John R. Kasich, Governor
Mary Taylor, Lt. Governor
Scott J. Nally, Director

9/20/2013

Certified Mail

Yes	TOXIC REVIEW
Yes	PSD
Yes	SYNTHETIC MINOR TO AVOID MAJOR NSR
Yes	CEMS
Yes	MACT/GACT
Yes	NSPS
No	NESHAPS
Yes	NETTING
No	MAJOR NON-ATTAINMENT
Yes	MODELING SUBMITTED
Yes	MAJOR GHG
No	SYNTHETIC MINOR TO AVOID MAJOR GHG

Bill Rupert
BP-Husky Refining LLC
4001 Cedar Point Road
Oregon, OH 43616

RE: FINALAIR POLLUTION PERMIT-TO-INSTALL
Facility ID: 0448020007
Permit Number: P0111667
Permit Type: Initial Installation
County: Lucas

Dear Permit Holder:

Enclosed please find a final Ohio Environmental Protection Agency (EPA)Air Pollution Permit-to-Install (PTI) which will allow you to install or modify the described emissions unit(s) in a manner indicated in the permit. Because this permit contains several conditions and restrictions, we urge you to read it carefully. Because this permit contains conditions and restrictions, please read it very carefully. In this letter you will find the information on the following topics:

- **How to appeal this permit**
- **How to save money, reduce pollution and reduce energy consumption**
- **How to give us feedback on your permitting experience**
- **How to get an electronic copy of your permit**

How to appeal this permit

The issuance of this PTI is a final action of the Director and may be appealed to the Environmental Review Appeals Commission pursuant to Section 3745.04 of the Ohio Revised Code. The appeal must be in writing and set forth the action complained of and the grounds upon which the appeal is based. The appeal must be filed with the Commission within thirty (30) days after notice of the Director's action. The appeal must be accompanied by a filing fee of $70.00, made payable to “Ohio Treasurer Josh Mandel," which the Commission, in its discretion, may reduce if by affidavit you demonstrate that payment of the full amount of the fee would cause extreme hardship. Notice of the filing of the appeal shall be filed with the Director within three (3) days of filing with the Commission. Ohio EPA requests that a copy of the appeal be served upon the Ohio Attorney General’s Office, Environmental Enforcement Section. An appeal may be filed with the Environmental Review Appeals Commission at the following address:

Environmental Review Appeals Commission
77 South High Street, 17th Floor
Columbus, OH 43215

How to save money, reduce pollution and reduce energy consumption

The Ohio EPA is encouraging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Compliance Assistance and Pollution Prevention at (614) 644-3469. Additionally, all or a portion of the capital expenditures related to installing air pollution control equipment under this permit may be eligible for financing and State tax exemptions through the Ohio Air Quality Development Authority (OAQDA) under Ohio Revised Code Section 3706. For more information, see the OAQDA website: www.ohioairquality.org/clean_air

How to give us feedback on your permitting experience

Please complete a survey at www.epa.ohio.gov/survey.aspx and give us feedback on your permitting experience. We value your opinion.

How to get an electronic copy of your permit

This permit can be accessed electronically via the eBusiness Center: Air Services in Microsoft Word format or in Adobe PDF on the Division of Air Pollution Control (DAPC) Web page, www.epa.ohio.gov/dapc by clicking the "Search for Permits" link under the Permitting topic on the Programs tab.

If you have any questions, please contact Toledo Department of Environmental Services at (419)936-3015 or the Office of Compliance Assistance and Pollution Prevention at (614) 644-3469.

Sincerely,

Michael W. Ahern

Michael W. Ahern, Manager
Permit Issuance and Data Management Section, DAPC

Cc: U.S. EPA
TDES; Michigan; Indiana; Canada

Response to Comments – September 19, 2013

Facility ID:	0448020007
Facility Name:	BP-Husky Refining LLC
Facility Description:	Refinery
Facility Address:	4001 Cedar Point Road, Oregon, Ohio 43697
Permit:	P0111667, Permit-to-Install – Modification to Existing Refinery
A public notice for the draft permit issuance was published in Ohio EPA'S Weekly Review and appeared in the Toledo Blade on May 3, 2013. The comment period was extended to June 10, 2013. .	
Hearing date (if held)	June 5, 2013
Hearing Public Notice Date (if different from draft public notice)	May 3, 2013

The following comments were received during the comment period specified. Ohio EPA reviewed and considered all comments received during the public comment period. By law, Ohio EPA has authority to consider specific issues related to protection of the environment and public health. Often, public concerns fall outside the scope of that authority. For example, concerns about zoning issues are addressed at the local level. Ohio EPA may respond to those concerns in this document by identifying another government agency with more direct authority over the issue.

In an effort to help you review this document, the questions are grouped by topic and organized in a consistent format. PDF copies of the original comments in the format submitted are available upon request.

1. Written comments received from the public during the comment period (both letters and email)

Comment 1: BPH's use of project netting impermissibly subtracted emissions increases at Step 1 of the NSR Project

Response 1: In order to deal with the additional coker 3 blowdown gas generated due to decreased cycle times, BPH chose to modify the coker wet gas compressor system to be able to handle the blowdown gas. This meant that the flare gas recovery system (FGRS), which historically has handled the Coker 3 blowdown gas, will not see additional gas, and, therefore, will not produce additional emissions. Instead, the FGRS will see less gas and will produce fewer emissions. The emissions reductions could be used for netting, but they were not. Therefore, netting at Step 1 of the NSR Project analysis did not occur.

Ohio EPA asked BPH to provide additional information to address this issue. Their response provides a more detailed explanation and can be found in Attachment 1, under the response to Comment 1.

Comment 2: BPH omitted increased emissions associated with the modifications to the crude 1 heater and vacuum unit 1 heater.

Response 2: Ohio EPA does not believe that the changes to either the crude 1 heater or the vacuum unit 1 heater resulted in increased capacity of these units.

The crude 1 heater will be replaced with a larger heater; however, the capacity of this part of the refinery will not change because the additional heat is needed to replace heat that is no longer available in the raw materials coming into the heater due to other Toledo Feedstock Optimization project (TFO) changes.

The larger heater on the vacuum 1 unit will allow the vacuum 1 distillation tower to improve the separation of gas oil and residuum. It does not increase the capacity of the associated units.

Neither of these changes are expected or designed to increase the total crude processing capacity of the refinery.

Comment 3: BPH omitted increased emissions associated with the modifications to the "A" diesel Hydrotreater (ADHT).

Response 3: Ohio EPA asked BPH for a more detailed explanation of the changes to the hydrotreater. Their explanation follows:

The additional steam needed for the increased load on the ADHT is accounted for in the incremental steam production value included in the TFO project emissions for the Alstom boilers. Note that the Alstom boilers are the worst-case source for steam from an emissions standpoint, since the other source is the off-site, third party, First Energy Plant. To the extent the additional steam comes from First Energy, the emissions associated with the production of that steam would not be included in the TFO project permitting since First Energy and BPH are separate sources.

There will be a slight increase in hydrogen demand as a result of the TFO project. Incremental hydrogen demand at the refinery is provided by the off-site, third party, Linde (formerly BOC, as identified in the commenter's statement) hydrogen plant. However, since that plant is a separate source (see Response 30, below), any additional emissions necessary to meet that demand would not be included in the TFO netting analysis. An additional on-site BPH source of hydrogen is the Reformer 3 process unit. However, its unit operations are dictated by its feed availability and gasoline product demands, not refinery hydrogen needs. Additionally, since the installation of Reformer 3 is a contemporaneous project, the entire potential to emit (PTE) for Reformer 3 is already included in the TFO project netting.

Ohio EPA agrees with BPH that the First Energy and Linde plants are separate sources and should not be considered as part of the BPH source for major NSR purposes. Therefore, the additional steam or hydrogen produced at these plants would not be counted as upstream increases. However, the emissions increases associated with the increased steam use were accounted for by BPH by assuming that it would come from the Alstom Boilers. In addition, Ohio EPA believes that any other increases due to the ADHT changes have been properly accounted for within the permit.

Comment 4: BPH omitted increased emissions associated with de-bottlenecking.

Response 4: Ohio EPA believes it is appropriate to use an assumed operating rate for units that will be affected by the project but will not be physically modified. This approach is supported by a July 25, 2001, Letter to Ms. Bliss Higgins, Assistant Secretary, Environmental Services Division, Louisiana Department of Environmental Quality, from Rebecca Weber, Associate Director for Air, Multimedia and Planning Division, U.S. EPA Region 4 regarding Motiva Enterprises LLC, Low Sulfur Gasoline Project - Related Emissions Increase Methodology.

Comment 5: The netting analysis improperly inflates the baseline emissions for the crude 1 heater and the vacuum 1 heater.

Response 5: In this case, the commenter compared the 2004 and 2005 emissions inventory data against the shutdown credits described in the permit and found differences between the two. These values should be the same because the shutdown credits should be based on actual emissions. Ohio EPA had BPH review the original emissions inventory submissions and found that they were based on older emission factors that are no longer correct. The factors used to develop the 2004-2005 emissions data were the best available at the time, but since then BPH has done extensive work to develop more accurate emission factors. This development work was a result of preparing information for the Greenhouse Gas Mandatory Reporting Rule. The calculation of actual emissions for the shutdown credits used the new emission factors which give the most accurate estimation of actual emissions. Ohio EPA agrees with this approach.

Comment 6: The netting analysis improperly inflates the baseline emissions for the multiple affected and modified units: The coker 3 heater (B032), the coker 2 heater (B017), the AHDHT heater (B029), and the naphtha hydrotreater heater (B022).

Response 6: See the response to Comment 5.

Comment 7: The netting analysis improperly relies on AP-42 emission factors.

Response 7: Ohio EPA requires companies to use the best emissions information available when calculating emissions during the permitting process. For existing sources, usually the best information comes from site-specific emissions test data. However, in a lot of cases, site-specific emissions test data is not available. In those cases, Ohio EPA allows the use of other emissions data to determine actual emissions. The AP-42 document is a significant source of emissions information and it is often used. Ohio EPA accepts the use of AP-42 information when no better information is available.

As part of our review, Ohio EPA reviewed the emissions information used for the calculations and is satisfied that the best information was used.

Comment 8: The netting analysis improperly relies upon previously-used shutdown credits.

Response 8: Ohio EPA reviewed the shutdown credits referred to by the commenter and determined that they were used for a previous netting permit but not for a previous PSD permit. Shutdown credits cannot be used if they were relied upon in a previous prevention of significant deterioration (PSD) permit, but they can be used if they were used for a previous netting permit. Ohio EPA feels that the shutdown credits were properly included because all increases and decreases that occur during the contemporaneous period should be included, and they were one of the decreases that occurred during the contemporaneous period.

Comment 9: The project has been Improperly piecemealed.

Response 9: Ohio EPA reviewed multiple recent projects to determine whether any should be aggregated with the current TFO project. Based on this review, we determined that past projects should not be grouped with this one. We also asked BPH to prepare a response to each of the NRDC-specific comments concerning potential project aggregation. Since the information provided by BPH is information that only they would know, Ohio EPA recommends that the commenter read the BPH response directly. Please see the attached BPH responses to NRDC comments 11-30 in the Attachment 1.

Ohio EPA reviewed the submitted information and concurs with BPH that the project has not been improperly piecemealed.

Comment 10: The permit is improperly grounded in the assumption that increased utilization of a unit does not trigger PSD best available control technology (BACT) for that unit.

Response 10: This comment is not correct. The NSR rules specifically provide that BACT applies only to an "emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit." OAC 3745-31-15(D); 42 CFR 52.21(j)(3). The rules also provide that increased utilization, by itself, is not a physical change or change in the method of operation. OAC 3745-31-01(JJJ)(5)(f); 40 CFR 52.21(b)(2)(iii)(f).

Under Ohio rules, BAT applies when a new source is installed or when an existing source is modified. BAT does not apply when an existing source sees increased utilization.

Comment 11: BAT analyses were erroneously excluded for sources with increased utilization**.**

Response 11: Please see Response 10.

Comment 12: Controls proposed fail to satisfy BAT for NOx emission sources.
21.
Response 12: After receiving this comment, Ohio EPA again reviewed our analysis of BAT for NOx sources. We also asked BPH to revise the cost effectiveness analysis provided in the application to align it with U.S. EPA's "Office of Air Quality Planning Standards Cost Control Manual (CCM)." Based on the second review, Ohio EPA concludes that the BAT described for NOx emissions sources was correct.

This conclusion is based, in part, on the following:

1. The revised cost-effectiveness study for add-on controls demonstrated that it was not cost effective to require add-on NOx controls. See the revised study attached as Exhibit 1.

2. We did not consider BACT for NOx as established under the Hyperion permit for for these reasons:

    a. Hyperion Energy Center has not been built yet and the referenced permit has expired. A press release from the company on March 15, 2013[1], indicates that they will not seek an extension to the current permit, and that instead they plan to apply for a new permit.

    b. Although some of the heaters in the now expired permit for Hyperion were required to install selective catalytic reduction system (SCR), this was based on the applicant volunteering to install SCR on heaters for which the cost-effectiveness of SCR was estimated to be $30,000 per ton of NOx reduced or less[2]. A cost-effectiveness threshold of $30,000/ton is unreasonably high for Ohio BAT purposes.

3. Ohio EPA did not consider the BACT emission limits for CENCO refinery and TOSCO Refining

[1] See the press release from: http://denr.sd.gov/hyperionaqmain.aspx
[2] See page 53 of the Hyperion 2007 air permit application.
from: http://www.hyperionec.com/files/HEC_SD_PSD_App.pdf

Company as possible BAT limits because these facilities are located in severe non-attainment areas. We cannot consider emission limits established for sources located in severe non-attainment areas when we evaluate BAT because Ohio's BAT is restricted to only requirements found in states with similar air quality. See the definition of BAT below:

> *Best available technology (BAT) means any combination of work practices, raw material specifications, throughput limitations, source design characteristics, an evaluation of the annualized cost per ton of air pollutant removed, and air pollution control devices that have been previously demonstrated to the Director of Environmental Protection to operate satisfactorily in this state or other states with similar air quality on substantially similar air pollution sources.*

Ohio EPA reviewed some other sources, but came to the conclusion that because we determined that it is cost prohibitive to install add-on control for NOx reduction for these particular heaters, add-on control was excluded as BAT.

Comment 13: Controls proposed fail to satisfy BAT for CO and volatile organic compounds (VOC) emission sources.

Response 13: CO emissions depend on the efficiency of combustion. The less efficient the combustion, the more CO and VOC emissions will result as products of incomplete combustion. Additionally, gaseous fuel combusts efficiently and a heater burning only gaseous fuel can be designed to be highly efficient. Based on the RACT/BACT/LAER Clearinghouse (RBLC) database for recent determinations for CO emissions from refinery-fuel gas-fired heaters, permitted levels in these BACT determinations range from 0.04-0.08 lb/MMBtu using only good combustion practices. No other add-on control technologies for CO were required for gas-fired heaters. Therefore, we agreed with the BPH's proposed BAT for CO as 0.06 lb/MMBtu with good combustion practices for the new heaters.

A. The rate of VOC emissions also depends on combustion efficiency. Combustion efficiency is typically very high with gaseous fuels and VOC emissions are extremely low. VOC emissions are minimized by using good combustion practices, which incorporate high combustion temperatures, long residence times, and turbulent mixing of fuel and combustion air. For these reasons, we agreed with BPH that additional controls would not be cost-effective. As with CO, BAT for VOC is proposed to be good combustion practices for the new heaters.

B. The commenter states that oxidation catalysts are proposed to control CO and VOC emissions from two newheaters at the Flint Hills West Refinery in Corpus Christi, Texas and suggests that this is evidence that oxidation catalyst should be considered for CO and VOC on the TFO project's modified heaters.

C. On this issue, OEPA notes the following:

1. Although there may be occasional instances where oxidation catalyst is used on a gas-fired heater, such instances are the exception because CO and VOC emissions from gas-fired sources are already relatively low.

2. The Texas permit application is still under agency review and no permit has yet been issued.

3. The Texas application only proposes oxidation catalyst on one (not two) heaters[3], the "Sat Gas # 3 heater," which fires only natural gas[4]. The Toledo project heaters fire refinery fuel gas. Refinery fuel gas contains sulfur which decreases the activity of conventional oxidation catalysts[3].

4. The other Texas project heater affected by BACT (CCR hot oil heater – which fires refinery fuel gas) is not proposed to use oxidation catalyst. No explanation is provided in the Texas application.

Further, Ohio EPA reviewed similar emissions sources and determined that BAT emissions limits set for air pollutants CO and VOC contained in the draft PTI are considered to meet Ohio BAT.

Comment 14: Controls proposed fail to satisfy BAT for SO2and PM sources.

Response 14: We concur with BPH that PM, PM_{10} and $PM_{2.5}$ emission rates from gas-fired process heaters are inherently low because they achieve high combustion efficiencies and burn clean fuels. For this reason, good heater design and operation is recognized as BAT for particulate emissions from the gas-fired process heaters.

Ohio reviewed the information in the application provided by BPH and determined that compliance with recently issued New Source Performance Standard (NSPS) Ja which regulates SO_2 by limiting the allowable H_2S content of refinery fuel gas to no more than 162 ppm_v H_2S on a short term (3 hr average) basis is considered BAT. See Response 12.

Further, Ohio EPA reviewed similar emissions sources and determined that BAT emissions limits set for air pollutants PM and SO2 contained in the draft PTI are considered to meet Ohio BAT.

Comment 15: Controls proposed fail to satisfy BAT for fugitive equipment leaks.

Response 15: Ohio EPA maintains that we do not require cost-effective analysis for add-on control until minimum threshold for VOC of 80 tons per year (TPY) has been triggered. VOC of 80 TPY is twice the significant threshold for VOC, i.e., 40 TPY. In this case, emissions from fugitive leaks are 6.06 TPY. Ohio EPA considers this amount of emission to be too small to require cost-effectiveness analysis.

Further, Ohio EPA reviewed similar emissions sources and agreed with BPH that BAT for fugitive leaks is considered to be compliant with the applicable NSPS GGGa and Refinery Maximum Achievable Control Technology (MACT) Standards CC and Leak Detection and Repair (LDAR) regulations.

Comment 16: Emissions from diluent processing were inappropriately omitted.

Response 16: Diluent commonly is mixed with heavy crude oil to facilitate the transportation of the material through pipelines. The diluent may consist of light synthetic crudes that BPH is already

[3] See EPA Fact sheet for oxidation catalyst. Note: non-conventional, platinum based catalysts are more sulfur tolerant – but are more expensive.
[4] See Flint Hill application page 263 (pdf page 272)
http://www.fhrcorpuschristi.com/upload/FHRProjEagleFordAmendment%20ApplicationRecdbyTCEQDraft.pdf

processing or liquefied petroleum gas LPG condensates or gasoline range material similar to the blending components made at the refinery. Since BPH is already processing a comparable volume of heavy crude oils that contain diluents, the refinery does not have to seek permit modification to handle the diluent that is co-mingled with the heavy crude. Any diluent material that is received with the crude will be processed along with other components of the crude, and will be included in the refinery products. It will, therefore, have no impact on refinery emissions beyond what is characteristic of the crude slate as a whole. These impacts are fully accounted for in the netting calculations for this permit.

See Responses 2 and 17.

Citizen Comments

Comment 17: The gasoline that we use doesn't have to come from the tar sands of Canada.

Response 17: Ohio EPA does not regulate where refineries get their crude oils from and we cannot take this comment into consideration when determining whether to issue or deny the proposed permit. Ohio EPA can only deny issuance an air permit if it is determined that a proposed installation and changes to the existing units will not comply with state or federal air pollution standards, and we have determined that the proposed installation and changes to the existing units meet state and federal air pollution standards.

Also, see the response to comment 8.

Comment 18: Who's doing the air particulates monitoring? How often? What are you looking for? Where is this information listed so that we know it? How do we know that it's going to be safe?

Response 18: Ohio EPA follows a complex procedure following U.S. EPA guidance and rules to decide where monitors must be placed in order to determine the ambient concentrations of criteria pollutants (particulate matter, sulfur dioxide, nitrogen oxides, ozone, carbon monoxide and lead). These procedures and rules were followed before deciding the current locations of the existing monitors. The siting of additional monitors is possible, but many factors must be considered prior to actually siting a monitor. This includes: (1) the type of pollutant desired to be monitored (each monitor only measures one pollutant); (2) the possible locations of the monitor (siting criteria must be met); (3) who is going to operate and maintain the monitor; and (4) who is going to pay to operate and maintain the monitor and any sample analysis that must be done. Ohio EPA has one of the most extensive monitoring networks of any state. Toledo is monitoring for the criteria pollutants as required in locations approved by U.S. EPA. Ohio EPA's monitoring plans are reviewed by U.S. EPA each year.

The specifics of the Toledo/Lucas County air monitoring stations, including to the parameters measured, location and sampling schedules, are found on page 5 of in the Ohio Air Monitoring Network 2013-2014 at: http://epa.ohio.gov/Portals/27/ams/sites/AirMonitoringNetwork13-14.pdf

Ohio EPA's goal is to protect the health of all Ohioans, including Oregon residents. Modeling results of the potential emissions from the facility indicate that the BPH facility will be within National Ambient Air Quality Standards and Ohio's Air Toxics Policy. These standards are set to be protective of public health. Ohio EPA also has established restrictive emissions limits for the pollutants this facility will emit. Ohio EPA believes that if BPH complies with the final permit, public health will be protected.

Comment 19: What are the plans for the petcoke from the BP plant?

Response 19: BPH has contracted with First Energy to take all of the petroleum coke from coker 3. BPH will send their coke to First Energy on the conveyor belt included in this expansion of Coker 3.

2. U.S. EPA's written comments

Comment 20: In BPH's permit application, it states that the reduction in coker blowdown gases will offset any other increases in the amount of gas going to the flare system from the coker as a result of the project. There does not appear to be a qualitative analysis that demonstrates that the reduction in coker blowdown gases is significant enough to prevent an increase in flared gases. Please provide an analysis that demonstrates this.

Response 20: See Response 1.

Comment 21: In BPH's permit application; it states that the sulfur loading at the sulfur recovery units (SRUs) will likely increase as a result of the project. It also states that the SRUs are already running near capacity. The emission calculations assume that using the SRUs will increase to the current maximum capacity; however, there is no additional documentation supporting the assumption that the sulfur loading will not increase above the maximum capacity of the SRUs. Sulfur loading above the maximum capacity of the SRUs may result in higher sulfur emissions in the heaters and boilers that use refinery gas, and higher emission and/or increased acid gas flaring due to the increased downtime of the SRUs. All of these would affect the emissions analysis presented by BPH. Please provide additional documentation to support the assumptions made for the SRUs.

Response 21: Ohio EPA asked BPH to provide additional information to address these concerns.

BPH informed us that the SRUs had been currently running at about 260 long tons per day (LTPD). Based on the information submitted in the application, the TFO project would add 40 LTPD to the SRUs making the total sulfur load to 300 LTPD. This is within the existing permit limit and design capacity, which is 309 LTPD, of the equipment.

BPH informed us that the refinery has, and will continue to have, sulfur load-shedding procedures in place to assure that SRU capacity is not exceeded and to reduce sulfur production in the event of unplanned equipment outages at the sulfur recovery plant. Ohio EPA agrees with BPH that these procedures, and other controls and monitoring, are effective to control sulfur emissions and minimize acid gas flaring.

Sulfur loading above the maximum capacity of the SRUs will not result in higher sulfur emissions in the heaters and boilers that use refinery gas because the removal of sulfur from the refinery fuel gas is not affected by the capacity of the SRUs.

The concerns about potential excess sulfur emissions in the heaters and boilers that use refinery gas are addressed in the permit terms and conditions. The permit will require BPH to continuously monitor the total sulfur content of the fuel gas burned in all heaters and boilers at the refinery. The sulfur dioxide (SO2) emissions from the sulfur plant also are continuously monitored. The maximum allowable emissions from each of the sources affected by the project are specified in the permit and included in the netting analysis for the project. An additional "cushion" is provided by the reduction of SO2 emissions of other unaffected heaters as a result of the TFO project, since the modifications to the coker gas plant will substantially reduce the total sulfur content of the fuel gas going to all refinery heaters and boilers, including those that are not otherwise affected by the project.

Comment 22: Ensure all permits-to-install (PTIs) that fall within the contemporaneous period are addressed. It appears that PTIs P0106190 and P0107416 issued June 24, 2010, and May 8, 2012, respectively, were not addressed in the netting analysis.

Response 22: Ohio EPA did not consider the above referenced PTIs because the TFO project increases alone did not exceed the PSD significance level of 40 tons per year for VOC. Thus, BPH was not required to consider these contemporaneous projects.

Comment 23: Emission units: B015, B030, B031, B033, B034 and B035 have interim S02 limits listed in the draft permit, but do not list final SO2 limits. Please clarify what the final limits will be for the emission units.

Response 23: Ohio EPA concurs with U.S. EPA's comment and, accordingly, added a term and condition in the final permit under B.10.a)(5) to clarify individual emission limits for B015, B030, B031, B033, B034 and B035 established in the previous permits remain unchanged.

Comment 24: On page 15 of the draft permit, the final SO2 limit for B029 is listed as 0.94 tons per year (TPY), but on page 38 it is listed as 0.69 TPY. Please clarify which limitation is correct and ensure the permit is consistent.

Response 24: The limit of 0.69 TPY listed on page 38 is a typographical error. The correct limit for B029 is 0.94 TPY SO2. The final permit is modified to reflect the correct limit.

Comment 25: BPH's analysis does not include the permit issued on January 4, 2013, which imposed SO2 limits on multiple units. The imposed limits were taken to avoid PSD for SO2 for this permitting action. The draft permit should clearly indicate that the interim and final SO2 limits are synthetic minor limits under PSD.

Response 25: All of the SO2 limits included in the permit issued on January 4, 2013, are included in the draft permit and ,TFO project netting analysis. U.S. EPA is correct that the final SO2 limits are synthetic minor limits. The interim group limit is temporary, designed to assure that there will be no significant net emission increase in SO2 emissions during the period in which the project is being constructed and until the improvements to the coker gas plant are operational.

Comment 26: The cost analysis for selective catalytic reduction (SCR) as best available technology (BAT) has several discrepancies from the Office of Air Quality and Planning Standards Cost Control Manual (CCM), which is referenced in various sections as the basis for calculations. The CCM indicates that for SCR, there should be no additional labor costs, no additional supervisory labor, no property taxes, minimal insurance, insignificant administrative costs and no overhead costs; however, BPH's SCR analysis includes significant costs for all of these items. The CCM indicates that for an SCR, the equipment life should be 20 years, but BPH used 15 years. The cost of catalyst replacement incorrectly uses a cost recovery factor instead of a future worth factor. It is unclear why BPH is including 1 percent of the cost of natural gas for the proposed heater toward the BAT cost analysis. Please provide an explanation for deviating from the recommendations in the CCM or reevaluate the SCR BAT consistent with the CCM recommendations.

Response 26: See Response 12.

Comment 27: BPH proposes installing larger heaters for the crude unit and the vacuum unit. The current size of crude 1 heater is 325 MMBtu/hr and after the TFO project it will be 450 MMBtu/hr. The current size of vacuum 1 heater is 140 MMBtu/hr and after the TFO project it will be 150 MMBtu/hr. However, the permit strategy write-up states that the project will not increase the overall crude capacity of the refinery. Please provide an explanation for needing the larger heaters if the refining capacity is not increasing.

Response 27: See Response 2.

Comment 28: The draft permit has carbon dioxide (CO2) as a surrogate for greenhouse gas (GHG) emissions, including a CO2 TPYTPY GHG BACT limit for emission units B037, B038 and B039. However, both the table on page 64 of the permit's Staff Determination as well as the Applicable Compliance Method on page 74 specify a carbon dioxide equivalent value. Since the regulated pollutant is GHG, the GHG emission limit(s) should account for not only CO2, but for all GHGs emitted. Please also clarify how compliance will be demonstrated for each of the GHGs.

22. **Response 28:** As explained in the Staff Determination, CO2 emission limits for new heaters are proposed rather than CO_2e because CO_2 represents more than 99.5 percent of the CO_2e emissions from these combustion sources and is therefore a good surrogate for total GHG emissions. N_20 and CH_4 emissions from gas-fired combustion sources are very small and the same control options (good combustion practices, energy efficient design, etc.) that minimize CO_2 emissions also control these other pollutants.

23.

24. Ohio EPA believes that it was proper to use CO_2 as a surrogate for all GHGs when addressing heater emissions.

25.

Comment 29: The permit's Staff Determination "Selection of GHG BACT" section says that "compliance will be demonstrated through records of the heater design, records of fuel usage, and maintenance records." Please explain what is meant by "records of the heater design" and how that will be used to demonstrate compliance with the GHG emission limits.

Response 29: The BACT control methods intended to be verified by the heater design records are those which will help the heater achieve a high thermal efficiency. They are:

- high heat recovery through use of a convection section; and
- automated draft 02 controls with 02 monitoring.

The design records for the new installed heaters will show this information. BPH suggests including a term in the permit requiring that BPH retain records showing that these elements are included in the design of the heater and to make those records available to Ohio EPA upon request.

Separately, the permit requires periodic burner tuning (which will be verified by maintenance records already required by boiler MACT) and using only gaseous fuels (verified by records of fuel used).

Finally, the permit requires tracking GHG/CO2 emissions against an allowable permit limit.

Comment 30: The permit strategy write-up includes discussion of carbon capture and sequestration (CCS). Much of the information is verbatim from Appendix F of the application. Please provide additional detail on its analysis of CCS and how it was determined as an infeasible option for BACT.

Response 30: Beginning in the middle of page 32 of US EPA guidance, "PSD and Title V Permitting Guidance for Greenhouse Gases," reads:

"For the purposes of a BACT analysis for GHGs, US EPA classifies CCS as an add-on pollution control technology that is available for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production … etc."

The proposed refinery process heaters do not fit into either of these categories (i.e., large emitting or high-purity).

Based on US EPA's guidance, it seems clear that a CO2 capture system for small- to medium-size combustion systems, such as the refinery process heaters, is not expected to be a reasonable BACT option. This is understandable because the capture of CO2 from a heater's exhaust is significantly more difficult than from the types of industrial gas streams that US EPA references as having potential for CCS. The increased difficulty is due to four predominant factors: the heater exhaust's low CO2 concentration; low pressure; low quantity of CO2 available for capture; and the high variability of load for this unit. While these factors do not make it technically impossible, they do make it expensive and energy intensive.

Further, based on the cost information in "The Report of the Interagency Task Force on Carbon Capture and Storage (August 2010)," it would cost BPH more than $300 million during the first 10 years of operation, excluding the cost associated with related energy. BPH indicated that the TFO project is estimated to cost $400 million. Therefore, we concur with BPH that it would be cost prohibitive to install CO2 capture systems on the proposed heaters.

Further, we are unaware of any available suitable sequestration site or CO2 transportation infrastructure that could be used by this project. Also, a suitable sequestration site cannot be developed in any time frame compatible with this project.

Comment 31: How are the coker blowdown gases handled if the coker wet gas compressor trips? Is there an alternate routing? How would an outage of the coker wet gas compressor affect the emissions from the flare?

Response 31: If the wet gas compressor trips, all of the gas from the coker would be routed to the flare. However, the coker wet gas compressor is a very important part of the process, is very reliable, and the refinery maintains it in good working order, to keep the coker operating at peak efficiency. Indeed, a review of the operating data from the cokers indicates that over the past 10 years, the Coker Wet Gas Compressor has tripped or otherwise been shut down only once while the coker was in service. That shutdown, which occurred in early September, 2013, resulted from water getting into the compressor motor windings during a severe storm event even though the motor is designed to be completely waterproof. In response to this event, steps are being taken to ensure that a similar failure will not occur in the future, and there is no reason to anticipate that trips of the compressor will become any more frequent in the future. Certainly, there is nothing about the TFO project that would adversely affect that reliability.

Although the TFO project reroutes the coker blowdown from the flare gas recovery compressors directly to the coker wet gas compressors, this will not increase the amount of gas that would be flared if the Coker Wet Gas Compressor trips over the current configuration. This is because the flare gas recovery compressors are currently routed to the Coker Wet Gas Compressor. Therefore, if the Coker Wet Gas Compressor trips currently the gases captured by the flare gas recovery system are routed to the flare, similar to the future arrangement. In fact, with the blowdown gas currently going to the Flare Gas Recovery Compressors, there is an increased likelihood that the gas would be routed to the flares, as there are additional compressors involved in the current configuration. If any of the compressors in the current alignment were to trip off line when the Cokers are in the blowdown, the blowdown gas would be routed to the flares. Bypassing the flare gas recovery compressors eliminates the potential for those compressors tripping off line and routing the gas to the flare, even when the Coker Wet Gas Compressor is working.

