COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection
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SUBJECT: Review of Application for Plan Approval
United Refining Company
Warren, Warren County

TO: File #62-017G

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This plan approval is for the construction and modification of air emissions sources at the refinery in Warren. The refinery upgrade project will allow United to produce lower sulfur fuels while increasing crude capacity by 5,000 barrels per day (bpd) and allow for the processing of heavier asphaltic crudes.

These modifications are necessary to meet the US EPA Low Sulfur Gasoline and Diesel requirements. The present sulfur content of gasoline at the refinery is in the range of 715 ppm. Under the new requirements United must reduce the sulfur in the gasoline to 330 ppm by January 2004 (phase 1) and further reduce the sulfur to 250 ppm by June 2006 (phase 2) and finally to 30 ppm by January 2008 (phase 3). This plan approval covers Phase 2 and 3 of the Compliance Plan approved by the EPA to meet the low sulfur fuel requirements of 40 CFR Part 80, Subpart H. The Compliance Plan was submitted to the EPA by United seeking regulatory relief under 40 CFR Section 80.270. The EPA approved the Plan on November 16, 2001

The applicant will modify the North Crude Heater at the refinery by installing low NOx burners (LNB). The applicant will also make changes to the existing tail gas treating unit to accommodate the increased throughput. The reduction of NOx emissions will reduce the overall increase of emission from the project below significant levels and will allow the project to “net out” of New Source Review (NSR) and Prevention of Significant Deterioration (PSD) for NOx emissions (40-ton increase threshold).

Several of the existing refinery combustion units will primarily fire refinery gas with fuel oil as a backup. This switch (from oil to refinery gas) will also decrease emissions without making a modification to the source. Examples of these sources include the DHT1 and DHT2 heaters, the pretreater heater, Vacuum heater, Prefact Reboiler 2, and the FCC charge heater. Other sources at the Refinery will see emission increases due to the ripple effect of increased throughput (such as the East and West Reformer Heaters, flares, sulfur recovery unit, Sat Gas Reboiler, Sat Gas KVG, and T-241 heater).

Along with the Crude Unit modification is the modification of a crude oil booster pump that will allow for an increase in crude throughput. Additional changes to the Unit are needed to handle this additional flow. Other changes are necessary at down stream units such as the Vacuum Unit where the feed rate to the Vacuum Tower system will be increased. This will require modification of the vacuum steam ejectors. As a result of the increase in heavy residual product, pumps and heat exchangers will be revamped to handle the new product and increased flow.

The new process units include a delayed coker unit, material handling, an FCC Feed Hydrotreater, a Hydrogen Reformer, Hydrogen Flare, additional new Sulfur Recovery components, and the Emergency Pit Flare.

The delayed coker unit will process vacuum residue from various heavy crudes and FCC Clarified Oil as well as sludge type wastes that can be pumped to the unit from areas such as wastewater treatment. The materials are vaporized and cracked as it passes through the furnace and through the drum. Successive cracking and polymerization of the liquid trapped in the drum occurs until it is converted to vapor and coke. The products from the process are LPG, unstabilized naphtha, light Coker gas oil, heavy Coker gas oil and coke. The coke will be removed from the drums using high-pressure water, drained and transported with a front-end loader to a conveyor and transferred to either a rail car or truck. The conveyor will be equipped with a baghouse to control fugitive dust emissions from this operation.

The purpose of the FCC Feed Hydrotreater is to lower the FCC feedstock sulfur and to convert some of the feed to lighter products. The hydrotreater unit is comprised of two sections, the reaction section and the stripping section. Hydrogenation and cracking reactions occur in fixed catalyst beds in the reaction section. The FCC Feed Hydrotreater will process vacuum gas oils and heavy gas oil from the Delayed Coker Unit.

The Hydrogen Plant produces hydrogen by steam reforming of natural gas feed, with final purification by means of a Pressure Swing Absorption (PSA) system. Tail gas produced by the PSA system is consumed within the Hydrogen Plant as part of the fuel gas to the reforming furnace. Process condensate produced within the Hydrogen Plant is treated and reused within the unit. The FCC Feed Hydrotreater and the DHT2 Distillate Hydrotreater consume the hydrogen product. A new, elevated Hydrogen Flare is proposed in connection with the Hydrogen Reformer. It will function as a typical emergency flare to combust gasses released at times of excessive pressure. Besides emissions that will result from emergency flaring, the Hydrogen Flare will cause slight emission increases from combustion of gas at the pilot light.

The refinery currently has a sulfur recovery plant (SRU2) and a backup unit (SRU1). A new sulfur recovery plant will be constructed to handle the additional hydrogen sulfide gas that will ultimately be converted to elemental sulfur (a saleable product). In addition to the SRU, the Tail Gas Treating Unit (TGTU) processes the tail gas from the SRU. Most of the sulfur contained in the tail gas stream is recovered as hydrogen sulfide and returned to the SRU as feed. An Amine Regeneration Unit will be added to recover the rich amine containing hydrogen sulfide. This amine acquired the hydrogen sulfide from scrubbing sour gases. The rich amine is sent into a regenerator, which separates the hydrogen sulfide from the amine. The lean amine is then sent back to the scrubbers to continue the process. The acid gases (containing hydrogen sulfide) are sent to the SRU. The other sulfur recovery component is the vacuum vent gas unit that collects the vapors only from the vacuum tower and removes the hydrogen sulfide. The acid gas is sent to the SRU. The new SRU3 will be designed with O2 enrichment. This design takes a stream of 90% O2, 10% N2 instead of air to convert the H2S to SO2 which is then catalytically converted to elemental sulfur. Such a design allows for a smaller unit because less N2 is flowing through and eliminates the need for another Tail Gas Treating Unit.

The additional flare (pit flare) is required to accommodate higher instantaneous emergency loads from the new units. These loads are generally gases that occur from a situation in which the pressure becomes excessive and relief valves open. The existing FCC flare on the island will remain and will continue to incinerate all the initial loads. When the load becomes excessive, the additional gases will be diverted to the new pit flare. The pit flare is a network of several small burners enclosed by an earthen wall to block and absorb the radiation during the flaring occurrences. New emissions will occur as a result of combustion of gas to maintain the flare’s pilot light.

