Exhibit 2

# EXHIBIT 2

Illinois Environmental Protection Agency
CORE Project Summary

Illinois Environmental Protection Agency
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# Project Summary for Construction Permit Applications from ConocoPhillips Wood River Refinery and ConocoPhillips Wood River Products Terminal for a Coker and Refinery Expansion (CORE) Project

<u>Wood River Refinery</u>
Site Identification No.: 119090AAA
Application No.: 06050052
Date Received: May 15, 2006

<u>Wood River Products Terminal</u>
Site Identification No.: 119050AAN
Application No.: 06110049
Date Received: November 27, 2006

<u>Schedule</u>
Public Comment Period Begins: March 24, 2007
Public Hearing: May 8, 2007
Public Comment Period Closes: June 7, 2007

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## I. INTRODUCTION

ConocoPhillips operates the Wood River Refinery located in Roxana, Illinois to produce a variety of petroleum products for distribution in the St. Louis, Chicago, and Indianapolis Metropolitan areas and throughout the Midwest. Wood River is positioned by refining capacity and by geographical location to process the growing volumes of Canadian heavy crude. The Coker and Refinery Expansion (CORE) Project entails installing facilities to increase both the total crude processing and percentage of heavier crude at the Wood River Refinery in order to increase the supply of petroleum products to the Upper Midwest.

In order to handle the increased product throughput, ConocoPhillips is also proposing certain changes at the Wood River Products Terminal (also owned by ConocoPhillips). The Illinois EPA is considering ConocoPhillips's CORE project and the changes to the Wood River Products Terminal to comprise a single larger project for the purpose of the federal rules for Prevention of Significant Deterioration (PSD) and the state rules for Major Stationary Sources Construction and Modifications (MSSCAM).

The Illinois EPA has reviewed the applications from both the refinery and the terminal and made a preliminary determination that both applications for the proposed CORE project meet applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the air pollution control construction permits that it would propose to issue for this project. However, before issuing these permits, the Illinois EPA is holding a public comment period, with public hearing to receive oral and written comments on the proposed issuance of these permits and the terms and conditions of the draft permits.

## II. PROJECT DESCRIPTION

The CORE project entails various changes to the refinery to increase both the total crude processing and the percentage of heavier crude at the refinery. The following are the key elements occurring at the refinery:

- New delayed coking unit and associated coker units to convert vacuum residue to clean products and conversion feeds which will enable the processing of higher volumes of heavy crude;
- Metallurgical upgrades and other equipment revisions of Distilling Unit 1 (DU-1) and the addition of a new Vacuum Flasher (VF5) to handle the high acid, high sulfur heavy crudes;
- Restart the idled Distilling Unit 2 Lube Crude (DU-2 LC) column to provide additional crude unit processing capacity;
- Metallurgical upgrades and other equipment revisions of Fluid Catalytic Cracking Unit 1 (FCCU 1) and Fluid Catalytic Cracking Unit 2 (FCCU 2) to handle the higher acid charge and change in the unit yields, and installation of new wet gas scrubbers (WGS) and selective catalytic reduction (SCR) systems on the flue gas from these units;

- Restart the Distilling West Catalytic Cracking Unit (FCCU 3) and associated equipment to allow for the processing of the additional gas oil
- New hydrogen plant;
- Restart of Lube Vacuum Fractionation Column as a Hydrocracker Post-Fractionator (HCF);
- Restart of Catalytic Feed Hydrotreater as an Ultra Low Sulfur Diesel Hydrotreater (ULD-2);
- Additional sulfur processing capacity;
- Additional amine treating and sour water stripping;
- Modifications to the wastewater treatment plant.

In order to handle the increased product throughput, ConocoPhillips is also proposing certain changes at the Wood River Products Terminal (also owned by ConocoPhillips). The following are the key elements occurring at the terminal:

- One new gasoline tank;
- Two new ethanol tanks;
- Two new distillate oil tanks;
- Expansion of the existing truck loading rack;

## A. Process Descriptions (Refinery)

### 1. North Property Department

The North Property Operating Department will consist of a new Vacuum Flasher Unit (VF5), delayed coking unit (DCU2) and supporting facilities. An intermediate stream from existing Distilling Unit 1 (DU-1) and the restarted Distilling Unit 2 (DU-2) Lube Crude units (LC) will feed VF5. Another intermediate stream from VF5 and a stream from the currently operating Vacuum Flashers VF-2 and VF-4 will serve as DCU2 charge.

### 1.1 Vacuum Flasher 5 (VF5)

A single new 400 mmBtu/hr process heater will be constructed that fires gaseous fuels. It will be used to supply process heat to VF5. The heater will be equipped with Ultra Low nitrogen oxides ($NO_x$) Burners (ULNBs). Vacuum system vent gas will be treated for hydrogen sulfide ($H_2S$) removal and returned to the VF5 furnace for combustion in a specially designed burner separate from the refinery's main plant fuel gas system. The heater will be equipped with a continuous emission monitoring system (CEMS) for carbon monoxide (CO) to demonstrate compliance with the USEPA's NESHAP regulations for Heaters and Boilers. The vent gas will be monitored with a CEMS for hydrogen sulfide ($H_2S$) to demonstrate compliance with New Source Performance Standard (NSPS) Subpart J. The overall increase in vacuum flasher capacity will be used to produce coker feed and will utilize existing storage facilities.

