM_{2.5}$	0.89	0.39
		SO_2	1.67	0.73
CT1	Cooling Tower	PM	0.81	3.53
		PM_{10}	0.40	1.77
		$PM_{2.5}$	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH_3	2.25	9.87
CT2	Cooling Tower	PM	0.81	3.53
		PM_{10}	0.4	1.77
		$PM_{2.5}$	0.01	0.01
		NH_3	2.25	9.87
FUG1	Equipment Fugitives (5)	VOC	0.08	0.37
		NH_3	0.68	2.97
FUG2	Equipment Fugitives (5)	VOC	0.08	0.37
		NH_3	0.68	2.97
WWTP	Wastewater Treatment	NH_3	0.20	0.88
FLR1	Flare (Normal Operations)	VOC	0.72	3.14
		NO_x	1.61	7.07
		CO	5.45	23.87
		SO_2	0.24	1.04
		NH_3	1.96	8.57
FLR2	Flare (Normal Operations)	VOC	0.72	3.14
		NO_x	1.61	7.07
		CO	5.45	23.87
		SO_2	0.24	1.04
		NH_3	1.96	8.57
FLR1MSS	Flare MSS (Startup and Controlled MSS)	VOC	1.42	0.27
		NO_x	72.86	8.19
		CO	32.39	1.38
		SO_2	7.24	1.45
		NH_3	119.37	12.30
FLR2MSS	Flare MSS (Startup and Controlled MSS)	VOC	1.42	0.27
		NO_x	72.86	8.19

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		CO	32.39	1.38
		SO_2	7.24	1.45
		NH_3	119.37	12.30
FUG1MSS	MSS Uncontrolled Venting (6)	VOC	1.00	0.05
		PM	0.52	0.12
		PM_{10}	0.24	0.06
		$PM_{2.5}$	0.04	0.01
		NH_3	0.61	2.38
FUG2MSS	MSS Uncontrolled Venting (6)	VOC	1.00	0.05
		PM	0.52	0.12
		PM_{10}	0.24	0.06
		$PM_{2.5}$	0.04	0.01
		NH_3	0.61	2.38

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

Date: TBD

Permit Amendment
Source Analysis & Technical Review

Company	**Beaumont New Ammonia LLC**	Permit Number	**169687**
City	**Nederland**	Project Number	**375277**
County	**Jefferson**	Regulated Entity Number	**RN111536918**
Project Type	**Amendment**	Customer Reference Number	**CN606039899**
Project Reviewer	**Ariel Ramirez**	Received Date	**June 17, 2024**
Site Name	**OCI Clean Ammonia Production Facility**		

Project Overview

Beaumont New Ammonia LLC (BNA) (*previously BNA Clean Ammonia LLC, name change updated on March 31, 2025*) operates an ammonia production facility located in Jefferson County, Beaumont, Texas. BNA submitted an expedited New Source Review (NSR) permit amendment application proposing to authorize a second production train (Train 2) which will operate in the same capacity as Train 1, currently under construction as authorized by TCEQ project no. 344545. BNA represented the final decision to execute the Train 1 construction project was made without relying on any commercial benefits from a potential future ammonia production train. At the time BNA decided to construct Train 1, BNA could only confirm sufficient market demand for the amount of clean ammonia product that one train can produce. Therefore, the Train 1 project was, and is, a commercially viable independent project. International demand for clean ammonia has grown rapidly, and BNA only recently confirmed market demand to justify a second ammonia train. Therefore, BNA is now responding to the recent demand growth by planning to execute the Train 2 project as a stand-alone new project. The proposed amendment project for Train 2 will include construction of the following new emission sources: gas-fired startup heater, cooling water tower, fugitive piping components, an elevated flare, and maintenance, startup, and shutdown (MSS) activities. BNA is also requesting emission increases for the existing gas-fired auxiliary boiler (EPN BLR1). Maintenance, Startup, and Shutdown (MSS) activities are authorized by this permit.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)
PM	4.51	9.02	4.51
PM_{10}	2.69	5.38	2.69
$PM_{2.5}$	0.88	1.76	0.88
VOC	4.45	8.90	4.45
NO_X	19.38	38.76	19.38
CO	29.48	58.96	29.48
SO_2	4.09	8.18	4.09
NH_3	36.53	73.06	36.53

