



**PERMIT-TO-INSTALL APPLICATION
OHIO RIVER CLEAN FUELS FACILITY
VILLAGE OF WELLSVILLE, COLUMBIANA AND JEFFERSON COUNTIES, OHIO**

SUBMITTED TO:

OHIO ENVIRONMENTAL PROTECTION AGENCY

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MODULE 5

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1.0 PROCESS DESCRIPTION

In this process, sulfur, mercury, and other impurities that would adversely impact the Fischer-Tropsch and Product Upgrade processes are removed from the syngas generated in the gasifiers (Module 3). Figure 12 is a block flow diagram of the syngas cleanup process (see Attachment 5A). As described below, several of the processing steps will not be sources of air emissions and are therefore not subject to permitting. They are discussed here to provide a more complete understanding of this process.

1.1 High-Pressure High-Temperature (HPHT) Filter

The bulk of the fly ash contained in the raw syngas is removed using a commercially demonstrated high-pressure, high-temperature filter. Carbon dioxide is used as a blowback filter cleaning gas to periodically clean the filter, to reduce inerts in the syngas. The fly ash is stripped to remove entrained raw syngas and then pneumatically conveyed to an intermediate storage vessel equipped with a bin vent filter. The filtered syngas stream passes on to the wet scrubbing unit. Fly ash is collected and handled as described in Module 4.

1.2 Wet Scrubbing Unit

The wet scrubbing unit (WSU) will consist of six equally-sized trains (one for each gasifier). The syngas leaving the dry solids removal HPHT filter of each gasifier train will be further cleaned through wet scrubbing. This step will remove residual fly ash to a level of less than 1 ppm. The WSU will also remove other minor contaminants, such as soluble alkali salts, hydrochloric acid, and hydrofluoric acid. Caustic and makeup water will be continuously added to the scrubber to control the concentration of contaminants in the blowdown stream, to maintain a near neutral pH, and to compensate for water loss due to syngas saturation. A bleed stream of the contaminated water (bleed water) will be sent to the Primary Water Treatment Unit to recover the contaminants. Scrubbed syngas will proceed to the Sour CO-Shift Unit. The WSU will not be a source of air emissions.

1.3 Sour CO-Shift Unit

The Sour CO-Shift Unit will not be a source of air emissions. It will consist of three equally-sized trains designed to adjust the hydrogen to CO ratio of the syngas as needed for the Fischer-Tropsch process. To accomplish the CO-shift, about two-thirds of the water-saturated syngas from the WSU will be treated by catalytic conversion using CO to react with the water vapor. Hydrogen and CO₂ will be produced during this reaction. Specifically, a chemical reaction will occur in which a fraction of the CO will be oxidized to form CO₂ while steam will be reduced to produce H₂ resulting in the desired ratio of H₂ to CO. Process condensates will be sent to the Sour Water Stripping Unit. The CO-shifted syngas will be directed to activated carbon mercury guard beds for removal of mercury and then to the Acid Gas Removal Unit.

1.4 Mercury Guard Beds

The preliminary design for the mercury guard beds calls for seven beds, each 12 feet in diameter and 6 to 7 feet deep. They will be connected in parallel and will use HGR® activated granular sulfur-impregnated carbon. Greater than 99% of elemental mercury will be removed. Residual mercury will be removed in the acid gas removal unit.

1.5 Sour Water Stripping Unit

Process condensates leaving the Sour CO-Shift Unit and the Tailgas Treating Unit (see Section 1.8) will contain acid components as well as CO and ammonia (NH₃). To neutralize and remove volatile components from these wastewater streams, they will be treated in a stripper column. The off-gas streams of the stripper will be partly condensed in a quench vessel while released vapors will be routed to the Sulfur Recovery Unit (see Section 1.7) for thermal treating. This unit will be a totally enclosed process with no discharges to the atmosphere.

1.6 Acid Gas Removal Unit

Three equally-sized Acid Gas Removal (AGR) Units will be used to remove hydrogen sulfide (H₂S), carbonyl sulfide (COS), CO₂, and other trace components such as cyanide, ammonia, mercury, and metal carbonyls from the syngas. Rectisol® (or an equivalent process) has been selected. The process uses methanol as a physical solvent and operates at cryogenic temperature for removal of acid gases. H₂S, COS, and CO₂ will be physically absorbed from the raw gas by the cooled solvent. Rectisol® is a mature technology and there are many operating reference sites.

The AGR Unit will generate by-product and waste streams that will be further processed or discharged. One CO₂ stream will contain three percent CO and will be sent to the Coal Milling and Drying Unit for firing/incineration to supplement other heating sources (see Module 2 – Feedstock Processing). A separate CO₂ stream will be vented to the atmosphere during initial phases of plant operation although the plant will be designed for advanced carbon management including capture and beneficial use of CO₂ (such as for enhanced oil recovery). Another stream that will be generated from stripping acid gases from the syngas will contain over 50 molar percent H₂S with other sulfur components. That sulfur-rich stream will be sent to the Sulfur Recovery Unit for conversion to elemental sulfur.

Because of the importance of removing sulfur species prior to the Fischer-Tropsch process, the sweet syngas will be routed to three zinc oxide sulfur guard bed trains where trace sulfur will be removed. Following the sulfur guard beds, the syngas will be ready for Fischer-Tropsch and Product Upgrade (Module 6).

1.7 Sulfur Recovery Unit

Approximately 95 to 97% of the H₂S present in the sulfur-rich AGU exhaust stream will be converted to elemental sulfur in the Sulfur Recovery Unit (SRU). Additional streams processed there will include sour gases from the Primary Water Treatment Unit and the Sour Water Stripping Unit. The SRU will be based on the industry-standard Claus process involving thermal and multi-stage catalytic conversion of H₂S to sulfur.

Two equally-sized trains will produce high quality, elemental, liquid sulfur. The elemental sulfur formed during the reaction in the Claus furnace will be condensed in a sulfur condenser and separated from the process gas by an integrated separator. In multiple consecutive stages, the process gas will be reheated, routed across a catalyst bed in a Claus reactor, and cooled again for sulfur condensation and separation. The separated liquid sulfur will be collected and routed to the Sulfur Forming Unit (see Section 1.11). Residual gas from the Claus process (i.e., tailgas) will be sent to the Tailgas Treating Unit. Residual sulfur compounds will also be vented in spent degassing air and sulfur pit sweep air.

1.8 Tailgas Treating Unit

The Tailgas Treating Unit (TGTU) will consist of two equally-sized trains. The tailgas from the SRU will still contain sulfur compounds, including H₂S, SO₂, and elemental sulfur as sulfur vapor. To increase the total conversion of sulfur compounds, a Shell Claus Off-gas Treatment (SCOT) process will be used. The SCOT process consists of a catalytic reduction section where tailgas will be heated and reacted with H₂ over a catalyst. At a temperature of about 460 °F, all sulfur species in the tailgas will be hydrogenated (reduced) to H₂S by catalytic treatment. The surplus sour water will be sent to the Sour Water Stripping Unit for treatment. The residual hydrogenated tailgas will be sent to the Tailgas Compression Unit. Under normal operating conditions this process will not be a source of air emissions. Under startup and shutdown conditions, tailgas would be vented. As discussed in Section 1.10, vented gases will be routed directly to the Tailgas Thermal Oxidizers.

1.9 Tailgas Compression Unit

The Tailgas Compression Unit (TGCU) will consist of two trains each sized for 50% of the design capacity. Residual hydrogenated tailgas from the TGTU will be recycled from the TGCU to the AGR Unit for further treatment. This process will not be a source of air emissions.

1.10 Tailgas Thermal Oxidizer

The BACT analysis for this module has determined that tailgas from the TGTU will be sent to two identical Tailgas Thermal Oxidizers (TTOs) during startup and shutdown events. Sulfur from the sulfur pit sweep air and the spent degassing air will also be sent to the TTO where it will be oxidized to SO₂. Additionally, CO and NO_x from one or more low-NO_x incinerator burner(s) will be emitted from the TTOs on a continuous basis.

1.11 Sulfur Forming Unit

The Sulfur Forming Unit (SFU) will not be a source of air emissions. Liquid sulfur will be transferred from the SRU sulfur pits, filtered, and evenly distributed to a number of sulfur pelletizing belts. The pelletizing solidification belts will be located indoors. These belts will be cooled via water sprayed against the lower side of the belts, which will cause the liquid sulfur to be evenly distributed on top of the belt in droplet form. The sulfur droplets will solidify in the form of uniformly sized pellets. A silicon-based release agent will be applied for smooth discharging of the cooled pellets from the belts. Adjacent to the SFU, space will be provided for intermediate storage and loading facilities for road transport. The trace amount of H₂S present in the sulfur droplets will remain in the sulfur as it solidifies.

1.12 Primary Water Treatment Unit

The primary water treatment unit will not be a source of atmospheric emissions. Three equal-sized trains will process bleed water from the Wet Scrubbing Units and slag removal area. Dissolved gases, H₂S, and ammonia will be processed. Most of the wastewater will be sent to a clarifier, while some will go to Process Wastewater Treatment. Sour gases will be routed to the Sulfur Recovery Unit for thermal treatment.

1.13 Process Wastewater Treatment

The function of the Process Wastewater Treatment System is to collect and treat gasification process wastewater by evaporation to produce a salt material for landfill disposal and to return distillate-quality product water for demineralizer makeup. Treatment of wastewater from the gasifier wastewater stream consists of an upstream treatment by a high efficiency reverse osmosis (HERO) for volume reduction and metals removal. The HERO system theoretically reduces the volume of wastewater for disposal by approximately 85%. The concentrated reject stream from the HERO process is reduced to dryness in a triple effect evaporator/crystallizer. Solids from the crystallizer are dewatered in a filter press for off-site disposal. Permeate from the HERO process and distillate from the evaporator/crystallizer is recycled for reuse in the facility. Vented air emissions from this process are expected to be *de minimis*. However, the characteristics of this vent stream will not be completely defined until the FEED study has been completed. If it is determined that emissions from this process are not *de minimis*, they will be included in a future permit modification.

2.0 AIR EMISSIONS INVENTORY

The Syngas Cleanup process removes impurities from syngas. Some impurities are removed and collected as solids (sulfur), some are removed in liquid phase (e.g., solids, hydrochloric and hydrofluoric acids, and soluble alkali salts), and some are removed in the gaseous phase. This emissions inventory focuses on the gaseous-phase constituents that will be removed from syngas and discharged to the atmosphere.

2.1 Acid Gas Removal

Acid gases will be removed from the syngas using the Rectisol[®] process. As described in Section 1.6, Rectisol[®] is a licensed chemical process that uses methanol at subzero temperatures as a solvent. U.S. EPA has not published air pollution emission factors for the Rectisol process. Consequently, emission estimates have been based on process engineering estimates developed during the preliminary design for the facility. Refined engineering estimates may be developed during the detailed design stage.