### 1.2 Delayed Coking Unit 2 (DCU2)

The project centers on the construction of a new four-drum delayed coker unit, DCU2. Process heat will be supplied to the unit by two new coker charge heaters. Each heater is sized for a maximum firing rate of 330 MMBtu/hr firing gaseous fuels. Coker overhead vapors will be separated by a new coker gas plant where methane/ethane fractions will be separated to an amine treater to remove $H_2S$ prior to routing to the main refinery fuel gas system. Propane ($C_3$) and butane ($C_4$) compounds will be diethanolamine (DEA) and caustic treated prior to sale or downstream processing. Off-gas from the caustic regeneration system will be treated and routed to the DCU2 charge heaters. Both DCU2 heaters will be equipped with ULNBs and a CEMS for CO and $SO_2$ to demonstrate compliance with the USEPA regulations included in Heater and Boiler MACT and NSPS Subpart J.

The delayed coking process includes the batch operation of unheading and cutting coke from the previously on-stream drum into a pit directly below the drum. The cut coke will then be transferred to a crusher/conveyor system via crane, crushed and conveyed to either a coke laydown pile or directly to a truck loading silo. Material that has been transferred to the coke laydown pile will normally be reclaimed by a reclaimer/stacker. If necessary, a front end loader may be used as a backup for the reclaimer/stacker. The reclaimed material will be reclaimed to the truck silo for loading. All coke will be transported off-site by tractor trailer trucks.

## 1.3 Delayed Coker Naphtha Hydrotreater (DCNH)

The naphtha stream produced at DCU2 is fed directly to the delayed coker naphtha hydrotreater (DCNH) where the material is hydrotreated and stabilized prior to routing to storage and/or downstream units. Process heat required for the process will be supplied by a new 20 MMBtu/hr heater fired with gaseous fuels and equipped with ULNBs.

## 1.4 Supporting Facilities

The new North Property Operations will be supported by a new cooling water tower and elevated flare (Delayed Coker Flare). With a circulating rate of 50,000 gpm, the cooling water tower will supply cooling water for the North Property Operating Department. It will be constructed with high efficiency drift eliminators to minimize the amount of water loss due to evaporation.

The Delayed Coker Flare will service all of the new operating units in North Property Operating Department and will be equipped with a Flare Gas Recovery System (FGRS) which will act to recover normally recurring streams for use as fuel, rather than flaring. Gas recovered by the FGRS will be returned with the VF5 vacuum overhead hydrocarbon system and treated prior to combustion in the VF5 heaters.

## 2. Distilling-Gas Operating Department

As part of the CORE Project certain recently idled units will be returned to service to increase the refinery's production capabilities.

### 2.1 Distilling Unit 2 Lube Column (DU-2 LC)

Crude oil processing capacity will be expanded by the restart of DU-2 LC. The restart of DU-2 LC allows for the facility to process additional crude oil and produce additional intermediate products that serve as feed for downstream processing units. The CORE Project is anticipating increased throughput of crude oil, and production of jet fuel and ultra low sulfur diesel. Two new crude tanks will be constructed in the South West Tank Farm.

### 2.2 Distilling West - Fluidized Catalytic Cracking Unit-3 (FCCU 3)

The idled Fluidized Catalytic Cracking Unit (FCCU 3) at Distilling West will also be restarted as part of the CORE Project. FCCU 3 will be equipped with a Wet Gas Scrubber (WGS) for sulfur dioxide ($SO_2$) and particulate matter (PM) control. Additionally, FCCU 3 will be equipped with Selective Catalytic Reduction (SCR) for $NO_x$ control. The restart of FCCU 3 will require the unit be treated as a new unit rather than an existing unit, as required by a Consent Decree.

Overhead hydrocarbons from the FCCU Main Fractionator will be routed to the existing Distilling West (DW) cracked gas plant where methane/ethane fractions will be routed to either the DW or main plant's refinery fuel gas system. Propane ($C_3$) and butane ($C_4$) compounds will be DEA and caustic treated prior to sale or downstream processing. Off-gas from the DW caustic regeneration system will be routed to the DW caustic regenerator thermal oxidizer. An existing cooling water tower will be restarted to supply process cooling water to FCCU 3.

## 3. Alky Cracking Utilities Operating Department

Along with the restart of FCCU 3, the composition of the feed stream to the existing fluidized catalytic cracking units, FCCU 1 and FCCU 2, will be affected by the implementation of the CORE Project.

### 3.1 Cracking Units

Changes planned for Fluidized Catalytic Cracking Unit 1 (FCCU 1) will include metallurgical upgrades to the feed preheat exchange equipment and the feed piping, internal changes to the fractionator trays, installation of new light-cycle oil cooling, alterations to the high pressure separator, and CO heater enhancements. Fluidized Catalytic Cracking Unit 2 (FCCU 2) alterations will include metallurgical upgrades feed preheat exchange equipment and the feed piping, internal changes to the fractionator trays, installation of new light-cycle oil cooling, alterations to the high pressure separator, and CO heater enhancements. The installation of an SCR system and a Wet Gas Scrubber (WGS) on FCCU 2 and FCCU 2 will greatly reduce the emissions of these units. The existing Electrostatic Precipitators on each of the existing FCCUs will be decommissioned with the startup of the WGS.

Post-CORE Operations will entail storage of additional catalytic cracking feed, catalytic naphtha and ultra low sulfur diesel.

3.2 Ultra Low Sulfur Diesel 2 Unit (ULD2)

The existing Catalytic Cracking Feed Hydrotreater Unit (CFHT) will be converted into an Ultra Low Sulfur Diesel (ULSD) Unit. The conversion will require the installation of an additional process heater. This new heater will operate at a maximum rated heat input of 55 MMBtu/hr while firing gaseous fuels, and will be equipped with ULNB.

