TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

COMBINED
NOTICE OF PUBLIC MEETING
AND
APPLICATION AND PRELIMINARY DECISION
FOR AIR QUALITY PERMITS

PROPOSED AIR QUALITY PERMIT NUMBERS 170854, PSDTX1614, HAP81, AND GHGPSDTX227

APPLICATION AND PRELIMINARY DECISION. Energy Transfer Petrochemical Holdings, LLC, 8111 Westchester Dr. Suite 600, Dallas, Texas 75225, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of proposed State Air Quality Permit 170854, issuance of Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1614, issuance of Hazardous Air Pollutant Major Source [FCAA §112(g)] Permit HAP81, and issuance of Greenhouse Gas (GHG) PSD Air Quality Permit GHGPSDTX227 for emissions of GHGs, which would authorize construction of the Energy Transfer Petrochemicals Facility located at 2300 North Twin City Highway, Nederland, Jefferson County, Texas 77627. This application was processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. **AVISO DE IDIOMA ALTERNATIVO.** El aviso de idioma alternativo en español está disponible en https://www.tceq.texas.gov/permitting/air/newsourcereview/airpermits-pendingpermit-apps. The proposed facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide, sulfuric acid mist, and greenhouse gases. The proposed facility will emit the following air contaminants which are significant for the FCAA §112(g) action: hazardous air pollutants. In addition, the facility will emit the following air contaminants: hydrogen sulfide and ammonia.

The degree of PSD increment predicted to be consumed by the proposed facility and other increment-consuming sources in the area is as follows:

Sulfur Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
3-hour	181	512
24-hour	81	91
Annual	5	20

PM_{10}

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	8	30

Nitrogen Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
Annual	22	25

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (μg/m³)	Allowable Increment (μg/m³)
24-hour	8.65	9
Annual	2.73	4

This application was submitted to the TCEQ on October 28, 2022. The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Beaumont regional office, and at Marion and Ed Hughes Public Library, 2712 Nederland Avenue, Nederland, Jefferson County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Beaumont Regional Office, 3870 Eastex Freeway, Beaumont, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-93.999496,29.993133&level=13.

PUBLIC COMMENT / PUBLIC MEETING. You may submit public comments to the Office of the Chief Clerk at the address below. The TCEQ will consider all public comments in developing a final decision on the application. A public meeting will be held and will consist of two parts, an Informal Discussion Period and a Formal Comment Period. A public meeting is not a contested case hearing under the Administrative Procedure Act. During the Informal Discussion Period, the public will be encouraged to ask questions of the applicant and TCEQ staff concerning the permit application. The comments and questions submitted orally during the Informal Discussion Period will not be considered before a decision is reached on the permit application, and no formal response will be made. Responses will be provided orally during the Informal Discussion Period. During the Formal Comment Period on the permit application, members of the public may state their formal comments orally into the official record. At the conclusion of the comment period, all formal comments will be considered before a decision is reached on the permit application. A written response to all formal comments will be prepared by the executive director and will be sent to each person who submits a formal comment or who requested to be on the mailing list for this permit application and provides a mailing address. Only relevant and material issues raised during the Formal Comment Period can be considered if a contested case hearing is granted on this permit application.

The Public Meeting is to be held:

Thursday, November 30, 2023 at 7:00 PM
Nederland Performing Arts Center at Nederland High School
2101 N 18th Street
Nederland, Texas 77627

Persons with disabilities who need special accommodations at the meeting should call the Office of the Chief Clerk at 512-239-3300 or 1-800-RELAY-TX (TDD) at least five business days prior to the meeting.

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 170854, for PSD Air Quality Permit Number PSDTX1614, and for Hazardous Air Pollutant Major Source [FCAA §112(g)] Permit HAP81. There is no opportunity to request a contested case hearing regarding the portion of the application for GHG PSD Air Quality Permit Number GHGPSDTX227. A contested case hearing is a legal proceeding similar to a civil trial in a state

district court. A person who may be affected by emissions of air contaminants, other than GHGs, from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application for the portion of the application for GHG PSD Air Quality Permit GHGPSDTX227. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 170854, for PSD Air Quality Permit Number PSDTX1614, and for Hazardous Air Pollutant Major Source [FCAA §112(g)] Permit HAP81 the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the State Air Quality Permit Number 170854, for PSD Air Quality Permit Number PSDTX1614, Hazardous Air Pollutant Major Source [FCAA §112(g)] Permit HAP81 and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www14.tceq.texas.gov/epic/eComment/, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Energy Transfer Petrochemical Holdings LLC at the address stated above or by calling Ms. Celia Chu, Project Manager, Environmental at (713) 989-6428.

Notice Issuance Date: October 12, 202

COMISIÓN DE CALIDAD AMBIENTAL DE TEXAS

EJEMPLO A

COMBINADO AVISO DE REUNIÓN PÚBLICA Y DE SOLICITUD Y DECISIÓN PRELIMINAR PARA UNOS PERMISOS DE CALIDAD DEL AIRE

NÚMEROS DE PERMISOS PROPUESTOS: 170854, PSDTX1614, HAP81, AND GHGPSDTX227

SOLICITUD Y DECISIÓN PRELIMINAR. Energy Transfer Petrochemical Holdings, LLC, 8111 Westchester Dr., Suite 600, Dallas, Texas 75225, ha solicitado a la Comisión de Calidad Ambiental de Texas (TCEQ, por sus siglas en inglés) la emisión del permiso estatal de calidad del aire propuesto 170854, la emisión del permiso de calidad del aire de prevención del deterioro significativo (PSD, por sus siglas en inglés) PSDTX1614, la emisión del Permiso de Fuente Principal de Contaminantes Peligrosos del Aire [FCAA §112(g)] HAP81, y la emisión del Permiso de Calidad del Aire PSD de Gases de Efecto Invernadero (GHG) GHGPSDTX227 para emisiones de GHG, que autorizarían la construcción de la Instalación Petroquímica de Energy Transfer ubicada en 2300 North Twin City Highway, Nederland, Condado de Jefferson, Texas 77627. Esta solicitud se procesó de manera expedita, como lo permiten las reglas de la comisión en el 30 Código Administrativo de Texas, Capítulo 101, Subcapítulo J. La instalación propuesta emitirá los siguientes contaminantes del aire en cantidad significativa: monóxido de carbono, óxidos de nitrógeno, compuestos orgánicos, partículas, incluidas las partículas con diámetros iguales o inferiores a 10 micrones y a 2,5 micrones, dióxido de azufre, vapor de ácido sulfúrico y gases de efecto invernadero. La instalación propuesta emitirá los siguientes contaminantes del aire que son significativos para la acción FCAA §112(g): contaminantes peligrosos del aire (HAPs). Además, la instalación emitirá los siguientes contaminantes del aire: sulfuro de hidrógeno y amoníaco.

El grado de incremento de la PSD que se prevé que consumirán la instalación propuesta y otras fuentes consumidoras de incremento de la zona es el siguiente:

Dióxido de Azufre

Tiempo máximo de promedio	**Incremento máximo consumido (μg/m^3)**	**Incremento permisible (μg/m^3)**
3 horas	181	512
24 horas	81	91
Anual	5	20

Material Particulado Incluyendo Material Particulado con Diámetros de 10 Micrones o Menos

Tiempo máximo de promedio	**Incremento máximo consumido (μg/m^3)**	**Incremento permisible (μg/m^3)**
24 horas	8	30

Dióxido de Nitrógeno

Tiempo máximo de promedio	**Incremento máximo consumido (μg/m^3)**	**Incremento permisible (μg/m^3)**
Anual	22	25

Material Particulado Incluyendo Material Particulado con Diámetros de 2.5 Micrones o Menos

Tiempo máximo de promediado	**Incremento máximo consumido (μg/m^3)**	**Incremento admisible (μg/m^3)**
24 horas	8.65	9
Anual	2.73	4

Esta solicitud se presentó a la TCEQ el 28 de octubre de 2022. El director ejecutivo ha determinado que las emisiones de contaminantes del aire de la instalación propuesta que están sujetas a la revisión de la PSD no violarán ninguna regulación estatal o federal de calidad del aire y no tendrán ningún impacto adverso significativo en los suelos, la vegetación o la visibilidad. Se han evaluado todos los contaminantes del aire y se utilizará la "mejor tecnología de control disponible" (BACT) para el control de estos contaminantes.

El director ejecutivo ha completado la revisión técnica de la solicitud y ha preparado un proyecto de permiso que, de ser aprobado, establecería las condiciones en las que la instalación debe operar. La solicitud de permiso, la decisión preliminar del director ejecutivo, el proyecto del permiso y el resumen de determinación preliminar del director ejecutivo y el análisis de la calidad del aire del director ejecutivo estarán disponibles para su visualización y copia en la oficina central de la TCEQ, la oficina regional de la TCEQ Beaumont y en la Biblioteca Pública Marion y Ed Hughes, 2712 Nederland Avenue, Nederland, Condado de Jefferson, Texas a partir del primer día de publicación de este aviso. El archivo de cumplimiento de la instalación, si existe alguno, está disponible para su revisión pública en la oficina regional Beaumont de la TCEQ, 3870 Eastex Freeway, Beaumont, Texas.

INFORMACIÓN DISPONIBLE EN LÍNEA. Estos documentos pueden consultarse a través del sitio Web de la Comisión en www.tceq.texas.gov/goto/cid: la decisión preliminar del director ejecutivo que incluye el proyecto de permiso, el resumen de la determinación preliminar del director ejecutivo, el análisis de la calidad del aire y, una vez disponible, la respuesta del director ejecutivo a los comentarios y la decisión final sobre esta solicitud. Acceda a la Base de Datos Integrada de comisionados (CID, por sus siglas en inglés) utilizando el enlace anterior e ingrese el número de permiso para esta solicitud. La ubicación pública mencionada anteriormente proporciona acceso público a Internet. Este enlace a un mapa electrónico de la ubicación general del sitio o instalación se proporciona como cortesía pública y no como parte de la solicitud o aviso. Para conocer la ubicación exacta, consulte la solicitud. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-93.999496,29.993133&level=13.

COMENTARIO PÚBLICO/REUNIÓN PÚBLICA. Puede enviar comentarios públicos a la Oficina del Secretario Principal en la dirección que aparece abajo. La TCEQ tendrá en cuenta todos los comentarios del público para tomar una decisión final sobre la solicitud. Se celebrará una reunión pública que constará de dos partes, un Período de Discusión Informal y un Período de Comentarios Formales. Una reunión pública no es una audiencia de caso impugnado conforme a la Ley de Procedimiento Administrativo. Durante el Período de Discusión Informal, se alentará al público a hacer preguntas al solicitante y al personal de la TCEQ sobre la solicitud de permiso. Los comentarios y preguntas presentados oralmente durante el Período de Discusión Informal no se considerarán antes de tomar una decisión sobre la solicitud de permiso, y no se dará una respuesta formal. Las respuestas se facilitarán oralmente durante el periodo el Período de Discusión Informal. Durante el Período de Comentarios Formales sobre la solicitud de permiso, los miembros del público podrán hacer constar oralmente sus comentarios formales en el acta oficial. Una vez concluido el periodo de comentarios, se tendrán en cuenta todos los comentarios formales antes de tomar una decisión sobre la solicitud de permiso. El director ejecutivo preparará una respuesta por escrito a todos los comentarios formales y la enviará a cada persona que presente un comentario formal o que haya solicitado figurar en la lista de correo para esta solicitud de permiso y proporcione una dirección postal. En caso de que se conceda una audiencia sobre esta solicitud de permiso, sólo se tendrán en cuenta las cuestiones relevantes y materiales planteados durante el periodo de comentarios formales.

La Reunión Pública se celebrará:

Jueves, 30 de noviembre 2023 a las 7:00 PM
Nederland Performing Arts Center en Nederland High School
2101 N 18th Street
Nederland, Texas 77627

Las personas con discapacidades que necesiten acomodaciones especiales en la reunión deben llamar a la Oficina del Secretario Principal al 512-239-3300 o 1-800-RELAY-TX (TDD) por lo menos cinco días hábiles antes de la reunión.