The primary exhaust stream from the process will be waste carbon dioxide (CO₂). That CO₂ stream (estimated 83.3 mole%) will contain approximately 0.04 mole% CO, 0.00004 mole% carbonyl sulfide (COS) and 0.0001 mole% H₂S as summarized below.

Table 2.1 – Summary of Acid Gas Removal Emissions (3 Units)

Species	MW	mole fraction	lb-mole/hr	lb/hr	tpy
CO	28	0.000406	33.06	925.7	4,055
COS	60.08	0.0000004	0.033	1.96	8.57
H ₂ S	34	0.000001	0.08	2.8	12

Preliminary process modeling indicates that the total exhaust gas flow rate from the three AGR units will be about 81,420 lb-mole/hour. Based on the expected mole fractions of the regulated pollutants, the associated emission rates are shown above. Source-specific emissions would be equal to one-third of each of the above values, as follow: CO (308.6 lb/hr and 1,352 tpy), COS (0.65 lb/hr and 2.9 tpy), and H₂S (0.93 lb/hr and 4 tpy).

Based on the Best Available Control Technology (BACT) analysis presented in Section 4.0, actual emissions from this process are expected to equal the potential emissions summarized above. This process has been designed for the purpose of removing syngas contaminants. By-products of that process are gas streams that contain very low constituent concentrations. Process modifications and control technologies have not been identified that are cost-effective alternatives to venting these dilute gas streams. Therefore, actual and potential emissions are reported on the appropriate application forms as being equivalent.

2.2 Sulfur Recovery Unit/Tailgas Treating Unit

The second source of air emissions from this process module will be the sulfur recovery/ tailgas treating units. These processes remove hydrogen sulfide from the sour syngas and produce elemental sulfur. In the process, sulfur compounds would be vented to the atmosphere from the sulfur pit if left uncontrolled. During startup and shutdown periods, tailgas from the Tailgas Treating Unit (TGTU) would also be vented.

Based on the results of the BACT analysis presented in Section 4.0, Tailgas Thermal Oxidizers (TTO) will be used to control these emissions. Sulfur vented from the sulfur pit sweep air and spent degassing air will be oxidized to SO₂ in the TTOs (pending the outcome of FEED evaluations). In addition, combustion by-products from fuel burned in the thermal oxidizers will be emitted from the TTO stacks on a continuous basis. Estimates for these components of thermal oxidizer emissions are presented below.

Tailgas Combustion During Startup and Shutdown

As discussed in Section 1.8, under normal operations, tailgas from the TGTU will be recycled to the AGRU via the TGPU. During startup and shutdown, however, tailgas will be sent directly from the TGTU to the TTO. Three startups and shutdowns per year are expected. Each event will be approximately two-hours in duration. Emission estimates for thermal oxidation of the tailgas are presented in the Supporting Calculations. It is assumed that the temperature of the TTO will be high enough to oxidize sulfur species (H₂S and COS) to sulfur dioxide, but not high enough to oxidize CO which will therefore pass through. Average hourly and annual potential emission rates for tailgas constituents include:

- Carbon monoxide: 0.14 lb/hr (0.6 tpy)
- Sulfur dioxide: 13.3 lb/hr (58.4 tpy)
- Nitrogen dioxide: 3.4 lb/hr (14.7 tpy)
- Hydrogen sulfide: 0.0 lb/hr (0.0 tpy)
- Carbonyl sulfide: 0.0 lb/hr (0.0 tpy)

Maximum actual hourly emissions will be significantly higher, as shown in the Supporting Calculations, due to the short duration of startups and shutdowns. Average hourly emission rates assuming that annual emissions are averaged over 8,760 hours per year are shown above. Insignificant levels of particulate, VOC, and other pollutants are expected from these intermittent process emissions because those constituents will have been removed by the upstream cleaning processes.

Sulfur Pit Sweep Air and Spent Degassing Air

Estimates of potential sulfur pit sweep air and spent degassing air emissions from the SRU have been based on operation of a similar process at a smaller model facility. Based on a sulfur production rate of 125 long tons (LT) per day (equivalent to 140 short tons), uncontrolled H₂S emissions were estimated at 3.7 lb/hr and 16.4 tpy. For the current application, it is assumed that two 500-LT/day (560-short ton/day) units will be needed. Scaling up from the 125 LT/day facility indicates that emissions from the ORCF SRU will be eight times larger than the model facility (i.e., 1,000/125 = 8). The estimated mass loading of H₂S from the process is therefore 29.9 lb/hr and 131 tpy. H₂S will be converted to SO₂ through combustion in the TTOs. Therefore, actual and potential emissions are reported in terms of SO₂. Actual and potential emissions are assumed to be equivalent at 56.3 lb/hr (246.7 tpy) because the SRU process will not operate without the TTOs in operation and they are assumed to operate 8,760 hours per year. Assuming that the thermal oxidizer vent gas composition of the ORCF facility will be similar to the model facility, the concentration of SO₂ present in the exhaust gas will be less than 250 ppmv dry basis at 0% excess air.

Tailgas Thermal Oxidizer Burner Emissions

Emissions of criteria pollutants will be produced by combustion of natural gas as a heat source for the TTOs. Emission estimates are based on the quantity of fuel (MMscf) burned over time.

Because the TTOs have not been designed at this time, preliminary engineering estimates have been developed. These estimates are based on the projected natural gas combustion in the TTO for the model 125 LT/D plant (152,000 scfd). Assuming natural gas (LHV 950 Btu/scf), the heat input to each of two TTOs is estimated at 24 MMBtu/hr.

Accordingly, emission estimates for criteria pollutants from fuel combustion in the TTOs can be based on a fuel consumption rate equal to the 48 MMBtu/hr heat input:

$$48 \text{ MMBtu/hr} \times \text{scf}/950 \text{ Btu} = 0.051 \text{ MMscf/hr (two TTOs)}$$

Criteria pollutant emissions estimates for the combined TTOs based on operation at total heat inputs equivalent to 48 MMBtu/hr are provided in the following Supporting Calculations (Attachment 5B). Actual emissions from fuel combustion in the TTOs are expected to equal potential emissions with the exception of NO₂ which will be reduced through the use of low-NO_x burners.

Tailgas Thermal Oxidizer Emission Summary

A summary of tailgas thermal oxidizer emissions is provided in the Supporting Calculations. Average hourly emission estimates reflecting the expected three annual startup and shutdowns are provided instead of maximum hourly values. Actual emissions from the TTOs are expected to be the same as potential emissions with the exception of nitrogen oxide emissions. Actual

nitrogen oxide emissions associated with operation of the TTO burners are expected to be approximately one-half of the potential emissions based on use of low-NOx burners.

3.0 SOURCE-SPECIFIC APPLICABLE REGULATIONS

This section presents information concerning applicable state and federal regulations as well as specific exemptions, as appropriate. State regulatory references are to the Ohio Administrative Code (OAC), unless otherwise noted. Source-specific regulations are discussed relative to each permit application module. Facility-wide applicable regulations are addressed in the Application Introduction.

3.1 State Regulations

3.1.1 Control of Visible Particulate Emissions from Stationary Sources. (3745-17-07)

The tailgas thermal oxidizers will be sources of particulate matter. Stationary sources are subject to Chapter 3745-17-07(A)(1)(a) which limits visible particulate emissions to less than 20% opacity as a six-minute average. Chapter 3745-17-07(A)(1)(b) further states that the 20% opacity limit may not be exceeded for more than six consecutive minutes in any sixty minutes and never shall the opacity exceed 60% as a 6-minute average.

3.1.2 Permit to Install New Sources (3745-31)

The tailgas thermal oxidizers will be part of a major stationary source. Because the major stationary source is located within an attainment area for all criteria pollutants, according to 3745-31-12(A), each emissions unit is subject to an evaluation of best available control technology (BACT). The BACT analysis for these emission units is provided in Appendix A.

3.1.3 Permit to Install Exemptions (3745-31-03)

A Permit to Install exemption is applicable to the 8,460-gallon methanol tank needed for the Rectisol[®] trains. OAC 3745-31-03(A)(1)(i)(iv) grants a permanent exemption to storage for organic liquids with a capacity of less than 75 cubic meters (19,850 gallons). The methanol storage tank proposed for ORCF is therefore exempt from the permit-to-install application process.

3.2 Federal Regulations

3.2.1 *NSPS Subpart J – Standards of Performance for Petroleum Refineries (40 CFR 60.100)*

The ORCF facility will be subject to NSPS Subpart J, Petroleum refineries. A precedent exists for this determination in the March 18, 2005 Plan Approval issued by the Pennsylvania Department of Environmental Protection for the WMPI PTY., LLC coal to clean fuels project in Schuylkill County, Mahanoy Township (Plan Approval No. 54-399-034). This rule applies to facilities engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. “Petroleum” is defined as the crude oil removed from the earth and the oils derived from tar sands, shale, and coal. While the term “oil” is not defined, it is assumed to apply to the hydrocarbon wax that is produced through the Fischer-Tropsch process and subsequently cracked and reformed to produce F-T diesel fuel, F-T naphtha, and LPG.

Relative to Module 5 – Syngas Cleanup, Subpart J applies to the Claus sulfur recovery units because they exceed the sulfur production threshold of 20 long tons per day (LTD). The Claus units are subject to standards for SO₂ because the sulfur recovery plant is followed by a SCOT catalytic reduction system and final incineration in the thermal oxidizers (40 CFR 60.104(a)(2)(i)). ORCF must not discharge or cause the discharge of any gases into the atmosphere from the Claus sulfur recovery plant containing in excess of 250 ppm by volume (dry basis) SO₂ at zero percent excess air on a 12-hour rolling average basis.

Monitoring requirements of 40 CFR 60.105(a)(6) include an instrument for continuously monitoring and recording the concentration of reduced sulfur and oxygen emissions. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, 0% excess air). Alternative monitoring options are presented in 40 CFR 60.105(a)(7).

3.2.2 *NSPS Subpart Ja – Proposed Standards of Performance for Petroleum Refineries Constructed, Reconstructed, or Modified after May 14, 2007 (40 CFR 60.100a)*

This proposed rule maintains the requirements of Subpart J as discussed above, but adds a limit for H₂S emissions from sulfur recovery plants. The proposed limit is 10 ppmv (dry basis, 0% excess air) determined on a 12-hour rolling average basis. In the event that this standard takes effect prior to issuance of this Permit to Install, ORCF will ensure that sulfur recovery plant emissions comply with the applicable emission limits and monitoring requirements.