<u>New Source Performance Standards (NSPS), MACT, and NESHAPS</u>

The modified North Crude Heater is subject to the NSPS of 40 CFR 60 subpart J Standards of Performance for Petroleum Refineries. The three heaters are required to comply with the standards of sulfur oxides. The refinery uses a fuel gas system, which provides fuel to the heaters and is monitored with hydrogen sulfide analyzers (CEMs). The new sources (delayed coker, FCC Hydrotreater, and the Hydrogen Reformer Unit) are also subject to Subpart J but are also subject to Subpart GGG (pertaining to Equipment Leaks of VOC in Petroleum Refineries) and Subpart QQQ (pertaining to VOC emissions from Petroleum Refinery Wastewater Systems). In addition, the sources are subject to the MACT standards in 40 CFR 63 Subpart CC (pertaining to Hazardous Air Pollutants from Petroleum Refineries. Also, the refinery is subject to the NESHAP requirements of 40 CFR 61 Subpart FF (pertaining to the Emission Standards for Benzene Waste Operations). The hydrogen flare and the emergency pit flare are subject to 40 CFR 60 Subpart J and GGG. In addition, these flares are also subject to 40 CFR 63 Subpart CC. The SRU3/ARU3 is subject to the NSPS Subparts GGG and QQQ and the MACT subparts CC and UUU as well as the NESHAPS Subpart FF.

<u>PSD/NSR Applicability</u>

In accordance with 40 CFR 52, a net emissions change equals emissions increases associated with the proposed modification minus source-wide creditable contemporaneous emissions decreases and increases. The PSD baseline uses average emissions during the previous two-year, unless these years do not represent typical operations, in which case an alternate two-year period may be selected. The first step is to compare the actual baseline to the future potential. Future potential emissions are the maximum allowable or maximum possible from the proposed project. A comparison is also made between actual and potential for NSR. If the comparison results in a value above the significant threshold established in 25 Pa Code Section 127.203, the project would be considered major for that pollutant. If above the threshold and if it is an NSR Pollutant, it would be considered a significant increase. The second step for the NSR comparison (if the source was not a significant increase) examines the contemporaneous increases and decreases after January 1, 1991. If it is a significant increase for an NSR pollutant the second step examines the contemporaneous period, which begins 5 years before commencement of construction for the project. The following table represents the difference in actual and future potential emissions and indicates the significant emission threshold for NSR and PSD, respectively (Table 1).

Table 1

Pollutant	2000/2001 Avg. Actual Emissions (TPY)	Future Potential Emissions (TPY)	Project Increases or Decrease (TPY)	Significant Emission Threshold TPY	Applicable Program
NOx	526.7	562.9	36.2	40	NSR/PSD
CO	397.5	621	223.6	100	PSD
VOC	769.7	743	-26.7	40	NSR
TSP	195.2	179.5	-15.7	25	PSD
PM-10	160.1	137.5	-22.6	15	PSD
SO2	2654.8	2157	-497.8	40	NSR

From the above Table 1, it is indicated that the CO emissions exceed the significant threshold for PSD and therefore the project is subject to the PSD requirements for this pollutant.

The next table (Table 2) identifies the current allowable, future potential and change in potential emissions along with the contemporaneous changes and the significant emission threshold for the NSR second step for the applicability determination. The applicability determination was conducted in accordance with 25 Pa Code Section 127.211.

Pollutant	Current Allowable (TPY)	Future Potential Emissions (TPY)	Change in Potential to Emit (TPY)	Contemporaneous Change (TPY)	Net Emission Increase (TPY)	Significant Emission Threshold (TPY)
NOx	1113.3	562.9	-550.4	17.1	36.2	40
VOC	1919.1	743	-1176.1	6.93	-26.7	40
SO2	3950.3	2157	-1793.3	-582	-497.8	40

Results from Table 1 and Table 2 indicate that the source is not major for the NSR pollutants (NOx, VOC, and SO2). Both tables also show that VOC and SO2 emissions from the project will decrease (when comparing the baseline of actual emissions to future PTE. The coker unit will accept high sulfur fuel oil and divert it away from combustion in process heaters. Most process heaters will burn fuel gas instead, which will significantly lower SO2 emissions. As an example, the actual 200/2001 SO2 average emissions from the boilers 1,2, and 3 (total combined) were 635.1 TPY. After the project is completed, the SO2 emissions are expected to be approximately 169.3 TPY. Similarly, the SO2 emissions from the FCC regenerator will decrease from 1072.6 TPY to 372.3 TPY. Other sources such as the vacuum heater, DHT2 heater, and the prefract reboiler 2 will decrease SO2 emissions to a lesser extent. The VOC emissions decrease mainly due to reductions in fugitive emissions from refinery components (approximately 489.9 TPY 2000/2001 average to 254.4 TPY after the project). The VOC decreases offset the increase in wastewater fugitive VOC emissions, fugitive emissions from new sources, and increase in throughput. As an example the wastewater treatment and tanks will increase by approximately125.4 TPY (from the baseline of 194.8 to the future emissions of 320.2 TPY) and 68.5 TPY (from the baseline of 39.09 TPY to the future emissions of 107.6 TPY), respectively. The new components will contribute 102.67 TPY of fugitive emissions. To accomplish the reduction in emissions from the fugitive components, the new units will use a screening value of 1,000 ppmv except for heavy and light liquid pump seals, which will use a screening value of 2,000 ppmv. These components are subject to 40 CFR 63 Subpart CC, which incorporates 40 CFR Part 63 Subpart H requirements. The existing components shall use a screening value of 2,500 ppmv. A condition will be included in the plan approval to use these screening values and comply with Subpart CC as appropriate. The wastewater flow rates were approximately 0.858 mgd in 2000 and 0.832 mgd in2001. The potential wastewater flow rate is approximately 1.115 mgd. Tank thru put will also increase for several of the tanks. As an example the average thru put for tank 409 for the 2000/2001 baseline was approximately 319,567 barrels per year and the future potential for that tank is 732,000 barrels per year. Attached to this memo are Tables for the baseline and the future average emissions for the criteria pollutants for each of the sources at the refinery.