OPORTUNIDAD PARA UNA AUDIENCIA DE CASO IMPUGNADO. Puede solicitar una audiencia de caso impugnado en relación con las partes de la solicitud de permiso estatal de calidad del aire número 170854, de permiso de calidad del aire PSD número PSDTX1614 y de permiso de fuente principal de contaminantes peligrosos del aire [FCAA §112(g)] HAP81. No hay oportunidad de solicitar una audiencia de caso impugnado en relación con la parte de la solicitud de GHG PSD Permiso de Calidad del Aire Número GHGPSDTX227. Una audiencia de caso impugnado es un procedimiento legal similar a un juicio civil en un tribunal de distrito del estado. Una persona que pueda verse afectada por las emisiones de contaminantes del aire, distintos de los GEI, de la instalación tiene derecho a solicitar una audiencia. Una solicitud de audiencia de caso impugnado debe incluir lo siguiente (1) su nombre (o, en el caso de un grupo o asociación, el de un representante oficial),

dirección postal y número de teléfono diurno; (2) el nombre del solicitante y el número de permiso; (3) la declaración "solicito/solicitamos una audiencia de caso impugnado"; (4) una descripción específica de cómo se vería usted perjudicado por la solicitud y las emisiones atmosféricas de la instalación de una forma no común al público en general; (5) la ubicación y distancia de su propiedad en relación con la instalación; (6) una descripción del uso que usted hace de la propiedad que puede verse afectada por la instalación; y (7) una lista de todas las cuestiones de hecho controvertidas que presente durante el periodo de comentarios. Si la solicitud la presenta un grupo o asociación, deberá identificarse con nombre y dirección física a uno o varios miembros que estén legitimados para solicitar una audiencia. También deben identificarse los intereses que el grupo o asociación pretende proteger. También pueden presentar sus propuestas de ajustes a la solicitud/permiso que satisfagan sus preocupaciones. Las solicitudes de una audiencia de caso impugnado deben presentarse por escrito en un plazo de 30 días a partir de la fecha del presente anuncio a la Oficina del Secretario Judicial, en la dirección indicada en la sección de información que figura más abajo.

Sólo se concederá una audiencia de caso impugnado sobre la base de cuestiones de hecho controvertidas o cuestiones mixtas de hecho y de derecho que sean relevantes y materiales para las decisiones de la Comisión sobre la solicitud. La Comisión sólo podrá conceder una solicitud de audiencia de caso impugnado sobre cuestiones que el solicitante haya presentado en sus comentarios oportunos y que no hayan sido retirados posteriormente. Las cuestiones que no se presenten en los comentarios públicos no podrán ser examinadas durante una audiencia.

ACCIÓN DEL DIRECTOR EJECUTIVO. El director ejecutivo puede emitir la aprobación final de la solicitud para la parte de la solicitud de GHG PSD Permiso de Calidad del Aire GHGPSDTX227. Si no se recibe una solicitud de audiencia de caso impugnado oportuna o si se retiran todas las solicitudes de audiencia de caso impugnado oportunas en relación con el Permiso Estatal de Calidad del Aire Número 170854, para el Permiso de Calidad del Aire PSD Número PSDTX1614, y para el Permiso de Fuente Principal de Contaminantes Peligrosos del Aire [FCAA §112(g)] HAP81, el director ejecutivo podrá emitir la aprobación final de la solicitud. La respuesta a los comentarios, junto con la decisión del director ejecutivo sobre la solicitud, se enviará por correo a todas las personas que hayan presentado comentarios públicos o estén en una lista de correo para esta solicitud, y se publicará electrónicamente en el CID. Si se reciben solicitudes de audiencia a tiempo y no se retiran, el director ejecutivo no emitirá la aprobación final del Permiso Estatal de Calidad del Aire Número 170854, para el Permiso de Calidad del Aire PSD Número PSDTX1614, Fuente Principal de Contaminantes Peligrosos del Aire [FCAA §112(g)] Permiso HAP81 y remitirá la solicitud y las peticiones a los Comisionados para su consideración en una reunión programada de la comisión.

LISTA DE CORREO. Puede solicitar ser colocado en una lista de correo para obtener información adicional sobre esta solicitud enviando una solicitud a la Oficina del Secretario Oficial a la dirección a continuación.

CONTACTOS E INFORMACIÓN DE LA AGENCIA. Los comentarios y solicitudes públicas deben enviarse electrónicamente a www14.tceq.texas.gov/epic/eComment/, o por escrito a la Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Si se comunica con la TCEQ electrónicamente, tenga en cuenta que su dirección de correo electrónico, al igual que su dirección postal física, se convertirá en parte del registro público de la agencia. Para obtener más información sobre esta solicitud de permiso o el proceso de permisos, llame al Programa de Educación Pública al número gratuito 1-800-687-4040. Si desea información en español, puede llamar al 1-800-687-4040.

También se puede obtener más información de la Energy Transfer Petrochemical Holdings LLC en la dirección indicada anteriormente o llamando a la Sra. Celia Chu, Gestora de Proyectos, Medio Ambiente, al (713) 989-6428.

Fecha de Emisión del Aviso: 12 de octubre de 2023

Special Conditions

Permit Numbers 170854, PSDTX1614, HAP81, and GHGPSDTX227

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 by weight 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, Industrial-Commercial-Institutional Steam Generating Units.

    C. Subpart Kb, Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

    D. Subpart VVa, Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

    E. Subpart NNN, Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations.

    F. Subpart RRR, Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.

    G. Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.

4. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61:

    A. Subpart A, General Provisions.

    B. Subpart J, Equipment Leaks (Fugitive Emission Sources) of Benzene.

    C. Subpart V, Equipment Leaks (Fugitive Emission Sources).

    D. Subpart BB, Benzene Emissions from Benzene Transfer Operations.

    E. Subpart FF, Benzene Waste Operations.

5. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

A. Subpart A, General Provisions.

B. Subpart XX, Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations.

C. Subpart YY, Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards.

D. Subpart EEEE, Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline).

E. Subpart ZZZZ, Reciprocating Internal Combustion Engines.

F. Subpart DDDDD, Hazardous Air Pollutants for Industrial for Institutional, Commercial, and Industrial Boilers and Process Heaters.

Pyrolysis Furnaces

6. The following requirements shall apply to the pyrolysis furnaces (EPNs H-1001, H-1002, H-1003, H-1004, H-1005, and H-1006).

A. Except where provided otherwise in paragraph D of this Special Condition, emissions of NO_X, CO, and NH_3 from each pyrolysis furnace shall not exceed the following values. Compliance with the NO_X emissions limits shall be achieved through the use of a Selective Catalytic Reduction (SCR) system.

(1) Short-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.015 lb/MMBtu	1-hr
CO	100 ppmvd	1-hr
NH_3	10 ppmvd	1-hr

(2) Long-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.010 lb/MMBtu	Annual
CO	50 ppmvd	Annual

Concentration of a pollutant in the exhaust of a pyrolysis furnace shall be evaluated on a dry basis, corrected to 3% oxygen.

B. Compliance with the NO_X and CO emission limits of paragraph A shall be demonstrated through use of Continuous Emissions Monitoring System (CEMS) in accordance with Special Condition No. 34.

C. Compliance with the ammonia (NH_3) emission limits of paragraph A shall be continuously demonstrated through use of a CEMS in accordance with Special Condition No. 34. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

D. The NO_X and CO emission limits of subparagraph A(1) of this Special Condition shall not apply to a pyrolysis furnace during non-routine operation of the pyrolysis furnace.

E. During decoking operations, pyrolysis furnace effluent shall be captured and directed to the flame zone of a pyrolysis furnace.

KCOT Regenerator

7. The KCOT regenerator (EPN PK1102) shall be subject to the following requirements.

A. The permit holder shall comply with the following case-by-case MACT emission limitation as determined pursuant to 40 CFR § 63.43(d):

(1) Each emission limitation and work practice standard for metal and organic HAP applicable to petroleum refinery catalytic cracking units which would apply under 40 CFR Part 63, Subpart UUU (83 FR 60696, Nov. 26, 2018), if the KCOT unit were located at a petroleum refinery, including the following specific compliance options:

(a) The metal HAP emission limitation and work practice standards specified at 40 CFR § 63.1564(a)(1)(ii).

(b) The organic HAP emission limitation and work practice standards specified at 40 CFR 63.1565(a)(1)(i).

(2) Each applicable sampling, monitoring, recordkeeping, and reporting requirement specified under Subpart UUU for petroleum refinery catalytic cracking units, including the following specific compliance options:

(a) (Metal HAP) Initial performance testing as specified in Table 4 (entry 3.b) to 40 CFR Part 63, Subpart UUU, which specifies recording of the coke burn-off rate, computed per equation 1 at 40 CFR § 63.1564(b)(4)(i).

(b) (Metal HAP) Ongoing compliance monitoring as specified in Table 6 (entry 7) to 40 CFR Part 63, Subpart UUU, which specifies daily recording of the average coke-burnoff rate using equation 1 at 40 CFR § 63.1564(b)(4)(i) and conducting a performance test once every year, except that the applicable PM limit is that specified in paragraph B (below).

(c) (Metal HAP) Continuous parametric monitoring as specified in Table 7 (entry 2.c) to 40 CFR Part 63, Subpart UUU, which specifies monitoring of the hourly and 3-hr rolling average gas flow rate and scrubber liquid flow rate to determine compliance with the minimum liquid-to-gas ratio established during the performance test.

(d) (Organic HAP) Ongoing compliance monitoring as specified in Table 13 (Entry 2.a) to 40 CFR Part 63, Subpart UUU, which specifies use of a continuous monitoring system to demonstrate compliance with the applicable CO emissions limit.

(3) Install, calibrate, and operate CO_2, O_2, and CO monitors meeting the applicable Performance Specifications referenced at 40 CFR § 60.105a(b)(2). Continuously monitor and record the air blower rate using control room instrumentation.

B. The permit holder shall comply with the following BACT emission limitations and compliance determination requirements.

Pollutant	Averaging Period	Emission Limit	Compliance Monitoring Requirements
CO	1-hr block	500 ppmvd (0% O_2)	CEMS (Special Condition No. 35)
NO_X	1-hr block	20 ppmvd (0% O_2)	CEMS (Special Condition No. 35)
NH_3	1-hr block	10 ppmvd (0% O_2)	CEMS (Special Condition No. 35)

Pollutant	Averaging Period	Emission Limit	Compliance Monitoring Requirements
Particulate Matter	1-hr block	0.5 lb/1,000 lb coke burnoff	Metal HAP compliance monitoring requirements specified in paragraph A.
H_2SO_4	1-hr block	0.33 lb/1,000 lb coke burnoff	Initial stack sampling for H_2SO_4 to determine H_2SO_4/PM ratio in stack gas. Ongoing compliance with Metal HAP compliance monitoring requirements specified in paragraph A.
SO_2	1-hr block	50 ppmvd (0% O_2)	CEMS (Special Condition No. 35)
SO_2	365-day rolling (updated daily)	25 ppmvd (0% O_2)	CEMS (Special Condition No. 35)
HCN	Comply with CO limit specified herein.		
VOC	Comply with CO limit specified herein.		

C. During periods of startup and shutdown of the KCOT unit, the permit holder may elect to comply with the following requirement in lieu of the CO emission limit specified in paragraph B above:

Collect the hourly average oxygen concentration monitoring data required under paragraph A of this Special Condition and maintain the hourly average oxygen concentration at or above 1 volume percent (dry basis).

D. Prior to the start of operations, the permit holder shall submit final design specifications for the scrubber through a permit alteration or amendment.

Boilers

8. The following requirements shall apply to the boilers (EPNs B-801, B-802, B-803, and B-804):

A. Except where provided otherwise in paragraph D of this Special Condition, emissions of NO_X CO, and NH_3 from each boiler shall not exceed the following values.

(1) Short-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.015 lb/MMBtu	1-hr
CO	100 ppmvd	1-hr
NH_3	10 ppmvd	1-hr

(2) Long-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.010 lb/MMBtu	Annual
CO	50 ppmvd	Annual

Concentration of a pollutant in the exhaust of a boiler shall be evaluated on a dry basis, corrected to 3% oxygen.

B. Compliance with the NO_X and CO emission limits of paragraph A shall be demonstrated through use of CEMS in accordance with Special Condition No. 34.

C. Compliance with the ammonia (NH_3) emission limits of paragraph A shall be continuously demonstrated through use of a CEMS in accordance with Special Condition No. 34. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

D. During non-routine operations for a boiler, the requirements of subparagraph A(1) shall not apply.

Heaters

9. The following requirements shall apply to the OCT Charge Heater (EPN H-501) and the KCOT Process Heater (EPN H-201):

A. Except where provided otherwise in paragraph D of this Special Condition, emissions of NO_X CO, and NH_3 from each boiler shall not exceed the following values.

(1) Short-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.015 lb/MMBtu	1-hr
CO	100 ppmvd	1-hr
NH_3	10 ppmvd	1-hr

(2) Long-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.010 lb/MMBtu	Annual
CO	50 ppmvd	Annual

Concentration of a pollutant in the exhaust of a process heater shall be evaluated on a dry basis, corrected to 3% oxygen.

B. Compliance with the NO_X and CO emission limits of paragraph A shall be demonstrated through use of CEMS in accordance with Special Condition No. 34.

C. Compliance with the ammonia (NH_3) emission limits of paragraph A shall be continuously demonstrated through use of a CEMS in accordance with Special Condition No. 34. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

D. During non-routine operations for a process heater, the requirements of subparagraph A(1) shall not apply.

10. The following requirements shall apply to the Regeneration Gas Heater (EPN H-502) and the GRU Charge Heater (EPN H-371):

A. Emissions of NO_X and CO from each heater shall not exceed the following values.

(1) Short-term average limits:

Pollutant	Emission Limit	Averaging Period
NO_X	0.030 lb/MMBtu	1-hr
CO	100 ppmvd	1-hr

(2) Long-term average limits:

Pollutant	Emission Limit	Averaging Period
CO	50 ppmvd	Annual

The concentration of a pollutant in the exhaust of a heater shall be evaluated on a dry basis, corrected to 3% oxygen.

