



## 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.

**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<sup>1</sup>, 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<sup>2</sup>. 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 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.

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

<sup>1</sup> See the press release from: <http://denr.sd.gov/hyperionaqmain.aspx>

<sup>2</sup> See page 53 of the Hyperion 2007 air permit application.  
from: [http://www.hyperionec.com/files/HEC\\_SD\\_PSD\\_App.pdf](http://www.hyperionec.com/files/HEC_SD_PSD_App.pdf)

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.

The commenter states that oxidation catalysts are proposed to control CO and VOC emissions from two new heaters 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.

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<sup>3</sup>, the "Sat Gas # 3 heater," which fires only natural gas<sup>4</sup>. The Toledo project heaters fire refinery fuel gas. Refinery fuel gas contains sulfur which decreases the activity of conventional oxidation catalysts<sup>3</sup>.
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 SO<sub>2</sub> and PM sources.

**Response 14:** We concur with BPH that PM, PM<sub>10</sub> and PM<sub>2.5</sub> 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<sub>2</sub> by limiting the allowable H<sub>2</sub>S content of refinery fuel gas to no more than 162 ppm<sub>v</sub> H<sub>2</sub>S 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 SO<sub>2</sub> contained in the draft PTI are considered to meet Ohio BAT.

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

<sup>3</sup> See EPA Fact sheet for oxidation catalyst. Note: non-conventional, platinum based catalysts are more sulfur tolerant – but are more expensive.

<sup>4</sup> See Flint Hill application page 263 (pdf page 272)

<http://www.fhrcorpuschristi.com/upload/FHRProjEagleFordAmendment%20ApplicationRecdbyTCEQDraft.pdf>

**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 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 (SO<sub>2</sub>) 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 SO<sub>2</sub> 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 SO<sub>2</sub> limits listed in the draft permit, but do not list final SO<sub>2</sub> 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 SO<sub>2</sub> 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 SO<sub>2</sub>. 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 SO<sub>2</sub> limits on multiple units. The imposed limits were taken to avoid PSD for SO<sub>2</sub> for this permitting action. The draft permit should clearly indicate that the interim and final SO<sub>2</sub> limits are synthetic minor limits under PSD.

**Response 25:** All of the SO<sub>2</sub> 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 SO<sub>2</sub> limits are synthetic minor limits. The interim group limit is temporary, designed to assure that there will be no significant net emission increase in SO<sub>2</sub> 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 (CO<sub>2</sub>) as a surrogate for greenhouse gas (GHG) emissions, including a CO<sub>2</sub> 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 CO<sub>2</sub>, but for all GHGs emitted. Please also clarify how compliance will be demonstrated for each of the GHGs.

**Response 28:** As explained in the Staff Determination, CO<sub>2</sub> emission limits for new heaters are proposed rather than CO<sub>2</sub>e because CO<sub>2</sub> represents more than 99.5 percent of the CO<sub>2</sub>e emissions from these combustion sources and is therefore a good surrogate for total GHG emissions. N<sub>2</sub>O and CH<sub>4</sub> emissions from gas-fired combustion sources are very small and the same control options (good combustion practices, energy efficient design, etc.) that minimize CO<sub>2</sub> emissions also control these other pollutants.

Ohio EPA believes that it was proper to use CO<sub>2</sub> as a surrogate for all GHGs when addressing heater emissions.

**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 O<sub>2</sub> controls with O<sub>2</sub> 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/CO<sub>2</sub> 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 CO<sub>2</sub> in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> concentration; low pressure; low quantity of CO<sub>2</sub> 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 CO<sub>2</sub> capture systems on the proposed heaters.