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	June 20, 2024
Site rating & classification:	Unclassified
Company rating & classification:	Unclassified
Has the permit changed on the basis of the compliance history or rating?	No
Did the Regional Office have any comments? If so, explain.	No

Public Notice Information

Requirement	Date
Legislator letters mailed	6/25/24

Requirement	**Date**
Date 1st notice published	7/11/24
Publication Name: Beaumont Enterprise	
Pollutants: anhydrous ammonia, carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide	
Date 1st notice Alternate Language published	7/11/24
Publication Name (Alternate Language): El Perico	
1st public notice tearsheet(s) received	7/16/24
1st public notice affidavit(s) received	7/16/24
1st public notice certification of sign posting/application availability received	8/15/24
SB709 Notification mailed	6/26/24
Date 2nd notice published	8/29/24
Publication Name: Beaumont Enterprise	
Pollutants: anhydrous ammonia, carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide	
Date 2nd notice published (Alternate Language)	8/29/24
Publication Name (Alternate Language): El Perico	
2nd public notice tearsheet(s) received	9/3/24
2nd public notice affidavit(s) received	9/3/24
2nd public notice certification of sign posting/application availability received	9/30/24

Public Interest

Number of comments received	3
Number of meeting requests received	0
Number of hearing requests received	1
Date meeting held	
Date response to comments filed with OCC	
Date of SOAH hearing	

Federal Rules Applicability

Requirement	
Subject to NSPS?	**Yes**
Subparts **A & Db**	
Subject to NESHAP?	**No**
Subparts &	
Subject to NESHAP (MACT) for source categories?	**No**
Subparts	
Nonattainment review applicability: The site is a minor source located in Jefferson County, which is designated as in attainment or unclassified for all pollutants; therefore, nonattainment review is not applicable.	
PSD review applicability: The site is a minor named source and proposed emissions are all less than the unnamed PSD major source threshold of 100 tpy; therefore, PSD review is not applicable.	

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement

Title V applicability: The site is a minor source and not subject to the Title V program.

Periodic Monitoring (PM) applicability: This site is a minor source and is not subject to 40 CFR 70 periodic monitoring requirements; however, the following monitoring requirements are included in the Special Conditions:

- Fugitives: utilize the 28AVO monitoring program for NH3 fugitive emissions
- Flare: continuous monitoring of flare pilot flame; equipped with continuous flow monitor, btu analyzer and ammonia analyzer
- Boiler/Heater: totalizing fuel flow meter recorded monthly; fuel analysis for heating value every six months; visible emission/opacity observations quarterly; Boiler shall be equipped with CEMS for CO, NOx, and O2, while periodic emission testing (semiannual) shall be conducted on the heaters if operated.
- Cooling Tower: NH3 monthly monitoring; Drift eliminators achieve a vendor guaranteed drift <0.001%.
- Wastewater: monthly sampling to determine ammonia concentration

Compliance Assurance Monitoring (CAM) applicability: CAM is not applicable to this project because there are no facilities that have a pre-control potential to emit equal to or greater than the amount required for the site to be classified as a major source under 30 TAC §122.

Process Description

Liquid anhydrous ammonia (NH3) will be catalytically synthesized from hydrogen (H2) and nitrogen (N2). The synthesized NH3 will be recovered and processed to meet anhydrous ammonia product specifications and sent offsite via pipeline. The H2 and N2 will be supplied via pipeline from third-party suppliers. The H2 and N2 will be combined and compressed before feeding the mixed gasses to the NH3 synthesis converter system. The converter system will catalytically convert the H2 and N2 into NH3, but the conversion is limited for each pass through the converter unit, so the converter system will be operated in a circulating loop configuration for multiple passes through the converter to achieve the specified conversion in the system effluent. No excess gases are produced from the NH3 synthesis converter system during normal operation. The effluent from the NH3 synthesis converter system will be fed to an integrated product recovery section including an NH3 chiller system, NH3 refrigeration system, and effluent compression system. The recovered synthesis converter effluent will be processed in a downstream NH3 scrubber and distillation tower to achieve anhydrous NH3 product specifications. The final NH3 product will be transferred to another facility via pipeline for offsite storage and transportation. During normal operation, a low-pressure purge gas process stream will be generated from the NH3 scrubber unit. The purge gas will contain H2 and NH3, but the stream has no potential value as fuel because no fuel will be burned in any combustion unit during normal facility operations. During normal operation, the conversion reactions generate more heat than needed by the entire process, and no combustion-generated heat or steam is needed during normal operation; therefore, the purge gas will be sent to the flare. One elevated flare will be used to control emission from excess gasses generated from the process during normal and MSS operations. The excess gas streams will be gathered in a flare header system and routed to the flare. The flare will manage ammonia vapors vented from pressure safety relief valves, drums, heat exchangers, compressors, pump casings, equipment clearing operations, and other vessels during planned MSS and upset conditions. A sweep gas will be injected into the flare header to prevent air from accumulating in the headers, which could otherwise lead to safety concerns. Supplemental fuel will also be added as needed to maintain the minimum required fuel heating value of the combined flow to the flare. The flare will be unassisted, and the appropriate minimum heating value will be 200 Btu/scf on a lower heating value basis.