3.2.3 *NSPS Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (40 CFR 60.690)*

Subpart QQQ establishes standards for management of VOC emissions that will be applicable to the ORCF process wastewater treatment unit. Because specific details of the wastewater

treatment system, including emission estimates, have not been developed at this time, the specific requirements of this Subpart have not been determined.

3.2.4 National Emission Standards for Hazardous Air Pollutants: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR 63, Subpart UUU)

This rule applies to the process vents or group of process vents on Claus sulfur recovery units or the tailgas treatment units serving them. This MACT standard reinforces the emission limits established by the NSPS for petroleum refineries (Subpart J) and establishes continuous emission monitoring requirements. Table 31 of Subpart UUU requires that new Claus sulfur recovery units subject to the NSPS install and operate a continuous monitoring system to measure and record the hourly concentration of SO₂ (dry basis, 0% excess air) for each exhaust stack. The system(s) must include an oxygen monitor for correcting the data for excess air.

4.0 BACT ANALYSIS

The syngas cleanup process contains two primary sources of air emissions: the Acid Gas Removal Unit and the Sulfur Recovery/Tailgas Treating Unit. The Acid Gas Removal Unit will consist of three Rectisol[®] (or equivalent) trains. The only PSD pollutant emitted from the AGR unit will be carbon monoxide. Each Rectisol[®] train is estimated to produce 1,352 tons per year. Section 4.1 presents the BACT determinations for the acid gas removal process.

The second source of air emissions from this process module will be the sulfur recovery/ tailgas treating units. These processes remove hydrogen sulfide from the sour syngas and produce elemental sulfur as a by-product. Section 4.2 presents the BACT determination for sulfur dioxide emissions from the sulfur recovery/tailgas treating processes.

4.1 Module 5 – Acid Gas Removal Carbon Monoxide (CO)

Two CO₂-rich streams (small and large) will be produced in the Rectisol[®] trains. The CO concentration in the small CO₂ stream will be about 3%. The volume of that stream is small enough and it has sufficient heat value to be useful as a supplemental fuel in the feedstock drying process (see Module 2). The larger CO₂ stream is intended for eventual use in enhanced oil recovery (EOR) although ORCF is requesting limits that will permit the discharge of the large CO₂ stream initially. That stream will contain 400 ppm CO and because of the large volume of the stream (approximately 171,000 acfm at 65 °F), it will generate approximately 309 lb/hr and 1,352 tpy of CO from each of the three units, as shown above.

The following assessment of available control technologies is based on engineering knowledge of the Rectisol process and technologies for CO control.

4.1.1 Available Control Technologies – Acid Gas Removal Carbon Monoxide (CO)

- Oxidization (thermal, catalytic, or regenerative)
- Cryogenic Separation
- Pressure-Swing Absorption

4.1.2 Technically Infeasible Options – Acid Gas Removal Carbon Monoxide (CO)

Catalytic Oxidation

Catalytic oxidation requires that the gas stream be conditioned by first eliminating COS and H₂S, followed by pre-heat to at least 600 °F. To remove the sulfur species present in the CO₂ stream, COS would need to be hydrolyzed to H₂S. Next, H₂S would need to be entirely removed by a sulfur scavenger such as an iron bed. The entire gas stream would then be passed over a monolithic catalyst bed. A sulfur-tolerant catalyst could also be used, but experience indicates that a fraction of the SO₂ would be oxidized to SO₃, leading to the formation of aluminum sulfate

which would eventually block the catalyst pores. SO₂ would eventually poison the catalysts sites. Because it is not technically feasible to completely hydrolyze the COS, it would be impossible to eliminate the SO₂ and SO₃ in the oxidation bed. Hence, this option is not considered technically feasible for the current plant configuration.

Cryogenic Separation

Thermodynamic calculations for stream compression and cooling to the critical temperature required to liquefy the CO₂ were completed for this BACT analysis. An Aspen™ process model was used to determine the separation efficiency. The universal quasi-chemical (UNIQUAC) model was used with component interaction parameters (Abrams and Prausnitz, 1975). The model results indicate that a quantitative separation of CO and CO₂ is not possible. This technology is therefore considered to be infeasible.

4.1.3 Technology Ranking – Acid Gas Removal Carbon Monoxide (CO)

An evaluation of control technology effectiveness for carbon monoxide emissions from the Rectisol® process is shown in the following table.

Table 4.1.3 – Technology Ranking – CO From AGR

Technology	Estimated Control Efficiency (%)	Basis
Thermal Oxidation	>99	Engineering estimates
Regenerative Oxidation	>99	
Pressure Swing Adsorption	>99	

4.1.4 Evaluate Most Effective Controls – Acid Gas Removal Carbon Monoxide (CO)

Thermal Oxidizer

Thermal oxidation would involve injecting additional air and natural gas into the Rectisol® exhaust gas and combusting the oxygen enriched mixture to oxidize the natural gas and the CO to carbon dioxide at a bulk gas temperature of approximately 1,500 °F. While technically feasible, this option requires a significant volume of natural gas and combustion air to achieve the threshold temperature. Two adiabatic flame calculations were evaluated: (1) where the stream is heated to 1,492 °F with approximately 40% excess theoretical oxygen (10 vol.% O₂ in the reacted exhaust gas) to ensure extinction of the carbon monoxide in the exhaust gas and (2) where the combusted stream is heated to 1,398 °F with approximately 15% excess theoretic oxygen (6 vol.% in the reacted exhaust gas). A significant volume of natural gas and air would be required for both cases (ranging from 7.76 x 10⁷ scf/day to 1.85 x 10⁸ scf/day). The annual cost of natural gas (at the September 2007 price of \$6.28/MMBtu) would be \$1,400,000/day and \$463,000/day, respectively. Based on the extremely high fuel cost and not accounting for any

capital or operational expenses, the cost effectiveness of the low-cost (\$463,000/day) oxidizer solution would be:

Annual cost of fuel only: \$168.98 million
 Assumed 99% control of 4,056 tpy CO: 4,015 tpy controlled

Cost Effectiveness (fuel only): \$42,087/ton

However, the control efficiency of this technology must be discounted by the impact of burning 7.76×10^7 scf/day of natural gas. Applying the EPA AP-42 (Section 1.4) emissions factors for CO (and NO_x) based on the amount of natural gas used in the burner, an estimated 1,629 tpy of CO would be generated (and 5,430 tpy of NO_x). Consequently, the cost effectiveness of the technology would actually be:

Annual cost of fuel only: \$168.98 million
 Actual CO controlled: 4,015 tpy – 1,629 tpy formed = 2,386 tpy

Cost Effectiveness (fuel only): \$70,821/ton

The additional environmental impact of 5,430 tpy of NO_x emissions and associated controls that would be required for those emissions indicates that thermal oxidation is neither cost-effective nor environmentally appropriate.

Regenerative Thermal Oxidizer (RTO)

In the case of a RTO, a ceramic substrate must be heated to around 1,200 °F. This is best accomplished by co-firing natural gas with excess air and mixing the hot gases with the exhaust gas. An excess oxygen concentration of 6 vol.% in the bulk mixture is typically prescribed. The ceramic surface promotes complete oxidation of CO and may reduce CO levels to as low as 10 ppmv in the bulk gas. Nitrogen fixation is limited to less than 20 ppmv by the lower flame temperature. This case is therefore closely representative of the 1,398 °F adiabatic flame temperature case discussed for thermal oxidation above (lower cost case). Carbon monoxide and NO_x emissions of 279 tpy CO and 917 tpy NO_x, respectively are possible. However, this option would still require a daily natural gas cost of \$590,000. Based on the fuel cost alone and the additional CO (and NO_x) emissions, the minimum cost effectiveness would be:

Annual cost of fuel only: \$168.98 million

Actual CO controlled: 4,015 tpy – 279 tpy formed = 3,736 tpy

Cost Effectiveness (fuel only): \$45,230/ton

The additional environmental impact of 917 tpy of NO_x emissions and associated controls that would be required for those emissions indicates that regenerative thermal oxidation is neither cost-effective nor environmentally appropriate.

Pressure-Swing Adsorption

The basic concept of pressure-swing adsorption (PSA) is to use a porous ceramic bed to separate the gases on the basis of their relative diffusivities through small pores. Species with higher pore-diffusivity will pass through the bed at a faster rate. The entire stream must first be pressurized to around 1,200 psia to drive the gases through the porous bed. Eventually, the bed will become saturated with the adsorbed, low diffusivity species (i.e., CO₂). At this point the bed must be depressurized to release and remove the adsorbed CO₂ from the bed. Thus, a minimum of two parallel beds are required for continuous process operation as each unit is first saturated at pressure and then depressurized. In this manner, it would be possible to remove most of the CO and a significant fraction of the sulfur species from the bulk CO₂. The pressurized CO, H₂S, and COS can be returned to the process. However, in order to achieve an efficiency of 99% CO removal, multiple PSA beds in series may be required. For this BACT analysis, only a single, parallel bed, process has been considered.

Preliminary capital cost estimates for a PSA system are based on a recent study prepared by Fluor/UOP. In that study, Fluor/UOP determined that the cost of a PSA system sufficient to process 470,000 lb/hr of total gas flow would be approximately \$25 million. Scaling up to the estimated gas flow from the Rectisol process (3.37 million lb/hr) results in an estimated capital cost of about \$180 million. The capital recovery cost, therefore, would be the product of the capital investment (\$180,000,000) and the capital recovery factor (CRF). The CRF is calculated according to the following equation:

$$CRF = [i (1 + i)^n] / [(1 + i)^n - 1]$$

Where:

CRF= capital recovery factor

i = interest rate (assumed at 7 percent)

n = equipment life (assumed 10 years for the equipment)

According to this equation, the CRF is 0.1424 and the resulting annual capital recovery cost would be about \$25,632,000 (i.e., 0.1424 x \$180,000,000).

Accounting for energy recovery of the CO₂ that is expanded upon release from the PSA beds, the net energy requirement to pressurize the Rectisol® CO₂ is at least 80-100 MWe. At an assumed cost of \$0.0534/kWh, the annual cost of electricity alone would be about \$37.42 million dollars, as shown below:

$$90 \text{ MWh} \times \$0.0534/\text{kWh} \times 1,000 \text{ kWh/MWh} \times 8,760 \text{ hr/yr} = \$42.1 \text{ million}$$

Based on the combined capital and energy costs, the minimum cost effectiveness would be:

Annual capital recovery:	\$25.6 million
Annual energy cost only:	\$42.1 million
Actual CO controlled:	4,015 tpy
Cost Effectiveness:	\$16,900/ton

Indirect costs to install and operate a PSA large enough to control the CO emissions from the Rectisol[®] trains have not been developed at this time. However, because the current plant design calls for the sale of approximately 300 MW of electricity, the sale of nearly one-third of that output may have significant impacts on the project economic viability. Effectively, the consumption of 90 MWe of electricity to operate this PSA results in a revenue loss of \$42.1 million/yr for a net impact to the project equivalent to \$74.8 million/yr. Based on that actual cost impact to the project, the cost effectiveness would be:

Annual capital recovery:	\$25.6 million
Annual energy cost only:	\$42.1 million
Annual lost revenue (lost energy sales):	\$42.1 million
Actual CO controlled:	4,015 tpy
Cost Effectiveness (energy only):	\$27,347/ton

This economic evaluation indicates that pressure swing adsorption would not be a cost-effective alternative. A complete assessment of direct and indirect costs associated with the PSA would be expected to demonstrate an even higher dollar per ton effectiveness.