Further, we are unaware of any available suitable sequestration site or CO<sub>2</sub> 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. BP-Husky Refining's written comments

**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-H<sub>2</sub>S sulfur, the east side mix drum fuel gas will only be monitored for H<sub>2</sub>S. As a consequence, when the ADHT heater is burning east side mix drum fuel gas, its SO<sub>2</sub> 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 SO<sub>2</sub> 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 SO<sub>2</sub> 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 SO<sub>2</sub>) 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 (SO<sub>2</sub>) emissions limit..." to "...the sulfur dioxide (SO<sub>2</sub>) 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 NO<sub>x</sub> 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 SO<sub>2</sub> lb/hr limit is a state BAT limit from an earlier permit and should also sunset along with the existing 12-month rolling SO<sub>2</sub> limit as provided in 2.b)(2)c. BAT for this current permit was established to be compliance with the NSPS Ja H<sub>2</sub>S 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 SO<sub>2</sub> 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 H<sub>2</sub>S 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 (SO<sub>2</sub>) emissions limit..." to "the sulfur dioxide (SO<sub>2</sub>) 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 SO<sub>2</sub> resulting from the combustion of H<sub>2</sub>S 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 SO<sub>2</sub> 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 (SO<sub>2</sub>) emissions limit and all its monitoring ..." to "...the sulfur dioxide (SO<sub>2</sub>) 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<sub>2</sub> 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<sub>2</sub> as a surrogate for GHG. Please make all references in this condition as CO<sub>2</sub>, not CO<sub>2e</sub>. Also, the 12 months value for CO<sub>2</sub> 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 PM<sub>10</sub>, PM<sub>2.5</sub>, 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<sub>2</sub>e in this paragraph should be changed to CO<sub>2</sub>.

**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 CO<sub>2e</sub> 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 CO<sub>2e</sub> 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 SO<sub>2</sub> 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 SO<sub>2</sub> 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 startup 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 CO<sub>2e</sub> with CO<sub>2</sub> only. CO<sub>2</sub> is a surrogate for GHG for these heaters. The numerical emission limit specified was calculated reflective of just CO<sub>2</sub>.

**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 PM<sub>10</sub>, PM<sub>2.5</sub>, 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 CO<sub>2e</sub> with CO<sub>2</sub> 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 Hovenssa 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, 3<sup>rd</sup> 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, 3<sup>rd</sup> 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 NO<sub>x</sub>, VOC, SO<sub>2</sub>, PM<sub>10</sub>/PM<sub>2.5</sub> 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 SO<sub>2</sub> 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<sub>2</sub>S 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<sub>2</sub>S 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 NO<sub>x</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub>/mmBtu for the Crude 1 heater; and, 0.07 lb NO<sub>x</sub>/mmBtu for the Vac 1 heater. BPH cannot reconstruct today exactly what served as the basis for the NO<sub>x</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub> testing emission factors on the largest combustion emission source shutdown by this project, the Crude 1 Heater (B015). The NO<sub>x</sub> emissions credits for the shutdown of this large heater were based on the past stack testing of this heater. Likewise, NO<sub>x</sub> emissions for the increased utilization of the Coker 3 Heater (B032) are based on available stack test data. Similarly, estimates of SO<sub>2</sub> emissions from all combustion sources utilized continuous H<sub>2</sub>S monitoring data for the refinery fuel gas and other test data for non-H<sub>2</sub>S 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 NO<sub>x</sub>,

SO<sub>2</sub>, 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

**Comment 11:** 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*).

**Response:** 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 USEPA adopted 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 started changes to enable the refining of tar sands crudes at least as early as the 1990s, with modifications to the Sulfur Recovery Unit (“SRU”) specifically to improve sulfur conversion 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, BP formally launched a \$235 million project to enable the refinery to process heavy sour crude. (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 3<sup>rd</sup> 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 3<sup>rd</sup> 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. (2<sup>nd</sup> 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.

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

Response: 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.

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

Response: As set forth below, none of the four projects referenced is a "part of an overall strategy to allow the BPH Toledo Refinery the 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.

**Comment 30: 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).

Response: To be considered parts of the same source, the Linde H<sub>2</sub> 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<sup>th</sup> 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.