For both of the foregoing reasons, there is no reason believe that the TFO project will increase either the frequency of wet gas compressor trips or the quantity of gas that would be released to the flare in the event that such a trip did occur. TFO may result in a small increase in the sulfur content of the coker wet gas. However, the difference in emissions that would result from that cause alone would be very small and would be far less than the emissions that the refinery flare system “could have accommodated” during the baseline period.

Comment 32: The final permit should be clear and include final limitations for each of the listed units or state that the limitations in the previous permit are still applicable after the expiration of the interim limits.

Response 32: See Response 23.

Comment 33: Does the emission analysis for coker 3 include the effect of the increased feed temperature (due to it not being used as a preheat source for the crude unit)?

Response 33: Yes, the emissions analysis included all of the effects of the removal of the crude preheat train. The current design slightly cools the coker feed (vac bottoms) before the material is sent to the coker 3 unit. That cooler material is then re-heated in the coker 3 furnace to the temperature required to properly operate the coker unit and cause the heavy material to crack and form coke and other petroleum streams in the coke drums.

The new design will not be appreciably different than this – the vacuum bottoms will not be cooled in the new design, but will be fed to the coker 3 heater slightly warmer than the current design. This directionally decreases the amount of heat that must be added by coker 3 furnace firing. (Conversely, the decreased crude preheat will directionally increase the firing required at the crude furnaces. This heat increase is included in the TFO permit.) The effect of this shift in heat balance is conservatively addressed in the TFO emissions calculations by assuming that the crude 1, vacuum 1 and coker 3 furnaces all fire at their maximum designed firing rate in the future.

Other than the furnace emissions (discussed above) the coker feed system is a closed system, and there are no other emissions impacts from hotter coker feed.

III. <u>BP-Husky Refining’s written comments</u>

Comment 34: Section B, 4; Editorial comment: put the "and" after P036, instead of before.

Response 34: The correction will be made in the final permit.

Comment 35: Section B, 10.c)(1); The language in this condition states to monitor RFG burned in "each" heater in the group limit. However, the ADHT heater (B029), which is listed in B.10.a)(2), is a swing user between the east side mix drum fuel gas and the TIU mix drum fuel gas. Because of its very low levels of non-H2S sulfur, the east side mix drum fuel gas will only be monitored for H2S. As a consequence, when the ADHT heater is burning east side mix drum fuel gas, its SO2 emissions will be calculated in the same manner as is to be used for Reformer 3.

Response 35: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 36: Section B, 10.c)(1); The ASTM test method D5504-08 specified in this condition measures only certain species of reduced sulfur compounds. As a result, it will tend to understate somewhat the actual SO2 emissions. BPH proposes to revise this paragraph, as well as paragraph 10.e)(1), to conform to the specifications for total sulfur monitoring contained in the recently entered consent decree covering the BP Whiting Indiana Refinery, to which U.S. EPA and several environmental NGOs were parties and which was entered sub nom. United States, et al. v. BP Products North America, Inc., Civil No. 2:12 CV 207, N. D. Ind., Hammond Div. The language of the decree addressing total sulfur monitoring is contained in ¶42.c. on page 30. An excerpt of the decree with the relevant language and specifications is attached hereto as Exhibit 1.

Response 36: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 37: Section B, 10.c)(2); Request including "monitor" after “continuous total sulfur.”

Response 37: The requested change was made in the final permit.

Comment 38: Section B, 10.c)(2)(b); Request deleting (2)(b) because this condition is redundant with the conditions requiring that records of calculations be kept in 10.c)(3) and (4) below.

Response 38: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was deleted.

Comment 39: Section B, 10.c)(3, (4) and (5); BPH proposes various additions to and reorganizations of these record-keeping requirements to better distinguish what records need to be kept for which units (a) during the period the multi-unit SO2 limit is in effect, and (b) the period after that when the final limits are in effect. In addition, some changes are proposed to reflect that the ADHT heater sometimes burns fuel gas from the east side mix drum and that other heaters subject to these requirements might do so in the future as well.

Response 39: The proposed change was made in the final permit.

Comment 40: Section B, 10.e)(1)c.i. This paragraph, which describes the method to be used to calculate the incremental project-related emissions from the Alstom boilers, must be revised slightly to reflect that the MMBtu heat input is a constant and does not vary with hours of operation. This is a conservative simplifying assumption that avoids the necessity to determine which part of the Alstom boiler firing is attributable to the project. The values used for this calculation, 2328 MMBtu/day until the initial start-up of the modifications to the coker gas plant and 3624 MMBtu/day thereafter, reflect the maximum daily steam demand by the project and thus will tend to overstate the project-related emissions from the boilers.

Response 40: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 41: Section B, 10.e)(1)c.iii and e)(1)h.; These sections must be revised to reflect that the ADHT heater currently does, and other heaters subject to these requirements may in the future, burn fuel gas from the east side mix drum.

Response 41: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 42: Section B, 10.e)(2); BPH is proposing language on certification of the total sulfur monitoring systems that is also taken directly from the BP Whiting Consent Decree, see Comment 3 above, but with one exception. The Whiting Decree specifies that American Society for Testing and Materials (ASTM) method D3246-05 be used as the reference method for Relative Accuracy Audit (RAA) and Relative Accuracy Test Audit (RATA) tests, since there are no U.S. EPA methods that test for total sulfur. See Exhibit 1 hereto. As documented in Exhibit 2, however, BP's testing consultant has recommended using a closely related ASTM method, D6667, in lieu of D3246. Moreover, because neither of these test methods can be performed in the field, using them requires collection of bag samples for transportation to the laboratory for analysis. This introduces a potential source of error, which may make neither of those methods less appropriate for RATA tests. A possible alternative would be to use modified versions of U.S. EPA Methods 15 or 16 for purposes of the RATA tests. While these methods may slightly understate total sulfur, the difference between the results of these tests and the values returned by the monitor system (which combusts the gas at high temperature to be certain that all of the sulfur is converted to SO2) may not be great enough to prevent certification of the monitor. These issues will need to be addressed in the very near future with EPA in the context of the Whiting Consent Decree. Therefore, to reflect this current uncertainty, BPH is proposing that the TFP permit allow use of ASTM D3246 or D6667 or "other method approved by Ohio EPA Central Office."

Response 42: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 43: Section C, 1.b)(1)h; The description under the "Applicable Rules/Requirements" column says, "…this emissions unit is a large gaseous fuel subcategory…." However, in the final rule 63.7575, does not define a "large gaseous fuel subcategory" and 63.7499 does not include a "large gaseous fuel" subcategory. Suggest replacing this language with "this emissions unit is a unit designed to burn gas 1 fuels per 40 CFR 63.7499."

Response 43: The requested change was made in the final permit.

Comment 44: Section C, 1.b)(2)a; Request changing "…this sulfur dioxide (SO2) emissions limit..." to "…the sulfur dioxide (SO2) emissions limit of 21.02 ton per year…" in order to clarify to which limit the language refers.

Response 44: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 45: Section C, 1.e)(3); This section refers to quarterly reporting required under federal rules. BPH had originally requested OEPA to make these reports due on the last day of the month immediately following the end of each calendar quarter, and the draft of (3)b. does do this. However, that makes (3)b. inconsistent with (3)a. and also makes (3)b. inconsistent with federal requirements. So, for this and all similar sections, we request the introductory language in (3)b. be revised so as to make the reports referred to in that paragraph due within 30 days following the end of each calendar quarter.

Response 45: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 46: Section C, 1.f)(1)a; In the last paragraph of this condition the sentence beginning, "Multiply the stack test derived…" and ending with "… 12-month total NOx emissions…" can be deleted. This is redundant with the conditions (1)a.i. and (1)a.ii above.

Response 46: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 47: Section C 2.b)(1)a.; The existing short-term SO2 lb/hr limit is a state BAT limit from an earlier permit and should also sunset along with the existing 12-month rolling SO2 limit as provided in 2.b)(2)c. BAT for this current permit was established to be compliance with the NSPS Ja H2S concentration limit in fuel gas.

Response 47: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 48: Section C, 2.b)(1)b.; The existing 12-month rolling SO2 emission limit for the ADHT furnace should be 2.32 TPY rather than 2.35 TPY. This existing limit (2.32 TPY) was established in a previous permit where 160 ppm was used as the allowable H2S content of fuel gas under NSPS subpart J. 1000 Btu/scf was used as a conservative estimate of fuel gas heating value and standard conditions were assumed to be 68 degrees F rather than 60 degrees F used today. See proposed changes to 2.e)(2)g.

Response 48: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 49: Section C, 2.b)(1)i; The description under the "Applicable Rules/Requirements" column says, "this emissions unit is a large gaseous fuel subcategory… ." 63.7575 does not define a "large gaseous fuel subcategory" and 63.7499 does not include a "large gaseous fuel" subcategory. Suggest replacing this language with, "this emissions unit is a unit designed to burn gas 1 fuels as defined in 40 CFR 63.7575."

Response 49: The requested change was made in the final permit.

Comment 50: Section C, 2.b)(2)c; Request changing, "…this sulfur dioxide (SO2) emissions limit..." to "the sulfur dioxide (SO2) emissions limits of 0.6 pound per hour and 2.32 tons per year…" in order to clarify what limits are being referred to.

Response 50: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 51: Section C, 2.b)(2)c; Please change "shall not exceed 0.69 ton per rolling…" to "shall not exceed 0.94 ton per rolling…" to match the limit in Section B.10.a)(3). (0.94 TPY is the correct number)

Response 51: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 52: Section C, 2.d)(2); Request changing "...in terms of standard cubic feet per day, MMBtu per day" to "…in terms of standard cubic feet per day, MMscf per day."

Response 52: The requested change was made in the final permit.

Comment 53: Section C, 2.f)(1); At various points in this section, 22.8 MMBtu/hr is referred to as the "maximum" or "maximum allowable" heat input. This is not correct. The permit does not limit the hourly heat input. BPH requests that the 22.8 MMBtu firing rate be characterized as the "design" firing rate.

Response 53: The requested change was made in the final permit.

Comment 54: Section C, 2.f)(2)f.; Changes to this paragraph are necessary to (a) accurately reflect how the limit was developed, (b) clarify that this limit also becomes void pursuant to C.2.b)(2)c. and (c) to make clear that, while this limit remains in force, it applies only to SO2 resulting from the combustion of H2S in fuel gas.

Response 54: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 55: Section C, 2.f)(2)g. ; See Comment 48.

Response 55: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 56: Section C, 3.b)(1)a; The cross-reference to b)(2)a should also include b)(2)b, which is the provision that sunsets the existing SO2 limits once the new final limit becomes effective.

Response 56: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 57: Section C, 3.b)(1)i; The description under the "Applicable Rules/Requirements" column says, "this emissions unit is a large gaseous fuel subcategory…." 63.7575 does not define a ”large gaseous fuel subcategory” and 63.7499 does not include a ”large gaseous fuel” subcategory. Suggest replacing this language with "this emissions unit is a unit designed to burn gas 1 fuels as defined in 40 CFR 63.7575."

Response 57: The requested change was made in the final permit.

Comment 58: Section C, 3.b)(2)b; Request changing "…this sulfur dioxide (SO2) emissions limit and all its monitoring ..." to "…the sulfur dioxide (SO_2) emissions limits of 4.6 lbs/hr and 20.46 tons per year and all their monitoring …" in order to clarify what limits are being referred to.

Response 58: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 59: Section C, 3.d)(5) & (6); Request that the second paragraph in condition 3.d)(6) be moved to condition 3.d)(5) - it is the SO_2 permit condition that will expire when the heaters start up.

Response 59: The requested change was made in the final permit.

Comment 60: Section C, 3.f)(1); At various points in this section, 230 MMBtu/hr is referred to as the "maximum" or "maximum allowable" heat input. This is not correct. The permit does not limit the hourly heat input. BPH requests that the 230 MMBtu firing rate be characterized as the "design" firing rate.

Response 60: The requested change was made in the final permit.

Comment 61: Section C, 4.b)(2)k; The emissions limit of 82,375 tons per rolling 12 months is for CO_2 as a surrogate for GHG. Please make all references in this condition as CO_2, not CO_2e. Also, the 12 months value for CO_2 should be 82,375.

Response 61: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 62: Section C, 4.f)(1)c., g. and j.; Compliance with the PM10, PM2.5, VOC and PE emission limits may be presumed from the fact that this unit is limited to burning gaseous fuel. BPH requests that language be added to these three (3) paragraphs recognizing that fact.

Response 62: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 63: Section C, 4.f)(1)d., f. h. and k.; Consistent with earlier comments, the MMBtu/hr firing rates in these paragraphs should be referred to as the "design" firing rates rather than the "maximum" firing rates.

Response 63: The requested change was made in the final permit.

Comment 64: Section C, 4.f)(1)k.; All references to CO_2e in this paragraph should be changed to CO_2.

Response 64: The requested change was made in the final permit.

Comment 65: Section C, 5.b)(1)a.; Since the 75 TPY limit applicable to the three SRUs will not become effective until well after this permit is issued, that limit should not be listed in the table but should instead simply be referenced via the cross-reference to b)(2)c. Alternatively, if the limit is to be listed here it should be preceded by the language in b.(2)c. clarifying when it becomes effective.

Response 65: The requested change was made in the final permit.

Comment 66: Section C, 5.d)(5); The record-keeping requirements of this paragraph should not become effective until the 75 TPY limit goes into effect, which will not be until the new heaters start up.

Response 66: The requested change was made in the final permit.

Comment 67: Section C, 6.; On September 11, 2012. BPH received from Ohio EPA a permit to install (PTI No.P0110958) authorizing the Refinery to remove the Vac 1 Vent Gas from the Crude 1 Heater where it is currently being combusted (after treatment in the Crude 1 amine contactor) and vent it instead directly to the refinery fuel gas system for treatment and ultimate combustion. The draft permit was prepared with the understanding that this changeover would be completed before the final TFO permit was issued. However, it now appears that the changeover will be delayed. Therefore, BPH will need the this permit to allow the Refinery to handle this Vac 1 Vent Gas either as it currently is being handled or as authorized by P0110958. All of the changes proposed for this section C, 6. are related to that issue.

Response 67: The requested change was made in the final permit.

Comment 68: Section C, 7.b)(2)d; This section requires that the flares comply with OAC 3745-21-09(DD). The flares are also subject to substantially similar MACT requirements in 40 CFR Part 63, Subpart A. Because there are some slight differences between the two rules, this creates some administrative problems. For this reason, BPH requests that, consistent with USEPA streamlining policies, compliance with the MACT requirements shall be deemed to constitute compliance with the Ohio rule.

Response 68: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 69: Section C, 9.b)(1)a. and b)(2)g.; e)(1); f)(1),; The limits shown in row a of the table in b)(1) do not become applicable until after start-up of the P036 modifications associated with the TFO project occur. BPH recommends, therefore, that the future limits be moved to a new paragraph 1.b)(2)g. and the existing emission limits (and associated reporting and compliance determination methods) be added back into this permit in sections 9.b)(1)., e)(1) and f)(1) respectively to cover the period prior to the completion of the project.

Response 69: The requested change was made in the final permit.

Comment 70: Section C, 9.b)(2)e; The current language of this condition discusses Refinery MACT Subpart CC lack of applicability to the coker blowdown vent after the TFO project. However, additional clarification language should be added to reflect the pre-TFO current operation wherein this blowdown vent is regulated by Subpart CC.

Response 70: The requested change was made in the final permit.

Comment 71: Section C, 9.d)(5); BPH suggest the addition of a requirement to keep records of the number of coking cycles each month.

Response 71: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 72: Section C, 9.e)(1)a.; A requirement to report exceedences of the CO2e limit for the coker should probably be added to this paragraph.

Response 72: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 73: Section C, 9.f)(1)a. and c.; In both of these sections, the term "design number" of coking cycles should be substituted for the terms "maximum" and "maximum expected" number of coking cycles, since 626 cycles per year is a design number and not necessarily a maximum. Also, language should be added providing that compliance with the 12-month rolling VOC and CO2e limits is to be based on the application of the test-derived emission factors times the actual number of coker cycles each month.

Response 73: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 74: Section C, 10.b)(1)b.; Since the 75 TPY limit applicable to the three SRUs will not become effective until well after this permit is issued, that limit should not be listed in the table but should instead simply be referenced via the cross-reference to b)(2)c.

Response 74: The requested change was made in the final permit.

Comment 75: Section C, 10.b)(2)f; Request including the leak detection and repair streamlining language included in the other emissions units. This condition only references 21-09(T).

Response 75: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 76: Section C, 10.d)(4); Inclusion of Specification 6 is a mistake. It is a carry-over error in the current permit for this unit. Specification 6 is for emissions monitors with flow measurement. Specification 2 is for just SO2 ppm CEM, which is what BPH has.

Response 76: Ohio EPA acknowledges the error and, therefore, the above-referenced term was modified accordingly.

Comment 77: Section C, 10.d)(8); This condition requires maintaining records of the combined P009 & P037 SO2 12-month rolling emissions. This record-keeping requirement should only become applicable when the 75 TPY combined limit becomes applicable following startup of the new heaters.

Response 77: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 78: Section C, 10.e)(1); BPH suggests that the language "…after initial startup of the new crude heaters (B037 and B038) and vacuum heater (B039)" be substituted for the phrase "After initial statup of the TFO project," since "startup of the TFO project" is a somewhat vague term.

Response 78: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 79: Section C, 10.f)(1)a, f(1)c, f)(1)d, f)(1)e, f)(1)f; The compliance language for these conditions should be revised to provide that compliance demonstrations are to be based on actual rather than maximum firing rates.

Response 79: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 80: Section C, 12.b)(1)h; The description under the "Applicable Rules/Requirements" column says "…this emissions unit is a large gaseous fuel subcategory…." 63.7575 does not define a "large gaseous fuel subcategory" and 63.7499 does not include a "large gaseous fuel" subcategory. Suggest replacing this language with "…this emissions unit is a unit designed to burn gas 1 fuels as defined in 40 CFR 63.7575."

Response 80: The requested change was made in the final permit.

Comment 81: Section C, 13.d)(2)c, d)(2)e; Request replacing CO2e with CO2 only. CO2 is a surrogate for GHG for these heaters. The numerical emission limit specified was calculated reflective of just CO2.

Response 81: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 82: Section C, 13.f)(1)c., g.& j.; Compliance with the PM10, PM2.5, VOC and PE emission limits may be presumed from the fact that this unit is limited to burning gaseous fuel. BPH requests that language be added to these four paragraphs recognizing that fact.

Response 82: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Comment 83: Section C, 13.f)(1)k; Request replacing CO2e with CO2 only. This is a surrogate for GHG for these heaters.

Response 83: Ohio EPA concurs with the applicant and, therefore, the above-referenced term was modified accordingly.

Attachment 1

(BP Husky's response to NRDC comments)

BP HUSKY'S DRAFT RESPONSES
TO
COMMENTS SUBMITTED BY NATURAL RESOURCES DEFENSE COUNCIL, ENVIRONMENTAL INTEGRITY PROJECT, AND GLOBAL COMMUNITY MONITOR
ON THE
TOLEDO FEEDSTOCK OPTIMIZATION PROJECT PERMIT TO INSTALL P0111667

Section I: The Application Does not Adequately Account for All of the Emission Increases

Comment 1: Taking credit for removing the coker blow down from the Flare Gas Recovery System in Step 1 of the netting is impermissible Project Netting. *(NRDC Comments pp. 4-5)*

Response: One of the scope items in the TFO project is to decrease coker cycle time, which will have the effect of increasing the number of coking cycles and therefore the number of coker blowdown events. To prevent an increase in blowdown emissions from occurring, the TFO project will change the piping configuration so that the coker blowdown will no longer go to the flare gas recovery compressor and then to the coker wet gas compressor. Instead it will be piped directly to the coker wet gas compressor during normal operations.

Each blowdown event releases about 50,000 standard cubic feet (scf) of gas to the flare gas recovery system (FGRS). This gas is composed mainly of steam and entrained hydrocarbon vapors. The Coker 3 blowdown gas currently occupies space in the FGRS that otherwise would be available to capture gases from other sources in the refinery, if needed. Diverting the blowdown gas directly to the wet gas compressor will increase the available capacity in the FGRS. As a part of the scope of the TFO project, the coker wet gas compressor is being modified to allow it to compress the additional gas in order to recover the additional blowdown gas.

As explained above, the re-routing of the Coker 3 blowdown stream has the benefit of freeing up flare gas recovery compressor capacity. However, the project permitting has not taken credit for any reduced flare emissions. Thus, there is no netting since no emission reduction credits are being generated or claimed as a result of this change. The situation here is distinguishable from the situation in the Hovensa case cited by the commenter, in that by moving the blowdown to the wet gas compressor, BPH is not seeking to generate any netting credits. It is simply taking steps to prevent an increase in emissions that might otherwise occur. Under the commenters' approach, BPH would be required to include in Step 1 a hypothetical increase in emissions that is not necessary, is not intended and will not occur. The rules do not require this.

Comment 2: The increase in firing rate of the crude heater will allow it to send more feed to all downstream units and will cause emission increases from those units that were not included in the netting analysis *(NRDC Comments at pp. 6-7)*

Response: The design firing rate of the new Crude 1 and Vacuum 1 heaters will increase by 125 mmBtu/hr and 10 mmBtu/hr, respectively, compared with the existing heaters. The increase in the design firing rate at the Crude 1 and Vacuum 1 heaters do not support an increase in design crude refining capacity on these units.

At the Crude 1 heater, the additional design firing rate of 125 mmBtu/hr is needed to compensate for reductions in available heat from the Coker 3 unit after the TFO modifications. The refinery utilizes significant heat integration to maximize its overall energy efficiency. In the current configuration, Coker 3 feed goes through a series of heat exchangers that assist in the preheat of the Crude 1 feed. In effect, the exchangers cool down the Coker 3 feed and heat up the Crude 1 feed. As part of the TFO project, the Coker 3/Crude preheat exchangers will be bypassed. Since the feed to the Coker 3 unit will not be used to preheat the Crude 1 unit feed, the new Crude 1 heater will need to fire higher to compensate for this loss in preheat. This heat integration change accounts for approximately 85 mmBtu/hr of additional Crude 1 heater firing. The additional 40 mmBtu/hr in Crude 1 heater capacity is required as a heat source for the modifications to the Coker Gas Plant.

At the Vacuum 1 heater, the additional design firing rate of 10 mmBtu/hr is needed to enable the refinery to recycle certain streams from the Crude 2 unit and the Coker 3 unit to the Vacuum 1 distillation tower in order to improve the separation of gas oil and residuum that are contained in these streams. This new recycle option will allow the refinery to better optimize the processing of the material contained in these streams compared with current operation.

The TFO project does not increase the total crude processing capacity at the refinery. Rather, TFO is a crude substitution project that will enable the refinery to process different kinds of heavy crude compared with the current configuration.

Comment 3: The increase in coker feed rate will result in increased utilization of downstream units thus increasing emissions from those units. Emissions from processing these increases should be but were not included in the netting (*NRDC Comments at p. 7).*

Response: The increased Coker 3 feed rate will not result in an increased feed rate to the downstream process units with the possible exception of a small increase the diesel hydrotreater (ADHT) utilization, which is accounted for in the project emissions. While it is true that slightly more of the feed for the downstream units will come from the Coker, less will come from the Crude 1 and Vac 1 units. The only downstream unit that will see an increase in feed rate as a result of the TFO Project is the A Diesel hydrotreater (ADHT). The small emissions impact from this increase is included in the netting. Since the amount of crude is not changing, total combined outputs from the Crude 1/ Vac 1 Unit and Coker 3 will be essentially the same.

Comment 4: The increase in hydrotreatment at the ADHT will require additional steam, resulting in an increase in boiler emissions, and additional hydrogen, resulting in an increase in emissions from the BOC hydrogen plant or Reformer 3. *(NRDC Comments at pp. 7-8)*

Response: The additional steam needed for the increased load on the ADHT is accounted for in the incremental steam production value included in the TFO project emissions for the Alstom boilers. Note that the Alstom Boilers are the worst-case source for steam from an emissions standpoint, since the other source is the off-site, 3rd party, First Energy Plant. To the extent the additional steam comes from First Energy, the emissions associated with the production of that steam would not be included in the TFO project permitting since First Energy and BPH are separate sources.

There will be a slight increase in hydrogen demand as a result of the TFO project. Incremental hydrogen demand at the refinery is provided by the off-site, 3rd party Linde (formerly BOC, as identified in the commenter's statement) hydrogen plant. However, since that plant is a separate source (see response to Comment 30 below), any additional emissions needed to meet that demand would not be included in the TFO netting analysis. An additional on-site BPH source of hydrogen is the Reformer 3 process unit. However, its unit operations are dictated by its feed availability and gasoline product demands, not refinery hydrogen needs. Additionally, since the installation of Reformer 3 is a contemporaneous project, the entire PTE for Reformer 3 is already included in the TFO project netting.

Comment 5: BP underestimated emission increases from the steam boilers by using the difference between baseline and emissions at an assumed operating rate rather than the difference between baseline and potential emissions from the boilers. *(NRDC Comments at p.8).*

Response: USEPA has recognized that this is the appropriate way to calculate emission increases from units, like steam boilers, that will be affected by a project but are not being modified. See July 25, 2001 Letter to Ms. Bliss Higgins, Assistant Secretary, Environmental Services Division, Louisiana Department of Environmental Quality from Rebecca Weber, Associate Director for Air, Multimedia and Planning Division, USEPA Region 4 Re: Motiva Enterprises LLC, Low Sulfur Gasoline Project - Related Emissions Increase Methodology. It is not appropriate to "re-permit" the entire unutilized capacity of the plant steam system on every project that uses a small amount of additional steam.

Section II: The Draft Permit Does Not Accurately Determine Baseline Emissions

Comment 6: The baseline emissions of NOx, VOC, SO2, PM10/PM2.5 and CO shown in the application are overstated since they are higher than the emissions reported in the 2004/05 emission inventory reports. *(NRDC Comments at pp. 8-9 and pp.10-12).*

Response: Since the time BPH prepared the emission fee and inventory reports for 2004 and 2005, several improvements to its emissions estimation methodology have been made. These improvements are reflected in the baseline emission calculations.

The biggest improvement was made as a result of the requirements of the Greenhouse Gas Mandatory Reporting Rule (MRR) that requires specific quality assurance procedures for the monitoring of fuel burned in combustion sources. Most notably, the GHG MRR requires facilities to do pressure and/or temperature corrections of the fuel flow monitors and additional quality assurance for the heating values of the fuel burned. The fuel usage estimated for the original 2004 and 2005 fee reported numbers were based on fuel flow rates that were not corrected for temperature or pressure and the heating value used was on a low heating value (LHV) basis versus the updated method using high heating value (HHV). In addition, the 2004 and 2005 fuel usage values for the existing Crude 1 heater did not include the vacuum off-gas that was also burned in that heater. For the baseline estimates used in the TFO application, BPH recalculated the baseline emissions using the raw data from 2004 and 2005 and correcting the values with the same methodology used when estimating the fuel usage and heating value today (i.e.: the best currently known methods).

Comment 7: The results of 2010 total reduced sulfur testing do not provide a representative basis for the 2004/05 baseline SO2 emissions, since BPH's crude slate has been steadily changing to include more Canadian tar sands derivatives which is higher in sulfur than conventional crudes. (*NRDC Comments at p 10).*

Response: There is no question that non-H_2S sulfur compounds existed in the Refinery fuel gas in 2004 and 2005. The test data collected in 2010 and 2011 is the best information available from which to estimate the baseline concentrations of those compounds. In addition, the non-H_2S sulfur species, which is what was being measured in the 2010/11 tests, are believed to come primarily from the Coker. There is no significant difference in Refinery coker rates in 2004/5 versus those during the 2010/11 testing.

Comment 8: BP's NOx emission factors for the existing Crude 1 and Vac 1 heaters are inconsistent with what was reported to the USEPA and included in Appendix A to the 2001 Consent Decree. *(NRDC Comments at p. 10).*

Response: The NOx emission factors used in the TFO permitting for the existing Crude 1 and Vac 1 heater baseline emission estimates are the same emission factors that the BPH refinery has used in its fee reporting estimates for many years (at least from 2000 through 2012) : 0.22 lb NOx/mmBtu for the Crude 1 heater; and, 0.07 lb NOx/mmBtu for the Vac 1 heater. BPH cannot reconstruct today exactly what served as the basis for the NOx emission factors and emission rates shown in Exhibit A to the 2001 Consent Decree between BP and the United States. However, those data were unquestionably pulled together on a highly expedited basis from nine separate refineries with very little QA/QC. The sole purpose for compiling those data was to provide the United States and BP with a frame of reference for negotiating system-wide NOx emissions reductions. Both parties recognized that there were likely to be inaccuracies in the factors and emissions for individual heaters, and originally there was an expectation that these data would eventually be QA/QC'd before the Consent Decree was finalized. But in the end, the desire of both parties to conclude negotiations led them to agree that the numbers were probably "mostly right" and that the errors were likely random. Therefore, the parties concluded that each side would live with any inaccuracies given that the sole purpose of Exhibit A was to provide a basis for measuring compliance with the consent decree's requirements to control 59.5% of firing capacity system-wide and to reduce system-wide NOx by 9,632 tons per year on an actual to allowable basis. In this context, small inaccuracies in the emission factors or total emissions were not material. The representation in the consent decree documents that the data was the best believed to be available at the time was intended to make clear that the data had not been QA/QC'd and was simply what was believed to be the best data that could be assembled in the time allotted.

Comment 9: The netting analysis improperly relies on AP-42 emission factors. *(NRDC Comments at pp.12-14)*

Response: AP-42 emissions factors are widely used in permitting across all industries in all States. Although, site-specific test data are preferred when available, that does not make AP-42 emission factors inappropriate. It is unrealistic to expect all permitted emissions estimates to be based on stack tests. That said, BPH did use stack test data where it was available to estimate the TFO project emissions. This includes the use of actual NOx testing emission factors on the largest combustion emission source shutdown by this project, the Crude 1 Heater (B015). The NOx emissions credits for the shutdown of this large heater were based on the past stack testing of this heater. Likewise, NOx emissions for the increased utilization of the Coker 3 Heater (B032) are based on available stack test data. Similarly, estimates of SO_2 emissions from all combustion sources utilized continuous H_2S monitoring data for the refinery fuel gas and other test data for non-H_2S sulfur compounds. While pollutants such as particulate (PM) and VOCs from gaseous fuel combustion sources are indeed calculated based on AP-42 emission factors, the use of AP-42 factors in these situations is standard for permitting and completely appropriate.

Comment 10: The netting improperly relies on emission reductions that were relied on by Ohio EPA in concluding that the Reformer Project did not trigger PSD. *(NRDC Comments at p. 14).*

Response: The only increases and decreases that are not creditable because they were previously "relied on" are those relied on in issuing a PSD permit for the pollutant at issue. US EPA Draft NSR Workshop Manual (1990) page A-39 states: "An emissions increase or decrease is creditable only if the relevant reviewing authority has not relied on it *in issuing a PSD permit* for the source . . . ." The Reformer 3 project did not trigger PSD for NOx, SO_2, or CO. Thus, the decreases (and increases) in those pollutants that resulted from the Reformer 3 project are creditable with respect to the TFO project. Indeed, they are required to be included in the netting.

Section III: The Project has been Improperly Piecemealed

<u>Comment 11</u>: The assertion in the TFO permit application that the TFO Project "simply allows the flexibility to substitute BPH's own Sunrise Canadian crude or other somewhat more corrosive crude oil feedstocks for the Canadian and other heavy source crude oils being processed today" is plainly untrue. The record indicates the true purpose of this Project — as well as many other projects at the refinery in recent years — is to both increase the throughput of the Refinery and to substantially increase the amount of sour heavy crude that it can process, from 60,000 BPD to 170,000 BPD. *(NRDC Comments at pp. 14-15).*

<u>Response</u>: The commenter is incorrect. This project does not increase refinery crude capacity. As explained in response to earlier comments (see comment 2), the increase in Crude 1 heater firing capacity is needed, not for higher crude rates, but to maintain existing crude rates despite a reduction in the ability to preheat the feed to the Crude Unit. Nor does the project increase the amount of heavy sour crude that can be processed at the Refinery compared with the design intent and permit limits of the 1999 Toledo Repositioning Project. In 1999, BP completed its original "Toledo Repositioning Project," revamping the Crude 1 and Vac 1 units, building a new coker and tripling its sulfur recovery capacity. That project was designed to increase the amount of heavy crude that could be processed by the Refinery, and it was anticipated that most of this heavy sour crude would come from Canadian sources. The present project does not materially change these capabilities. The purpose and effect of the TFO project is to allow the refinery to process crudes from the BPH Sunrise field in lieu of, not in addition to, the Canadian and other heavy sour crudes currently being processed.