Summary

This top-down BACT analysis of technologies for control of CO emissions from the Rectisol[®] process concludes that there is no available technology for control of the dilute carbon monoxide concentration present in the waste CO₂ stream.

4.1.5 Proposed BACT Limits and Control Options – Acid Gas Removal Carbon Monoxide (CO)

ORCF proposes the following BACT limit for carbon monoxide emissions from each of the three individual Rectisol[®] process trains in the Acid Gas Removal Unit:

- Proposed CO BACT Limit: 309 lb/hr per Rectisol[®] process train

4.2 Module 5 – Sulfur Recovery/Tailgas Treating Unit

During startup and shutdown periods, tailgas from the Tailgas Treating Unit (TGTU) would be vented to the atmosphere. Tailgas will contain H₂S. Sulfur compounds would also be vented to the atmosphere from the sulfur pit associated with the Sulfur Recovery Unit.

4.2.1 Available Control Technologies – Sulfur Recovery/Tailgas Treating Unit H₂S

Emissions of H₂S are by-products of the sulfur recovery and tailgas treatment process. A review of the RBLC database for Process Type 50.006 – Petroleum Refining Treating (hydrotreating, acid gas removal, SRUs, etc.) located BACT determinations for H₂S from sulfur recovery units as follow:

- Thermal oxidizer
- None indicated

4.2.2 Technically Infeasible Options – Sulfur Recovery/Tailgas Treating Unit H₂S

Use of one or more thermal oxidizers is technically feasible and has been demonstrated in numerous applications within similar refinery operations.

4.2.3 Technology Ranking – Sulfur Recovery/Tailgas Treating Unit H₂S

Thermal oxidizers are believed to be the only technically feasible control technology for hydrogen sulfide emissions from the sulfur recovery/tailgas treating units.

4.2.4 Evaluate Most Effective Controls – Sulfur Recovery/Tailgas Treating Unit H₂S

The use of one or more thermal oxidizers is believed to be the most effective technically feasible control technology for hydrogen sulfide emissions from the sulfur recovery/tailgas treating units.

4.2.5 Proposed BACT Limits and Control Options – Sulfur Recovery/Tailgas Treating Unit H₂S

Because H₂S will be oxidized in SO₂ in the thermal oxidizers, ORCF proposes to establish the NSPS Subpart J SO₂ limit as BACT for sulfur emissions from the SRU/TGTU system:

- Proposed SO₂ BACT Limit: < 250 ppm dry basis SO₂ @ 0% excess air (12-hr rolling average)

**ATTACHMENT 5A
MODULE 5
FIGURES**

**ATTACHMENT 5B
MODULE 5
SUPPORTING CALCULATIONS**

Supporting Calculations

Tailgas Thermal Oxidizer Emission Estimates

The following general assumptions apply to the derivation of TTO emissions:

125	capacity of model sulfur recovery plant used to derive all emission estimates (LT/D)
932	minimum required capacity of proposed ORCF sulfur recovery plant (LT/D)
1,000	proposed design capacity for ORCF (combined capacity of two 500 LT/D units)
8.0	Scaling factor: ORCF plant : model plant

1. Tailgas Combustion During Startup and Shutdown

Assumptions:

Total Flow to the TTOs during each startup or shutdown is: 4,668 lb-mole/hr
 Three startups and three shutdowns will occur each year. The duration of each event is two hours.
 Assume CO present in gas stream is not destroyed in the TTOs due to lower operating temperature.
 There is no SO₂ in the process gas - all SO₂ in exhaust has been formed from oxidation of sulfur compounds.
 Assume all H₂S and COS is oxidized to SO₂ in exhaust. (1 mole H₂S or COS forms 1 mole SO₂).
 Assume all N₂ is oxidized to NO₂ as fuel NO_x (1 mole N₂ forming 2 moles NO₂)
 Assume that thermal NO_x is accounted for by NG combustion shown in Part 3 (TTO Burners).
 Combined emissions from two TTOs are shown.
 The mole% composition of gas sent to the TTOs during startup and shutdown is as shown below.
 Actual emissions are assumed to be equivalent to potential emissions because TTO operation will be required.
 Assume actual operating hours are equal to potential (8,760 hr/yr)

Component	mole %	lb-mole/hr	MW	Actual and Potential Regulated Pollutant Emissions		
				lb/hr (max)	lb/hr (avg)	tpy
H ₂	4.34	202.6	NA	-	-	-
N ₂	0.57	26.6	NA	-	-	-
NO ₂	NA	NA	46.01	2,448	3.35	14.69
H ₂ Ov	0.85	39.7	NA	-	-	-
CO	0.08	3.7	28.01	105	0.14	0.63
CO ₂	90.9	4,243.1	NA	-	-	-
H ₂ S	3.24	151.2	NA	0	0	0
COS	0.015	0.7	NA	0	0	0
SO ₂	NA	NA	64.07	9,735	13.3	58.4
Totals:	100.0	4,668				

2. Sulfur Sweep Air and Spent Degassing Air

Assumptions:

Model emissions are based on the reference 125 LT/D plant (see Page 10).
 Potential emissions are based on linear scaling from the 125 LT/D plant to the proposed 1,000 LT/D plant.
 Potential emissions assume that all sulfur from the SRU is in the form of H₂S (uncontrolled)
 ORCF Actual estimates are for both TTOs combined.
 Actual emissions assume all H₂S has been converted to SO₂ and 98% control of SO₂ from TTO via FGD.

Component	Total Flow				Model 125 LT/day plant	
	lb-mole/hr	mole %	lb-mole/hr	MW	lb/hr	tpy
H ₂ S	876.18	0.0126	0.11	34	3.7	16.4

Component	Total Flow				Flow to TTO (1,000 LT/day plant)	
	lb-mole/hr	mole %	lb-mole/hr	MW	lb/hr	tpy
H ₂ S	7009.44	0.0126	0.88	34	29.9	131.0

Component	Total Flow				ORCF Emissions (1,000 LT/day)	
	lb-mole/hr	mole %	lb-mole/hr	MW	lb/hr	tpy
SO ₂ from TTO	7009.44	0.0126	0.88	64	56.3	246.7

Supporting Calculations

3. Combustion Emissions from Tailgas Thermal Oxidizer Burners

Assumptions:

There will be two equivalent TTOs

Natural gas LHV is: Btu/scf

Natural gas feed rate to model 125 LT/D thermal oxidizer:

 scfd

Assumed natural gas feed rate to ORCF thermal oxidizers:

 scfd

Heat input rating for each TTO is:

 MMBtu/hr

Combined heat input for two TTOs:

 MMBtu/hr MMscf/hr

Sulfur content of natural gas is assumed to be 2,000 gr/MMscf

Values shown below are for both TTOs combined.

Pollutant	Emission Factor (lb/MMscf)	Actual Emissions (Controlled)		Potential Emissions (Uncontrolled)	
		lb/hr	TPY	lb/hr	TPY
Carbon Monoxide	84	4.26	18.64	4.26	18.64
Sulfur Dioxide	0.6	0.03	0.13	0.03	0.13
Nitrogen Dioxide	100 (50)	2.53	11.10	5.07	22.19
Lead	0.0005	2.53E-05	1.11E-04	2.53E-05	1.11E-04
PE, PM10, PM2.5	7.6	0.39	1.69	0.39	1.69
VOC	5.5	0.28	1.22	0.28	1.22
HAPS					
Total POM	8.80E-05	4.46E-06	1.95E-05	4.46E-06	1.95E-05
benzene	2.10E-03	1.06E-04	4.66E-04	1.06E-04	4.66E-04
dichlorobenzene	1.20E-03	6.08E-05	2.66E-04	6.08E-05	2.66E-04
formaldehyde	7.50E-02	3.80E-03	1.66E-02	3.80E-03	1.66E-02
hexane	1.80E+00	9.12E-02	3.99E-01	9.12E-02	3.99E-01
naphthalene	6.10E-04	3.09E-05	1.35E-04	3.09E-05	1.35E-04
toluene	3.40E-03	1.72E-04	7.55E-04	1.72E-04	7.55E-04
arsenic	2.00E-04	1.01E-05	4.44E-05	1.01E-05	4.44E-05
beryllium	1.20E-05	6.08E-07	2.66E-06	6.08E-07	2.66E-06
cadmium	1.10E-03	5.57E-05	2.44E-04	5.57E-05	2.44E-04
chromium	1.40E-03	7.09E-05	3.11E-04	7.09E-05	3.11E-04
cobalt	8.40E-05	4.26E-06	1.86E-05	4.26E-06	1.86E-05
manganese	3.80E-04	1.93E-05	8.43E-05	1.93E-05	8.43E-05
mercury	2.60E-04	1.32E-05	5.77E-05	1.32E-05	5.77E-05
nickel	2.10E-03	1.06E-04	4.66E-04	1.06E-04	4.66E-04
selenium	2.40E-05	1.22E-06	5.33E-06	1.22E-06	5.33E-06
Total Combustion HAPS		0.10	0.42	0.10	0.42

4. Summary of Tailgas Thermal Oxidizer Emissions (combined emissions from two TTOs)

Pollutant	Actual Emissions		Potential Emissions	
	lb/hr	TPY	lb/hr	TPY
Carbon Monoxide	4.40	19.27	4.40	19.27
Sulfur Dioxide	69.68	305.21	69.68	305.21
Nitrogen Oxides	5.89	25.79	8.42	36.88
Lead	0.00	0.00	0.00	0.00
PE, PM10, PM2.5	0.39	1.69	0.39	1.69
VOC	0.28	1.22	0.28	1.22
Total Combustion HAPS	0.10	0.42	0.10	0.42

**ATTACHMENT 5C
MODULE 5
DOCUMENTATION**

LIST OF REFERENCES

- Abrams, D. S., Prausnitz, J. M., “*Statistical Thermodynamics of Liquid Mixtures. A New Expression for the Excess Gibbs Energy Partly and Completely Miscible Systems*”, AIChE J., Vol. 21, pp/ 116-128, 1975.
- Pennsylvania DEP, *Plan Approval No. 54-399-034* (WMPI PTY., LLC Coal To Clean Fuels, Schuylkill County, PA), March 18, 2009.
- U.S. EPA, AP-42 Section 1.4 – *Natural gas Combustion*, July 1998.
- U.S. EPA, RACT/BACT/LAER Clearinghouse (RBLC);
website: <http://cfpub.epa.gov/RBLC>
- 2007 AspenTech Code licensed to Idaho National Laboratory; website:
<http://www.aspentech.com/brochures/aspentech.pdf>