Vapor Oxidizer

11. The following requirements shall apply to the Thermal Oxidizer (EPN TO):

A. The thermal oxidizer (EPN TO) shall achieve a VOC destruction efficiency of at least 99.9 percent.

B. The thermal oxidizer (EPN TO) firebox exit temperature shall be maintained at not less than 1650°F and exhaust oxygen concentration not less than 3 percent on a six-minute average while waste gas is being fed into the oxidizer prior to initial stack testing. After the initial stack test has been completed, the six minute average temperature shall be equal to, or greater than the respective hourly average maintained during the most recent satisfactory stack testing required by Special Condition No. 36.

C. The thermal oxidizer (EPN TO) exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

Quality assured (or valid) data must be generated when the thermal oxidizer (EPN TO) 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 thermal oxidizer (EPN TO) operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

D. The oxygen analyzer used to satisfy this Special Condition shall continuously monitor and record oxygen concentration when waste gas is directed to the thermal oxidizer (EPN TO). It shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.

The oxygen analyzer shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified Performance Specification No. 3, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

The analyzer shall be quality-assured at least semiannually using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5 percent of the incinerator operating time. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

Quality assured (or valid) data must be generated when the thermal oxidizer (EPN TO) 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 thermal oxidizer (EPN TO) operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Elevated Flare

12. Flares 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 gas stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal and maintenance flow conditions.

The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) shall be performed if requested by the appropriate Texas Commission on Environmental Quality (TCEQ) Regional Office to demonstrate compliance with these requirements.

B. The flares 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 or an infrared 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 flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

D. For each flare, the permit holder shall install a continuous flow monitor that provides a record of the vent stream flow to the flare. The flow monitor sensor 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 shall be recorded each hour.

The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg.

The monitors 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 actual exit velocity determined in accordance with 40 CFR § 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 amendment applications dated October 28, 2022.

E. For each flare, the permit holder shall install a composition analyzer or calorimeter that provide a record of the vent stream composition or Btu content to the flares. The 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.

The permit holder shall install a composition analyzer system or calorimeter that provides a record of the vent stream composition or BTU content to the flare, or the waste gas stream directed to the flare shall be assumed to contain no BTU content and sufficient assist natural gas / fuel gas shall be added so that the flare meets the 40 CFR § 60.18 specifications of minimum heating value. If a composition analyzer system or calorimeter is installed, the 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 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.

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 e 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 calorimeters shall be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare, in British thermal units/standard cubic foot of the gas.

F. The composition analyzer systems or calorimeters 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 determined in accordance with 40 CFR §60.18(f)(3) shall be recorded at least once every 15 minutes.

Multi-Point Ground Flare (EPN GFL-1)

13. The multi-point ground flare (MPGF) shall be designed to comply with the following requirements, and to achieve at least 99.5% destruction efficiency for VOC.

A. <u>Operating Requirements</u>: The net heating value of the flare vent gas combustion zone (NHVcz) must be greater than or equal to 800 British thermal units per standard cubic foot (Btu/scf), which shall be demonstrated by continuously monitoring (i.e., at least once every 15 minutes), as follows:

(1) <u>Net Heating Values NHV_{cz} and NHV_{vg}.</u> Determine the concentration of individual components and effects of assist media in the flare vent gas using the methods in 40 CFR §§ 63.670(j), (l)(1), (m)(1), and Table 12 and Table 13 of 40 CFR 63 Subpart CC (MACT CC), as applicable. Alternatively, the net heating value of the flare vent gas and hydrogen concentration may be directly monitored following the methods provided in 40 CFR §63.670(l)(2)–(3), as applicable. Different monitoring methods may be used

to determine vent gas composition for different gaseous streams provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined following the options in this condition.

Notwithstanding any contrary part of this paragraph, for a gas chromatograph or mass spectrometer for compositional analysis for net heating value, the calibration error (CE) of net heating value (NHV) measured versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE may be used in accordance with 40 CFR § 63.2450(e)(5)(x).

(2) Flare Vent Gas Flow Rate Requirements. Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring calculating, and recording the cumulative volumetric flow rates in the flare header or headers that feed the flare, including any supplemental natural gas used with the flare. The flow rate monitoring systems must comply with 40 CFR § 63.670(i), as applicable. The monitors shall meet the measurement location, accuracy, and calibration requirements of Table 13 to 40 CFR Part 63, Subpart CC.

B. Pilot Flame Requirements: Operate each stage of the pressure-assisted multi-point flare with a flame present at all times when regulated material is routed to that stage of burners. Each stage of burners that cross-lights in the pressure-assisted multi-point flare must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners. The pilot flame(s) on each stage of burners that use cross-lighting must be continuously monitored by a thermocouple, ultraviolet beam sensor, or infrared sensor, used to detect the presence of a flame. If a stage of burners on the flare uses cross-lighting, the distance between any two burners in series on that stage shall be no more than 6 feet when measured from the center of one burner to the next burner.

C. Visible Emission Requirements: When the MPGF is receiving regulated materials, it shall be operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours and meet 40 CFR § 63.670(c) and (h).

D. Pressure Monitor and Stage Valve Position Indicator Requirements: Install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flares operate within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in Table 13 to 40 CFR Part 63, Subpart CC.

E. Continuous Monitoring Requirements: Follow the specifications, calibration, and maintenance procedures according to the following:

(1) At all times, all monitoring equipment must operate and be maintained in a manner consistent with 40 CFR §§ 60.11(d), 63.6(e)(1)(i), 63.671(a), and Table 13 of MACT CC with the TCEQ as the Administrator.

(2) Any monitor downtime must comply with 40 CFR §§ 63.671(a)(4) and 63.671(c). 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.

(3) Unless otherwise specified, each measurement taken by the monitoring systems shall comply with 40 CFR §63.671(d).

F. Recordkeeping Requirements: Keep records according to 40 CFR § 63.655(i)(9)(i) through (x), except for the flare tip velocity and dilution operating limits requirements of §63.655(i)(9)(vii), and sufficient records to demonstrate compliance with this Special Condition.

G. Emission Determinations: Calculations of hourly and annual emissions to determine compliance with the MAERT limitations shall be determined and recorded using the monitoring data collected pursuant to this Special Condition applying the direct calculation method specified by §63.670(l)(5)(ii) and the emission factors and emissions methodology represented in the permit application, PI-1 dated October 28, 2022 and subsequent application updates associated with TCEQ Project No. 349610. Annual emissions shall be calculated by the end of the current month for the previous rolling 12-month period.

Fuel Gas

14. Combustion units are subject to the following requirements for fuel sulfur:

A. The pyrolysis furnaces, heaters, boilers, and the thermal oxidizer shall be fired with natural gas, plant fuel gas, and/or hydrogen.

B. Natural gas and plant fuel gas shall have a total sulfur content not to exceed 2 grains per 100 dscf on a rolling 12-month average.

C. Compliance with the requirements of paragraph C of this Special Condition shall be verified through sampling of fuel gas at least semi-annually. Fuel gas streams identified in paragraph B may be sampled individually, or a representative sample of blended fuel gas may be taken from the fuel gas header.

For natural gas, tariff sheets documenting the sulfur content of the fuel may be retained in lieu of performing sampling.

Visible Emissions

15. Opacity of emissions from each pyrolysis furnace, boiler, heater, thermal oxidizer, and emergency engine authorized by this permit shall not exceed 5 percent averaged over any six minute period.

Opacity shall be determined by EPA Test Method 9 during the initial compliance testing and at least once per year thereafter. In lieu of performing a required opacity test, the permit holder may verify that there are no visible emissions as determined by EPA Test Method 22. For opacity or visible emissions determinations other than those required during the initial compliance testing, determination of opacity or visible emissions for each pyrolysis furnace shall take place during decoking.

Compliance Assurance Monitoring

16. The following requirements apply to capture systems for the flares (EPNs FL-1 and GFL-1).

A. Either conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system; or verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21 once a year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

B. If there is a bypass for the control device, comply with either of the following requirements:

(1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

(2) Once a month, inspect the valves, verifying that the position of the valves and the condition of the car seals that prevent flow out the bypass.

A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service per this permit.

C. The date and results of each inspection performed shall be recorded. If the results of any inspection are not satisfactory, the deficiencies shall be recorded, and the permit holder shall promptly take necessary corrective action, recording each action with the date completed.

Storage Tanks

17. Storage tank throughput, fill/withdrawal rate, and service shall be limited to the following:

Tank Identifier	Service	Fill/Withdrawal rate (gallons/hour)	Rolling 12 Month Throughput (gallons)	Control
TK-908	Fuel oil	200,000	94,500,000	Atmosphere
TK-909	Methanol	420,000	84,000,000	IFR
TK-910	Pyrolysis gasoline	840,000	108,024,000	IFR

18. Storage tanks are subject to the following requirements: The control requirements specified in parts A–E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 psia at the maximum feed temperature or 95°F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

A. An internal floating deck or “roof” shall be installed. A domed external floating roof tank is equivalent to an internal floating roof tank. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

B. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and any seal gap measurements specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, Aug. 11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates inspection was performed, any measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

D. Each tank shall be designed and constructed with a sloped bottom and a sump that can be emptied so that each floating roof storage tank is drain dry when the floating roof is landed on its leg supports or cable-suspended at its lowest level. Drain-dry tank bottom and the associated sump(s) shall be designed in accordance with API 650 to minimize free-standing liquids in the tank to the extent practical. Tanks shall be constructed or equipped with a connection to a vapor recovery system that routes vapors from the vapor space under the landed roof to a control device.

E. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white. Storage tanks must be equipped with permanent submerged fill pipes.

F. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for each tank.

Cooling Tower

19. The cooling tower (EPN CT-801) and associated heat exchange systems shall be operated and monitored in accordance with the following:

A. The actual cooling water circulation rate shall be measured at least hourly. Measurements shall be reduced to an hourly average and recorded for use in emission calculations. In lieu of monitoring the actual circulation rate at least hourly, the permit holder may use either of the alternatives specified at 30 TAC 115.764(e).

If multiple sampling points are used, then the actual cooling water circulation rate associated with each sampling point shall be determined and recorded. The circulation rate associated with a particular sampling point can be estimated using engineering judgment. The method used to estimate flow associated with a sampling point shall be documented.

B. The VOC associated with the cooling tower (EPN CT-801) water shall be monitored with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition), a continuous on-line monitor conforming to the requirements of 30 TAC § 115.764(a)(6), 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 VOC emissions. The rolling 12 month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12 month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the two VOC monitored results.

C. The required frequency of sampling specified in paragraph B shall be at least once per week per sampling point. If no leak is identified during 26 consecutive weeks of weekly monitoring, the frequency of sampling may be reduced to monthly, and shall revert to weekly upon detection of a leak.

D. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. A leak (faulty equipment) is indicated by cooling tower water VOC concentrations above 80 ppbw at any sampling point.

Emissions from the cooling tower are not authorized if the VOC concentration of the water returning to the cooling tower exceeds 800 ppbw at any sampling point. Leaks associated with VOC concentrations above 800 ppbw are not subject to extensions for delay of repair under paragraph F of this permit condition.

E. Leaks (faulty equipment) shall be repaired at the earliest opportunity but no later than 45 calendar days after a leak is detected, unless the leak qualifies for delayed repair under paragraph F of this Special Condition. If the leak qualifies for delayed repair, then the leak shall be repaired according to the schedule specified in paragraph F of this Special Condition. In no case may repairs be delayed beyond the next shutdown.

F. The provisions of 40 CFR § 63.1088 (version published at 85 FR 40420; July 6, 2020), relating to situations where required repairs may be delayed, are incorporated by reference, except that each appearance of “HAP” shall be replaced by “VOC”.

20. The cooling tower (EPN CT-801) shall be operated and monitored in accordance with the following:

A. The cooling tower (EPN CT-801) shall each be equipped with drift eliminators having manufacturer’s design assurance of 0.0005% 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 6,000 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 total dissolved solids (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. Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

(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.

(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.

Wastewater Treatment

21. Process wastewater drains shall be equipped with water seals or equivalent. Lift stations, manholes, junction boxes, any other wastewater collection system components, and conveyances used to convey wastewater shall be equipped with a closed vent system that routes all organic vapor to the thermal oxidizer (EPN TO).

    Water seals shall be checked by visual or physical inspection quarterly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls. Water seals shall be restored as necessary within 24 hours. Records shall be maintained of these inspections and corrective actions taken.

22. The daily total wastewater flow into the wastewater treatment plant shall be monitored and recorded. The rolling 12 month wastewater flow shall be totaled on a monthly basis.