BACT/BAT Analysis

Based on United's analysis, the project is subject to PSD for CO emissions and Best Available Control Technology (BACT) is required for this pollutant. Best Available Technology (BAT) is required for all pollutants for new sources. A top-down approach was utilized to determine BACT/BAT for the various sources. This approach is outlined in the New Source Review Workshop Manual US EPA Draft Document. This approach involves determining the most stringent control technique available or emission level for a similar or identical emission source. If the applicant elects to apply this top level of control, no further evaluation is required. However, if it can be shown that the top-level control is technically, environmentally, or economically impractical on a case-by-case basis for the individual source, then the next most stringent level of control is determined and evaluated. The key steps to the BACT evaluation are:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank remaining control technologies by control effectiveness;
- Evaluate most effective controls and document results; if top option is not selected as BACT, evaluate next most effective control option; and
- Select BACT, which will be the most effective practical option not rejected based on energy, environmental, and economic impacts.

In order to determine available emission controls and the top level of control information in EPA BACT/LAER Clearinghouse was reviewed.

BAT for NOx emissions

United will install a delayed coker heater with a capacity of 116 MMBTU/hr, an FCC hydrotreater heater (91 MMBTU/hr), and a hydrogen reformer heater (344 MMBTU/hr). Burning refinery fuel gas will minimize NOx emissions. The clearinghouse data showed that the lowest emission rate or top level listed for a process heater is 0.066 lb/MMBTU using SNCR. However, in California, some process heaters are permitted in the 5 ppmdv at 3%O_2 to 12 ppmdv at 3% O_2 range based on LAER requirements and the use of Low NOx burners (LNB) with SCR. United proposes to install LNB on the delayed coker heater, the FCC hydrotreater, and the hydrogen reformer heater. The proposed emission rate for these two heaters is 0.04 lb/MMBTU which is approximately 33 ppmdv at 3% O_2.

Originally the FCC hydrotreater heater, delayed coker and the hydrogen reformer heater were expected to have design capacities of 66 MMBTU/hr, 116 MMBTU/hr and 290 MMBTU/hr. Foster Wheeler evaluated the cost economics using vendor quotes for equipment costs and the OAQPS Cost Estimating Methodology Manual. A cost analysis was prepared for the FCC hydrotreater heater examining SNCR and SCR controls. The applicant used the OAQPS format to examine the overall costs of controls. The equipment cost of each control was $339,534.00 and $389,300.00, respectively. Other costs such as instrumentation, sales tax and freight were added to give a total purchased equipment cost of $410,836.00 and $471,053.00, respectively. Total direct installation costs of each control were each $123,250.00. Total direct costs were $534,066.00 and $594,303.00, respectively. Similarly, using the OAQPS format, the annual costs were calculated for both SNCR and SCR. The total annualized cost of each control was $238,282.00 and $339,435.00, respectively. The catalyst life was approximated as 3 years and the interest rate for amortization was 7%. The NOx emissions using LNB were estimated as 11.0 TPY using a heat input for the heater of 62.7 MMBTU/hr at 0.04 lb/MMBTU. Using SNCR the emissions would be reduced to 0.026 lb/MMBTU and SCR the emissions would be reduced to 0.015 lb/MMBTU. This means the overall reduction (for this example) using SNCR and SCR would be 3.8 TPY and 6.9 TPY, respectively. Using the total annualized costs mentioned above the cost effectiveness for each control would be $61,976.00 and $49,440.00 per ton of NOx reduced.

Applying the same annualized cost and correcting for the new heat inputs the cost of SCR with LNB would be approximately $26,727.00 per ton of NOx reduced for the coker heater, $34,080.00 per ton of NOx reduced for the FCC hydrotreater, and $9,004.00 per ton of NOx reduced for the hydrogen reformer heater, respectively. Similarly the cost of SNCR with LNB would be approximately $33,561.00 per ton of NOx reduced for the coker heater, $42,703.00 per ton of NOx reduced for the FCC hydrotreater, and $11,298.00 per ton of NOx reduced for the hydrogen reformer heater, respectively. An example calculation is located below:

Additional reduction applying LNB and SNCR = 0.04 lb/MMBTU-0.026 lb/MMBTU = 0.014 lb/MMBTU

Coker Heater heat input = 116 MMBTU/hr

Reduction in TPY = (116 MMBTU/hr)(0.014 lb/MMBTU) = 1.624 #NOx reduced per hour or 7.1 TPY

Total annualized cost = $238,282.00

Cost Effectiveness = $238,282.00÷7.1 TPY NOx reduced = $33,561.00 per ton of NOx reduced

As indicated by the above information, the use of SNCR or SCR in addition to LNB for any of the three heaters would be considered economically infeasible and therefore the Department will accept the use of LNB alone as BAT for NOx for the three heaters.

BACT/BAT for CO Emissions

The clearinghouse data for gas fired combustion sources showed emission limits typically in the 0.038 to 0.2-lb/MMBTU range except for a few lower emission rates. However, all of these sources appear to be boilers. The only CO emission control method that has been applied to process heaters and boilers is good combustion control. Therefore, United proposes good combustion control with an emission rate of 0.084 lb/MMBTU as BACT/BAT for the delayed coker heater, FCC hydrotreater heater, and the hydrogen reformer heater.

BAT for VOC Emissions

VOC emissions from the process heaters are a result of incomplete fuel combustion. By carefully controlling the combustion process, VOC emissions can be minimized. The clearinghouse showed limits from 0.003 lb/MMBTU to 0.0072 lb/MBTU range. Therefore, United has proposed good combustion practices with emission rates of 0.005 lb/MMBTU for the delayed coker heater and the FCC hydrotreater heater. Based on vendor data, United proposes 0.003 lb/MMBTU for the hydrogen reformer heater. The proposed emission rates are BAT because they reflect the top level of control.