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

Response: 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(JJ)(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 Evaluation 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
<b>Direct Costs</b>		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	\$2,750,722
Ammonia Storage and Pumping	<i>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.</i>	Incl. in above
Initial Catalyst Charge		Incl. in above
(a) Total Equipment		<u>\$2,750,722</u>
(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]		<u>\$3,163,331</u>
(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)		<u>\$6,216,633</u>
<b>Indirect Costs</b>		
(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)		<u>\$1,740,657</u>
<b>Project Contingency</b>		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	\$1,193,593
<b>Total Plant Cost (TIC + TDC + Cont.)</b>		<b>\$9,150,883</b>
(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	
<b>SUMMARY</b>		
TOTAL CAPITAL INVESTMENT (TCI)		<b>\$9,333,901</b>



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
Catalyst Cost for one charge	(1) Purchased Equipment URS Estimate		82,212
NO <sub>x</sub> removal by SCR control	= tpy NO <sub>x</sub>	=	70.96
N (Ammonia requirement, ton/yr)	= (tpy NO <sub>x</sub> removed) (MW NH <sub>3</sub> , 17/ MW NO <sub>x</sub> , 46)	=	26.22

**Costs**

<b>A. Total capital investment, \$</b>	See Separate TCI Spreadsheet	=	\$9,333,901
<b>B. Direct Annual Costs, \$/yr</b>			
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
<b>TOTAL DIRECT COSTS</b>			<b>\$282,388</b>
<b>C. Indirect Annual Costs, \$/yr</b>			
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
<b>TOTAL INDIRECT COSTS</b>			<b>\$873,359</b>
<b>Total Annual cost</b>	= (Direct Annual Costs) + (Indirect Annual Costs)	=	<b>\$1,155,747</b>

**Cost Effectiveness**

NO <sub>x</sub> Emissions from Unit without SCR	= tpy NO <sub>x</sub>	=	78.8
NO <sub>x</sub> Removal from SCR	= tpy NO <sub>x</sub> , 90% of uncontrolled	=	71.0
<b>Cost Effectiveness</b>	<b>\$/tons NO<sub>x</sub></b>	=	<b>\$16,288.22</b>

- 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
<b>Direct Costs</b>		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	\$1,422,899
Ammonia Storage and Pumping	SCR quote of \$3MM for a 520	Incl. in above
Initial Catalyst Charge	MMBtu/hr furnace has been scaled to TFO furnace using ratio of sizes raised to 0.6 power.	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
<b>Indirect Costs</b>		
(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
<b>Project Contingency</b>		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	\$617,424
<b>Total Plant Cost (TIC + TDC + Cont.)</b>		<b>\$4,733,586</b>
(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	
<b>SUMMARY</b>		
TOTAL CAPITAL INVESTMENT (TCI)		<b>\$4,828,258</b>



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 <sub>x</sub> removal by SCR control	= tpy NO <sub>x</sub>	=	23.65
N (Ammonia requirement, ton/yr)	= (tpy NO <sub>x</sub> removed) (MW NH <sub>3</sub> , 17/ MW NO <sub>x</sub> , 46)	=	8.74

**Costs**

<b>A. Total capital investment, \$</b>	See Separate TCI Spreadsheet	=	\$4,828,258
<b>B. Direct Annual Costs, \$/yr</b>			
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
<b>TOTAL DIRECT COSTS</b>			<b>\$196,839</b>
<b>C. Indirect Annual Costs, \$/yr</b>			
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
<b>TOTAL INDIRECT COSTS</b>			<b>\$453,745</b>
<b>Total Annual cost</b>	<b>= (Direct Annual Costs) + (Indirect Annual Costs)</b>	<b>=</b>	<b>\$650,584</b>

**Cost Effectiveness**

NO <sub>x</sub> Emissions from Unit without SCR	= tpy NO <sub>x</sub>	=	26.3
NO <sub>x</sub> Removal from SCR	= tpy NO <sub>x</sub> , 90% of uncontrolled	=	23.7
<b>Cost Effectiveness</b>	<b>\$/tons NO<sub>x</sub></b>	<b>=</b>	<b>\$27,506.51</b>

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