RBLC Matching Facilities for Search Criteria:
 Permit Date Between 1/1/1997 And 11/13/2007
 And Process Type Contains "50.006": Petroleum Refining Treating Waste (hydrotreating, acid gas removal, SRU's, ect.)
 Pollutant: Hydrogen Sulfide (H₂S)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1 UNIT	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVG TIME CONDITION
WY-0042	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	INCINERATOR, TAIL GAS	17000	SCFM	SHELL CLAUD OFFGAS TREATING (SCOT) TAIL GAS INCINERATOR FOLLOWING A 3-STAGE CLAUD PLANT.	3-STAGE CLAUD PLANT TO BE FOLLOWED BY SCOT TAIL GAS SYSTEM	0.8	LB/H	
LA-0196	BATON ROUGE REFINERY	TAIL GAS (FROM SRU) CLEANUP UNIT T 301 VENT	46.3	MM CFD	A PORTION OF THE FLOW MAY BE ROUTED TO THE INCINERATORS.	TAIL GAS CLEANUP UNIT (TGCU) CONSISTING OF BEAYON AND FLEXSORB-SE ABSORBER TECHNOLOGIES	1.77	LB/H	HOURLY MAXIMUM
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	NO. 3 SRU TAIL GAS INCINERATOR, V-27			ALL ACID GAS MUST BE PROCESSED IN THE NO 1, NO 2, OR NO 3 SULFUR RECOVERY UNIT (SRU), BURNED IN THE NO 1, NO 2, OR NO 3 SRU INCINERATOR, SENT TO THE SULFURIC ACID PLANT, OR SENT TO THE FUEL GAS RECOVERY SYSTEM. IT IS NOT PERMISSIBLE UNDER ANY CONDITION TO VENT ACID GAS DIRECTLY TO THE ATMOSPHERE.	EMISSIONS TO THE ATMOSPHERE NOT ALLOWED. SEE PROCESS NOTES.	0.01	LB/H	LESS THAN
TX-0346	WEST REFINERY	DIST HYDROTREATER STRIPPER REBOILER, 37BA2, KK-3				FUEL LIMITED TO NAT GAS, AND/OR REFINERY FUEL GAS	0.1	GR/DSCF	3 H AV
WY-0024	LOUISIANA LAND & EXPLORATION CO.-LOST CABIN GAS PT	GAS COMPRESSOR	8.1	SCFM		INCINERATION NOT FEASIBLE DUE TO CO2 CONTENT OF GAS	0.5	LB/H	
WY-0042	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	VENT, CO2 PRODUCT	8100	SCFM		INCINERATION NOT FEASIBLE DUE TO CO2 CONTENT OF GAS	0.5	LB/H	
TX-0375	LYONDELL - CITGO REFINING, LP	TAIL GAS THERMAL OXIDIZERS (2)			THE TWO TAIL GAS THERMAL OXIDIZERS (TGU-1CN AND TGU-1CN2) ARE PART OF THE SULFUR RECOVERY UNIT (SRU) COMPLEX.	LEAK DETECTION AND REPAIR PROGRAM.	0.06	LB/H	EACH
TX-0424	EXXONMOBILE OIL CORP., BEAUMONT REFINERY	THERMAL OXIDIZER, SRU 2/3	200	ll/d	THROUGHPUT IS 200 LONG TONS PER DAY FOR EACH SRU, FUELED BY NATURAL GAS OR REFINERY GAS, CONTAINING < 150 PPMV OF H2S. SRUS 2 & 3 CONSIST OF A 3 STAGE CLAUD UNIT FOLLOWED BY A HYDROGENATION/HYDROLYSIS SECTION WHERE SULFUR COMPOUNDS ARE REDUCED TO H2S. THE TAIL GAS IS THEN ROUTED TO THE TAIL GAS TREATMENT UNIT, THEN SENT TO THE THERMAL OXIDIZER FOR INCINERATION.	LIMIT OF < 150 PPMV OF H2S IN FUEL, TAIL GAS ROUTED TO TAIL GAS TREATMENT UNIT -- SELECTIVE AMINE ABSORBERS BEFORE INCINERATION.	0.75	LB/H	
TX-0315	EXXON MOBIL BAYTOWN	SCU2 CLAUD C VENT				NONE INDICATED	876	H/YR	SEE NOTE
TX-0322	CITGO CORPUS CHRISTI REFINERY- WEST PLANT	TAIL GAS INCINERATOR, 554-ME5	9	MMBTU/H	THROUGHPUT CAN ALSO BE 100 MMBTU/H. VE ARE NOT ALLOWED FROM THIS PROCESS.	NONE INDICATED	0.3	LB/H	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	FLEXSORB ADSORBER VENT SCU2T801			FROM SCU2	NONE INDICATED	4.76	LB/H	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	SCU, TGCU				NONE INDICATED	3.86	LB/H	

RBLC Matching Facilities for Search Criteria:
 Permit Date Between 1/1/1997 And 11/13/2007
 And Process Type Contains "50.006"; Petroleum Refining Treating Waste (hydrotreating, acid gas removal, SRU's, ect.)
 Pollutant: Hydrogen Sulfide (H₂S)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1 UNIT	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVG TIME CONDITION
TX-0346	WEST REFINERY	SULFUR RECOVERY UNIT TAIL GAS INCINERATOR, TGI-1			EPN: H-15A EMISSIONS FROM SRU 1 & 2 S PITS AND ASSOCIATED S LOADING OPERATIONS SHALL BE COLLECTED BY A VAPOR COLLECTION SYSTEM AND ROUTED TO THE SRU TGI VIA THE S PITS. ALL ACID GAS OR OTHER WASTE GASES SHALL BE BURNED IN THE INCINERATORS AND/OR FLARE (EMERGENCY USE). IT IS NOT PERMISSIBLE UNDER ANY CONDITIONS TO VENT WASTE GASES DIRECTLY TO THE ATMOSPHERE. TAIL GAS MAY BE VENTED TO THE ATMOSPHERE THROUGH THE INCINERATOR IN THE EVENT THAT ONLY AN INCINERATOR SHUTS DOWN, GIVEN SRU AND TAIL GAS TREATING UNITS ARE STILL OPERATIONAL. ALL WASTE GAS FROM THE AMINE REGENERATION UNITS NOS 1 & 2 CONTAINING H ₂ S AND/OR VOC SHALL BE ROUTED TO THE SRUs NORMALLY. UNDER EMERGENCY CONDITIONS THE VENT STREAMS WILL BE SENT TO A FLARE. THE MINIMUM FIREBOX CHAMBER TEMPERATURE IN THE SRU TGI SHALL NOT BE BELOW 1200 DEG F DURING NORMAL OPERATING CONDITIONS. THE EMERGENCY CUTOFF TEMP FOR THE TGI SHALL BE A MINIMUM OF 1600 DEG F.	NONE INDICATED	10 PPM		
TX-0346	WEST REFINERY	SULFUR RECOVERY UNIT TAIL GAS INCINERATOR, TGI-2			EPN: H-15B EMISSIONS FROM SRU 1 & 2 S PITS AND ASSOCIATED S LOADING OPERATIONS SHALL BE COLLECTED BY A VAPOR COLLECTION SYSTEM AND ROUTED TO THE SRU TGI VIA THE S PITS. ALL ACID GAS OR OTHER WASTE GASES SHALL BE BURNED IN THE INCINERATORS AND/OR FLARE (EMERGENCY USE). IT IS NOT PERMISSIBLE UNDER ANY CONDITIONS TO VENT WASTE GASES DIRECTLY TO THE ATMOSPHERE. TAIL GAS MAY BE VENTED TO THE ATMOSPHERE THROUGH THE INCINERATOR IN THE EVENT THAT ONLY AN INCINERATOR SHUTS DOWN, GIVEN SRU AND TAIL GAS TREATING UNITS ARE STILL OPERATIONAL. ALL WASTE GAS FROM THE AMINE REGENERATION UNITS NOS 1 & 2 CONTAINING H ₂ S AND/OR VOC SHALL BE ROUTED TO THE SRUs NORMALLY. UNDER EMERGENCY CONDITIONS THE VENT STREAMS WILL BE SENT TO A FLARE. THE MINIMUM FIREBOX CHAMBER TEMPERATURE IN THE SRU TGI SHALL NOT BE BELOW 1200 DEG F DURING NORMAL OPERATING CONDITIONS. THE EMERGENCY CUTOFF TEMP FOR THE TGI SHALL BE A MINIMUM OF 1600 DEG F.				
WY-0024	LOUISIANA LAND & EXPLORATION CO.-LOST CABIN	INCINERATOR, TAIL GAS (PHASE II)	17 SCFM		SCOT TAIL GAS INCINERATOR FOLLOWING A 3 STAGE CLAUS PLANT.			10 PPM	
*LA-0213	ST. CHARLES REFINERY	THERMAL OXIDIZER NO. 3 (SRU) (2005-39)	50 MMBTU/H					0.8 LB/H	HOURLY MAXIMUM

RBLC Matching Facilities for Search Criteria:
 Permit Date Between 1/1/1997 And 11/13/2007
 And Process Type Contains "50.006"; Petroleum Refining Treating Waste (hydrotreating, acid gas removal, SRU's, ect.)
 Pollutant: Hydrogen Sulfide (H₂S)