Many types of leak detection and repair (LDAR) programs are used to control VOC emissions from equipment leaks. These programs include Reasonably Available Control Technology (RACT) standards such as 25 Pa Code Section 129.58, NSPS, and MACT standards for both existing and new sources. The petroleum refinery MACT standard for new sources is the most stringent standard or top level of control applied in practice. United proposes to apply the new source technical requirements of the petroleum refinery MACT standard to all new equipment leak sources in VOC service as the top level of control and BAT for these emission sources.

BAT for TSP and PM-10 Emissions

TSP and PM-10 emissions from combustion of gaseous fuels are primarily a result of incomplete fuel combustion. By carefully controlling the combustion process, these emissions can be minimized. The clearinghouse data showed that the only TSP or PM-10 emission control methods that have been applied to gas fired combustion sources is good combustion control and the use of fuel specifications requiring the use of gas. Therefore, United proposes burning only refinery process gas with good combustion control and an emission rate of 0.008 lb/MMBTU as BAT for the delayed coker heater and the FCC hydrotreater heater. Vendor data for the hydrogen reformer heater indicates that an emission rate of 0.005 lb/MMBTU can be achieved for this source.

TSP and PM-10 emissions from cooling towers result from cooling tower drift, which consists of droplets entrained from the cooling tower recirculation water. These droplets contain dissolved solids, which form TSP and PM-10 after evaporation of the water. A drift eliminator to limit drift to 0.001% of the cooling tower recirculation flow is generally considered to be BACT. United proposes a drift eliminator to limit drift to 0.001% of the cooling tower recirculation flow as the top level of control and as BAT.

The material handling, transportation and storage of the petroleum coke will generate TSP and PM-10 emissions. Typical emission control for these potentially fugitive emissions include the wetting the material by either direct or indirect spray, total or partial enclosure, wind breaks, best operating practices, and dust collection systems. These combined methods will be applied to the sources as BAT. Raw coke will be handled as a wet material. Conveyors will be partially enclosed and vented to a fabric collector (with an emission limitation of 0.01 gr/dscf) before being transported offsite by rail or truck. In examining other States regulations pertaining to storage, handling and transport of coke, Rule 1158 from the Antelope Valley Air Quality Management District appears to specifically address this subject. In most cases Rule 1158 would require total enclosure, however an exception to this is for sources that have moisture content of at least 12%. Therefore as part of the BAT requirement, the facility will be required to maintain the moisture content of at least 12% for the coke storage and handling. The moisture content must be monitored at least once per operator shift for the moisture content.

BAT for SO_2 Emissions

Emissions of SO_2 from the process heaters will be controlled by not burning fuel oil (except in the boilers 1,2,and 3, east reformer heater, crude heater and pretreater heater) and only burning desulfurized refinery fuel gas. The refinery fuel gas will be desulfurized to approximately 0.01 gr H_2S per dscf, which will limit SO_2 emissions to 0.0268 lb/MMBTU. This level of control is more stringent than the petroleum refinery NSPS (40 CFR 60 Subpart J) that limits H2S to 0.10 gr/dscf. The clearinghouse does not show any lower emission rates for a similar source. Fuel gas desulfurization is the only technology applied to similar sources. Therefore, United proposes burning only desulfurization refinery fuel gas to limit SO_2 emissions to 0.0268 lb/MMBTU as the top level of control and as BAT for the new process heaters.

The SRU3/ARU3 does not emit directly to the atmosphere but instead feeds into the existing tail gas treatment unit (TGTU). The TGTU will be modified to accommodate the additional feed but will contain the same emissions rates that were given in the original plan approval (62-312-031) and subsequent Title V Operating Permit. In order to control SO_2 emissions from the SRU3, only refinery fuel gas will be burned. In addition, a combination of efficient sulfur recovery and tail gas treatment will be used to limit emissions from the sulfur recovery unit. The highest overall sulfur recovery listed in the clearinghouse is 99.8%. As the top level of control and BAT, United proposed to limit SO_2 emissions to 250 ppmv at 0% O_2 and to achieve at least 99.8% overall sulfur recovery

<u>Air Quality Impact (Modeling Analysis)</u>

The final technical review of the air quality modeling analysis for United Refining Company’s (United) proposed Refinery Upgrade and Coker Project is complete. The analysis, submitted as part of Plan Approval Application 62-017G, demonstrates that the allowable emission increases of carbon monoxide (CO) from United’s proposed modification will not cause or contribute to air pollution in violation of the National Ambient Air Quality Standards (NAAQS).

The analysis was performed Tetra Tech FW, Incorporated (formerly Foster Wheeler Environmental Corporation). The Department's comments from the second technical review (see February 24, 2003 memorandum) have been adequately addressed. The analysis is consistent with the U.S. Environmental Protection Agency's (EPA) Guideline on Air Quality Models (GAQM), codified in Appendix W to 40 CFR § 51, and associated modeling guidance. Furthermore, the analysis satisfies the air quality analysis requirements of EPA's Prevention of Significant Deterioration of Air Quality (PSD) regulations, promulgated in 40 CFR § 52.21 and incorporated by reference in 25 Pa. Code § 127.83.

United is proposing a refinery upgrade to produce lower sulfur fuels. The expected increase in emissions of CO exceeds the established significant emission rate under 40 CFR § 52.21 (b) (23) (i), thus triggering an air quality analysis for CO.

The ISC-PRIME model was used in the analysis. ISC-PRIME, however, is not yet listed as a preferred model in the GAQM. Consistent with the recommendations of Section 3.2 of the GAQM, the Department requested approval to use ISC-PRIME in this analysis in a letter to the EPA Region III Administrator dated March 20, 2003. The permitting agency is required under 40 CFR § 52.21 (l) (2) to give public notice and provide the opportunity for public comment on the use of any alternative model.

ISC-PRIME (version 01228) was executed using Lakes Environmental ISC-AERMOD View software. Regulatory default options were chosen as well as options for rural dispersion coefficients and elevated terrain.

