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 compare to the De Minimis levels) are different. This difference occurs because the

[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

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/m³)

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
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

$PM_{2.5}$	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
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
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
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.