3.3 Alkylation Unit (Alky)/Benzene Extraction Unit (BEU)

The increased catalytic cracking and coker operations will result in an increase in alkylation production and increased firing in the existing Alky HM-2 Heater due to higher alkylate production. A new heater will be built to replace two existing, older heaters. This new heater will operate at a maximum rated heat input of 250 MMBtu/hr while firing gaseous fuels, and will be equipped with ULNB. This heater will accommodate the higher refining rates with the increased catalytic naphtha production. An increased alkylate throughput through gasoline component storage tanks is also expected.

4. Aromatics Operating Department

4.1 Hydrocracking Unit (HCU)

The Hydrocracking Unit (HCU) will be expanded by returning to service the idled Lubricants Vacuum Fractionation Column (VFC) as a hydrocracker post-fractionator (HCF). The current HCU recycles fractionator bottoms, which contains significant amount of diesel range material, to the front of the reactor increasing overall naphtha conversion of the unit. Rerouting the existing HCU fractionator bottoms to the HCF allows for recovery of the diesel range product. The idled HCF Heater will be restarted to supply heat to the HCF. The HCF heater will fire gaseous fuels, in addition to the hydrocracker post fractionator vent gases as was previously operated. Since sulfur compounds deactivate the HCU catalyst, the feed to the HCF will already be hydrotreated for sulfur removal, and the vent gas has negligible amounts of hydrogen sulfide. The diesel recovered in the HCF will be mixed with the existing diesel streams for production of on-specification ULSD. An existing, idle cooling water tower will be restarted to supply process cooling water to the HCU post fractionator.

4.2 Hydrogen Plant 2 (HP2)

The increased hydrogen demand from the expanded desulfurization and hydroprocessing operations throughout the refinery will be satisfied by the construction of a new hydrogen plant, (HP2). A continuous emission monitoring system (CEMS) for CO will be installed on a new heater. This new heater will operate at a maximum rated heat input of 1,275 MMBtu/hr while firing a combination of gaseous fuels including Pressure Swing Adsorption (PSA) off-gas from the hydrogen plant, which is primarily carbon monoxide and light hydrocarbons. Since sulfur compounds deactivate the reforming catalyst used for hydrogen production, PSA off gas contains negligible amounts of hydrogen sulfide ($H_2S$).

A dedicated flare and 15,000 gpm cooling water tower will be constructed to support the unit operations.

4.3 Catalytic Reformers

Total reformer feed production will increase up to the hydrotreating/reforming capacity of the refinery. This increased production will also result in an increase in reformate throughput for the existing storage facilities.

5. Sulfur Plant

The CORE Project will construct two additional sulfur recovery unit trains (SRU-E and SRU-F) which include separate Claus Trains, a Tail Gas Units (TGU) and Thermal Oxidizers. Each of the new thermal oxidizers will be equipped with an $SO_2$ CEMS. Along with the additional recovery facilities there will be a new sour water stripper and additional sulfur storage and loading facilities. The feed for the sour water stripper will be stored in an existing tank that will be modified by adding a dome to the external floating roof to minimize the potential odor issues with this material. The vapors recovered from the storage and loading facilities will be routed to the Claus Trains or TGU to ensure that captured residual $H_2S$ and $SO_2$ is controlled. A new cooling water tower will be installed to provide cooling water to the new SRUs.

6.0 Other Support Facilities

The CORE Project also requires significant upgrades in the refinery's critical supporting facilities, including wastewater treating capabilities of the plant. In particular, the wastewater treatment plant (WWTP) will be upgraded to accommodate an increase in wastewater flow and solids and organic loading due to increased refining operations and to treat the wastewater from the new wet gas scrubbers (WGS) on FCC Units. The modifications include new scrubber solids clarifiers, reconfiguring Pond 1 to activated sludge service, modifications to Pond 2 with a denitrification zone added to the back of the pond, and a new final clarifier. In addition, new process sumps will be installed to support the new and expanded process units. Emissions from the existing primary treatment system are controlled by existing flares.

## B. Process Descriptions (Terminal)

### 1. Loading Rack

The existing loading rack will be physically modified by adding loading bays/arms. The rack will continue to load petroleum products and various gasoline feed stocks into trucks. A new loading rack control device (e.g., vapor combustion unit (VCU)) will be installed to control VOM emissions from the loading rack.

### 2. Storage Tanks

New tanks will be installed as part of this project as follows: two ethanol tanks with internal floating roofs, one gasoline tank with internal floating roof, and two new distillate tanks. Several existing tanks will experience an increase in utilization as a result of this project. These existing tanks will not be physically modified.

## C. Project Startup Schedule

Given the scope of the CORE Project, activities will be completed in phases. Certain restarted units will be brought on-line prior to the new units to increase refining capacity. It is expected that the restart of some existing, but idle, equipment will occur during 2008. With the increased crude and cracking capacity, some existing and operating equipment will experience increased utilization during 2008. The remaining grassroots construction and modifications are expected to be completed and on-line for a 2009 startup.

# III. PROJECT EMISSIONS

The potential annual emissions of this project are summarized below. Actual emissions will be less than the potential emissions to the extent that the refinery would operate at less than its maximum capacity and control equipment normally operates to achieve emission rates that are lower than the applicable standards and limitations.