Twenty-one (five new plus sixteen existing) sources with a net emissions increase were entered in the model. All but three sources were entered as standard point sources. The existing T-241 Heater stack (Source ID 57) has a rain cover and was characterized in the model according to EPA's Model Clearinghouse policy stated in Memorandum 89 using an effective exit velocity and inside diameter. The proposed Hydrogen Flare stack (Source ID 231) was characterized in the model as a point source with an effective release height calculated according to SCREEN flare guidance. Realistic values for exit temperature, exit velocity, and inside diameter were entered instead of the SCREEN defaults. The proposed Ground Flare (Source ID 229) actually consists of hundreds of short flare pipes surrounded by a high wall. It was entered in the model as a single point source with an effective inside diameter calculated from the rectangular area formed by the surrounding wall. It would have been more appropriate to conservatively characterize this source as an area source with a release height equal to the height of the surrounding wall. The emissions from the ground flare would be so small, however, that an area source characterization in the model does not change the maximum CO impacts from the project.

Direction-specific building downwash parameters for each emission point were calculated by the PRIME version of EPA's Building Profile Input Program and entered in the model's source pathway.

The model's receptor domain covers a 20 by 20 km area centered on the facility. Three Cartesian receptor grids were centered on the facility with the following receptor spacing: a 6 by 6 km grid with 100 meter spacing, a 12 by 12 km grid with 250 meter spacing, and a 20 by 20 km grid with 500 meter spacing. Additional receptors were placed along the plant boundary at about 50-meter intervals.

Receptor elevations were determined from 7.5-minute U.S. Geological Survey digital elevation model (DEM) data using a distance-weighted interpolation of the nearest four DEM values.

One year of site-specific surface meteorological data was used in the model. Data was collected at two levels, 30 meters and 70 meters, from August 1, 1988 through July 31, 1989. The data collected at 30 meters was used in this analysis because it more closely represents the release heights of United's sources. The 30-meter data included temperature, wind direction, wind speed, and sigma-theta. Stability class was calculated from the sigma-theta data. Mixing heights were derived from upper air data collected at Pittsburgh International Airport, located approximately 175 km southwest of United.

The preliminary analysis predicts the maximum CO impacts to be below the Class II area significance levels. This is sufficient to demonstrate that the proposed modification will not cause or contribute to a violation of the CO NAAQS. A "full" impact NAAQS demonstration is therefore not necessary. There is no increment standard for CO. The results of the CO preliminary analysis are presented in the following table.

Preliminary Analysis Results for CO

Pollutant	Averaging Period	Highest Modeled Impact	Class II Area Significance Level
		$\mu g/m^3$	$\mu g/m^3$
CO	1-hour	804.7	2000
	8-hour	352.6	500

No visibility impairment analysis was performed since CO is not associated with degradation in visibility. No significant impact on soils and vegetation is anticipated. There is no expected impact on air quality from residential, commercial, and industrial growth associated with the project.

A Class I Area impact analysis was not necessary since the nearest Federal Class I Area is over 300 km away and beyond the generally accepted range of CALPUFF, the recommended long-range transport model.

<u>Modified Sources</u>

Crude Heater

The North Crude Heater will be equipped with LNB rated at 147 MMBTU/hr. The South Crude Heater will not be upgraded to LNB. The manufacturer of the LNB is NAO. The heater will have 14 burners. The average heat input is 122 MMBTU/hr per heater. The heater will burn refinery fuel gas at 104,901 cubic feet per hour (scfh) and 918.9 million cubic feet on an annual basis. The average BTU content of the refinery gas is 1020 BTU/scf. In addition, the applicant has indicated that there will be oil burners that will burn approximately 100 gallons per hour and 876,000 gallons per year of fuel per day. The BTU content of the oil is 150,000 BTU/gal. The emissions from the crude heater after modification are listed in the following table:

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
SO2	46.22	202.5
CO	9.27	40.6

NOx	6.68	29.5

The refinery fuel gas that is fed to the heater is monitored with an H2S CEM analyzer. There is also a fuel gas meter to monitor the amount of refinery gas combusted in the crude heater. NOx and CO emission tests will be required to verify compliance with the above limits.

Tail Gas Treatment Unit

The existing tailgas treatment unit (TGTU) will be modified to accommodate the increased throughput. The trays in the quench tower will be modified, piping will be modified, heat transfer and pump modifications will also occur. The SRU2 (existing) will not be modified and will continue feeding the TGTU. The new SRU3 will feed the TGTU in parallel with SRU2. The modification to the TGTU will allow the unit to accept the increase in load associated with SRU3. Once every three to four years the TGTU may need to come down for maintenance. During this time, the acid gas from the SRU units will be sent to the flare for destruction. The refinery charge will be reduced and sweet crude (low sulfur) will be run to reduce emission impacts. United has requested 30 days over two years as a permit limit to be allowed to send the acid gas to the flare. A notice sixty days in advance would be provided to the Department before any turnaround will occur.

Ferguson/TPA manufactured the existing TGTU. The Claus sulfur plant is rated for 70 long tons per day. H2S and SO2 are monitored using a CEMS. The CEMS are certified on an annual basis through relative accuracy testing. Mass flow calculations can determine SO2 emissions based on the H2S content of the fuel gas. Records will be kept on quantity of fuel gas combusted in the heater, feed rate to the unit, analysis of heat content of the fuel and oxygen content in the heater. This data will allow continuous monitoring of the emissions through calculations and analyzer output. The emissions from the unit are listed in the following table (the emissions are from the SRU2 Incinerator C108, these emissions do not include the emissions from the hot oil heater Source 108A):

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
SO2	12.0	52.6
CO	8.4	36.8
NOx	2.1	9.3
VOC	2.1	9.2

The NOx emissions are based on manufacturer guarantee. CO and VOC emissions are based on AP-42 emission factors. SOx emissions are based on the CEMS analyzer. The refinery fuel gas that is fed to the heater is monitored with an H2S CEM analyzer. There is also a fuel gas meter to monitor the amount of refinery gas combusted in the unit. Method 11 (40 CFR 60) will be performed annually to demonstrate the accuracy of the H2S CEMS. Method 6C will be performed initially 180 days after startup and every five years thereafter upon renewal of the Title V permit.