The NH3 production facility for the proposed Train 2 will also include utility and support systems including a cooling tower and diesel-fired emergency engines (to be authorized under PBR). Train 2 will also produce additional wastewater to be managed in a single common wastewater system (WWTP) for managing Train 1 and Train 2 wastewater. The WWTP system only includes basic physical and chemical water quality polishing steps and does not include biotreatment or other conventional treatment units. A new gas-fired startup heater and existing gas-fired auxiliary boiler (authorized by TCEQ project no. 344545) will only be fired for limited durations to supply process heat and steam during plant startups and other MSS-related operating scenarios.

Project Scope

The proposed amendment project for Train 2 will include construction of the following new emission sources: gas-fired startup heater, cooling water tower, fugitive piping components, an elevated flare, and MSS activities. BNA is also requesting annual emission increases for the existing gas-fired auxiliary boiler (EPN BLR1) that was initial authorized by the NSR Permit. Emergency-use stationary internal combustion engines will also be constructed but the engine specifications are subject to change, so representative engine emission rates have been calculated for separate authorization under PBR. Emissions from the PBR-authorized sources have been included in the final modeling submittal.

Changes to the MAERT

EPN(s)	Source	Comment
BLR1	Auxiliary Boiler	Annual emissions increase to support new Train 2
HTR2	Startup Heater	New emission sources associated with Train 2
CT2	Cooling Tower	
FUG2	Equipment Fugitives	
FLR2	Flare (Normal Operations)	
FLR2MSS	Flare MSS (Startup and Controlled MSS)	
FUG2MSS	MSS Uncontrolled Venting	
WWTP	Wastewater Treatment	Emissions increases associated with additional wastewater produced by new Train 2

Changes to the Special Conditions

A summary of the draft permit requirements, including control, monitoring, recordkeeping and reporting requirements, is given below.

SC No.	Comment
4	Limit on fuel gas combusted at facility, includes requirements for natural gas sampling. Added reference to new HTR2
5	NOx and CO limitations for the boiler and heaters. Added reference to new HTR2.
7	Fuel flow requirements for the boiler and heaters. Added reference to new HTR2.
8	Periodic testing requirements for heaters. Added reference to new HTR2.
9	Tune-up requirements for heater in accordance with 40 CFR DDDDD. Added reference to new HTR2.
10	Opacity requirements for the boiler and heaters, added reference to new HTR2.
11.E	Existing subpart E moved into its own standalone condition 13.
12	New condition added reflective of requirements for EPN FLR2 only. Referenced 40 CFR §63.670 requirements identified in this Special Condition shall specify the methods used to determine the parameters outlined in that condition. The facility is not subject to or regulated under 40 CFR 63 Subpart CC. Refer to project file for more details.
13	Additional operational limits pertaining to the flares moved into standalone condition and are reflective of

SC No.	Comment
	the final impact analysis. The existing language has been updated to include reference to both flares FLR1 and FLR2.
14-15	Control, monitoring, and recordkeeping NH3 and PM requirements for the cooling tower; added reference to new CT2.
17	Requirements for catalyst handling updated to reflect requirements are applicable for each train, as represented in emissions calculations.
19	Requirements for wastewater including ammonia concentration sampling; updated to refer to PI-1 for current application rather than initial application.
20	Stack sample requirements for the boiler and heaters, added reference to new HTR2 throughout
Att. C	MSS Activity Summary; updated table to also refer to new EPNs FUG2MSS and FLR2MSS as appropriate.