23. The minimum mixed liquor total suspended solids (MLSS) concentration in the aeration basins on a daily average basis shall not be less than 3,500 mg/L. The MLSS concentration is the arithmetic average of all samples collected during the 24-hour period. The MLSS concentrations shall be monitored and recorded daily using Method 160.2 (Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020 or Method 2540D (Standard Methods of the Examination of Water and Wastewater, 18th Edition, American Public Health Association).

24. Emissions from the vents upstream of the biological treatment shall be controlled by the thermal oxidizer (EPN TO).

25. Spent caustic shall be routed to the Wet Air Oxidization Unit (WAO). The WAO shall be controlled by the thermal oxidizer (EPN TO). Treated effluent from the WAO shall be routed to the benzene stripper.

26. Benzene area wastewater shall be routed to the benzene stripper. The benzene stripper shall be operated in accordance with 40 CFR Part 61, Subpart FF.

27. Wastewater treatment plant emissions shall be estimated every month using the following procedure.

    A. The permit holder shall sample the wastewater prior to the equalization tanks monthly to determine the concentrations of all air contaminants. Sampling locations, sampling procedures, test methods and calculations shall be as follows:

        (1) The sampling locations shall be prior to the primary clarifier, and equalization tanks (TK-801A, and TK-801B);

        (2) Sampling procedures shall be as specified in the TPDES permit applicable to the site. A copy of the TPDES permit and any precedent application representations shall be submitted for inclusion in the file for this permit prior to the start of operation of the facilities covered by this permit;

        (3) Test methods shall include EPA SW-846 methods 8260B, 8270C, and 8015B; and

        (4) Calculations shall be as specified in permit application, PI-1 dated October 28, 2022, as updated.

    The influent wastewater flow rates shall be measured and recorded when a sample required by this condition is collected. Records of sampling results shall be maintained for all air contaminants.

    B. The permit holder shall calculate short term loading rate in terms of lb/hr and rolling 12-month loading rate in terms of tpy for each air contaminant. The measured concentrations of each speciated air contaminant shall be converted to an equivalent mass emission rate based upon the flow rates during the sample collection period using the calculation methods and assumptions in the permit application, PI-1 dated October 28, 2022, as updated. The MLSS used in the emission calculation shall be either the minimum identified in Special Condition No. 23 or the measured concentration for the day the sampling required for this condition is completed. The short term emission rate calculations for such air contaminants shall be based on the concentrations and flow rates measured during sampling. The rolling 12-month emission rate calculation for each air contaminant shall be based on the rolling 12-month average contaminant concentration and the rolling 12-month wastewater flow. All other inputs into the calculation shall match those in the permit application for that averaging period (worst case). Total VOC mass emission rates shall be calculated as the sum of the individual speciated VOC mass emission rates.

    C. Records of sampling location, sampling procedures, sample chain of custody forms, test methods, sampling results, calculated emission rates, and sample of calculations shall be maintained.

Emergency Engines

28. The following requirements apply to the emergency generators (EPNs EE-803, EE-804, and EE-805) and the emergency firewater pumps (EPNs EE-801 and EE-802):

    A. Fuel for each engine shall be limited to ultra-low sulfur diesel (ULSD) containing no more than 15 ppmw total sulfur.

B. Each engine shall be limited to 100 hours per year during non-emergency situations, as defined at 40 CFR § 63.6640(f).

C. Each engine shall be equipped with a non-resettable hour meter.

D. The emergency generator shall satisfy the Tier 2 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.

E. Each firewater pump shall satisfy the Tier 3 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.

F. Compliance with the emission limits of paragraph D and E of this Special Condition shall be demonstrated by retaining a copy of the manufacturers' certificate of conformity.

Fugitives

Piping, Valves, Connectors, Pumps, Agitators, and Compressors – 28VHP

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

A. The requirements of paragraphs F and G shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

- piping and instrumentation diagram (PID);
- a written or electronic database or electronic file;
- color coding;
- a form of weatherproof identification; or
- designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in Paragraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve;

or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shut down as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and the TCEQ Executive Director may require early unit shut down or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items G through H of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

28CNTQ (Connectors Inspected Quarterly)

30. In addition to the weekly physical inspection required by Item E of Special Condition No. 29, all accessible connectors in gas/vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition No. 29.

A. Allowance for reduced monitoring frequencies.

(1) The frequency of monitoring may be reduced from quarterly to semiannually if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

(2) The frequency of monitoring may be reduced from semiannually to annually if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

B. If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph. The percent of connectors leaking used in paragraph A shall be determined using the following formula:

$$\frac{C_l + C_s}{C_t} \times 100 = C_p$$

Where:

C_l = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

C_s = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

C_t = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

C_p = the percentage of leaking connectors for the monitoring period.

Piping, Valves, Pumps, and Compressors in Contact with Ammonia – 28AVO

31. 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 once per shift.

B. Immediately, but no later than one hour 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.

Continuous Demonstration of Compliance

32. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for each device listed in Special Condition No. 34. The monitored data shall be reduced to an hourly average flow rate at least once each 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 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

33. The permit holder shall install and operate an analyzer which continuously monitors the heat content of fuel supplied to each pyrolysis furnace and boiler. For sources which receive fuel from a common fuel gas header, a single analyzer may be installed in the fuel gas header.

34. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) for equipment listed below for O_2, CO, NO_X, and NH_3.

EPN	Source Name
H-1001	Pyrolysis Furnace 1
H-1002	Pyrolysis Furnace 2
H-1003	Pyrolysis Furnace 3
H-1004	Pyrolysis Furnace 4
H-1005	Pyrolysis Furnace 5
H-1006	Pyrolysis Furnace 6
B-801	Steam Boiler 1
B-802	Steam Boiler 2
B-803	Steam Boiler 3
B-804	Steam Boiler 4
H-501	OCT Charge Heater
H-201	KCOT Process Heater
PK-1102	KCOT Regenerator

The permit holder shall additionally install, calibrate, and maintain a CEMS for the KCOT Regenerator (EPN PK-1102) for CO_2 and SO_2.

35. Each CEMS required under this permit shall satisfy the following requirements

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. Subparagraph (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. The monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of ppmvd, lb/MMBtu, and/or lb/hr, as applicable at least once every week as follows:

(1) The measured 1-hr average concentration (in units of ppmvd) from the CEMS shall be converted to a dry basis and corrected to the reference oxygen concentration.

(2) The converted concentration, corrected for oxygen, shall be converted to an emissions factor (in units of lb/MMBtu) by using an appropriate F-factor determined as specified in EPA Method 19, Equation 19-13, determined using the measured hydrogen content of the fuel gas.

(3) The emission rate (in units of lb/hr) shall be determined by multiplying the emission factor by the fuel flow rate and fuel heat content measured as required under Special Condition Nos. 32 and 33.

(4) In case the permit holder elects to monitor stack exhaust flow as provided for in Special Condition No. 32, the emission rate (in units of lb/hr) shall be determined by multiplying the measured concentration (converted and corrected as needed) by the exhaust flow

rate; and the emission factor (in units of lb/MMBtu) shall be determined by dividing the emission rate by the monitored fuel flow rate, using fuel flow rate and fuel heat content data measured as required under Special Condition Nos. 32 and 33.

D. 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.

E. 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.

F. Quality-assured (or valid) data must be generated when the source generating emissions 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 source generating emissions 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.

Initial Determination of Compliance

36. 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 sources of emissions specified in Paragraph G of this Special Condition, and to demonstrate compliance with Special Condition Nos. 1, 6, 8, and 9. 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 EPA Reference Methods.

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 Title 40 Code of Federal Regulation Part 60 (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. Pollutants shall be tested according to the following groupings:

(1) For group 1 sources (paragraph G(1) of this Special Condition), air contaminants to be tested for include (but are not limited to) CO, NO_X, and NH_3. Testing for NH3 is only required on units equipped with SCR.

For any pyrolysis furnace listed in paragraph G(1) of this Special Condition, sampling for PM_{10} shall be required if a violation of Special Condition No. 15 occurs. The time required to complete sampling shall be extended to 365 days. This requirement shall not apply more than one time per furnace.

(2) For group 2 sources (paragraph G(2) of this Special Condition), air contaminants to be tested for include (but are not limited to) CO, NO_X, H_2SO_4, and SO_2. Initial and subsequent annual testing for particulate matter shall be conducted as specified in Special Condition 7, and is not covered by the Special Condition, other than the pre-test notification and reporting requirements of paragraphs A and E.

(3) For the TO, air contaminants to be tested for include (but are not limited to) VOC.

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 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 TCEQ Regional Office.

D. The facility being sampled shall operate as indicated in Paragraph H 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 stack sampling shall be performed within 120 days for the following sources if the following requirements are satisfied. 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 “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.
One copy to each local air pollution control program, if one exists.

F. Sampling ports and platform(s) shall be incorporated into the design of each source listed in paragraph G according to the specifications set forth in “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.

G. Sources of emissions subject to stack sampling requirements, and pollutants to be tested, are as follows.

(1) Group 1 sources.

EPN	Source Name
H-1001	Pyrolysis Furnace 1
H-1002	Pyrolysis Furnace 2
H-1003	Pyrolysis Furnace 3
H-1004	Pyrolysis Furnace 4
H-1005	Pyrolysis Furnace 5
H-1006	Pyrolysis Furnace 6
B-801	Steam Boiler 1
B-802	Steam Boiler 2
B-803	Steam Boiler 3
B-804	Steam Boiler 4
H-501	OCT Charge Heater
H-502	KCOT Process Heater

(2) Group 2 sources.

EPN	Source Name
PK-1101	KCOT Regenerator

(3) The thermal oxidizer (EPN TO).

H. Facilities shall operate as follows during sampling:

(1) For pyrolysis furnaces, sampling shall occur at the maximum heat duty that can be reasonably achieved during sampling. In case sampling for PM_{10} is required for any furnace, such sampling shall occur during decoking operations.

(2) For the boilers and heaters, sampling shall occur at the maximum heat duty that can be reasonably achieved during sampling.

(3) For the thermal oxidizer, sampling shall occur during the maximum waste gas flow rate.

(4) For the KCOT regenerator, sampling shall occur at the maximum air blower rate that can be reasonably achieved during sampling.

Maintenance, Startup, and Shutdown

37. This permit authorizes the emissions for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment B) attached to this permit.

Additionally, this permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, and portable control devices identified in Special Condition No. 45 and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities listed in this Attachment, and (c) does not operate as a replacement for an existing authorized facility.

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 below, may be tracked through the work orders or equivalent. Emissions from activities identified below 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 volume purged shall be less than 50 cubic feet.

Pump repair/replacement

Fugitive component (valve, pipe, flange) repair/replacement

Compressor repair/replacement (excluding cracked gas compressor, ethylene refrigerant compressor, and propylene refrigerant compressor in olefins unit)

Heat exchanger repair/replacement

Vessel repair/replacement

The performance of each planned MSS activity not identified in Attachment A (or designated above as a routine maintenance activity) 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.

38. Process units and facilities, with the exception of those identified in Special Condition Nos. 40, 41, 42, and 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) 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 No. 39. 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 5,000 ppmv. 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.

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lb of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition 38.E must be documented when occurring as part of any MSS activity.

39. 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:

5,000*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.

40. This permit authorizes emissions from EPNs MSS_TKLAND and MSS_TMPCTL for the storage tanks identified in Special Condition No. 17 during planned floating roof landings. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated in the MAERT. The following requirements apply to tank roof landings.

  A. At all times that the roof is resting on its leg supports, the tank emissions shall be controlled by a closed vent system and control device meeting the following specifications:

    (1) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).

    (2) The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when the vapor space is directed to the control device. The vapor recovery system collection rate shall be no less than 100 cubic feet per minute when the tank is idle or the tank is being drained, and two times the fill rate when the tank is being refilled.

    (3) The control device shall be operated as required by Special Condition No. 45.

  The roof shall be landed on its lowest legs unless entry or inspection is planned.

  The requirements of this paragraph do not apply to uncontrolled degassing and/or ventilation conducted pursuant to paragraphs B–E of this Special Condition.

  B. The control requirements of Paragraph A of this Special Condition may be waived during emptying and set-up for tank degassing if the following conditions are met:

    (1) The tank will be completely emptied for the purposes of inspection and maintenance.

    (2) The process of emptying the tank when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as practicable.

    (3) Degassing of the vapor space under the landed roof begins within 24 hours after the tank has been emptied.

  C. After the tank has been completely emptied, the tank shall not be opened except as necessary to set up for degassing and cleaning. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC partial pressure of the standing liquid in the tank has been reduced to less than 0.02 psia prior to ventilating the tank. Controlled degassing of the vapor space under the landed roof shall be completed as follows:

    (1) Any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 5,000 ppmv. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There

shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

(2) The vapor space under the floating roof shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design.

(3) A volume of purge gas equivalent to twice the volume of the vapor space under the floating roof must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of purge gas volume shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition No. 39.A or 39.B.

(4) 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.

(5) Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.15 psia.

D. The tank shall not be opened or ventilated without control, except as allowed by (1) or (2) below until one of the criteria in part D of this condition is satisfied.

(1) Minimize air circulation in the tank vapor space.