In addition to the above emissions, the unit will produce approximately 0.34 lb/hr and 1.5 TPY fugitive VOC emissions based on a permit restriction of 2500 ppm for LDAR.

New Sources

Delayed Coker Unit/ Material Handling

The Delayed Coker Unit will be manufactured by Foster Wheeler (or equivalent). The rated heat capacity for the unit is 116 MMBTU/hr. The unit will process material from the vacuum unit bottoms at a rate of approximately600 barrels per hour, 14,000 barrels per day, and 5.1 million barrels per year. The particulate from the unit will be controlled by a spray chamber at a design rate of 1550 scfm. The water flow rate for the chamber is approximately 100 gpm. The actual inlet and outlet volume of gases is 6000 acfm (at 1200ºF) and 800 acfm (at 1212ºF and 79% moisture). The inlet TSP is approximately 0.75 #/hr and the outlet is less than 0.25 #/hr. The removal efficiency of the spray chamber for TSP is approximately 66%. The unit will use 40 Low NOx Burners (LNB) rated at 2.9 MMBTU/hr each to reduce potential NOx emissions. The fuel gas flow rate is anticipated at 129,900 scfh based on a heat content of 900-1100 btu/scf. A flow meter will be used to measure and monitor the gas flow rate. A pressure indicator will be used to monitor the fuel gas pressure. The operating flow rate for the system is 37,400 scfm at approximately 310ºF. The emissions from the delayed coker unit are listed in the following table:

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	0.75	3.3
PM-10	0.1	0.4
SO2	2.71	11.9
CO	8.28	36.3
NOx	4.04	17.7
VOC	0.545	2.4

The particulate, PM-10, NOx and VOC emissions are based on manufacturer guarantee. CO emissions are based on AP-42 emission factors. SOx emissions are based on 162 ppm H2S Mass Balance. The refinery fuel gas that is fed to the heater is monitored with an H2S CEM analyzer. There is also a fuel gas meter to monitor the amount of refinery gas combusted in the coker unit. NOx and CO emission tests will be required to verify compliance with the above limits.

In addition to the above emissions, the coker unit will produce approximately 13.24 lb/hr and 58 TPY fugitive VOC emissions based on the EPA Protocol for LDAR.

The coke will be removed from the drums using high-pressure water, drained and transported with a front-end loader to a conveyor and transferred to either a rail car or truck. The conveyor will be equipped with a baghouse to control fugitive dust emissions from this operation. The fabric collector will have a design inlet volume of 1500 scfm at 280ºF and air to cloth ratio of 3.5:1. The bags will be cleaned with reverse air jets initiated by an expected pressure drop range. This range along with the manufacture, bag type, dimensions and type of fabric will be required to be identified within 30 days of startup. The emissions from the exhaust of the collector will be limited to 0.01 gr/dscf, 0.13 pound per hour and 0.56 TPY. The collector will be required to have a magnehelic gauge or equivalent installed to indicate the pressure drop across the collector.

FCC Feed Hydrotreater Heater

The FCC Feed Hydrotreater will be manufactured by Foster Wheeler (or equivalent). The rated heat capacity for the unit is 91 MMBTU/hr. The unit will process hydrotreater reactor material at a rate of approximately 1040 barrels per hour FCC Feed, 25,000 barrels per day FCC Feed, and 9.1 million barrels per year FCC Feed. The unit will use 11 Low NOx Burners (LNB) rated at 8.25 MMBTU/hr each to reduce potential NOx emissions. The emissions from the FCC Feed Hydrotreater are listed in the following table:

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	0.68	2.9
PM-10	0.09	0.40
SO2	2.44	10.3
CO	7.46	31.6
NOx	1.82	7.7
VOC	0.49	2.1

The particulate, PM-10, and NOx emissions are based on manufacturer guarantee. CO and VOC emissions are based on AP-42 emission factors. SOx emissions are based on 162 ppm H2S Mass Balance. In addition to the above emissions, the FCC Feed Hydrotreater will produce approximately 4.95 lb/hr and 21.7 TPY fugitive VOC emissions from various valves, flanges, pumps and sample connectors based on the EPA Protocol for LDAR.

Hydrogen Reformer Unit

The Hydrogen Reformer Unit will be manufactured by Foster Wheeler (or equivalent). The unit will process 1.4 million standard cubic feet per hour (MMSCF/hr), 33.3 MMSCF/day, and 12,121.2 MMSCF/yr of Natural Gas Feed (converting to Hydrogen using steam followed by final purification of the Hydrogen in a Pressure Swing Absorption [PSA] system). The rated heat capacity for the unit is 344 MMBTU/hr. The unit will use 19 Low NOx Burners (LNB) rated at 18.1 MMBTU/hr each to reduce potential NOx emissions. The fuel gas flow rate is anticipated at 382,200 scfh based on a heat content of 900-1100 btu/scf. A flow meter will be used to measure and monitor the gas flow rate. A pressure indicator will be used to monitor the fuel gas pressure. The exhaust flow rate for the system is 98,300 scfm at approximately 350ºF. The emissions from the Hydrogen Reformer Unit are listed in the following table:

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	1.60	7.0
PM-10	1.60	7.0
SO2	9.22	40.4
CO	28.21	123.6
NOx	13.76	60.3
VOC	1.03	4.5

The particulate, PM-10, NOx and VOC emissions are based on manufacturer guarantee. CO emissions are based on AP-42 emission factors. SOx emissions are based on 162 ppm H2S Mass Balance. The refinery fuel gas that is fed to the heater is monitored with an H2S CEM analyzer. There is also a fuel gas meter to monitor the amount of refinery gas combusted in the Hydrogen Reformer Unit. NOx and CO emission tests will be required to verify compliance with the above limits.

In addition to the above emissions, the Hydrogen Reformer Unit will produce approximately 5.16 lb/hr and 22.6 TPY fugitive VOC emissions based on the EPA Protocol for LDAR.