Annual Emissions of the Project (Tons/Year)[a]

| | $NO_x$ (PSD) | $NO_x$ (NA NSR) | CO | $SO_2$ | VOM | PM | $PM_{10}$ | $PM_{2.5}$[b] |
|---|---|---|---|---|---|---|---|---|
| Refinery CORE Increases | 986.7 | 948.6 | 1,039.1 | 1,548.3 | 329.0 | 319.2 | 224.8 | 224.8 |
| Terminal CORE Increases | 9.5 | 9.5 | 23.8 | 0.0 | 54.0 | 10.0 | 1.9 | 1.9 |
| Refinery CORE Decreases (shown as negative values) | -1,043.7 | -1,043.7 | -15.5 | -11,131.4 | -0.3 | -131.3 | -131.3 | -131.3 |
| Creditable Contemporaneous Emission Increases | 775.4 | 896.6 | 171.3 | 148.8 | 140.8 | 53.7 | 53.7 | 53.7 |
| Creditable Contemporaneous Emission Decreases (shown as negative values) | -732.6 | -822.9 | -288.4 | -1,733.6 | -116.5 | -396.0 | -381.2 | -398.6 |
| Net Emissions Increase (or Decrease) | **-4.7** | **-11.9** | **930.3** | **-11,167.9** | **407.0** | **-144.4** | **-232.1** | **-249.5** |

Notes:

a. Annual emissions of the project include the Wood River Products Terminal.

b. Emissions of $PM_{2.5}$ in this table are expressed as emissions of $PM_{10}$, which is being used as a surrogate pollutant.

## IV. APPLICABLE EMISSION STANDARDS

The application shows that the proposed project will readily comply with applicable state and federal emission standards, including the emission standards and regulations of the State of Illinois (35 Ill. Adm. Code: Subtitle B) and applicable federal emission standards adopted by the USEPA (40 CFR Part 60 and 40 CFR Part 63).

## V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The proposed project is considered a major project under the federal rules for Prevention of Significant Deterioration (PSD), 40 CFR 52.21, for emissions of carbon monoxide (CO). The Illinois EPA has been delegated authority by the United States EPA to administer the federal PSD program in Illinois. These rules are relevant for these pollutants because the refinery is located in an area whose air quality is classified as attainment for CO.

Because the ConocoPhillips is already a major source of emissions, the criterion for whether the proposed project is considered major is whether the permitted emissions of the project for one or more pollutants regulated by PSD would qualify as significant, as defined by the PSD rules. The project meets this criterion for CO with a permitted increase in annual emissions that is greater than 100 tons. The project is therefore subject to the certain substantive requirements of the PSD rules for CO.

The substantive requirement of the PSD rules for a major project for a pollutant are: 1) A case-by-case determination of Best Available Control Technology (BACT), 2) An ambient air quality impact analysis to confirm that the project would not cause or contribute to a violation of the National Ambient Air Quality Standard(s) (NAAQS) or applicable PSD increment(s); and 3) An assessment of the impacts on soils, vegetation and visibility.

## A. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The proposed CORE Project triggers the PSD permitting requirements due to the potential CO emissions increase. The new and modified units that will contribute to the increase in CO emissions include:

- Eight process heaters,
- Two existing fluidized catalytic cracking units,
- One restarted fluidized catalytic cracking unit,
- Two new flares,
- Three thermal oxidizers (associated with the two new sulfur recovery units and the cracked gas plant), and
- Loading Rack Control Device (e.g., vapor combustion unit)

As part of a PSD review for CO emissions, a Best Available Control Technology (BACT) analysis is required. The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21]. Consistent with USEPA guidance, BACT was evaluated using a "top-down" analysis. Presented below are the five basic steps of a top-down BACT review procedure as identified by the USEPA New Source Review Workshop Manual. Under the top-down analysis for the emission unit in question, the most stringent control available for a similar or identical source or source category is presumed to constitute BACT unless the impacts accompanying this level of control are excessive. Then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique, environmental, economic, or cost objections.

Step 1. Identify all control technologies.
Step 2. Eliminate technically infeasible options.
Step 3. Rank remaining control technologies by control effectiveness.
Step 4. Evaluate most effective controls and document results.
Step 5. Select BACT.

The USEPA has consistently interpreted the BACT requirement as containing two core elements that must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies, (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."

The BACT requirement only applies for the pollutants that are subject to PSD review and the emission units that are newly installed or physically modified, or have incurred a change in the method of operation. Therefore, the BACT analysis is only required for new or modified CO emission units included in this project.

1. Process Heaters

The only CO emissions control strategy identified in the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database for refinery fuel gas or natural gas fired process heaters is to adhere to good combustion practices. Based on the manufacturer's guarantee, each of the affected process heaters will be able to meet a CO emission rate of 0.02 lb/MMBtu through the use of good combustion practices.

**Proposed BACT Control**: The affected heaters shall be maintained and operated with good combustion practices to reduce emissions of CO. Emissions of CO from the affected heaters shall not exceed 0.02 lb/mmBtu, HHV.

2. Distilling West (DW) Cracked Gas Plant

The only CO emissions control strategy identified in the RBLC database for refinery fuel gas or natural gas fired thermal oxidizers is to adhere to good combustion practices. Several of the previous BACT determinations noted that the thermal oxidizer acts as a control device for another pollutant and that, as a result, CO emissions would not be controlled.

ConocoPhillips agrees that adhering to good combustion practices is an available option for the three new thermal oxidizers that will be constructed as a part of the CORE Project.