In 2007, when the BP-Husky Joint Venture was formed, the parties did announce an intent to increase the heavy sour crude capacity of the Toledo Refinery to 170,000 barrels per day by 2015. TFO is not that project. Increasing heavy sour crude capacity to 170,000 barrels per day would require an entirely new crude unit, a significant increase in residuum destruction (coking or other methods), and an equally large expansion of hydrotreating and sulfur recovery capacity. None of these is included in this project.

The original plan to take the Refinery to 170,000 barrels per day of heavy sour crude has been deferred due to significant changes in the market that have occurred since 2007. These changes include uncertainty in the regulatory landscape, declining demand for transportation fuels, and growth in domestic crude supply. Several factors have led to these changes, including the new U.S corporate average fuel efficiency (CAFE) standards, the slower economy, and the changed long range outlook for refined products. As a consequence, whether the larger project will ever be undertaken remains uncertain. Production from the Sunrise field is just beginning to ramp up, and the TFO project is scaled to allow the Toledo Refinery to process the early production since the that early production fits within the Toledo Refinery's existing heavy sour crude capacity. All that is required for TFO is to upgrade the metallurgy of the Crude 1 and Vac 1 units to accommodate a slightly more acidic crude slate and to modify the Coker 3 unit to achieve its original design of 14 hour cycle time.

If it ever occurs, the second expansion of the Sunrise oil field would increase the production of Sunrise crudes by another 60-100 kbpd. One or more follow-on projects may or may not be undertaken at that point to allow Toledo to process some or all of this additional Sunrise crude. Due to uncertainty over the future demand, it is not clear whether or when the second step the Sunrise development would occur. Moreover, if it does occur, it is not clear that the additional Sunrise crude would be processed at Toledo.

Ohio EPA has reviewed these plans with BPH and has concluded that the possibility of a second Sunrise-related project at the Toledo Refinery is too uncertain to require that BPH include that possibility in the current permit. Accordingly, if it does ever occur, it would likely be permitted as a new project.

Comment 12: The subject TFO Project is just the tail end of a massive, multi-phased Refinery expansion designed to increase the throughput of the refinery while simultaneously increasing the amount of sour heavy crude.*(NRDC Comments at p. 15).*

Response: The TFO Project is not the tail end of a series of projects that should be aggregated. As indicated above, TFO represents a project opportunity that started in 2007 with the formation of the BP Husky joint venture to develop the Sunrise oil field in Canada and refine the production from that field at Toledo. As discussed below, none of the projects that preceded TFO have any material relationship to the development of the Sunrise field. They cannot reasonably be considered to be part of a single physical change.

Comment 13: Because "[s]ubstantially related, nominally separate changes can be seen as one change when viewed as a whole," the EPA views "[a]ggregation of nominally separate changes that are substantially related as 'fit[ting] within one of the ordinary meanings of physical change.'" Thus, aggregation is required if a collection of projects are "substantially related."*(NRDC Comments at p.15)*

Response: The "substantially related" test for aggregation was an interpretation of the term of "physical change or change in the method of operation" that USEPAadopted and issued shortly before the end of the Bush Administration. That test never went into effect, however, because the interpretation was stayed by the Obama Administration prior to its effective date while EPA considered a petition for reconsideration. See 74 Fed. Reg 7284 (February 13, 2009), 74 Fed. Reg. 11509 (March 18, 2009), 74 Fed. Reg. 22693 (May 14, 2009). On April 15, 2010, USEPA proposed to grant the petition for reconsideration and announced its intention to revoke the 2009 interpretation. See 75 Fed. Reg. 19567 (April 15, 2010). In doing so, USEPA indicated that it believed the appropriate test for aggregation was to ask whether two nominally separate projects "are sufficiently related to fit within one of the ordinary meanings of a single physical change." *Id*. at 19571. Further it suggested that, in answering this question, agencies and sources should consider the types of factors articulated in USEPA's traditional aggregation guidance (e.g: closeness in timing, common funding and managed together, etc.). This is the last published statement USEPA has made on the aggregation issue in the Federal Register, and USEPA has referred to this as its current interpretation of the aggregation policy on multiple occasions. For the reasons outlined in responses to other Comments in this section, the TFO project is a separate project and separate "physical change" from the other past projects, and thus is appropriately permitted separately.

Comment 14: BP startedchanges to enable the refining of tar sands crudes at least as early as the 1990s, withmodifications to the Sulfur Recovery Unit ("SRU") specifically to improve sulfurconversion to allow a significant increase in sour crude processing. *(NRDC Comments at pp 15-16 and fn 25).*

Response: Chris McCormack, whose LinkedIn profile is cited as the authority for this comment is the technical manager of the Toledo Refining Company. The Toledo Refining Company Refinery is the former Sun Refinery in East Toledo. It is located several miles away from the BPH Toledo refinery and the two refineries are owned, operated and controlled by completely different companies. The project referred to here thus appears to have been a project at the former Sun Refinery rather than at the BPH refinery.

Comment 15: In 1999, BPformally launched a $235 million project to enable the refinery to process heavy sourcrude.*(NRDC Comments at p 16 and fn 26).*

Response: This comment is correct. In the late 1990s, BP applied for and obtained a permit to make the changes necessary to allow the Crude/Vac 1 process units to refine heavy sour crude, with the expectation that most of this new crude would come from Canada. The major elements of this project were (a) to change the metallurgy and increase slightly the capacity of the C/V1 heaters and distillation columns, (b) to significantly increase coking capacity via construction of a large new Coker referred to as Coker 3, and (c) to nearly triple the sulfur recovery capacity. It was this project that provided the BPH Refinery with its current capacity to process heavy sour crude approximately 14 years ago. That project had nothing to do with the Sunrise oil field and the separation in timing to the current TFO permit is alone sufficient to demonstrate that the projects are not sufficiently related to be considered parts of a single physical or operational change.

Comment 16: Another $95 million was spent in 2004 on a Clean Fuels and Sour Crude Project, which enabled the refinery to produce low-sulfur gasoline and diesel and expanded two existing hydrotreaters and a hydrogen plant*(NRDC Comments at p. 16 and fn 27).*

Response: As finally executed, the "Total Clean Fuels/Total Sour Crude" (TCF/TSC) project did not include a hydrogen plant. When BP initially filed its application, the plan was to have a 3rd party build a hydrogen plant next to the BP refinery with that plant supplying hydrogen primarily, if not exclusively, to the BP refinery. That hydrogen plant would have been considered a support facility for the BP refinery and therefore part of the BP refinery source. For this reason, BP included the expected potential emissions from that proposed hydrogen plant in the permit's analyses of the project emission impacts. In the end, however, the 3rd party, BOC (now Linde), elected to build the hydrogen plant next to what was then the Sun Oil Refinery and to supply hydrogen to both the Sun and BP refineries. This hydrogen plant is not, therefore, contiguous or adjacent to the BP refinery, and is not under common control with the BP Refinery. It is also not a support facility for the BP Refinery and therefore has a different two digit SIC code. For all of these reasons, Ohio EPA concluded, in issuing the permit for the TCF/TSC project, that the hydrogen plant was a separate source from the BP Refinery for the TCF/TSC project. See the Netting Determination, PTI 04-01346, at page 1, in attachment 1.

The commenter's inference that the TCF/TSC project was a part of an ongoing process to increase either overall crude capacity or the ability to process more Canadian Crude is also incorrect. The primary function of the TCF/TSC project was to allow the Refinery to make gasoline and diesel that met the Tier II sulfur-in-fuel requirements promulgated by USEPA. To do this, BP expanded the "B Gas Oil Treater" (BGOT), which hydrotreats (*i.e.*, desulfurizes) the feed to the FCCU, the refinery's largest source of gasoline blending stocks. In addition, BP made more minor improvements to the ADHT, which hydrotreats diesel. The "total sour crude" part of the project involved upgrading the metallurgy in the Crude/Vac 2 unit to allow it to process crudes with somewhat higher sulfur content (medium sour crudes). This did not, however, increase the refinery's capacity to process more Canadian or other heavy sour crudes.

It is also worth noting that, at the time of the TCF/TSC project there were no plans to expand heavy sour crude capacity at the Toledo Refinery beyond the design of the 1999 Toledo Repositioning Project. Those plans arose only with the formation of the BPH joint venture in 2007. The TCF/TSC Project was planned, permitted and executed well before that Joint Venture was formed.

Comment 17: In a December 2007 press release, BP announced an exchange with Husky wherein BP acquired a 50% stake in the Sunrise oil field in Alberta from Husky in exchange for a half-share in the Toledo Refinery. At that time, BP stated the Toledo Refinery's capacity was 155,000 BPD, of which 60,000 BPD or 39% was heavy oil. According to the 2012 Husky Annual Report, this was all Sunrise tar sands crude. *(2nd NRDC Comments at p.16 and fns 28 & 29).*

Response: The first two sentences of this comment are correct. However, as noted above, the plan announced in the 2007 press release has not happened and may never happen. As to the final sentence, we have reviewed the 2012 BP-Husky annual report and cannot locate any statement indicating that the heavy oil refined at Toledo in 2007 "was all Sunrise tar sands crude." Indeed, it is not possible for this statement to be true since the Sunrise field will not begin production until 2014.

Comment 18: In January 2010, BPH announced a $400 million major upgrade program, which included replacing two existing catalytic reformers and a hydrogen plant with a single 42,000 BPD reformer (the Reformer 3 Project).*(NRDC Comments at p. 16 and fn 30).*

Response: This comment is correct except that BPH actually applied for the permit to construct Reformer 3 in July 2008 rather than January 2010. Again, however, the implication that the Reformer 3 Project was part of a series of projects intended to expand crude capacity and/or the capacity of the refinery to process additional heavy sour crude is untrue. In August 2010, BPH supplied Ohio EPA with extensive information on the relationship between the Reformer 3 Project and a possible multi-phase heavy crude project that BPH was considering, but that it ended up not pursuing. After reviewing this information, Ohio EPA wrote to BPH in February, 2011, advising BPH that, based on the information presented, it agreed that the then-anticipated future heavy crude project was separate from the Reformer 3 project and could be permitted separately. Copies of the information provided to Ohio EPA and of Ohio EPA's response are included here as Attachments 2 and 3.

The heavy crude project under consideration in 2010 has since been canceled in favor of what is now the TFO project. Thus, the lack of a significant relationship between the Reformer 3 Project and the TFO project is, if anything, even clearer now than it was in 2010. BPH applied for a permit for the Reformer 3 project in July 2008, the permit was issued in June 2009, and BPH commenced construction on the $400 million project in August 2010. As indicated above, BPH was at that point still working to define the scope of the Sunrise-related project or projects it intended to undertake. BPH did not actually apply for the TFO permit until October 2012, four years after it applied for the Reformer 3 permit, more than three years after that permit was issued and two full years after construction on the Reformer had commenced. The gap in timing is alone sufficient to demonstrate that the Reformer 3 Project and the TFO Project are not sufficiently related to be considered parts of a single physical or operational change.

Comment 19: BPH has announced plans to invest $2.5 billion more in the Refinery by 2015 to increase refining capacity and enable it to process crude oil produced at the Sunrise field. BPH has stated that this investment will increase the capacity of the Refinery to 170,000 BPD of heavy oil and bitumen.The TFO Project was reportedly planned by BP before the formation of the joint venture with Husky.*(NRDC Comments at p. 16 and fn 31)*

Response: BP and Husky did make an announcement of a planned refinery expansion in 2007 in connection with the formation of their Joint Venture. However, as discussed above, that is not the TFO project. The multi-billion dollar investment that would be required to increase the capacity of the Refinery to 170,000 barrels per day of heavy oil and bitumen has been deferred and it may not occur at all. We have reviewed the source cited to support the assertion that the project aimed at doubling heavy crude capacity was planned before the formation of the joint venture but can identify nothing that would support that assertion. As noted earlier, BP had no plans to meaningfully increase heavy sour crude processing capabilities at Toledo prior to the formation of the BP-Husky Joint Venture ("JV").

Comment 20: BPH characterized the purpose of these projects, collectively, as being "to reconfigure and increase capacity at the Refinery to accommodate Sunrise production as its primary feedstock."*(NRDC Comments at p. 16 and fn 32).*

Response: The actual statement from the Husky 2012 annual report to which the commenter is referring is as follows:

> Husky plans to continue to pursue projects to . . . reconfigure and increase capacity at the BP-Husky Toledo Refinery to accommodate Sunrise production as its primary feedstock.

The commenter appears to misconstrue this statement to be a description of the TFO project itself. As noted earlier, the JV announced at its inception a long term goal of reconfiguring and increasing the capacity of the Toledo Refinery so that it may, at some point in the future, accommodate Sunrise production as its primary feed stock. But that is not what the current TFO project does. The TFO project will not increase the heavy crude capacity of the Toledo Refinery. Its sole function is to make relatively minor changes that are necessary to substitute Sunrise production for the Refinery's existing heavy sour crude slate.

Comment 21: The 2011 BPH Annual Report indicates that, at that time, the Refinery was only processing 50% heavy crude. Subsequent projects, including the TFO Project, were designed to increase this to 100% heavy crudes and increase the refinery's capacity to 170,000 BPD. Thus, the TFO Project is just one component of a collection of modifications designed to increase the capacity of the Refinery and to increase its ability to process heavy sour crudes.*(NRDC Comments at p. 16- 17 and fns 33 & 34)*

Response: There have been no past projects that were designed, with or without the current TFO project, to increase the Refinery's capacity to 170,000 barrels per day of heavy crude. As discussed below, other than the Delta Valve project, none of the projects undertaken at the refinery since 1999 have increased the amount of heavy crude the Refinery can process. And even the Delta Valve project was intended to achieve what had always been the original design for the 1999 Repositioning project. While the amount of heavy crude actually processed at the Refinery has increased somewhat since 1999, that is the result primarily of using capacities that have been in place for more than a dozen years. TFO does not change this. After TFO, the refinery crude capacity will remain at approximately 160,000 barrels per day and heavy crude capacity will be unchanged from current levels of 50-60% of that total. The current TFO project is a crude substitution project that will allow the refinery to process different kinds of heavy crude compared with the current configuration. The TFO project does not increase the total crude processing capacity at the refinery or materially change the ability of the refinery to process heavy crude.

Comment 22: Based on available data, the changes that have been made to enable the Refinery to increase its throughput from 140,000 BPD of conventional crude up to 170,000 BPD of heavy sour crude include at least the following*(NRDC Comments at p. 17)***:**

- **Increase in hydrogen production.**

Response: The Refinery hydrogen production has not increased appreciably since the 2004 TCF/TSC Project. The additional hydrogen needed for that project was provided by the BOC (Linde) hydrogen plant that was built adjacent to what was then the Sun Refinery. Reformer 3 produces high purity hydrogen, and the startup of that unit allowed the Refinery to shut down the Refinery's existing hydrogen plant and the two existing Reformers, which were also hydrogen producers. The Reformer 3 hydrogen production capacity is 63 million standard cubic feet per day (SCF/D). The hydrogen capacities of the existing hydrogen plant and the two existing reformers, all of which are being shut down, are 36 million SCF/D for the old hydrogen plant, 36 million SCF/D for Reformer 2, and 14.4 SCF/D for Reformer 1. Thus, the net hydrogen capacity of the refinery will actually decline by 23.4 million SCF/D with the start-up of the Reformer 3 unit and the shutdown of the Reformers 1 and 2, and Hydrogen plants. All of these shutdowns were required in the Reformer 3 permit and the units will not be restarted. The refinery has nowhere near the hydrogen or hydrotreating capacity it would need to increase heavy sour crude processing to any significant degree.

- **Expansion in capacity of Coker 2 and 3 (PTI 04-01471) by installing automated Delta valves on the head drums to reduce cycle time**

Response: When Coker 3 was first built it was designed to operate at 14-hour cycles. It was not able to achieve that cycle time. The Delta Valve project was an attempt to fix this issue so that the Coker 3 could operate at its original design rate. While that project did reduce the Coker 3 cycle time somewhat, the Coker still does not operate consistently at its 1999 design capacity.. The Coker 3 scope in the TFO project is another attempt to achieve the 14-hour cycle time that was part of the Coker 3 original design. Even if successful, it is far too small an improvement in residuum processing capabilities to enable a significant increase in heavy crude processing. In fact, because the Sunrise crudes are expected to increase the amount of residuum and coke produced per barrel of feed, achieving a 14-hour cycle time will be necessary to maintain Toledo's current heavy crude rates with the Sunrise crudes.

- **New Alstom boilers to increase steam capacity, required to refine increased amounts of heavy sour crudes**

Response: The Alstom boilers did not increase Refinery steam capacity. They were built as replacements for two older and larger boilers that BP elected to shut down to meet the NOx reduction requirements of the 2001 Consent Decree with EPA. The combined capacity of the two older boilers was 623 mmBtu/hour. The combined permitted maximum annual average firing rate of the two Alstom Boilers is 430 mmBtu/hr.

- **Increased capacity of the SRU**

There have been no changes to the refinery sulfur recovery capacity since the 1999 TRP project. Prior to that project, the refinery had one sulfur recovery unit (SRU), with a sulfur recovery capacity of about 99 LT/D of sulfur. As part of the TRP project, two new SRU units were added, each with a capacity of approximately 105 LT/D. Thus, with the startup of the TRP project in 1999, the refinery had a total of 309 LT/D. There have been no further modifications to the SRU units and the refinery's capacity remains today at 309 LT/D (346 ST/D) total for all SRU units.

BPH does have an acid gas line to the neighboring ChemTrade (formerly Marsulex) Sulfuric Acid Plant. That line allows the refinery to sell some of the sulfur-rich acid gas stream to this 3rd party customer, allowing an alternative outlet (vs. the SRU) for up to about 105 LT/D of refinery captured sulfur. This alternative outlet for some of the acid gas also gives the refinery some backup/redundancy to help respond to SRU upsets.

- **Increased B-GOT throughput and installation of a new B-GOT furnace.**

Response: There were two projects that impacted the BGOT unit. First, the TCF/TSC project was required to meet federal Tier II Clean Fuels requirements. These standards effectively required that 100% of the FCCU feed be hydrotreated. The expansion of the BGOT (including the new furnace) was needed for these purposes, but was actually insufficient to allow the FCCU to operate at its permitted capacity of 55,000 barrels per day on an annual average. In 2011/12, BPH developed the BGOT Recycle Gas Compressor Project which is intended to address this problem. Since the BGOT Recycle Gas Compressor Project is contemporaneous with the TFO project, the emissions impacts of that project are included in the TFO netting. Also, these BGOT projects are independent of and unrelated to the TFO project and Sunrise crude.

- **Modifications to FCCU (PTI P010887)**

Response: The only change authorized by PTI P010887 was the replacement of an existing, obsolete, fuel gas-fired furnace that was used to pre-heat feed to the FCCU during start-ups with a heat exchange system that serves the same function using steam as the heating mechanism. There was no impact on the operation of the FCCU.

- **Higher intensity diesel hydrotreating, including larger hydrotreating reactor and high furnace firing rate**

Response: This comment appears to be referring to the improvements made to the ADHT as a part of the 2004 TCF/TSC project. As noted above, that project was undertaken for the sole purpose of allowing the Refinery to reduce the sulfur content of diesel from about 500 ppm to the 15 ppm level and gasoline from about 120 ppm to 30 ppm specified in the Tier II Clean Fuels rule. The firing rate was actually reduced on an annual average basis as a result of the TCF/TSC project.

- **Conversion of Refinery to full FCC resid cracking mode, including shutdown of all bottoms processing units**

Response: Since no citation is provided, it is unclear where the commenter got the impression that the Toledo Refinery had been or would be converted to "full FCC resid cracking mode, including shutdown of all bottoms processing units," but that has not been done at the Toledo Refinery nor is it contemplated for any future project.

Comment 23: The current Toledo Refinery Technical Manager's LinkedIn Profile lists many capacity increase and heavy crude expansion projects that do not appear to be identified in Ohio EPA's files related to the TFO project, some of which are named so as not to be recognizable for what they really are—capacity increase projects for heavy sour crudes that would have triggered PSD review. *(NRDC Comments at p. 18).*

Response: Chris McCormick, who is the person to whose LinkedIn account the commenter refers in support of this comment, does not work at the BPH Toledo Refinery. The referenced LinkedIn page indicates, rather, that Mr. McCormick is the technical manager for the Toledo Refining Company, which is the owner and operator of what used to be the Sun Refinery in Toledo. This is a separate refinery from the BPH Toledo Refinery. Note that the two gentlemen referenced in footnote 38 also have no connection to the BPH Toledo Refinery, but instead appear to have done work at the former Sun refinery, now owned by Toledo Refining Company. The one project on this list that appears to be a BPH Toledo Refinery project is the "Feedstock Optimization Project." This presumably is the present TFO project, since Brian Robicheaux was recently named the general project manager for this project.

__Comment 24__: **The instant Project includes increasing the firing rate of the crude, vacuum, coker, and ADHT heaters. This is required to allow the Toledo Refinery to process increased amounts of heavy sour crude. We note that this change also effectively increases the capacity of the entire Refinery, allowing the use of excess capacity developed in downstream units in a long succession of projects discussed elsewhere in these comments, because increasing the capacity of the crude unit means downstream units must process the increased amounts of naphtha, gas oil, resids separated in the distillation columns. The TFO Project and its predecessors increased the capacity of every unit that receives the increased product from the crude unit (see Section I above concerning debottlenecking)**. *(NRDC Comments at p. 21).*

__Response__: See responses to Comments 2, 3 and 4.

__Comment 25__: **The Application asserts that this Project "will not increase the BPH refinery's overall crude capacity." (Ap.at 1). This claim is wrong, and contrary BP's own press releases. In a December 2007 press release, BP stated the Toledo Refinery's capacity was 155,000 BPD of which 60,000 BPD or 39% was heavy oil. In a March 2013 press release, announcing the startup of the new Reformer 3 Project, BP reported the refinery throughput as 160,000 BPD. The December 2007 BP press release states that the refinery "will be expanded to process approximately 170,000 bpd of heavy oil and bitumen by 2015, with 2015 being the year that the instant Project is slated to come online. Further, while the Application asserts "Nor is it intended to increase the amount of Canadian crude processed at the Refinery" (Ap.at 1), this increase in firing rate and other prior and currently proposed changes are required to allow the Refinery to process increased amount of tar sands crudes, consistent with BP's long term blueprint.** *(NRDC Comments at p. 21-22)*

__Response__: See responses to Comments 2, 11, and 12.

__Comment 26__: **The TFO Project accomplishes this by decreasing the cycle time of Coker 3 increasing the throughput by about 5,000 BPD. A previous modification similarly decreased cycle time of Cokers 2 and 3**. *(NRDC Comments at p. 22).*

__Response__*:* See response to Comments 3 and 23 above. If achieved, the 5,000 bpd expected increase in Coker 3 feed rate will simply be the result of finally achieving the 14 hour per cycle operating rate for which Coker 3 was originally designed in 1998. That increase does not materially change the ability of the refinery to process heavy crude.

__Comment 27__: **The various crude fractions from the crude distillation unit and coker (naphtha, diesel, gas oil) must be cleaned up to meet product specifications and to remove catalyst poisons prior to further processing. Hydrotreating means adding hydrogen to treat the feed. Thus, hydrotreating and hydrogen production are intimately related. Huge increases in hydrogen production would be required to increase refinery throughput and to substitute heavy sour crudes for conventional crudes.** *(NRDC Comments at p. 23-25).*

__Response__: This comment is basically correct. And, it serves to rebut the commenters' persistent claim that the TFO project – or any other projects since the 1999 Toledo Repositioning Project – have had as their purpose or effect a meaningful increase in the amount of heavy sour crude that can be processed at Toledo. There has been no appreciable increase in hydrotreating capacity at the refinery since 2000 other than that associated with the TCF/TSC project in 2005. See discussion in response to Comment 16 above. And that increase was not even large enough to allow the FCCU to operate at permitted rates. When it comes on line in May 2014, the new BGOT recycle gas compressor will relieve this bottleneck somewhat, but is much too small an increase in hydrotreating capacity to support an increase in either overall crude processing or heavy sour crude processing.

The same is true with regard to hydrogen. As noted in response to Comment 23 above, the Refinery's internal hydrogen production capacity has actually declined by about 23 million SCF/D as a result of the Reformer 3 project. Even with the additional hydrogen BPH might be able to get from Linde (which must also supply the Toledo Refining Company refinery) there is far too little hydrogen capacity to support any appreciable increase in hydrotreating.

<u>Comment 28</u>: **BP started planning a multi-refinery crude replacement program at least as earlyas 2005, dubbed the Canadian eXtra Heavy Oil (CXHO) program. This programincluded modifying the Toledo Refinery to process tar sands crudes.This program wascombined with the "Clean Fuels Project" to meet new Tier II gasoline and diesel sulfurlimits.It was variously referred to as the Total Sour Crude Project and the "CanadianeXtra Heavy Oil Program" or CXHO. It was being carried out at both Whiting andToledo.***(NRDC Comments at p 25).*

<u>Response</u>: In 2004 and 2005, BP was exploring the possibility of converting its three "northern tier" refineries – Cherry Point, WA, Whiting, IN, and Toledo, OH – to process Canadian heavy oils. Discussions regarding these possible projects were held with USEPA and each of the potentially affected state agencies. In 2006, a decision was made to focus the capital required for such a project at the BP Whiting Indiana refinery both because it was the largest of the three refineries and because its dependence on West Texas-type intermediate crudes made it most vulnerable economically. As a result, Whiting, rather than either Cherry Point or Toledo, was selected for an investment to increase Canadian heavy crude processing (referred to at that time as the CXHO project). Subsequently, in 2007, an alternative plan for Toledo emerged and resulted in the Joint Venture agreement with Husky. As discussed above, however, that Joint Venture has yet to lead to any concrete plans to increase the amount of heavy crude that can be processed at Toledo. To date, the only heavy crude-related project to be sanctioned is the current one, which is simply designed to allow the JV's Sunrise Crude to be substituted for the other heavy sour crude types that are currently being processed.

The CXHO project was not combined with the TCF/TSC project. That latter project actually preceded the CXHO investigations since the Clean Fuels requirements became effective in 2005.

<u>Comment 29</u>: **The following four "contemporaneous" projects are plainly part of an overall strategy to allow the Refinerythe flexibility to process increasing amounts of a wide range of heavy crudes that arecoming on the market in the short term, including Canadian tar sands crudes and crudesfrom the Utica Shale in eastern Ohio, Pennsylvania, New York, and West Virginia. The instant Project could not beimplemented without the changes made in these three separately permitted projects.***(NRDC Comments at pp. 25-27).*

<u>Response</u>: As set forth below, none of the four projects referenced is a "part of an overall strategy to allow the BPH Toledo Refinerythe flexibility to process increasing amounts of a wide range of heavy crudes," and none is necessary to allow implementation of the TFO project:

- **Reformer 3**:

  This project is addressed in response to Comment 18.

- **BGOT Recycle Gas Compressor**:

This project is addressed in response to Comments 16 and 23.

- **FCCU Preheat Heater:**

  This project is addressed in response to Comment 23.

- **CV1 Offgas Rerouting:**

  The CV1 off-gas rerouting project has nothing to do with the purposes / strategies cited by the commenter. The project is driven by reliability and maintenance concerns. The project re-routes the off-gas from the Vac 1 tower of the Crude/Vac 1 process unit. Currently this off-gas is routed to a dedicated amine treater before being burned in the firebox of the Crude 1 heater. The project re-routes the off-gas to the refinery's fuel gas system where it will be amine treated with the rest of the refinery's fuel gas and burned in heaters throughout the refinery as needed. The refinery has incurred a lot of maintenance issues with the current amine treater / contactor. The amine treater / contactor that currently treats this off-gas will be shut down; it will not be utilized for other purposes. The new configuration will reduce maintenance and the flaring of untreated off-gas. The Crude 2 off-gas system is currently configured in the same manner and it has a good history of reliability and low maintenance. The refinery expects the same results by rerouting the off-gas from CV1.

<u>Comment 30</u>: The BOC/Linde Hydrogen Plant must be considered to be a part of the Refinery and its emissions increase added into the netting. *(NRDC Comments at pp. 27-30).*

<u>Response</u>: To be considered parts of the same source, the Linde H_2 Plant (formerly BOC) and the Refinery would have to be, at a minimum, "contiguous or adjacent." Plainly they are not contiguous as they are located several miles apart. The commenter argues that despite the distance between them they should be considered adjacent because of the functional relationship between them. However, the Sixth Circuit has recently confirmed that the term "adjacent" refers exclusively to physical proximity, not functional relationships. *Summit Petroleum Corp. v. USEPA*, Case Nos. 09-4348, 10-4572, (6^{th} Cir, August 7, 2012). Further, the *Summit* case makes clear that the presence of a pipeline connection between the two sites is not alone sufficient to make them adjacent. The two sites must be close together. The Linde plant is located approximately four (4) miles from the BPH refinery on a plot of land that is actually contiguous to another refinery, the Toledo Refining Company. Under these circumstances Linde cannot be considered to be adjacent to the BPH Refinery.

In addition, the Linde plant cannot be considered to be a support facility for, or to be under the control of, the BPH refinery since it is providing hydrogen to both the BPH Refinery and the Toledo Refining Co.

<u>Comment 31</u>: The application improperly assumes that increased utilization does not trigger PSD BACT *(NRDC Comments at p.30-31)*

<u>Response</u>: The NSR rules specifically provide that BACT applies only to an "emissions unit at which a net emissions increase in thepollutant would occur as a result of a physical change or change in the method of operation in the unit." OAC 3745-31-15(D); 42 CFR 52.21(j)(3). The rules also provide that increased utilization, by itself, is not a physical change or change in the method of operation. OAC 3745-31-01(JJJ)(5)(f); 40 CFR 52.21(b)(2)(iii)(*f*).

Comment 32: Controls proposed fail to satisfy BAT *(NRDC Comments at pp. 31-36)***.**

Response:

Comment 33: Emissions from diluent processing were omitted

Response: This project is a crude substitution project. It will not increase the ability of the refinery to process heavy crude oil. Rather, the TFO project will enable the refinery to substitute one type of heavy crude oil for another. Diluent commonly is mixed with heavy crude oil to facilitate the transportation of the material through pipelines. The diluent may consist of light synthetic crudes that the refinery is already processing or LPG condensates or gasoline range material similar to the blending components made at the refinery. Since the refinery is already processing a comparable volume of heavy crude oils that contain diluents, the refinery does not have to invest in additional equipment or seek permit modifications to handle the diluent that is comingled with the heavy crude. Any diluent material that is received with the crude will be processed along with other components of the crude and will be included in the refinery products. It will therefore have no impact on refinery emissions beyond what is characteristic of the crude slate as a whole. These impacts are fully accounted for in the netting calculations for this permit. The crude processing capacity of the refinery will not change as a result of the TFO project.