RBLCID	FACILITY NAME	PROCESS NAME	THRUPUT UNIT	THRUPUT UNIT	PROCESS NOTES	CTRLDESC	EMIS LIMIT1 UNIT	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVG TIME CONDITION
TX-0423	FLINT HILLS RESOURCES EAST REFINERY	SRU, NO. 2			PROCESS INCLUDES CLAUS UNIT, TAIL GAS TREATING UNIT (TGTU), AND TAIL GAS INCINERATOR. EXPECTED TO RECOVER A MINIMUM OF 99.8 WT % OF THE INCOMING SULFUR. AVAILABLE AS H ₂ S. DEMISTER PADS ARE INSTALLED AT THE OUTLET OF EACH SULFUR CONDENSER TO AID IN SULFUR COALESCING AND TO PREVENT ENTRAINED SULFUR FROM BEING CARRIED TO THE NEXT CATALYST BED. THE TAIL GAS INCINERATOR IS FIRED WITH REFINERY FUEL GAS.	SRU SYSTEM RECOVERERS MINIMUM OF 99.8% OF INCOMING S (AS H ₂ S), 3 STAGE CLAUS UNIT AND TAIL GAS TREATING UNIT (TGTU) REDUCE THE INCOMING H ₂ S. CLAUS UNIT CONSISTS OF: THERMAL REACTOR, WASTE HEAT BOILER, 3	99.8 % REDUC		
TX-0424	EXXONMOBILE OIL CORP., BEAUMONT REFINERY	SULFUR PIT SRU 1			USED FOR 14 DAY/YEAR WHEN THE THERMAL OXIDIZER IS DOWN. ANNUAL EMISSION LIMITS ARE BASED ON USAGE OF 336 H/YR	STACK BURNER	0.04 LB/H		
TX-0424	EXXONMOBILE OIL CORP., BEAUMONT REFINERY	SULFUR TRUCK LOADING. SRU 2/3			SULFUR FROM EACH OF THE SULFUR PITS IS PUMPED TO LOADING ARMS FOR TRUCK LOADING.. THREE LOADING ARMS FOR TRUCK LOADING WILL HAVE VAPORS CONTROLLED BY COMBUSTION IN THE STACK BURNERS.	STACK BURNERS	0.03 LB/H		
TX-0312	MITCHELL TREATING FACILITY	(2) SELEXOL SWEETENER NO 1&2, SLXOL-T01&-T02			ALL SELEXOL UNIT FLASH GAS STREAMS THAT ARE NOT RECYCLED BACK INTO THE PROCESS MUST BE BURNED IN THE THERMAL OXIDIZERS.	SWEET NAT GAS CONTAINING NO MORE THAN 5 GR H ₂ S/100 DCSF	0.21 LB/H		EACH UNIT
TX-0408	INDIAN ROCK GATHERING COMPANY LP	SULFUR RECOVERY UNIT	20	LTD	TOTAL SULFUR PRODUCTION LIMITED TO 20 LONG TONS PER DAY (LTD) BASED ON 98.5 SRU EFFICIENCY.	THERMAL OXIDIZER	0.37 LB/H		
*OH-0308	SUNOCO, INC., TOLEDO REFINERY	SULFUR RECOVERY UNIT			CLAUS SULFUR RECOVERY UNIT AND SULFUR PIT WITH TAIL GAS UNIT AND INCINERATOR CONTROL. CONTINUOUS MONITORING SYSTEM FOR SO ₂ EACH SRU IS SUBJECT TO THE REQUIREMENTS OF PART 60 SUBPARTS A AND J, AND PART 63 SUBPARTS A AND UUU	THERMAL OXIDIZER, 7 MMBTU/HR	1.23 T/YR		BASED ON 365-DAY SUM OF DAILY EMISSIONS 3 HR ROLLING AVERAGE
*PA-0243	CONOCOPHILLIPS COMPANY EAST REFINERY	HYDRODESULFURIZATION UNIT NO.2 SULFUR RECOVERY UNIT					0.1 GR/DSCF		
TX-0393	MOBIL BEAUMONT REFINERY	SULFUR RECOVER THERMAL OXIDIZER (EACH)					0.12 LB/H		
TX-0393	MOBIL BEAUMONT REFINERY	SULFUR RECOVERY VENTS 2 & 3					0.75 LB/H		
TX-0393	MOBIL BEAUMONT REFINERY	SRU SULFUR PIT					1.05 LB/H		EACH
TX-0393	MOBIL BEAUMONT REFINERY	SRU 2/3 SULFUR TRUCK LOADING					0.04 LB/H		
TX-0424	EXXONMOBILE OIL CORP., BEAUMONT REFINERY	SRU VENT, 2 & 3			USED FOR THE 14 DAYS/YEAR THAT THE THERMAL OXIDIZER IS DOWN.		0.03 LB/H		
TX-0424	BEAUMONT REFINERY						1.05 LB/H		EACH

**ATTACHMENT 5D
MODULE 5
OEPA APPLICATION FORMS**

Section II - Specific Air Contaminant Source Information

NOTE: One copy of this section should be filled out for each air contaminant source covered by this PTI application. See the line by line PTI instructions for additional information.

1. Company identification (name for air contaminant source for which you are applying): ACID GAS REMOVAL TRAINS
2. List all equipment that are part of this air contaminant source: 3 RECTISOL PROCESS TRAINS
3. Air Contaminant Source Installation or Modification Schedule (must be completed regardless of date of installation or modification):

When did/will you begin to install or modify the air contaminant source? (month/year) SECOND QUARTER 2008

When did/will you begin to operate the air contaminant source? (month/year) THIRD QUARTER 2011 OR after issuance of PTI _____

4. Emissions Information: The following table requests information needed to determine the applicable requirements and the compliance status of this air contaminant source with those requirements. Suggestions for how to estimate emissions may be found in the instructions to the Emissions Activity Category (EAC) forms required with this application. If you need further assistance, contact your Ohio EPA permit representative.

- If total potential emissions of HAPs or any Air Toxic is greater than 1 ton/yr, fill in the table for that (those) pollutant(s). For all other pollutants, if "Emissions before controls (max), lb/hr" multiplied by 24 hours/day is greater than 10 lb/day, fill in the table for that pollutant.
- If you have no add-on control equipment, "Emissions before controls" will be the same as "Actual emissions"
- Annual emissions should be based on operating 8760 hr/yr unless you are requesting operating restrictions to limit emissions in line # 8 or have described inherent limitations below.
- If you use units other than lb/hr or ton/yr, specify the units used (e.g., gr/dscf, lb/ton charged, lb/MMBtu, ton/12-months).
- Requested Allowable (ton/yr) is often equivalent to Potential to Emit (PTE) as defined in OAC rule 3745-31-01 and OAC rule 3745-77-01.

Pollutant	Emissions before controls (max) (lb/hr)	Actual emissions (lb/hr)	Actual emissions (ton/year)	Requested Allowable (lb/hr)	Requested Allowable (ton/year)
Particulate emissions (PE) (formerly particulate matter, PM)	0	0	0	0	0
PM ₁₀ (PM < 10 microns in diameter)	0	0	0	0	0
Sulfur dioxide (SO ₂)	0	0	0	0	0
Nitrogen oxides (NO _x)	0	0	0	0	0
Carbon monoxide (CO)	926	926	4,055	926	4,055
Organic compounds (OC)	0	0	0	0	0
Volatile organic compounds (VOC)	0	0	0	0	0
Total HAPs	2.0	2.0	8.6	2.0	8.6
Highest single HAP (COS):	2.0	2.0	8.6	2.0	8.6
Air Toxics (see instructions) (H ₂ S):	2.8	2.8	12	2.8	12

Section II - Specific Air Contaminant Source Information

Provide your calculations as an attachment and explain how all process variables and emission factors were selected. Note the emissions factor(s) employed and document the origin. Example: AP-42, Table 4.4-3 (8/97); stack test, Method 5, 4/96; mass balance based on MSDS; etc.

5. Does this air contaminant source employ emissions control equipment?

Yes - fill out the applicable information below.

No - proceed to item # 6.

Note: Pollutant abbreviations used below: Particulates = PE; Organic compounds = OC; Sulfur dioxide = SO₂; Nitrogen oxides = NO_x; Carbon monoxide = CO

Cyclone/Multiclone

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Cyclone Multiclone Rotoclone Other _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Fabric Filter/Baghouse

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
Pressure type: Negative pressure Positive pressure
Fabric cleaning mechanism: Reverse air Pulse jet Shaker Other _____
 Lime injection or fabric coating agent used: Type: _____ Feed rate: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Wet Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Spray chamber Packed bed Impingement Venturi Other _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
pH range for scrubbing liquid: Minimum: _____ Maximum: _____
Scrubbing liquid flow rate (gal/min): _____
Is scrubber liquid recirculated? Yes No
Water supply pressure (psig): _____ NOTE: This item for spray chambers only.
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Electrostatic Precipitator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____

Section II - Specific Air Contaminant Source Information

Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Plate-wire Flat-plate Tubular Wet Other _____
Number of operating fields: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Concentrator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design regeneration cycle time (minutes): _____
Minimum desorption air stream temperature (°F): _____
Rotational rate (revolutions/hour): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Catalytic Incinerator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum inlet gas temperature (°F): _____
Combustion chamber residence time (seconds): _____
Minimum temperature difference (°F) across catalyst during air contaminant source operation: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Thermal Incinerator/Thermal Oxidizer

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum operating temperature (°F) and location: (See line by line instructions.)
Combustion chamber residence time (seconds): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Flare

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Enclosed Elevated (open)
Ignition device: Electric arc Pilot flame
Flame presence sensor: Yes No
 This is the only control equipment on this air contaminant source

Section II - Specific Air Contaminant Source Information

If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Condenser

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: Indirect contact Direct contact
Maximum exhaust gas temperature (°F) during air contaminant source operation: _____
Coolant type: _____
Design coolant temperature (°F): Minimum _____ Maximum _____
Design coolant flow rate (gpm): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Carbon Absorber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: On-site regenerative Disposable
Maximum design outlet organic compound concentration (ppmv): _____
Carbon replacement frequency or regeneration cycle time (specify units): _____
Maximum temperature of the carbon bed, after regeneration (including any cooling cycle): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Dry Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Reagent(s) used: Type: _____ Injection rate(s): _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Paint booth filter

Type: Paper Fiberglass Water curtain Other _____
Design control efficiency (%): _____ Basis for efficiency: _____

Other, describe _____

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____

Design control efficiency (%): _____ Basis for efficiency: _____

Section II - Specific Air Contaminant Source Information

This is the only control equipment on this air contaminant source
 If no, this control equipment is: Primary Secondary Parallel
 List any other air contaminant sources that are also vented to this control equipment:

6. Attach a Process or Activity Flow Diagram to this application for each air contaminant source included in the application. The diagram should indicate their relationships to one another. See the line by line PTI instructions for additional information.
7. Emissions egress point(s) information: PTIs which allow total emissions in excess of the thresholds listed below will be subject to an air quality modeling analysis. This analysis is to assure that the impact from the requested project will not exceed Ohio's Acceptable Incremental Impacts for criteria pollutants and/or Maximum Allowable Ground Level Concentrations (MAGLC) for air toxics. Permit requests that would have unacceptable impacts can not be approved as proposed. See the line by line PTI instructions for additional information.

Complete the tables below if the requested allowable annual emission rate for this PTI exceeds any of the following:

- Particulate Matter (PM10): 10 tons per year
- Sulfur Dioxide (SO2): 25 tons per year
- Nitrogen Oxides (NOx): 25 tons per year
- Carbon Monoxide (CO): 100 tons per year
- Air Toxic: 1 ton per year. An air toxic is any air pollutant for which the American Council of Governmental Industrial Hygienists (ACGIH) has established a Threshold Limit Value (TLV).