Best Available Control Technology

Source Name	EPN	Best Available Control Technology Description
Auxiliary Boiler Startup Heater	BLR1 HTR2	The boiler and heater will utilize good combustion practices, fire low-sulfur fuel, and will be equipped with low-NOx burners with a NOx emission factor of 0.036 lb/MMBtu. The Applicant represented selective catalytic reduction is not appropriate emission control technology due to the limited duration of each operating period and SCR design “turndown” limitations. The Applicant provided the following additional information to justify low-NOx burners as BACT: Low-NOx burners are proposed based on the planned heater design. The startup heater will be designed for natural draft combustion air intake. Ultra-low-NOX burner systems are compatible with more sophisticated methods of controlling air feed rates and other combustion zone conditions. Therefore, low- NOX burners are proposed for compatibility with the basic type of heater to be installed. Both combustion units are represented to only operate intermittently to support planned startup events and other MSS activities. CO factor based on TCEQ Tier I BACT for gas-fired heaters with 100 ppmvd for short-term fluctuations in combustion conditions. The boiler will be equipped with CEMS for NOx and CO. Similar to HTR1, the applicant has provided the following information to justify not requiring CEMS for HTR2: The primary role of the Startup Heater will be to provide process heat during plant-wide startups, BNA has identified certain operating scenarios outside of a plant-wide startup when additional process heat may be needed, and the Startup Heater would be operated for short durations outside of a plant-wide startup. These “non-startup” heater operating scenarios would occur infrequently, and total annual operations will not exceed the 960 hours/year value used to estimate annual emissions for the Startup Heater (as per heater emissions calculation Table C-3 in Appendix C of the confidential application document). These “non-startup” operating scenarios would not be expected to occur every year and would not normally be scheduled with enough advanced notice to coordinate a RATA test if a CEMS were required. The total cost of a CEMS is disproportionately high compared to the proposed lb/hr and TPY emissions from the Startup Heater considering the heater will be operated only during plant-wide startup events. Also, the heater is integrated with the ammonia process unit and is not designed to operate outside of plant startup events. Operating the heater during normal plant operations could cause damage to certain process equipment. The plant is designed to operate continuously for more than a year without a shutdown or startup for a unit turnaround. Shutting down and restarting the entire plant just to perform annual Appendix F/Procedure 1 RATA tests on the Startup Heater would lead to unnecessary plant startup emissions exceeding the potential emission rates from the Startup Heater. In lieu of CEMs and as detailed above, the Applicant has represented periodic testing and tune up requirements for the heater as identified in CNDs 8 and 9.
Cooling Tower	CT2	Monthly monitoring of NH3 in water per Appendix P using the appropriate EPA or ASTM method, or an online NH3 analyzer. Drift eliminators achieve a vendor guaranteed drift <0.001%. The applicant represented that the cooling water will not pass through any heat