**Proposed BACT Control**: The affected unit shall be maintained and operated with good combustion practice to reduce emissions of CO. Emissions of CO from the affected unit shall not exceed 0.082 lb/mmBtu, HHV.

3. Fluidized Catalytic Cracking Units (FCCU)

There are four possible options for controlling CO emissions from FCCUs:

- High Temperature Regeneration
- Thermal Oxidation (CO Heater),
- Catalytic Oxidation, or
- CO Combustion Promoter

Since FCCU 1 and FCCU 2 are partial combustion units while FCCU 3 is a complete combustion unit, BACT for FCCU 3 is evaluated separately. High temperature regeneration, catalytic oxidation, and CO combustion promoter are not technically feasible CO control options for FCCU 1 and FCCU 2 as described below:

FCCU 1 and FCCU 2 are both partial combustion units that are currently controlled by separate CO heaters. Therefore, high temperature regeneration is not feasible for these units.

FCCU regenerator flue gas contains entrained particulate matter. Catalytic oxidation cannot be used on waste gas streams containing particulate due to the potential for catalyst fouling, which prohibits oxidation. Both FCCU 1 and FCCU 2 will employ a wet gas scrubber for particulate removal and placing a catalytic oxidizer downstream of the wet gas scrubbers has also been considered.

Catalytic oxidizers are designed so that the waste gases pass through a flame area and then through a catalyst bed where CO is oxidized to $CO_2$ at temperatures of 650 to 1,000 °F. The FCCU 1 and FCCU 2 regenerator flue gas will exit the wet gas scrubbers at 175 °F. The process of reheating the flue gas will result in the formation of additional combustion products, including CO. Increasing fuel usage and creating more combustion pollutants to reduce CO from the FCCU regenerator is an unacceptable compromise. Furthermore, the RBLC has no record of this technology being successfully used as CO control for these emissions sources. Therefore, catalytic oxidation is technically and environmentally infeasible for CO control of the modified FCCUs.

The low CO concentrations resulting from the operation of the CO heaters for FCCU 1 and FCCU 2 makes the use of CO combustion promoter unnecessary for these units. In addition, the use of CO combustion promoters can increase $NO_X$ emissions, which could have negative environmental impacts since the refinery is located in an ozone non-attainment area. Therefore, the use of CO combustion promoter is technically and environmentally infeasible for CO control of the modified FCCU 1 and FCCU 2.

The only technically feasible CO control option for FCCU 1 and FCCU 2 is the use of CO heaters.

For FCCU 3, the use of catalytic oxidation is technically infeasible for the same reasons as described above for FCCU 1 and FCCU 2. Also, thermal oxidation is technically infeasible for the following reasons:

FCCU 3 is a full combustion unit (i.e., a high temperature regenerator). Based on this design, the CO concentrations in the regenerator flue gas are well below the levels needed for the operation of a CO heater. Based on the RBLC review, there are no full combustion units utilizing a CO heater. Therefore, this control option is technically infeasible for FCCU 3.

**Proposed BACT Control**: The affected units FCCU 1 and FCCU 2 shall be controlled by venting emissions to a CO heater or other combustion device. The affected unit FCCU 3 shall utilize high temperature regeneration, i.e., full combustion, supplemented with CO promoter as needed to comply with the applicable hourly limit. Emissions of CO from affected units FCCU 1 and FCCU 2 shall not exceed 100 ppmdv corrected to 0 percent oxygen on a 365 day rolling average and 500 ppmdv corrected to 0 percent oxygen on an hourly average basis. Emissions of CO from FCCU 3 shall not exceed 150 ppmdv corrected to 0 percent oxygen on a 365 day rolling average and 500 ppmdv corrected to 0 percent oxygen on an hourly average basis.

4. Flares

The RBLC database shows four BACT determinations for the control of CO emissions from refinery flares in recent years. None of these previous determinations identifies the use of a CO control technology or methodology.

Due to the inherent design of a flare (i.e., the pilot gas exhaust does not pass through a duct or stack), it is not possible to use any post-combustion air pollutant control devices. Furthermore, no process changes that would reduce the CO emissions exist. Since the flares serve as VOM control devices in an 8-hour ozone non-attainment area, their operation is necessary. Therefore, no CO control technologies exist for the new flares.

**Proposed BACT Control:** The affected units shall be operated with equipment design specifications and work practices consistent with the NSPS requirements for flares in 40 CFR 60.18. Gaseous fuels meeting the requirements of 40 CFR 60.104(a)(1) and process upset gases (as defined in 40 CFR 60.101(e)) shall be the only gases combusted in the affected units.

5. Sulfur Recovery Units (SRU)

The only CO emissions control strategy identified in the RBLC database for refinery fuel gas or natural gas fired thermal oxidizers is to adhere to good combustion practices. Several of the previous BACT determinations noted that the thermal oxidizer acts as a control device for another pollutant and that, as a result, CO emissions would not be controlled.

ConocoPhillips agrees that adhering to good combustion practices is an available option for the three new thermal oxidizers that will be constructed as a part of the CORE Project.

**Proposed BACT Control:** The thermal oxidizer on each affected unit shall be maintained and operated with good combustion practice to reduce emissions of CO. Emissions of CO from the affected units shall not exceed 0.082 lb/mmBtu, HHV.

6. Loading Rack Control Device (e.g. vapor combustion device)

Due to the inherent nature of combustion-based emission control devices, it is not possible to use any post-combustion control devices for CO. Since the vapor combustion device would serve as a control device for emissions of VOM, its operation is necessary. Therefore, no CO control technologies are available for this device.