(a) One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. Other manways or access points may be opened as necessary to remove or de-volatilize the remaining liquid. Wind barriers shall be installed at all open manways and access points to minimize air flow through the tank.

(b) Access points shall be closed when not in use.

(2) Minimize time and VOC partial pressure.

(a) The VOC partial pressure of the liquid remaining in the tank shall not exceed 0.044 psi as documented by the method specified in part D.(1) of this condition;

(b) Blowers may be used to move air through the tank without emission control at a rate not to exceed 3000 cfm for no more than 72 hours. All standing liquid shall be removed from the tank during this period; and

(c) Records shall be maintained of the blower circulation rate, the duration of uncontrolled ventilation, and the date and time all standing liquid was removed from the tank.

E. The tank may be opened without restriction and ventilated without control after all standing liquid has been removed from the tank or the liquid remaining in the tank has a VOC partial pressure of less than 0.02 psia. These criteria shall be demonstrated in one of the following ways:

(1) Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if

practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2) If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated:

(a) Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A Appendix 1.

(b) Take a representative sample of the liquid remaining in the tank and verify that the hexane soluble VOC concentration is less than 1000 ppmw using EPA method 1664.

(c) Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify that the VOC concentration is less than 1000 ppmw through the procedure in Special Condition No. 39.A or 39.B.

(3) No standing liquid, verified through visual inspection.

(4) Once the VOC vapor pressure of the liquid remaining in the tank is verified to be less than 0.02 psia in accordance with the procedures in paragraph (1) above, any additional water flushes do not require additional vapor pressure verification.

The permit holder shall maintain records to document the method used to release the tank.

F. The occurrence of each roof landing and the associated emissions shall be recorded and the rolling 12 month tank roof landing emissions shall be updated on a monthly basis. These records shall include at least the following information (as applicable):

(1) The identification of the tank and emission point number, and any control devices or controlled recovery systems used to reduce emissions;

(2) The reason for the tank roof landing;

(3) For the purpose of estimating emissions, the date, time, and other information specified for each of the following events:

(a) The roof was initially landed;

(b) All liquid was pumped from the tank to the extent practicable;

(c) Start and completion of controlled degassing, and total volumetric flow;

(d) All standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to < 0.02 psia.

(e) If there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow;

(f) Refilling commenced, liquid filling the tank, and the volume necessary to float the roof; and

(g) Tank roof off supporting legs, floating on liquid.

(4) The estimated quantity of each air contaminant, or mixture of air contaminants, emitted between events (c) and (g) with the data and methods used to determine it. The emissions associated with roof landing activities shall be calculated using the methods described in Section 7.1.3.2 of AP-42 “Compilation of Air Pollution Emission Factors,

Chapter 7—Storage of Organic Liquids" dated November 2006 (or later edition) and the permit application.

41. Fixed roof storage tanks are subject to the requirements of Special Condition No. 40.C. and 40.D. If the ventilation of the vapor space is controlled, the emission control system shall meet the requirements of Special Condition No. 40.B.(1) through 40.B.(4). Records shall be maintained per Special Condition 40.E.(3)c through 40.E.(3)e, and 40.E.(4).

42. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Prior to initial use, identify any liquid in the truck. Record the liquid level and document the VOC partial pressure. After each liquid transfer, identify the liquid, the volume transferred, and its VOC partial pressure.

B. If vacuum pumps or blowers are operated when liquid is in or being transferred to the truck, the following requirements apply:

(1) If the VOC partial pressure of the liquid in or being transferred to the truck is greater than 0.50 psi at 95°F, the vacuum/blower exhaust shall be routed to a control device or a controlled recovery system.

(2) Equip fill line intake with a "duckbill" or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

(3) A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(a) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a "duckbill" or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(b) If the vacuum truck exhaust is controlled with a control device other than an engine or oxidizer, VOC exhaust concentration upon commencing each transfer, at the end of each transfer, and at least every hour during each transfer shall be recorded, measured using an instrument meeting the requirements of Special Condition No. 39.A or 39.B.

C. Record the volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12 month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in paragraphs A through D of this Special Condition do not apply.

43. 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.

44. All permanent facilities must comply with all operating requirements, limits, and representations in this permit during planned startup and shutdown unless alternate requirements and limits are identified in this permit.

45. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. Each device used must meet all the requirements identified for that type of control device.

    Controlled recovery systems identified in this permit shall be directed to an operating process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

    A. Carbon Adsorption System (CAS).

        (1) The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

        (2) The CAS shall be sampled downstream of the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the VOC.

        (3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 39.A or B.

        (4) Breakthrough is defined as the highest measured VOC concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

        (5) Records of CAS monitoring shall include the following:

            (a) Sample time and date.

            (b) Monitoring results (ppmv).

            (c) Canister replacement log.

        (6) Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30 percent of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

    B. Thermal Oxidizer.

        (1) The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the oxidizer.

(2) The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

C. Internal Combustion Engine.

(1) The internal combustion engine shall have a VOC destruction efficiency of at least 99 percent.

(2) The engine must have been stack tested with butane or propane to confirm the required destruction efficiency within the period specified in subparagraph 3 below. VOC shall be measured in accordance with the applicable United States Environmental Protection Agency (EPA) Reference Method during the stack test and the exhaust flow rate may be determined from measured fuel flow rate and measured oxygen concentration. A copy of the stack test report shall be maintained with the engine. There shall also be documentation of acceptable VOC emissions following each occurrence of engine maintenance that may reasonably be expected to increase emissions including oxygen sensor replacement and catalyst cleaning or replacement. Stain tube indicators specifically designed to measure VOC concentration shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable VOC analyzers meeting the requirements of Special Condition 4.A are also acceptable for this documentation.

(3) The engine shall be operated and monitored as specified below.

(a) If the engine is operated with an oxygen sensor-based air-to-fuel ratio (AFR) controller, documentation for each AFR controller that the manufacturer's or supplier's recommended maintenance has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers shall be maintained with the engine. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation. The engine must have been stack tested within the past 12 months in accordance with paragraph (2) above.

The test period may be extended to 24 months if the engine exhaust is sampled once an hour when waste gas is directed to the engine using a detector meeting the requirements of Special Condition 4.A. 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 engine. The concentrations shall be recorded and the MSS activity shall be stopped as soon as possible if the VOC concentration exceeds 100 ppmv above background.

(b) If an oxygen sensor-based AFR controller is not used, the engine exhaust to atmosphere shall be monitored continuously and the VOC concentration recorded at least once every 15 minutes when waste gas is directed to the engine. 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 engine. The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 39.A. An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background. The MSS activity shall be stopped as soon as possible if the VOC concentration exceeds 100 ppmv above background for more than one minute. The date and time of all alarms and the actions taken shall be recorded. The engine must have been stack tested within the past 24 months in accordance with paragraph (2) above.

D. The plant flare system operated in accordance with Special Condition Nos. 12 and 13.

E. A liquid scrubbing system may be used upstream of carbon adsorption. A single carbon can or a liquid scrubbing system may be used as the sole control device if the requirements below are satisfied.

(1) The exhaust to atmosphere shall be monitored continuously and the VOC concentration recorded at least once every 15 minutes when waste gas is directed to the scrubber.

(2) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 39.A.

(3) An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background. The MSS activity shall be stopped as soon as possible when the VOC concentration exceeds 100 ppmv above background for more than one minute. The date and time of all alarms and the actions taken shall be recorded.

F. A closed loop refrigerated vapor recovery system

(1) The vapor recovery system shall be installed on the facility to be degassed using good engineering practice to ensure air contaminants are flushed from the facility through the refrigerated vapor condensers and back to the facility being degassed. The vapor recovery system and facility being degassed shall be enclosed except as necessary to insure structural integrity (such as roof vents on a floating roof tank).

(2) VOC concentration in vapor being circulated by the system shall be sampled and recorded at least once every 4 hours at the inlet of the condenser unit with an instrument meeting the requirements of Special Condition 39.

(3) The quantity of liquid recovered from the tank vapors and the tank pressure shall be monitored and recorded each hour. The liquid recovered must increase with each reading and the tank pressure shall not exceed one inch water pressure while the system is operating.

46. Transfer of solid materials, including catalyst, to or from process equipment shall be conducted consistent with the following requirements:

A. Particulate emissions shall be minimized as follows during loading of solids into process equipment:

(1) Equipment for loading solids shall be designed and configured such that solids are dropped from a height not to exceed 2 feet; or

(2) A vacuum or vacuum truck shall be used to convey solids, where the vacuum/vacuum truck exhaust is controlled using a HEPA filter or portable dust collector.

B. Particulate emissions shall be minimized as follows during unloading of solids from process equipment using one of the following methods:

(1) Process equipment shall be flooded with water prior to transfer of solids;

(2) Solids shall be transferred to a bin or container which minimize the action of wind currents on dust formation; or

(3) If a portable vacuum or vacuum truck is used to remove solids, the system shall be enclosed such that the only vent to the atmosphere is through the vacuum/vacuum truck exhaust, and such exhaust shall be controlled using a HEPA filter or portable dust collector.

C. The permit holder shall record the type of solids transferred, the method of transfer, and the type of control device employed (if any).

Case-by-Case MACT Permit

47. Associated Permit Number HAP81 implements the requirements of Section 112(g) of the Federal Clean Air Act, 40 CFR 63 Subpart B, and 30 TAC 116.400 for case-by-case MACT permitting. Special Condition Nos. 7 and 36 have been developed to demonstrate compliance with the case-by-case MACT permit.

Greenhouse Gas Emissions

48. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. If construction, a physical change or a change in method of operation results in Prevention of Significant Deterioration (PSD) review for criteria pollutants, records shall be sufficient to demonstrate the amount of emissions of GHGs from the source as a result of construction, a physical change or a change in method of operation does not require authorization under 30 TAC §116.164(a). If there is construction, a physical change or change in the method of operation that will result in a net emission increase of 75,000 tpy or more CO_{2e} and PSD review is triggered for criteria pollutants, greenhouse gas emissions are subject to PSD review.

49. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, record keeping, and reporting requirements related to Greenhouse Gas (GHG) emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit.

50. Permittee shall calculate the CO_{2e} emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.

51. Records of emissions of GHG, and how they were determined, in compliance with Special Condition Nos. 48, 49, and 50 must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction.

Recordkeeping

52. The records required by these special conditions shall be maintained in either hard copy or electronic format and shall be maintained for at least five years rather than the two-year period specified in General Condition No. 7. These records shall be made immediately available at the request of personnel from the TCEQ or any air pollution control agency with jurisdiction.

Date: TBD

Permit Numbers 170854, PSDTX1614, HAP81, and GHGPSDTX227

Attachment A

Inherently Low Emitting Activities

Activity	Emissions				
	VOC	NO_x	CO	PM	H_2S/SO_2
Aerosol Cans	x			x	
Catalyst charging/handling				x	

Date: TBD

Permit Numbers 170854, PSDTX1614, HAP81, and GHGPSDTX227

Attachment C

MSS Activity Summary

Facilities	Description/Activity	EPN
All process units	Process equipment degassing and opening	MSS_ATM MSS_TMPCTL
Floating Roof Storage Tanks	Tank MSS	MSS_TKLAND
Vacuum trucks	Operate vacuum trucks	MSS_ATM
see Attachment A	Miscellaneous low emitting activities	MSS_ATM

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 170854, PSDTX1614, and HAP81

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)
H-1001	Pyrolysis Furnace 1	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
H-1002	Pyrolysis Furnace 2	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
H-1003	Pyrolysis Furnace 3	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
H-1004	Pyrolysis Furnace 4	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
H-1005	Pyrolysis Furnace 5	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
H-1006	Pyrolysis Furnace 6	NO_X	7.35	-
		NO_X (MSS)	14.69	-
		CO	36.75	-
		PM	3.68	-
		PM_{10}	3.68	-
		$PM_{2.5}$	3.68	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC	2.65	-
		SO_2	2.88	-
		NH_3	2.24	-
FURN_CAP	Pyrolysis Furnaces	NO_X	-	128.67
		CO	-	482.90
		PM	-	96.51
		PM_{10}	-	96.51
		$PM_{2.5}$	-	96.51
		VOC	-	69.49
		SO_2	-	75.69
		NH_3	-	58.73
B-801	Steam Boiler 1	NO_X	11.59	-
		NO_X (MSS)	23.18	
		CO	57.99	-
		PM	5.80	-
		PM_{10}	5.80	-
		$PM_{2.5}$	5.80	-
		VOC	4.18	-
		SO_2	4.55	-
		NH_3	3.53	-
B-802	Steam Boiler 2	NO_X	11.59	-
		NO_X (MSS)	23.18	
		CO	57.99	-
		PM	5.80	-
		PM_{10}	5.80	-
		$PM_{2.5}$	5.80	-
		VOC	4.18	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	4.55	-
		NH_3	3.53	-
B-803	Steam Boiler 3	NO_X	11.59	-
		NO_X (MSS)	23.18	
		CO	57.99	-
		PM	5.80	-
		PM_{10}	5.80	-
		$PM_{2.5}$	5.80	-
		VOC	4.18	-
		SO_2	4.55	-
		NH_3	3.53	-
B-804	Steam Boiler 4	NO_X	11.59	-
		NO_X (MSS)	23.18	
		CO	57.99	-
		PM	5.80	-
		PM_{10}	5.80	-
		$PM_{2.5}$	5.80	-
		VOC	4.18	-
		SO_2	4.55	-
		NH_3	3.53	-
BLR_CAP	Steam Boilers	NO_X	-	135.35
		CO	-	507.95
		PM	-	101.51
		PM_{10}	-	101.51
		$PM_{2.5}$	-	101.51
		VOC	-	73.09
		SO_2	-	79.62