Source Name	EPN	Best Available Control Technology Description
		exchanger containing VOC; therefore, there is no potential for VOC leaks into the cooling tower.
Fugitives	FUG2	The total projected uncontrolled annual VOC emissions are <10tpy; therefore, an additional LDAR program is not required for fugitive VOC emissions. For fugitive NH_3 emissions, the 28AVO LDAR program will be utilized.
Wastewater	WWTP	The Applicant verified the stie will not have a conventional wastewater treatment plant. Site wastewater treatment consists of a simple package treatment system consisting of pH neutralization followed by oil skimming in a corrugated plate interceptor separator in case of any separable non-aqueous liquids. No storage or biological treatment of wastewater is proposed and uncontrolled site-wide VOC emissions from all wastewater system components are less than 5 tpy. BNA proposes covered conveyance systems for process wastewater, monthly sampling to determine the ammonia concentrations, and routine operator checks of the systems for emissions of NH_3.
Flare	FLR2	The current NSR permit authorizes one elevated, unassisted flare (Emission Point Number [EPN] FLR1), which is not within the scope of the review for the current project as it is not proposed to be modified. The current amendment application proposes to authorize one additional elevated, unassisted flare (EPN FLR2) at the site. Flares are used to control routine emissions, planned maintenance, startup, and shutdown (MSS), and process upsets. BACT for VOCs is compliance with 40 CFR § 60.18 specifications for maximum tip velocity and minimum net heating value. A waste gas flow monitor and a gas composition analyzer or calorimeter are required. The flares are required to be equipped with a thermocouple or infrared monitor to ensure the presence of a pilot flame. Visible emissions are prohibited except for periods not to exceed a total of five minutes during any two consecutive hours. Special Condition No. 12.H requires pilot and supplemental (fuel) gas combusted in the new flare (EPN FLR2) to be sweet natural gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet. Since the Beaumont New Ammonia LLC site is an ammonia production facility and not a petroleum refinery, the provisions of 40 CFR Part 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries do not apply to this site. The design and monitoring requirements in 40 CFR Part 63 Subpart CC have not been established as BACT for all flares across various industries. Nonetheless, the new flare (EPN FLR2) at this site is represented to comply with the design and operating requirements of 40 CFR Part 63 Subpart CC. The flare (EPN FLR2) requirements in the permit for this site include reference to 40 CFR §63.670 requirements. These requirements specify the methods used to determine the parameters outlined within even though the facility is not subject to or regulated under 40 CFR Part 63 Subpart CC.
MSS Flaring	FLR2MSS	
MSS Venting – Process Equipment MSS (Solids Handling Operations)	FUG2MSS	Transfer and handling of catalyst will generate minimal particulate emissions. Current TCEQ Tier I BACT for conventional bulk material handling does not apply to these process catalyst transfers as the catalyst material will contain precious metals and will not be handled as an aggregate material. Because the catalyst is costly, the catalyst will not be stored in open piles or dropped from heights as would be common with gravel or other typical aggregate materials addressed in current TCEQ Tier I BACT. Annual emissions of PM from catalyst transfers are minimal (less than 1 tpy). BNA proposes Best Management Practices for catalyst transfers as follows: - Minimize particulate losses by bringing catalyst onsite in containers ready to transfer directly into process (e.g., no onsite blending). - Manage catalyst outside the process in containers that are kept closed except as needed for transfers directly from containers into process equipment with minimal drop heights.

Source Name	EPN	Best Available Control Technology Description
		- Include catalyst lock hoppers and other design features to enclose the transfer points into and out of the process equipment with dust capture systems that vent back into the process to the extent practical.

Permits Incorporation: None.

Impacts Evaluation

Was modeling conducted?	**Yes**	Type of Modeling:	**AERMO (Version 23132)**
Is the site within 3,000 feet of any school?			**N**o

Based on the modeling review, the air quality analysis (AQA) is acceptable for all review types and pollutants. The health effects review is complete and no adverse health effects are expected to occur among the public health, welfare, or the environment as a result of exposure to the emissions from the facilities authorized by this permit. Please see the model audit dated August 14, 2024 (WCC Content ID 7219879) for full details.

Project Reviewer	Date	Section Manager	Date
Ariel Ramirez		Bonnie Evridge	

The TCEQ is committed to accessibility.
To request a more accessible version of this report, please contact the TCEQ Help Desk at (512) 239-4357.

Compliance History Report

Compliance History Report for CN606039899, RN111536918, Rating Year 2024 which includes Compliance History (CH) components from September 1, 2019, through August 31, 2024.

Customer, Respondent, or Owner/Operator:	CN606039899, Beaumont New Ammonia Llc	**Classification:** UNCLASSIFIED	**Rating:** -----
Regulated Entity:	RN111536918, OCI CLEAN AMMONIA PRODUCTION FACILITY	**Classification:** UNCLASSIFIED	**Rating:** -----
Complexity Points:	10	**Repeat Violator:** NO	
CH Group:	05 - Chemical Manufacturing		
Location:	1575 LONE STAR DR NEDERLAND, TX 77627-1316, JEFFERSON COUNTY		
TCEQ Region:	REGION 10 - BEAUMONT		

ID Number(s):

AIR NEW SOURCE PERMITS PERMIT 169687
STORMWATER PERMIT TXR1558MU
STORMWATER PERMIT TXR1585NV
STORMWATER PERMIT TXR1548QQ
STORMWATER PERMIT TXR1549QQ
STORMWATER PERMIT TXR1538SO
WASTEWATER EPA ID TX0145165
WASTEWATER PERMIT WQ0005440000
INDUSTRIAL AND HAZARDOUS WASTE EPA ID TXR000087021
INDUSTRIAL AND HAZARDOUS WASTE SOLID WASTE REGISTRATION # (SWR) 98993

Compliance History Period: September 01, 2019 to August 31, 2024 **Rating Year:** 2024 **Rating Date:** 09/01/2024

Date Compliance History Report Prepared: July 21, 2025

Agency Decision Requiring Compliance History: Permit - Issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit.