**Proposed BACT Control:** The control device for the loading rack shall be maintained and operated with good combustion practices to reduce emissions of CO. Emissions of CO from the control system shall not exceed 0.0835 lb/1,000 gallons of petroleum product loaded, during loading of material.

## B. AIR QUALITY ANALYSIS

A Significant Impact Analysis was completed for CO emissions to evaluate the impacts of this project on ambient air quality. The proposed project will only affect the CO emission rates from certain new and modified emission units at the Refinery and Products Terminal, therefore only these emission units were addressed in this analysis. Furthermore, the modeled CO emission rate for the modified emission units included only the incremental increase attributable to the project, or the net emission increase. The maximum modeled ambient concentrations were then compared to the corresponding PSD significant impact levels for CO and the CO monitoring *de minimis* level.

The CO emissions rates that were modeled for the combustion units at the facilities were based on full-load, reduced-load (i.e., 50% and 75% load), and start-up mode (i.e., 25%, 50%, and 75% load) analyses as directed by the Illinois EPA.

This analysis determined that modeled concentrations from the project did not exceed the PSD significant impact levels or the monitoring *de minimis* level (575 $\mu g/m^3$, 8-hour average) for any load scenario. Therefore, no further analysis or pre-construction monitoring was required for CO.

Maximum Modeled CO Impacts for the Full Load Analysis ($\mu g/m^3$)

| Averaging Period | Maximum Concentration | PSD Significant Impact Level | NAAQS |
|---|---|---|---|
| 1-hour | 222.1 | 2,000 | 40,000 |
| 8-hour | 173.0 | 500 | 10,000 |

Maximum Modeled CO Impacts for the 75% Load Analysis ($\mu g/m^3$)

| Averaging Period | Maximum Concentration | PSD Significant Impact Level | NAAQS |
|---|---|---|---|
| 1-hour | 188.8 | 2,000 | 40,000 |
| 8-hour | 142.2 | 500 | 10,000 |

Maximum Modeled CO Impacts for the 50% Load Analysis ($\mu g/m^3$)

| Averaging Period | Maximum Concentration | PSD Significant | NAAQS |
|---|---|---|---|

| | | Impact Level | |
|---|---|---|---|
| 1-hour | 146.1 | 2,000 | 40,000 |
| 8-hour | 110.7 | 500 | 10,000 |

Maximum Modeled CO Impacts for the 25% Load Analysis (µg/$m^3$)

| Averaging Period | Maximum Concentration | PSD Significant Impact Level | NAAQS |
|---|---|---|---|
| 1-hour | 131.0 | 2,000 | 40,000 |
| 8-hour | 82.3 | 500 | 10,000 |

### C. IMPACTS ON SOIL, VEGETATION AND VISIBILITY

ConocoPhillips addressed the potential impact of the CO emissions of the proposed project on soils, vegetation, and visibility. The assessment concluded that CO emissions would not adversely impact soil, vegetation or visibility in the Wood River area. Since the maximum air quality impacts predicted for CO emissions from the project are below the PSD significant impact levels, the existing air quality should not be measurably affected by this project.

## VI. NON-ATTAINMENT NEW SOURCE REVIEW (NA NSR)

ConocoPhillips is a major stationary source that is located in an area that is classified as moderate non-attainment for the 8-hour ozone standard. The emissions increases associated with the CORE Project at the Wood River refinery and terminal are significant for VOM since the net emission increase is greater than 40 tons per year. Therefore, it is necessary to apply for an NA NSR permit for VOM emissions in accordance with the applicable requirements of 35 IAC Part 203 Subpart C, as well as 40 CFR Part 51 Appendix S.

### A. LOWEST ACHIEVABLE EMISSION RATE (LAER)

The proposed CORE Project triggers NA NSR permitting requirements for VOM emissions since the refinery and the terminal are located in a non-attainment area for ozone. The new and modified units that will contribute to the increase in VOM emissions include:

- Eight process heaters,
- Two existing fluidized catalytic cracking units,
- One restarted fluidized catalytic cracking unit,
- Two new flares,
- Three thermal oxidizers (associated with the two new sulfur recovery units and the cracked gas plant),
- One new diesel storage tank,
- Three new cooling water towers,
- New waste water treatment equipment,
- Fugitive emissions (e.g., leaks from valves, flanges, etc.),
- Two new crude oil storage tanks,
- One new methanol storage tank, and

- One existing sour water storage tank.
- One existing loading rack
- One gasoline tank
- Two ethanol tanks
- Two distillate tanks

For major modifications in non-attainment areas, LAER is the most stringent emission limitation derived from either of the following:

- The most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or
- The most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emissions limitation contained in a SIP for a category of source must be considered LAER unless either a more stringent emission limitation has been achieved in practice or the applicant is able to demonstrate that the SIP limitation is not achievable in this case. In addition, LAER cannot be less stringent than any applicable NSPS requirement.

1. Process Heaters

The only VOM emissions control technology identified in the RBLC database for refinery fuel gas or natural gas fired process heaters is to adhere to good combustion practices. Based on the manufacturer's guarantee, each of the affected process heaters will be able to meet a VOM emission rate of 0.003 lb/MMBtu through the use of good combustion practices.

**Proposed LAER Control:** The affected heaters shall be maintained and operated with good combustion practices to reduce emission of VOM. Emissions of VOM from the affected heaters shall not exceed 0.003 lb/mmBtu, HHV.