Exhibit 1

[Revised Cost Eval*uat*ion for SCR (add on control)]

BAT Cost Calculations

BP Toledo - SCR Cost Analysis (Crude 1 furnace 450 mmbtu/hr total) Total Capital Investment (updated 7-11-13)		
SCR System for NOx removal from 40 ppm to 4 ppm		
Item	**Basis**	**Cost**
Direct Costs		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	$2,750,722
Ammonia Storage and Pumping	*SCR quote of $3MM for a 520 MMBtu/hr furnace has been scaled to TFO furnace using ratio of sizes raised to 0.6 power.*	Incl. in above
Initial Catalyst Charge		Incl. in above
(a) Total Equipment		$2,750,722
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$137,536
(c) Sales Tax (0.06 x [1a]) (revised per OEPA comment)	OAQPS, Sect. 1, Table 2.4	$0
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.4	$275,072
Total Purchased Equipment Cost, PEC [1a thru 1d]		$3,163,331
(2) Direct Installation (0.083 *100/23 * PEC)	Peters & Timmerhaus, 1991	$1,141,550
(3) Instrumentation Controls (installed) (0.02 *100/23 * PEC)	P & T, 1991	$275,072
(4) Piping (installed) (0.073 *100/23 * PEC)	P & T, 1991	$1,004,014
(5) Electrical (installed) (0.046 *100/23 * PEC)	P & T, 1991	$632,666
TOTAL DIRECT COST (TDC) (1thru 5)		$6,216,633
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$310,832
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$621,663
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$310,832
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$497,331
TOTAL INDIRECT COST (TIC) (6+7)		$1,740,657
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$1,193,593
Total Plant Cost (TIC + TDC + Cont.)		**$9,150,883**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$183,018
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$9,333,901**

BAT Cost Calculations

BP Toledo BAT Cost Effectiveness Analysis for SCR (Crude 1)

Total Capital Investment (updated 7-11-13)

Unit Characteristics

Crude 1 Heater Firing Rate	MMBtu/hr	=	450
H	= annual operating hours	=	8,760
	(1) Purchased Equipment		
Catalyst Cost for one charge	URS Estimate		82,212
NO_x removal by SCR control	= tpy NO_x	=	70.96
N (Ammonia requirement, ton/yr)	= (tpy NO_x removed) (MW NH_3, 17/ MW NO_x, 46)	=	26.22

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$9,333,901
B. Direct Annual Costs, $/yr			
1. Operating labor	Revised per EPA comment. $0 per OAQPS	=	$0
2. Supervisory labor	Revised per EPA comment. = (0.15) x (operating labor)	=	$0
3. Maintenance labor and materials	= (0.015 * TCI); OAQPS Eq 2.46	=	$140,009
4. Catalyst replacement	Revised per EPA comment. = Cost x FWF (OAQPS Eq 2.52); 7% x [1/(1 + 7%)^5 years -1)]	=	$14,296
5. Catalyst disposal	Not addressed in this analysis.	=	$0
6. Ammonia (anhydrous)	= (N) x ($425/ ton)	=	$11,145
7. Electrical	OAQPS Eq 2.9	=	$116,938
TOTAL DIRECT COSTS			**$282,388**
C. Indirect Annual Costs, $/yr			
1. Overhead	Revised per EPA comment.	=	$0
2. Property Taxes, insurance, admin.	Revised per EPA comment.	=	$0
3. Capital recovery	Revised per EPA comment. = (0.0944) x [total capital investment - catalyst replacement cost)]; OAQPS Eq 2.52: 7% x [1/(1 + 7%)^20 years -1)]	=	$873,359
TOTAL INDIRECT COSTS			**$873,359**
Total Annual cost	**= (Direct Annual Costs) + (Indirect Annual Costs)**	**=**	**$1,155,747**

Cost Effectiveness

NOx Emissions from Unit without SCR	= tpy NOx	=	78.8
NOx Removal from SCR	= tpy NOx, 90% of uncontrolled	=	71.0
Cost Effectiveness	***$/tons NOx***	=	***$16,288.22***

- The capital recovery factors assumes a 20 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

BAT Cost Calculations

BP Toledo - SCR Cost Analysis (Vacuum 1 Furnace - 150 MMBtu/hr) Total Capital Investment		
SCR System for NOx removal from 40 ppm to 4 ppm		
Item	**Basis**	**Cost**
Direct Costs		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	$1,422,899
Ammonia Storage and Pumping	*SCR quote of $3MM for a 520 MMBtu/hr furnace has been scaled to TFO furnace using ratio of sizes raised to 0.6 power.*	Incl. in above
Initial Catalyst Charge		Incl. in above
(a) Total Equipment		$1,422,899
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	$71,145
(c) Sales Tax (0.06 x [1a]) (revised per OEPA comment)	OAQPS, Sect. 1, Table 2.4	$0
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.4	$142,290
Total Purchased Equipment Cost, PEC [1a thru 1d]		$1,636,334
(2) Direct Installation (0.083 *100/23 * PEC)	Peters & Timmerhaus, 1991	$590,503
(3) Instrumentation Controls (installed) (0.02 *100/23 * PEC)	P & T, 1991	$142,290
(4) Piping (installed) (0.073 *100/23 * PEC)	P & T, 1991	$519,358
(5) Electrical (installed) (0.046 *100/23 * PEC)	P & T, 1991	$327,267
TOTAL DIRECT COST (TDC) (1thru 5)		$3,215,751
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$160,788
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	$321,575
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	$160,788
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	$257,260
TOTAL INDIRECT COST (TIC) (6+7)		$900,410
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	$617,424
Total Plant Cost (TIC + TDC + Cont.)		**$4,733,586**
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	$94,672
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		**$4,828,258**

BAT Cost Calculations

BP Toledo BAT Cost Effectiveness Analysis for SCR (Vacuum 1)

Unit Characteristics

Vac 1 Heater Firing Rate	MMBtu/hr	=	150
H	= annual operating hours	=	8,760
Catalyst Cost for one charge	URS Estimate		21,635
NO_x removal by SCR control	= tpy NO_x	=	23.65
N (Ammonia requirement, ton/yr)	= (tpy NO_x removed) (MW NH_3, 17/ MW NO_x, 46)	=	8.74

Costs

A. Total capital investment, $	See Separate TCI Spreadsheet	=	$4,828,258
B. Direct Annual Costs, $/yr			
1. Operating labor	Revised per EPA comment. $0 per OAQPS	=	$0
2. Supervisory labor	Revised per EPA comment. = (0.15) x (operating labor)	=	$0
3. Maintenance labor and materials	= (0.015 * TCI); OAQPS Eq 2.46	=	$72,424
4. Catalyst replacement	Revised per EPA comment. = Cost x FWF (OAQPS Eq 2.52); 7% x [1/(1 + 7%)^5 years -1)]	=	$3,762
5. Catalyst disposal	Not addressed in this analysis.	=	$0
6. Ammonia (anhydrous)	= (N) x ($425/ ton)	=	$3,715
7. Electrical	OAQPS Eq 2.9	=	$116,938
TOTAL DIRECT COSTS			**$196,839**
C. Indirect Annual Costs, $/yr			
1. Overhead	Revised per EPA comment.	=	$0
2. Property Taxes, insurance, admin.	Revised per EPA comment.	=	$0
3. Capital recovery	Revised per EPA comment. = (0.0944) x [total capital investment - catalyst replacement cost)]; OAQPS Eq 2.52: 7% x [1/(1 + 7%)^20 years -1)]	=	$453,745.20
TOTAL INDIRECT COSTS			**$453,745**
Total Annual cost	**= (Direct Annual Costs) + (Indirect Annual Costs)**	**=**	**$650,584**

Cost Effectiveness

NOx Emissions from Unit without SCR	= tpy NOx	**=**	26.3
NOx Removal from SCR	= tpy NOx, 90% of uncontrolled	**=**	23.7
Cost Effectiveness	***$/tons NOx***	**=**	***$27,506.51***

- The capital recovery factors assumes a 20 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

FINAL

Division of Air Pollution Control
Permit-to-Install
for
BP-Husky Refining LLC

Facility ID:	0448020007
Permit Number:	P0111667
Permit Type:	Initial Installation
Issued:	9/20/2013
Effective:	9/20/2013

Division of Air Pollution Control
Permit-to-Install
for
BP-Husky Refining LLC

Table of Contents

Authorization

Facility ID:	0448020007
Facility Description:	Toledo Refinery
Application Number(s):	M0001680, A0045758, A0046815
Permit Number:	P0111667
Permit Description:	Modifications to a petroleum refinery to increase the flexibility to process a higher percentage of alternative crude oil feedstocks.
Permit Type:	Initial Installation
Permit Fee:	$11,850.00
Issue Date:	9/20/2013
Effective Date:	9/20/2013

This document constitutes issuance to:

BP-Husky Refining LLC
4001 Cedar Point Road
P.O. Box 696
Oregon, OH 43697

of a Permit-to-Install for the emissions unit(s) identified on the following page.

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Toledo Department of Environmental Services
348 South Erie Street
Toledo, OH 43604
(419)936-3015

The above named entity is hereby granted a Permit-to-Install for the emissions unit(s) listed in this section pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Scott J. Nally
Director

Authorization (continued)

Permit Number: P0111667
Permit Description: Modifications to a petroleum refinery to increase the flexibility to process a higher percentage of alternative crude oil feedstocks.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

Emissions Unit ID: **B019**
Company Equipment ID: Crude/Vac 2 Furnace
Superseded Permit Number: P0111328
General Permit Category and Type: Not Applicable

Emissions Unit ID: **B029**
Company Equipment ID: ADHT Furnace
Superseded Permit Number: 04-01346
General Permit Category and Type: Not Applicable

Emissions Unit ID: **B032**
Company Equipment ID: Coker 3 Furnace
Superseded Permit Number: 04-01471
General Permit Category and Type: Not Applicable

Emissions Unit ID: **B039**
Company Equipment ID: TBD
Superseded Permit Number:
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P009**
Company Equipment ID: Sulfur Recovery Unit #1
Superseded Permit Number: P0107122
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P011**
Company Equipment ID: Crude/Vac 1
Superseded Permit Number: P0110958
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P025**
Company Equipment ID: Refinery WWT System
Superseded Permit Number: P0103974
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P028**
Company Equipment ID: "A" Train Diesel Hydrotreater
Superseded Permit Number: 04-708
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P036**
Company Equipment ID: Coker 3
Superseded Permit Number: 04-01471
General Permit Category and Type: Not Applicable

Emissions Unit ID: **P037**
Company Equipment ID: Sulfur Recovery Unit #2 and #3
Superseded Permit Number: P0107122
General Permit Category and Type: Not Applicable

Emissions Unit ID:	**P038**
Company Equipment ID:	TRP Amine Treater
Superseded Permit Number:	04-1046
General Permit Category and Type:	Not Applicable

Group Name: Coker II & Naptha Treater Heater

Emissions Unit ID:	**B017**
Company Equipment ID:	Coker II Heater
Superseded Permit Number:	04-01290
General Permit Category andType:	Not Applicable
Emissions Unit ID:	**B022**
Company Equipment ID:	Naphtha Treater Heater
Superseded Permit Number:	04-01290
General Permit Category andType:	Not Applicable

Group Name: Crude 1 A & B Furnaces

Emissions Unit ID:	**B037**
Company Equipment ID:	TBD
Superseded Permit Number:	
General Permit Category andType:	Not Applicable
Emissions Unit ID:	**B038**
Company Equipment ID:	TBD
Superseded Permit Number:	
General Permit Category andType:	Not Applicable

A. Standard Terms and Conditions

1. **Federally Enforceable Standard Terms and Conditions**

   a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under State law only:

      (1) Standard Term and Condition A.2.a), Severability Clause

      (2) Standard Term and Condition A.3.c) through A. 3.e)General Requirements

      (3) Standard Term and Condition A.6.c) and A. 6.d), Compliance Requirements

      (4) Standard Term and Condition A.9., Reporting Requirements

      (5) Standard Term and Condition A.10., Applicability

      (6) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install

      (7) Standard Term and Condition A.14., Public Disclosure

      (8) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

      (9) Standard Term and Condition A.16., Fees

      (10) Standard Term and Condition A.17., Permit Transfers

2. **Severability Clause**

   a) A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

   b) All terms and conditions designated in parts B and C of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under State law only, only if specifically identified in this permit as such.

3. **General Requirements**

   a) The permittee must comply with all terms and conditions of this permit. Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification.

b) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the federally enforceable terms and conditions of this permit.

c) This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

d) This permit does not convey any property rights of any sort, or any exclusive privilege.

e) The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

4. Monitoring and Related Record Keeping and Reporting Requirements

a) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

(1) The date, place (as defined in the permit), and time of sampling or measurements.

(2) The date(s) analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of such analyses.

(6) The operating conditions existing at the time of sampling or measurement.

b) Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c) Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

(1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Toledo Department of Environmental Services.

(2) Quarterly written reports of (i) any deviations from federally enforceable emissionlimitations, operationalrestrictions, andcontroldeviceoperatingparameterlimitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Toledo Department of Environmental Services. The written reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

(3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, andreportingrequirements contained in this permit shall be submitted (i.e., postmarked) to the Toledo Department of Environmental Services every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

(4) This permit is for an emissions unit located at a Title V facility. Each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

d) The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

5. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the Toledo Department of Environmental Services in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

6. Compliance Requirements

a) The emissions unit(s) identified in this Permit shall remain in full compliance with all applicable State laws and regulations and the terms and conditions of this permit.

b) Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

c) Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

(1) At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

(3) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

(4) As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

d) The permittee shall submit progress reports to the Toledo Department of Environmental Services concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

(1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

(2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

7. Best Available Technology

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

8. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

9. Reporting Requirements

The permittee shall submit required reports in the following manner:

a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Toledo Department of Environmental Services.

b) Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the Toledo Department of Environmental Services. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

10. Applicability

This Permit-to-Install is applicable only to the emissions unit(s) identified in the Permit-to-Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s).

11. Construction of New Sources(s) and Authorization to Install

a) This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.

b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended by up to 12 months if application is made to the Director within a reasonable time before the termination date and the party shows good cause for any such extension.

c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as “permanently shut down” in Ohio EPA’s “Air Services” along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update will constitute notifying of the permanent shutdown of the affected emissions unit(s).

d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

No emissions unit certified by the authorized official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31.

e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or other any reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

12. Permit-To-Operate Application

The permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77. The permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if the proposed new or modified source(s) would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification must be obtained before the operation of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d).

13. Construction Compliance Certification

The applicant shall identify the following dates in the online facility profile for each new emissions unit identified in this permit.

a) Completion of initial installation date shall be enteredupon completion of construction and prior to start-up.

b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

14. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly (i.e., postmarked), by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

16. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

17. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the “Owner/Contact Change” functionality in Air Services once the transfer is legally completed.The change must be submitted through Air Services within thirty days of the ownership transfer date.

18. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

19. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

B. Facility-Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

   a) None.

2. The following emissions units contained in this permit are subject to 40 CFR Part 60 Subpart A and J: B017, B019, B022, B029, B032, P009, and P037. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency

3. The following emissions units contained in this permit are subject to 40 CFR Part 60 Subpart A and Ja: P036, B037, B038 and B039. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency.

4. The following emissions units contained in this permit are subject to 40 CFR Part 60 Subpart A and GGGa: P009, P011, P025, P028, P036, and P038. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency.

5. The following emissions unit contained in this permit is subject to 40 CFR Part 60 Subpart A and QQQ: P025. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the appropriate Ohio EPA district or local air agency.

6. The following emissions unit contained in this permit is subject to 40 CFR Part 60 Subpart A and NNN: P036. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency.

7. The following emissions unit contained in this permit is subject to 40 CFR Part 61 Subpart A and FF: P025. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gpoaccess.gov or by contacting the appropriate Ohio EPA district or local air agency.

8. The following emissions units contained in this permit are subject to 40 CFR Part 63 Subpart A and CC: P009, P011, P025, P028, P036, P037 and P038. The complete NSPS and MACT requirements, including the MACT General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency.

9. The following emissions units contained in this permit are subject to 40 CFR Part 63 Subpart A and DDDDD: B017. B019, B022, B029, B032, B037, B038, and B039. The complete NSPS and MACT requirements, including the MACT General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website http://ecfr.gov or by contacting the appropriate Ohio EPA district or local air agency.

10. Interim sulfur dioxide (SO_2) limits

a) Applicable Emissions Limitations and/ or Control Requirements

(1) Interim SO_2 limit for B036, Reformer 3 heater

Beginning on the effective date of this permit, and continuing until the earlier of (a) the initial startup of the new Crude 1 Heaters (B037 and B038) and new Vacuum 1 Heater (B039) or (b) December 31, 2015, the SO_2 emissions from the Reformer 3 heater (B036) shall not exceed 30 tons SO_2 per year, as a rolling, 12-month summation of the monthly emissions. Thereafter, except as provided in paragraphs a)(2) and a)(3) below, the SO_2 emissions shall not exceed the level established in Permit to Install P0103694 issued on August 7, 2009 (38.00 tons per rolling, 12-month period).

(2) Interim Multi-Unit SO_2 Emission Limit

Beginning on the date of initial startup of heaters B037, B038 and B039 and continuing until the later of (a) fifteen (15) months thereafter, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant being constructed as part of the Toledo Feedstock Optimization Project, the total combined SO_2 emissions from the units listed below shall not exceed 207.5 tons SO_2 per year as a rolling, 12-month summation of the monthly emissions.

B030	BGOT Heater
B033	East BGOT Heater
B015	Existing Crude 1 Heater
B031	Existing Vacuum 1 Heater
B037/B038	Replacements For Crude 1 Heater
B039	Replacement Vacuum 1 Heater
B019	Crude Vacuum 2 Heaters
B017	Coker 2 Heater
B032	Coker 3 Heater
B022	Naphtha Hydrotreater Heater
B029	ADHT Heater
B034/B035	Alstom Boilers (Incremental Firing)
B036	Reformer 3 Heater
P009	SRU 1
P037	SRU 2&3

(3) Beginning the later of (a) fifteen (15) months after initial startup of heaters B037, B038 and B039 or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant being constructed as part of the Toledo Feedstock Optimization Project, SO_2 emissions from the following heaters shall not exceed the limits included in Table 1:

Table 1 – Individual SO_2 emission Limits

Heater	Tons SO_2 Per Rolling, 12-Month Period
B017, Coker 2 Heater	3.64
B019, Crude Vacuum 2 Heater	12.15
B022, Naphtha Hydrotreater Heater	3.64
B032, Coker 3 Heater	11.64
B036, Reformer 3 Heater	22.8
B029, ADHT Heater	0.94

(4) For purposes of clarity, the first month used in a 12-month rolling average compliance period is the calendar month in which the emission limitation becomes effective, and the first complete 12-month rolling average compliance period is 12 calendar months later (e.g., for a limit effective on January 15, the first month in the period is January and the first complete 12-month period ends on the 31st of the following December).

(5) Individual emission limits established in the previous permits for emission units B015, B030, B031, B033, B034, and B035 remain unchanged.

b) Operational Restrictions

(1) The Crude 1 (B015) and Vacuum 1 (B031) heaters shall be permanently shut down within 180 days after the initial startup of heaters B037, B038 and B039.

(2) [40 CFR 63.7500(a) – Table 3(3)]

An existing process heater located at a major source facility must perform a one-time energy assessment on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements Table 3 in the Appendices of 40 CFR 63 Subpart DDDDD satisfies this requirement. The assessment shall be completed by January 31, 2016 unless otherwise required or allowed by 40 CFR Part 63, Subpart DDDDD.

c) Monitoring and/or Recordkeeping Requirements

(1) By no later than the date of initial startup of heaters B037, B038 and B039, the permittee shall install, calibrate, operate, and maintain instrumentation to monitor and record the concentration by volume (dry basis) of total sulfur (expressed as SO_2) in the refinery fuel gas burned in each of the heaters and boilers listed in a)(2) (except for the Reformer 3 Heater (B036) and the ADHT heater (B029) during periods in which it is firing fuel gas from the East Side Mix Drum). Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of total sulfur in the fuel gas being burned. Such

continuous monitoring and recording equipment shall be installed operated and calibrated pursuant to the requirements specified in ASTM D7166-10, 40 CFR Part 60 Appendices A and F, the applicable performance specification test of 40 CFR Part 60 Appendix B, and the portions of 40 CFR 63.13 applicable to CEMs, except that the requirements of e)(2) of this permit shall apply in lieu of the requirements of 40 CFR Part 60 Appendix F §§5.1.1, 5.1.3 and 5.1.4. Data from the continuous total sulfur analyzer(s) shall be used to demonstrate and report compliance with the SO_2 emissions limitations in a)(1), a)(2), and a)(3).

At least 45 days before commencing certification testing of the continuous total sulfur expressed as SO_2 monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of total sulfur expressed as SO_2 emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F except that the requirements of e)(2) of this permit shall apply in lieu of the requirements of 40 CFR Part 60 Appendix F §§5.1.1, 5.1.3 and 5.1.4. The quality assurance/quality control plan and a logbook dedicated to the continuous total sulfur (expressed as SO_2) monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits, relative accuracy audits (RAAs), and/or relative accuracy test audits (RATAs) in units of the standard(s), in accordance with and at the frequencies specified in e)(2).

Each continuous monitoring system consists of all the equipment used to acquire data and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

The permittee shall maintain documentation from Ohio EPA that the continuous total sulfur monitoring system has been certified in accordance with test methods contained in 40 CFR Part 60, Appendix B, or other test methods as approved by Ohio EPA, Central Office. The letter of certification shall be made available to the Ohio EPA upon request.

The permittee shall maintain records of all data obtained by the continuous total sulfur monitoring system including, emissions of total sulfur in units of the applicable standards in the appropriate averaging period, results of daily zero/span calibration checks, and magnitudes of manual calibration adjustments.

(2) The permittee shall maintain records of all data obtained by the continuous total sulfur monitor expressed as $SO_{2,}$ including, but not limited to:

a. concentration of SO_2 in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. results of quarterly cylinder gas audits;

c. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

d. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

e. hours of operation of the emissions unit, and continuous total sulfur monitoring system;

f. the date, time, and hours of operation of the emissions unit without the continuous total sulfur monitoring system;

g. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous total sulfur monitoring system; as well as,

h. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(3) For the period during which the Interim Multi-Unit SO_2 Emission Limit established by a)(2) is in effect, the permittee shall record and maintain records of:

a. The volume of fuel burned in each of the heaters listed in a)(2) in standard cubic feet per day and the mix drum from which that fuel gas originates. If a heater draws fuels gas from more than one mix drum, the amount of fuel gas burned from each mix drum shall be recorded and maintained separately. ;

b. the daily average total sulfur concentration (expressed as SO_2) in the fuel gas burned in each of the heaters listed in a)(2);

c. the daily total SO_2 emissions from each such heater, listed in a)(2), calculated in accordance with e)(1)c;

d. the monthly average SO2 emissions from SRU 1, 2 and 3 (P009 and P037) calculated in accordance with e)(1)c.iv; and

e. the total combined SO_2 emissions for all emissions units listed in a)(2) for the calendar month and for the rolling, 12-month period calculated in accordance with e)(1)c.

(4) After the individual SO_2 emission limitations in a)(3), Table 1 become effective, the Permittee shall record and maintain records of:

a. The volume of fuel burned in each of the heaters listed in a)(3) in standard cubic feet per day and the mix drum from which that fuel gas originates. If a heater draws fuels gas from more than one mix drum, the amount of fuel gas burned from each mix drum shall be recorded and maintained separately;

b. the daily average total sulfur concentration (expressed as SO_2) in the fuel gas burned in each of the heaters listed in a)(3), and (ii) the daily, monthly and rolling

12-month total SO_2 emissions from each heater listed in a)(3) calculated in accordance with e)(1)(d)-(h), as applicable; and

c. the daily average H_2S concentration in the fuel gas burned in the Reformer 3 Heater (P036), and any other such heater listed in a)(3) that burns fuel gas from the East Side Mix Drum, and (ii) the daily, monthly and rolling 12-month total SO_2 emissions from each such heater listed in a)(3) calculated in accordance with e)(1)(a) –(h) as applicable.

d) Reporting Requirements

(1) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

(2) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. all exceedances of the rolling, 12-month emission limitations for SO_2 specified in 10.a).

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

b. The permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of SO_2 emissions in excess of the emission limits in a)(1), a)(2) or a)(3). The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

c. These quarterly reports shall be submitted within 30 days of the end of the quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous total sulfur monitor;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total SO_2 emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous total sulfur monitoring system while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous total sulfur monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous total sulfur monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous total sulfur monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

e) Testing Requirements

(1) Compliance with the emission limitation(s) in a)(1), a)(2) and a)(3) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation

Reformer 3 Heater (B036) emissions shall not exceed 30 tons SO_2 per year, as a rolling 12-month summation of the monthly emissions during the period specified in a)(1).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

Where:

Fuel total sulfur = Concentration of the H_2S measured in the fuel fired plus a 35 ppmv allowance for non-H_2S sulfur based on past testing at the BP-Husky refinery, or more recent test value if future testing is performed.

b. Emission Limitation

Reformer 3 Heater (B036) shall not exceed 22.8 tons SO_2 per year as a rolling 12-month summation of the monthly emissions during the period specified in a)(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

Where:

Fuel total sulfur = concentration of the H_2S measured in the fuel fired plus a 35 ppmv allowance for non-H_2S sulfur based on past testing at the BP-Husky refinery, or a more recent test value if future testing is performed.

c. Emission Limitation

The total combined SO_2 emissions from the emissions units listed in a)(2) shall not exceed 207.5 tons SO_2 per year as a rolling, 12-month summation of the monthly emissions during the period specified in a)(2).

Applicable Compliance Method:

i. Alstom Boiler (B034 & B035) incremental emissions of SO_2 shall be calculated by dividing the Alstom boiler incremental firing rate (mmBtu/day) by the fuel heating value (btu/scf) multiplying by the daily average total sulfur in the fuel (ppmv) as recorded by the total sulfur continuous emissions monitoring system, dividing by the constant 379 (scf/lbmole), and multiplying by the molecular weight of SO_2 64 lbs/lbmole. Sum the daily emissions for each day in the month to determine the monthly SO_2 emissions. Add the monthly SO_2 emissions for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

For this calculation, the Alstom Boiler incremental firing rate shall be equal to 2328 mmBtu/day until the initial start-up of the modifications to the Coker Gas Plant and equal to 3624 mmBtu/day thereafter.

ii. Calculate the Reformer 3 Heater (B036) SO_2 emissions by multiplying the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in (scf sulfur / mmscf fuel), multiplying by the molecular weight of SO_2 (64 lbs/lbmole) and dividing by the conversion of 379 (scf/lbmole) which is based on standard conditions at 60° F and 14.7 psia. Sum the daily emissions for each day in the month to determine the monthly SO_2 emissions. Add the monthly SO_2 emissions for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

Where:

Fuel total sulfur = actual concentration of the H_2S in the fuel fired as measured by the H_2S continuous emissions monitoring system (CEMS) plus a 35 ppmv allowance for non-H_2S sulfur from past testing or more recent test value if future testing is performed.

35 ppmv non-H_2S sulfur is based on past testing at the BP-Husky refinery

iii. For other Heaters listed in a)(2), SO_2 emissions shall be calculated by multiplying the daily fuel burned (mmscf) by the daily average concentration of the total sulfur in the fuel fired (scf sulfur/ mmscf fuel) divided by the constant 379 (scf/lbmole) and multiplied by the molecular weight of SO_2 64 lbs/lbmole. Sum the daily emissions for each day in the month to determine the monthly SO_2 emissions. Add the monthly SO_2 emissions for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

Where:

The daily average concentration of sulfur in the fuel fired (a) from the East Side Mix Drum shall be actual concentration of the H_2S in the fuel fired as measured by the H_2S continuous emissions monitoring system (CEMS) plus a 35 ppmv allowance for non-H_2S sulfur from past testing or more recent test value if future testing is performed and (b) from all other source shall be the daily average total sulfur concentration as recorded by the relevant total sulfur continuous monitoring system..

iv. SO_2 emissions from SRU 1, 2, and 3 (P009 and P037) of a)(2) shall be calculated by using the monthly average SO_2 concentration from the CEMS and the calculated monthly total gas flow to determine the monthly total SO_2 emissions. Add the monthly SO_2 emissions for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period

d. Coker 2 heater (B017) shall not exceed 3.64 tons SO_2 per year as a rolling, 12-month summation of the monthly emissions beginning on the date specified in a.(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

e. Emission Limitation

Naphtha Treater Heater (B022) emissions shall not exceed 3.64 tons per year as a SO_2 per rolling, 12-month summation of the monthly emissions beginning on the date specified in a.(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

f. Emission Limitation

Crude Vac 2 (B019) emissions shall not exceed 12.15 tons per year SO_2 as a rolling 12-month summation of the monthly emissions beginning on the date specified in a.(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2

g. Emission Limitation

Coker 3 Heater (B032) shall not exceed 11.64 tons SO_2 per rolling, 12-months period, beginning on the date specified in a.(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

h. Emission Limitation

ADHT Heater (B029) shall not exceed 0.94 tons SO_2 per rolling, 12-months period, beginning on the date specified in a.(3).

Applicable Compliance Method:

The permittee shall demonstrate compliance with the allowable SO_2 emission limitation above as follows:

i. multiply the daily fuel burned (mmscf) by the daily average concentration of the fuel total sulfur (ppmv) in scf sulfur / mmscf fuel;

ii. multiply i. above by the molecular weight of SO_2 (64 lbs/lbmole), and then divide by the conversion factor of 379 (scf/lbmole), which is based on standard conditions at 60° F and 14.7 psia;

iii. sum the daily emissions from ii. above for each day in the month to determine the monthly SO_2 emissions; and

iv. add the monthly SO_2 emissions from iii. above for the current month to the SO_2 emissions for the previous 11 months to determine the SO_2 emissions per rolling, 12-month period.

Fuel total sulfur when burning ESMD refinery fuel gas shall equal the actual concentration of the H_2S in the fuel fired as measured by the H_2S continuous emissions monitoring system (CEMS) plus a 35 ppmv allowance for non-H_2S sulfur from past testing or more recent test value if future testing is performed. 35 ppmv non-H_2S sulfur is based on past testing at the BP-Husky refinery

Fuel total sulfur when burning other refinery fuel gas shall be based on the continuous total sulfur analyzer for that fuel gas.

(2) Within 60 days of installation and at least once every three (3) years thereafter, the permittee shall conduct a RAA or RATA of each the continuous total sulfur (expressed as SO_2) monitoring system to demonstrate compliance with ORC section 3704.03(I). The Permittee shall also conduct cylinder gas audits each calendar quarter in which a RAA or RATA is not performed. For RAA and RATA reference method comparisons, the most current version of either ASTM D3246 or D6667, or other test method approved by Ohio EPA Central Office shall be used as the reference method.

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous total sulfur expressed as SO_2 monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of the most current version of either ASTM D3246, D6667, or other test method approved by Ohio EPA Central Office; and ORC section 3704.03(I).

C. Emissions Unit Terms and Conditions

1. B019, Crude/Vac 2 Furnace

Operations, Property and/or Equipment Description:

Crude Vac 2 Furnace 258 mmBtu per hr Higher Heating Value basis

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	Nitrogen oxides (NO_x) emissions shall not exceed 262.8 tons per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 21.02 tons per rolling, 12-month period. See b)(2)a., b)(2)b., b)(2)h., and b)(2)i. See section B.10.a)(2), and B.10.a.(3)
b.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule.
c.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1).
d.	OAC rule 3745-18-54(W)(1)	See b)(2)e.
e.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)f., b)(2)g., and b)(2)h.
f.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 60.101 This emissions unit is a fuel gas combustion device located at a	See b)(2)c. and b)(2)d. [60.104(a)(1)]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	petroleum refinery and subject to the applicable emissions limitations/ control requirements specified in this section.]	
g.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 16)	See b)(2)i.
h.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480-7575) [In accordance with 63.7575, this emissions unit is in the ”unit designed to fire gas 1 fuels”subcategory existing process heater located at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)i., c)(3), and c)(4) (63.7500(a) Table 3 requirements)

(2) Additional Terms and Conditions

a. Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, this sulfur dioxide (SO_2) emissions limit of 21.02 tpy and all of its monitoring, record keeping and reporting requirements shall expire and sulfur dioxide (SO_2) emissions from this emissions unit shall not exceed 12.15 tons per rolling, 12-month period.

Section B.10.c) and 10.d) of this permit outlines the monitoring, record keeping, reporting, and compliance demonstration required to maintain compliance with the new SO_2 limit.

b. Permit to Install 04-01290 issued 7/25/2002 incorporated the emission limits and schedules set out in paragraphs 14-18 and 21 of the Consent Decree (United States of America, et al., v. BP Exploration & Oil Co., et al., Civil Action No. 2:96CV095 RL, Date of Entry 8/29/2001) that require this emissions unit to be subject to the requirements of 40 CFR 60 Subpart J.

c. The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA-recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis. Pursuant to the fuel gas definition in 40 CFR 60.101(d), this standard is also applicable if the permittee combines and combusts natural gas or liquefied petroleum (LP) gas in any proportion with refinery fuel gas in this emissions unit.

d. The permittee may choose to comply with the applicable provisions of 40 CFR Part 60, Subpart Ja to satisfy the requirements of this subpart for this emissions unit.

e. The emission limitation specified by OAC 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.104(a)(1).

f. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

g. Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendix F, the permittee shall maintain a written quality assurance/quality control plan for the continuous hydrogen sulfide monitoring system, designed to ensure continuous valid and representative readings of hydrogen sulfide emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

[40 CFR 60.13] and [40 CFR Part 60, Appendix F]

h. Pursuant to 40 CFR 60.2 and 40 CFR Part 60, Appendix F, the continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

i. This emissions unit is subject to the initial notification requirements of 40 CFR 63 Subpart DDDDD (Boiler MACT) as outlined in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, SSMP, or site-specific monitoring plans requirements of Subpart DDDDD or any other requirements in 40 CFR 63 Subpart A).

c) Operational Restrictions

(1) The permittee shall burn only refinery fuel gas, natural gas, or LP gas in this emissions unit.