Component Period Selected: June 17, 2019 to June 17, 2024

TCEQ Staff Member to Contact for Additional Information Regarding This Compliance History.

Name: TCEQ Staff Member **Phone:** (512) 239-1000

Site and Owner/Operator History:

1) Has the site been in existence and/or operation for the full five year compliance period? NO
2) Has there been a (known) change in ownership/operator of the site during the compliance period? NO

Components (Multimedia) for the Site Are Listed in Sections A - J

A. Final Orders, court judgments, and consent decrees:
N/A

B. Criminal convictions:
N/A

C. Chronic excessive emissions events:
N/A

D. The approval dates of investigations (CCEDS Inv. Track. No.):
N/A

E. Written notices of violations (NOV) (CCEDS Inv. Track. No.):
A notice of violation represents a written allegation of a violation of a specific regulatory requirement from the commission to a regulated entity. A notice of violation is not a final enforcement action, nor proof that a violation has actually occurred.

N/A

F. Environmental audits:
N/A

G. Type of environmental management systems (EMSs):
N/A

H. Voluntary on-site compliance assessment dates:
N/A

I. Participation in a voluntary pollution reduction program:
N/A

J. Early compliance:
N/A

Sites Outside of Texas:
N/A

TCEQ Interoffice Memorandum

To: Ariel Ramirez
Mechanical/Coatings Section

Thru: Chad Dumas, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Logan Smith and Ahmed Omar, P.E.
ADMT

Date: October 14, 2022

Subject: Air Quality Analysis Audit - OCI Clean Ammonia LLC (RN111536918)

1. Project Identification Information

Permit Application Number: 169687
NSR Project Number: 344545
ADMT Project Number: 8180
County: Jefferson
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\8180\8180.pdf

Air Quality Analysis: Submitted by Burns & McDonnell, September 2022, on behalf of OCI Clean Ammonia LLC. Additional information and modeling were provided September and October 2022.

2. Report Summary

The air quality analysis is acceptable for all review types and pollutants. The results are summarized below.

A. Minor Source NSR and Air Toxics Analysis

Table 1. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	68	817

Table 2. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	5.4	7.8
SO_2	3-hr	60	25
PM_{10}	24-hr	24	5
$PM_{2.5}$	24-hr	13	1.2
$PM_{2.5}$	Annual	0.6	0.2

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
NO_2	1-hr	13	7.5
NO_2	Annual	0.6	1
CO	1-hr	483	2000
CO	8-hr	297	500

The annual $PM_{2.5}$ and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor.

The GLCmax for 24-hr $PM_{2.5}$, 3-hr SO_2, and 24-hr PM_{10} represent the maximum predicted concentrations over five years of meteorological data.

The GLCmax for all other pollutants and averaging times are the maximum predicted concentrations associated with one year of meteorological data.

Intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 De Minimis analyses. Please refer to the Modeling Emissions Inventory section for details.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The $PM_{2.5}$ De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of a $PM_{2.5}$ NAAQS based on the analyses documented in EPA guidance and policy memorandums[3].

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the worst-case source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.02 µg/m³ and 0.001 µg/m³, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De Minimis levels, a full impacts analysis is required.

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf

[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

Table 3. Total Concentrations for Minor NSR NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	3-hr	54	173	227	1300
PM_{10}	24-hr	21	87	108	150
$PM_{2.5}$	24-hr	10	21	31	35
$PM_{2.5}$	Annual	0.6	9.5	10.1	12
NO_2	1-hr	10	90	100	188

The GLCmax for 3-hr SO_2 is the maximum high, second high (H2H) predicted concentration across five years of meteorological data.

The 24-hr PM_{10} GLCmax is the maximum high, sixth high (H6H) predicted concentration over five years of meteorological data.

The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The GLCmax for annual $PM_{2.5}$ represents the highest five-year average of the maximum predicted concentrations determined for each receptor.

The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor.