Both 25 Pa Code Chapter 123.51 (pertaining to combustion units with rated heat input greater than 250 MMBTU/hr) and Chapter 145.1-145.85 (pertaining to the NOx allowance trading regulations) require the installation of a NOx CEM for this source.

Emergency Hydrogen Flare

The Hydrogen flare is an elevated flare that is manufactured by NAO and will burn fuel gas from upsets at the refinery. The flare stack diameter and height are 60 inches and 150 feet, respectively. The flare will accommodate higher instantaneous emergency loads from the new units. New emissions will occur as a result of combustion of gas to maintain the flare's pilot light. The applicant has indicated that an ultraviolet pilot light monitor and pressure transmitters would be installed to indicate a continuous pilot and when gas was flaring. Information will be monitored and recorded on a DCS system. The data will indicate when upsets occur and will alert the operator for corrective action. Fugitive emissions (such as valves) for the flare will also be monitored according to the LDAR requirements. Emissions from the flare (from the pilot only) were estimated using AP-42 emission factors. The opacity from the flare will be minimized using steam to assist in combustion. The control equipment will be operated and maintained according to the manufacturer' recommendations. The emissions from the flare are listed in the following table (these emissions are fro the pilot only). The particulate, PM-10, CO, NOx and VOC emissions are based on AP-42 emission factors

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	0.1	0.4
PM-10	0.1	0.4
CO	0.53	2.3
NOx	0.44	1.9
VOC	0.41	1.8

Sulfur Recovery Unit 3 (SRU3) / Amine Regeneration Unit (ARU3)

The new SRU is rated at 115 Long Tons Per Day (LTPD). Sour gas from the refinery sources (such as the FCC and the Crude Unit) is converted to acid gas using absorption with an amine solution. The amine becomes rich and it must be converted back to lean amine through the amine regeneration unit. The Vacuum Vent Gas Unit is a separate amine recovery unit that collects the vapors only from the vacuum tower and removes H2S. The acid gas from the amine regenerator is sent to the SRU. The tail gas from the SRU3 goes to the existing Tail Gas Treatment Unit (TGTU) where most of the sulfur contained in the tail gas stream is removed as H2S and returned to the SRU as feed. The TGTU also produces a treated vent gas producing less than 250 ppmv of SO_2 after incineration. The emission limits for this source were previously mentioned (see above paragraph entitled Tail Gas Treatment Unit).

The existing Hot Oil Heater is rated at 5.6 MMBTU/hr while firing refinery gas. The emissions from the heater are included in the following table:

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	0.04	0.2
PM-10	0.04	0.2
SO2	0.09	0.4
CO	0.39	1.7
NOx	0.39	1.7
VOC	0.03	0.1

Emergency Pit Flare

The pit flare is a ground flare that is manufactured by NAO and will burn fuel gas from upsets at the refinery. The flare will accommodate higher instantaneous emergency loads from the new units. The pit flare is a network of several small burners enclosed by an earthen wall to block and absorb the radiation during the flaring occurrences. New emissions will occur as a result of combustion of gas to maintain the flare's pilot light. The applicant has indicated that an ultraviolet (UV) pilot light monitor and pressure transmitters would be installed to indicate a continuous pilot and when gas was flaring. Information will be monitored and recorded on a DCS system. The data will indicate when upsets occur and will alert the operator for corrective action. Fugitive emissions (such as valves) for the flare will also be monitored according to the LDAR requirements. Emissions from the flare (from the pilot only) were estimated using AP-42 emission factors. The opacity from the flare will be minimized using steam to assist in combustion. The control equipment will be operated and maintained according to the manufacturer' recommendations. The emissions from the pit flare are listed in the following table (these emissions are from the pilot only).

Pollutant	Emission limit (#/hr)	Emission limit (TPY)
Particulate	0.1	0.4
PM-10	0.1	0.4
SOx	0.35	1.5
CO	1.07	4.7
NOx	0.88	3.9
VOC	0.82	3.6

Source Emission Limits

The potential emissions from the individual sources could be greater than those reported in the application if different fuels are applied or operating scenarios occur. The applicant has developed the potential limits for the individual sources at the facility based on AP-42, stack tests, and fuel types. The following table is a summary of the potential emission limits in lb/hr and TPY. The limits will be applied to the permit to ensure the increases do not exceed the allowable and thereby trigger additional NSR or PSD (for pollutants other than CO).

ID	Source	NOx #/hr/TPY	CO #/hr/TPY	VOC #/hr/TPY	TSP #/hr/TPY	PM-10 #/hr/TPY	SO2 #/hr/TPY
31	Boilers 1,2,3 (gas) & (oil)	7.63 26.3	3.86 16.3	0.24 1.00	2.86 7.20	2.54 6.40	73.74 169.30
34	Boiler 4	23.77 68.8	14.02 40.6	0.92 2.7	1.27 3.7	1.27 3.7	4.58 13.3
35	Boiler 5	3.92 17.2	3.28 14.4	0.22 0.9	0.30 1.3	0.30 1.3	1.07 4.7
42	FCC Charge Heater	1.80 7.5	3.69 15.4	0.24 1.0	0.34 1.4	0.34 1.4	1.21 5.0
44	DHT1 Heater	0.29 1.3	0.25 1.1	0.02 0.1	0.02 0.1	0.02 0.1	0.08 0.4
49	East Reformer Heater (gas) & (oil)	12.63 50.3	4.69 18.7	0.3 1.2	2.2 9.2	2.0 8.2	53.36 220.5
50	North Crude Heater (gas) & (oil)	6.68 29.2	9.17 40.6	0.6 2.6	2.35 10.3	2.16 9.4	46.22 202.5
50A	South Crude Heater (gas) & (oil)	21.62 94.6	6.99 30.6	0.42 1.8	6.84 30.0	6.05 26.5	180.79 791.8
51	Pretreater Heater (oil) & (Gas)	5.1 21.6	2.35 10.1	0.14 0.6	2.12 8.8	1.88 7.80	55.47 230.3
52	West Reformer Heater	8.49 34.2	5.08 20.5	0.33 1.3	0.46 1.9	0.46 1.9	1.66 6.7
53	Sat Gas Reboiler	1.86 8.2	1.56 6.8	0.10 0.4	0.14 0.6	0.14 0.6	0.51 2.2
54	Vacuum Heater	1.10 4.8	3.77 16.5	0.25 1.1	0.34 1.5	0.34 1.5	1.23 5.4
55	DHT2 Heater	2.46 10.5	3.36 14.4	0.22 0.9	0.31 1.3	0.31 1.3	1.10 4.7
56	Prefrac Reboiler 2	1.38 5.8	1.89 7.9	0.12 0.5	0.17 0.7	0.17 0.7	0.62 2.6
57	T-241 Heater	1.27 4.3	12.2 41.1	0.07 0.2	0.10 0.3	0.10 0.3	0.35 1.2
101	FCC Regenerator	8.85 38.8	13.44 58.8	0.0 0.0	18.96 83.0	12.36 54.1	85.00 372.3
102	Combo Flare	2.24 9.8	1.33 5.8	1.02 4.5	0.12 0.5	0.12 0.5	0.43 1.9
102	FCC Flare	2.24 9.8	1.33 5.8	1.02 4.5	0.12 0.5	0.12 0.5	0.43 1.9