Complete Table 7-A below for each stack emissions egress point. An egress point is a point at which emissions from an air contaminant source are released into the ambient (outside) air. List each individual egress point on a separate line.

Table 7-A, Stack Egress Point Information						
Company Name or ID for the Egress Point (examples: Stack A; Boiler Stack; etc.)	Type Code*	Stack Egress Point Shape and Dimensions (in)(examples: round 10 inch ID; rectangular 14 X 16 inches; etc.)	Stack Egress Point Height from the Ground (ft)	Stack Temp. at Max. Capacity (F)	Stack Flow Rate at Max. Capacity (ACFM)	Minimum Distance to the Property Line (ft)
RECTISOL UNIT 1	A	ROUND 7-FEET ID	75	65	~171,000	200
RECTISOL UNIT 2	A	ROUND 7-FEET ID	75	65	~171,000	700
RECTISOL UNIT 3	A	ROUND 7-FEET ID	75	65	~171,000	1,200

*Type codes for stack egress points:

- A. vertical stack (unobstructed): There are no obstructions to upward flow in or on the stack such as a rain cap.
- B. vertical stack (obstructed): There are obstructions to the upward flow, such as a rain cap, which prevents or inhibits the air flow in a vertical direction.
- C. non-vertical stack: The stack directs the air flow in a direction which is not directly upward.

Complete Table 7-B below for each fugitive emissions egress point. List each individual egress point on a separate line. Refer to the description of the fugitive egress point type codes below the table for use in completing the type code column of the table. For air contaminant sources like roadways and storage piles, only the first 5 columns need to be completed. For an air contaminant source with multiple fugitive emissions egress points, include only the primary egress points.

Section II - Specific Air Contaminant Source Information

Table 7-B, Fugitive Egress Point Information

Company ID for the Egress Point (examples; Garage Door B, Building C; Roof Monitor; etc.)	Type Code*	Egress Point Description (examples: garage door, 12 X 30 feet, west wall; outside gravel storage piles; etc.)	Fugitive Egress Point Height from the Ground (ft)	Minimum Distance to the Property Line (ft)	Exit Gas Temp. (F)
NA					

*Type codes for fugitive egress point:

- D. door or window
- E. other opening in the building without a duct
- F. no stack and no building enclosing the air contaminant source (e.g., roadways)

Complete Table 7-C below for each Stack Egress Point identified in Table 7-A above. In each case, use the dimensions of the largest nearby building, building segment or structure. List each individual egress point on a separate line. Use the same Company Name or ID for the Egress Point in Table 7-C that was used in Table 7-A. See the line by line PTI instructions for additional information.

Table 7-C, Egress Point Additional Information (Add rows as necessary)

Company ID or Name for the Egress Point	Building Height (ft)	Building Width (ft)	Building Length (ft)
RECTISOL UNIT	328 (GASIFIER)	108	114
RECTISOL UNIT 2	328 (GASIFIER)	108	114
RECTISOL UNIT 3	328 (GASIFIER)	108	114

8. Request for Federally Enforceable Limits

As part of this permit application, do you wish to propose voluntary restrictions to limit emissions in order to avoid specific requirements listed below, (i.e., are you requesting federally enforceable limits to obtain synthetic minor status)?

- yes
- no
- not sure - please contact me if this affects me

If yes, why are you requesting federally enforceable limits? Check all that apply.

- a. to avoid being a major source (see OAC rule 3745-77-01)
- b. to avoid being a major MACT source (see OAC rule 3745-31-01)
- c. to avoid being a major modification (see OAC rule 3745-31-01)
- d. to avoid being a major stationary source (see OAC rule 3745-31-01)
- e. to avoid an air dispersion modeling requirement (see Engineering Guide # 69)
- f. to avoid another requirement. Describe: _____

If you checked a., b. or d., please attach a facility-wide potential to emit (PTE) analysis (for each pollutant) and synthetic minor strategy to this application. (See line by line instructions for definition of PTE.) If you checked c., please attach a net emission change analysis to this application.

Section II - Specific Air Contaminant Source Information

9. If this air contaminant source utilizes any continuous emissions monitoring equipment for indicating or demonstrating compliance, complete the following table. This does not include continuous parametric monitoring systems.

Company ID for Egress Point	Type of Monitor	Applicable performance specification (40 CFR 60, Appendix B)	Pollutant(s) Monitored
NA			

10. Do you wish to permit this air contaminant source as a portable source, allowing relocation within the state in accordance with OAC rule 3745-31-03 or OAC rule 3745-31-05?

- yes - Note: notification requirements in rules cited above must be followed.
- no

11. The appropriate Emissions Activity Category (EAC) form(s) must be completed and attached for each air contaminant source. At least one complete EAC form must be submitted for each air contaminant source for the application to be considered complete. Refer to the list attached to the PTI instructions.

EMISSIONS ACTIVITY CATEGORY FORM GENERAL PROCESS OPERATION

This form is to be completed for each process operation when there is no specific emissions activity category (EAC) form applicable. If there is more than one end product for this process, copy and complete this form for each additional product (see instructions). Several State/Federal regulations which may apply to process operations are listed in the instructions. Note that there may be other regulations which apply to this emissions unit which are not included in this list.

1. Reason this form is being submitted (Check one)

New Permit Renewal or Modification of Air Permit Number(s) (e.g.

P001) _____

2. Maximum Operating Schedule: 24 hours per day ; 365 days per year

If the schedule is less than 24 hours/day or 365 days/year, what limits the schedule to less than maximum? See instructions for examples. _____

3. End product of this process: SWEET SYNGAS

4. Hourly production rates (indicate appropriate units). Please see the instructions for clarification of "Maximum" and "Average" for new versus existing operations:

Hourly	Rate	Units (e.g., widgets)
Average production	49 MMscf	SYNGAS
Maximum production	65 MMscf	SYNGAS

5. Annual production rates (indicate appropriate units) Please see the instructions for clarification of "Maximum" and "Actual" for new versus existing operations:

Annual	Rate	Units (e.g., widgets)
Actual production	0.43×10^6 MMscf	SYNGAS
Maximum production	0.57×10^6 MMscf	SYNGAS

6. Type of operation (please check one):

Continuous

Batch (please complete items below)

Minimum cycle* time (minutes): _____

Minimum time between cycles (minutes): _____

Maximum number of cycles per daily 24 hour period: _____

(Note: include cycle time and set up/clean up time.)

**"Cycle" refers to the time the equipment is in operation.

7. Materials used in process at maximum hourly production rate (add rows/pages as needed):

Material	Physical State at Standard Conditions	Principle Use	Amount**
METHANOL	LIQUID	SOLVENT EXTRACTION	~100,000 GALLONS PER YEAR
STEAM	GAS	ACID GAS REMOVAL	TO BE DETERMINED
COOLING WATER	LIQUID	PROCESS COOLING	TO BE DETERMINED

** Please indicate the amount and rate (e.g., lbs/hr, gallons/hr, lbs/cycle, etc.).

8. Please provide a narrative description of the process below (e.g., coating of metal parts using high VOC content coatings for the manufacture of widgets; emissions controlled by thermal oxidizer...):

ACID GASES WILL BE PHYSICALLY ABSORBED FROM SOUR SYNGAS USING CYROGENIC METHANOL. SEE SECTION 1.6 OF THE APPLICATION FOR DISCUSSION.

Section II - Specific Air Contaminant Source Information

NOTE: One copy of this section should be filled out for each air contaminant source covered by this PTI application. See the line by line PTI instructions for additional information.

1. Company identification (name for air contaminant source for which you are applying): SULFUR RECOVERY UNIT/ TAILGAS TREATING UNIT
2. List all equipment that are part of this air contaminant source: 2 Claus trains, 2 SCOT trains, 2 Tailgas Compression Trains
3. Air Contaminant Source Installation or Modification Schedule (must be completed regardless of date of installation or modification):

When did/will you begin to install or modify the air contaminant source? (month/year) SECOND QUARTER 2008

When did/will you begin to operate the air contaminant source? (month/year) THIRD QUARTER 2011 OR after issuance of PTI _____

4. Emissions Information: The following table requests information needed to determine the applicable requirements and the compliance status of this air contaminant source with those requirements. Suggestions for how to estimate emissions may be found in the instructions to the Emissions Activity Category (EAC) forms required with this application. If you need further assistance, contact your Ohio EPA permit representative.

- If total potential emissions of HAPs or any Air Toxic is greater than 1 ton/yr, fill in the table for that (those) pollutant(s). For all other pollutants, if "Emissions before controls (max), lb/hr" multiplied by 24 hours/day is greater than 10 lb/day, fill in the table for that pollutant.
- If you have no add-on control equipment, "Emissions before controls" will be the same as "Actual emissions"
- Annual emissions should be based on operating 8760 hr/yr unless you are requesting operating restrictions to limit emissions in line # 8 or have described inherent limitations below.
- If you use units other than lb/hr or ton/yr, specify the units used (e.g., gr/dscf, lb/ton charged, lb/MMBtu, ton/12-months).
- Requested Allowable (ton/yr) is often equivalent to Potential to Emit (PTE) as defined in OAC rule 3745-31-01 and OAC rule 3745-77-01.

Pollutant	Emissions before controls (max) (lb/hr)	Actual emissions (lb/hr)	Actual emissions (ton/year)	Requested Allowable (lb/hr)	Requested Allowable (ton/year)
Particulate emissions (PE) (formerly particulate matter, PM)	0.4	0.4	1.7	0.1	1.7
PM ₁₀ (PM < 10 microns in diameter)	0.4	0.4	1.7	0.4	1.7
Sulfur dioxide (SO ₂)	69.7	69.7	305.2	69.7	305.2
Nitrogen oxides (NO _x)	8.4	5.9	25.8	5.9	25.8
Carbon monoxide (CO)	4.4	4.4	19.3	4.4	19.3
Organic compounds (OC)	0.3	0.3	1.2	0.3	1.2
Volatile organic compounds (VOC)	0.3	0.3	1.2	0.3	1.2
Total HAPs	0.1	0.1	0.4	0.1	0.4
Highest single HAP (HEXANE):	0.1	0.1	0.4	0.1	0.4
Air Toxics:	0.1	0.1	0.4	0.1	0.4

Section II - Specific Air Contaminant Source Information

Provide your calculations as an attachment and explain how all process variables and emission factors were selected. Note the emissions factor(s) employed and document the origin. Example: AP-42, Table 4.4-3 (8/97); stack test, Method 5, 4/96; mass balance based on MSDS; etc.

5. Does this air contaminant source employ emissions control equipment?

Yes - fill out the applicable information below.

No - proceed to item # 6.