(2) The quality of the natural gas, LP gas and/or refinery fuel gas burned in this emissions unit shall meet, on an “as burned” basis, a sulfur content that is sufficient to comply with the allowable hydrogen sulfide emission limitation of 0.10 grain per dry standard cubic foot as a volume-weighted, rolling 3-hour average.

(3) [40 CFR 63.7500(a) – Table 3(2)]

An existing process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the boiler or process heater as specified in § 63.7540(a)(10) or (a)(12). Pursuant to 63.7540(a)(13), If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) Each month, the permittee shall monitor and record the daily average volumetric firing rate in units of standard cubic feet per hour. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total NO_x emission rates in units of tons in accordance with the procedure outlined in section f).

(3) In order to demonstrate compliance with the emission limitation of 230 mg/dscm (0.10 grain/dscf or 162 parts per million by volume dry basis) of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)b. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows

a. The span value for this instrument shall be 425 mg/dscm of H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(4) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendix B, the permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous hydrogen sulfide monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. The letter/document of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(5) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendices B & F, the permittee shall operate and maintain equipment to continuously monitor and record hydrogen sulfide content of the fuel burned in this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous hydrogen sulfide monitoring system including, but not limited to:

a. hydrogen sulfide content of the fuel burned in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. hydrogen sulfide content of the fuel burned, in units of the applicable standard(s) and in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous hydrogen sulfide monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous hydrogen sulfide monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous hydrogen sulfide monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(6) In order to demonstrate compliance with the 21.02 tons SO_2 per rolling, 12-month period emission limitation, the permittee shall monitor and record the monthly average volumetric firing rate in units of standard cubic feet per month. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total SO_2 emission rates in units of tons in accordance with the procedure outlined in section f).

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, this term and condition will become void and the terms and conditions of Section B.10.a)(3) will become applicable.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas, LP gas, or refinery fuel gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall submit quarterly deviation (excursion) reports that identify each month all exceedances of the following allowable emission limitations:

a. 262.8 tons NO_x per rolling, 12-month period; and

b. 21.02 tons SO_2 per rolling, 12-month period.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, term e)(2)b above will become void and the permittee will be required to comply with the terms and conditions of Section B.10.a)(3)

(3) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous hydrogen sulfide monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of hydrogen sulfide content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, emissions unit, and/or control equipment;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(4) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

262.8 tons NO_x per rolling, 12-month period

Applicable Compliance Method:

The NO_x emission limitation above shall be demonstrated as follows:

i. multiply the monthly total gas flow (mmscf) by the monthly average fuel gas heating value (Btu/scf) and then multiply by the most recent NO_x emission factor (lb/mmBtu) determined by stack testing; and

ii. add the monthly total to the total for the previous 11 calendar months to determine the rolling, 12-month total NO_x emissions.

If required, the permittee shall establish a new NO_x emission factor in units of pounds NO_x per million Btu of heat input using Methods 3A, 7E and 19 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

21.02 tons SO_2 per rolling, 12-month period

Applicable Compliance Method:

The SO_2 emission limitation above shall be demonstrated as follows:

i. multiply the monthly average H_2S concentration by the monthly total gas flow to determine the lbs H_2S per month;

ii. convert the H_2S to SO_2 at a rate of 34 pounds H_2S to 64 pounds SO_2 emissions; and

iii. add the monthly total to the total for the previous 11 calendar months to determine the rolling, 12-month total SO_2 emissions.

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, term f)(1)b above will become void and be replaced with the terms and conditions of Section B.10.a)(3).

c. Emission Limitation:

The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average H_2S concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA-recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis.

Applicable Compliance Method:

Ongoing compliance with the hydrogen sulfide emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

d. Emission Limitation:

Visible PE shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance using Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

e. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this limit is demonstrated through condition c)(1), which requires the permittee to burn only refinery fuel gas, natural gas, or LP gas in this emissions unit.

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA - approved test methods may be used with prior approval from the Ohio EPA.

g) Miscellaneous Requirements

(1) None.

2. B029, ADHT Furnace

Operations, Property and/or Equipment Description:

A-DHT Furnace – 22.8 mmBtu/hr natural gas, LP gas, and refinery fuel gas fired heater with low NO_x burners

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) (PTI 04-01346 modification issued on 1/18/2007)	Carbon monoxide (CO) emissions shall not exceed 1.88 pounds per hour. Nitrogen oxides (NO_x) emissions shall not exceed 1.60 pounds per hour. Particulate matter emissions less than or equal to 10 microns in diameter (PM10) shall not exceed 0.17 pound per hour. Sulfur dioxide (SO_2) emissions shall not exceed 0.60 pound per hour. Volatile organic compound (VOC) emissions shall not exceed 0.12 pound per hour. See b)(2)a, c and d
b.	OAC rule 3745-31-05(D) (PTI 04-01346 modification issued on 1/18/2007)	CO emissions shall not exceed 7.21 tons per rolling, 12-month period. NO_x emissions shall not exceed 6.13 tons per rolling, 12-month period. PM10 emissions shall not exceed 0.65 ton per rolling, 12-month period. SO_2 emissions shall not exceed 2.32 tons

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		per rolling, 12-month period. VOC emissions shall not exceed 0.47 ton per rolling, 12-month period. See b)(2)b., b)(2)c., and b)(2)i.
c.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule. See c)(1).
d.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1)
e.	OAC rule 3745-18-54(W)(1)	See b)(2)f.
f.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)g. and b)(2)h.
g.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 60.101 This emissions unit is a fuel gas combustion device located at a petroleum refinery that was installed after Jun 11, 1973 and prior to May 14, 2007 and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)d., and b)(2)e. [60.104(a)(1)]
h.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 16)	See b)(2)j. (63.7506(b)
i.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480-7575) [In accordance with 63.7575, this emissions unit is an existing process heater in the ”unit designed to fire gas 1 fuels” subcategory located at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)j., c)(2) and c)(3) (63.7500(a))

(2) Additional Terms and Conditions

a. The requirements of this rule include compliance with the requirements of OAC rules 3745-17-07(A)(1), 3745-17-10(B)(1), OAC rule 3745-31-05(D), and 40 CFR Part 60, Subpart J.

b. The A-DHT Furnace (B029) shall be limited to a maximum firing rate of 175,200 mmBtu per rolling, 12-month period.

c. Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, the sulfur dioxide (SO_2) emissions limits of 2.32 tpy and 0.06 lb/hr and all of its monitoring, record keeping and reporting requirements shall expire and sulfur dioxide (SO_2) emissions from this emissions unitshall not exceed 0.94 ton per rolling, 12-month period.

Section B.10.c) and 10.d) of this permit outlines the monitoring, record keeping, reporting, and compliance demonstration required to maintain compliance with the new limit

d. The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis. Pursuant to the fuel gas definition in 40 CFR 60.101(d), this standard is also applicable if the permittee combines and combusts natural gas or liquefied petroleum (LP) gas in any proportion with refinery fuel gas in this emissions unit.

e. The permittee may choose to comply with the applicable provisions of 40 CFR Part 60, Subpart Ja to satisfy the requirements of this subpart for this emissions unit.

f. The emission limitation specified by OAC 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.104(a)(1).

g. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

h. The permittee shall maintain a written quality assurance/quality control plan for the continuous hydrogen sulfide monitoring system, designed to ensure continuous valid and representative readings of hydrogen sulfide emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

[40 CFR 60.13] and [40 CFR Part 60, Appendix F]

i. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

j. This emissions unit is subject to the initial notification requirements of 40 CFR 63 Subpart DDDDD (Boiler MACT) as outlined in in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, SSMP, and site-specific monitoring plans requirements of Subpart DDDDD or any other requirements in 40 CFR 63 Subpart A).

c) Operational Restrictions

(1) The permittee shall burn only natural gas, LP gas, and refinery fuel gas in this emissions unit.

(2) [40 CFR 63.7500(a) – Table 3(2)]

An existing process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the boiler or process heater as specified in § 63.7540(a)(10) or (a)(12). Pursuant to 63.7540(a)(13), If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type, quantity, and heating value in BTU/dscf of fuel burned in this emissions unit.

(2) The permittee shall monitor and record the daily firing rate in terms of standard cubic feet per day, mmscf per day. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total NO_x emission rates in units of tons in accordance with the procedure outlined in section f).

(3) In order to demonstrate compliance with the emission limitation of 230 mg/dscm (0.10 grain/dscf or 162 parts per million by volume dry basis) of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)b. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows:

a. The span value for this instrument shall be 425 mg/dscm of H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(4) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendix B, the permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous hydrogen sulfide monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. The letter/document of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(5) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendices B & F, the permittee shall operate and maintain equipment to continuously monitor and record hydrogen sulfide content of the fuel burned in this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous hydrogen sulfide monitoring system including, but not limited to:

a. hydrogen sulfide content of the fuel burned in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. hydrogen sulfide content of the fuel burned, in units of the applicable standard(s) and in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous hydrogen sulfide monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous hydrogen sulfide monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous hydrogen sulfide monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(6) In order to demonstrate compliance with the 2.32 tons SO_2 per rolling, 12-month period emission limitation, the permittee shall monitor and record the monthly average volumetric firing rate in units of standard cubic feet per month. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total SO_2 emission rates in units of tons in accordance with the procedure outlined in section f).

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, this term and condition will become void and the terms and conditions of Section B.10.a)(3) will become applicable.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas, LP gas, or refinery fuel gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall submit quarterly deviation (excursion) reports that identify each month when:

a. the firing rate of this emissions unit exceeded 175,200 mmBtu per rolling, 12-month period; and

b. SO_2 emissions from this emissions unit exceeded 2.32 tons per rolling, 12-month period.

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, the requirement to report on the 2.32 ton per rolling, 12-month period SO_2 emission limitation will become void, and permittee will be required to comply with the terms and conditions of Section B. 10.a)(3).

(3) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous hydrogen sulfide monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of hydrogen sulfide content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, and/or emissions unit;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit.

(4) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 1.88 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (22.8 mmBtu/hr) by the CO emission factor from AP-42 Table 1.4-1 dated 7/98 (84 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

CO emissions shall not exceed 7.21 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the maximum allowable annual heat input (175,200 mmBtu/yr) by the CO emission factor from AP-42 Table 1.4-1 dated 7/98 (84 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the annual firing rate restriction is maintained, compliance with the annual limitation shall be demonstrated.

c. Emission Limitation:

NO_x emissions shall not exceed 1.60 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (22.8 mmBtu/hr) by the manufacturer's NO_x emission factor (0.07 lb/mmBtu).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 7 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. Emission Limitation:

NO_x emissions shall not exceed 6.13 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the maximum allowable annual heat input (175,200 mmBtu/yr) by the manufacturer's NO_x emission factor (0.07 lb/mmBtu) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual emissions limitation is assumed if the permittee maintains compliance with the annual firing rate restriction.

e. Emission Limitation:

PM10 emissions shall not exceed 0.17 pound per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (22.8 mmBtu/hr) by the PM10 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 201 and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

f. Emission Limitation:

PM10 emissions shall not exceed 0.65 ton per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the maximum allowable annual heat input (175,200 mmBtu/yr) by the PM10 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the annual firing rate restriction is maintained, compliance with the annual limitation shall be demonstrated.

g. Emission Limitation:

SO_2 emissions shall not exceed 0.60 pound per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (22.8 mmBtu/hr) by the NSPS subpart J allowable concentration of H_2S in fuel gas (162 ppm) divided by 1 million, multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the ideal gas volume (387 ft^3/lb-mole), divided by an conservative average heating value for refinery fuel gas (1000 Btu/scf) and multiplied by ($1x10^6$ Btu/mmBtu).

Compliance with this emissions limitation shall be demonstrated by complying with the NSPS limit of 162 ppm H_2S in refinery fuel gas using the monitoring and record keeping requirements for H_2S continuous emissions monitoring system in d).

h. Emission Limitation:

SO_2 emissions shall not exceed 2.32 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the maximum allowable annual heat input (175,200 mmBtu/yr) by the NSPS subpart J allowable concentration of H_2S in fuel gas (160 ppm) divided by 1 million, multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the ideal gas volume (387 ft^3/lb-mole), divided by the conservative heating value for refinery fuel gas (1000 Btu/scf) and multiplied by ($1x10^6$ Btu/mmBtu), and divided by 2,000 pounds per ton. Therefore, as long as compliance with the maximum allowable H_2S concentration in the fuel gas and the maximum annual firing rate restriction is maintained, compliance with the annual emission limitation shall be demonstrated. .

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038 and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, term f)(1)(h) above will become void and be replaced with the terms and conditions of Section B.10.e)(1)h.

i. Emission Limitation:

VOC emissions shall not exceed 0.12 pound per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (22.8 mmBtu/hr) by the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A.

Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

j. Emission Limitation:

VOC emissions shall not exceed 0.47 ton per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the maximum allowable annual heat input (175,200 mmBtu/yr) by the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the hourly emission limitation and the annual firing rate restriction is maintained, compliance with the annual emission limitation shall be demonstrated.

k. Emission Limitation:

The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis.

Applicable Compliance Method:

The H_2S continuous emissions monitoring system records required by d) shall serve as demonstration of compliance with this emission limitation.

If required, the permittee shall demonstrate compliance according to 40 CFR 60.106(f).

l. Emission Limitation:

Visible PE shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, compliance shall be demonstrated based upon the procedures specified in Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

m. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this emission limitation is demonstrated through condition c)(1), which requires this permittee to burn only refinery fuel gas, natural gas, or LP gas in this emissions unit..

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

g) Miscellaneous Requirements

(1) None.

3. B032, Coker 3 Furnace

Operations, Property and/or Equipment Description:

247 mmBtu per hour (HHV) heater fired with refinery fuel gas and/or natural gas (Coker 3 Furnace)

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) (PTI 04-01471, issued 7/17/2007)	Carbon monoxide (CO) emissions shall not exceed 18.94 pounds per hour and 82.96 tons per rolling, 12-month period. Nitrogen oxides (NO_x) emissions shall not exceed 14.95 pounds per hour and 65.48 tons per rolling, 12-month period. Particulate matter emissions less than or equal to 10 microns in diameter (PM10) shall not exceed 1.71 pounds per hour and 7.51 tons per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 4.60 pounds per hour and 20.46 tons per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 1.24 pounds per hour and 5.43 tons per rolling, 12-month period. See b)(2)a.and b. See Section B.10.a)(3)
b.	OAC rule 3745-31-05(D)	See b)(2)b., b)(2)h., and b)(2)i.
c.	OAC rule 3745-17-07(A)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		average, unless otherwise specified by the rule.
d.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1)
e.	OAC rule 3745-18-54(W)(1)	See b)(2)d.
f.	40 CFR Part 60, Subpart A	See b)(2)f., b)(2)g., and b)(2)i.
g.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 60.101 This emissions unit is a fuel gas combustion device located at a petroleum refinery that was installed after Jun 11, 1973 and prior to May 14, 2007 and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)c., b)(2)e. [60.104(a)(1)]
h.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 16)	See b)(2)j. (63.7506(b)
i.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480-7575) [In accordance with 63.7575, this emissions unit is an existing process heater in the ”unit designed to fire gas 1 fuels” subcategory at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)i. c)(3), and c)(4). (63.7500(a))

(2) Additional Terms and Conditions

a. The requirements of this rule include compliance with the requirements of OAC rules 3745-17-07(A)(1), 3745-17-10(B)(1), 40 CFR Part 60, Subpart J, and OAC rule 3745-31-05(D).

b. Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, the sulfur dioxide (SO_2) emissions limits of 4.6 lbs/hr and 20.46 tpy and all of their monitoring, record keeping and reporting requirements shall expire and sulfur dioxide (SO_2) emissions from this emissions unit shall not exceed 11.64 tons per rolling, 12-month period.

Section B.10.c) and 10.d)of this permit outlines the monitoring, record keeping, reporting, and compliance demonstration required to maintain compliance with the new SO_2 limit.

c. The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration greater than 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis. Pursuant to the fuel gas definition in 40 CFR 60.101(d), this standard is also applicable if the permittee combines and combusts natural gas or liquefied petroleum (LP) gas in any proportion with refinery fuel gas in this emissions unit.

d. The emission limitation specified by OAC rule 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.104(a)(1).

e. The permittee may choose to comply with the applicable provisions of 40 CFR Part 60, Subpart Ja to satisfy the requirements of this subpart for this emissions unit.

f. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

g. The permittee shall maintain a written quality assurance/quality control plan for the continuous hydrogen sulfide monitoring system, designed to ensure continuous valid and representative readings of hydrogen sulfide emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

[40 CFR 60.13] and [40 CFR Part 60, Appendix F]

h. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software. [40 CFR 60.2 and 40 CFR Part 60, Appendix F]

i. This emissions unit is subject to the initial notification requirements in 40 CFR 63 Subpart DDDDD (Boiler MACT) as outlined in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, SSMP, site-specific monitoring plans of this Subpart DDDDD or any other requirements in 40 CFR 63 Subpart A).

c) Operational Restrictions

(1) The permittee shall burn only natural gas, LP gas, and refinery fuel gas in this emissions unit.

(2) The quality of the natural gas, LP gas and/or refinery fuel gas burned in this emissions unit shall meet, on an “as burned” basis, a sulfur content that is sufficient to comply with the allowable hydrogen sulfide emission limitation of 0.10 grain per dry standard cubic foot as a volume-weighted, rolling 3-hour average.

(3) [40 CFR 63.7500(a) – Table 3(2)] An existing process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the boiler or process heater as specified in § 63.7540(a)(10) or (a)(12). Pursuant to 63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) In order to demonstrate compliance with the emission limitation of 230 mg/dscm (0.10 grain/dscf or 162 parts per million by volume dry basis) of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)b. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows

a. The span value for this instrument shall be 425 mg/dscm of H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(3) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendix B, the permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA’s Central Office documenting that the continuous hydrogen sulfide monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. The letter/document of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(4) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendices B & F, the permittee shall operate and maintain equipment to continuously monitor and record hydrogen sulfide content of the fuel burned in this emissions unit in units of the applicable standard(s).

The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous hydrogen sulfide monitoring system including, but not limited to:

a. hydrogen sulfide content of the fuel burned in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. hydrogen sulfide content of the fuel burned, in units of the applicable standard(s) and in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous hydrogen sulfide monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous hydrogen sulfide monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous hydrogen sulfide monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(5) In order to demonstrate compliance with the 20.46 tons SO_2 per rolling, 12-month period emission limitation, the permittee shall monitor and record the monthly average volumetric firing rate in units of standard cubic feet per month. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total SO_2 emission rates in units of tons in accordance with the procedure outlined in section f).

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, this term and condition will become void and the terms and conditions of Section B.10.a)(3) will become applicable.

(6) The permittee shall monitor and record the daily average firing rate in terms of standard cubic feet per hour. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total CO, NO_x, PE, and VOC emission rates in units

of tons per month and tons per year in accordance with the procedure outlined in section f)

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas, LP gas, or refinery fuel gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous hydrogen sulfide monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of hydrogen sulfide content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, and/or emissions unit;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(a) The permittee shall submit deviation (excursion) reports that identify each day when the CO, NO_x, PE, and/or VOC pound per hour and/or rolling, 12-month emission limitations specified under A.I.1 were exceeded. The reports shall be submitted (i.e., postmarked) to the Toledo Division of Environmental Services quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters

(b) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 18.94 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (230 mmBtu/hr) by the CO emission factor from AP-42 Table 1.4-1 dated 7/98 (84 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

CO emissions shall not exceed 82.96 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the hourly emission limitation (18.94 lbs/hr) by the maximum annual hours of operation (8,760 hrs/yr) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the hourly allowable emission limitation is maintained, compliance with the annual limitation shall be demonstrated.

c. Emission Limitation:

NO_x emissions shall not exceed 14.95 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (230 mmBtu/hr) by the NO_x emission factor for this emissions unit as determined using Method 7E of 40 CFR Part 60, Appendix A on August 17, 1999 (0.065 lb/mmBtu).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. Emission Limitation:

NO_x emissions shall not exceed 65.48 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the rolling, 12-month firing rate in mmBtu by the NO_x emission factor determined during the most recent emissions test that demonstrated compliance divided by 2,000 pounds per ton. On August 17, 1999, the permittee conducted a Method 7E compliance test demonstrating an average NO_x emission rate of 0.065 lb/mmBtu.

e. Emission Limitation:

PM10 emissions shall not exceed 1.71 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (230 mmBtu/hr) by the PM10 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 201 and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

f. Emission Limitation:

PM10 emissions shall not exceed 7.51 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the allowable hourly emission rate (1.71 lbs/hr) by the maximum annual hours of operation (8,760 hrs/yr) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the hourly allowable emission limitation is maintained, compliance with the annual limitation shall be demonstrated..

g. Emission Limitation:

SO_2 emissions shall not exceed 4.60 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input in mmBtu/hr (230 mmBtu/hr) by the NSPS subpart J allowable concentration of H_2S in fuel gas (160 ppmv) divided by 1 million, multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the ideal gas volume (387 ft^3/lb-mole), divided by an estimated average heating value for refinery fuel gas (1324 Btu/scf), and multiplied by ($1x10^6$ Btu/mmBtu).

Compliance with this emissions limitation shall be demonstrated by the monitoring and record keeping requirements for H_2S continuous emissions monitoring system in d).

h. Emission Limitation:

SO_2 emissions shall not exceed 20.46 tons per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the design heat input (230 mmBtu/hr) by the NSPS subpart J allowable concentration of H_2S in fuel gas (162 ppmv) divided by 1 million, multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the ideal gas volume (379 ft^3/lb-mole), divided by an annual average heating value of fuel burned (1347 Btu per standard cubic foot), and multiplied by ($1x10^6$ Btu/mmBtu), multiplying by the maximum hours of usage (8760 hr/yr) and divided by 2,000 pounds per ton.

Therefore, as long as compliance with the hourly emissions limit and the maximum allowable H_2S concentration in the fuel gas is maintained, compliance with the annual emission limitation shall be demonstrated.

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038 and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, term f)(1)(h) above will become void and be replaced with the terms and conditions of Section B.10.e)(1)g.

i. Emission Limitation:

VOC emissions shall not exceed 1.24 pounds per hour.

Applicable Compliance Method:

The hourly emission limitation was developed by multiplying the design heat input (230 mmBtu/hr) by the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA approved test methods may be used with prior approval from Ohio EPA.

j. Emission Limitation:

VOC emissions shall not exceed 5.43 ton per rolling, 12-month period.

Applicable Compliance Method:

The annual emission limitation was developed by multiplying the allowable hourly emission rate (1.24 lbs/hr) by the maximum annual hours of operation (8,760 hrs/yr) and divided by 2,000 pounds per ton. Therefore, as long as compliance with the hourly allowable emission limitation is maintained, compliance with the annual limitation shall be demonstrated.

k. Emission Limitation:

The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis.

Applicable Compliance Method:

The H_2S continuous emissions monitoring system records required by d) shall serve as demonstration of compliance with this emission limitation.

If required, the permittee shall demonstrate compliance according to 40 CFR 60.106(f).

l. Emission Limitation:

Visible PE shall not exceed 20% opacity, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, compliance shall be demonstrated based upon the procedures specified in Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

m. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this emission limitation is demonstrated through compliance with condition c)(1), which requires this permittee to burn only refinery fuel gas, natural gas, or LP gas in this emissions unit..

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

g) Miscellaneous Requirements

(1) None.

4. B039, TBD

Operations, Property and/or Equipment Description:

150 mmBtu/hr (HHV) refinery process heater fired with any combination of refinery fuel gas, natural gas and/or LP gas (Vacuum 1 Furnace)

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) – Ohio Best Available Technology (BAT) requirements	Carbon monoxide (CO) emissions shall not exceed 0.06 lb/mmBtu heat input. See b)(2)b.
b.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	Particulate matter emissions less than or equal to 10 microns in diameter (PM10) and particulate matter emissions less than or equal to 2.5 microns in diameter (PM2.5) shall not exceed 7.451E-03 lb/mmBtu heat input and 4.90 tons per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.0054 lb/mmBtu heat input and 3.54 tons per rolling, 12-month period. See., b)(2)b., b)(2)c., and b)(2)d and c)(1).
c.	OAC rule 3745-31-10 through 20	Carbon dioxide(CO_2) as a surrogate for GHG emissions shall not exceed 82,375 tons per rolling, 12-month period.
d.	OAC rule 3745-31-05(A)(3), as effective 12/01/06	See b)(2)e.
e.	OAC rule 3745-31-05(D) (Synthetic minor restriction to avoid major new source review)	Sulfur dioxide (SO_2) emissions shall not exceed 7.06 tons per rolling, 12-month period. See b)(2)k., and Section B.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
f.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule. See c)(1).
g.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1).
h.	OAC rule 3745-18-54(W)(1)	See b)(2)f.
i.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)g. through b)(2)j.
j.	40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a) [In accordance with 60.101a, this emissions unit is a fuel gas combustion device located at a petroleum refinery that was installed after May 14, 2007 and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)a.
k.	40 CFR Part 63, Subpart A (40 CFR 63.1-16)	Table 10 to Subpart DDDDD of Part 63 — Applicability of General Provisions to Subpart DDDDD shows which parts of the General Provisions in 40 CFR 63.1-16 are applicable to Subpart DDDDD.
l.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575) [In accordance with 63.7485, this emissions unit is a new process heater designed to burn gas 1 subcategory fuels that is located at a major source of HAP]	There are no applicable emissions limitations specified by this rule for this emissions unit. The permittee shall comply with the applicable work practice standards of Table 3 to Subpart DDDDD. [63.7500(a), 63.7540(a)(12)] See c)(3).

(2) Additional Terms and Conditions

a. The permittee shall comply with the emissions limits in b)(2)a.i. and ii. below.

i. The permittee shall comply with either the emission limit in paragraph b)(2)a.i.(a) or the fuel gas concentration limit in paragraph b)(2)a.i.(b).

(a) The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(b) The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(c) The permittee has elected to comply with H_2S limits in permit condition b)(2)a.i.(b). Therefore, the remaining monitoring, recordkeeping, reporting and testing requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(1), this will be allowed upon notification to Ohio EPA. The permittee shall submit a permit modification request to Ohio EPA prior to the change.

ii. The permittee shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs b)(2)a.ii.(a) through (d).

(a) The permittee shall comply with the limit in either paragraph b)(2)a.ii.(a)(i) or (ii). The permittee may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in 40 CFR 60.107a; if fuel gas composition is not monitored as specified in 40 CFR 60.107a(d), the permittee must comply with the concentration limits in paragraph b)(2)a.ii.(a)(i) as follows.

(i) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(ii) 0.040 pounds per million British thermal units (lb/mmBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(iii) The permittee has elected to comply with NO_x limits in permit condition b)(2)a.ii.(a)(ii). Therefore, the remaining monitoring and recordkeeping requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(2), this will be allowed upon notification to Ohio EPA. The permittee shall submit an administrative permit modification request to Ohio EPA prior to the change.

b. The requirements of OAC 3745-31-05(A)(3) also include compliance with the requirements OAC rule 3745-31-10 through 20, OAC rule 3745-17-07(A)(1), OAC rule 3745-17-10(B)(1), and the applicable provisions for SO_2 specified in 40 CFR Part 60, Subpart Ja.

c. All PM10 emissions are assumed to be less than or equal to 2.5 microns in diameter because the permittee shall burn only natural gas, LP gas, and refinery fuel gas in this emissions unit.

d. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to the Ohio Revised Code (ORC) changes effective August 3, 2006 (Senate Bill 265 changes), such that BAT is no longer required by State regulations for National Ambient Air Quality Standards (NAAQS) pollutant(s) less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then BAT emission limitations/control measures no longer apply for pollutants with potential emissions less than 10 tons per year..

e. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The Best Available Technology (BAT) requirements listed under OAC rule 3745-31-05(A)(3) do not apply to the PM2.5, PM10, SO_2 or VOC emissions from this air contaminant source since the uncontrolled potential to emit for PM2.5, PM10, SO_2 and VOC is less than 10 tons per year taking into account the federally enforceable restriction on the maximum H_2S concentration in the fuel gas specified under 40 CFR Part 60, Subpart Ja.

f. The emission limitation specified by OAC 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.102a(g)(1).

g. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

h. Each continuous hydrogen sulfide monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. At least 45 days before commencing certification testing of the continuous hydrogen sulfide monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of hydrogen sulfide emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the applicable standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

i. Each continuous NO_x monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. At least 45 days before commencing certification testing of the continuous NO_x monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of NO_x emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

j. The continuous emission monitoring systems consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

k. The emissions of CO_2 as a surrogate for GHG shall not exceed 82,375 tons per rolling, 12-month period and sulfur dioxide shall not exceed 7.06 tons per rolling, 12-month period. To ensure federal enforceability during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall not exceed the emission levels specified in the following table:

Month(s)	Maximum Allowable Cumulative Emissions of SO_2 (Tons)	Maximum Allowable Cumulative Emissions of CO_2 (Tons)
1	1.41	16,469
1-2	2.12	24,704
1-3	2.61	30,468
1-4	3.11	36,233
1-5	3.60	41,997
1-6	4.09	47,761
1-7	4.59	53,526

Month(s)	Maximum Allowable Cumulative Emissions of SO_2 (Tons)	Maximum Allowable Cumulative Emissions of CO_2 (Tons)
1-8	5.08	59,290
1-9	5.58	65,054
1-10	6.07	70,818
1-11	6.57	76,583
1-12	7.06	82,375

After the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, compliance with the annual emission limitation for $CO_2$and SO_2 shall be based upon the rolling, 12-month summations of the monthly emissions for CO_2 and SO_2

c) Operational Restrictions

(1) The permittee shall burn only natural gas, LP gas, and refinery fuel gas in this emissions unit.

(2) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(3) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

[40 CFR 63.7500(a)(1) – Table 3]

A new or existing boiler or process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the process heater as specified in § 63.7540.

[40 CFR 63.7540(a)(12)]

If your process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, and the unit is designed to burn gas 1, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shut down, but you must inspect each burner at least once every 72 months.

[40 CFR 63.7540(a)(13)]

If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

[40 CFR 63.7510(g)]

For new affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable tune-up as specified in § 63.7540(a).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit

(2) The permittee shall record the following for this emissions unit:

a. the volume, in mmscf, of fuel gas combusted per month;

b. the volume, in mmscf, of fuel gas combusted per rolling, 12-month period;

c. the CO_2emission rate, in tons, for each month of operation;

d. the SO_2 emission rate, in tons, for each month of operation; and

e. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the monthly$CO_2$and SO_2 emissions, in tons.

Also, during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall record the cumulative $CO_2$and SO_2 emissions, in tons, for each calendar month.

(3) In order to demonstrate compliance with the emission limitation of 230 mg/dscm (0.10 grain/dscf) (the equivalent concentration is 162 parts per million by volume dry basis) of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)b. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows.

a. The span value for this instrument shall be 425 mg/dscm of H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(4) The permittee shall operate and maintain equipment to continuously monitor and record H_2S emissions from this emissions unit in units of the applicable standard(s). The

continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous H_2S monitoring system including, but not limited to:

a. emissions of H_2S in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of H_2S, in units of the applicable standard(s) and in the appropriate averaging period (ppmv determined hourly on a 3-hour rolling average basis and determined daily on a 365 successive calendar day rolling average basis);

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. of the applicable standard(s);

f. hours of operation of the emissions unit, continuous H_2S monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous H_2S monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous H_2S monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(5) Regarding the installation of the continuous NO_x monitoring system, within 30 days of achieving maximum production but not later than 150 days of startup of this emission unit, the permittee shall submit information detailing the location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 2. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous NO_x monitoring system meets the requirements of Performance Specification 2. Once received, the letter/document of certification shall be maintained on-site and shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(6) The permittee shall install, operate, and maintain equipment to continuously monitor and record NO_x emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system including, but not limited to:

a. emissions of NO_x in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NO_x in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous NO_x monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous NO_x monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous NO_x monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(7) In order to demonstrate compliance with the 7.06 tons SO_2 per rolling, 12-month period emission limitation, the permittee shall install, operate, and maintain equipment to continuously monitor and record total sulfur (expressed as SO_2) emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60 as outlined in Section B10.of this permit.