2. Distilling West (DW) Cracked Gas Plant

The RBLC database states for past permits that since thermal oxidizers are themselves control devices, no additional control of the VOM that is generated through the combustion of combustion of supplementary fuel. Therefore, no VOM control technologies are necessary for the three new thermal oxidizers.

**Proposed LAER Control:** The affected unit shall be maintained and operated with good combustion practice to reduce emissions of VOM. Emissions of VOM from the affected unit shall not exceed 0.005 lb/mmBtu, HHV.

3. Components

The only method of controlling VOM emissions from fugitive equipment leaks identified in the RBLC database is the application of a Leak Detection and Repair (LDAR) program.

**Proposed LAER Control:** Affected components shall comply with the applicable general standards in 40 CFR 63.162 (40 CFR 63, Subpart H) for components in gas/vapor service, light liquid service, and heavy liquid service, and the following specific standards:

- Affected pumps (light liquid service) shall comply with the standards for pumps in light liquid service in 40 CFR 63.163.
- Affected compressors (gas service) shall comply with the standards for compressors in 40 CFR 63.164.
- Affected pressure relief devices (gas/vapor service) shall comply with the standards for pressure relief devices in gas/vapor service in 40 CFR 63.165.
- Affected sampling connection systems shall comply with the standards for sampling connection systems in 40 CFR 63.166.
- Affected open-ended valves or lines shall comply with the standards for open-ended valves or lines in 40 CFR 63.167.
- Affected valves (gas/vapor service and light liquid service) shall comply with the standards for valves in gas/vapor service and in light liquid service in 40 CFR 63.168.
- Affected pumps, valves, and connectors in heavy liquid service, shall comply with the standards for pumps, valves, and connectors in heavy liquid service in 40 CFR 63.169.

For affected components, the Permittee shall monitor the component to detect leaks by the method specified in 40 CFR 63.180(b), except that a more stringent definition of a leak shall apply, i.e., an instrument reading of 500 parts per million or greater from valves in gas and light liquid service and an instrument reading of 2,000 ppm or greater from pumps in light liquid service shall be considered a leak.

Emissions of VOM from the new affected components at the refinery shall not exceed 45.8 tons per year. Emissions of VOM from the affected components and existing components at the terminal shall not exceed 2.5 tons per year (combined). Compliance with these limits shall be determined using published USEPA methodology for determining VOM emissions from leaking components.

4. Storage Tanks

ConocoPhillips proposes to satisfy LAER for refinery tanks A-98, A-99, and 80-6 and terminal tanks 209, 210, 2003 through the use of fixed roof tanks in combination with dual-seal internal floating roof tanks. All deck fittings will be gasketed and, where possible, will utilize an additional fabric sleeve to further minimize VOM emissions. This proposed tank design meets the most stringent of the federal and state rules regulating petroleum liquid storage tanks installed at petroleum refineries and terminals.

VOM emissions are expected to be small for the proposed tank A-126, methanol storage tank, and distillate storage tanks 2001 and 2002 due to the low vapor pressure of the materials being stored. The RBLC database states for low vapor pressure storage tanks that the VOM control is typically limiting the maximum vapor pressure of the material stored in the tank.

**Proposed LAER Control:**

- Affected tanks A-98, A-99, 80-6, 209, 210, 2003 shall be controlled by an internal floating roof (i.e., domed external floating roof for tank 80-6) with a primary liquid-mounted seal consistent with the control requirements of the 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC and a secondary rim-mounted seal.
- The true vapor pressure of the material stored in the affected tank A-126 shall not exceed 0.09 psia at the maximum monthly average storage temperature.
- The true vapor pressure of the material stored in the affected methanol tank shall not exceed 3.5 psia at the maximum monthly average storage temperature.
- The true vapor pressure of the material stored in the affected distillate tanks shall not exceed 0.1 psia at the maximum storage temperature.

5. Fluidized Catalytic Cracking Units (FCCU)

The only VOM emissions control strategy identified in the RBLC database for fluidized catalytic cracking units is to adhere to good combustion practices. ConocoPhillips proposes that a VOM emission rate of 0.05 pounds per thousand pounds of coke burned (lb/Mlb coke) be established as the LAER emission limit for FCCU 1 and FCCU 2.

FCCU 3 was previously included in a PSD permit that was issued by the IEPA to Premcor. This VOM emissions from FCCU 3 stated in that permit was based upon the assumption that 95 percent of the VOM in the regenerator will be destroyed due to operating temperatures that range form 1,200 to 1,400 F. Therefore, the VOM emission factor of 11 lb/Mbbl for Premcor's PSD permit was equal to 5 percent of the AP-42 emission factor. To be consistent with the 2002 Premcor PSD permit, ConocoPhillips also proposes that the LAER limit for VOM emissions from FCCU 3 be 11 lb/Mbbl.

**Proposed LAER Control:** The affected units shall be maintained and operated with good air pollution control practice to reduce emissions of VOM. Emissions of VOM from FCCU 1 and FCCU 2 shall not exceed 0.05 lb/1000 lb of coke burned. Emissions of VOM from FCCU 3 shall not exceed 11 lb/1000 bbl of feed.

6. Cooling Water Towers

Based on the review of the RBLC and other sources of information, drift loss eliminators are considered LAER for controlling VOM emissions from the three new cooling water towers. With this control, the drift loss from the three cooling towers will be limited to 0.006 percent.