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	-	61.77
PK-201	KCOT Regenerator	NO_X	37.89	165.93
		CO	576.63	2,525.64
		SO_2	131.86	288.76
		PM	23.80	104.24
		PM_{10}	23.80	104.24
		$PM_{2.5}$	23.80	104.24
		H_2SO_4	20.95	91.73
		VOC	6.61	28.94
		HCN	27.29	119.52
		NH_3	7.02	30.72
H-501	OCT Charge Heater	NO_X	2.24	6.52
		CO	11.17	24.47
		SO_2	0.88	3.84
		NH_3	0.68	2.98
		PM	1.12	4.89
		PM_{10}	1.12	4.89
		$PM_{2.5}$	1.12	4.89
		VOC	0.81	3.52
H-502	Regeneration Gas Heater	NO_X	0.74	3.24
		CO	1.85	4.05
		SO_2	0.15	0.64
		PM	0.19	0.81
		PM_{10}	0.19	0.81
		$PM_{2.5}$	0.19	0.81
		VOC	0.14	0.59
H-201	KCOT Process Heater	NO_X	5.53	16.14

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NO_X (MSS)	11.06	
		CO	27.66	60.56
		SO_2	2.17	9.50
		NH_3	1.69	7.37
		PM	2.77	12.11
		PM_{10}	2.77	12.11
		$PM_{2.5}$	2.77	12.11
		VOC	1.99	8.72
H-371	GRU Charge Heater	NO_X	0.21	0.89
		CO	0.51	1.11
		SO_2	0.04	0.18
		PM	0.06	0.23
		PM_{10}	0.06	0.23
		$PM_{2.5}$	0.06	0.23
		VOC	0.04	0.16
GFL-1	Ground Flare	NO_X	223.45	-
		NO_X (MSS)	5,217.46	-
		CO	446.09	-
		CO (MSS)	10,416.01	-
		VOC	372.66	-
		VOC (MSS)	6,857.47	-
		H_2S	8.50	-
		SO_2	9.53	-
		SO_2 (MSS)	797.95	-
FL-1	Elevated Flare	NO_X	26.09	-
		NO_X (MSS)	260.88	-
		CO	52.09	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
		CO (MSS)	520.81	-
		VOC	84.36	-
		VOC (MSS)	843.58	-
		H_2S	0.05	-
		H_2S (MSS)	0.43	
		SO_2	3.99	-
		SO_2 (MSS)	39.90	-
FLRCAP	Flares Cap	NO_X	-	669.19
		CO	-	1,335.94
		VOC	-	1,133.43
		H_2S	-	0.93
		SO_2	-	44.95
TO	Thermal Oxidizer	NO_X	1.29	1.13
		CO	1.61	1.41
		SO_2	0.13	0.12
		PM	0.17	0.15
		PM_{10}	0.17	0.15
		$PM_{2.5}$	0.17	0.15
		VOC	0.23	0.06
CT-801	Cooling Tower	VOC	201.60	88.31
		PM	7.21	31.57
		PM_{10}	1.85	8.07
		$PM_{2.5}$	0.02	0.05
		H_2S	0.19	0.08
EE-801	Firewater Pump Engine 1	NO_X	3.46	0.18
		CO	3.03	0.16
		VOC	3.46	0.18

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		SO_2	0.01	0.01
		PM	0.18	0.01
		PM_{10}	0.18	0.01
		$PM_{2.5}$	0.18	0.01
EE-802	Firewater Pump Engine 2	NO_X	3.46	0.18
		CO	3.03	0.16
		VOC	3.46	0.18
		SO_2	0.01	0.01
		PM	0.18	0.01
		PM_{10}	0.18	0.01
		$PM_{2.5}$	0.18	0.01
EE-803	Emergency Generator 1	NO_X	28.22	1.42
		CO	15.44	0.78
		VOC	28.22	1.42
		SO_2	0.03	0.01
		PM	0.89	0.05
		PM_{10}	0.89	0.05
		$PM_{2.5}$	0.89	0.05
EE-804	Emergency Generator 2	NO_X	28.22	1.42
		CO	15.44	0.78
		VOC	28.22	1.42
		SO_2	0.03	0.01
		PM	0.89	0.05
		PM_{10}	0.89	0.05
		$PM_{2.5}$	0.89	0.05
EE-805	Emergency Generator 3	NO_X	28.22	1.42
		CO	15.44	0.78

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		VOC	28.22	1.42
		SO_2	0.03	0.01
		PM	0.89	0.05
		PM_{10}	0.89	0.05
		$PM_{2.5}$	0.89	0.05
FUG	Equipment Leak Fugitives	VOC	48.96	214.44
		CO	0.03	0.11
		H_2S	0.02	0.09
NH3FUG	SCR Fugitives	NH_3	1.55	6.76
V-702	Olefins Regeneration Vent	VOC	0.14	0.09
		CO	7.32	4.92
TK-908	Tank 908	VOC	3.01	0.69
TK-909	Tank 909	VOC	1.02	0.73
TK-910	Tank 910	VOC	3.82	7.79
WWTP	Wastewater Treatment Plant	VOC	1.92	8.37
MSS_ATM	Uncontrolled MSS Activities	VOC	64.35	30.26
		PM	0.07	0.01
		PM_{10}	0.04	0.01
		$PM_{2.5}$	0.01	0.01
MSS_TKLAND	Tank MSS Activities	VOC	389.24	2.87
MSS_TMPCTL	MSS Temporary Control Device	NO_X	2.73	0.18
		CO	1.66	0.11
		SO_2	0.65	0.05
		PM	0.17	0.02
		PM_{10}	0.17	0.02
		$PM_{2.5}$	0.17	0.02
		VOC	7.09	0.08

Emission Sources - Maximum Allowable Emission Rates

(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
SO_2 - sulfur dioxide
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
CO - carbon monoxide
NH_3 - ammonia
H_2SO_4 - sulfuric acid
HCN - hydrogen cyanide
H_2S - hydrogen sulfide
(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.

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX227

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized 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 authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
FURN_CAP	Pyrolysis Furnaces	CO_2 (5)	1,672,669.44
		CH_4 (5)	85.05
		N_2O (5)	16.99
		CO_2e	1,679,856.91
BLR_CAP	Steam Boilers	CO_2 (5)	1,759,446.00
		CH_4 (5)	89.47
		N_2O (5)	17.87
		CO_2e	1,767,006.34
PK-201	KCOT Regenerator	CO_2 (5)	703,985.22
		CH_4 (5)	20.63
		N_2O (5)	4.13
		CO_2e	705,729.89
H-501	OCT Charge Heater	CO_2 (5)	84,726.72
		CH_4 (5)	4.31
		N_2O (5)	0.87
		CO_2e	85,090.80
H-502	Regeneration Gas Heater	CO_2 (5)	14,007.24
		CH_4 (5)	0.72
		N_2O (5)	0.15
		CO_2e	14,067.43
H-201	KCOT Process Heater	CO_2 (5)	209,766.96
		CH_4 (5)	10.67
		N_2O (5)	2.13
		CO_2e	210,668.33
H-371	GRU Charge Heater	CO_2 (5)	3,826.37
		CH_4 (5)	0.20

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
		N_2O (5)	0.04
		CO_2e	3,842.81
FLRCAP	Flares Cap	CO_2 (5)	630,388.13
		CH_4 (5)	32.06
		N_2O (5)	6.41
		CO_2e	633,096.9
TO	Thermal Oxidizer	CO_2 (5)	2,434.99
		CH_4 (5)	0.13
		N_2O (5)	0.03
		CO_2e	2,445.45
EE-801	Firewater Pump Engine 1	CO_2 (5)	10.46
		CH_4 (5)	0.01
		N_2O (5)	0.01
		CO_2e	10.59
EE-802	Firewater Pump Engine 2	CO_2 (5)	10.46
		CH_4 (5)	0.01
		N_2O (5)	0.01
		CO_2e	10.59
EE-803	Emergency Generator 1	CO_2 (5)	53.42
		CH_4 (5)	0.01
		N_2O (5)	0.01
		CO_2e	54.10
EE-804	Emergency Generator 2	CO_2 (5)	53.42
		CH_4 (5)	0.01
		N_2O (5)	0.01
		CO_2e	54.10
EE-805	Emergency Generator 3	CO_2 (5)	53.42
		CH_4 (5)	0.01
		N_2O (5)	0.01
		CO_2e	54.10

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
FUG	Equipment Leak Fugitives	CO_2 (5)	0.11
		CH_4 (5)	0.09
		N_2O (5)	13.84
		CO_2e	345.98
MSS_TMPCTL	MSS Temporary Control Device	CO_2 (5)	226.74
		CH_4 (5)	0.02
		N_2O (5)	0.01
		CO_2e	227.71

(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) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
HFCs - hydrofluorocarbons
PFCs - perfluorocarbons
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015):
CO_2 (1), N_2O (298), CH_4(25), SF_6 (22,800), HFC (various), PFC (various)
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

Date: TBD

Preliminary Determination Summary

Energy Transfer Petrochemical Holdings, LLC
Permit Numbers 170854, PSDTX227, HAP81, and GHGPSDTX1614

I. Applicant

Energy Transfer Petrochemical Holdings LLC
100 Green Street
Marcus Hook, Pennsylvania 19061-4800

II. Project Location

Energy Transfer Petrochemicals Facility
2300 North Twin City Highway
Jefferson County
Nederland, Texas 77627

III. Project Description

Energy Transfer Petrochemical Holdings, LLC (ET) proposes to construct a new petrochemicals complex at a greenfield site in Nederland, Jefferson County. The petrochemicals complex will produce olefins (propylene and ethylene). Significant sources of emissions include pyrolysis furnaces, steam boilers, heaters, a KCOT regenerator, flares, a thermal oxidizer, equipment leak fugitives, a process vent, a cooling tower, storage tanks, a wastewater treatment plant, and emergency engines. Maintenance, startup, and shutdown (MSS) emissions will be authorized under this permit.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	1,676.25
NO_x	1,131.86
SO_2	503.40
CO	4,951.83
PM	352.22
PM_{10}	328.72
$PM_{2.5}$	320.70
H_2SO_4	91.73
H_2S	1.10
NH_3	168.33
HCN	119.52
CO_2	5,081,658.99
CH_4	257.15
N_2O	48.68

CO_2 Equivalents (CO_{2e})	5,102,515.67

CO2e - carbon dioxide equivalents based on global warming potentials of CH_4 = 25, N_2O = 298.

V. Federal Applicability

The petrochemical complex is located in Jefferson County, which is classified as attainment for all criteria pollutants. The petrochemical complex is a named source, and has a potential to emit (PTE) in excess of 100 tpy for at least one pollutant. PSD review applies to the following pollutants for which the PTE exceeds an applicable significance threshold (40 CFR § 52.21(b)(23)(i)): VOC, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4. The PTE for H_2S is less than the applicable significance thresholds, and PSD requirements do not apply for these pollutants. Finally, the petrochemical complex has a PTE in excess of 100 tpy (mass basis) and 75,000 tpy GHG (CO_{2e} basis) for GHG. GHG are therefore subject to regulation (40 CFR § 52.21(b)(49)(iv)) and PSD BACT requirements apply to GHG.

The petrochemical complex is located in Jefferson County, which is classified as attainment for all criteria pollutants. Nonattainment review is not applicable.

The KCOT unit itself has the potential to emit more than 10 tpy of HCN, constituting a major source of HAP. ET has evaluated the applicability provisions for all Part 63 NESHAP standards that would potentially apply to the KCOT regenerator, including Subparts UUU; Subparts XX and YY; Subparts F, G, and H; and Subpart FFFF (Refinery MACT, Ethylene MACT, HON, and MON, respectively), and has been unable to identify a standard in Part 63 under which the unit "has been specifically regulated or exempted." Therefore, the KCOT is an affected source pursuant to 30 TAC § 116.400, and must submit an application for a case-by-case MACT limit pursuant to 30 TAC § 116.404.