(8) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(9) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

e) Reporting Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit

(2) Pursuant to the 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. Construction date (no later than 30 days after such date);

b. Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. Actual start-up date (within 15 days after such date); and

d. Date of performance testing (if required, at least 30 days prior to testing).

(3) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous H_2S monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of H_2S content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, emissions unit, and/or control equipment;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system and/or control equipment while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(x) and (xi).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(4) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NO_x monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of NO_x emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NO_x and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous NO_x monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous NO_x monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous NO_x monitoring system, emissions unit, and/or control equipment;

xi. the date, time, and duration of any downtime** of the continuous NO_x monitoring system and/or control equipment while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(x) and (xi).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit.

(5) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(6) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

(7) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 0.06 lb/mmBtu heat input.

Applicable Compliance Method:

This emission limitation was established based on the permittee's engineering estimate. If required, compliance with theCO emissions limitation above shall be demonstrated using Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

NO_x emissions shall not exceed: 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or 0.040 lb/mmBtu higher heating value basis determined daily on a 30-day rolling average basis.

Applicable Compliance Method:

The permittee shall demonstrate initial compliance according to the requirements of 40 CFR 60.104a(i) and 40 CFR 60.8.

Ongoing compliance with the NO_x emission limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

c. Emission Limitation:

PM10 and PM2.5 emissions shall not exceed 7.451E-03 lb/mmBtu heat input each

Applicable Compliance Method:

ThePM10/PM2.5 emission limitation above was developed by dividing the PM10/PM2.5 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf).Compliance is presumed by using only gaseous fuels

If required, the permittee shall demonstrate compliance with the hourly PM10/PM2.5 allowable emission limitation using Methods 201A and 202 of 40

CFR Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. Emission Limitation:

PM10 and PM2.5 emissions shall not exceed 4.90 tons per rolling, 12-month period.

Applicable Compliance Method:

The tons per year emission limitation above was developed by dividing the PM10/PM2.5 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf), multiplying by the design heat input (150 mmBtu/hr HHV), multiplying by the maximum annual hours of operation (8,760 hours), and then dividing by 2,000 pounds per ton. Therefore, as long as compliance with the lb/mmBtu allowable emission limitation is maintained, compliance with the annual emission limitation shall be demonstrated.

e. Emission Limitations:

The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

Applicable Compliance Method:

The permittee has elected to comply with H_2S limits established in permit condition b)(2)a.i.(b), rather than the SO_2 limits under b)(2)a.i.(a). The permittee shall demonstrate initial compliance with the H_2S limits according to the requirements of 40 CFR 60.104a(j) and 40 CFR 60.8.

Ongoing compliance with the H_2S limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

If the permittee chooses to comply with the SO_2 limits in b)(2)a.i.(a), initial compliance with this emission limitation shall be determined in accordance with the procedures specified in 40 CFR 60.104a(j) and 40 CFR 60.8.

If the permittee chooses to comply with the SO_2 limits in b)(2)a.i.(a), then ongoing compliance with the SO_2 emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in 40 CFR Part 60, Subparts A and Ja; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

f. Emission Limitation:

SO_2 emissions shall not exceed 7.06 tons per rolling, 12-month period

Applicable Compliance Method:

Theannual emission limitation above was developed by multiplying the design firing rate per rolling, 12-month period (0.1364 mmscf/hr) by the permittee's maximum rolling, 12-month average total sulfur expressed as SO_2 concentration in fuel gas (70 ppm), divided by 1E06, multiplied by (1E06 scf/mmscf), multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the standard molar volume (379 scf/lb-mole), and divided by (2,000 lbs/ton) multiplied by 8760 hours/year.

Ongoing compliance with this emission limitation shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60.

g. Emission Limitation:

VOC emissions shall not exceed 0.0054 lb/mmBtu heat input.

Applicable Compliance Method:

The hourly emission limitation was developed by dividing the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf). Compliance is presumed by using only gaseous fuels.

If required, the permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

h. Emission Limitation:

VOC emissions shall not exceed 3.54 tons per rolling, 12-month period.

Applicable Compliance Method:

The tons per year emission limitation above was developed by dividing the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf), multiplying by the design heat input (150 mmBtu/hr), multiplying by the maximum annual hours of operation (8,760 hours), and then dividing by 2,000 pounds per ton. Therefore, as long as compliance with the short-term allowable emission limitation is maintained, compliance with the annual emission limitation shall also be demonstrated.

i. Emission Limitation:

Visible PE shall not exceed 20 percent opacity, as a six-minute average, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance using Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

j. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this emission limitation may be demonstrated by the following one-time calculation of potential to emit: Divide the particulate emission factor from Table 1.4-2 of AP-42 dated 7/98 (1.9 lb/mmscf) by the average heating value for natural gas specified in Table 1.4-2 of AP-42 dated 7/98 (1,020 Btu/scf) to obtain the maximum particulate emissions (0.002 lb/mmBtu).Compliance is presumed by using only gaseous fuels.

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

k. Emission Limitation:

CO_2emissions shall not exceed 82,347 tons per rolling, 12-month period.

Applicable Compliance Method:

The allowable CO_2emissions limitation was established to reflect the potential to emit for this emissions unit based on an emission factor (125.4 lbs CO_2/mmBtu) derived from actual refinery fuel gas data collected pursuant to the GHG MMR rule (40 CFR Part 98) from 2010 up to June 13, 2012, and is based on the highest annual average emission factor calculated during this time period for the TIU Mix Drum. This emissions limitation was established by multiplying the

CO_2emission factor (125.4 lbs CO_2/mmBtu) by the design hourly heat input (150 mmBtu/hr), multiplying by the maximum annual hours of operation (8,760 hrs/yr) and dividing by 2,000 pounds per ton.

Compliance shall be demonstrated by multiplying the annual average site-specific emission factor (lb/mmscf) derived from actual refinery fuel gas data collected pursuant to the GHG MMR rule (40 CFR Part 98) by the actual fuel usage (mmscf/rolling, 12-month period) and dividing by 2,000 pounds per ton.

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup.

b. The emission testing shall be conducted to:

i. demonstrate compliance with the allowable mass emission rate(s) for CO, and NO_x in the appropriate averaging period(s);

ii. demonstrate compliance with the allowable concentration of H_2S in the fuel gas burned, except that a performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

c. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

i. for CO, Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A; and

ii. for NO_x, 40 CFR 60.104a(i).

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the appropriate Ohio EPA District Office or local air agency. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the appropriate Ohio EPA District Office or local air agency. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA District Office's or local air agency's refusal to accept the results of the emission test(s).

f. Personnel from the appropriate Ohio EPA District Office or local air agency shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the appropriate Ohio EPA District Office or local air agency within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the appropriate Ohio EPA District Office or local air agency.

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of any newly installed continuous hydrogen sulfide monitoring system in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specification 7 and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous hydrogen sulfide monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7 and ORC section 3704.03(I).

Ongoing compliance with the hydrogen sulfide emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

(4) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NO_x monitoring system in units of the applicable standard(s) to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous NO_x monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Ongoing compliance with the NO_x emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

(5) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(6) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

g) Miscellaneous Requirements

(1) None.

5. P009, Sulfur Recovery Unit #1

Operations, Property and/or Equipment Description:

Sulfur Recovery Unit (SRU) 1, 120 long tons per day, with tail gas treatment unit and thermal oxidizer

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	See b)(2)a. through b)(2)c.
b.	OAC rule 3745-17-07(A)	See b)(2)g.
c.	OAC rule 3745-17-11(B)(1)	See b)(2)h.
d.	OAC rule 3745-18-54(W)(7)	See b)(2)i.
e.	OAC rule 3745-21-09(T)	See b)(2)j.
f.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 40 CFR 60.104(a)(1) this emissions unit is a Claus sulfur recovery plant with a design capacity for sulfur feed of greater than 20 long tons per day that includes a fuel gas combustion device (incinerator) where construction commenced after 10/4/1976 and prior to 5/14/2007 and is subject to the emissions limitations/ control measures specified in this section]	See b)(2)d. through b)(2)f.
g.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)l. through b)(2)n.
h.	40 CFR Part 63, Subpart A (40 CFR 60.1-16)	Table 6 to Subpart CC - Applicability of NESHAP General Provisions to Subpart

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		CC, specifies which parts of the General Provisions in 40 CFR 63.1-16 apply. Table 44 to Subpart UUU of Part 63 — Applicability of NESHAP General Provisions to Subpart UUU shows which parts of the General Provisions in 40 CFR 63.1-16 apply.
i.	40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657) [In accordance with 40 CFR 63.648(a) this emissions unit is a petroleum refinery process unit located at an existing major of hazardous air pollutants subject to the emissions limitations/control measure specified in this section.]	See b)(2)k.
j.	40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 63.1579) [In accordance with 40 CFR 63.1562, this emissions unit is a sulfur recovery plant with a Claus sulfur recovery unit and tail gas treatment unit, located at an existing major source of HAP emissions, that is subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) and subject to the emission limitations/ control measures specified in this section.]	The SO_2 emission limitation specified by this rule is equivalent to that specified by 40 CFR Part 60, Subpart J under 40 CFR 60.104(a)(2)(i). [Table 29 to 40 CFR Part 63, Subpart UUU]

(2) Additional Terms and Conditions

a. This permit to install incorporates the emission limits and schedules set out in paragraphs 14-18 and 21 of the Consent Decree (United States of America, et al., v. BP Exploration& Oil Co., et al., Civil Action No. 2:96CV095 RL).Operational Restrictions.

b. The permittee shall re-route all NSPS sulfur recovery pit emissions such that they are treated, monitored, and included as part of the sulfur recovery plant's emissions subject to the NSPS Subpart J limit for SO_2, 40 CFR 60.104(a)(2), by no later than the first turnaround of the Claus train that occurs after July 18, 2001.

c. Upon start-up of the new crude heaters (B037 and B038) and vacuum heater (B039) the combined sulfur dioxide (SO_2) emissions from SRU #1 (P009), and SRU #2 & SRU #3 (P037) shall not exceed 75 tons per rolling, 12-month period.

For purposes of clarity, the first month used in a 12-month rolling average compliance period is the calendar month in which the emission limitation becomes effective, and the first complete 12-month rolling average compliance period is 12 calendar months later (e.g., for a limit effective on January 15, the first month in the period is January and the first complete 12-month period ends on the 31st of the following December).

d. The permittee shall not burn in the tail gas incinerator any refinery fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)(the equivalent concentration is 162 parts per million by volume of H_2S dry basis) as a volume-weighted, rolling 3-hour average concentration greater than 0.10 grain per dry standard cubic foot, except during periods of startup, shutdown or malfunction of the refinery fuel gas amine systems provided that the permittee shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. The monitoring, record keeping and reporting requirements for compliance with this condition is maintained under B032 of this permit.

e. The permittee may choose to comply with the applicable provisions of 40 CFR Part 60, Subpart Ja to satisfy the requirements of this subpart for this emissions unit.

f. The permittee shall not discharge or cause the discharge of any gases into the atmosphere from the Claus sulfur recovery plant containing in excess of 250 ppm SO_2 by volume (dry basis) at zero percent excess air as a rolling, 12-hour average.

g. This emissions unit is exempt from the visible PE limitations specified in OAC rule 3745-17-07(A) pursuant to OAC rule 3745-17-07(A)(3)(h) because the emissions unit is not subject to a mass emission limitation in OAC rule 3745-17-11.

h. The uncontrolled mass rate of particulate emissions (PE)* from this emissions unit is less than 10 pounds/hour. Therefore, pursuant to OAC rule 3745-17-11(A)(2)(a)(ii), Figure II of OAC rule 3745-17-11 does not apply. In addition, Table I of OAC rule 3745-17-11 does not apply because the process weight rate is equal to zero. "Process weight" is defined in OAC rule 3745-17-01(B)(17).

* The burning of gaseous fuels is the only source of PE from this emissions unit

i. The emission limitation specified by OAC rule 3745-18-54(W)(7) is less stringent than the emission limitation specified by 40 CFR Part 60, Subpart J.

j. The permittee shall comply with the applicable leak detection and repair requirements specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 63, Subpart CC for both equipment in organic HAP service and equipment not in organic HAP service. The MACT level monitoring of 40 CFR Part 63, Subpart CC is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T)

k. The permittee shall comply with the applicable leak detection and repair requirements specified in 40 CFR Part 63, Subpart CC.

l. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

m. The permittee shall maintain a written quality assurance/quality control plan for the continuous SO_2 monitoring system, designed to ensure continuous valid and representative readings of SO_2 emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous SO_2 monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

n. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart J (40 CFR 60.100 – 60.109).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

(3) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 63.1579).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

a. The span values for this monitor are 500 ppm SO_2 and 25 percent O_2.

b. The performance evaluations for this SO2 monitor under 40 CFR 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(2) The permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous SO_2 monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. The letter/document of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request. [40 CFR 60.13] and [40 CFR Part 60, Appendix B]

(3) The permittee shall operate and maintain equipment to continuously monitor and record SO_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous SO_2 monitoring system including, but not limited to:

a. emissions of SO_2 in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of SO_2 in units of ppm SO_2 by volume (dry basis) at zero percent excess as a rolling, 12-hour average;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous SO_2 monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the continuous SO_2 monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous SO_2 monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(4) The permittee shall monitor and record the monthly average stack oxygen content, fuel gas burned in the thermal oxidizer rate (in scf), and tail gas treater vent gas rate (in scf), and determine the monthly total gas flow. In addition, the permittee shall calculate and record the monthly average SO_2 concentration in the SRU stack from the data recorded by the continuous emission monitor. From these data, the permittee shall calculate and record the monthly total SO_2 emissions for that month and the 12-month, rolling summation of the monthly emissions in accordance with the procedures specified in f).

(5) Upon start-up of the new crude heaters (B037 and B038) and vacuum heater (B039), the permittee shall maintain records of the following:

a. monthly SO_2 emissions from this emissions unit;

b. the combined SO_2 emissions from SRU #1 (P009), SRU #2 and #3 (P037) per rolling, 12-month period.

(6) See 40 CFR Part 60, Subpart J (40 CFR 60.100 – 60.109).

(7) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

(8) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 63.1579).

e) Reporting Requirements

(1) Upon start-up of the new crude heaters (B037 and B038) and vacuum heater (B039) the permittee shall submit quarterly deviation (excursion) reports that identify each month when the combined SO_2 emissions from SRU #1, and SRU #2, and SRU #3 (emissions units P009 and P037) exceeded 75 tons per rolling, 12-month period.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous SO_2 monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of SO_2 emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapter 3745-18, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous SO_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total SO_2 emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous SO_2 monitoring system while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous SO_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous SO_2 monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous SO_2 monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(3) See 40 CFR Part 60, Subpart J (40 CFR 60.100 – 60.109).

(4) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

(5) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 63.1579).

(6) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

The permittee shall not burn in the tail gas incinerator any refinery fuel gas that contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf or 162 ppmvd) as a volume-weighted, rolling 3-hour average.

Applicable Compliance Method:

Ongoing compliance shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of Emissions Unit B032 of this permit, and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60. If required, compliance shall also be demonstrated based upon the methods and procedures of 40 CFR 60.106(e)(1).

b. Emission Limitation:

250 ppm SO_2 by volume (dry basis) at zero percent excess air as a rolling, 12-hour average

Applicable Compliance Method:

Ongoing compliance shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit, and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60.

If required, the permittee shall demonstrate compliance using the methods and procedures of 40 CFR 60.106(f).

c. Emission Limitation:

Upon start-up of the new crude heaters (B037 and B038) and vacuum heater (B039) the combined sulfur dioxide (SO_2) emissions from SRU #1, and SRU #2

&SRU #3 (emissions units P009 and P037) shall not exceed 75 tons per rolling, 12-month period.

Applicable Compliance Method:

The monthly emissions of SO_2 from this emissions unit are calculated by multiplying the calculated total flue gas volume (scf/month) corrected to 0% O_2 by the SO_2 density at 60 F (0.1733 lb SO_2/ft^3 SO_2) multiplied by a temperature correction factor of (560R /520R) to correct the SO_2 density to the standard temperature (100 F) of the SO_2 CEMs then multiplied by the monthly average concentration of SO_2 in the flue gas (ppmv) as measured by the CEMS, divided by 1E06, and divided by 2,000 pounds per ton.

Add the SO_2 emissions from the current month to the total SO_2 emissions for the previous 11 months to determine the tons of SO_2 emitted per rolling, 12-month period from this emissions unit. Add the tons of SO_2 emissions per rolling, 12-month period from Emissions Unit P009 to the tons of SO_2 emissions per rolling, 12-month period from Emissions Unit P037 to determine the combined emissions from P009 and P037.

Compliance with this emissions limitation shall be demonstrated by the monitoring and recordkeeping requirements specified in d).

(2) See 40 CFR Part 60, Subpart J (40 CFR 60.100 – 60.109).

(3) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

(4) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 63.1579).

g) Miscellaneous Requirements

(1) None.

6. P011, Crude/Vac 1

Operations, Property and/or Equipment Description:

Distillation tower and vacuum distillation tower identified as Crude 1 and Vacuum 1 (also known as Crude Vac 1). Vapors extracted from Crude Vac 1 are ducted via the Crude 1 Overhead System either directly to the refinery fuel gas system or to the Crude 1 amine contactor and then combusted in the firebox of the Crude 1 heater (B015). All fugitive emissions from Crude Vac 1 are included with this emissions unit.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) (Chapter 31 Modification, Best Available Technology (BAT) conditions)	10.09 tons per year volatile organic compound (VOC) emissions (from equipment leaks) See b)(2)h.
b.	OAC rule 3745-31-05(D) (PTI P0110958 issued 9/11/2012)	See b)(2)a.
c.	OAC rule 3745-18-54(W)(2)	The sulfur dioxide (SO_2) emissions from this emissions unit shall not exceed 0.40 pound per ton of actual process weight input. See b)(2)a.
d.	OAC rule 3745-21-09(M)(1)	See b)(2)b.
e.	OAC rule 3745-21-09(T)	See b)(2)c.
f.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)d.
g.	40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a) [In accordance with 40 CFR 60.590a, this emissions unit is a process unit located at a petroleum refinery which has equipment	See b)(2)e. [60.592(a)]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	(defined by 40 CFR 60.591a) that was added after 11/7/2006 and subject to the emissions limitations/control measures specified in this section]	
h.	40 CFR Part 63, Subpart A (40 CFR 60.1-16)	Table 6 to subpart CC specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to subpart CC. [63.642(c)]
i.	40 CFR Part 63, Subpart CC (40 CFR 60.640 - 63.657) [In accordance with 40 CFR 63.640, this emissions unit is a petroleum refining process unit located at an existing major source of HAP emissions subject to the emissions limitations/control measures specified in this section.]	See b)(2)f. and b)(2)g. [63.640(d)(5)] [63.640(p)(2)]

(2) Additional Terms and Conditions

a. The SO_2 emission limitation specified by OAC rule 3745-18-54(W)(2) is less stringent than the emission limitation specified under 40 CFR 60.104. All refinery heaters and boilers burning refinery fuel gas are subject to the standards for sulfur oxides under 40 CFR 60.104 (NSPS Subpart J) or 40 CFR 60.102a(g)(1) (NSPS Subpart Ja) which restricts the permittee from burning in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis. Continuous compliance with this emission limitation is monitored by the permittee's hydrogen sulfide continuous monitoring systems (CEMS). Monitoring, recordkeeping, reporting and testing requirements for the fuel gas CEMS are contained under specific emissions unit terms and conditions for fuel burning equipment.

b. The permittee shall control the emissions from the vacuumdistillation tower (Vac 1)by piping the vapors directly to the refinery fuel gas system or by treating the vapors in the Crude 1 amine contactor to the requirements of 40 CFR Part 60, Subpart J and then combusting the vapors in the firebox of the Crude 1 heater (B015). (OAC rule 3745-21-09(M)(1)).

c. The permittee shall comply with the applicable requirements for equipment leaks specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGGa for both equipment in organic HAP service and equipment not in organic HAP service. The MACT level monitoring of 40 CFR Part 60, Subpart GGGa is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

d. 40 CFR Part 60 subpart A provides the applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

e. The permittee shall comply with the applicable requirements for equipment leaks specified in 40 CFR Part 60, Subpart GGGa.

f. Pursuant to 40 CFR 63.640(p)(2), equipment leaks that are subject to the provisions of 40 CFR 63 Subpart CC and 40 CFR Part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

g. When Vac 1 vent gas from this process is ducted to the refinery's fuel gas system,it is not part of the Subpart CC affected source per 63.640(d)(5). No testing, monitoring, recordkeeping, or reporting is required under this subpart for refinery fuel gas system or emission points routed to refinery fuel gas systems.

h. When Vac 1 vent gas is routed to the Crude 1 amine contactor and then to the firebox of the Crude 1 heater, the permittee shall comply with the requirements of 40 CFR Part 63, Subpart CC for miscellaneous process vents.

i. The annual VOC emission limitation was established for PTI purposes to reflect the potential to emit for this emissions unit. Therefore, it is not necessary to develop monitoring, record keeping and/or reporting requirements to ensure compliance with this limitation

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

d) Monitoring and/or Recordkeeping Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

(3)

e) Reporting Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

The SO_2 emissions from this emissions unit shall not exceed 0.40 pound per ton of actual process weight input.

Applicable Compliance Method:

Compliance with this emissions limitation is demonstrated by venting the process vapors produced at this emissions unit to the refinery fuel gas system where the hydrogen sulfide concentration of fuel gas is reduced to less than 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA-recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis or to theCrude 1 amine contactor where H2S concentration is reduced to less than 0.10 gr/dscf, and then to the firebox of the Crude 1 heater (B015).

b. Emission Limitation:

10.09 tons per year VOC emissions from equipment leaks

Applicable Compliance Method:

As long as compliance with the applicable leak monitoring and repair requirements of NSPS Subpart GGGa are maintained compliance with the with this emission limit above shall be demonstrated.

The emission limit of 10.09 tons per year VOC emissions from equipment leaks was established to reflect the potential to emit for this emissions unit using the procedures specified in *Protocol for Equipment Leak Emission Estimates* (EPA document 453/R-95-017, subsequent updates to *Protocol for Equipment Leak Emission Estimates*, or alternative emission factor approved by Ohio EPA) to calculate the VOC emissions from equipment leaks. A summary of the calculations was submitted to Ohio EPA in Application for P0112686.Per permit condition 3(b)(2)(f), no ongoing compliance demonstration is required.

(2) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(3) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

g) Miscellaneous Requirements

(1) None.

7. P025, Refinery WWT System

Operations, Property and/or Equipment Description:

Process oily water system and storm water system (including drains, manholes, junction boxes, lift stations, laterals, and trunklines) within the refinery and refinery wastewater treatment system (excluding Belt Filter Presses P013 & P014) with the following treatment and control systems: carbon canisters and three benzene strippers with non-condensables vented to the Hydrocarbon Flare System

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) (Chapter 31 Modification) Best Available Technology (BAT) requirements	See b)(2)a.
b.	OAC rule 3745-21-09(M)(2)	See b)(2)b.
c.	OAC rule 3745-21-09(T)	See b)(2)c.
d.	OAC rule 3745-21-09(UU)(4)	See b)(2)d.
e.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units subject to 40 CFR 60. The definitions listed under 40 CFR 60.691 apply for all standards and requirements under 40 CFR Part 60, Subpart QQQ.
f.	40 CFR Part 60, Subpart GGGa (40 CFR 60.590a-593a)	The permittee shall comply with the applicable requirements of 40 CFR Part 60, Subpart GGGa for the piping components of the three benzene strippers in the process unit within P025 for the purpose of Subpart GGGa.
g.	40 CFR Part 60, Subpart QQQ (40 CFR 60.640-699)	Group 2 wastewater streams that are managed in a piece of equipment subject

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	[In accordance with 40 CFR 60.690(a)(4), this emissions unit is an aggregate facility subject to the emission limitations/control measures specified in this section]	to 40 CFR Part 60, Subpart QQQ, shall comply with the requirements of 40 CFR 60.692-1 to 60.692-5 and 40 CFR 60.693-1 and 60.693-2, except during periods of startup, shutdown or malfunction. A group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of 40 CFR Part 60, Subpart QQQ, is required to comply only with 40 CFR Part 63, Subpart CC. See b)(2)e.
h.	40 CFR Part 61, Subpart A (40 CFR 61.01-61.19)	40 CFR Part 61, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 61. The definitions listed in 40 CFR 61.341 apply for all the standards and requirements under 40 CFR Part 61, Subpart FF.
i.	40 CFR Part 61, Subpart FF (40 CFR 61.340-61.359) [In accordance with 40 CFR 61.340, this emission unit is a petroleum refinery subject to the emissions limitations/control measures specified in this section.]	Comply with all the applicable standards and requirements of 40 CFR Part 61, Subpart FF. See b)(2)f.
j.	40 CFR Part 63, Subpart A (40 CFR 63.1-63.16)	Table 6 of 40 CFR Part 63, Subpart CC specifies the provisions of 40 CFR Part 63, Subpart A, that apply and those do not apply to permittees of sources subject to Subpart CC. [63.642(c)]
k.	40 CFR Part 63, Subpart CC (40 CFR 63.640-63.657) [In accordance with 40 CFR 63.641, this emission unit is a group 1 wastewater stream	Comply with the applicable wastewater provisions specified in 40 CFR 63.647 Comply with the applicable requirements of 40 CFR 63.640(p)(2). See b)(2)g.

(2) Additional Terms and Conditions

a. Compliance with the requirements of this rule includes compliance with the requirements of OAC rule 3745-21-09(M)(2), OAC rule 3745-21-09(T), OAC rule 3745-21-09(UU)(4), 40 CFR Part 60, Subpart QQQ, 40 CFR Part 61, Subpart FF, and 40 CFR Part 63, Subpart CC.

b. Except for any wastewater separator which is used solely for once-through, noncontact cooling water or for intermittent tank farm drainage resulting from accumulated precipitation, the permittee shall control the emissions of VOC from any wastewater separator by equipping all forebay sections and other separator sections with covers and seals which minimize the amount of oily water exposed to the ambient air. In addition, all covers and forebay and separator sections shall be equipped with lids and seals which are kept in a closed position at all times, except when in actual use. [OAC 3745-21-09(M)(2)]

c. The permittee shall comply with the applicable requirements for equipment leaks specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGGa for both equipment in organic HAP service and equipment not in organic HAP service. The NSPS and MACT level monitoring of 40 CFR Part 60, Subpart GGGa is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

d. All process wastewater from the crude desalter shall be discharged to a steam stripper for the removal of condensable hydrocarbons, and all VOC emissions from the steam stripper shall be vented to a flare that complies with the requirements of OAC 3745-21-09(DD)(10)(d). [OAC 3745-21-09(UU)(4)]

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(DD)(10)(d) by demonstrating compliance with the flare requirements in 40 CFR Part 63, Subpart A. The MACT level monitoring of 40 CFR Part 63, is generally more stringent than the Ohio requirements of OAC rule 3745-21-09(DD)(10).

e. Individual Drain Systems Subject to 40 CFR Part 60, Subpart QQQ

TABLE 1 Individual Drain Systems Subject to 40 CFR Part 60, Subpart QQQ			
Emissions Unit ID	**Facility Description**	**Individual Drain System Description**	**Controls**
P025	Lift station for T157, T159, and T161	Junction Box	Tight seal cover
P025	Lift station for T153-T156	Junction Box	Tight seal cover
P034	Stormwater Diversion Chamber	Junction Box	Tight seal cover and carbon canister
P028	"A" Train Diesel Hydrotreater	Drains in entire unit	Water seals
P029	"B" Train Gas Oil Hydrotreater	Drains in entire unit	Water seals
P036	Coker 3	Drains in entire unit	Water seals
P037	SRU #2 and #3	Drains in entire unit	Water seals
T153	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T154	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T155	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T156	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T157	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T159	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T161	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T163	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T164	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T166	Storage of petroleum liquids	Tank drain system	Drain/dike valve
T167	Storage of petroleum liquids	Tank drain system	Drain/dike valve
P025	84-inch trunk line sewer (existing)	Drains refinery process units, tank fields, parking lots, building roofs	Water seals

TABLE 1 Individual Drain Systems Subject to 40 CFR Part 60, Subpart QQQ			
Emissions Unit ID	**Facility Description**	**Individual Drain System Description**	**Controls**
P025	72-inch sewer (installed pursuant PTI P0103974 issued 3/23/2009)	Drains the east tank field, a portion of the west tank field, and parking lots and building roofs located in the south end of the refinery. Discharges to the existing 84-inch trunk line sewer.	Water seals
P025	(2) 54-inch sewers (installed pursuant PTI P0103974 issued 3/23/2009)	One drains a portion of the west tank field and parking lots and building roofs located in the south end of the refinery. The other drains refinery process units. Both 54-inch sewers discharge to the new 72-inch trunk line sewer.	Water seals
P025	Separator (existing)	Treatment of oily water and storm water received from the refinery through the existing 84-inch trunk line sewer.	Floating roof covers

f. Table II, Benzene Waste NESHAPs (40 CFR Part 61, Subpart FF) Affected Equipment

The Toledo refinery complies with the 6 Mg/yr option in Subpart FF [61.342(e)]. This compliance option allows the refinery some discretion on which portions of the waste water system are controlled as long as the uncontrolled total benzene quantity (as determined by procedures in 40 CFR 61.355(k)) is less than or equal to 6.0 Mg/yr. To meet this requirement, the refinery at the time of issuance of this permit, shall control the following equipment in benzene waste service to the standards of 40 CFR Part 61, Subpart FF.

Affected Unit Description	Applicable Standard (Controls)
Sump #1	[61.346 - Standards: Individual Drain Systems] (Carbon Canisters)
Sump #2	[61.346 - Standards: Individual Drain Systems] (Carbon Canisters)
Sump #3	[61.346 - Standards: Individual Drain Systems] (Carbon Canisters)
T166 (PR-500014)	[40 CFR 61.351 - Alternative Standards for Tanks] (EFR in compliance with NSPS Kb standards)
T167 (PR-500015)	[40 CFR 61.351 - Alternative Standards for Tanks] (EFR in compliance with NSPS Kb standards)
3 Parallel Vacuum Benzene Strippers (1 new one being installed pursuant this permit)	[40 CFR 61.348 - Standards: Treatment Processes] (Closed vent system vented to the main hydrocarbon flare system (West& East flares). If West flare taken out of service, there is a backup tie into the SRU #1 Acid Gas Flare.)
Drain at T089 (PR-500151) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T010 (PR-500152) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T011 (PR-500153) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T016 (PR-500154) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T017 (PR-500155) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T018 (PR-500156) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T019 (PR-500157) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T044 (PR-500158) to Sump #1	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T041 (PR-500130) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T040 (PR-500131) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T120 (PR-500132) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)

Drain at T084 (PR-500134) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T085 (PR-500135) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T035 (PR-500143) to Sump #2	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T166 (PR-500014) to Sump #6	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at T167 (PR-500015) to Sump #6	[61.346 - Standards: Individual Drain Systems] (Water Seal)
Drain at Desalters	Piped to the benzene wastewater stripper (Waste Treatment Unit) which has its overhead non-condensable exhaust routed to the West Flare (closed vent system)

Note: The Oil Water Sewer API Separators do not need to meet the requirements of 40 CFR 61.347 because the refinery complies with the 40 CFR 61.342(e) (6 Mg/yr option), not 40 CFR 61.342(c).

g. Pursuant to 40 CFR 63.640(p)(2), equipment leaks subject to the requirements of 40 CFR 63 Subpart CC and 40 CFR 60 Subpart GGGa, need only comply with the requirements of 40 CFR 60 Subpart GGGa.

c) Operational Restrictions

(1) See 40 CFR Part 63, Subpart CC (40 CFR 63.640-657).

(2) See 40 CFR Part 61, Subpart FF (40 CFR 61.340-359).

(3) See 40 CFR Part 60, Subpart QQQ (40 CFR 60.690-699).

(4) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a-593a).

d) Monitoring and/or Recordkeeping Requirements

(1) See 40 CFR Part 63, Subpart CC (40 CFR 63.640-657).