A background concentration for SO_2 was obtained from the EPA AIRS monitor 482450011 located at 623 Ellias St., Port Arthur, Jefferson County. The applicant used the second highest 3-hr concentration of the most recent year (2021) for 3-hr value. The ADMT was unable to verify the background concentration reported by the applicant; however, the background concentration reported by the applicant is conservative. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

A background concentration for PM_{10} was obtained from the EPA AIRS monitor 481670004 located at 2516 Texas Avenue., Texas City, Galveston County. The H2H 24-hr concentration from the most recent three years (2019-2021) was used for the 24-hr value. The use of this monitor is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482010058 located at 7210 ½ Bayway Dr., Baytown, Harris County. The three-year average (2019-2021) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value. The three-year average (2019-2021) of the annual concentrations was used for the annual value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

A background concentration for NO_2 was obtained from the EPA AIRS monitor 482011034 at 1262 1/2 Mae Drive, Houston, Harris County. The three-year average (2019-2021) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the worst-case source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.02 $\mu g/m^3$ and 0.001 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in Table 3 above, the results are less than the NAAQS.

Table 4. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
ammonia	7664-41-7	1-hr	174	Western Property Line	180

The GLCmax location is listed in Table 4 above. The GLCmax and the GLCni are the same.

3. Model Used and Modeling Techniques

AERMOD (Version 22112) was used in a refined screening mode.

According to the applicant, emissions from routine flare operations (Model ID FLR1), flare planned MSS equipment clearing (Model ID FLR1MSS2), and flare startup operations (Model ID FLR1MSS1) will not occur simultaneously. Therefore, the following three scenarios were modeled using source groups:

- Routine: Includes all sources except Model IDs HTR1, BLR1, FLR1MSS1 and FLR1MSS2.
- MSS Startup: Include all sources except Model IDs FLR1, FLR1MSS2, and FUG1MSS2.
- MSS Equipment Clearing: Include all sources except Model IDs HTR1, BLR1, FLR1 and FLR1MSS1.

The results associated with the scenario with the maximum predicted concentration are reported in the tables above. For annual analyses, the applicant did not include all sources in one single source group. Since all sources operate over the course of a year, the ADMT conducted test modeling including all sources in a single source group and verified that the applicant's approach will not affect the overall modeling results.

A. Land Use

Low roughness and elevated terrain were used in the modeling analysis. These selections are generally consistent with the AERSURFACE analysis, topographic map, DEMs, and aerial photography.

The result of the AERSURFACE run (0.1 meter) falls between low and medium roughness length value ranges, and the applicant did not provide justification for the selection of low roughness over medium roughness. However, the ADMT conducted test modeling using meteorological datasets associated with medium roughness and verified that the applicant's approach will not affect the overall modeling conclusion.

B. Meteorological Data

Surface Station and ID: Jefferson, TX (Station #: 12917)
Upper Air Station and ID: Lake Charles, LA (Station #: 3937)
Meteorological Dataset: 2014-2018 for PM_{10}, $PM_{2.5}$, 3-hr SO_2, and 1-hr NO_2 analyses; 2016 for all other analyses
Profile Base Elevation: 4.9 meters

While five years of meteorological data were used for the 1-hr NO_2 analysis, one year of meteorological data was used for the annual NO_2 analysis. Also, while five years of meteorological data were used for the 3-hr SO_2 analysis, one year of meteorological data was used for the 1-hr SO_2 analysis. It is unlikely that these inconsistencies will affect the overall modeling results.

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

Some receptors on the southeast side of the property were modeled on-site. This is conservative.

D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the plot plan and modeling report.

4. Modeling Emissions Inventory

The modeled emission point, area, and volume source parameters and rates were consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The computation of the effective stack diameters for the flares is consistent with TCEQ modeling guidance.

The applicant assumed full conversion of NO_x to NO_2, which is conservative.

For the 1-hr SO_2 and 1-hr NO_2 de Minimis and NAAQS analyses, emissions from the emergency engines (EPNs ENG1 and ENG2) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from each engine were represented to occur for no more than 100 hours per year.

For the 1-hr SO_2 and 1-hr NO_2 de Minimis and NAAQS analyses, emissions from flare planned MSS equipment clearing (Model ID FLR1MSS2), and flare startup operations (Model ID FLR1MSS1) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from flare planned MSS equipment clearing, and flare startup operations were represented to occur for no more than 4 and 40 hours per year, respectively.

With the exceptions above, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.