VI. Control Technology Review

Control technology is consistent with PSD BACT for PSD pollutants (VOC, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and GHG) and state minor NSR BACT for H_2S. Emission limitations for HAPs are not less stringent than the emission limitation achieved in practice by the best controlled similar facility**.** A control technology review was conducted for all pollutants. The controls described in this section were determined to satisfy BACT and MACT requirements based on a review of recently issued permits from Texas and other states, and consideration of the RACT/BACT/LAER Clearinghouse (RBLC) data provided by the applicant. A more detailed description of the control technology review is included in the permit file**.**

<u>Pyrolysis Furnaces (EPNs H-1001, H-1002, H-1003, H-1004, H-1005, and H-1001)</u>

The pyrolysis furnaces will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through use of low NO_X burners and SCR. The permit limits NO_X emissions to 0.015 lb/MMBtu fuel fired (HHV basis) on a 1-hr average and 0.010 lb/MMBtu fuel fired on an annual average. Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis) on a 24-hr average. Emissions of CO are limited to 50 ppmvd (3% O_2 basis) on a 1-hr average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of PM and VOC are limited through good combustion practices and use of gaseous fuels.

The furnace exhaust cannot be controlled by SCR during non-routine operation because the temperature is not sufficiently high to support catalyst activity. The permit provides waivers from the NO_X and CO concentration limits during non-routine operations, provided that the MAERT limits are met.

Decoking operations result in incomplete combustion within the furnace tubes, resulting in formation of CO and particulate. The permit requires that decoke effluent be redirected to the furnace firebox (to destroy organic particulate and CO).

GHGs from the pyrolysis furnaces will be limited through good combustion practices, automated air/fuel controller, and a stack temperature that does not exceed 340°F.

Steam Boilers (EPNs B-801, B-802, B-803, and B-804)

The boilers will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through the use of low NO_X burners and SCR. The permit limits NO_X emissions to 0.015 lb/MMBtu fuel fired (HHV basis) on a 1-hr average and 0.010 lb/MMBtu fuel fired on an annual average. Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis) on a 24-hr average. Emissions of CO are limited to 50 ppmvd (3% O_2 basis) on a 1-hr average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of PM and VOC are limited through good combustion practices and the use of gaseous fuel.

GHGs from the boilers will be limited through use of low carbon fuels, inspecting and tuning the burners annually, and preventative maintenance.

KCOT Regenerator (EPN PK-201)

The KCOT Unit is a fluidized catalytic cracking plant, which cracks light hydrocarbon liquids to form propylene and pyrolysis gasoline. The proposed KCOT Unit differs from refinery FCC Units in that it does not use vacuum gasoil (VGO) or other similar “heavy” streams as its feedstock. Instead, it will use LPGs, natural gasoline, and externally generated recycle streams as its primary feedstocks. The KCOT is also configured to optimize the production of propylene, rather than the production of fuels. ET is not aware of any other proposed installation of an FCC Unit outside of a petroleum refinery, and expects to find no comparable units permitted for purposes of a Tier I analysis. Therefore, a Tier II analysis has been conducted, using petroleum refinery FCC Units as the target source category for identifying technology transfer options.

Emissions of NO_X are minimized through use of SCR. The permit limits NO_X emissions to 20 ppmvd (0% O_2) on a 365-day rolling average. Ammonia slip from the SCR is limited to 10 ppmvd (0% O_2 basis) on a 24-hr average. Emissions of CO are limited to 500 ppmvd (0% O_2 basis) on a 1-hr average. PM emissions are limited to 0.5 lb/1,000 lb coke burnoff through use of a wet gas scrubber. H_2SO_4 is limited to 0.33 lb/1,000 lb coke burnoff through use of a wet gas scrubber. SO_2 emissions are limited to 50 ppmvd (0% O_2) on a 7-day rolling average and 25 pppmvd (0% O_2) on a 365-day rolling average through use of a wet gas scrubber. HCN emissions are limited through compliance with MACT UUU emission limitations for organic HAP.

GHGs are limited through good combustion practices and operation of the unit with a high conversion rate to minimize coke formation.

OCT Charge Heater (EPN H-501)

The heaters have a maximum firing rate above 100 MMBtu/hr. The heaters will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through the use of low NO_X burners and SCR. The permit limits NO_X emissions to 0.015 lb/MMBtu fuel fired (HHV basis) on a 1-hr average and 0.010 lb/MMBtu fuel fired on an annual average. Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis) on a 24-hr average. Emissions of CO are limited to 100 ppmvd (3% O_2 basis) on a 1-hr average and 50 ppmvd (3% O_2 basis) on an annual average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of particulate and VOC are limited through good combustion practices and the use of gaseous fuel.

GHGs from the boilers will be limited through use of low carbon fuels and good combustion practices.

KCOT Process Heater (EPN H-201)

The heaters have a maximum firing rate above 100 MMBtu/hr. The heaters will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through the use of low NO_X burners and SCR. The permit limits NO_X emissions to 0.015 lb/MMBtu fuel fired (HHV basis) on a 1-hr average and 0.010 lb/MMBtu fuel fired on an annual average. Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis) on a 24-hr average. Emissions of CO are limited to 100 ppmvd (3% O_2 basis) on a 1-hr average and 50 ppmvd (3% O_2 basis) on an annual average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of particulate and VOC are limited through good combustion practices and the use of gaseous fuel.

GHGs from the boilers will be limited through use of low carbon fuels and good combustion practices.

Regeneration Gas Heater (EPN H-502)

The heaters have a maximum firing rate of less than 40 MMBtu/hr. The heaters will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through the use of low NO_X burners. The permit limits NO_X emissions to 0.03 lb/MMBtu fuel fired (HHV basis) on a 1-hr average. Emissions of CO are limited to 100 ppmvd (3% O_2 basis) on a 1-hr average and 50 ppmvd (3% O_2 basis) on an annual average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of particulate and VOC are limited through good combustion practices and the use of gaseous fuel.

GHGs from the boilers will be limited through use of low carbon fuels and good combustion practices.

GRU Charge Heater (EPN H-371)

The heaters have a maximum firing rate of less than 40 MMBtu/hr. The heaters will fire natural gas, plant fuel gas, and/or hydrogen. Emissions of NO_X are minimized through the use of low NO_X burners. The permit limits NO_X emissions to 0.03 lb/MMBtu fuel fired (HHV basis) on a 1-hr average. Emissions of CO are limited to 100 ppmvd (3% O_2 basis) on a 1-hr average and 50 ppmvd (3% O_2 basis) on an annual average. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf. Emissions of particulate and VOC are limited through good combustion practices and the use of gaseous fuel.

GHGs from the boilers will be limited through use of low carbon fuels and good combustion practices.

Ground Flare (EPN GFL-1)

The permit requires continuous monitoring for waste gas volumetric flow, waste gas composition or heating value, presence of pilot flame, and visible emissions for the elevated flare. The flare must achieve a minimum destruction/removal efficiency (DRE) of 99.5% for VOC and 98% DRE for H_2S. This is to be achieved through compliance with work practices and operational requirements in 40 CFR Part 63, Subparts YY. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf.

GHGs from the flare will be limited through good process design, good flare design, best operational practices, and routing appropriate vents to fuel.

Elevated Flare (EPN FL-1)

The permit requires continuous monitoring for waste gas volumetric flow, waste gas composition or Btu content, presence of pilot flame, and visible emissions for the elevated flare. The flare must achieve a minimum destruction/removal efficiency (DRE) of 99% for hydrocarbons containing three carbon atoms or less, and 98% for all other compounds. This is to be achieved through compliance with operating requirements at 40 CFR § 60.18. SO_2 emissions are limited through use of low-sulfur fuel gas. The permit limits total sulfur in natural gas and plant fuel gas to 2 gr/100dscf.

GHGs from the flare will be limited through good process design, good flare design, best operational practices, and routing appropriate vents to fuel.

Thermal Oxidizer (EPN TO)

The thermal oxidizer will be used to control dilute waste gas streams primarily generated in the treatment of process water generated in the ethylene plant and KCOT unit. The thermal oxidizer must achieve 99.9% destruction efficiency. This is to be demonstrated through initial stack sampling and by maintaining the firebox temperature at or above the temperature demonstrated during the stack test (6-minute average) during subsequent operations. Prior to the initial stack test, the firebox temperature must be maintained at or above 1650°F. Collateral NO_X emissions are limited to 0.06 lb/MMBtu, based on the higher heating value of the waste gas.

GHGs from the thermal oxidizer will be limited through good thermal oxidizer design and best operational practices.

Cooling Tower (EPN CT-801)

Process-to-water heat exchangers can generate emissions of VOC due to leaks in the heat exchanger, which are emitted at the cooling tower. **The cooling tower is non-contact design.** The permit requires weekly sampling of cooling water for strippable VOC. Corrective action must be taken if total strippable hydrocarbon content of the cooling water exceeds 0.08 ppmw equivalent, and delay of repair procedures cannot be used if the strippable hydrocarbon content exceeds 0.8 ppmw. Additionally, the permit specifies that a cooling water concentration qualifying as a leak under MACT XX is also a leak for purposes of permit compliance.

Dissolved solids in the cooling water may also result in particulate emissions at the cooling tower. The permit requires that particulate emissions be minimized through the drift eliminators which are designed to limit total liquid drift to no greater than 0.0005%. Drift eliminators must be inspected regularly and must be repaired or replaced when defects are discovered.

Firewater Pump Engine 1 and Firewater Pump Engine 2 (EPNs EE-801 and EE-802)

The emergency firewater pumps must satisfy EPA Tier 3 (40 CFR § 1039) requirements. The engines will fire ultra-low sulfur diesel fuel, consisting of no more than 15 ppm sulfur by weight. The engines are limited to 100 hours per year of non-emergency operation and must have a non-resettable runtime meter.

GHGs from the emergency engines will be limited through engine design and certification in accordance with CFR standards, limited operational hours, and proper operation and maintenance.

Emergency Generator 1, Emergency Generator 2, and Emergency Generator 3 (EPNs EE-803, EE-804, and EE-805)

The emergency generator is limited to those satisfying EPA Tier 2 (40 CFR § 1039) requirements. The engines will fire ultra-low sulfur diesel fuel, consisting of no more than 15 ppm sulfur by weight. The engines are limited to 100 hours per year of non-emergency operation and must have a non-resettable runtime meter.

GHGs from the emergency engines will be limited through engine design and certification in accordance with CFR standards, limited operational hours, and proper operation and maintenance.

Equipment Leak Fugitives (EPN FUG)

Fugitive emissions from piping components in VOC service will be monitored using the TCEQ 28VHP and 28CNTQ leak detection and repair (LDAR) programs. These LDAR programs require quarterly inspection of accessible valves, and pump, compressor and agitator seals in vapor and light liquid service using a portable hydrocarbon analyzer, with a leak definition of 500 ppmv VOC for valves, and 2000 ppmv VOC for pump, compressor and agitator seals. Flanges and other connectors must be monitored quarterly with a portable hydrocarbon analyzer, with a leak definition of 500 ppmv VOC. A first attempt must be made to repair leaks with 5 days, and repairs must be completed within 15 days. GHGs from equipment leak fugitives will be limited through compliance with the LDAR monitoring program.

Olefins Regeneration Vent (EPN V-702)

Emissions of VOC and CO from the regeneration vents are directed to the vent gas control system to the maximum extent practicable prior to any uncontrolled venting.

Tank 908 (EPN TK-908)

Tank 908 is a fixed roof tank that will store fuel oil, which has a true vapor pressure of less than 0.5 psia. The tank is a fixed roof tank that will be painted white and equipped with submerge fill mechanism.

Tank 909 (EPN TK-909)

Tank 909 is an internal floating roof tank that will store methanol. The tank is designed with a mechanical shoe primary seal. The tank will be painted white, and designed as drain dry with a connection to a control device for use during floating roof landings.

Tank 910 (EPN TK-910)

Tank 910 is an internal floating roof tank that will store pyrolysis gasoline. The tank is designed with a mechanical shoe primary seal. The tank will be painted white, and designed as drain dry with a connection to a control device for use during floating roof landings.

Wastewater Treatment Plant (EPN WWTP)

Stripped gases from pretreatment will be routed to a control device, that all collection system conveyances to the biological treatment unit are of hard piped/covered design, with vents upstream of the biological treatment unit vented to the thermal oxidizer, and that the wastewater treatment system have an overall VOC reduction efficiency of at least 90 percent efficient.

Spent sulfidic caustic will be routed to a wet air oxidation unit, which is controlled by the thermal oxidizer. Benzene area wastewater will be routed to the benzene stripper, and the stripper must be operated in accordance with 40 CFR Part 61, Subpart FF.

The level of mixed liquor suspended solids (MLSS) in the biological oxidation treatment unit must be maintained above 3,500 mg/L. Additionally, the permit requires that monthly samples be taken for the WWTP to determine the MLSS and inlet VOC loading, and sampled data must be used to determine compliance with the permit emission limits.

Process vents

Process vents will be routed to the flares or thermal oxidizer, with the exception of the Regeneration Vent (EPN V-702).

Plant fuel gas

Plant fuel gas is limited to 2 grains sulfur per 100 dscf.