(2) See 40 CFR Part 61, Subpart FF (40 CFR 61.340-359).

(3) Carbon Canisters Monitoring for 40 CFR 61 Subpart FF compliance. The permittee shall comply with either section d)(3)a. or d)(3)b. below at all locations where a carbon canister(s) is utilized as the control device under the Benzene Waste NESHAP (40 CFR 61.354(d)).

a. Utilizing primary and secondary carbon canisters in series:

i. The permittee shall monitor for breakthrough between the primary and secondary carbon canisters at times when there is actual flow to the carbon canister, in accordance with the frequency specified in 40 CFR 61.354(d) The permittee shall replace the secondary carbon canisters with fresh carbon canisters immediately when VOC breakthrough of 50 ppm is detected. The original secondary carbon canister or a new carbon canister will be used as the new primary carbon canister. For this section, "immediately" means within twenty-four (24) hours.

ii. The permittee shall maintain a supply of fresh carbon canisters at each facility at all times.

iii. Until installation of the second carbon canister all monitoring shall be conducted as specified in

b. Utilizing single carbon canisters:

i. The permittee shall monitor for breakthrough from the carbon canisters at times when there is actual flow to the carbon canister, in accordance with the frequency specified in 40 CFR 61.354(d)

ii. For the single canister option, canisters will be replaced immediately when breakthrough is determined as follows:

(a) For canisters less than or equal to 55 gallon drum size, breakthrough is any reading of VOC above background. The permittee currently monitors these weekly to determine breakthrough;

(b) For canisters larger than 55 gallons, breakthrough is defined as either:

(i) 50 ppm VOC; or

(ii) 1 ppm benzene. To use 1 ppm benzene, canisters must be monitored for VOC. When a reading of 10 ppm VOC is detected, monitoring for benzene must be conducted on the following schedule:

Daily if the historical replacement interval is two weeks or less, or Monday, Wednesday and Friday, if the historical replacement interval is greater than two weeks.

iii. For purposes of section d)(3).b, the term "immediately" shall be defined to mean: within eight (8) hours for canisters with historical replacement intervals of two weeks or less; or within twenty-four (24) hours for canisters with a historical replacement interval of more than two weeks.

iv. The permittee shall maintain a supply of fresh carbon canisters at each facility at all times.

v. Single carbon canisters can be replaced with a dual system at any time provided US EPA is notified and single canister monitoring is continued until the second canister is installed.

(4) Records for sections d)(3)a. and d)(3)b. shall be maintained in accordance with 40 CFR 61.356(j)(10) for carbon adsorbers not regenerated directly on site

(5) Monitoring requirement for OAC rule 3745-21-09.

a. Except for any wastewater separator which is used solely for once-through, noncontact cooling water or for intermittent tank farm drainage resulting from accumulated precipitation, the permittee shall check all separator covers and forebay and separator sections by visual inspections quarterly to ensure that they are equipped with lids and seals that are kept in a closed position at all times except when in actual use.

[OAC rule 3745-21-09(M)(2)

b. The permittee shall collect and record the following information each day: the operating times for the Benzene wastewater stripper system including piping from the decanter, Tanks 14 & 15 to the Benzene strippers and the piping system to the West flare, and the crude desalters. At times when the hydrocarbon flare is out of service for maintenance or repair, the permittee will vent to the SRU 1 Acid Gas Flare.

[OAC rule 3745-21-09(UU)(4)

(6) See 40 CFR Part 60, Subpart QQQ (40 CFR 60.690-699).

(7) See 40 CFR Part 60 Subpart GGGa (40 CFR 60.590a-593a)

e) Reporting Requirements

(1) See 40 CFR Part 63, Subpart CC (40 CFR 63.640-657).

(2) See 40 CFR Part 61, Subpart FF (40 CFR 61.340-359).

(3) See 40 CFR Part 60, Subpart QQQ (40 CFR 60.690-699).

(4) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a-593a).

(5) Deviation Reporting Requirements for OAC rule 3745-21-09

The permittee shall submit quarterly deviation (excursion) reports that identify the following: Except for any wastewater separator which is used solely for once-through, noncontact cooling water or for intermittent tank farm drainage resulting from accumulated precipitation, the permittee shall submit deviation (excursion reports) that identify all occurrences where covers, forebay and other separator sections were not equipped with lids, seals, or kept in a closed position except when in actual use. The quarterly reports shall be submitted, electronically through Ohio EPA Air services, within 30 days of the end of the quarter. If no deviations occurred during the quarter the permittee shall submit a statement that no deviations occurred during the calendar quarter.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

[OAC rule 3745-21-09(M)(2)]

(6) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) See 40 CFR Part 63, Subpart CC(40 CFR 63.640-657).

(2) See 40 CFR Part 61, Subpart FF(40 CFR 61.340-359).

(3) See 40 CFR Part 60, Subpart QQQ (40 CFR 60.690-699)

(4) See 40 CFR Part 60, Subpart GGGa.

g) Miscellaneous Requirements

(1) None.

8. P028, "A" Train Diesel Hydrotreater

Operations, Property and/or Equipment Description:

"A" Train Diesel Hydrotreater. All fugitive emissions from ADHT are included with this emissions unit

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) (Chapter 31 Modification) Best Available Technology (BAT) requirements	22.03 tons per year volatile organic compound (VOC) emissions (from equipment leaks). See b)(2)e.
b.	OAC rule 3745-21-09(T)	See b)(2)a.
c.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)b.
d.	40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a) [In accordance with 40 CFR 60.590a, this emissions unit is a process unit located at a petroleum refinery which has equipment (defined by 40 CFR 60.591a) that was added after 11/7/2006 and subject to the emissions limitations/control measures specified in this section]	See b)(2)c. [60.592a]
e.	40 CFR Part 63, Subpart A (40 CFR 60.1-16)	Table 6 of 40 CFR Part 63, Subpart CC specifies the provisions of 40 CFR Part 63, Subpart A, that apply and those do not apply to permittees of sources subject to Subpart CC. [63.642(c)]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
f.	40 CFR Part 63, Subpart CC (40 CFR 60.640 - 63.657) [In accordance with 40 CFR 63.640, this emissions unit is a petroleum refining process unit located at an existing major source of HAP emissions subject to the emissions limitations/control measures specified in this section.]	See b)(2)d. [63.640(p)(2)].

(2) Additional Terms and Conditions

a. The permittee shall comply with applicable requirements for equipment leaks specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGGa for both equipment in organic HAP service and equipment not in organic HAP service. The NSPS and MACT level monitoring of 40 CFR Part 60, Subpart GGGa is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

b. 40 CFR Part 60 subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

c. The permittee shall comply with applicable requirements for equipment leaks specified in 40 CFR Part 60, Subpart GGGa.

d. Pursuant to 40 CFR 63.640(p)(2), equipment leaks subject to 40 CFR 63 Subpart CC and 40 CFR 60 Subpart GGGa need only comply with the applicable leak detection and repair requirements specified in 40 CFR Part 60, Subpart GGGa.

e. The annual VOC emission limitation was established for PTI purposes to reflect the potential to emit for this emissions unit. Therefore, it is not necessary to develop monitoring, record keeping and/or reporting requirements to ensure compliance with this limitation

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

d) Monitoring and/or Recordkeeping Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

e) Reporting Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a.

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

22.03 tons per year VOC emissions, from equipment leaks

Applicable Compliance Method:

As long as compliance with the applicable leak monitoring and repair requirements of NSPS Subpart GGGa is maintained, compliance with the emission limitationabove shall be demonstrated.

The emission limit of 22.03 tons per year VOC emissions from equipment leaks was established to reflect the potential to emit for this emissions unit using the procedures specified in *Protocol for Equipment Leak Emission Estimates* (EPA document 453/R-95-017, subsequent updates to *Protocol for Equipment Leak Emission Estimates*, or alternative emission factor approved by Ohio EPA) to calculate the VOC emissions from equipment leaks. A summary of the calculations was submitted to Ohio EPA in Application for P0112686.

Per permit condition 3(b)(2)(f), no ongoing compliance demonstration is required.

(2) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(3) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

g) Miscellaneous Requirements

(1) None.

9. P036, Coker 3

Operations, Property and/or Equipment Description:

Coker 3/ delayed petroleum coker with Bubble tower, Blowdown Scrubbing System, Coker Gas Treatment Plant and two Coke drums.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) (Chapter 31 Modification)	13.85 tons of VOC per rolling 12-month period (from coke cutting) 10.81 tons of VOC from fugitive emissions (equipment leaks) per rolling 12-month period See b)(2)g, c)(1), and c)(2)
b.	OAC rule 3745-31-10 through 20	Carbon dioxide equivalent (CO_2e) emissions from coke drum venting and coke cuttingshall not exceed 804.62 tons per rolling, 12-month period.
c.	OAC rule 3745-21-09(T)	See b)(2)a.
d.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 60.19)	See b)(2)b.
e.	40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a)	The permittee shall depressurize each coke drum to 5 psig or less prior to discharging the coke drum steam exhaust to the atmosphere. This limitation is less stringent than that limitation established by ORC 3704.03(T).

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		[60.103(i)]
f.	40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a)	See b)(2)c.
g.	40 CFR Part 60, Subpart NNN (40 CFR 60.660 – 60.668) [In accordance with 40 CFR 60.660, this emissions unit includes an absorber/stripper and debutanizer distillation process that produces chemicals listed in 40 CFR 60.667 (propane and butane)	See b)(2)f. [60.662]
h.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 63.16)	Table 6 to Subpart CC of 40 CFR Part 63 — General Provisions Applicability to Subpart CC shows which parts of the General Provisions of 40 CFR 60.1 -16 apply. [63.642(c)]
i.	40 CFR Part 63, Subpart CC (40 CFR 63.640 -63.657) [In accordance with 40 CFR 63.640, this emissions unit is a petroleum refining process unit located at an existing major source of HAP emissions subject to the emissions limitations/control measures specified in this section.]	See b)(2)d. and b)(2)e. (40 CFR 63.640(p)(2))

(2) Additional Terms and Conditions

a. The permittee shall comply with all the applicable requirements of OAC rule 3745-21-09(T). Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGGa for both equipment in organic HAP service and equipment not in organic HAP service. The NSPS level monitoring of 40 CFR Part 60, Subpart GGGa is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

b. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

c. The permittee shall comply with the applicable requirements of 40 CFR Part 60, subpart GGGa.

d. Pursuant to 40 CFR 63.640(p)(2), equipment leaks that are subject to the provisions of both 40 CFR Part 60, Subpart GGGa and 40 CFR Part 63, Subpart CC are required to comply only with the provisions specified in 40 CFR Part 60, Subpart GGGa.

e. Until the startup of the modifications to P036 associated with the TFO project, the coker blowdown vent shall comply with the applicable requirements for the miscellaneous process vent provisions of 40 CFR Part 63, Subpart CC.After the TFO startup, during periods when the blowdown vent is routed to the refinery fuel gas system, it will no longer be a miscellaneous process vent as defined under 40 CFR 63.641. Pursuant to 63.640(d)(5), emission points routed to a fuel gas system, as defined in 40 CFR 63.641 have no testing, monitoring, recordkeeping, or reporting requirements.

f. The permittee shall comply with the requirements in 40 CFR Part 60, Subpart NNN as they apply to the vent from the Coker Gas Plant unless US EPA approves alternative requirements. The permittee has indicated that a request to use an alternative monitoring plan will be submitted to U.S. EPA for the Coker Gas Plant.

g. Upon startup of the modifications to P036 associated with of the TFO project, these VOC limits in b(1)(a), and associated monitoring recordkeeping and reporting requirements shall expire and the following limits shall take effect:

i. The combined volatile organic compound (VOC) emissions from coke drum venting, coke cutting. and coke drum draining shall not exceed 9.35 tons per rolling, 12-month period; and

ii. The volatile organic compound (VOC) emissions from equipment leaks shall not exceed 13.99 tons per year.

c) Operational Restrictions

(1) Until the startup of the P036 modifications associated with of the TFO project occur, the permittee shall vent the coker blowdown emission to the refinery flare gas recovery system

(2) After startup of the P036 modifications associated with of the TFO project occur, the permittee shall do the following:

a. The permittee shall depressurize each coke drum to 2.0 psig or less prior to discharging the coke drum exhaust to the atmosphere.

b. Uncondensed coke drum blowdown vent vapors from this emissions unit shall be vented to the wet gas compressor/refinery fuel gas system during normal operations so long as the drum pressure exceeds 2.0 psig.

(3) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(4) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(5) See 40 CFR Part 60, Subpart NNN (40 CFR 60.660 – 60.668).

(6) See 40 CFR Part 63, Subpart CC (40 CFR 63.640 – 60.657)

d) Monitoring and/or Recordkeeping Requirements

(1) Emissions occurring during any malfunction, bypassing control equipment, startup or shutdown period must be quantified and recorded.

(2) Until the startup of the P036 modifications associated with the TFO project occur, the permittee shall maintain records of all periods when the blowdown emissions from this emissions unit were not vented to the flare gas recovery system.

(3) After the startup of the P036 modifications associated with the TFO project, the permittee shall maintain records of all periods when the blowdown emissions from this emissions unit were not vented to the refinery fuel gas system when the coker drum pressure exceeded 2.0 psig and any periods when the coke drum was initially vented to the atmosphere when the drum pressure exceeded 2.0 psig.

(4) The permittee shall record the pressure inside the coke drum prior to discharging the coke drum steam to atmosphere.

(5) The permittee shall record the number of coking cycles each month.

(6) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(7) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(8) See 40 CFR Part 60, Subpart NNN (40 CFR 60.660 – 60.668).

See 40 CFR Part 63, Subpart CC(40 CFR 63.640 -63.657).

e) Reporting Requirements

(1) The permittee shall submit quarterly deviation (excursion) reports of the following:

a. Until the startup of the P036 modifications associated with the TFO project all periods when:

i. emissions from coke cutting exceeded 13.85 tons of VOC per rolling 12-month period;

ii. emissions from equipment leaks exceeded 10.81 tons per year; or

iii. the blowdown emissions were not vented to the flare gas recovery system.

b. After the startup of the P036 modifications associated with the TFO project:

i. Each month when the combined VOC emissions from coke drum venting, coke cutting and coke drum draining exceeded 9.3 tons per rolling, 12-month period.

ii. Each month when the combined greenhouse gas emissions exceeded 804.62 tons of CO2e per rolling 12 month period or VOC emissions from fugitive leaks exceeded 13.99 tons per year.

iii. All periods when blowdown vent vapors from this emissions unit were vented to the atmosphere without first depressuring the coker drum to less than 2.0 psi; and the actual coke drum pressure, for each such event.

If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(3) See 40 CFR Part 60, Subpart Ja(40 CFR 60.100a – 60.109a).

(4) See 40 CFR Part 60, Subpart NNN (40 CFR 60.660 – 60.668).

(5) See 40 CFR Part 63, Subpart CC (40 CFR 63.640 -63.657).

(6) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. VOC emissions from coke cutting shall not exceed 13.85 tons per year of VOC per rolling, 12-month period

Applicable Compliance Method:

Compliance shall be determined by multiplying the VOC emission factor of 44.28 pounds VOC per blowdown cycle by the number of blowdown cycles per month to obtain the monthly total VOC emissions, add this value to the total for the previous 11 months to obtain the 12-month total VOC emissions (in pounds), and divide by 2000 lbs/ton.

If required, the permittee shall conduct testing of the emissions unit to determine the coke cutting emissions factor, and submit the results of that testing to Ohio EPA. Upon approval by the Director, the new emission factor shall be used for purposes of demonstrating compliance with the specified emission limit.

b. Emission Limitation:

The combined VOC emissions from coke drum venting, coke cutting.and coke drum draining shall not exceed 9.35 tons per rolling, 12-month period.

Applicable Compliance Method:

Theallowable VOC emission limitation above was developed by multiplying the permittee's combined VOC emission factor (for venting, cutting, and draining based on stack testing submitted in Permit to Install Application no. A0045758)of 29.8568 lb/cycle by the design number of coking cycles per year (626), and then dividing by 2,000 pounds per ton.

Compliance will be determined monthly by multiplying the total number of coking cycles each month by the emission factor of 29.8568 lbs/cycle (or any more representative factor developed though further testing) and then adding that product to the sum of the calculated VOC emissions for the previous 11 months.

If required, the permittee shall verify the coke cutting emission factor using Methods 1 through 4 and 18, 25 or 25A, as appropriate, and Method 204 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

c. Emission Limitation:

10.81 tons per year of VOC as a rolling, 12-month summation from fugitive equipment leaks

Applicable Compliance Method:

If required, compliance shall be determined by using the procedures specified in Protocol for Equipment Leak Emission Estimates (EPA document 453/R-95-017, subsequent updates to Protocol for Equipment Leak Emission Estimates, or alternative emission factor approved by Ohio EPA).

d. Emission Limitation:

13.99 tons per year VOC emissions from equipment leaks.

Applicable Compliance Method:

As long as compliance with the applicable leak monitoring and repair requirements of NSPS Subpart GGGais maintained, compliance with the emission limitationabove shall be demonstrated..

The emission limit of 13.99 tons per year VOC emissions from equipment leaks was established to reflect the potential to emit for this emissions unit using the procedures specified in *Protocol for Equipment Leak Emission Estimates* (EPA document 453/R-95-017, subsequent updates to *Protocol for Equipment Leak Emission Estimates*, or alternative emission factor approved by Ohio EPA) to calculate. A summary of the calculations was submitted to Ohio EPA in Application for P0112686. Per condition b)(2)(h), not ongoing compliance demonstration is necessary.

e. Emission Limitation:

The combined CO_2e emissions from coke drum venting, and coke cutting shall not exceed 804.62 tons per rolling, 12-month period.

Applicable Compliance Method:

The CO_2e emission limitation above was developed by multiplying the permittee's combined CO_2e emission factor [for venting, cutting, and draining based on stack testing submitted in Permit to Install Application A0045758] of 2570.69 lbs CO2e/cycle by the design number of coking cycles per year (626), and then dividing by 2,000 pounds per ton.

Compliance will be determined monthly by multiplying the total number of coking cycles each month by the emission factor of 2570.69 (or any more representative factor developed though further testing) and then adding that product to the sum of the calculated VOC emissions for the previous 11 months.

(2) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(3) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(4) See 40 CFR Part 60, Subpart NNN (40 CFR 60.660 – 60.668).

(5) See 40 CFR Part 63, Subpart CC (40 CFR 63.640 -63.657).

g) Miscellaneous Requirements

(1) None.

10. P037, Sulfur Recovery Unit #2 and #3

Operations, Property and/or Equipment Description:

Sulfur Recovery Unit #2 and #3 with common tail gas treater, sulfur pits, and thermal oxidizer

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) (PTI 04-1046 as modified on August 5, 1998)	Carbon monoxide (CO) emissions shall not exceed 2.7 lbs/hr and 8.07 tons per rolling, 12-month period. Nitrogen oxides (NO_x) emissions shall not exceed 4.4 lbs/hr and 12.76 tons per rolling, 12-month period. Particulate matter emissions less than or equal to 10 microns in diameter (PM10) shall not exceed 0.6 lb/hr and 1.74 tons per rolling, 12-month period; Sulfur dioxide (SO_2) emissions from this emissions unit shall not exceed 172 tons per rolling, 12-month period. Fugitive volatile organic compound (VOC) emissions from equipment leaks shall not exceed 6.2 tons per year (from fugitive equipment leaks) See b)(2)a. and b)(2)n.
b.	OAC rule 3745-31-05(D)	

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		See b)(2)b. and b)(2)c.
c.	OAC rule 3745-07-07(A)(1)	See b)(2)d.
d.	OAC rule 3745-17-11(B)(1)	See b)(2)e.
e.	OAC rule 3745-18-06(E)(2)	See b)(2)n.
f.	OAC rule 3745-21-09(T)	See b)(3)f.
g.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)g., b)(2)l., and b)(2)m.
h.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 40 CFR 60.104(a)(1) this emissions unit is a Claus sulfur recovery plant with a design capacity for sulfur feed of greater than 20 long tons per day that includes a fuel gas combustion device (incinerator) where construction commenced after 10/4/1976 and prior to 5/14/2007 and is subject to the emissions limitations/ control measures specified in this section]	See b)(2)h. and i. [60.104(a)]
i.	40 CFR Part 60, Subpart GGG (40 CFR 60.590 - 593) [In accordance with 40 CFR 63.640(p) equipment leaks that are also subject to the provisions of 40 CFR 60 and 61 are required to comply with the requirements of 40 CFR Part 63, Subpart CC.]	See b)(2)j. [60.592]
j.	40 CFR Part 63, Subpart A (40 CFR 63.1-16)	Table 6 to Subpart CC — General Provisions Applicability to Subpart CC, specifies which parts of the General Provisions in 40 CFR 63.1-16 apply. Table 44 – Applicability of NESHAP General Provisions to Subpart UUU shows which part of the General Provisions in 40 CFR 63.1-16 apply. [40 CFR 63.642(c) and 63.1577]
k.	40 CFR Part 63, Subpart CC (40 CFR 640 - 679) [In accordance with 40 CFR	see b)(2)k. [63.648]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	63.648(a) this emissions unit is a petroleum refinery process unit located at an existing major of hazardous air pollutants subject to the emissions limitations/control measure specified in this section.]	
l.	40 CFR Part 63, Subpart UUU (40 CFR 63.1560-1579) [In accordance with 40 CFR 63.1562, this emissions unit is a sulfur recovery plant with a Claus sulfur recovery unit and tail gas treatment unit, located at an existing major source of HAP emissions, that is subject to the NSPS for sulfur oxides in 40 CFR 60.104(a)(2) and subject to the emission limitations/ control measures specified in this section.]	The SO_2 emission limitation specified by this rule is equivalent to that specified by 40 CFR Part 60, Subpart J under 40 CFR 60.104(a)(2)(i). [Table 29 to 40 CFR Part 63, Subpart UUU]

(2) Additional Terms and Conditions

a. The requirements of this rule also include compliance with OAC rule 3745-21-09(T), 40 CFR Part 60, Subpart GGG, and 40 CFR 60 Subpart J.

b. This permit to install incorporates the emission limits and schedules set out in paragraphs 14-18 and 21 of the Consent Decree (United States of America, et al., v. BP Exploration & Oil Co., et al., Civil Action No. 2:96CV095 RL).

The permittee shall re-route all NSPS sulfur recovery plant sulfur pit emissions such that they are treated, monitored, and included as part of the sulfur recovery plant's emissions subject to the NSPS Subpart J limit for SO_2, 40 CFR 60.104(a)(2), by no later than the first turnaround of the Claus train that occurs after July 18, 2001.

c. Upon initial startup of the new crude heaters (B037 and B038) and vacuum heater (B039), the combined sulfur dioxide (SO_2) emissions from SRU #1 (P009), and SRU #2 & SRU #3 (P037) shall not exceed 75 tons per rolling, 12-month period

For purposes of clarity, the first month used in a 12-month rolling average compliance period is the calendar month in which the emission limitation becomes effective, and the first complete 12-month rolling average compliance period is 12 calendar months later (e.g., for a limit effective on January 15, the first month in the period is January and the first complete 12-month period ends on the 31st of the following December).

d. This emissions unit is exempt from the visible PE limitations specified in OAC rule 3745-17-07(A) pursuant to OAC rule 3745-17-07(A)(3)(h) because the emissions unit is not subject to a mass emission limitation in OAC rule 3745-17-11.

e. The uncontrolled mass rate of particulate emissions (PE)* from this emissions unit is less than 10 pounds/hour. Therefore, pursuant to OAC rule 3745-17-11(A)(2)(a)(ii), Figure II of OAC rule 3745-17-11 does not apply. In addition, Table I of OAC rule 3745-17-11 does not apply because the process weight rate is equal to zero. "Process weight" is defined in OAC rule 3745-17-01(B)(17).

* The burning of gaseous fuels is the only source of PE from this emissions unit

f. The permittee shall comply with the applicable leak detection and repair requirements specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGG for both equipment in organic HAP service and equipment not in organic HAP service. The NSPS and MACT level monitoring of 40 CFR Part 60, Subpart GGG is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

g. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

h. The permittee shall not burn in the tail gas incinerator or any refinery fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)(the equivalent concentration is 162 parts per million by volume of H_2S dry basis) as a volume-weighted, rolling 3-hour average concentration greater than 0.10 grain per dry standard cubic foot, except during periods of startup, shutdown or malfunction of the refinery fuel gas amine systems provided that the permittee shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. The monitoring, record keeping, and reporting requirements for these requirements are maintained under B032 of this permit.

i. The permittee shall not discharge or cause the discharge of any gases into the atmosphere from the Claus sulfur recovery plant containing in excess of 250 ppm SO_2 by volume (dry basis) at zero percent excess as a rolling, 12-hour average.

j. Pursuant to 40 CFR 63.640(p)(1) equipment leaks that are also subject to the provisions of 40 CFR part 60 Subpart GGG, are required to comply only with the provisions specified in 40 CFR 63 Subpart CC

k. The permittee shall comply with the applicable leak detection and repair requirements specified in 40 CFR Part 63, subpart CC.

l. The permittee shall maintain a written quality assurance/quality control plan for the continuous SO_2 monitoring system, designed to ensure continuous valid and representative readings of SO_2 emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous SO_2 monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

m. The emission limitation specified by OAC rule 3745-18-06(E)(2) is less stringent than the limitation specified by 40 CFR Part 60, Subpart J.

n. The annual VOC emission limitation was established for PTI purposes to reflect the potential to emit for this emissions unit. Therefore, it is not necessary to develop monitoring, record keeping and/or reporting requirements to ensure compliance with this limitation.

c) Operational Restrictions

(1) A pilot flame shall be maintained at all times in the TRP Acid Gas flare's pilot light burner.

(2) See 40 CFR Part 60, Subpart J (40 CFR 60.100-109).

(3) See 40 CFR Part 63, Subpart CC (40 CFR 60.640-679).

(4) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560-1579).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall monitor and record the monthly average volumetric firing rate in the Thermal Oxidizer in units of standard cubic feet per month. From these data, the permittee shall calculate and maintain records of the monthly and rolling, 12-month total CO, NO_x and PM10 emission rates in units of tons in accordance with the procedure outlined in section f).

(2) The permittee shall properly install, operate and maintain a device to continuously monitor the presence of the flare pilot flame when the emissions unit is in operation. The monitoring device and any recorder shall be installed, calibrated, operated and

maintained in accordance with the manufacturer's recommendations, instructions and operating manuals. For each day the emissions unit is in operation, the permittee shall record all periods during which there was no flare pilot flame or the monitoring equipment was not operating.

(3) The permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

a. The span values for this monitor are 500 ppm SO_2 and 25 percent O_2.

b. The performance evaluations for this SO_2 monitor under 40 CFR 60.13(c) shall use Performance Specification 2. Methods 6 or 6C and 3 or 3A shall be used for conducting the relative accuracy evaluations.

(4) The permittee shall maintain on-site, the document(s) of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous SO_2 monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. The letter(s)/document(s) of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(5) The permittee shall operate and maintain equipment to continuously monitor and record SO_2 emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous SO_2 monitoring system including, but not limited to:

a. emissions of SO_2 in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of SO_2 in pounds per hour, ppm SO_2 by volume (dry basis) at zero percent excess as a rolling, 12-hour average, and tons SO_2 per rolling, 12-month period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous SO_2 monitoring system;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous SO_2 monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous SO_2 monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(6) The permittee shall monitor and record the monthly average stack oxygen content, fuel gas burned in the thermal oxidizer rate, and tail gas treater vent gas rate, and determine the monthly total gas flow. In addition, the permittee shall calculate and record the monthly average SO_2 concentration in the SRU stack from the data recorded by the continuous emission monitor. From these data, the permittee shall calculate and record the monthly total SO_2 emissions for that month and the 12-month, rolling summation of the monthly emissions in accordance with the procedures specified in f).

(7) Emissions occurring during any malfunction, bypassing, startup or shutdown period shall be quantified and recorded.

(8) Upon initial startup of the new crude heaters (B037 and B038) and vacuum heater (B039), the permittee shall maintain records of the following:

a. monthly SO_2 emissions from this emissions unit;

b. the combined SO_2 emissions from SRU #1 (P009), SRU #2 and #3 (P037) per rolling, 12-month period.

(9) See 40 CFR Part 60, Subpart J (40 CFR 60.100-109).

(10) See 40 CFR Part 63, Subpart CC (40 CFR 60.640-679).

(11) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560-1579).

e) Reporting Requirements

(1) After initial startup of the new crude heaters (B037 and B038) and vacuum heater (B039), the permittee shall submit quarterly deviation (excursion) reports that identify each month when the combined SO_2 emissions from SRU #1, and SRU #2 & SRU #3 (emissions units P009 and P037) exceeded 75 tons per rolling, 12-month period.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous SO_2 monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR Parts 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of SO_2 emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapter 3745-18, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous SO_2 and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total SO_2 emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous SO_2 monitoring system while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous SO_2 monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous SO_2 monitoring system, and emissions unit;

xii. the date, time, and duration of any downtime** of the continuous SO_2 monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

[40 CFR 60.7]

(3) The permittee shall submit quarterly deviation (excursion) reports that identify each period when emissions exceeded any of the following emissions limitations:

a. 8.07 tons CO per rolling, 12-month period;

b. 12.76 tons NO_x per rolling, 12-month period; and

c. 1.74 tons PM10 per rolling, 12-month period.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(4) See 40 CFR Part 60, Subpart J (40 CFR 60.100-109).

(5) See 40 CFR Part 63, Subpart CC (40 CFR 60.640-679).

(6) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560-1579).

(7) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 2.7 pounds per hour.

Applicable Compliance Method:

Compliance shall be demonstrated by multiplying the actual heat input to the thermal oxidizer (mmBtu/hr) by the CO emission factor from AP-42 Table 1.4-1 dated 7/98 (84 lb/mmscf) divided by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

CO emissions shall not exceed 8.07 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the actual firing rate of the thermal oxidizer per rolling, 12-month period (mmscf) by the CO emission factor from AP-42 Table 1.4-1 dated 7/98 (84 lb/mmscf), and dividing by 2,000 pounds per ton.

c. Emission Limitation:

NO_x emissions shall not exceed 4.4 lbs/hr

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the heat input to the thermal oxidizer (mmBtu/hr) by the manufacturer's guaranteed low-NO_x burner emission factor of 0.10 lb/mmBtu.

If required, Methods 1 through 4 and Method 7E of 40 CFR Part 60, Appendix A shall be used to demonstrate compliance. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

d. Emission Limitation:

NO_x emissions shall not exceed 12.76 tons per rolling, 12-month period

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the firing rate to the thermal oxidizer (mmBtu/hr) by the NO_x emission manufacturer's emission factor (0.10 lb/mmBtu), multiplying by the maximum annual operating hours (8,760 hours), and divided by 2,000 pounds per ton.

e. Emission Limitation:

PM-10 emissions shall not exceed 0.6 lb/hr

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the heat input to the thermal oxidizer (mmBtu/hr) by the PM-10 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf), and dividing by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf).

If required, Methods 201 and 202 of 40 CFR Part 51, Appendix M shall be used to demonstrate compliance. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

f. Emission Limitation:

PM10 emissions shall not exceed 1.74 tons per rolling, 12-month period

Applicable Compliance Method:

Compliance may be demonstrated by multiplying the heat input to the thermal oxidizer (mmBtu/hr) by the PM-10 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf), divided by the average heating value for natural gas specified in AP-42 Table 1.4-1 dated 7/98 (1,020 Btu/scf), multiplying by the maximum annual operating hours (8,760 hrs/yr), and dividing by 2,000 pounds per ton.

g. Emission Limitation:

250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air

Applicable Compliance Method: The monitoring and recordkeeping requirements of d) shall be used to demonstrate compliance. If required, the procedures outlined under 40 CFR 60.106(f) shall be used to demonstrate compliance.

h. Emission Limitation:

6.2 tons per year VOC emissions (from fugitive equipment leaks)

Applicable Compliance Method:

Compliance with this emissions limit is demonstrated by compliance with the applicable leak monitoring and repair requirements of NSPS Subpart GGG.