Note: Pollutant abbreviations used below: Particulates = PE; Organic compounds = OC; Sulfur dioxide = SO₂; Nitrogen oxides = NO_x; Carbon monoxide = CO

Cyclone/Multiclone

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Cyclone Multiclone Rotoclone Other _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Fabric Filter/Baghouse

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
Pressure type: Negative pressure Positive pressure
Fabric cleaning mechanism: Reverse air Pulse jet Shaker Other _____
 Lime injection or fabric coating agent used: Type: _____ Feed rate: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Wet Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Spray chamber Packed bed Impingement Venturi Other _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
pH range for scrubbing liquid: Minimum: _____ Maximum: _____
Scrubbing liquid flow rate (gal/min): _____
Is scrubber liquid recirculated? Yes No
Water supply pressure (psig): _____ NOTE: This item for spray chambers only.
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Electrostatic Precipitator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____

Section II - Specific Air Contaminant Source Information

Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Plate-wire Flat-plate Tubular Wet Other _____
Number of operating fields: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Concentrator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design regeneration cycle time (minutes): _____
Minimum desorption air stream temperature (°F): _____
Rotational rate (revolutions/hour): _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Catalytic Incinerator

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Minimum inlet gas temperature (°F): _____
Combustion chamber residence time (seconds): _____
Minimum temperature difference (°F) across catalyst during air contaminant source operation: _____

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Thermal Incinerator/Thermal Oxidizer

Manufacturer: TO BE DETERMINED Year installed: 2ND QUARTER 2008
What do you call this control equipment: TAILGAS THERMAL OXIZIDERS (2)
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other SULFUR COMPOUNDS
Estimated capture efficiency (%): >99% Basis for efficiency: ENGINEERING DESIGN
Design control efficiency (%): >99.9 Basis for efficiency: STOICHIOMETRIC CONVERSION CALCS
Minimum operating temperature (°F) and location: TO BE DETERMINED (See line by line instructions.)
Combustion chamber residence time (seconds): TO BE DETERMINED

This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:
TAILGAS TREATING UNIT (STARTUP AND SHUTDOWN ONLY) AND SULFUR RECOVERY UNIT SULFUR PIT SWEEP AIR AND SPENT DEGASSING AIR

Flare

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____
Type: Enclosed Elevated (open)
Ignition device: Electric arc Pilot flame

Section II - Specific Air Contaminant Source Information

Flame presence sensor: Yes No
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Condenser

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: Indirect contact Direct contact
Maximum exhaust gas temperature (°F) during air contaminant source operation: _____
Coolant type: _____
Design coolant temperature (°F): Minimum _____ Maximum _____
Design coolant flow rate (gpm): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Carbon Absorber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Type: On-site regenerative Disposable
Maximum design outlet organic compound concentration (ppmv): _____
Carbon replacement frequency or regeneration cycle time (specify units): _____
Maximum temperature of the carbon bed, after regeneration (including any cooling cycle): _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Dry Scrubber

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____
Design control efficiency (%): _____ Basis for efficiency: _____

Reagent(s) used: Type: _____ Injection rate(s): _____
Operating pressure drop range (inches of water): Minimum: _____ Maximum: _____
 This is the only control equipment on this air contaminant source
If no, this control equipment is: Primary Secondary Parallel
List any other air contaminant sources that are also vented to this control equipment:

Paint booth filter

Type: Paper Fiberglass Water curtain Other _____
Design control efficiency (%): _____ Basis for efficiency: _____

Other, describe

Manufacturer: _____ Year installed: _____
What do you call this control equipment: _____
Pollutant(s) controlled: PE OC SO₂ NO_x CO Other _____
Estimated capture efficiency (%): _____ Basis for efficiency: _____

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Design control efficiency (%): Basis for efficiency:

This is the only control equipment on this air contaminant source

If no, this control equipment is: Primary Secondary Parallel

List any other air contaminant sources that are also vented to this control equipment:

6. Attach a Process or Activity Flow Diagram to this application for each air contaminant source included in the application. The diagram should indicate their relationships to one another. See the line by line PTI instructions for additional information.
7. Emissions egress point(s) information: PTIs which allow total emissions in excess of the thresholds listed below will be subject to an air quality modeling analysis. This analysis is to assure that the impact from the requested project will not exceed Ohio's Acceptable Incremental Impacts for criteria pollutants and/or Maximum Allowable Ground Level Concentrations (MAGLC) for air toxics. Permit requests that would have unacceptable impacts can not be approved as proposed. See the line by line PTI instructions for additional information.

Complete the tables below if the requested allowable annual emission rate for this PTI exceeds any of the following:

- Particulate Matter (PM10): 10 tons per year
- Sulfur Dioxide (SO2): 25 tons per year
- Nitrogen Oxides (NOx): 25 tons per year
- Carbon Monoxide (CO): 100 tons per year
- Air Toxic: 1 ton per year. An air toxic is any air pollutant for which the American Council of Governmental Industrial Hygienists (ACGIH) has established a Threshold Limit Value (TLV).

Complete Table 7-A below for each stack emissions egress point. An egress point is a point at which emissions from an air contaminant source are released into the ambient (outside) air. List each individual egress point on a separate line.

Table 7-A, Stack Egress Point Information						
Company Name or ID for the Egress Point (examples: Stack A; Boiler Stack; etc.)	Type Code *	Stack Egress Point Shape and Dimensions (in)(examples: round 10 inch ID; rectangular 14 X 16 inches; etc.)	Stack Egress Point Height from the Ground (ft)	Stack Temp. at Max. Capacity (F)	Stack Flow Rate at Max. Capacity (ACFM)	Minimum Distance to the Property Line (ft)
TAILGAS THERMAL OXIDIZER 1	A	ROUND, 4.5-FEET ID	150	500	36,500	1,200
TAILGAS THERMAL OXIDIZER 2	A	ROUND, 4.5-FEET ID	150	500	36,500	1,200

*Type codes for stack egress points:

- A. vertical stack (unobstructed): There are no obstructions to upward flow in or on the stack such as a rain cap.
- B. vertical stack (obstructed): There are obstructions to the upward flow, such as a rain cap, which prevents or inhibits the air flow in a vertical direction.
- C. non-vertical stack: The stack directs the air flow in a direction which is not directly upward.

Complete Table 7-B below for each fugitive emissions egress point. List each individual egress point on a separate line. Refer to the description of the fugitive egress point type codes below the table for use in completing the type code column of the table. For air contaminant sources like roadways and storage piles, only the first 5 columns need to be completed. For an air contaminant source with multiple fugitive emissions egress points, include only the primary egress points.

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Table 7-B, Fugitive Egress Point Information

Company ID for the Egress Point (examples; Garage Door B, Building C; Roof Monitor; etc.)	Type Code*	Egress Point Description (examples: garage door, 12 X 30 feet, west wall; outside gravel storage piles; etc.)	Fugitive Egress Point Height from the Ground (ft)	Minimum Distance to the Property Line (ft)	Exit Gas Temp. (F)
NA					

*Type codes for fugitive egress point:

- D. door or window
- E. other opening in the building without a duct
- F. no stack and no building enclosing the air contaminant source (e.g., roadways)

Complete Table 7-C below for each Stack Egress Point identified in Table 7-A above. In each case, use the dimensions of the largest nearby building, building segment or structure. List each individual egress point on a separate line. Use the same Company Name or ID for the Egress Point in Table 7-C that was used in Table 7-A. See the line by line PTI instructions for additional information.

Table 7-C, Egress Point Additional Information (Add rows as necessary)

Company ID or Name for the Egress Point	Building Height (ft)	Building Width (ft)	Building Length (ft)
TAILGAS THERMAL OXIDIZER 1	580 (COOLING TOWER)	240	240
TAILGAS THERMAL OXIDIZER 2	580 (COOLING TOWER)	240	240

8. Request for Federally Enforceable Limits

As part of this permit application, do you wish to propose voluntary restrictions to limit emissions in order to avoid specific requirements listed below, (i.e., are you requesting federally enforceable limits to obtain synthetic minor status)?

- yes
- no
- not sure - please contact me if this affects me

If yes, why are you requesting federally enforceable limits? Check all that apply.

- a. to avoid being a major source (see OAC rule 3745-77-01)
- b. to avoid being a major MACT source (see OAC rule 3745-31-01)
- c. to avoid being a major modification (see OAC rule 3745-31-01)
- d. to avoid being a major stationary source (see OAC rule 3745-31-01)
- e. to avoid an air dispersion modeling requirement (see Engineering Guide # 69)
- f. to avoid another requirement. Describe: _____

If you checked a., b. or d., please attach a facility-wide potential to emit (PTE) analysis (for each pollutant) and synthetic minor strategy to this application. (See line by line instructions for definition of PTE.) If you checked c., please attach a net emission change analysis to this application.

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9. If this air contaminant source utilizes any continuous emissions monitoring equipment for indicating or demonstrating compliance, complete the following table. This does not include continuous parametric monitoring systems.

Company ID for Egress Point	Type of Monitor	Applicable performance specification (40 CFR 60, Appendix B)	Pollutant(s) Monitored
CLAUS UNITS (5)	TO BE DETERMINED	40 CFR 60.105(a)(6)	SULFUR DIOXIDE

10. Do you wish to permit this air contaminant source as a portable source, allowing relocation within the state in accordance with OAC rule 3745-31-03 or OAC rule 3745-31-05?

- yes - Note: notification requirements in rules cited above must be followed.
 no

11. The appropriate Emissions Activity Category (EAC) form(s) must be completed and attached for each air contaminant source. At least one complete EAC form must be submitted for each air contaminant source for the application to be considered complete. Refer to the list attached to the PTI instructions.

EMISSIONS ACTIVITY CATEGORY FORM GENERAL PROCESS OPERATION

This form is to be completed for each process operation when there is no specific emissions activity category (EAC) form applicable. If there is more than one end product for this process, copy and complete this form for each additional product (see instructions). Several State/Federal regulations which may apply to process operations are listed in the instructions. Note that there may be other regulations which apply to this emissions unit which are not included in this list.

1. Reason this form is being submitted (Check one)

New Permit Renewal or Modification of Air Permit Number(s) (e.g. P001) _____

2. Maximum Operating Schedule: 24 hours per day ; 365 days per year

If the schedule is less than 24 hours/day or 365 days/year, what limits the schedule to less than maximum? See instructions for examples. _____

3. End product of this process: SULFUR

4. Hourly production rates (indicate appropriate units). Please see the instructions for clarification of "Maximum" and "Average" for new versus existing operations:

Hourly	Rate	Units (e.g., widgets)
Average production	41.3 TONS	SULFUR
Maximum production	47 TONS	SULFUR

5. Annual production rates (indicate appropriate units) Please see the instructions for clarification of "Maximum" and "Actual" for new versus existing operations:

Annual	Rate	Units (e.g., widgets)
Actual production	361,800 TONS	SULFUR
Maximum production	412,000 TONS	SULFUR