Maintenance, Startup, and Shutdown (EPNs MSS_ATM, MSS_TKLAND, and MSS_TMPCTL)

The permit specifies control requirements for vessel maintenance and cleaning activities. Process vessels must be degassed to an appropriate control device until the measured VOC concentration in the process vessel is verified to be less than 5,000 ppmv VOC. Process vessels containing no more than 50 lb VOC for which a connection to a control device is not available may be opened to the atmosphere without any prior control. Catalyst handling is performed in a manner that minimizes particulate matter emissions.

Degassing of process vessels may use the plant flare system or a temporary control device. Temporary control devices must meet the operational requirements specified in the permit.

A storage tank may not be opened to the atmosphere unless the tank has been degassed to control, and the residual VOC concentration in the tank is reduced to 5,000 ppmv or less. Once a tank is opened, measures must be taken to minimize emissions until all standing liquid is removed from the tank. For floating roof storage tanks storing liquids with a VOC vapor pressure of 0.5 psia or greater, the tank vapor space must be collected to a functioning closed vent system and control device any time the floating roof is landed on its supporting legs, except that control requirements are waived for up to 24 hours following emptying of the tank for inspection and maintenance.

Vacuum trucks must be equipped with a “duck bill” hose tip in order to minimize air entrainment into the truck’s storage tank. The exhaust of the vacuum truck must be directed to a control device if the liquid being collected has a VOC vapor pressure in excess of 0.5 psia.

VII. Air Quality Analysis

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

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr, 3-hr, 24-hr, and annual SO_2, 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, and 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for annual PM_{10} and 1-hr and 8-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA’s interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is 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 $PM_{2.5}$ and ozone 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 an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[3].

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to

[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

compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m^3)

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	31	7.8
SO_2	3-hr	30	25
SO_2	24-hr	20	5
SO_2	Annual	1.4	1
PM_{10}	24-hr	8	5
PM_{10}	Annual	0.97	1
$PM_{2.5}$ (NAAQS)	24-hr	7.1	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.85	0.2
$PM_{2.5}$ (Increment)	24-hr	7.7	1.2
$PM_{2.5}$ (Increment)	Annual	0.94	0.2
NO_2	1-hr	41	7.5
NO_2	Annual	2	1
CO	1-hr	314	2000
CO	8-hr	158	500

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), 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 all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

Intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 PSD De Minimis analyses. See section 4 for additional details.

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 1000 and 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.57 µg/m^3 and 0.02 µg/m^3, 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. Please note that the precursor emissions (SO_2 and NO_x) used in the MERP analysis were based on project emission increases and recently permitted or pending emissions within 10 kilometers (km) of the project site.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	2.2	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project and recently permitted or pending emissions of O_3 precursor emissions (NO_x and VOC). For the project and recently permitted or pending NO_x and VOC emissions within 10km of the project site, 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. 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 1000 tpy Harris County source, the applicant estimated an 8-hr O_3 concentration of 2.2 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are greater than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that the 24-hr SO_2 exceeds the respective monitoring significance level and requires the gathering of ambient monitoring information. The De Minimis analysis modeling results indicate that the 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance levels.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	20	13
PM_{10}	24-hr	8	10
NO_2	Annual	2	14
CO	8-hr	158	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient SO_2 and $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 482450628 located at Port Arthur, Jefferson County. The three-year average (2020-2022) of the 99th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value (38 µg/m^3). The second high 3-hr concentration from 2022 was used for the 3-hr value (38 µg/m^3). 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 and proximity of the monitor to the project site (approximately 14 km to the southeast). These background concentrations were also used as part of the NAAQS analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482450021 located at 2200 Jefferson Dr., Port Arthur, Jefferson County. The applicant calculated a three-year average (2020-2022) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (20.1 µg/m^3). The applicant calculated a three-year average (2020-2022) of the annual concentrations for the annual value (8.2 µg/m^3). 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 and proximity of the monitor to the project site (approximately 10 km to the southeast). These background concentrations were also used as part of the NAAQS analysis.

Since the project has a net emissions increase of 100 tons per year (tpy) or more of volatile organic compounds or nitrogen oxides, the applicant evaluated ambient O_3 monitoring data to satisfy requirements in 40 CFR 52.21 (i)(5)(i)(f).

A background concentration for O_3 was obtained from the EPA AIRS monitor 482451035 located at 1800 N. 18th St., Nederland, Jefferson County. A three-year average (2020-2022) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (62 ppb). This monitor is reasonable based on the proximity of the monitor to the project site (approximately 1 km southwest). This background concentration was also used as part of the NAAQS analysis.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that the 1-hr and 3-hr SO_2, 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, and 1-hr and annual NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	103	38	141	196
SO_2	3-hr	181	38	219	1300
PM_{10}	24-hr	7	105	112	150
$PM_{2.5}$	24-hr	5	20	25	35

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
$PM_{2.5}$	Annual	2.7	8.2	10.9	12
NO_2	1-hr	137	46	183	188
NO_2	Annual	22	7	29	100

The 1-hr SO_2 GLCmax is the maximum five-year average of the 99th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The 3-hr SO_2 GLCmax 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 annual $PM_{2.5}$ GLCmax is the maximum five-year average of the predicted annual 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. The annual NO_2 GLCmax is the maximum predicted concentration over five years of meteorological data.

A background concentration for PM_{10} was obtained from EPA AIRS monitor 482450628 located at Port Arthur, Jefferson County. The maximum H2H 24-hr concentration from 2020-2022 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 and proximity of the monitor to the project site (approximately 14 km to the southeast).

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 482451035 located at 1800 N. 18th St., Nederland, Jefferson County. The three-year average (2018-2020) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations were used for the 1-hr value. The annual concentration from 2020 was used for the annual value. Monitoring data for 2021 and 2022 are less than 75% complete and do not meet the EPA’s requirement for completeness, however, the ADMT reviewed the available 2021 and 2022 monitoring data and verified that the background concentrations are comparable to the background concentrations from previous years. This monitor is reasonable based on the proximity of the monitor to the project site (approximately 1 km southwest).

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 1000 and 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.57 $\mu g/m^3$ and 0.02 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS. Please note that the precursor emissions (SO_2 and NO_x) used in the MERP analysis were based on project emission increases and recently permitted or pending emissions within 10 km of the project site.

Table 5. Total Ozone Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (ppb)	Background (ppb)	Total Conc. = [Background + GLCmax] (ppb)	Standard (ppb)
O_3	8-hr	2.2	62	64.2	70

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions and recently permitted or pending emissions of O_3 precursor emissions (NO_x and VOC) within 10km of the project site. For the project and recently permitted or pending NO_x and VOC emissions, 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 1000 tpy Harris County source, the applicant estimated an 8-hr O_3 concentration of 2.2 ppb. When the estimates of ozone concentrations from the project emissions are added to the background concentration listed in the table above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 3-hr, 24-hr, and annual SO_2, 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 6. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
SO_2	3-hr	181	512
SO_2	24-hr	81	91
SO_2	Annual	5	20
PM_{10}	24-hr	8	30
$PM_{2.5}$	24-hr	8.65	9
$PM_{2.5}$	Annual	2.73	4
NO_2	Annual	22	25

The GLCmax for the 3-hr and 24-hr SO_2, 24-hr $PM_{2.5}$, and 24-hr PM_{10} is the maximum H2H predicted concentration across five years of meteorological data. For annual $PM_{2.5}$, annual SO_2 and annual NO_2, the GLCmax represents the maximum predicted concentration over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in the table above represent the total predicted concentrations associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Breton Wilderness Area, is located approximately 500 km from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 2 μg/m^3 occurred approximately 100 meters from the property line towards the north. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 20 km from the proposed sources, in the direction of the Breton Wilderness Area Class I area is 0.05 μg/m^3. The Breton Wilderness Area Class I area is an additional 480 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Breton Wilderness Area Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 19.3 km from the proposed sources in the direction the Breton Wilderness Area Class I area. The Breton Wilderness Area Class I area is an additional 480.7 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Breton Wilderness Area Class I area.

F. Minor Source NSR and Air Toxics Review

Table 7. Project-Related Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (μg/m^3)	De Minimis (μg/m^3)
H_2S	1-hr	0.30	2 (If property is residential, recreational, business, or commercial)
H_2S	1-hr	2.58	3 (If property is not residential, recreational, business, or commercial)

Table 8. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (μg/m^3)	Standard (μg/m^3)
SO_2	1-hr	231	817

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
H_2SO_4	1-hr	4	50
H_2SO_4	24-hr	2	15

Table 9. Generic Modeling Results

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per tpy)
CT [CT801_1 thru CT801_24]	2.86	0.05
FUG3000 [FUG3000A and FUG3000B]	5.71	0.24
FUG9000 [FUG9000A thru FUG9000D]	1.78	0.08
WWT [WWT1 thru WWT4]	8.87	0.45
FUG1000	2.79	0.09
FUG2000	2.15	0.07
FUG4000	3.68	0.13
FUG5000	3.79	0.13
FUG6000	4.55	0.16
FUG7000	6.51	0.26
FUG8000	7.57	0.32
NH3FUG	4.27	NA
TK908	2.90	NA
TK909	3.20	NA
TK910	6.86	0.17
MSSEQU1	2.79	0.06
MSSEQU2	28.40	0.94
MSSEQU3	9.38	0.22

Source ID	1-hr GLCmax ($\mu g/m^3$ per lb/hr)	Annual GLCmax ($\mu g/m^3$ per tpy)
MSSEQU4	2.69	0.07
MSSEQU5	22.12	0.65
MSSVAC1	2.24	NA
MSSVAC2	26.89	NA
MSSVAC3	7.91	NA
MSSVAC4	2.24	NA
MSSVAC5	20.31	NA
TK909M	3.15	NA
TK910M	6.10	0.20
MSSILE1	2.79	NA
MSSILE2	28.40	NA
MSSILE3	9.38	NA
MSSILE4	2.69	NA
MSSILE5	22.12	NA
H1001	0.22	0.003
H1002	0.22	0.003
H1003	0.22	0.003
H1004	0.22	0.003
H1005	0.22	0.003
H1006	0.22	0.003
B801	0.16	0.002
B802	0.16	0.002

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per tpy)
B803	0.16	0.002
B804	0.16	0.002
PK201	0.21	NA
H501	1.00	NA
H201	0.22	NA
GFL1_ST	0.31	NA
GFL1M_ST	0.004	NA
FL1	0.30	NA
FL1MSS	0.09	NA
TO	2.95	0.03
MSSCNT1	1.50	0.02
MSSCNT2	1.71	0.02
MVCU3	NA	0.006
FURN_CAP	NA	0.003
BLR_CAP	NA	0.002
FLRCAP	NA	0.002
MVCU2	NA	0.001
MVCU4	NA	0.003
MVCU5	NA	0.001
MVCU6	NA	0.001
MVCU7	NA	0.001
MVCU8	NA	0.001

Table 10. Minor NSR Project (Increases Only) Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	10% ESL (µg/m^3)
distillates (petroleum), hydrotreated light 64742-47-8	1-hr	142	350
ammonia 7664-41-7	1-hr	14	18
n-butane 106-97-8	1-hr	16	6600
1-butene 106-98-9	1-hr	28	1900
1-butene 106-98-9	Annual	2	160
1,3-butadiene 106-99-0	1-hr	27	51
1,3-butadiene 106-99-0	Annual	1.59	0.99
ethylene 74-85-1	1-hr	190.97	140
ethylene 74-85-1	Annual	14.98	3.4
fuel oil, residual 68476-33-5	1-hr	16	100
hydrogen cyanide 74-90-8	1-hr	5.71	2
n-hexane 110-54-3	1-hr	453	560
n-hexane 110-54-3	Annual	7	20
methanol 67-56-1	1-hr	251	390
n-pentane 109-66-0	1-hr	930	5900
phenol mixed oils (mixture) NA	1-hr	5	20
pyrolysis gasoline (< 40% benzene) NA	Annual	1.79	1.1

The evaluations of 1-hr hydrogen cyanide, annual 1,3-butadiene, 1-hr and annual ethylene, and annual pyrolysis gasoline (< 40% benzene) were completed using Step 6 of the MERA guidance document.

Table 11. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	GLCni ($\mu g/m^3$)	GLCni Location	ESL ($\mu g/m^3$)
benzene	71-43-2	1-hr	328	W Property Line	24	S Property Line	170
benzene	71-43-2	Annual	7.1	W Property Line	0.17	30m NW	4.5
pyrolysis gasoline (< 40% benzene)	NA	1-hr	1001	W Property Line	101	84m SW	420

Table 12. Minor NSR Hours of Exceedance for Health Effects

Pollutant	Averaging Time	2 X ESL GLCmax
pyrolysis gasoline (< 40% benzene)	1-hr	2

The GLCmax and the GLCni locations are listed in Table 11 above. The locations are listed by their approximate distance and direction from the property line of the project site.

Estimated off-property concentrations of non-criteria air contaminants were evaluated by the TCEQ Toxicology Division, and found to be protective of public health and welfare.

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the “Endangerment and Cause or Contribute Finding”, are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA’s PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ’s adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The Executive Director's preliminary determination is that the permits should be issued.