The emission limit of 6.2 tons per year VOC emissions from equipment leaks was established to reflect the potential to emit for this emissions unit using the procedures specified in Protocol for Equipment Leak Emission Estimates (EPA document 453/R-95-017, subsequent updates to Protocol for Equipment Leak Emission Estimates, or alternative emission factor approved by Ohio EPA) to calculate the VOC emissions from equipment leaks. Per condition b)2)(o), no ongoing compliance demonstration is required.

i. Emission Limitation:

SO_2 emissions from this emissions unit shall not exceed 172 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance with this emissions limitation shall be demonstrated by compliance with the emissions limitation specified in j).

j. Emission Limitation:

Following the initial startup of the new crude heaters (B037 and B038) and vacuum heater (B039), the combined SO_2 emissions from SRU #1, SRU #2, and SRU #3 (emissions units P009 and P037) shall not exceed 75 tons per rolling, 12-month period.

Applicable Compliance Method:

The monthly emissions of SO_2 from this emissions unit are calculated by multiplying the calculated total flue gas volume (scf/month) corrected to 0% O_2 by the SO_2 density at 60 F(0.1733 lb SO_2/ft^3 SO_2) multiplied by a temperature correction factor of (560R/ 520R) to correct the SO_2 density to the standard temperature of the SO_2 CEMS (100 F) then multiplied by the monthly average concentration of SO_2 in the flue gas (ppmv) as measured by the CEMS, divided by 1E06, and divided by 2,000 pounds per ton. Add the SO_2 emissions from the current month to the total SO_2 emissions for the previous 11 months to determine the tons of SO_2 emitted per rolling, 12-month period from this emissions unit. Add the tons of SO_2 emissions per rolling, 12-month period from Emissions Unit P009 to the tons of SO_2 emissions per rolling, 12-month period from Emissions Unit P037 to determine the combined emissions from P009 and P037.

Compliance with this emissions limitation shall be demonstrated by the monitoring and recordkeeping requirements specified in d).

(2) Ongoing compliance with the SO_2 emission limitations contained in this permit, 40 CFR Part 60 and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60.

(3) See 40 CFR Part 60, Subpart J (40 CFR 60.100-109).

(4) See 40 CFR Part 63, Subpart CC (40 CFR 60.640-679).

(5) See 40 CFR Part 63, Subpart UUU (40 CFR 63.1560 – 1579).

g) Miscellaneous Requirements

(1) None.

11. P038, TRP Amine Treater

Operations, Property and/or Equipment Description:

TRP Amine treating unit

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T)	5.0 tons per year volatile organic compound (VOC) emissions (from equipment leaks) See b)(2)f. and b)(2)g.
b.	OAC rule 3745-21-09(T)	See b)(2)a.
c.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)b.
d.	40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a) [In accordance with 40 CFR 60.590a, this emissions unit is a process unit located at a petroleum refinery which has equipment (defined by 40 CFR 60.591a) that was added after 11/7/2006 and subject to the emissions limitations/control measures specified in this section]	The permittee shall comply with applicable requirements for equipment leaks specified in 40 CFR Part 60, Subpart GGGa. [60.592(a)]
e	40 CFR Part 63, Subpart A (40 CFR 60.1-16)	Table 6 to subpart CC specifies the provisions of subpart A of this part that apply and those that do not apply to owners and operators of sources subject to subpart CC. [63.642(c)]
f.	40 CFR Part 63, Subpart CC (40 CFR 60.640 - 63.657)	See b)(2)d. and b)(2)e.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	[In accordance with 40 CFR 63.640, this emissions unit is a petroleum refining process unit located at an existing major source of HAP emissions subject to the emissions limitations/control measures specified in this section.]	[63.640(d)(5)] [63.640(p)(2)]

(2) Additional Terms and Conditions

a. The permittee shall comply with applicable requirements for equipment leaks specified in OAC rule 3745-21-09(T).

Consistent with the U.S. EPA streamlining policy, the permittee may elect to demonstrate compliance with OAC rule 3745-21-09(T) by demonstrating compliance with the equipment leak standards in 40 CFR Part 60, Subpart GGGa for both equipment in organic HAP service and equipment not in organic HAP service. The MACT level monitoring of 40 CFR Part 60, Subpart GGGa is generally more stringent than the LDAR requirements of OAC rule 3745-21-09(T).

b. 40 CFR Part 60 subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

c. The permittee shall comply with applicable requirements for equipment leaks specified in 40 CFR Part 60, Subpart GGGa.

d. Pursuant to 40 CFR 63.640(p)(2), equipment leaks that are subject to the provisions of both 40 CFR Part 60, Subpart GGGa and 40 CFR Part 63, Subpart CC are required to comply only with the provisions specified in 40 CFR Part 60, Subpart GGGa.

e. Vapors from this process are ducted to the refinery's fuel gas system and therefore are not part of the Subpart CC affected source per 63.640(d)(5). No testing, monitoring, recordkeeping, or reporting is required under this subpart for refinery fuel gas system or emission points routed to refinery fuel gas systems.

f. Compliance with the requirements of this rule includes compliance with the requirements of OAC rule 3745-21-09(T), and 40 CFR Part 60, Subpart GGGa.

g. The annual emission limitation was established for PTI purposes to reflect the potential to emit for this emissions unit. Therefore, it is not necessary to develop monitoring, record keeping and/or reporting requirements to ensure compliance with this limitation.

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

d) Monitoring and/or Recordkeeping Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

e) Reporting Requirements

(1) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a).

(2) See 40 CFR Part 63, Subpart CC (40 CFR 63.640 – 63.657).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

5.0 tons per year VOC emissions from equipment leaks

Applicable Compliance Method:

As long as compliance with the applicable leak monitoring and repair requirements of NSPS Subpart GGGa is maintained, compliance with the emission limitationabove shall be demonstrated.

The emission limit of 5.0 tons per year VOC emissions from equipment leaks was established to reflect the potential to emit for this emissions unit using the procedures specified in Protocol for Equipment Leak Emission Estimates (EPA document 453/R-95-017, subsequent updates to Protocol for Equipment Leak Emission Estimates, or alternative emission factor approved by Ohio EPA) to calculate the VOC emissions from equipment leaks. A summary of the calculations was submitted to Ohio EPA in Application for P0112686. Per condition b)(2)f., no ongoing compliance demonstratio9n is required.

(2) See 40 CFR Part 60, Subpart GGGa (40 CFR 60.590a – 60.593a)a.

(3) See 40 CFR Part 63, Subpart CC (40 CFR 60.640 – 63.657).

g) Miscellaneous Requirements

(1) None.

12. Emissions Unit Group -Coker II & Naptha Treater Heater: B017,B022,

EU ID	Operations, Property and/or Equipment Description
B017	Coker 2 Heater 77 mmBtu per hr
B022	Naptha Treater Heater 77 mmBtu per hr

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(D)	See b)(2)a., b)(2)b., b)(2)h., and b)(2)i.
b.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule.
c.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1).
d.	OAC rule 3745-18-54(W)(1)	See b)(2)e.
e.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)f., b)(2)g., and b)(2)i.
f.	40 CFR Part 60, Subpart J (40 CFR 60.100-109) [In accordance with 60.101 This emissions unit is a fuel gas combustion device located at a petroleum refinery and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)c. and b)(2)d. [60.104(a)(1)]
g.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 16)	See b)(2)j.
h.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480-7575)	See b)(2)j. c)(2) and c)(3). [63.7500(a) Table 3 requirements]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	[In accordance with 63.7575, this emissions unit is in the "unit designed to fire gas 1 fuels"subcategory existing process heater located at a major source of HAP emissions and subject to the applicable emissions limitations/ control requirements specified in this section.]	

(2) Additional Terms and Conditions

a. Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, the emissions of sulfur dioxide (SO_2) from each of these emissions units shall not exceed 3.64 tons per rolling, 12-month period.

Section B.10.c) and) of this permit outlines the monitoring, record keeping and reporting requirements and compliance demonstration required to maintain compliance with this emissions limit.

b. Permit to Install 04-01290 issued 7/25/2002 incorporated the emission limits and schedules set out in paragraphs 14-18 and 21 of the Consent Decree (United States of America, et al., v. BP Exploration & Oil Co., et al., Civil Action No. 2:96CV095 RL, Date of Entry 8/29/2001) that require this emissions unit to be subject to the requirements of 40 CFR 60 Subpart J.

c. The permittee shall burn no fuel gas in this emissions unit that has a volume-weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis. Pursuant to the fuel gas definition in 40 CFR 60.101(d), this standard is also applicable if the permittee combines and combusts natural gas or liquefied petroleum (LP) gas in any proportion with refinery fuel gas in this emissions unit.

d. The permittee may choose to comply with the applicable provisions of 40 CFR Part 60, Subpart Ja to satisfy the requirements of this subpart for this emissions unit.

e. The emission limitation specified by OAC rule 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.104(a)(1).

f. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

g. The permittee shall maintain a written quality assurance/quality control plan for the continuous hydrogen sulfide monitoring system, designed to ensure continuous valid and representative readings of hydrogen sulfide emissions in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60. [40 CFR 60.13 and 40 CFR Part 60, Appendix F]

h. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

i. This emissions unit is subject to the initial notification requirements of 40 CFR 63 Subpart DDDDD (Boiler MACT) as outlined in 63.9(b) (i.e., it is not subject to the emission limits, performance testing, monitoring, SSMP, or site-specific monitoring plans of this Subpart DDDDD or any other requirements in 40 CFR 63 Subpart A).

c) Operational Restrictions

(1) The permittee shall burn only refinery fuel gas, natural gas, or LP gas in this emissions unit.

(2) [40 CFR 63.7500(a) – Table 3(2)]

An existing process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the boiler or process heater as specified in § 63.7540(a)(10) or (a)(12). Pursuant to 63.7540(a)(13), If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than refinery fuel gas, natural gas, or LP gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall record the following for this emissions unit:

a. the volume of fuel gas combusted per month; and

b. the volume of fuel gas combusted per rolling, 12-month period.

(3) In order to demonstrate compliance with the emission limitation of 230 mg/dscm (0.10 grain/dscf or 162 parts per million by volume dry basis) of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)b. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.105(a)(4), as follows

a. The span value for this instrument shall be 425 mg/dscm of H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.

(4) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendix B, the permittee shall maintain on-site, the document of certification received from the U.S. EPA or the Ohio EPA's Central Office documenting that the continuous hydrogen sulfide monitoring system has been certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. The letter/document of certification shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(5) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendices B & F, the permittee shall operate and maintain equipment to continuously monitor and record hydrogen sulfide content of the fuel burned in this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous hydrogen sulfide monitoring system including, but not limited to:

a. hydrogen sulfide content of the fuel burned in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. hydrogen sulfide content of the fuel burned, in units of the applicable standard(s) and in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous hydrogen sulfide monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous hydrogen sulfide monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous hydrogen sulfide monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(6) The permittee shall maintain records of the monthly average H_2S of the fuel burned in this emissions unit as well as the rolling, 12-month SO_2 emissions.

Beginning the later of (a) fifteen (15) months after initial startup of B037, B038, and B039, or (b) the completion of construction and initial shakedown of the modifications to the Coker Gas Plant, this term and condition will become void, and the terms and conditions of Section B.10.a)(3) will become applicable.

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than refinery fuel gas, natural gas, or LP gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous hydrogen sulfide monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of hydrogen sulfide content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, emissions unit;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

The permittee shall burn no fuel gas in this emissions unit that has a volume weighted 3-hour average hydrogen sulfide (H_2S) concentration in excess of 230 mg/dscm (0.10 gr/dscf), or the U.S. EPA recognized equivalent concentration of 162 parts per million by volume of H_2S on a dry basis.

Applicable Compliance Method:

Ongoing compliance with the hydrogen sulfide emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

b. Emission Limitation:

Visible particulate emissions shall not exceed 20% opacity, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance using Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

c. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this limit is demonstrated through condition c)(1), which requires the permittee to burn only refinery fuel gas, natural gas, or LP gas in this emissions unit.

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

g) Miscellaneous Requirements

(1) None.

13. Emissions Unit Group -Crude 1 A & B Furnaces: B037,B038,

EU ID	Operations, Property and/or Equipment Description
B037	225 mmBtu/hr refinery process heater fired with any combination of refinery fuel gas, natural gas and/or LP gas (Crude 1 A Furnace)
B038	225 mmBtu/hr refinery process heater fired with any combination of refinery fuel gas, natural gas and/or LP gas (Crude 1 B Furnace)

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	ORC 3704.03(T) – Ohio Best Available Technology (BAT) requirements	Carbon monoxide (CO) emissions shall not exceed 0.06 lb/mmBtu heat input.
b.	OAC rule 3745-31-05(A)(3), as effective 11/30/01	Particulate matter emissions less than or equal to 10 microns in diameter (PM10) and particulate matter emissions less than or equal to 2.5 microns in diameter (PM2.5) shall not exceed 7.451E-03 lb/mmBtu heat input and 7.34 tons per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.0054 lb/mmBtu heat input and 5.31 tons per rolling, 12-month period. See b)(2)b., b)(2)c., and b)(2)d, and c)(1)
c.	OAC rule 3745-31-10 through 20	Carbon dioxide (CO_2) as a surrogate for GHG emissions shall not exceed 123,562 tons per rolling, 12-month period.
d.	OAC rule 3745-31-05(A)(3), as effective 12/01/06	See b)(2)e.
e.	OAC rule 3745-31-05(D)	Sulfur dioxide (SO_2) emissions shall not

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	(Synthetic minor restriction to avoid major new source review)	exceed 10.59 tons per rolling, 12-month period. See b)(2)k and Section B
f.	OAC rule 3745-17-07(A)(1)	Visible particulate emissions (PE) shall not exceed 20% opacity, as a 6-minute average, unless otherwise specified by the rule.
g.	OAC rule 3745-17-10(B)(1)	PE shall not exceed 0.020 pound per million Btu of heat input. See c)(1).
h.	OAC rule 3745-18-54(W)(1)	See b)(2).
i.	40 CFR Part 60, Subpart A (40 CFR 60.1-19)	See b)(2)g. through b)(2)i., and b)(2)j.
j.	40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a) [In accordance with 60.101a, this emissions unit is a fuel gas combustion device located at a petroleum refinery that was installed after May 14, 2007 and subject to the applicable emissions limitations/ control requirements specified in this section.]	See b)(2)a.
k.	40 CFR Part 63, Subpart A (40 CFR 63.1-16)	Table 10 to Subpart DDDDD of Part 63 — Applicability of General Provisions to Subpart DDDDD shows which parts of the General Provisions in 40 CFR 63.1-16 are applicable to Subpart DDDDD.
l.	40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575) [In accordance with 63.7485, this emissions unit is a new process heater designed to burn gas 1 subcategory fuels that is located at a major source of HAP]	There are no applicable emission limitations specified by this rule for this emissions unit. The permittee shall comply with the applicable work practice standards of Table 3 to Subpart DDDDD. [63.7500(a), 63.7540(a)(12)] See c)(3), (4), (5), and (6)

(2) Additional Terms and Conditions

a. The permittee shall comply with the emission limits in b)(2)a.i. and ii. below.

i. The permittee shall comply with either the emission limit in paragraph b)(2)a.i.(a) or the fuel gas concentration limit in paragraph b)(2)a.i.(b).

Pursuant to the fuel gas definition in 40 CFR 60.101a, this standard is also applicable if the permittee combines and combusts natural gas or liquefied petroleum (LP) gas in any proportion with refinery fuel gas in this emissions unit.

(a) The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(b) The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(c) The permittee has elected to comply with H_2S limits in permit condition b)(2)a.i.(b). Therefore, the remaining monitoring, recordkeeping, reporting and testing requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(1), this will be allowed upon notification to Ohio EPA. The permittee shall submit a permit modification request to Ohio EPA prior to the change.

ii. The permittee shall not discharge to the atmosphere any emissions of NO_X in excess of the applicable limits in paragraphs b)(2)a.ii.(a) through (d).

(a) The permittee shall comply with the limit in either paragraph b)(2)a.ii.(a)(i) or (ii). The permittee may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in 40 CFR 60.107a; if fuel gas composition is not monitored as specified in 40 CFR 60.107a(d), the permittee must comply with the concentration limits in paragraph b)(2)a.ii.(a)(i) as follows.

(i) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(ii) 0.040 pounds per million British thermal units (lb/mmBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(iii) The permittee has elected to comply with NO_x limits in permit condition b)(2)a.ii.(a)(ii). Therefore, the remaining monitoring and recordkeeping requirements in this permit are reflective of that compliance option. If the permittee decides to revise the compliance option at a later date as allowed by 40 CFR 60.102a(g)(2), this will be allowed upon notification to Ohio EPA. The permittee shall submit an administrative permit modification request to Ohio EPA prior to the change.

b. The requirements of OAC 3745-31-05(A)(3) also include compliance with the requirements of OAC rule 3745-31-10 through 20, OAC rule 3745-17-07(A)(1), OAC rule 3745-17-10(B)(1), OAC rule 3745-18-54(W)(1), and the applicable provisions for SO_2 specified in 40 CFR Part 60, Subpart Ja.

c. All PM10 emissions are assumed to be less than or equal to 2.5 microns in diameter based on c)(1) which requires that the permittee only burn natural gas, LP gas, and refinery fuel gas in this emissions unit.

d. The permittee has satisfied the Best Available Technology (BAT) requirements pursuant to Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3), as effective November 30, 2001, in this permit. On December 1, 2006, paragraph (A)(3) of OAC rule 3745-31-05 was revised to conform to the Ohio Revised Code (ORC) changes effective August 3, 2006 (Senate Bill 265 changes), such that BAT is no longer required by State regulations for National Ambient Air Quality Standards (NAAQS) pollutant(s) less than ten tons per year. However, that rule revision has not yet been approved by U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Therefore, until the SIP revision occurs and the U.S. EPA approves the revisions to OAC rule 3745-31-05, the requirement to satisfy BAT still exists as part of the federally-approved SIP for Ohio. Once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05, then BAT emission limitations/control measures no longer apply for pollutants with potential emissions less than 10 tons/year.

e. This rule paragraph applies once U.S. EPA approves the December 1, 2006 version of OAC rule 3745-31-05 as part of the State Implementation Plan.

The Best Available Technology (BAT) requirements listed under OAC rule 3745-31-05(A)(3) do not apply to the PM2.5, PM10, SO_2 or VOC emissions from this air contaminant source since the uncontrolled potential to emit for PM2.5, PM10, SO_2 and VOC is less than 10 tons per year taking into account the federally enforceable restriction on the maximum H_2S concentration in fuel gas specified under 40 CFR Part 60, Subpart Ja.

f. The emission limitation specified by OAC rule 3745-18-54(W)(1) is less stringent than the emission limitation specified pursuant to 40 CFR 60.102a(g)(1).

g. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are applicable to this emissions unit.

h. Each continuous hydrogen sulfide monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7. At least 45 days before commencing certification testing of the continuous hydrogen sulfide monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of hydrogen sulfide emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

i. Each continuous NO_x monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. At least 45 days before commencing certification testing of the continuous NO_x monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of NO_x emissions from the continuous monitor(s), in units of the applicable standard(s). The plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous NO_x monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; and to conduct relative accuracy test audits in units of the standard(s), in accordance with and at the frequencies required per 40 CFR Part 60.

j. The continuous emission monitoring systems consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

k. The emissions of CO_2 and sulfur dioxide from this emissions unit shall not exceed 123,562 tons per rolling, 12-month period and 10.59 tons per rolling, 12-month period, respectively. To ensure enforceability during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall not exceed the emission levels specified in the following table:

Month(s)	**Maximum Allowable Cumulative Emissions of SO_2(Tons)**	**Maximum Allowable Cumulative Emissions of CO_2(Tons)**
1	2.12	24,712
1-2	3.18	37,069
1-3	3.92	45,718
1-4	4.66	54,367
1-5	5.40	63,017
1-6	6.14	71,666
1-7	6.88	80,315
1-8	7.62	88,965
1-9	8.37	97,614
1-10	9.11	106,263
1-11	9.85	114,913
1-12	10.59	123,562

After the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, compliance with the annual emission limitation for CO_2 and SO_2 shall be based upon the rolling, 12-month summations of the monthly emissions for CO_2 and SO_2.

c) Operational Restrictions

(1) The permittee shall burn only natural gas, LP gas, and refinery fuel gas in this emissions unit.

(2) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(3) 40 CFR 63.7500(a)(1) – Table 3]

A new or existing boiler or process heater in the Gas 1 subcategory with heat input capacity of 10 million Btu per hour or greater shall conduct a tune-up of the process heater as specified in § 63.7540.

(4) [40 CFR 63.7540(a)(12)]

If your process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, and the unit is designed to burn gas 1, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shut down, but you must inspect each burner at least once every 72 months.

(5) [40 CFR 63.7540(a)(13)]

If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(6) [40 CFR 63.7510(g)]

For new affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable tune-up as specified in § 63.7540(a).

(7) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

d) Monitoring and/or Recordkeeping Requirements

(1) For each day during which the permittee burns a fuel other than natural gas, LP gas, or refinery fuel gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

(2) The permittee shall record the following for this emissions unit:

a. the volume, in mmscf, of fuel gas combusted per month;

b. the volume, in mmscf, of fuel gas combusted per rolling, 12-month period;

c. the CO_2 emission rate, in tons, for each month of operation;

d. the SO_2 emission rate, in tons, for each month of operation; and

e. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the monthly CO_2 and SO_2 emissions, in tons.

Also, during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall record the cumulative CO_2 and SO_2 emissions, in tons, for each calendar month.

(3) In order to demonstrate compliance with the emission limitation of 162 parts per million by volume dry basis of H_2S in the refinery fuel gas (and if applicable, combined fuel firing as noted in b)(2)a.i. above), the permittee shall operate and maintain an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in the refinery fuel gas or combined fuel stream before being burned in this emissions unit. The monitoring shall be conducted in accordance with 40 CFR 60.107a(a)(2), as follows

a. The span value for this instrument shall be 300 ppmv H_2S.

b. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H_2S in the fuel gas being burned.

c. The performance evaluations for this H_2S monitor under 40 CFR 60.13(c) shall use Performance Specification 7 of 40 CFR, Part 60, Appendix B. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses," is an acceptable alternative to EPA Method 15A.

(4) Pursuant to 40 CFR 60.13 and 40 CFR Part 60, Appendices B & F, the permittee shall operate and maintain equipment to continuously monitor and record hydrogen sulfide emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous hydrogen sulfide monitoring system including, but not limited to:

a. emissions of hydrogen sulfide in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of hydrogen sulfide, in units of the applicable standard(s) and in the appropriate averaging period (ppmv determined hourly on a 3-hour rolling average basis and determined daily on a 365 successive calendar day rolling average basis);

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. of the applicable standard(s);

f. hours of operation of the emissions unit, and continuous hydrogen sulfide monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous hydrogen sulfide monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous hydrogen sulfide monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(5) Regarding installation of the continuous NO_x monitoring system, within 30 days of achieving maximum production but not later than 150 days of startup of this emission unit, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 2. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous NO_x monitoring system meets the requirements of Performance Specification 2. Once received, the letter/document of certification shall be maintained on-site and shall be made available to the Director (the appropriate Ohio EPA District Office or local air agency) upon request.

(6) The permittee shall install, operate, and maintain equipment to continuously monitor and record NO_x emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system including, but not limited to:

a. emissions of NO_x in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NO_x in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, and continuous NO_x monitoring system;

g. the date, time, and hours of operation of the emissions unit without the continuous NO_x monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the continuous NO_x monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(7) In order to demonstrate compliance with the 10.59 tons SO_2 per rolling, 12-month period emission limitation, the permittee shall install, operate, and maintain equipment to continuously monitor and record total sulfur (expressed as SO_2) emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and

recording equipment shall comply with the requirements specified in 40 CFR Part 60 as outlined in Section B of this permit.

(8) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

e) Reporting Requirements

(1) The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas, LP gas, or refinery fuel gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

(2) Pursuant to the 40 CFR Part 60.7, the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. Construction date (no later than 30 days after such date);

b. Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

c. Actual start-up date (within 15 days after such date); and

d. Date of performance testing (if required, at least 30 days prior to testing).

(3) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous hydrogen sulfide monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of hydrogen sulfide content in excess of any applicable limit specified in this permit, 40 CFR Part 60, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted within 30 days following the end of each calendar quarter of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous hydrogen sulfide and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous hydrogen sulfide monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous hydrogen sulfide monitoring system, and/or emissions unit;

xi. the date, time, and duration of any downtime** of the continuous hydrogen sulfide monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(4) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NO_x monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the appropriate Ohio EPA District Office or local air agency, documenting all instances of NO_x emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations.

The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by within 30 days following the end of each calendar quarter and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NO_x and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total operating time (hours) of the emissions unit;

vi. the total operating time of the continuous NO_x monitoring system while the emissions unit was in operation;

vii. results and dates of quarterly cylinder gas audits;

viii. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

ix. unless previously submitted, the results of any relative accuracy test audit showing the continuous NO_x monitor out-of-control and the compliant results following any corrective actions;

x. the date, time, and duration of any/each malfunction** of the continuous NO_x monitoring system, and/or emissions unit;

xi. the date, time, and duration of any downtime** of the continuous NO_x monitoring system while the emissions unit was in operation; and

xii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(x) and (xi).

Each report shall address the operations conducted and data obtained during the previous calendar quarter.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit.

(5) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(6) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

(7) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 0.06 lb/mmBtu heat input.

Applicable Compliance Method:

This emission limitation was established based on the permittee's engineering estimate. If required, compliance with the CO emission limitation above shall be demonstrated using Methods 1 through 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitations:

NO_x emissions shall not exceed: 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or 0.040 lb/mmBtu higher heating value basis determined daily on a 30-day rolling average basis.

Applicable Compliance Method:

The permittee shall demonstrate initial compliance according to the requirements of 40 CFR 60.104a(i) and 40 CFR 60.8.

Ongoing compliance with the NO_x emission limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

c. Emission Limitation:

PM10 and PM2.5 emissions shall not exceed 7.451E-03 lb/mmBtu heat input each

Applicable Compliance Method:

The PM10/PM2.5 emission limitation above was developed by dividing the PM10/PM2.5 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf). Compliance is presumed by using only gaseous fuels.

If required, the permittee shall demonstrate compliance with the hourly PM10/PM2.5 allowable emission limitation using Methods 201A and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. Emission Limitation:

PM10 and PM2.5 emissions shall not exceed 7.34 tons per rolling, 12-month period.

Applicable Compliance Method:

The tons per year emission limitation above was developed by dividing the PM10/PM2.5 emission factor from AP-42 Table 1.4-2 dated 7/98 (7.6 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf), multiplying by the design heat input (225 mmBtu/hr HHV), multiplying by the maximum annual hours of operation (8,760 hours), and then dividing by 2,000 pounds per ton. Therefore, as long as compliance with the lb/mmBtu allowable emission limitation is maintained, compliance with the annual emission limitation shall be demonstrated.

e. Emission Limitation:

The permittee shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

Applicable Compliance Method:

The permittee has elected to comply with the H_2S limits established in permit condition b)(2)a.i.(b), rather than the SO_2 limits under b)(2)a.i.(a). The permittee shall demonstrate initial compliance with the H_2S limits according to the requirements of 40 CFR 60.104a(j) and 40 CFR 60.8.

Ongoing compliance with the H_2S limitation(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

If the permittee chooses to comply with the SO_2 limits in b)(2)a.i.(a), initial compliance with this emission limitation shall be determined in accordance with the procedures specified in 40 CFR 60.104a(j) and 40 CFR 60.8.

If the permittee chooses to comply with the SO_2 limits in b)(2)a.i.(a), then Ongoing compliance with the SO_2 emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in 40 CFR Part 60, Subparts A and Ja; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

f. Emission Limitation:

SO_2 emissions shall not exceed 10.59 tons per rolling, 12-month period

Applicable Compliance Method:

The annual emission limitation above was developed by multiplying the average firing rate per rolling, 12-month period (0.2045 mmscf/hr) by the permittee's maximum rolling, 12-month average total sulfur expressed as SO_2 concentration in the fuel gas (70 ppm), divided by 1E06, multiplied by (1E06 scf/mmscf), multiplied by the molecular weight of SO_2 (64 lb/lb-mole), divided by the standard molar volume (379 scf/lb-mole), and then divided by (2,000 lbs/ton).

Ongoing compliance with this emission limitation shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60.

g. Emission Limitation:

VOC emissions shall not exceed 0.0054 lb/mmBtu heat input.

Applicable Compliance Method:

The hourly emission limitation was developed by dividing the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf). Compliance is presumed by using only gaseous fuels.

If required, the permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

h. Emission Limitation:

VOC emissions shall not exceed 5.31 tons per rolling, 12-month period.

Applicable Compliance Method:

The tons per year emission limitation above was developed by dividing the VOC emission factor from AP-42 Table 1.4-2 dated 7/98 (5.5 lb/mmscf) by the average heating value for natural gas specified in AP-42 Table 1.4-2 dated 7/98 (1,020 Btu/scf), multiplying by the design heat input (225 mmBtu/hr), multiplying by the maximum annual hours of operation (8,760 hours), and then dividing by 2,000 pounds per ton. Therefore, as long as compliance with the short-term allowable emission limitation is maintained, compliance with the annual emission limitation shall be demonstrated.

i. Emission Limitation:

Visible PE shall not exceed 20 percent opacity as a six-minute average, unless otherwise specified by the rule.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance using Method 9 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

j. Emission Limitation:

PE shall not exceed 0.020 pound per million Btu of heat input.

Applicable Compliance Method:

Compliance with this emission limitation may be demonstrated by the following one-time calculation of potential to emit. Divide the particulate emission factor from Table 1.4-2 of AP-42 dated 7/98 (1.9 lb/mmscf) by the average heating value for natural gas specified in Table 1.4-2 of AP-42 dated 7/98 (1,020 Btu/scf) to obtain the maximum particulate emissions (0.002 lb/mmBtu).

If required, the permittee shall demonstrate compliance using the methods and procedures specified in OAC rule 3745-17-03(B)(9). Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

k. Emission Limitation:

CO_2 emissions shall not exceed 123,569 tons per rolling, 12-month period.

Applicable Compliance Method:

The allowable CO_2 emissions limitation was established to reflect the potential to emit for this emissions unit based on an emission factor (125.4 lbs CO_2/mmBtu) derived from actual refinery fuel gas data collected pursuant to the GHG MMR rule (40 CFR Part 98) from 2010 up to June 13, 2012, and is based on the highest annual average emission factor calculated during this time period for the TIU Mix Drum. This emissions limitation was established by multiplying the CO_2 emission factor (125.4 lbs CO_2/mmBtu) by the design hourly heat input (225 mmBtu/hr), multiplied by the maximum annual hours of operation (8,760 hrs/yr) and divided by 2,000 pounds per ton.

Compliance shall be demonstrated by multiplying the annual average site-specific emission factor (lb/mmscf) derived from actual refinery fuel gas data collected pursuant to the GHG MRR rule (40 CFR Part 98) by the actual fuel usage (mmscf/rolling, 12-month period) and dividing by 2,000 pounds per ton.

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup.

b. The emission testing shall be conducted to:

i. demonstrate compliance with the allowable mass emission rate(s) for CO and NO_x in the appropriate averaging period(s);

ii. demonstrate compliance with the allowable concentration of H_2S in the fuel gas burned, except that a performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance;

c. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

i. for CO, Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A.

ii. for NO_x, 40 CFR 60.104a(i);

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the appropriate Ohio EPA District Office or local air agency. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

e. Not later than 30 days prior to the proposed test date(s), the permittee shall submit an "Intent to Test" notification to the appropriate Ohio EPA District Office or local air agency. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA District Office's or local air agency's refusal to accept the results of the emission test(s).

f. Personnel from the appropriate Ohio EPA District Office or local air agency shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

g. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the appropriate Ohio EPA District Office or local air agency within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the appropriate Ohio EPA District Office or local air agency.

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of any newly installed continuous hydrogen sulfide monitoring system in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specification 7 and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous hydrogen sulfide monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 7 and ORC section 3704.03(I).

Ongoing compliance with the hydrogen sulfide emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

(4) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NO_x monitoring system in units of the applicable standard(s) to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Personnel from the Ohio EPA Central Office and the appropriate Ohio EPA District Office or local air agency shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the appropriate Ohio EPA District Office or local air agency and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous NO_x monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 2; and ORC section 3704.03(I).

Ongoing compliance with the NO_x emission limitation(s) contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Recordkeeping Section of this permit; and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

(5) See 40 CFR Part 60, Subpart Ja (40 CFR 60.100a – 60.109a).

(6) See 40 CFR Part 63, Subpart DDDDD (40 CFR 63.7480 – 7575).

g) Miscellaneous Requirements

(1) None.