104	West FCC KVG	1.20 5.3	0.74 3.3	0.02 0.1	0.00 0.0	0.00 0.0	0.01 0.01
105	Middle FCC KVG	0.29 1.3	0.44 1.9	0.44 1.9	0.00 0.0	0.00 0.0	0.14 0.6
106	East FCC KVG	0.29 1.3	0.44 1.9	0.44 1.9	0.00 0.0	0.00 0.0	0.14 0.6
107	Sat Gas KVG	2.15 9.4	2.65 11.6	1.47 6.5	0.00 0.0	0.00 0.0	0.14 0.6
108	SRU2 Incinerator	2.10 9.3	8.40 36.8	2.10 9.2	0.00 0.0	0.00 0.0	12.00 52.6
108	SRU2 Hot Oil Heater	0.39 1.7	0.39 1.7	0.03 0.1	0.04 0.2	0.04 0.2	0.09 0.4
211	Vapor Combustion Unit	7.5 15.4	18.8 38.4	18.8 38.4	0.64 2.8	NA	0.81 0.76
226	Delayed Coker Heater	4.04 17.7	8.28 36.3	0.55 2.4	0.75 3.3	0.10 0.4	2.71 11.9
227	FCC Feed Hydrotreater	1.82 7.7	7.46 31.6	0.49 2.1	0.68 2.9	0.09 0.4	2.44 10.3
228	Hydrogen Reformer	13.76 60.3	28.21 123.6	1.03 4.5	1.60 7.0	1.60 7.0	9.22 40.4
229	Ground Flare	0.88 3.9	1.07 4.7	0.82 3.6	0.10 0.4	0.10 0.4	0.35 1.5
231	Hydrogen Flare	0.44 1.9	0.53 2.3	0.41 1.8	0.05 0.2	0.05 0.2	0.18 0.8
232	Baghouse	NA	NA	NA	0.14 0.6	0.10 0.6	NA
	Tank Emissions	NA	NA	24.57 107.6	NA	NA	NA
	Fugitive Emissions from Components	NA	NA	58.08 254.4	NA	NA	NA
	Fugitive Cooling Water Tower	NA	NA	0.25 1.1	0.14 0.6	0.10 0.6	NA
	Wastewater Fugitives	NA	NA	73.11 320.2	NA	NA	NA
	Particulate Fugitives (handling)	NA	NA	NA	0.46 2.0	0.30 1.2	NA

The combustion units mentioned above shall only burn refinery fuel gas except for boilers 1,2,3, the east reformer heater, the north and south crude heaters, and the pretreater heater which may burn either refinery fuel gas or oil as indicated in the above table. The applicant will be required to maintain the fuel usage of each fuel type for each combustion unit and to use the fuel usage combined with the tested emission rate in lb/MMBTU of the most recent emission test to calculate the total annual emissions of each pollutant, respectively. The annual totals indicated in the above table are based on a 12-month rolling basis. The fuel oil burned for the boilers, east reformer heater, crude heater and pretreater heater shall continue to be sampled in accordance with the testing requirements for the sulfur content as indicated in the Title V Operating Permit.

The Delayed Coker unit, FCC Feed Hydrotreater, and Hydrogen Reformer shall conduct initial stack tests to determine compliance with the NOx, CO, VOC, TSP, PM-10 and SO2 emissions within 60 days of startup and once every five years thereafter. The North Crude Heater shall conduct initial tests for NOx, CO, VOC, TSP, PM-10 and SO2 within 60 days (with the North Crude Heater and South Crude Heater running to establish initial compliance (based on the #/MMBTU limits) because the North and South Crude Heaters share one common stack). Afterwards, the applicant will be required to conduct annual tests on the North and South Crude Heaters and compliance may be determined using a mass balance for NOx emissions and once every 5 years for SO2, CO, VOC and TSP. Boilers 1,2,3, and 5, and the FCC Charge heater shall be tested on an annual basis and may use a Department approved portable analyzer in accordance with the RACT permit to determine compliance with the NOx emission limits. Boilers 1,2,3, and 5, and the FCC Charge heater shall conduct emission tests for CO, VOC, SO2 and TSP at least once every 5 years. The DHT1, pretreater heater, Sat Gas Reboiler, Vacuum heater, DHT2, Prefrac Reboiler 2, T-241 heater, FCC regenerator, West, Middle, East & Sat Gas KVG's the SRU2 incinerator, the SRU2 hot oil heater, the Vapor Combustion Unit, and the West Reformer Heater shall be tested at least once every 5 years for NOx, CO, VOC, SO2, and TSP in accordance with the Title V Operating Permit.

Issuance of the plan approval is recommended with the appropriate conditions in the plan approval.

cc: New Source Review Section – Harrisburg
Warren District Field Office – Air Quality