**Proposed LAER Control:** The design drift loss from the drift eliminators on the affected units shall not exceed 0.006 percent (12-month rolling average).

7. Flares

The RBLC database states for past permits that since flares are themselves VOM control devices, no additional control of the VOM that is generated through the combustion of pilot fuel gas is necessary. Therefore, no additional VOM control technologies are necessary for the two new flares.

**Proposed LAER Control:** The affected units shall be operated with equipment design specifications and work practices consistent with the NSPS requirements for flares in 40 CFR 60.18. Gaseous fuels meeting the requirements of 40 CFR 60.104(a)(1) and process upset gases (as defined in 40 CFR 60.101(e)) shall be the only gases combusted in the affected units.

8. Sulfur Recovery Units (SRU)

The RBLC database states for past permits that since thermal oxidizers are themselves control devices, no additional control of the VOM that is generated through the combustion of combustion of supplementary fuel. Therefore, no VOM control technologies are necessary for the three new thermal oxidizers.

**Proposed LAER Control:** The thermal oxidizer on each affected unit shall be maintained and operated with good combustion practice to reduce emissions of VOM. Emissions of VOM from each affected unit shall not exceed 0.005 lb/mmBtu, HHV.

9. Wastewater Treatment Plant (WWTP)

It is not necessary to capture and control emissions from the scrubber solids clarifiers since the hydrocarbon content of the material in these clarifiers is negligible (i.e., the quantity of hydrocarbon material reaching the WGS at each FCCU will be minimal since nearly all hydrocarbon in these exhaust streams will be combusted in the CO heaters and/or FCCUs prior to reaching the WGS). Also, it is not possible to capture and control emissions from Ponds 1 and 2. Note that aerobic conditions are necessary for proper operation of the activated sludge areas in Ponds 1 and 2. Furthermore, since the denitrification zone will be located at the end of Pond 2, hydrocarbons should be destroyed prior to reaching this zone. Therefore the denitrification zone (and downstream secondary clarifier) are not a source of significant VOM emissions.

**Proposed LAER Control:** The WWTP shall be operated in accordance with good air pollution control practice to minimize emissions of VOM.

10. Loading Rack Control Device (e.g., Vapor Combustion Device)

The two types of technologies for controlling VOM emissions from a loading rack are vapor combustion and vapor recovery. Both of these options achieve a similar level of VOM control and both are technically feasible. The New Source Performance Standards require loading racks achieve 35 mg/L of gasoline loaded and the National Emission Standards for Hazardous Air Pollutants require loading racks achieve 10 mg/L of gasoline loaded. According to the RBLC, a loading rack control system is capable of achieving an emission rate of less than 7 mg/L of gasoline loaded.

**Proposed LAER Control:** Emissions of VOM from the loading rack control device (e.g., vapor combustion unit), expressed as Total Organic Compounds shall not exceed 7.0 mg/L of gasoline loaded.

## B. EMISSION OFFSETS

The emissions associated with a major project in a nonattainment area must not interfere with the state plan to achieve attainment of the national ambient air quality standards. This plan consists of new programs and regulations designed to achieve the national standards and is based on a detailed analysis of current and projected emission and air quality levels. In order to account for the emissions increase from a major project proposed in a nonattainment area, the applicant must provide compensating emission reductions from other sources that have not been relied on in the attainment plan. These emission reductions are commonly referred to as emission offsets. ConocoPhillips must obtain creditable emission decreases or offsets from the existing sources in the St. Louis/Metro-East ozone nonattainment area. Because this area is a moderate nonattainment area, emission offsets must be provided at a ratio of 1.15:1.0, i.e., for each ton of VOM emissions from the project, 1.15 ton of offsets must be provided. At this ratio, ConocoPhillips is required to provide VOM emission offsets of 440.1 tons per year.

## C. COMPLIANCE BY EXISTING SOURCES

ConocoPhillips has stated that the refinery and terminal are in compliance or subject to formal programs, i.e., consent decrees, to come into compliance with all applicable air pollution control requirements. In addition, other major sources in Illinois owned and operated by ConocoPhillips are also in compliance.

## D. ANALYSIS OF ALTERNATIVES

The Illinois EPA has broadly considered alternatives to this project, as required by 35 IAC 203.306. Much of the equipment requiring LAER is existing equipment on site which has been idle. Alternative sites would not possess the necessary piping infrastructure, and alternative sizes of equipment would not necessarily meet the consumer demands for gasoline supply. Accordingly, the benefits of the proposed project significantly outweigh its environmental and social costs.

## VII. PERMIT CONDITIONS

The conditions of the permit set forth the air pollution control requirements that the project must meet. These requirements include the applicable emission standards that apply to the project. They also include the measures that must be used and the emission limits that must be met as BACT for emissions of CO and LAER for emissions of VOM.

The permit also establishes enforceable limitations on the amount of emissions for which the project is permitted. In addition to annual limitations on emissions, the permit includes short-term emission limitations and operational limitations, as needed to provide practical enforceability of the annual emission limitations.

The permit also establishes appropriate compliance procedures for the ongoing operation of the plant, including requirements for emission testing, required work practices, operational monitoring, recordkeeping, and reporting. These measures are imposed to assure that the operation and emissions of the plant are appropriately tracked to confirm compliance with the various limitations and requirements established for individual emission units.

## VIII. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the application for the proposed project meets applicable state and federal air pollution control requirements. The Illinois EPA is therefore proposing to issue construction permits for the project.

Comments are requested on this proposed action by the Illinois EPA and the conditions of the draft permits.